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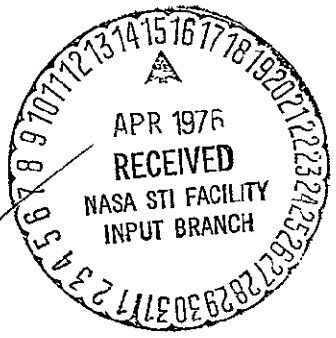


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# A PRELIMINARY SYSTEMS-ENGINEERING STUDY OF AN ADVANCED NUCLEAR-ELECTROLYTIC HYDROGEN-PRODUCTION FACILITY

Final Report



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Submitted to

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION
MARSHALL SPACE FLIGHT CENTER, ALABAMA 35812

IGT Project 8962
Contract NAS 8-30757
Modification No. 1



December, 1975

# SUMMARY AND FINDINGS

An advanced nuclear-electrolytic hydrogen-production facility concept has been synthesized at a conceptual level with the objective of minimizing estimated hydrogen-production costs. The concept is a closely-integrated, fully-dedicated (only hydrogen energy is produced) system whose components and subsystems are predicated on "1985 technology." Such a facility would become available in the 1990's assuming a requisite research and development program.

The principal components of the advanced-facility concept are —

- High-temperature gas-cooled reactor (HTGR) operating a helium-Brayton/ammonia-Rankine binary cycle with a helium reactor-core exit temperature of 980°C (1800°F)
- Acyclic d-c generators (obviates rectification)
- High-pressure, high-current-density electrolyzers based on solid-polymer electrolyte (SPE) technology (obviates mechanical compression).

Based on an assumed 3000 MWt HTGR the facility is capable of producing 8.7 million std cu m/day (325 million SCF/day) of hydrogen at pipeline conditions, 6900 kPa (1000 psia). Coproduct oxygen is also available at pipeline conditions at one-half this volume.

The study's basic thesis that a fully-dedicated, nuclear-based hydrogen-production facility employing water electrolysis can provide hydrogen competitively priced with other nuclear water-splitting processes seems substantiated.

Further, it has been shown that the incorporation of advanced technology throughout in the synthesis of the nuclear-electrolytic facility concept provides for a step-function improvement in overall nuclear-to-hydrogen energy-conversion efficiency. It provides an overall efficiency of about 43%, as compared with 25% for a contemporary nuclear-electric plant powering close-coupled contemporary industrial electrolyzers.

The corresponding hydrogen-production cost estimates (mid-1975 dollars and utility financing) are $4.81/GJ vs. $9.36/GJ ($5.07/million Btu vs. $9.88/million Btu). This is a cost reduction of 48% from the baseline contemporary facility concept.

Significant further hydrogen cost reductions are possible if one or more of the following departures from the nominal case for the advanced concept are made:

- Facility capacity factor is increased above 80%
- Coproduct oxygen is sold for byproduct credit (as opposed to being vented to the environment)
- Multiples of the facility are constructed in an optimum time-sequence, and operated as an integrated hydrogen-production complex supplying a large pipeline with product, and unit scale-up is performed
- Further technological advances leading to improved efficiencies and/or lower specific equipment cost are made available, e.g., increased reactor outlet temperatures.

These potential cost improvements beyond the nominal case advanced facility system are summarized in the table below.

ESTIMATED HYDROGEN-PRODUCTION COSTS

| System | $/GJ | $/million BTU |
|---|---|---|
| Baseline Case (LWR) | 9.36 | 9.88 |
| Nominal Advanced Case (HTGR) | 4.81 | 5.07 |
| Advanced Case (With $10/ton Oxygen Credit) | 4.19 | 4.42 |
| Advanced Case (With 90% vs. 80% Capacity Factor) | 4.37 | 4.61 |
| Advanced Case (With Twin Nuclear Reactors Instead of a Single Unit) | 4.13 | 4.35 |
| Advanced Case (With Oxygen Credit, 90% Capacity Factor and Twin Nuclear Units) | 3.00 | 3.15 |

Without question, the nuclear-to-shaftpower subsystem (i.e., the "nuclear plant" less generators) is dominant in its contribution to the achievement of both the high efficiency and the low cost (relative to the baseline current system). This fact is likely to be shared with alternative nuclear water-splitting processes under investigation.

The nuclear subsystem quite literally establishes the basic nuclear-to-hydrogen energy-conversion efficiency level of the system as the remaining process steps, electricity generation and water electrolysis, can be carried out at relatively high efficiencies by virtue of advanced technology equipment

and optimal integration in system synthesis. Altogether, the remaining shaftpower-to-hydrogen (at pipeline conditions) energy-conversion efficiency is 86% for the advanced system, vs. 74% for the current-technology baseline case.

The advanced concept's 980°C (1800°F) high-temperature gas-cooled reactor (HTGR) and binary-cycle shaftpower extraction approach yields a conversion efficiency of slightly above 50%. This is in sharp contrast to the contemporary light-water reactor (LWR) potential of about 34%.

In terms of net capital-related costs, the nuclear-to-shaftpower subsystem represents about 90% of the system total. However, this cost, in terms equivalent to dollars-per-installed kilowatt, is considerably lower than an LWR because of the much higher "productivity" of the nuclear plant in view of its 47% higher efficiency.

Because the facility is uniquely devoted to the production of hydrogen, several important new features (vis-a-vis the contemporary nuclear-electrolysis baseline) have been incorporated in the advanced concept. These considerably simplify the makeup of the plant with accompanying gains in efficiency and hydrogen-production costs.

Acyclic d-c generators are employed in lieu of conventional a-c generators in use for utility electricity generation. Not only are acyclics projected to be less costly than a-c machines with equal efficiency, the usual power conditioning steps required to match electrolyzer input requirements are completely eliminated. This saves a cost increment that is typically two or three times the generator cost, and a loss in conversion efficiency of 3% to 4%. System maintenance and operations will gain as well.

High-pressure, high-current-density electrolyzers based on the solid-polymer-electrolyte design approach are incorporated, being directly connected to the acyclic generators with short-run water-cooled aluminum busbars. These provide hydrogen (and oxygen) at pipeline pressure (6900 kPa, 1000 psi) directly, obviating expensive mechanical compression requirements. The high specific output of the advanced electrolyzers provides very significantly reduced equipment cost, while maintaining a high electrolysis efficiency level.

An assessment of the technological implications of the advanced-facility concept reveals the following principal needs or program goals, if the concept is to be pursued:

- HTGR capable of sustained operation at coolant-exit temperatures of 980°C (1800°F)
- Large acyclic (d-c) generators with liquid-metal current collectors
- High-current-density, high-efficiency electrolyzers capable of elevated pressure operation.

## ACKNOWLEDGMENTS

The Institute of Gas Technology received active support from a number of organizations and individuals in this systems-engineering assessment of an advanced nuclear-electrolytic hydrogen-production facility concept, and is pleased to acknowledge their support and contributions to this study.

The General Atomic Co., San Diego, provided significant design and cost information on the High-Temperature Gas-Cooled Reactor (HTGR) nuclear-to-shaftpower subsystem via a nominal consultative subcontract to IGT. The GA work was coordinated by Mr. Ralph L. Cummings with technical contributions from Messrs. John Niell and Robert G. Adams.

The General Electric Co.'s AC Motor and Generator Business Division, Schenectady, New York, supplied preliminary data on the acyclic d-c generator. Mr. L. M. Harvey and Mr. J R. Burnett assisted in this, and in consultation with IGT on the interfacing of the generators with the nuclear prime mover.

Technical information and advisory comments on superconducting d-c transmission systems, for electrolyzer power bussing, was received from the Los Alamos Scientific Laboratory, New Mexico. Dr. Fredrick J. Edeskuty, Director of the LASL d-c superconducting transmission project and Mr. John W. Dean assisted the study in this connection.

Significant information on electrolyzers was gained from three manufacturers, one for each basic type of electrolyzer examined in the study. Messrs. R. D. Feldwick and W. T. Kincaide of the Energy Systems group of Teledyne Isotopes, Timonium, Maryland, advised on the bipolar alkaline-electrolyte system. Mr. A. K. Stuart, President and General Manager of The Electrolyzer Corporation Ltd., Toronto, supplied information about the unipolar alkaline-electrolyte type system. Mr. L. J. Nutall of the General Electric Co. Aircraft Equipment Division, Wilmington, Massachusetts, provided information on the bipolar solid-polymer-electrolyte (SPE) system.

The support of the George C. Marshall Space Flight Center of NASA, which made this study possible, is gratefully acknowledged. Mr. William D. Powers was the Contracting Officer's Representative.

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## 1. INTRODUCTION AND BACKGROUND

The Institute of Gas Technology has performed a conceptual-level systems-engineering assessment of an advanced-technology, fully-dedicated nuclear-electrolytic hydrogen-production facility. This work was carried out under the sponsorship of the George C. Marshall Space Flight Center of the National Aeronautics and Space Administration under a $29,600 addendum to an in-existence contract (Contract NAS 8-30757) for a "Survey of Hydrogen Production and Utilization Methods." The final report for this main larger effort is listed under References Cited.*

The present study report represents an expanded derivative effort in the hydrogen-production area, and as such rather frequently references the Main Survey Report, particularly the section on water electrolysis. Material pertinent to the advanced nuclear-electrolytic concept that appears in the Main Survey Report is not reiterated here in the interest of brevity. Therefore, the reader interested in examining the substantial technical background of hydrogen production by water electrolysis, as well as other methods, is urged to acquire a copy of the Main Survey Report.

The utilization of nuclear energy to produce hydrogen energy (hydrogen as a fuel component, and hydrogen-oxygen reactants as energy commodities) is of fundamental significance in the sphere of future energy supplies. Nuclear-hydrogen is quite analogous to nuclear-electricity in that primary nuclear energy is converted to a "synthetic energy form" in both cases for the purposes of deploying this energy.

Quite obviously, nuclear electricity is today playing an expanding role in electrical-utility generation systems. About 8% of the electricity generated in the United States in 1975 was from nuclear plants. By 1985, it is expected that up to 50% of the nation's electricity will be produced from nuclear facilities. Improved generation efficiencies, and much more effective utilization of the nation's large uranium resources, could be achieved with further development and commercialization of high-temperature and breeder reactors, respectively.

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* The Main Survey Report is listed ahead of the References section but is not numbered as a reference because of its close relationship with the present report as discussed. It will be referred to in this report as "the Main Survey Report."

In contrast to such on-going nuclear-electric developments, nuclear-hydrogen is today strictly at the concept stage. This is understandable since hydrogen is not yet an in-use fuel-energy form, except in very specialized circumstances, e.g., as a rocket fuel. As documented in the Main Survey Report, hydrogen is, however, an important chemical intermediary in refining petroleum, and in ammonia and methanol production. As such, it now represents about 1% of U.S. energy consumption.

Looking ahead, based on prospects described in a number of recent energy planning and assessment documents such as IGT's "A Hydrogen Energy System"[25]* and the report of the NASA Hydrogen Energy Systems Technology Study[32]†, hydrogen may well be developed as a basic medium for energy delivery in the decades ahead. The forcing issue here is, of course, declining fossil fuel supplies in the face of increasing energy demands.

It is in this future energy-systems development context that it is appropriate to examine the nuclear production of hydrogen. Parallel study efforts focusing on coal-to-hydrogen and solar-energy production of hydrogen are needed as well. For it is coal, uranium, and solar energy that must be called upon to augment and eventually supplant diminishing fuel use of petroleum and natural gas in the decades ahead. Geothermal heat and controlled nuclear-fusion processes provide further possibilities for hydrogen production.

Thus nuclear-hydrogen may conceivably join nuclear-electricity as a second means of delivering nuclear energy. The two energy forms, electricity and hydrogen, appear to be complementary from the utilization standpoint with each capable of serving unique future needs: e.g., electrical lighting and hydrogen-fueled air transportation. There is also a large middle-ground of utilization that both forms can serve from a technical standpoint: for example, residential heating and cooling. As in the present

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* References are listed in the back of this report. They are indicated by small superscript numbers or directly as above. (e.g., Reference 25).

† This reference was not yet published at the time of the study, although some of its basic findings had been previewed as early as July 1975.[31]

case of energy-use competition between oil, natural gas and electricity, economics would presumably determine the relative share of the future market for electricity and hydrogen.

In viewing the evolution of a general hydrogen-energy system, hydrogen production clearly is of foremost importance.[25,31,32] Production means have been assessed in the Main Survey Report. Outside of hydrocarbon resources, the physical source of hydrogen is water. Those nuclear water-splitting processes currently under extensive consideration are listed below, along with a pertinent reference to a recent assessment:

- Nuclear-thermochemical hydrogen production[42]
- Nuclear-thermochemical/electrolytic (hybrid cycle) hydrogen production[16]
- Nuclear-electrolytic hydrogen production (this report).

Thermochemical and hybrid thermochemical/electrolytic* water-splitting processes can best be described as being in the laboratory stage today. (See the Main Survey Report's assessment of the state-of-the-art of thermochemical water-splitting and Westinghouse's assessment of a specific hybrid cycle.[17]) Both approaches offer promise of efficient and cost-effective hydrogen production if given extensive research and development.

In contrast, water electrolysis is a long-established industrial process. Further, where the electricity used in an electrolyzer is generated in nuclear plants, in a sense, nuclear-electrolytic hydrogen production is practiced today. In this respect, nuclear-electrolysis is an in-being, available technology. But today, in competition with hydrogen production from fossil fuels (and water), electrolysis remains a more expensive approach. Hence, it sees only limited use where very pure hydrogen and oxygen are needed and/or electricity is relatively inexpensive such as near large-scale hydroelectric generation facilities.

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*Also referred to as "thermo-electrochemical."

But fossil-fuel derived hydrogen must become significantly more expensive as hydrocarbon fuels become more scarce. Further, the economic gap between fossil-derived and nuclear-electrolytic hydrogen can be further closed if a special-purpose large-scale electrolysis facility were located adjacent to a nuclear electricity-generation facility. This would provide economies of scale and eliminate conventional electricity transmission and distribution costs. In addition to having "bus-bar power" immediately available, certain common-services arrangements between the nuclear-electric and water-electrolysis facilities might be arranged for further cost reductions.

Generally, when one speaks of nuclear-electrolysis for hydrogen production today, it is one of these two alternatives that is meant: 1) an electrolyzer facility operating on electricity purchased from a utility grid, in which a portion of the electricity is provided from nuclear plants, or 2) a co-located electrolysis facility and conventional nuclear generating plant based on contemporary light-water reactor technology.*

In contrast, the present study, and other assessments examining thermochemical[42] and hybrid thermochemical/electrolytic cycle[17] concepts, focus on a fully-dedicated and optimally-integrated nuclear hydrogen-production facility concept that employs technology not yet fully developed. As a nuclear-electrolytic hydrogen-production facility, the concept synthesized in this study comprises a third alternative, in addition to those approaches previously examined.

The objective here is to establish a concept potentially capable of effecting a significant further reduction in the estimated cost of hydrogen using nuclear electrolysis as a production means. Once documented, a "third technological alternative" will be available for making cost and efficiency comparisons on a broader basis.

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* The second alternative has been documented to establish a "baseline case" in this study. (See Section 3.) See also Reference 16.

In this context, then, what constitutes a truly advanced nuclear-electrolytic hydrogen-production facility concept? This "third step" in the progression noted above is likely to have the following basic features:

- Optimally-integrated, close-coupled equipment
- Fully-dedicated-to-hydrogen basis, free of any compromises due to the requirement for conventional electricity generation, for example
- Advanced-technology basis for components and subsystems throughout.

It is the study's thesis that such an advanced design would very significantly increase the overall conversion efficiency of nuclear heat to hydrogen. Several specific avenues can be cited (an example of each is noted in parentheses): increased subsystem efficiency (an HTGR in lieu of an LWR), elimination of unnecessary energy-conversion steps to decrease capital and operating costs (why generate a-c power and rectify it to d-c, when the latter is wanted for the electrolyzers and d-c generation is available?), physical close-coupling (electrical power bussing over several meters, as opposed to transmission over thousands of meters or further).

In order to achieve a comprehensive and systematic assessment of the advanced nuclear-electrolytic hydrogen production facility concept in this study, IGT has employed a systems-engineering approach. In brief, the components and subsystems constituting the facility (or system) were defined on a functional basis, rather than by prior-precedent. Interfacing of the principal subsystems, as these were progressively identified, was carried out by continuous liaison with appropriate manufacturers, associated with each subsystem area.* The final selection of operating equipment and design variables was thus done iteratively based on system optimization. The criterion was to minimize estimated hydrogen-production costs, and secondarily, to improve overall energy-conversion efficiency.

* See Acknowledgments.

Figure 1-1 pictorially represents the advanced system concept to be explored in the study as it was addressed at the onset. This report delineates

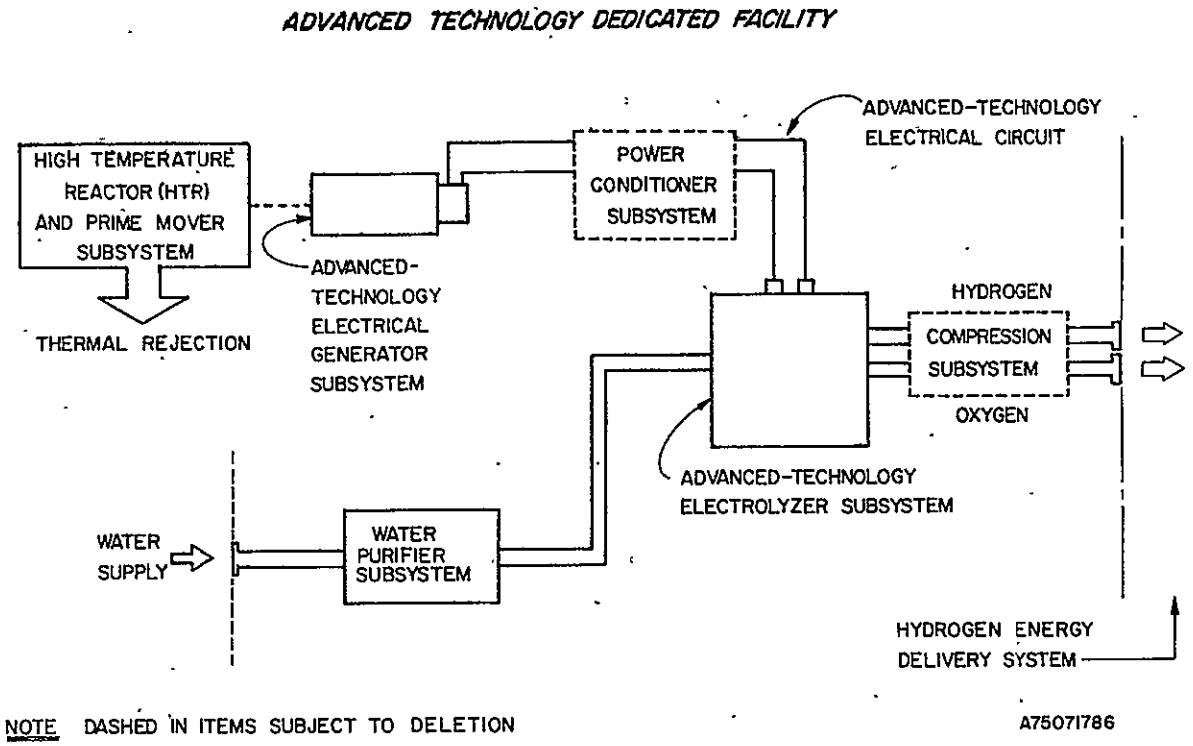


Figure 1-1. HYDROGEN-ENERGY PRODUCTION SYSTEM

the concept's evolution in terms of its specific equipment makeup, performance and operating efficiency, and, finally, its anticipated hydrogen production cost.

## 2. STUDY APPROACH AND SCOPE

### Objectives

This study has the objective of conceptualizing an advanced-technology, nuclear-electrolysis system for the production of hydrogen as explained in Section 1. Projected hydrogen-production costs and overall plant-efficiency estimates are to be developed for the concept.

This concept is an integrated and closely-coupled system based on a fully-dedicated high-temperature gas-cooled reactor (HTGR) in which all major facility equipment is selected and interfaced to optimize production cost and efficiency. The results of the study will hopefully serve as a useful "yardstick" for judging the potential attractiveness of other nuclear-hydrogen production processes, such as are under active investigation at IGT and elsewhere.[16,25,31,32,42] (See also the Main Survey Report for a review of ongoing work.) An "advanced-technology" base is used throughout.

### Study Approach

Today, electrolytic hydrogen production using nuclear energy is usually thought of in terms of an electrolysis facility "buying" electrical power from a utility system in which nuclear power is making a substantial contribution as base-load power. As discussed in the introduction, this concept is enhanced if one considers a "dedicated" but conventional nuclear-electric generation station associated directly with an electrolyzer facility. In either case, the concept is shown in block-diagram form in Figure 2-1. In effect, here there are two coupled systems (the solid-lined blocks) each with numerous subsystems, being used as interfaced subsystems. The interfacing means is strictly conventional 60-Hz electrical power. Though perhaps optimized as individual systems, they may not be optimum in the overall context of nuclear-to-hydrogen energy conversion. This larger, but nonoptimized "system" is shown as the dashed box in Figure 2-1.

Here we have the conventional case of the electrolyzer facility "buying" electricity from a nuclear generation facility. Electricity cost (mills/kWh) is the pivotal extrinsic variable that sets the cost of the produced hydrogen energy.

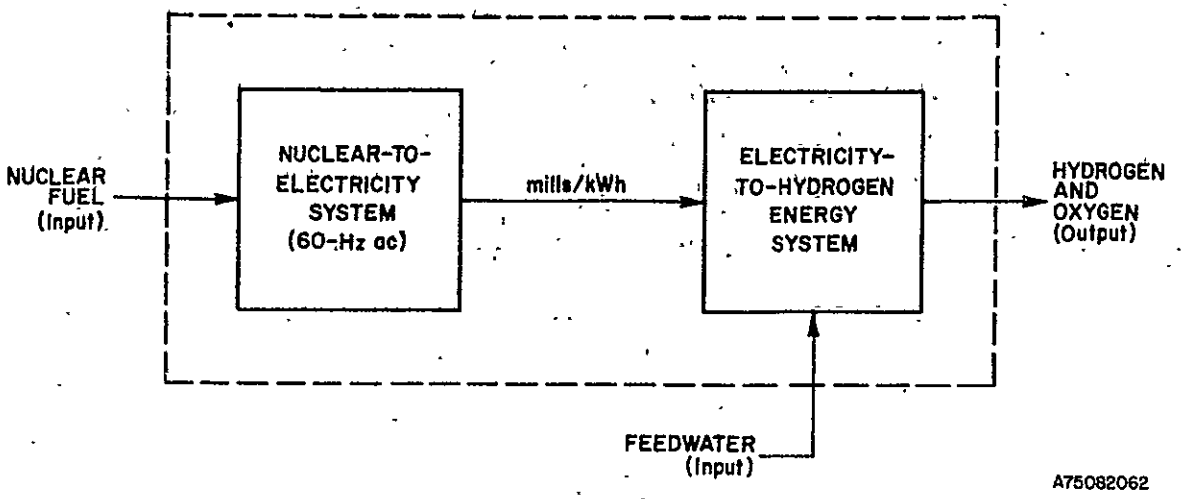


Figure 2-1. CONVENTIONAL NUCLEAR-ELECTROLYTIC HYDROGEN-PRODUCTION SCHEME

Looking ahead to the advanced nuclear-electrolytic production concept, in Figure 2-2, a collection of five yet-to-be-established subsystems are shown interfaced within an overall system. These are given functional names.

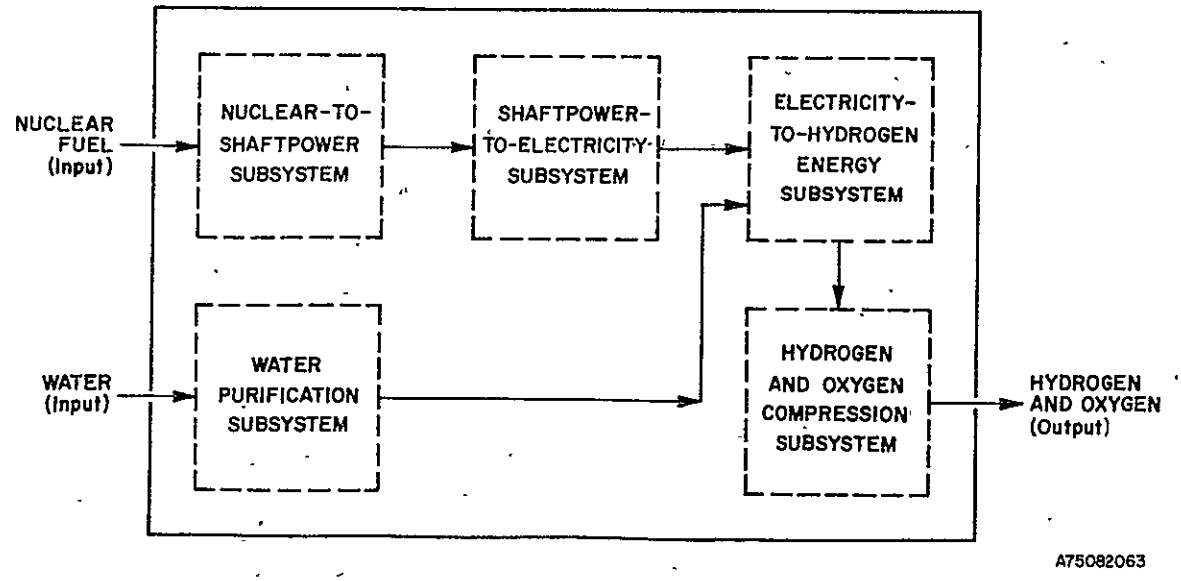


Figure 2-2. SUBSYSTEM AND INTERFACING LAYOUT OF THE ADVANCED NUCLEAR-ELECTROLYTIC PRODUCTION SYSTEM

The objective here is to avoid suboptimization (i. e., noninteractive optimization of the subsystems), in favor of reaching a truly optimum system configuration.

Among the technological advancements considered by IGT in the synthesis of this system (as a basic departure from the conventional nuclear-electrolytic scheme of Figure 2-1) are 1) an HTGR-operated binary thermodynamic cycle, i. e., topping/bottoming; 2) unconventional electrical generation means, e. g., acyclic d-c machines; 3) superconducting and/or cryoresistive d-c power bussing; and 4) advanced high-current density, high-pressure electrolyzer units.

Emphasis was given to the advantageous interfacing and physical arrangement of these subsystems. Energy conversion or conditioning steps, and associated physical equipment items, were eliminated where possible. In short, the study sought an optimized advanced-technology-based system that could be predicated, with reasonable confidence, at a conceptual level.

## Study Scope

Results of this preliminary assessment are presented in both technological and economic terms. The resulting advanced system concept (Figure 2-2) is contrasted with a base line, present-day, nuclear-electrolytic approach (Figure 2-1).

In addition to presenting preliminary costing and system efficiencies as derived in the study, those research and development goals and requirements judged necessary to be fulfilled in the context of physically achieving the subject advanced nuclear-electrolytic production concept are also delineated.

The study scope was constrained by the following assumed guidelines. In general, these were believed consistent with companion hydrogen-production studies, e. g., that of Reference 16:

1. The technology basis is that considered achievable by 1985, given that requisite research and development programs are to be actively pursued at sufficient funding levels (specific R&D areas are recommended in Section 10).

2. The advanced facility concept is assumed to be a stand-alone "grass roots" facility, but is not the first-of-a-kind or a demonstration unit (i.e., "learning-curve" and equipment manufacturing support base advantages are taken).

3. The costing is carried out on a utility-financing basis in terms of mid-1975 dollars using specific financing rules stated in the report. (See Section 9.)

Finally, the findings of the study must be recognized as those of a conceptual-level, exploratory inquiry. Based on the encouraging findings documented herein, it may now be appropriate to follow up this modest effort with a preliminary engineering-design evaluation, including more detailed cost estimates.

## 3. BASELINE NUCLEAR-ELECTROLYTIC HYDROGEN-PRODUCTION FACILITY

Non-fossil production of hydrogen and oxygen from water, as a potential large-scale endeavor, is usually currently envisioned as a state-of-the-art industrial electrolyzer serviced with electrical power from a conventional light-water nuclear electricity-generating facility. In this electrolysis case, overall efficiency of the nuclear-to-hydrogen energy process is usually rather low (20% to 25%).[16]

In defining the baseline case for the study, only those state-of-the-art features that could be placed on order or purchased in 1975 were assumed. The resulting facility equipment is therefore characterized as reflecting the best available current manufacturing practice, as determined by vendors; however, no effort was made to truly optimize the relationship between cost and efficiency. In establishing this baseline-case, effort was made to be consistent with previous nuclear hydrogen-production studies.[24, 47, 49] Plant siting considerations were based on the Atomic Energy Commission's hypothetical Middletown, USA.*

### Nuclear Electric Power Station

For the conventional plant, a dedicated pressurized-water reactor (PWR) facility is considered to have a thermal rating of 3000 MW and would be similar to PWR coming on-stream today (for example, units of the Zion nuclear power station of the Commonwealth Edison Co. and the Donald C. Cook nuclear plant of the Indiana and Michigan Electric Co.). A simplified schematic of the PWR power station is shown in Figure 3-1.

About 82,000 kg (90 tons) of enriched uranium oxide (3% to 5% $U^{235}$) are present in the reactor core. The fuel is usually formed into small, cylindrical pellets and placed in stainless steel or zirconium alloy rods that act as cladding to retain fission products.

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* This is described in Appendix A of "Guide for Economic Evaluation of Nuclear Reactor Plant Designs." [4]

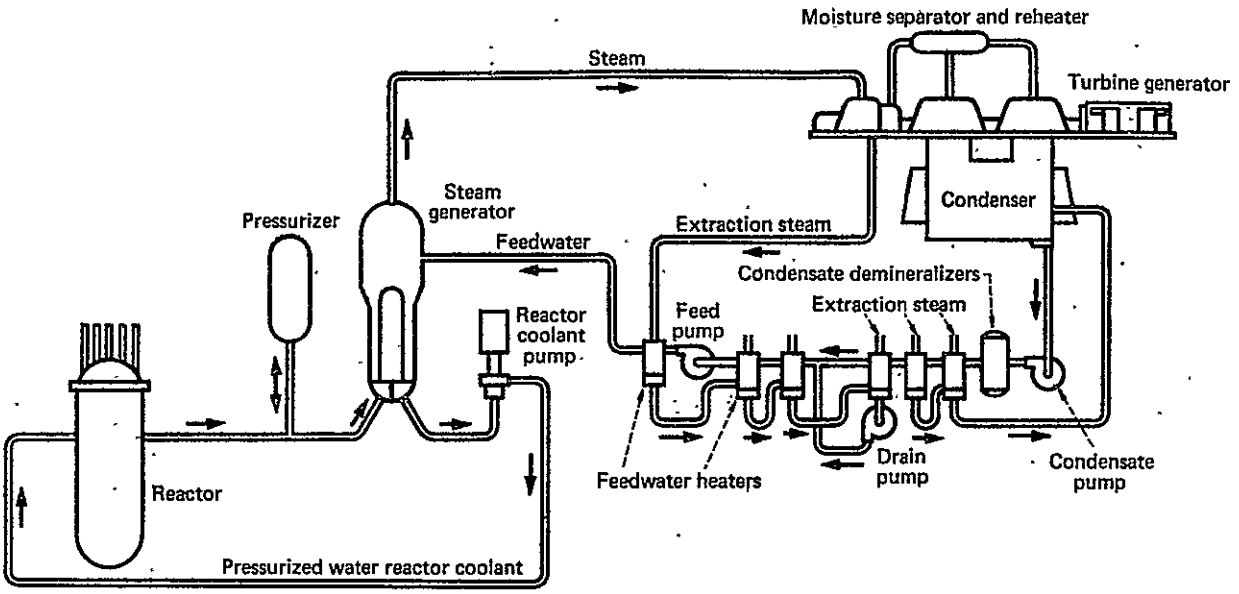


Figure 3-1. PWR FLOW SCHEMATIC[8]

Light water (i. e., ordinary water) is used to both moderate and cool the nuclear-fission process. Primary and secondary working-fluid loops are used. The primary closed-loop cooling water exits the reactor core at a temperature of about 320°C (600°F) and a pressure of 15,200 kPa (2200 psi). The primary coolant is circulated to a steam generator to produce steam in the secondary or turbine-driving loop at a temperature of 260°C (500°F) and 4800 kPa (700 psi).[11]

Work is extracted from the secondary steam loop by a single-shaft, condensing turbine. This turbogenerator would typically be a six-flow tandem-compound unit operating at 1800 rpm with a nominal electric power rating of 1000 MW. Provision is made to separate liquid moisture from the turbine stages as work is extracted to prevent blade erosion and obtain more efficient operation.[48] A 410 kPa (60 psi) closed hydrogen loop is used to cool the generator rotor, the stator is water cooled.[20] The machine is of the bleed-point type to provide steam for preheat of condensate feed and also to power the hydrogen compressors.

Water, or wet-cooling, is used to remove heat from the condenser section following the turbine. This heat is subsequently transferred to the environment via a natural-draft evaporative cooling tower.

Electrical Power-Conditioning Unit

A rectifier unit is required to supply the electrolyzer with direct current from the isolated phase supply system. A step-down transformer is needed to change the high voltage ac (22 kV) that was generated at and transmitted from the nuclear-electric plant to a voltage compatible with the rectifier and electrolyzer (1080 V). Conventional circuit breakers are used to switch the electrolyzers on and off. Silicon thyristors are used to rectify the a-c power. An electrical schematic is shown in Figure 3-2.

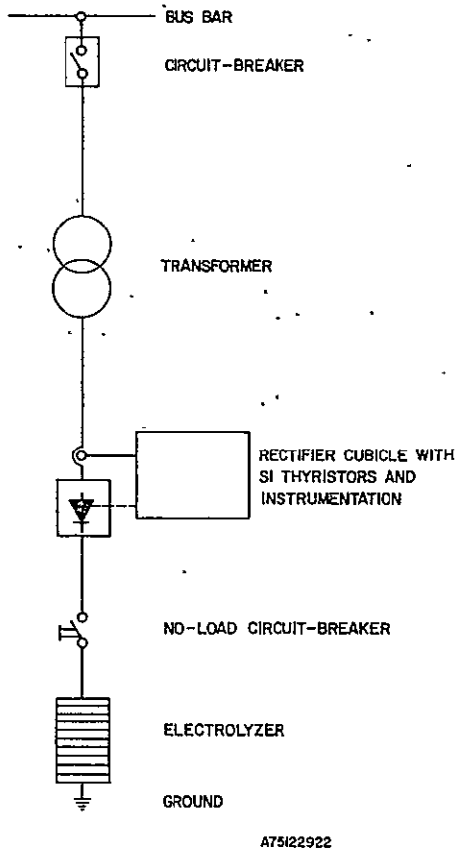


Figure 3-2. RECTIFIER UNIT WITH THYRISTORS[38]

Hydrogen-production rates can be varied by changing the d-c voltage. The power conditioning unit converts about 96% of the a-c input power to dc that is available for use by the electrolyzers.

Water-Purification Unit

The make-up feedwater must be of high purity because any contaminants would accumulate in the cell as water is electrolyzed thus causing operating and equipment problems. The water is passed through a series of ion exchangers resulting in a minimum water resistance of 1 MΩ/cm.[38] The purified water is stored in a stainless-steel tank for use in aqueous potassium-hydroxide solution electrolyte make-up.

Electrolyzer

The electrolysis of water has been adequately described in the Main Survey Report. A Lurgi electrolyzer* installation was selected as representative. Currently, Lurgi's largest unit (Type S 556) has a hydrogen capacity of 750 std cu m/hr (28,000 SCF/hr) of which 280 are required. The units are grouped into 14 sections of 20 units; a unit flow schematic diagram is shown in Figure 3-3. Each unit contains 139 plate-like cells.

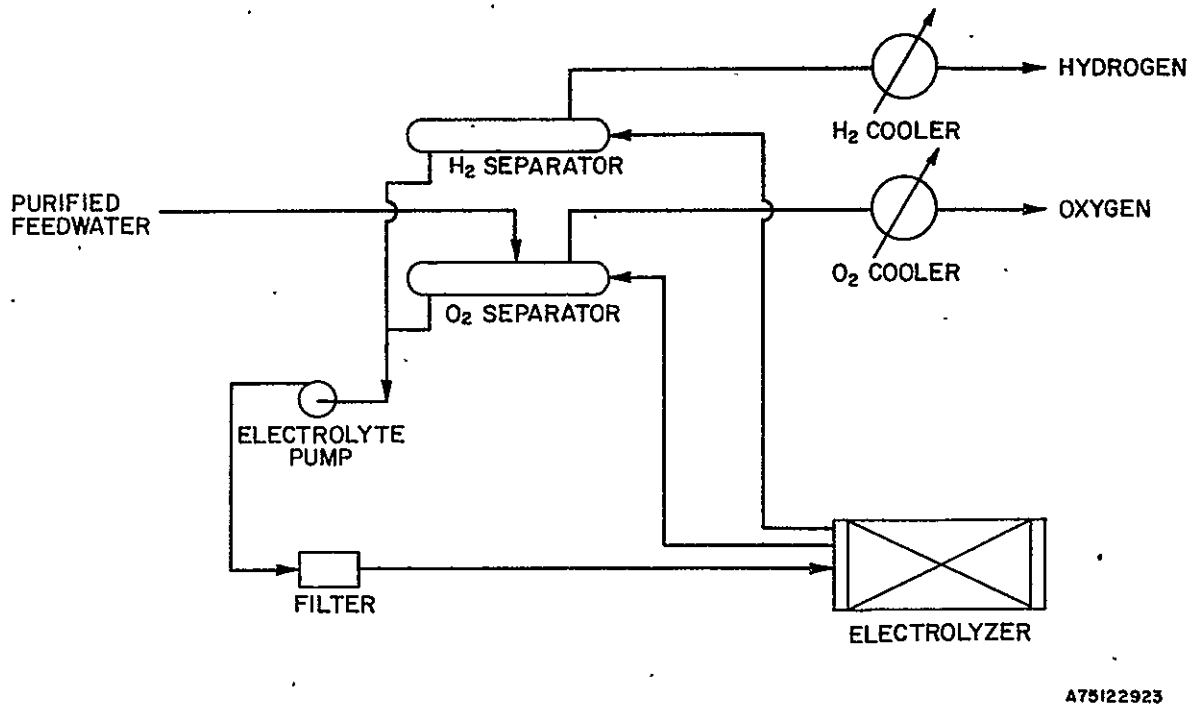


Figure 3-3. LURGI HIGH-PRESSURE WATER ELECTROLYZER UNIT

* Lurgi prefers the term "electrolytor."

Purified water is mixed with the system's electrolyte, filtered, and pumped into the electrolyzer. The 25% (wt) caustic-potash (KOH) solution electrolyte is circulated to the individual cells. As electrolysis proceeds the electrolyte/gas mixture flows upward through the cells. Hydrogen is collected in the cathode-side duct and oxygen in the anode-side duct. The separate hydrogen and oxygen streams and electrolyte are sent to their respective gas separators, with the electrolyte being recirculated through the cells and the gases sent to cooling units. The gases are produced at pressure (see below) with hydrogen at a purity of 99.9%.[38]

Hydrogen-Compression Unit

The hydrogen and oxygen gaseous products are at a pressure of 3100 kPa (450 psia) and the hydrogen then requires compression to the nominal pipeline pressure of 6900 kPa (1000 psi). Because of the large volume flow (5 million std cu m/day or 190 million SCF/day) and the relatively low compression ratio required (2.2:1) centrifugal-type compressors were selected. Two units in parallel are used with one additional compressor for spare purposes. Each unit consists of six casings with six stages per case. No interstage cooling is deemed necessary. The total power required to effect compression is 7.5 MW (about 10,000 horsepower). The compressors are driven by steam-condensing turbines, with steam being bled from the main turbogenerator.

Performance Characteristics

The nuclear power station operates at 33.1% efficiency and generates 992 MW of electric power from 3000 MW of nuclear heat. A loss of about 8 MW of electric power occurs when steam is bled for the hydrogen compressors. Delivery of the a-c electricity and power conditioning to d-c electricity takes place at an overall 96% efficiency, leaving about 952 MW to power the Lurgi electrolyzers. This electrolysis subsystem, after d-c rectification, operates at a net efficiency of 78% and produces 742 MW of hydrogen (higher heating value). This corresponds to a daily hydrogen stream rate of 5.01 million std cu m (187 million SCF) at a nominal pressure of 6900 kPa (1000 psia). Thus, the overall nuclear-heat-to-hydrogen conversion process for the baseline case operates at an efficiency of 24.7%. The energy balance is summarized in Table 3-1.

The assumed plant capacity factor is 80%, therefore annual production is 1.46 billion std cu m (54.6 billion SCF).

Table 3-1. BASE-CASE ENERGY AND MASS-FLOW BALANCE

| Input | Processing Function | Output |
|---|---|---|
| 3000 MW | Nuclear-Heat to a-c Electricity Conversion | (992 MW) |
| (992 MW) | a-c Electricity Transmission and Power Conditioning to d-c Electricity | (952 MW) |
| (952 MW) | d-c Electricity-to-Hydrogen at Pipeline Pressure | 742 MW |
| 3000 MW, Net Input | | 742 MW, Net Output |

$$\text{Overall Efficiency} = \frac{742 \text{ MW}}{3000 \text{ MW}} \times 100 = 24.7\%$$

$4.0 \times 10^6$ kg $H_2O$/day ($8.9 \times 10^6$ lbs/day) electrolysis* →

$4.5 \times 10^5$ kg $H_2$/day ($9.9 \times 10^5$ lbs/day)
$3.6 \times 10^6$ kg $O_2$/day ($7.9 \times 10^6$ lbs/day)

* Excludes cooling-water requirements.

## Hydrogen-Production Costs

The hydrogen-production facility is quite large and is intended to continuously supply a pipeline system, therefore it is operated as a utility, with hydrogen costed using utility-type financing. The financing rules used for both the baseline case and the advanced system are identical to allow consistent comparisons. These are presented in Section 9.

The total investment cost for the facility is $935 million in constant mid-1975 dollars. This includes direct, indirect, and contingency costs and interest during construction. No escalating effects during construction of the facility were considered. A hydrogen cost summary is presented in Table 3-2.

Table 3-2. BASE-CASE HYDROGEN-COST SUMMARY

| Facility Item | Capital Cost ($10^6$ $) |
|---|---|
| Nuclear-to-Electric Plant | 608 |
| Electrical Conditioning Unit | 50 |
| Electrolysis Plant | 269 |
| Water Treatment Unit | 4 |
| Compressor Unit | 4 |
| Total Plant Cost | 935 |

| Operating Cost Item | Annual Operating Cost ($10^6$ $) |
|---|---|
| Nuclear-to-Electric Plant Aggregate Direct | |
| Fuel | 18 |
| Operating and Maintenance | 5 |
| Electricity-to-Hydrogen Plant | |
| Raw Materials, Chemicals | 0.9 |
| Water | 0.4 |
| Direct Labor | 1.0 |
| Maintenance | |
| Labor | 3.2 |
| Supplies | 3.2 |
| Supervision | 0.6 |
| Administration and Overhead | 2.9 |
| Fixed Charges, Nuclear-to-Hydrogen Plant | 140 |
| Total Annual Cost | 175 |

Resulting Hydrogen Cost:

Annual cost ÷ annual production of $1.46 \times 10^9$ std cu m ($5.46 \times 10^{10}$ SCF) or $1.87 \times 10^7$ GJ ($1.77 \times 10^{13}$ Btu) = $0.12/std cu m ($3.21/1000 SCF) or $9.36/GJ ($9.88/$10^6$ Btu).

The largest single capital outlay is for the nuclear station, a breakdown of which is given in Table 3-3. Direct costs are taken from "The Nuclear Industry — 1974" and updated by 8% to reflect 1975 costs.[5] Indirect costs were estimated using percentage figures from "Power Plant Capital Costs, Current Trends and Sensitivity to Economic Parameters."[6]

Annual fuel costs were estimated assuming a nuclear fuel price of $0.25/million Btu. This corresponds to a $U_3O_8$ (yellow cake) cost of approximately $22/kg ($10/lb).

Table 3-3. NUCLEAR-PLANT CAPITAL-COST BREAKDOWN
Baseline Case, Mid-1975 Dollars

| Direct Costs | $/kWe |
|---|---|
| Land | 1 |
| Structures and Site Facilities | 66 |
| Reactor | 98 |
| Turbine Plant Equipment | 103 |
| Electric Plant Equipment | 38 |
| Miscellaneous Equipment | 6 |
| Contingency and Spare Parts | 24 |
| | 336 |
| **Indirect Costs** | |
| Construction Facilities, Equipment and Services (7% of Direct Cost) | 24 |
| Engineering and Construction Management Services (16% of Direct Cost) | 54 |
| Other Costs (5% of Direct Cost) | 17 |
| Interest During Construction (41% of Total Capital Outlay) | 177 |
| | 272 |

Total Capital Cost = Direct + Indirect Costs = $608/kWe

The required hydrogen price at the production facility (that is, excluding the cost of transmission and distribution to the consumer) is $0.12/std cu m ($3.21/1000 SCF) or $9.36/GJ ($9.88/million Btu).

## 4. ADVANCED FACILITY-CONCEPT FUNCTIONAL CHARACTERIZATION

In this section the advanced hydrogen-via-electrolysis facility concept, as broadly outlined in Section 1, is treated at the subsystem level, but still on a functional basis. No specific equipment or other "hardware" descriptions can be designated in this section. This step awaits the broad technical and economic descriptions to follow (Sections 5 – 7).

Using established systems-engineering procedures, the purpose of this section is to identify the functional entities comprising each of the major subsystems, and the subsystem interfacing within the system, i.e., the facility concept itself. Once named, design interactions between units are to be noted qualitatively and interfacing points between subsystems identified.

Figure 4-1 is a simplified input/output representation of the advanced nuclear-electrolytic hydrogen-production system concept. The rather

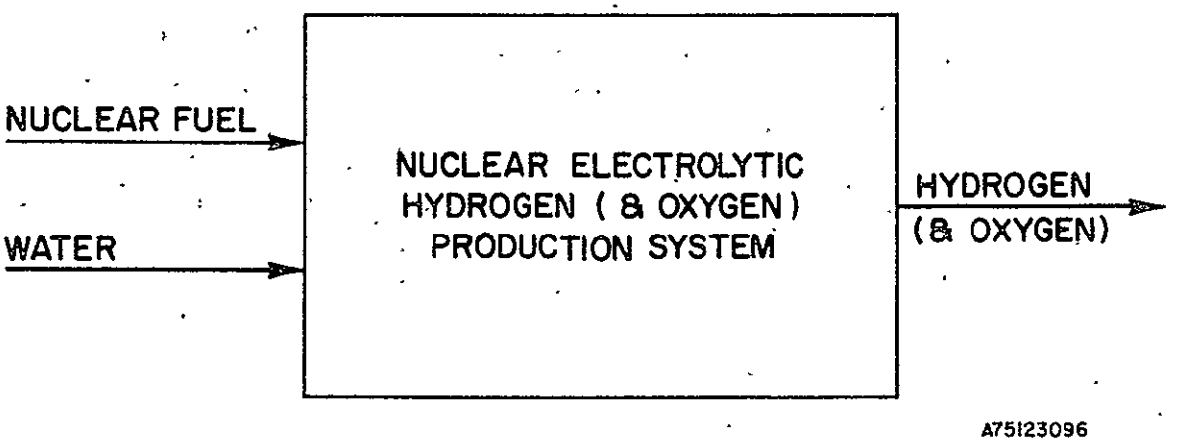


Figure 4-1. SYSTEM FUNCTIONAL DIAGRAM SHOWING INPUT/OUTPUT RELATIONSHIPS

complex nuclear-fuel cycle required to support continuing nuclear-reactor operations is represented simply as the "nuclear fuel" input. (The fuel cycles for the LWR, HTGR, LMFBR and other reactor types have been adequately described elsewhere, e.g., Reference 15.) Water, taken to be at "municipal quality" is the other basic input, and hydrogen (with coproduct oxygen) the output. Hydrogen is to be produced at a nominal pipeline pressure of 6900 kPa (1000 psi) in view of its assumed long-distance transmission to markets.

Earlier Figure 2-2 showed five nominal subsystems as being interfaced within the system to convert the nuclear and water inputs to the desired hydrogen-energy output. In Figure 4-2 only three subsystems are shown.

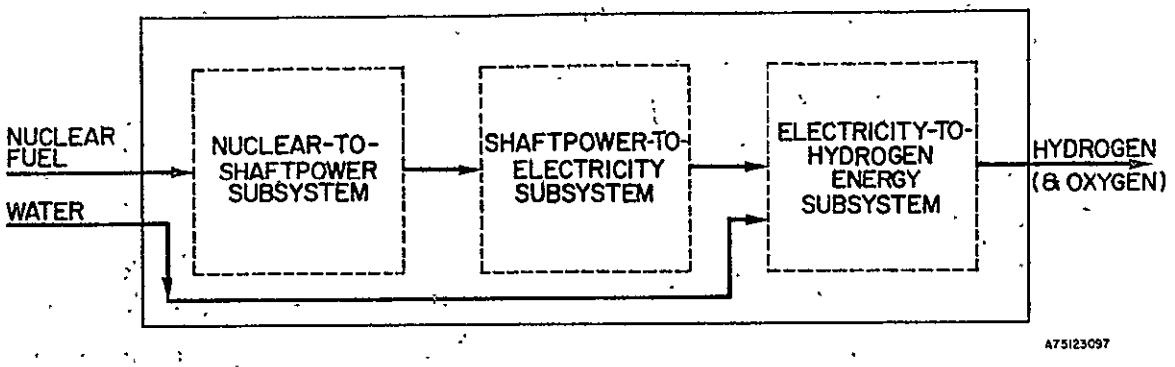


Figure 4-2. SYSTEM FUNCTIONAL DIAGRAM SHOWING SUBSYSTEMS AND SUBSYSTEM INTERFACING

The water purification and hydrogen compression functions are absorbed in the electricity-to-hydrogen energy subsystem.

Next, we examine each subsystem to define the constituent functional components and their intra-subsystem interfacing arrangements. Again, this will be essentially on a functional basis with associated technological and economic aspects of the subsystems to be developed subsequently (Sections 5, 6, and 7, respectively for each of the subsystems listed).

Nuclear-to-Shaftpower Subsystem

As shown in Figure 4-3, this subsystem is provided nuclear fuel as its principal input, and converts this energy into shaftpower output for the next subsystem. There are, in detail, numerous other inputs and outputs such as —

Other Inputs: Electricity, water, chemicals, control inputs, maintenance materials and supplies, etc.

Other Outputs: Heat, spent fuel elements, fission byproducts and radiation, various chemical residues, etc.

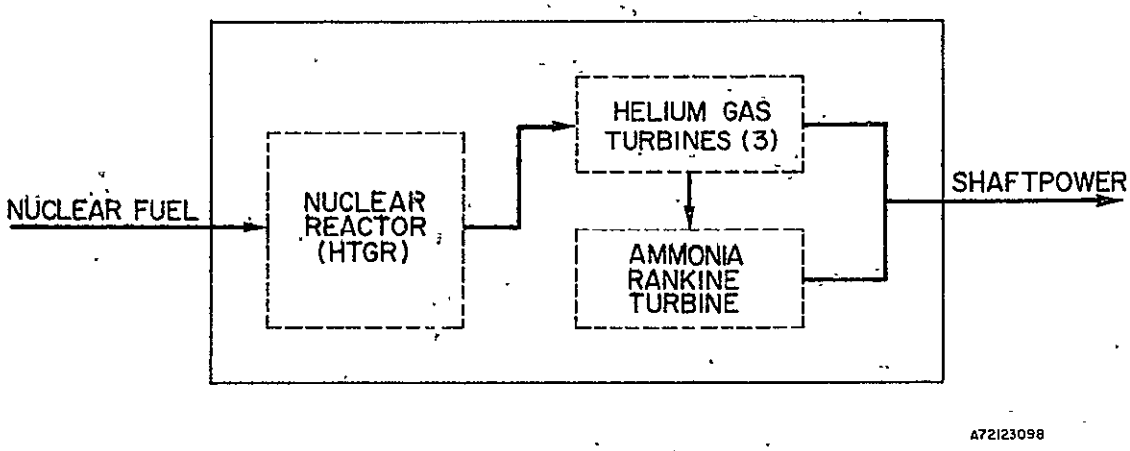


Figure 4-3. NUCLEAR-TO-SHAFTPOWER SUBSYSTEM

The key to the superior technical performance and economic advantages of the advanced facility concept over the baseline current-technology reference case, described in Section 3, is the incorporation of a high-temperature gas-cooled reactor (HTGR) in lieu of a light-water (LWR) or other in-use reactor types.

As will be covered in Section 5, the HTGR approach provides for significantly increased maximum temperatures at which nuclear heat is made available to shaftpower-generating power cycles. This provides for a marked step-up in overall energy conversion efficiency. Further, a greater work output results from a given-size physical nuclear facility. This will be shown to substantially reduce specific capital costs ($/kWh-installed), and very likely operating costs as well. Thus, for reasons of both energy conversion efficiency and reduced net energy costs, the HTGR is uniquely selected for the advanced facility concept. This choice is expressed in Figure 4-3.

In order to more effectively utilize heat from an HTGR, a binary power cycle is selected at the onset over a conventional single-cycle approach as now used with lower-temperature reactors. Reference 22 provides a comprehensive background and performance comparison for single, binary, and even ternary cycles.

The General Atomic Co., which was acting as the study's "expert adviser" in the important nuclear reactor facility area, has developed a very substantial experience base involving the helium gas-turbine power-cycle approach with the HTGR. Its high efficiency and advantageous costs, have been demonstrated in detailed engineering studies. Because of its very high turbine exit-temperature characteristics, the gas turbine is an excellent topping-cycle candidate. See Reference 21.

Further, GA has found that a superheated Rankine cycle, and specifically one using ammonia as the working fluid, best matches the helium-Brayton cycle for "bottoming" purposes. It is this helium-gas-turbine/ammonia-Rankine cycle that has been selected for the subsystem.

With these technical approaches in mind, the several basic units comprising the subsystem are reflected in Figure 4.3, a block diagram of the nuclear-to-shaftpower subsystem.

Shaftpower-to-Electricity Subsystem

The second major subsystem, shown in Figure 4-4, carries out the function of converting shaftpower derived from the nuclear-reactor power cycle to d-c electricity matched to the electrolyzer requirements.

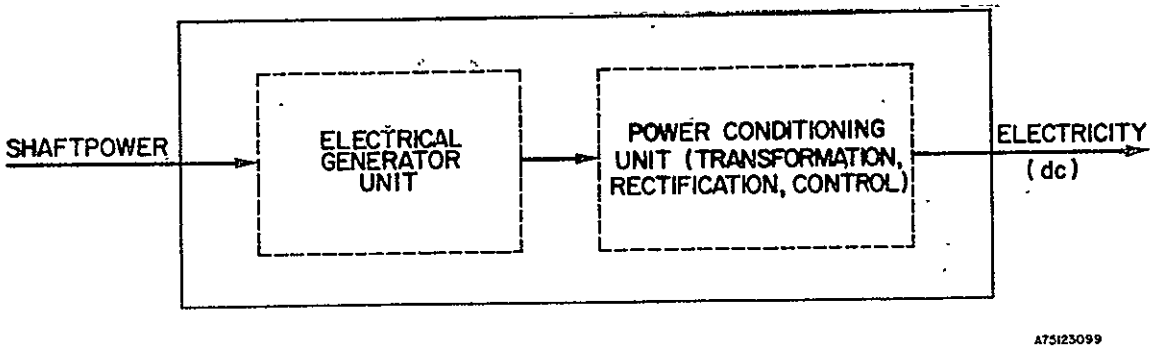


Figure 4-4. SHAFTPOWER-TO-ELECTRICITY SUBSYSTEM

In this subsystem two basic approaches can be taken, as will be covered in Section 6: 1) alternating current generation with subsequent rectification to direct current, or 2) direct current generation. In both the a-c and d-c

approaches either conventional (e. g., 60-Hz a-c generator) or unconventional technical means can be utilized. A significant case in point, reflecting an unconventional approach, is the acyclic non-commutated d-c generator using liquid-metal current collection. This will be described in technical detail subsequently.

Two units constitute the subsystem: the generator and the power conditioning unit. The latter can be extensive in hardware terms and expensive in the case of a-c generation requiring rectification to dc. It provides numerous functions depending on the generator type selected and electrolyzer: a-c control and switching, voltage transformation, rectification to dc, filtering, etc. In the case of d-c generation the requirements for power conditioning are minimal and may even be zero.

Electrical bussing of d-c power to the electrolyzers, and any a-c transmission/distribution requirement is a third major function of the subsystem, represented in Figure 4-4 as the output arrow.

Electricity-to-Hydrogen Subsystem

Figure 4-5 schematizes this subsystem, which is comprised of three principal units: water purification, electrolyzer, and mechanical compression.

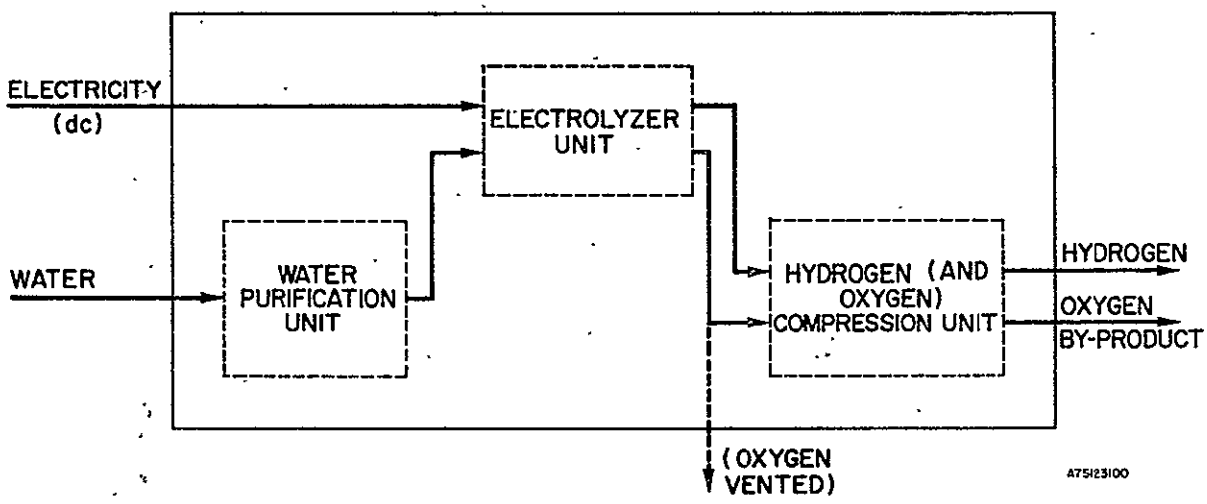


Figure 4-5. ELECTRICITY-TO-HYDROGEN SUBSYSTEM

Water purification is necessary to meet the requirement of the selected electrolyzer type. This varies from one type of electrolyzer to another but, as a minimum, high-level feedwater deionization is required in all practical systems for reasons noted in the Main Survey Report. (See the treatment of electrolysis of impure water.)

With regard to the electrolyzer itself, the governing technology is amply documented (see the Main Survey Report) and no further background will be provided here. Three basic types of electrolyzers will be examined with regard to subsystem application in Section 7.

One important characteristic in the electrolyzer for the advanced production facility concept is that of electrolysis pressure, since the hydrogen is wanted at "pipeline conditions", defined here as 6900 kPa (1000 psia). Available and in-development electrolyzer outlet pressures range from essentially atmospheric (a few inches of water-column) to as high as 21,000 kPa (3000 psi).* The Lurgi units described in Section 3 operate at 3100 kPa (450 psi).

The subsystem's mechanical compression unit is highly sensitive to the selected electrolysis pressure, in terms of both physical size and drive energy requirements. Its function is to compress the product hydrogen from electrolyzer outlet pressure to 6900 kPa (1000 psia). Additionally, the oxygen produced in electrolysis, if it is to be pipelined as a credit byproduct, must be also compressed to pipeline pressure.

Mechanical hydrogen compressors can be of the reciprocating or centrifugal type. It is noted that hydrogen as a very low-density gas is most burdensome to compress. Compressor swept volumes must be large, necessitating commensurate drive-energy requirements. The small molecular size of hydrogen aggravates the leakage problem.

An intriguing possibility, one focused upon in the study, is the elimination of a mechanical compression requirement by means of electrolysis at pipeline pressure. The pumping of electrolyzer feed-water to pipeline pressure requires very small capital outlay and drive-energy

* This very high pressure reference equates to breathing-oxygen generators for submarines. These require sizable pressure-vessel containment means.

cost in comparison with gaseous compression. The issue here, one discussed in the Main Survey Report and to be covered subsequently in this report, is the net cost and energy requirement for the selected pressure-electrolyzer. Again, it is noted that the Lurgi unit selected for the baseline case operates at nearly half the required pipeline pressure.

Subsystem Interfacing Considerations

As equipment and design points are selected it will be important to iteratively check the up- and down-stream effects on adjoining subsystems. Significant improvements in raising throughput efficiency, and in reducing capital and operating costs, may be possible through innovative interfacing as combined with the use of appropriate advanced technology.

Table 4-1 summarizes the selected subsystem interfacing points (Reference: Figures 4-1 to 4-5).

Table 4-1. SYSTEM/SUBSYSTEM INPUT/OUTPUTS AND INTERFACING POINTS

| System Inputs | System Output |
|---|---|
| Nuclear Fuel Energy<br>Feed-water | Hydrogen Gas at "Pipeline Conditions" (and oxygen likewise if wanted as a credit byproduct) |

Subsystem Inputs and Outputs

1. Subsystem: Nuclear-to-Shaftpower
   Input from outside system: Nuclear Fuel
   Output to Shaftpower-to-Electricity Systems:
   Shaftpower (at generator rpm)

2. Subsystem: Shaftpower-to-Electricity
   Input from Nuclear-to-Shaftpower Subsystem:
   Shaftpower (at generator rpm)
   Output to Electricity-to-Hydrogen Subsystem:
   Electricity (d-c as required and at electrolyzer)

3. Subsystem: Electricity-to-Hydrogen
   Input from outside system: Feed-water ("municipal" quality)
   Input from Shaftpower-to-Electricity Subsystem:
   Electricity (d-c as required and at electrolyzer)
   Output to outside system: Hydrogen (and Oxygen)
   at "Pipeline conditions" – 6900 kPa (1000 psi)

## 5. NUCLEAR-TO-SHAFTPOWER SUBSYSTEM

### General Description

A functional block diagram of the nuclear-to-shaftpower subsystem is provided in Figure 4-3. This subsystem is predicated on the high-temperature gas-cooled reactor (HTGR) and a high-efficiency binary-cycle shaftpower extraction configuration. The basis for this selection is discussed in Section 4.

In view of the dominant technical and cost significance of this subsystem in the synthesis of the overall advanced facility concept, IGT requested the assistance of the General Atomic Co. in formulating its conceptual design. A small consulting subcontract was provided for this purpose under the IGT study contract.

The basic text and figure material presented in this section is derived directly, and indirectly, from General Atomic.

### Nuclear Reactor (High-Temperature Gas Reactor)

In the nuclear fission process, neutrons are released and generate heat primarily by colliding with the fuel and surrounding media, thus raising the temperature. The resulting temperature increase is used to transfer heat to a turbine working fluid and ultimately to turn a shaft to perform work.

An HTGR utilizes helium gas as the turbine working-fluid coolant and graphite as moderator, core structure and reflector. A cutaway view of the reactor, as conceived of by GA, showing the essential features is presented in Figure 5-1. An HTGR is inherently more efficient than a light-water nuclear reactor (LWR) in that it is capable of sustaining higher operating temperatures and, hence, yields more work per unit of heat. The HTGR incorporates several safety features:

- Large, prompt negative overall reaction coefficient, together with large neutron lifetimes.
- Large thermal inertia of the core
- Refractory fuel material and cladding
- Inert one-phase coolant
- Prestressed-concrete reactor vessel with redundant prestressing

These features tend to provide safe operating capability and low levels of radioactive release even in the event of a major accident.[13]

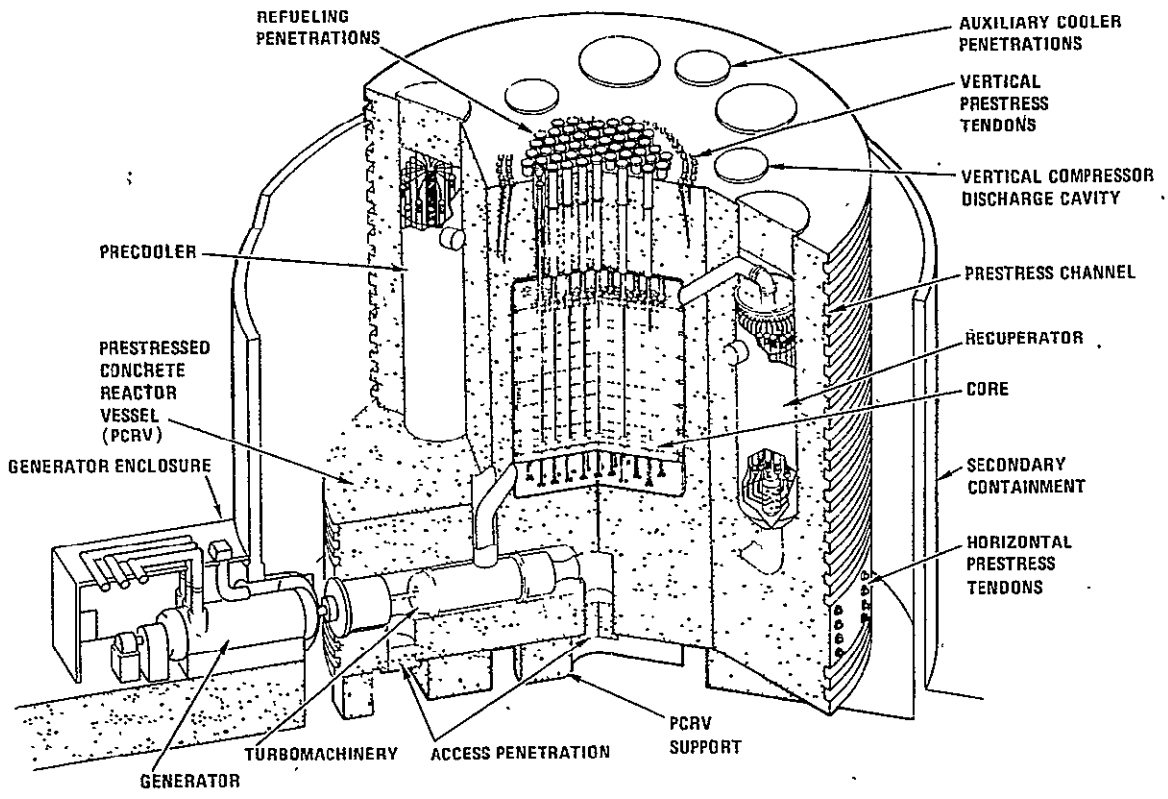


Figure 5-1. THREE-LOOP 3000-MWt GT-HTGR POWER PLANT[23]

The reactor core is made up of hexagon-shaped fuel elements, with the fuel in the form of coated particles of 93.2% enriched uranium-235 dicarbide as the fissile material, and thorium oxide as the fertile material. Natural thorium-232 is transformed to fissionable uranium-233 by a neutron-capture and two successive beta-decays. The newly formed fissile fuel is partially consumed, the remainder recovered when the spent fuel is reprocessed. Fuel loading is based upon a 3-year cycle; that is, approximately one-third of the core will be replaced on an annual basis. The initial fuel loading will consist of approximately 1700 kg (2 tons) of fully-enriched uranium and 3700 kg (4 tons) of thorium.

Lengthwise coolant holes are provided in the graphite matrix for helium flow past the fuel elements. The active core height is about 6.4 m (21 ft) and the mean core diameter 8.5 m (28 ft). The system temperature coefficient of reactivity is negative ($-4.3 \times 10^{-5}$/°C) for all fuel cycles and all normal and transient temperatures.[12] Thus, a run-away reaction would be intrinsically self-defeating.

Helium Power-Transfer Loops

The helium coolant transfers heat energy directly from the reactor core to the gas turbine and indirectly to the bottoming-cycle turbine. A flow diagram is given in Figure 5-2. Helium is particularly desirable as a reactor

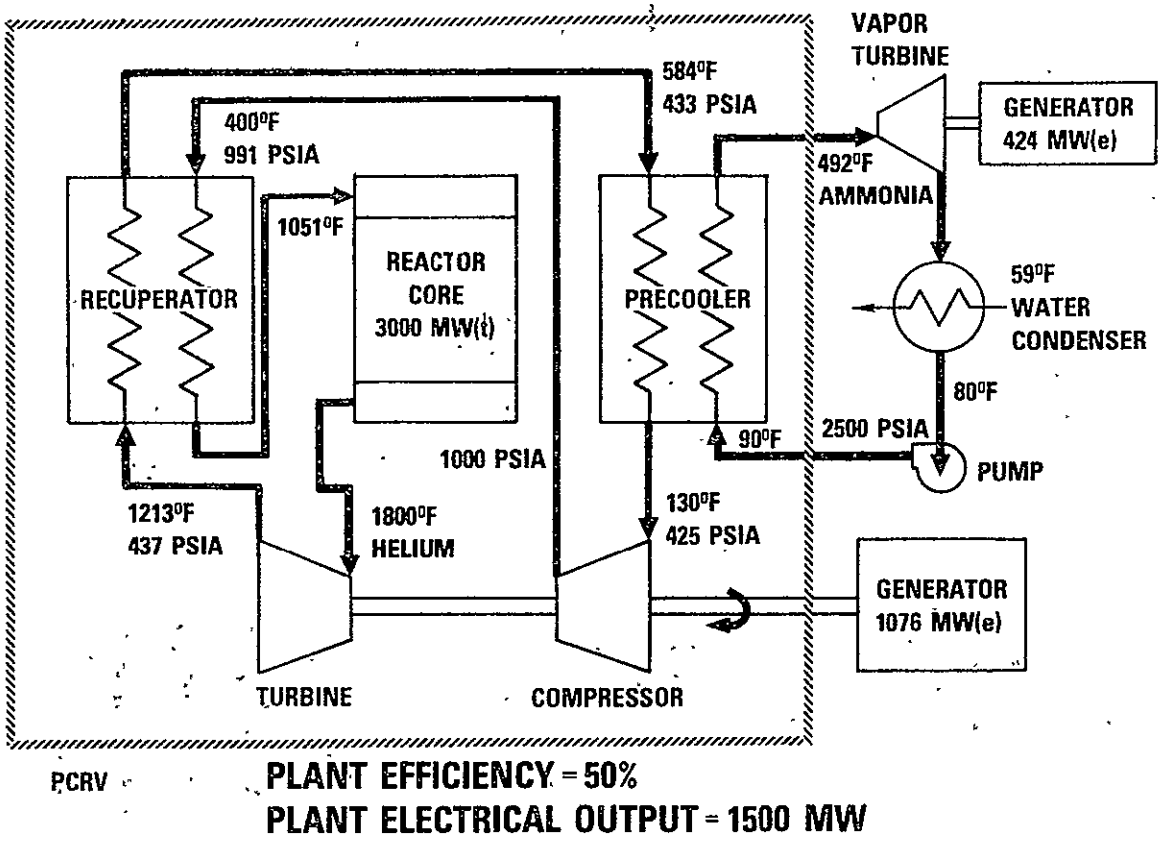


Figure 5-2. BINARY GT-HTGR WITH WET COOLING[23]

coolant since it is chemically inert and has excellent heat transfer characteristics. The reactor coolant system contains three independant primary-coolant loops, each having a helium compressor and a closed-loop gas turbine mounted on a single shaft. Helium is expanded through the gas turbines and passes through a recuperator that regenerates (reheats) helium returning to the core. The expended and cooled helium then further transfers heat to the bottoming cycle via the precooler before it is recompressed and returned to the reactor core.

The prestressed-concrete reactor vessel (PCRV), which is housed centrally within the reactor containment, is a multicavity pressure vessel that contains

the reactor core, the reactor coolant system, heat exchangers and the gas turbines (the electric generators are located externally). It is constructed of high-strength reinforced concrete prestressed vertically and circumferentially by tension members.[24]

Brayton Topping-Cycle Gas Turbine

A significant advantage of the closed-cycle gas turbine is that the compact size of the turbomachinery allows the design of a completely integrated circuit with its attendant safety and economic benefits. Figure 5-3 illustrates the configuration of a 370-MWe axial-flow turbomachine. Because of the high

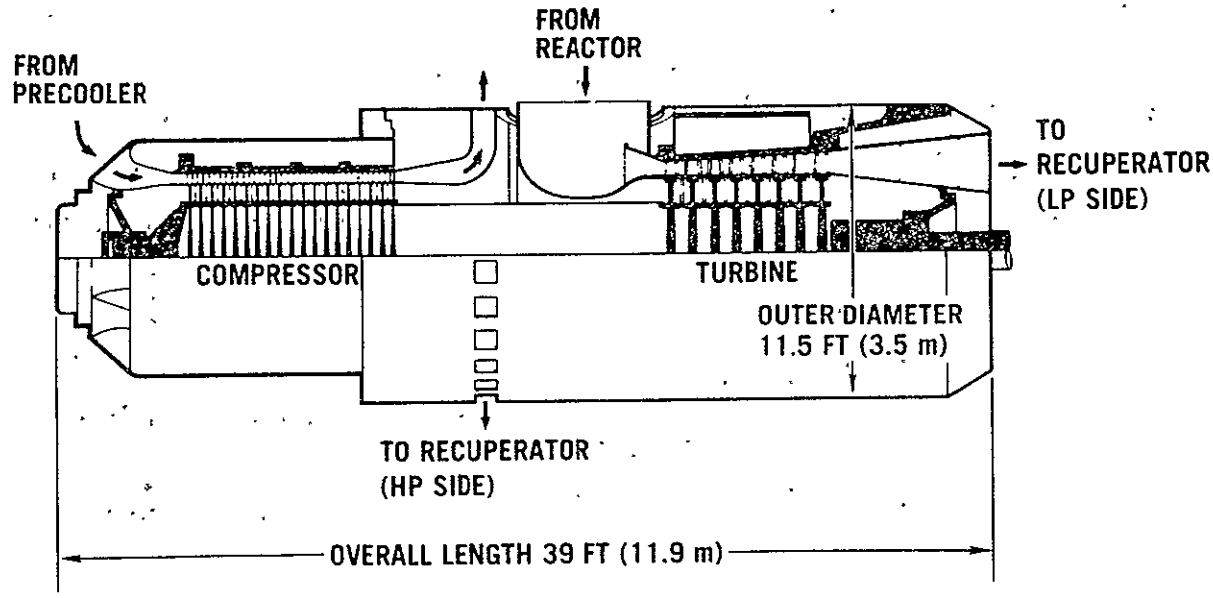


Figure 5-3. SIMPLIFIED CROSS SECTION SHOWING 370-MWe SINGLE-SHAFT HELIUM TURBOMACHINERY FOR GAS-TURBINE HTGR POWER PLANT[39]

pressure level of the working fluid, the dimensions of the unit are similar to those of conventional heavy duty open-cycle gas turbine units of 70-MWe capacity currently in utility generating service.[43] Three of these units are used in the system. A similar (but smaller) closed-loop helium turbine was recently commissioned in West Germany.[26]

The Brayton (or Joule) cycle consists of adiabatic compression, constant pressure heat addition and adiabatic expansion. By adding a recuperator to recover heat from the turbine exhaust, the efficiency is improved and gas turbine compression pressure ratios can be held down to about 2:1. This is especially important in minimizing the number of compressor stages required,

since a very low pressure rise per stage is practical with a light gas such as helium. The helium working fluid enters the compressor section of the turbomachine at 54°C (130°F) and 2930 kPa (425 psia) and is compressed to nominal coolant-system pressure of 6900 kPa (1000 psia). It is heated in the recuperator loop to the reactor core inlet temperature of 570°C (1050°F). While removing heat from the fission process the helium reaches its maximum temperature of 980°C (1800°F). Work is obtained from the hot helium gas by expansion through the turbine to an outlet condition of 650°C (1200°F) and 3000 kPa (440 psia). Use of the gas turbines alone to generate electricity results in a very attractive system with efficiencies of about 39%. Significantly higher efficiencies can be attained by utilizing a power bottoming loop in the binary cycle as selected for the subsystem in the present study.

Rankine Bottoming-Cycle Ammonia Turbine

Because there is a considerable amount of usable enthalpy available in the exhaust of the helium turbine, this can be recovered to increase system efficiency by incorporating a secondary or bottoming-cycle turbine. For the helium gas-turbine approach with direct coupling to the HTGR, the bottoming cycle should be selected on a "best fit" basis to the Brayton cycle. A supercritical Rankine cycle appears to best match in this case. As an ideal thermodynamic cycle, this consists of heat addition at constant pressure, isentropic expansion for work extraction, heat rejection at constant pressure, and isentropic compression. Since the cycle operates with a condensible vapor, liquid pumping at low work expenditure can be achieved.

The absence of latent heat in the purely gaseous working fluid of the gas turbine cycle means that undue irreversible temperature drop in the exchanger feeding the bottom cycle can only be avoided by supercritical operation of the latter. It is necessary, in other words, to form the approximately triangular-shaped bottom-cycle diagram to best fit the space shown as "available" for the bottom-cycles operation in Figure 5-4, and this can only be done in the absence of the input temperature plateau characteristic of a subcritical vapor cycle.[21]

The selection of the best working fluid for the bottoming cycle is a matter of technical compromises. Water is not a candidate because of the very high pressures necessary for supercritical operation. General Atomic Co. has

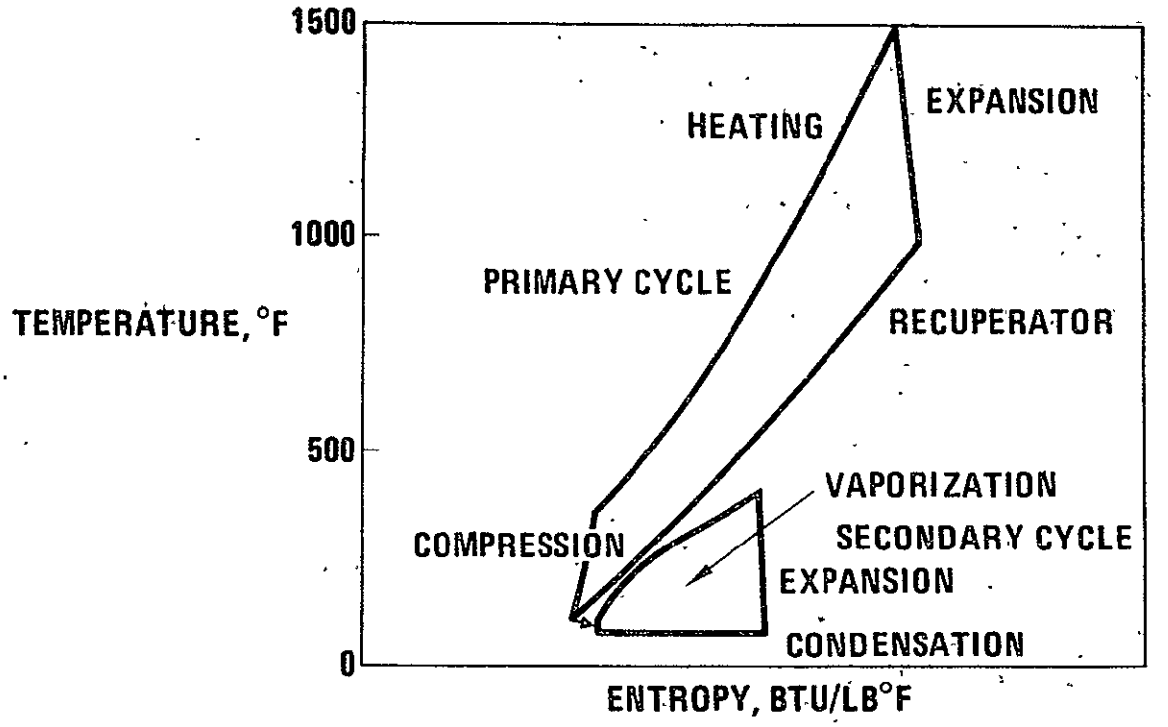


Figure 5-4. GAS-TURBINE HTGR BINARY-CYCLE PERFORMANCE[21]

focused on isobutane and ammonia in its detailed assessment and prefers the latter for the following reasons:

- Ammonia provides a high-density working fluid at reasonable pressures and hence provides for smaller components.
- Ammonia has a high specific heat and provides for good heat transfer that minimizes the heat exchange areas required.
- There is a solid industrial experience base with ammonia as a working fluid (refrigeration, ammonia synthesis, etc.)

On the other hand, isobutane provides a better match with regard to the topping/bottoming heat-exchange process; that is, minimum temperature differentials are experienced across the full heat-exchange temperature range from helium-to-isobutane. Also, isobutane provides fewer materials compatibility problems and is non-toxic (but is highly flammable).

Compared with steam turbines and open-cycle industrial gas turbines, the ammonia secondary cycle results in a very compact power conversion system. This is a consequence of the relatively high density of the ammonia working

fluid. For the subsystem one turbine is required and produces about 28% of the total shaftpower output. A split-flow arrangement of the turbine for thrust-load equalization, is shown in Figure 5-5. Heat is rejected to cooling water in a condenser section.[43]

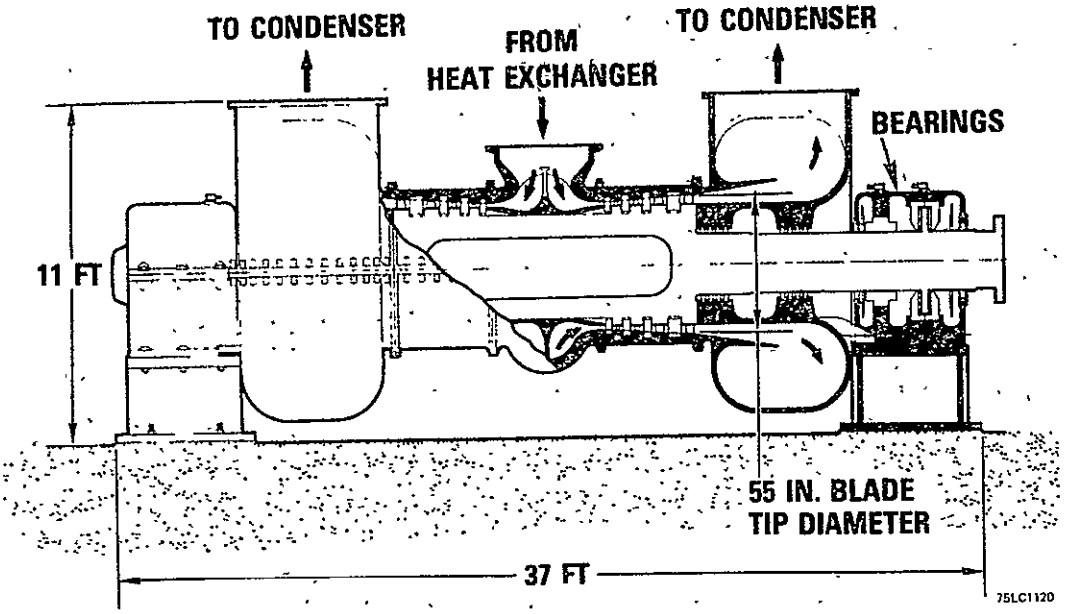


Figure 5-5. FOUR-STAGE SPLIT-FLOW AMMONIA TURBINE[43]

Low-Temperature Heat-Rejection Loop

About 99% of the heat not converted to work is rejected to the bottoming-cycle-condenser cooling water, the other 1% is lost to the reactor plant cooling water system.[13] Evaporative or wet cooling via a cooling tower is used to transfer heat from the cooling water to the surrounding environment. Most of the actual heat removal comes from evaporation of the cascading water droplets. Two natural-draft cooling towers are employed, whose structure consists of a reinforced-concrete hyperbolic shell, as shown in Figure 5-6. The narrowing or pinch near the middle increases the natural draft or chimney effect of the tower. Each tower is approximately 110 m (350 ft) in diameter and 120 m (400 ft) high.[10]

Integrated Nuclear Subsystem

In summary, the total nuclear-to-shaftpower subsystem incorporates the essential features of the General Atomic Mark II design HTGR. This design

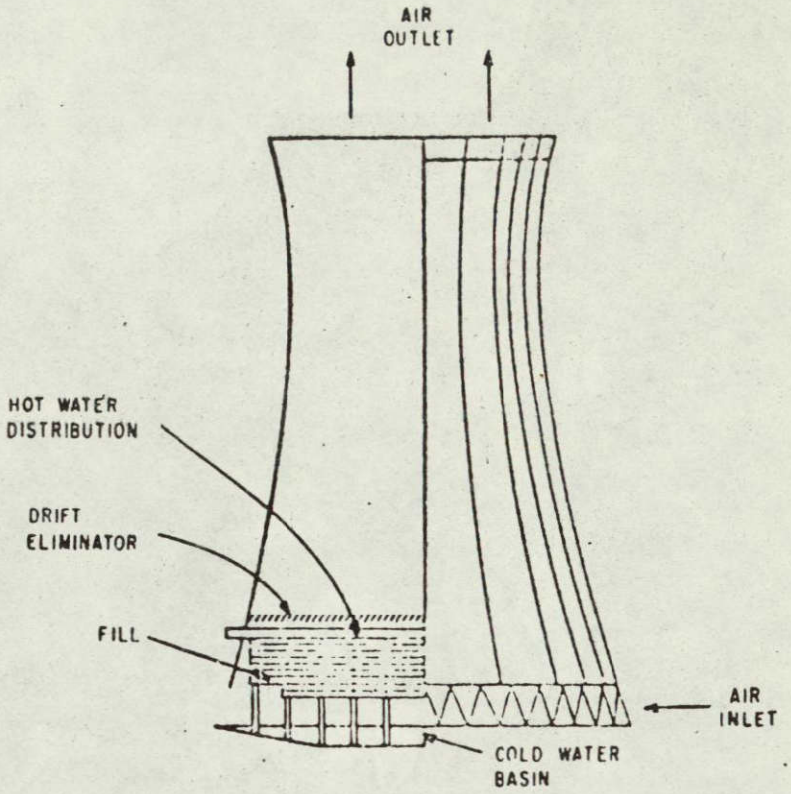


Figure 5-6. NATURAL-DRAFT WET-COOLING TOWER (Counter-Flow)[45]

features a 980°C (1800°F) helium gas-turbine inlet temperature for the topping cycle and a turbine inlet temperature of 255°C (490°F) for the ammonia bottoming cycle. The integrated configuration has significant envelope limitations and demanding maintenance requirements for the high-performance, high-reliability machinery. For the subsystem design point a 3000-MWt core is chosen. It provides for a 50% nuclear-heat-to-electricity efficiency as coupled to the binary power cycle and produces 1500 MW of shaftpower. An artist's conception of a similar facility is shown in Figure 5-7. This reflects the Mark I 820°C (1500°F) helium gas turbine without the binary cycle feature. In this case rejected heat is at a high enough temperature to permit use of a dry cooling tower. The actual physical arrangement to be employed is shown later in section 8. As will be seen, a different gas turbine arrangement will be utilized.

Subsystem Cost

The installed capital cost of a 3000-MWt HTGR plant with 980°C (1800°F) gas-turbine inlet temperature and the binary cycle is estimated to be $348/kWe. The basis of this estimate is mid-1975 dollars for direct, indirect, and

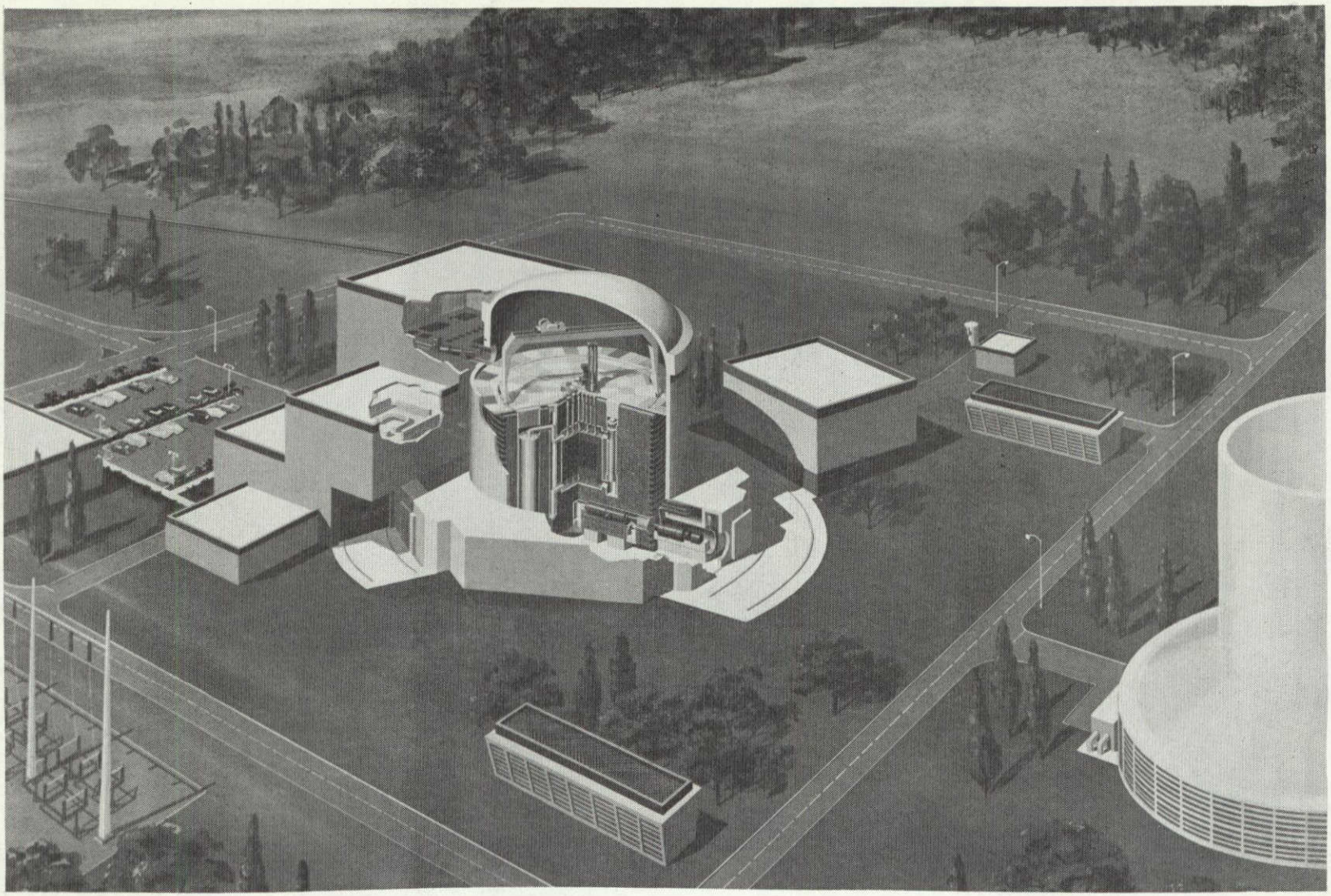

Figure 5-7. 1100 MWe GAS-TURBINE HTGR POWER PLANT[13]

contingency cost. Such costs as interest during construction, which is sizable, and escalation are not included. This estimate is greatly dependent on factors like labor costs, which vary nationwide; remoteness of the site, which affects construction services; and specific contractual terms.[13]

The fuel-cycle costs for the binary-cycle HTGR with a turbine inlet temperature of 980°C (1800°F) and an efficiency of 50% are estimated to be 2.32 mills/kWh in July 1975 dollars. Anticipated operating and maintenance costs are taken as being equal to a steam-cycle HTGR plant, which is 0.525 mills/kWh. This estimate includes plant staffing, consumable supplies and equipment, outside support services, nuclear liability insurance, and miscellaneous operating and maintenance expenses on the basis of 1975 costs.[12]

See Section 9 for the cost analysis of the overall advanced nuclear-electrolytic facility concept.

## 6. SHAFTPOWER-TO-ELECTRICITY SUBSYSTEM

### General Description

The shaftpower-to-electricity subsystem is presented in Figure 4-4. It receives shaftpower from the nuclear-to-shaftpower subsystem and provides d-c electrical power to the electricity-to-hydrogen subsystem. The designated interface is the electrical input connections of the electrolyzer unit modules. Thus the facility's electrical distribution (bussing) network is part of this subsystem.

In view of the basic requirement of electrolyzers for direct current electrical power (as opposed to alternating current), practice to date using conventional 60-Hz electricity from the utility grid is to condition the power at the electrolyzer site. Step-down transformers feeding controllable rectifier circuits are typically employed.

An alternative that is technically feasible in a dedicated facility concept of the type examined in the study is an all d-c system. Such an approach will be shown to have significant advantages in that the capital and operating costs and efficiency reductions associated with the power conditioning unit (Figure 4-5) can be avoided.

### Technical Description -- Electrical Generators

#### Conventional and Advanced-Technology a-c Generators

Conventional a-c electrical generators represent well developed technology and have been constructed in sizes up to approximately 1500 MWe.*

To effect 3-phase 60-Hz power a shaft speed of 1800 rpm is used in 4-pole generators and 3600 rpm in 2-pole generators. Generator output voltages lie in the range of 11 to 25 kV. Although this is conventionally stepped up to transmission levels of 345 to 765 kV via transformers this would not be required in the case of the close-coupled, dedicated facility.

* For perspective this is the nominal total output of the nuclear-to-shaftpower subsystem described in Section 5, involving four separate output shafts, three helium and one ammonia turbine.

In fact, step-down transformers would be required. An efficiency of 98.5% to 99% is achieved in conventional a-c generators with recirculating hydrogen coolant used to remove heat due to ohmic and frictional losses, and to reduce windage torque.

Since a-c generators represent mature, proven technology and because they are highly efficient, there appears to be little probability of "step-function" future gains technically, or in the area of costs.

Some work has been accomplished in cryogenic superconducting a-c generators (Reference 46). However, the principal motivation here is to reduce physical generator size in the large generator category. Conventional generators of larger than present maximum rating (about 1500 MWe) pose restrictive problems of volume and weight in being transported from the factory to the installation site. Consequently, further economies of scale (which up to now have been significant) are limited by the anticipated need to transport generators in sections for on-site assembly and installation. More compact superconducting generators may avoid this limitation in the future and provide a continuation of previous economy-of-scale trends.

Noting that the generator sizes to be coupled with the four turbine-shafts of the advanced facility are all less than 500 MWe, it is not clear that the superconductive generator technology offers any discrete advantages to the system being synthesized in this study. Hence, the conventional a-c generator remains the candidate device for further consideration.

Conventional d-c Generators

Direct current generators, if available in the sizes required and at competitive efficiencies and costs, are uniquely of interest to this subsystem. This is because d-c generation potentially eliminates the cost and efficiency penalties of rectification. In fact, all power-conditioning-unit functions are obviated, with the possible exception of emergency disconnect switching. This could mean a saving of 3 to 4 points of efficiency and a cost saving of as much as two-times that associated with the generator.

On the other hand, if d-c generators provide lower voltages, current levels are proportionately higher, which will require larger-capacity power bussing means. Close-coupled generator-to-electrolyzer electrical

paths will be important to minimize costs and distribution ohmic losses. Possibly, cryoresistive or superconducting d-c power circuits may offer salient advantages in this connection.

Conventional d-c generators are of the commutator/brush type. They are usually limited to less than about 10 MWe in size because of problems associated with the basic design approach (brush current density limitations, friction and wear problems, etc). Also, efficiencies of 94% to 95% are typical, significantly below a-c generators.

With these limitations of sizes and efficiency, the prospects of any realizable gains through the use of conventional d-c generators are at best small. For this reason the conventional d-c generator was dropped from further consideration in this study.

Acyclic d-c Generators

As discussed in the Main Survey Report there is, fortunately, an "unconventional" d-c generation alternative: the acyclic generator (References 1 and 9). The acyclic generator, sometimes referred to as a "unipolar" or "homopolar" machine, is a very old concept first demonstrated by Michael Faraday some 140 years ago. This was a simple conducting disk rotating about a shaft with a unidirectional magnetic field passing through the disk (which can be viewed as an infinite number of radial conductors).

As the disk rotates within the magnetic field an electric potential is induced between any two points at different radii. To utilize this electrical potential, a current collector is placed at the rim of the disk and another near the shaft. The resulting ripple-free d-c generator is an intrinsically low-voltage machine, but one capable of handling very large currents.

In practice several disks would be connected electrically in series and mounted on a single shaft. With this configuration, machines up to 500 MW with an operating voltage not exceeding 1000 V have been projected by the General Electric Co.'s large electrical machinery group at the company's Schenectady facility.[27]

The technological development responsible for moving this machine from the textbook to potential bulk-power-generation applications is the achievement of current collectors that are capable of handling very large currents. General Electric has achieved this through the use of liquid metal collectors, using a sodium-potassium (NaK) low-melting-temperature alloy.

Projected operating speeds for those d-c machines in the 100 to 500-MW range are significantly lower than conventional 2-pole 60-Hz generators that operate at 3600 rpm. Being limited by material stress constraints and allowable liquid metal collector peripheral speed, the larger d-c acyclic generators operate at 1000 to 2500 rpm for a power rating of 500 to 1000 MWe, respectively. Smaller machines operate up to, and above, 3600 rpm.

The acyclic generator is a constant-speed load-following device with full-range voltage control effected by adjusting the d-c field current. Excitation power is very low, about 0.1% of rating, and would be provided from a controllable solid-state power supply. Machine efficiency decreases from 98.5% at full load to 96% at one-quarter load.

The individual generators can be electrically connected in series for increased voltage levels up to approximately 1000 V. GE states that as many as three can be operated on one shaft. Mechanical limitations make it difficult to operate a larger number (Reference 28).

General Electric provided the following technical information (Table 6-1) in support of the IGT study (References 27 and 28).

From this table it can be seen that voltage levels of up to 1000-V dc, quite compatible with projected electrolyzer installations, are available at the higher power levels, say above 250 MWe. Efficiencies are comparable to those of a-c generators and, as will be seen, costs are lower.

It should be stressed that acyclic generators, vis-a-vis a-c generators, remain basically undeveloped as an industrially available device, apparently for lack of any major applications. Therefore, commensurate development would have to be achieved if the acyclic is to be produced in quantity and at the performance levels stated in Table 6-1.

Table 6-1. ESTIMATED ACYCLIC-GENERATOR TECHNICAL CHARACTERISTICS

| MWe Output | RPM | Efficiency | V | A | Size |
|---|---|---|---|---|---|
| 5 | 7200 | 98.5 | 28 | 180,000 | 3.6 ft diam<br>3.2 ft length |
| 25 | 4300 | 98.5 | 100 | 250,000 | 4.5 ft diam<br>5 ft length |
| 50 | 3600 | 98.5 | 167 | 300,000 | 5 ft diam<br>6.5 ft length |
| 100 | 2580 | 98.5 | 325 | 300,000 | 7.2 ft diam<br>9.3 ft length |
| 300 | 1500 | 98.5 | 1000 | 300,000 | 9.5 ft diam<br>12.5 ft length |
| 500 | 1000 | 98.5 | 1000 | 500,000 | 12.8 ft diam<br>17 ft length |
| (Selected Unit):* | | | | | |
| 60 | 3600 | 98.4 | 200 | 300,000 | 5.6 ft diam<br>6.6 ft length |

* See Section 8. This was based on the most recent information from GE.

However, several large special-purpose acyclic generators, using NaK collectors, have been constructed and placed into operation. Four of these generators have been in service for about 10 years at the U.S. Air Force's Arnold Engineering Development Center at Tullahoma, Tennessee. Each machine is capable of generating 550,000 A, at 45 V (about 25 MWe). The generators are not designed for continuous operation and are required to charge a large inductive storage unit (less than a minute). The stored energy is employed to energize a "hot-shot" type high Mach number wind tunnel.[3]

An individual generator in this installation is shown in Figure 6-1. The four-unit set and the large copper busses capable of interconnecting the generators with the load can be viewed in Figure 6-2.

Summarizing, the acyclic generator appears technically to be a most advantageous approach in the advanced electrolytic hydrogen facility. The

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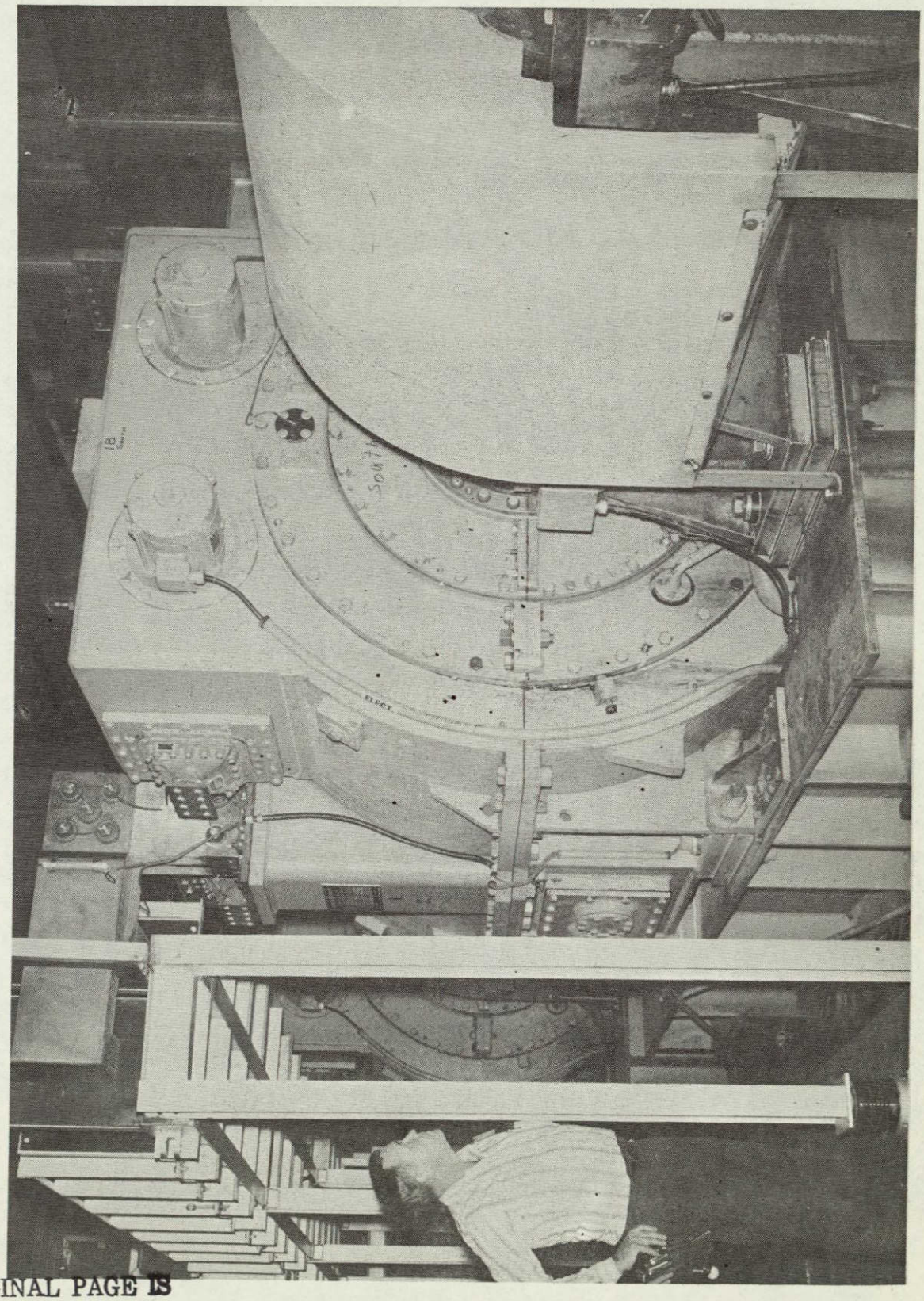

Figure 6-1. ACYCLIC GENERATOR[3]

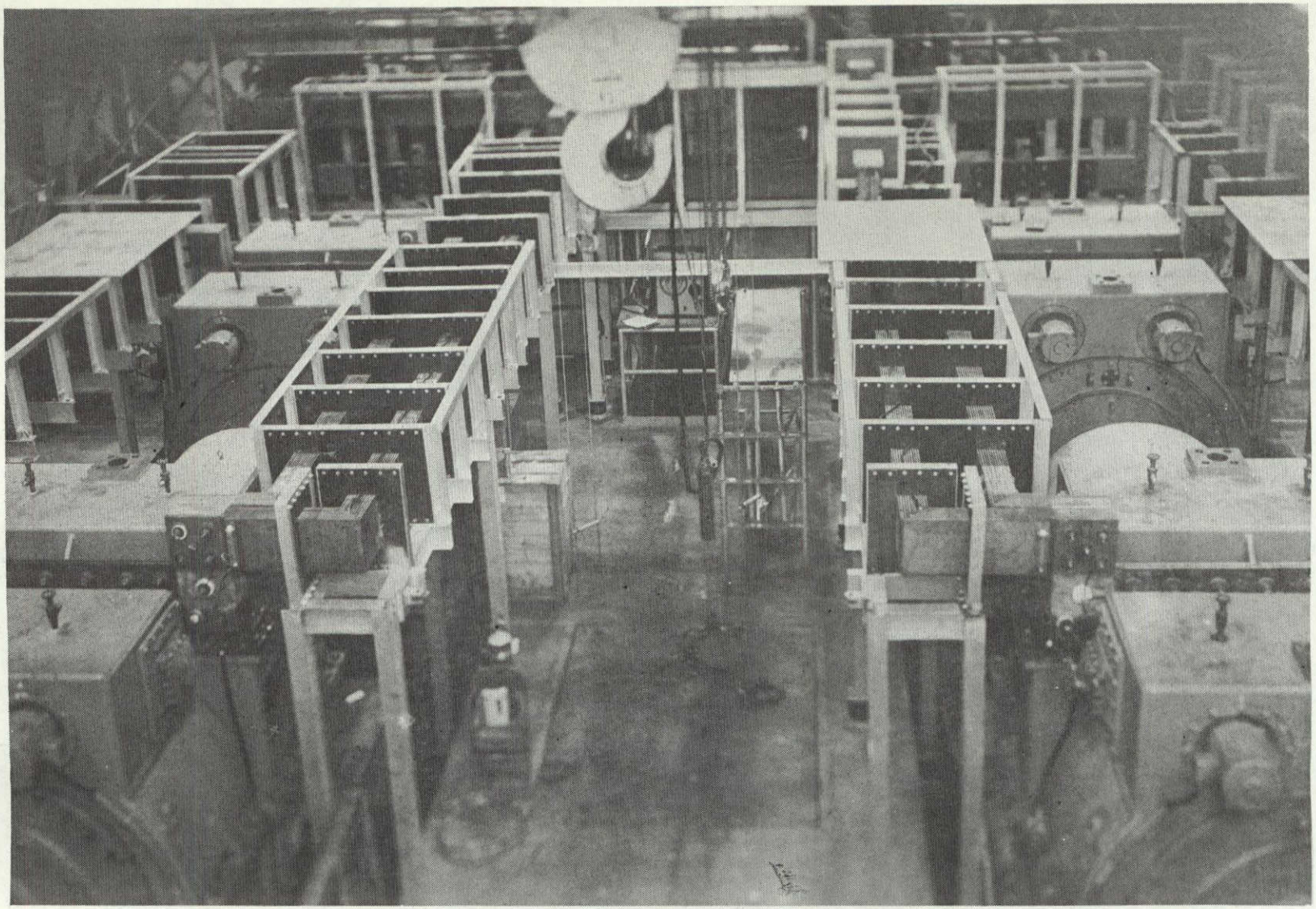

Figure 6-2. ACYCLIC-GENERATOR INSTALLATION[3]

efficiency and cost are comparable to that of a conventional a-c generator, and it provides for the complete elimination of the subsystem's power conditioning unit, particularly the high cost of the rectifier and losses associated with it.

## Power Conditioning

### Alternating-Current Generation Alternative

In the event that the shaft power from the nuclear plant was used to drive a-c generators a controllable a-c to d-c power conditioning system would be required. The power from the generators would likely be transferred to the electrolyzer site via overhead lines (though underground transmission could be employed).

At the electrolyzer site the a-c voltage is reduced to the approximate operating voltage of the electrolyzer with a step-down transformer. This lower voltage ac is then rectified and sent to the electrolyzer. Final adjustment of voltage level is accomplished during rectification by controlling the firing point of the thyristors, or as ac just prior to rectification by means of an induction regulator. Figure 3-3 reflects the power conditioning circuit arrangement specified by Lurgi for their electrolyzer installations.

Depending on the specific equipment used for power conditioning a 2% to 4% power loss can be expected. Current practice is to use separate power-conditioning units for each electrolyzer module.

### Direct-Current Acyclic Generation Alternative

The use of d-c acyclic generators as projected herein will require no power conditioning equipment. However, as a safety measure some form of fuse or circuit breaker between the generating plant and electrolyzer plant is desirable.

Voltage control needed for efficient electrolyzer operation is accomplished at the generator via field current control.

Power Distribution

As noted above, were a-c generation to be used, conventional overhead or perhaps underground power distribution equipment would be employed to transfer the power from the generators to the input transformers of the individual electrolyzer power conditioning units.

With the use of d-c acyclic generators, power distribution is somewhat more difficult in that large, low-voltage, high-current electrical distributors or bus-bars will be required. The latter system has been selected.

Natural air-cooling and forced internally cooled bussing systems of both copper and aluminum conductors was examined. A 0.5% distribution power loss and a generator-to-electrolyzer round-trip circuit length of 180 m (600 ft) formed the design basis. (See Section 8.)

Power dissipation densities of 9.9 W/kg Al (4.5 W/lb) and 4.8 W/kg Cu (2.2 W/lb) were calculated for these conditions. At these specific power-loss rates forced internal cooling may not be required. On the other hand, water-cooled conductors provide assurance of safe operation and offer increased installation compactness and flexibility. Aluminum provides for a lower cost design than copper by a factor of about 2.

Therefore, water-cooled aluminum power bussing has been selected for the study, however, a more detailed examination would be necessary to clearly deduce the cost-optimum system (forced or non-forced cooled bus bars). The water-cooled conductors could be fabricated by welding together two machined plates to form high-surface-area coolant passages.

Costs for copper and aluminum power-distribution conductors for the subsystem are shown in Figure 6-3. Material costs are estimated to be about $0.60/kW. Installation costs assumed a factor of 6 times this amount or $3.60/kW.

Two additional forms of d-c power distribution were briefly considered, superconducting and cryoresistive. Both are technically promising where longer bussing lengths are required, but since conventional bus-bars appear to be satisfactory for this subsystem application as described above, these advanced technology approaches were not further pursued.

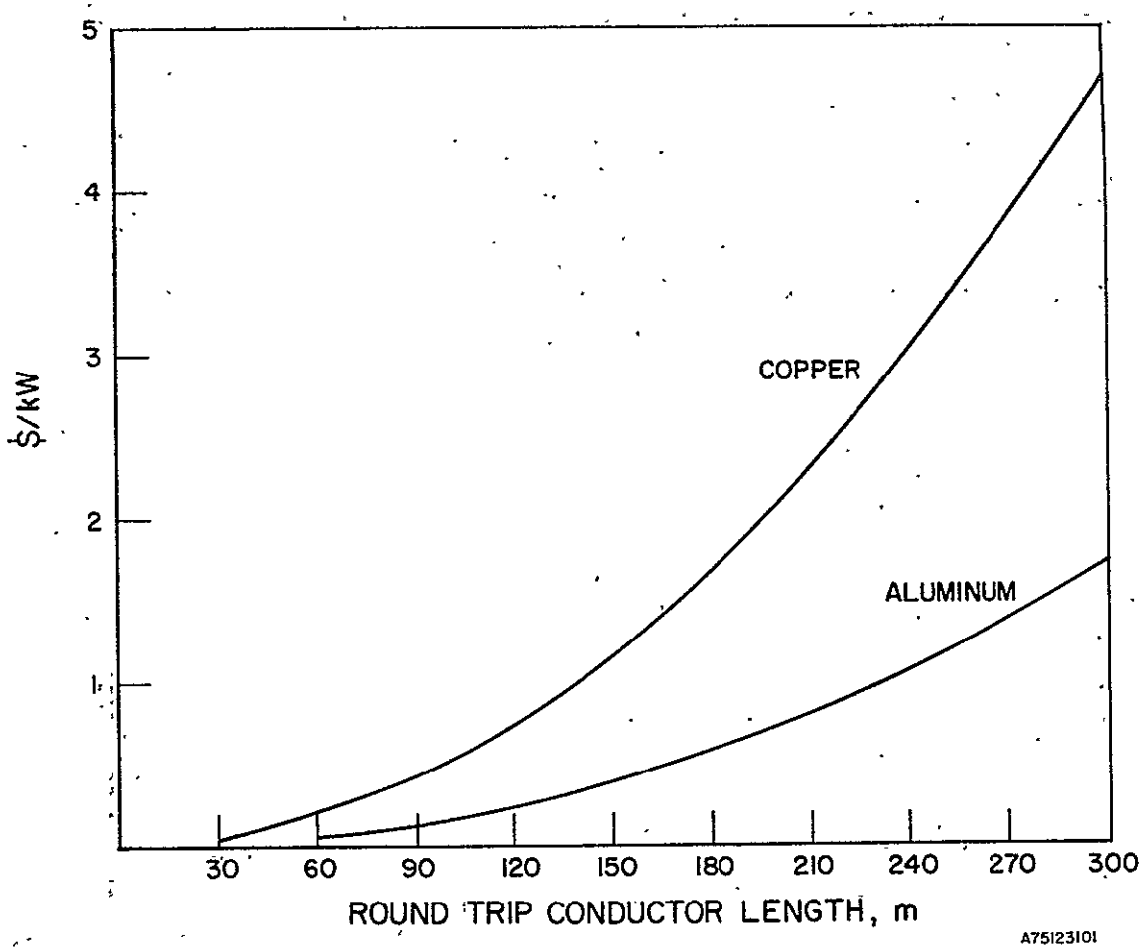


Figure 6-3. COST OF BUS BAR FOR 1000-V, 300,000-A LINE

The work at Los Alamos Scientific Laboratory (LASL) on d-c superconducting power-transmission-line (SPTL) research was particularly instructive. However, the much higher line voltages under consideration at LASL (100-200 kV vs. 1000 V) provide much lower specific current levels than required for the subsystem under study here.

LASL's general comment on the limitations involved in this application vis-a-vis the SPTL approach follows:

> "The line can be made to carry huge currents, but its limit is associated with the fault engineering and the conductor temperature stability. If for any of several reasons the superconductor should change from a superconducting state to a normal state, these huge currents need to be carried in a parallel copper

conductor as the power is off loaded. Huge currents then mean a huge heating rate in the copper as enough copper to carry the current safely may not be possible." (Reference 14.)

Subsystem Costs

In this section the costs of the two technically feasible shaftpower-to-electricity subsystem alternatives will be examined. These are 1) the conventional a-c generator plus power-conditioning units, and 2) the acyclic d-c generator. It will be recalled that conventional d-c generators are judged inapplicable to the subsystem. The data are summarized in Table 6-2.

For background and further detailed information on generator and power conditioning costs, the Main Survey Report section "Cost of Electrolytic Hydrogen" can be consulted by the reader.

Table 6-2. SUBSYSTEM EFFICIENCY AND SPECIFIC COST PER INSTALLED kWe

| Approach | Generator Unit[28] | Power Conditioning Unit[28] | Power Distribution | Total Subsystem |
|---|---|---|---|---|
| a-c Cost Plus Rectification | $15 (0.985) | $45 (0.975) | $0.4 (0.995) | $60.4 (0.955) |
| d-c Acyclic Cost Generator | $12 (0.985) | Does not apply | $3.6 (0.995) | $15.6 (0.980) |

It can be provisionally concluded that the d-c acyclic-generator approach is the distinctly superior alternative for this application as it is more favorable on both a cost and an efficiency basis.

## 7. ELECTRICITY-TO-HYDROGEN SUBSYSTEM

### General Description

The essential makeup of the electricity-to-hydrogen subsystem is presented in Figure 4-5. It consists nominally of 1) a water purification unit, 2) an electrolyzer unit, and 3) a hydrogen and (where oxygen is a produced commodity as well) an oxygen compression unit.

The basic subsystem inputs are 1) d-c electricity (from the shaftpower-to-electricity subsystem) and 2) water (a supply of municipal-quality water is assumed; raw river water or even seawater could be also used with appropriate desalination and purification).

### Status of Electrolyzer Technology

As recently discussed by researchers from the Brookhaven National Laboratory[35] and the Institute of Gas Technology,[36] there is a significant potential for improvement in electrolyzer efficiencies of today, for example as reflected in the baseline system value (of nominally 78%). Brookhaven summarizes this potential for the several electrolyzer types as follows:

> "For hydrogen production by water electrolysis to be competitive with the conventional methods, it is necessary to operate the electrolysis cells at high current densities ($\approx$1 amp $cm^{-2}$) and at high voltage efficiencies (close to 100% based on the higher heating value). Activation overpotential and ohmic overpotential contribute to the efficiency losses in water-electrolysis cells. The methods of improving the efficiencies of water-electrolysis cells are 1) maximization of real-to-apparent surface area of electrodes to reduce activation overpotential, 2) increase of operating temperature to reduce activation and ohmic overpotential losses, and 3) reduce the thickness between electrodes to decrease the ohmic drop in the cell. The present studies show that 1) in the General Electric solid-polymer-electrolyte cell, with high-surface-area electrodes, efficiencies close to 100% can be achieved at 80°C; 2) in the KOH electrolyte cell (e.g., Teledyne) using nickel electrodes, activation overpotentials at the hydrogen and oxygen electrodes are the main causes of efficiency losses; 3) an alkaline cell can operate at close to 100% efficiency with nickel electrodes at 150°C; 4) to operate at 150°C, it is necessary to replace asbestos, the currently used separator material (potassium titanate appears promising); and 5) elimination of the barrier (used to keep hydrogen and oxygen separated) can reduce cell resistance." (Reference 35.)

Also, with further development, and especially with the onset of large-volume production, electrolyzer capital costs are expected to become considerably more favorable than reflected in the baseline case (Section 3).

Increased electrolyzer-module size offers one important route to reduced costs. Economies-of-scale occur since the percent-effective cell area per unit cross-sectional area is progressively increased with absolute size.

However, present tooling limitations and other state-of-the-art factors limit the maximum size of electrolyzer-cell areas that can currently be constructed. For example, one manufacturer indicated that its maximum cell size hinges strictly on the size capacity of available injection molding equipment. It was further noted that the injection-molding industry is increasing its capability for larger sized moldings. In response to the needs of the automotive industry, among others, such development may permit larger electrolyzer cells to be fabricated in the future.

Technical Discussion

The fundamentals of water electrolysis and a general review of the technical state of development of electrolyzers have been covered in the Main Survey Report. A current-technology electrolyzer system has been described in Section 3 in connection with the baseline nuclear-electrolytic hydrogen-production facility. It will be recalled that this was a Lurgi alkaline-electrolyte bipolar pressure electrolyzer, a currently available system.

This section covers "advanced-technology" electrolyzer systems as considered for integration into the subject advanced hydrogen-production concept. Cost estimates are provided in a later portion of this section.

Three types of electrolyzers are considered; for simplicity and brevity, only one specific manufacturer for each technical design is discussed as follows:

| Generic Type | Specific Manufacturer (Exemplary) |
|---|---|
| Bipolar, Alkaline Electrolyte | Teledyne Energy Systems |
| Unipolar, Alkaline Electrolyte | The Electrolyzer Corp. Ltd., Stuart Cell |
| Bipolar, Solid Polymer Electrolyte (SPE) | General Electric Co. |

Again, considerable background for each of these basic systems is provided in the Main Survey Report and in references cited therein.

Bipolar Alkaline Electrolyte Electrolyzer (Teledyne Energy Systems)[19,33,34]

Teledyne is directing its current research and development efforts toward —

1. The design of a large alkaline module capable of producing 7500 standard liters per minute (one ton per day),
2. Electrode-surface optimization, and
3. The development of a substitute for the asbestos separator to permit higher temperature operations.

Figure 7-1 projects the anticipated reduction in cell voltage (efficiency increase) with development over time as a function of cell current density projected by Teledyne. The lower curve, marked "5 - 10 years", denotes the technological basis appropriate for the subject advanced hydrogen facility (i.e., "1985 technology"). Performance of the Teledyne equipment is here predicated on the forecast development of electrolyte temperatures in excess of 121°C (250°F). The shaded area below the reference curve represents more speculative "goals," which pivot upon further temperature increases. This implies significant advances in materials as acknowledged in Teledyne's ongoing research program (item 3 above).

Each of Teledyne's electrolyzer modules may be run from 25% to 100% hydrogen-generation capability. A typical corresponding d-c input voltage is 865 to 970 V, and individual module current is 826 to 3306 A. An efficiency recently quoted by Teledyne is 83.8% (Reference 33), which corresponds approximately with Curve B.

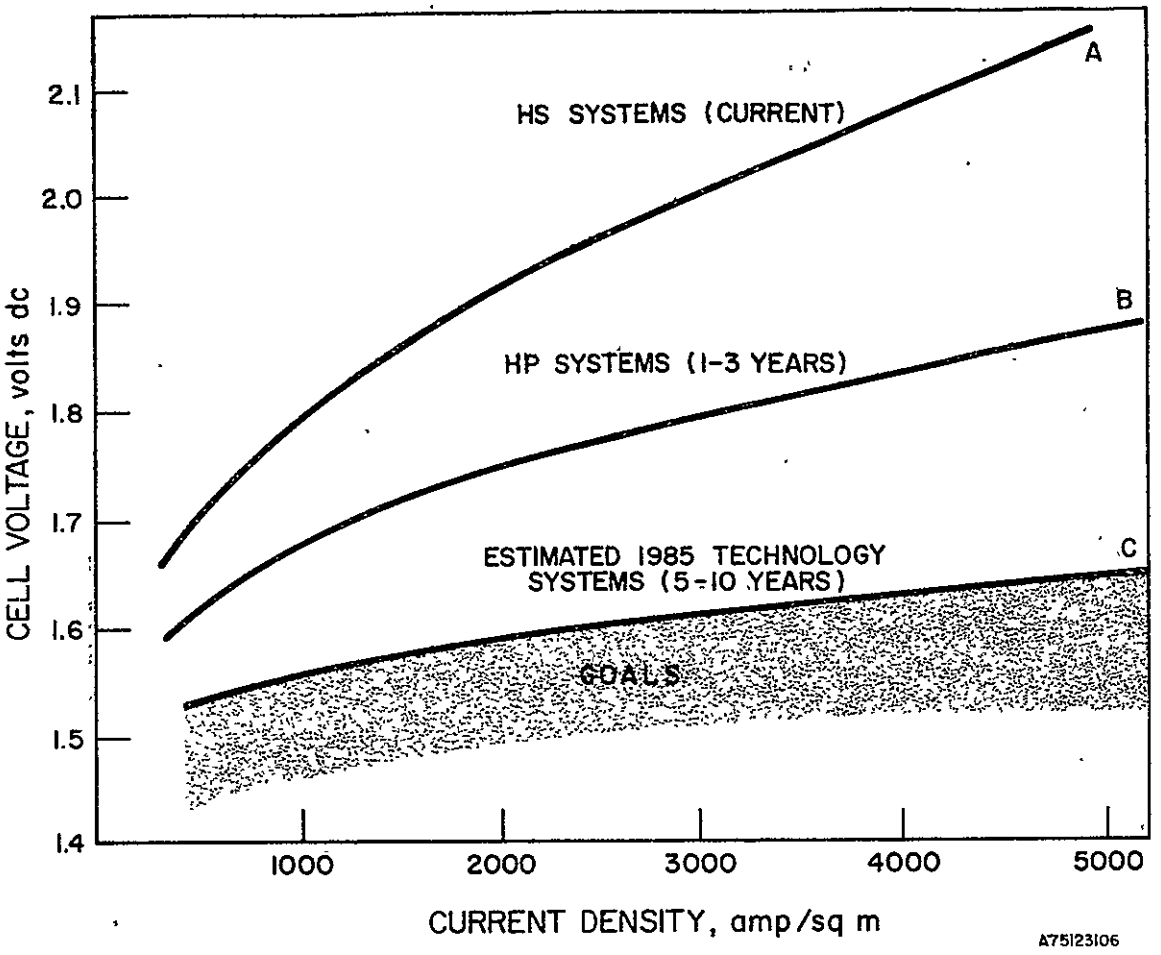


Figure 7-1. TELEDYNE BIPOLAR ALKALINE-ELECTROLYTE ELECTROLYZER DEVELOPMENT PROJECTIONS[34]

When requested to project to "1985 Technology" status for their system in support of the present study, Teledyne cited an estimated electrolyzer efficiency of 90%.[33] This is predicated on an ability to raise electrolytic temperatures to above 121$^0$ C (250$^0$ F) and cell operation in the vicinity of 5400 A/sq m (500 A/sq ft). This corresponds to Curve C in Figure 7-1, and characterizes the type of bipolar alkaline-electrolyzer judged to be applicable to the subject advanced hydrogen-production system.

Unipolar Alkaline-Electrolyte Electrolyzer (The Electrolyser Corp., Ltd.)[44]

The unipolar or tank-type electrolyzer, as represented by the Stuart Cell, which is marketed by The Electrolyser Corp., Ltd., of Toronto, Canada, is a mature and well-developed product. Reliability and simplicity in construction and operation lead to low maintenance and capital costs, as described in the Main Survey Report.

Currently, Stuart Cells are typically rated at 2.04 V, equivalent to an electrolysis efficiency of about 72%. Increases in efficiency can be achieved principally through increased electrolyte temperatures as is the case with the bipolar alkaline cell as discussed. A 2 to 3-year goal of 77% has been mentioned by the company. (See Main Survey Report.)

This can be achieved with improved separator materials on which some research is being conducted by the Electrolyser Corp. In lieu of an estimated efficiency corresponding to "1985 Technology," IGT has nominally increased the 77% figure by another 5% to 82%.

In view of the subject facility's need to achieve "pipeline pressure" hydrogen, a principal technical disadvantage of the unipolar cell in its present form, is its low gas-output-pressure capability. A maximum of mechanical compression equipment is needed to compress product hydrogen from atmospheric conditions to 6900 kPa (1000 psia). The associated capital cost and energy cost to provide this pressure capability is quite significant, as will be seen subsequently in this section.

The development of a unipolar electrolyzer capable of elevated output pressure presents an interesting challenge. If the challenge were to be met through innovative design and operation, the tank-type unit's virtues of physical and operational simplicity and ruggedness might well place it in a more competitive position for producing "pipeline condition" hydrogen (and oxygen).

Bipolar Solid-Polymer-Electrolyte (SPE) Electrolyzer (General Electric Co.)[40,41]

The solid-polymer-electrolyte electrolyzer concept has also been described at length in the Main Survey Report. Although not as yet fully developed, several unique advantages for this approach, as claimed by its

principal proponent, the General Electric Co., are particularly appealing in the context of the advanced nuclear-electrolytic facility concept under study here. They are principally –

1. The cell can operate with high differential pressures (> 1000 psi) in addition to high gas-generating pressures
2. There are no corrosive electrolytes to control or leak in the system
3. A minimum power requirement per unit gas generated results
4. High current-density capability can result in low capital costs as well as low operating cost.

General Electric has recently undertaken a study of "SPE Water Electrolysis Technology Development for Bulk Energy Storage Systems" under the sponsorship of The Brookhaven National Laboratory. This effort is expected to be concluded in January 1976. The present IGT study has been able to benefit significantly from information deriving from the GE study.

The most recent SPE electrolyzer design is reflected in the sketch of Figure 7-2. It is an end-grounded stack of cells with a positive electrical center-point feed at 1000-V d-c. The two "stacks" each consist of over 500 cells. At 3 sq m (30 sq ft) active cell area, the hydrogen-production rate is about 0.4 million std $m^3$/day (15 million SCF/day).[41] Efficiency is 86.45%.

Feedwater purification, deionization and gas/water separation functions are handled by appropriate ancilliary equipment. For 1000-psi electrolysis pressure the ancilliary energy requirements reduce the module efficiency about 0.15% to 86.3%.[40]

Hydrogen-Compression Equipment

The hydrogen product in the advanced concept facility is to be delivered to a pipeline condition of 6900 kPa (1000 psia). Any incremental pressure between the pipeline and the electrolyzer outlet pressure must be made up by mechanical compression equipment.

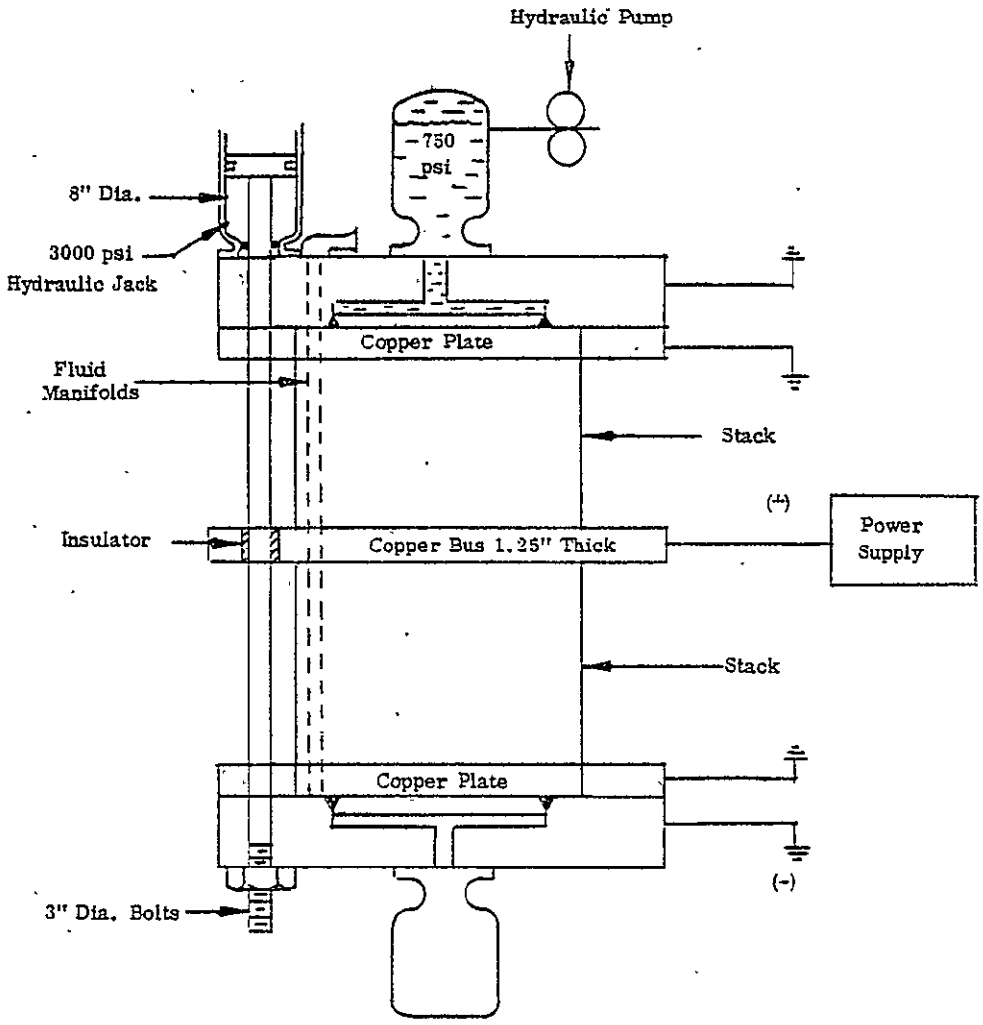


Figure 7-2. STACK AND END PLATE CONFIGURATION OF THE GENERAL ELECTRIC CO. SPE ELECTROLYZER[41]

Hydrogen is a difficult fuel gas to compress from an energy-content standpoint; its low volumetric energy density (high specific volume) requires:

1. Larger displacement compressors, and
2. Greater compression energy requirements

than the more common atmospheric gases: air, nitrogen, and oxygen. Further, its small molecular size causes greater leakage rates across piston rings, seals, etc. In the case of centrifugal compressors only a very limited pressure ratio can be provided with hydrogen per impeller stage for an established tip-speed limit.

Consequently, the capital cost and energy requirements for hydrogen compression for the very large flows contemplated for the subject facility of 5 million std cu m/day (300 million SCF/day) can be very significant to facility costs and overall efficiency.

In view of this, pressure-electrolysis at the rated output pressure is highly advantageous. It would obviate compressor capital, operating, and maintenance costs and eliminate all compressor-associated system inefficiencies. The maximum penalty due to mechanical compression is posed by electrolysis at atmospheric pressure, as would be expected, e.g., with conventional tank-type electrolyzers.

Figure 7-3 presents estimated compressor-plus-drive capital costs for various initial (i.e., electrolyzer outlet) pressures ($P_1$) in compressing hydrogen to 6900 kPa (1000 psia).

The more costly reciprocating-compressor curve (top line) is based on general planning-estimate information provided by Ingersoll-Rand.[7] Reciprocating compressors are capable of high stage-pressure ratios and high mechanical efficiencies. However, the equipment cost is relatively high, especially for a light gas like hydrogen. However, technically, reciprocating compressors are capable of compressing atmospheric pressure hydrogen to the specified pipeline pressure in a limited number of stages: about four.

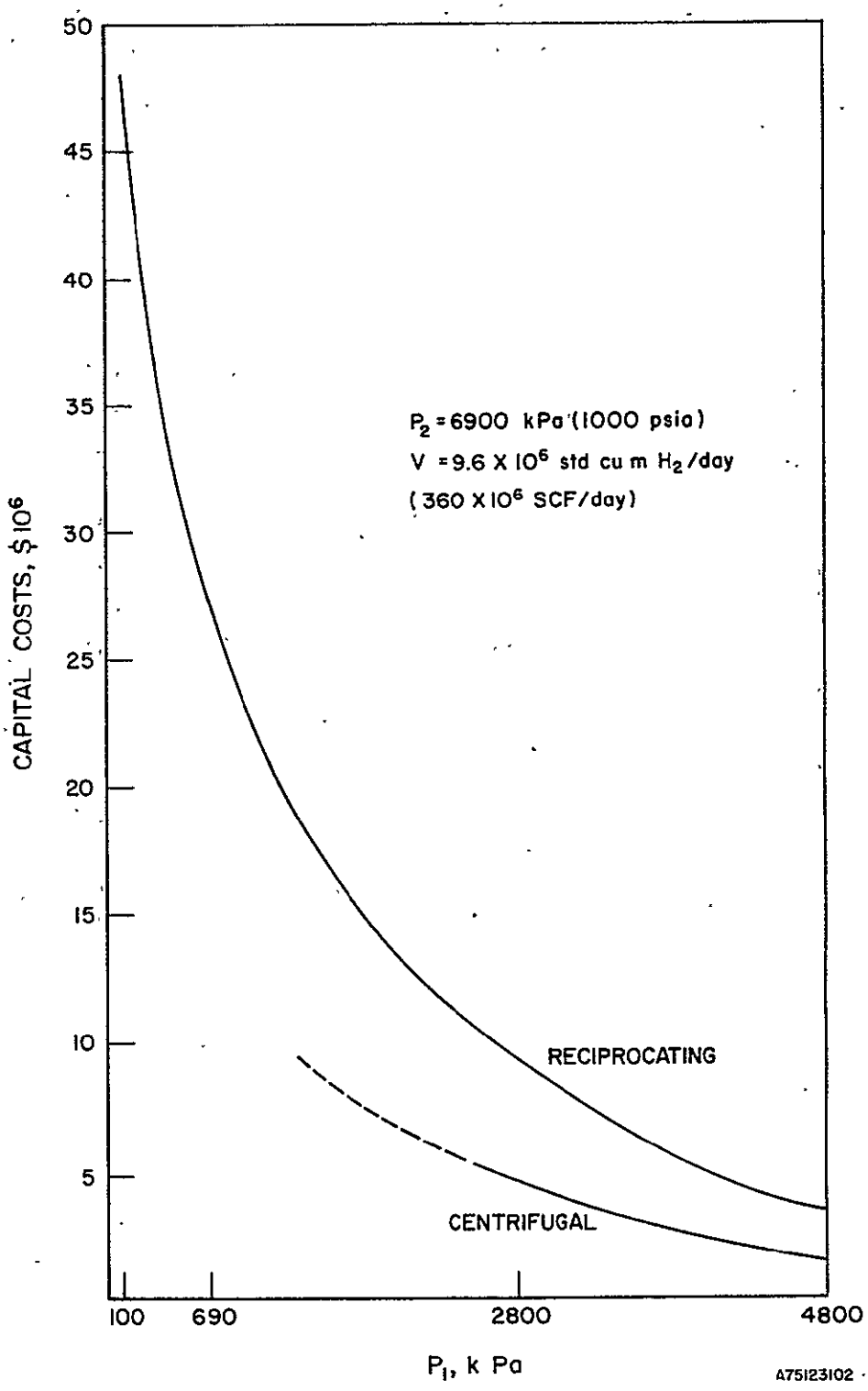


Figure 7-3. COMPRESSOR AND PRIME-MOVER COSTS FOR 1000-psia HYDROGEN-DELIVERY PRESSURE.
Nominal System Output: 360 million SCF/day

Such is not the case with lower cost (but less efficient) centrifugal compressors. With the very limited per-stage pressure ratio achievable with hydrogen (about 1.025 as compared to 1.4 with air), the operation of atmosphere-to-1000 psi all-centrifugal equipment is not practical. A reciprocating compressor would likely be selected for an initial pressure rise. It is not yet clear what would be an optimum transition point from reciprocating to centrifugal machines in such a composite arrangement. Further design analysis would be helpful in this area.

In view of this uncertainty, and hydrogen-service machine costs, the lower curve is strictly an estimated centrifugal compressor trend. The dashed section implies that the reciprocating/centrifugal transition point for very large pressure rises is not presently known, as mentioned.

Figure 7-4 shows the total cost of compression in terms of product-hydrogen-energy incremental costs. It is assumed here that electrical drives using local plant power are employed. Two power costs are noted, 8 and 16 mills/kWh to provide a measure of sensitivity to these compression energy costs.

Oxygen-Compression Equipment

If oxygen is to be sold as a byproduct from the facility, it is likely to be pipelined in parallel with the hydrogen. Oxygen compression to pipeline pressure will also be required, depending again on electrolyzer output pressure and oxygen-pipeline operating pressure.

Oxygen-compression technology is well-established industrially. Oxygen produced from air-separation plants is compressed and distributed in pipelines routinely to serve steel plants and other industrial customers. A typical pipeline pressure range is 2800 to 3400 kPa (400 to 500 psia).

This study did not, however, go into this subject outside of estimating the influence on hydrogen production costs were an oxygen byproduct credit to be taken. (See Section 9.)

Subsystem Costs

Table 7-1 summarizes the electricity-to-hydrogen subsystem costs for the three types of electrolyzer units reviewed above. Also included in the table is a summary of the representative efficiencies for the electrolyzer

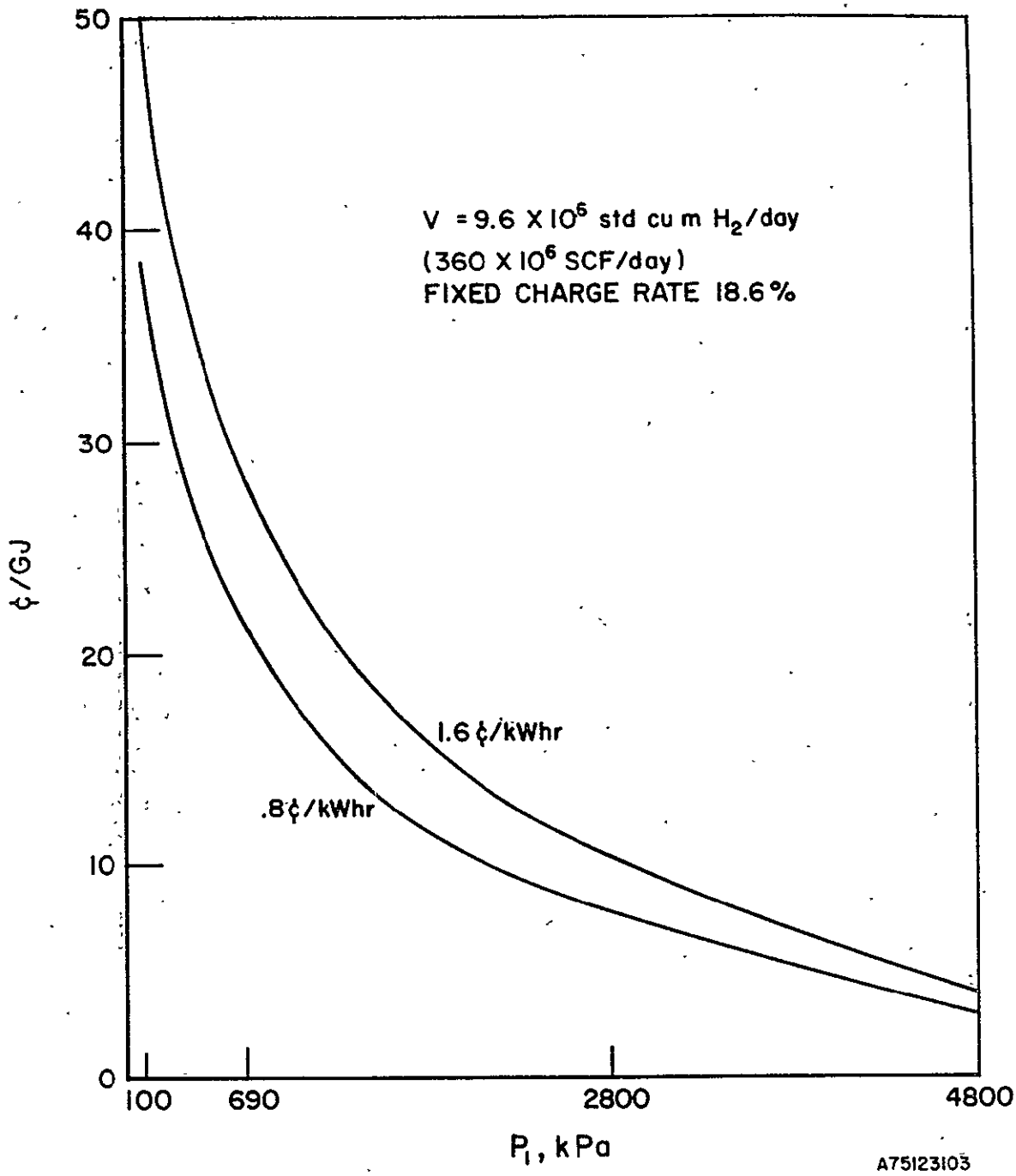


Figure 7-4. ENERGY COST OF COMPRESSION FOR HYDROGEN GAS TO 6900 kPa

## Table 7-1. COMPARISON OF ALTERNATIVE ELECTRICITY-TO-HYDROGEN SUBSYSTEM EQUIPMENT ON EFFICIENCY AND COST BASIS

| Electrolyzer Type | Cell Efficiency, % | Unit Efficiency, % | Total Efficiency (includes compression) % | $H_2$ Production Rate | Electrolyzer Specific Cost, $/kW $H_2$ Produced | Electrolyzer Cost, $ million | Compressor Cost,[d] $ million | Total Subsystem Cost, $ million |
|---|---|---|---|---|---|---|---|---|
| Bi-polar alkaline-electrolyte[a] | 90 | 89.4 | 87.2 | 8.790 X $10^6$ std cu m/day (328.1 X $10^6$ SCF/day) | 118 | 230.4 | 24.6 | 255.0 |
| Uni-polar alkaline-electrolyte[b] | 82 | 81.9 | 78.6 | 7.924 X $10^6$ std cu m/day (295.8 X $10^6$ SCF/day) | 100 | 176.0 | 39.3 | 215.3 |
| Bi-polar solid-polymer-electrolyte[c] | 86.45 | 86.3 | 86.3 | 8.699 X $10^6$ std cu m/day (324.7 X $10^6$ SCF/day) | 30 | 58.0 | 0 | 58.0 |

Based on representative information from (see text and Main Survey Report) –

[a] Teledyne Energy Systems

[b] The Electrolyser Corp. Ltd.

[c] General Electric Co.

[d] Ingersoll-Rand Co.

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unit without and with ancillary power requirements (electrolyte pumps, circulators, controls, etc.). Finally, the equivalent reduction in electrolyzer efficiency associated with hydrogen-compressor drive-energy demand is shown.

In this manner, where compression equipment is required to raise the product-hydrogen pressure to pipeline condition, the associated energy requirement is reflected as a decrease in electrolyzer-unit efficiency to yield a net subsystem efficiency. In effect, the electrical power required to drive the compressors is not available for electrolysis. Note that the efficiency for compression is for reciprocating compressors, and, hence, is likely to be higher than would be the case of centrifugal compressors.

Alternative compressor prime movers such as the main or auxiliary turbine shafts were not examined. However any differences in energy efficiency from the electrical drive approach would not be very substantial.

The basic electrolyzer costs were provided by the several manufacturers as noted. The basis for the estimates, in consonance with the overall study ground rules, was —

1. Mid-1975 dollars
2. "1985 technology" state-of-the-art with requisite R&D assumed (but no R&D costs are included)
3. Delivered items would be on assumed production basis, not "one of a kind" or the initial items produced.

## 8. ADVANCED-SYSTEM SYNTHESIS

### General Considerations

The selected high-efficiency nuclear-electrolytic hydrogen-production facility concept is an integration of the specific subsystems covered in Sections 5, 6, and 7, respectively.

Nuclear-to-Shaftpower Subsystem — A 3000-MWt high-temperature gas-cooled reactor (HTGR) operating at 980°C (1800°F) maximum helium-coolant temperature providing a total of 1500-MW shaftpower at 3600 rpm from 1) three helium-working-fluid Brayton-cycle gas turbines and 2) one ammonia-working-fluid Rankine-cycle turbine, operating in a binary cycle (topping/bottoming arrangement). Heat rejection from the ammonia bottoming loop is via evaporative cooling tower.

Shaftpower-to-Electricity Subsystem — Acyclic d-c generators (25) are directly driven on double-ended shafts by the helium and ammonia turbines at 3600 rpm producing a rated output of 300,000 A at 200 V each. Current collection within the generator is via liquid metal (NaK) conduction from the moving to the fixed components. No electrical transformation, switching, or a-c to d-c rectification is necessary. Electrical bussing from the acyclic generators to the electrolyzer units, a nominal distance of 180 m (600 ft), is via conventional water-cooled aluminum conduits.

Electricity-to-Hydrogen Subsystem — Bipolar electrolyzers (20) using solid-polymer-electrolyte (SPE) are used to dissociate purified water to hydrogen and oxygen gas at nominal output pressure of 6900 kPa (1000 psi). The nominal per-module operating-voltage is 1000-V d-c and the current is 75,000 A.

### Subsystem and System Sizing

The sizing of the system was established by a nuclear-reactor thermal-power level of 3000 MWt. This size HTGR is representative of GA's design-point (although a maximum of 3800 MWe is allowed under the Nuclear Regulatory Commission's (NRC, formerly Atomic Energy Commission) present statutes).[43] General Atomic Co. has studied even higher power-level HTGR designs, but the majority of its experience, as drawn from for the purposes of this study, is at the 3000-MWt level.

Based on the efficiencies of the subsystems which, in this system, operate basically in series from nuclear-heat-energy input to hydrogen-energy output, the selection of the reactor size also sets the facility's hydrogen output level. Nominally, this output is 8.7 million std cu m/day (325 million SCF/day) of hydrogen at pipeline pressure. Coproduced oxygen quantities are 4.4 million std cu m/day (162 million SCF/day), also available at pipeline pressure.

The principal subsystem items have each been selected on the basis of the individual experience and projections of representative suppliers of related hardware. Here IGT was guided strictly by advisements and recommendations received through both its general energy-related information channels and informally focused liaison activities carried out during the course of the study.

Table 8-1 summarizes major subsystem items as selected for the advanced-system synthesis. Individual unit sizing and net subsystems design capabilities are listed along with technical information sources.

Table 8-1 SUMMARY OF MAJOR SUBSYSTEM ITEMS SELECTED FOR THE ADVANCED SYSTEM

| | |
|---|---|
| **Nuclear-to-Shaftpower Subsystem** | |
| 1 | HTGR at 3000 MWt and 980°C (1800°F) helium outlet temperature |
| 3 | Helium gas turbines at 360-MW shaftpower |
| 1 | Ammonia turbine at 420-MW shaftpower |
| **Shaftpower-to-Electricity Subsystem** | |
| 25 | Acyclic d-c generators rated at 60 MWe, 300,000 A and 200-V d-c |
| 10 | Aluminum water-cooled bus bars operating at 300,000 A and 1000-V d-c |
| **Electricity-to-Hydrogen Subsystem** | |
| 20 | High-pressure, high-current-density electrolyzers of the bipolar solid-polymer-electrolyte type rated at 1000-V d-c and 75,000 A (75MW). Hydrogen-production rate is 435,000 std cu m/day (16.2 million SCF/day). |

Subsystem Selection and Interfacing

Functional descriptions of the three major subsystems were provided in Section 4, including a qualitative treatment of subsystem interfacing and basic system inputs and outputs. Each subsystem area has been technologically assessed and specific performance characteristics, as estimated by representative manufacturers, described.

In this section, a specific selection of subsystem facilities and equipment is made based on the various types covered in Sections 5 to 7. This selection will be oriented to maximizing the overall effectiveness of the production facility. The primary criterion will be a minimum estimated hydrogen-production cost, although rigorous cost-optimization was beyond the scope of the study. (See Section 9.)

Nuclear-to-Shaftpower Subsystem

Based on a 3000-MWt HTGR as designated by the General Atomic Co. and a helium-reactor outlet temperature of 980°C (1800°F), the nuclear-to-shaftpower system is selected to be essentially that described in Section 5.

Three helium gas-turbine assemblies comprise a compressor, a turbine, bearings and shaft, ducts and housing, and controls and ancillaries. Each is rated at 360-MW shaftpower. These operate at 3600 rpm and are arranged within the PCRV along a chordwise line in a symmetrical triangular or "delta" configuration (as opposed to the symmetrical radial alignment illustrated in Section 5). This provides for the needed double-ended drive arrangement in which two shafts from each gas turbine are made available for electrical generator drives. The double-ended arrangement was necessary to accomodate the electrical generators as will be discussed below.

A fourth turbine, a split-flow opposed ammonia-Rankine-cycle turbine provides two drive shafts providing an additional 420 MW at 3600 rpm.

Helium from the reactor at 980°C (1800°F), the GA "Mark II" design point, is routed directly to the gas turbines with no intermediate heat exchange. This is in accordance with GA design practice, observing the fact that the turbine units are completely contained within the PCRV.

The helium exiting the turbines and recuperators is then heat-exchanged with the ammonia bottoming-cycle working fluid. Designs with and without

intermediate heat exchange were examined. It was estimated by GA that the imposition of an intermediate heat-exchange loop using helium would penalize overall subsystem efficiency about 2% to 3% and raise subsystem costs by about 5%.

Although, in further design-analysis of this system, it may be deemed necessary to avoid the possibility of ammonia encroachment into the primary reactor/turbine, the current concept studied here does not utilize an intermediate heat-exchange loop.

The ammonia-loop heat rejection is via heat exchanger to a water loop connected to two evaporative cooling towers (access to a once-through cooling heat-sink would be advantageous, but this is assumed not available).

The subsystem is housed in a conventional-type reactor-containment building with the usual ancillaries and services provided as in central electricity-generation-station design. Procedures for operation and maintenance are conventional and all accepted safety measures would be incorporated.

Shaftpower-to-Electricity Subsystem

As noted in Section 6, the choice of electrical generators narrows down to 1) conventional a-c generators of the type used in utility service presently or 2) "unconventional" acyclic d-c generators.

Alternating-Current Generators

Alternating-current generators are, of course, well developed. Further, there does not appear to be significant growth potential in the basic technology. The prospect for cryogenic superconducting machines seems to be primarily in the direction of reduced generator size, as discussed in Section 6, not in itself useful to the design considered here.

The principal drawback of the a-c generator for the present application is the concommitant requirement for expensive power-conditioning equipment and the significant energy inefficiencies this entails. It is possible that these penalties could be somewhat ameliorated by operation at increased electrical frequency, say at 400 Hz. Rectifier equipment might be substantially lower in costs and higher in efficiency at these conditions. However, this avenue was not explored quantitatively in the study.

Acyclic Direct-Current Generators

The acyclic d-c generator as espoused by the General Electric Co. offers an advantageous alternative. Although basically requiring substantial research and development, acyclic machines of considerable size, as large as 25 MWe, have been placed in service. (See Figures 6-1 and 6-2.)

As can be seen in Table 6-1, for shaftpower of 360 MW, as available from the helium turbines, a nominal generator speed of around 1200 rpm was required, well below the 3600 rpm experience-base of the General Atomic designers.

GA conducted a preliminary assessment of helium-turbine shaftspeed design implications down to 1500 rpm. Significant problems were noted: equipment size increased markedly, additional turbine and compressor stages had to be added, and machine efficiencies were significantly reduced.[2]

Also, the basic departure from GA's established design experience at 3600 rpm was viewed as undesirable in light of the study's conceptual nature and limited means.

Accordingly, the approach of multiple generators on a single turbine shaft was examined. GE had previously reflected design concepts with up to three acyclics on a single shaft (Reference 9). For 3600 rpm, the nominal generator output power would be 50 MWe (Table 6-1).

GE indicated that the design could reasonably be extended to 60 MWe, providing for six units per helium turbine and seven for the ammonia-turbine. However, a maximum number of three generators on a single shaft was recommended. The option of six units on a single shaft, as required in the conventional GA radially aligned "single-ended" turbine layout within the PCRV (Figure 5-1), was definitely unacceptable. The problem is basically one of drive-shaft size.* This encroaches excessively on the functional design of the machine.[29]

* Large diameter shafts are required for the large torque carried through the generators nearer to the turbine.

The net result is a double-ended helium-turbine arrangement requiring the previously stated departure. The design was shifted from the radial turbine placement to the "delta" configuration within the PCRV. Three additional shaft penetrations of the PCRV are required as well. Since GA had earlier given some consideration to the "delta" arrangement, this was deemed an acceptable layout on a preliminary basis.

The higher power rating of the ammonia turbine (420 MW vs. 360 MW), considering the desirability of a "standard size" 60-MWe acyclic unit to be used throughout the facility, required seven generators. In a double-ended turbine arrangement, which the split-flow turbine configuration (Figure 5-5) readily lends itself to, one shaft would have four and the other would have three acyclic units. Although, four units on a shaft is non-optimum according to GE, such a design was assumed.

Acknowledging this, an eighth generator, a smaller a-c unit, is added to the ammonia turbine (on the three-acyclic-generator end). This unit is nominally sized at 5 MWe, 60 Hz. This unit provides about 4 MWe power to the electrolyzer ancillaries (feed-water pumps, etc.) and for the controlled field excitation power for the acyclic generators. The remaining 1 MWe a-c provides "house power" for the rest of the facility for operating machinery, lighting, environmental systems, and miscellaneous uses.

With the three-unit strings at each end of the three helium turbines and the seven generators (four plus three) associated with the single ammonia turbine, a total of 25 acyclic generators are provided. A single standard unit rated as follows was selected based on interfacing requirements with the electrolyzer units:

Table 8-2 ACYCLIC-GENERATOR DESIGN CHARACTERISTICS[29]

| | |
|---|---|
| Generator Efficiency | 98.4% |
| Generator Output Power | 60 MWe |
| Rotational Speed | 3600 rpm |
| Rated Current | 300,000 A |
| Rated Voltage | 200 V |
| Overall Diameter | 1.7 m (5.6 ft) |
| Overall length | 2.0 m (6.6 ft) |
| Installed Weight | 24,000 kg (52,000 lb) |

Direct-Current Electrical Distribution

As a portion of the subsystem, in view of designated interfacing points (Table 4-1), the electrical distribution components (busses) from the generators to the electrolyzers provide a significant technical challange due to the relatively large currents included.

Several approaches were explored to a preliminary level:

1. Conventional air-cooled conductors
2. Convective forced-cooled conduits (water and hydrogen)
3. Cryoresistive circuits
4. Superconducting circuits.

In the case of the acyclic-generator installation, depending on the generator-to-electrolyzer physical separation, the power-bussing problem may be aggravated since low-voltage d-c availability signifies large currents and, hence, large conductors (to limit ohmic power losses).

With this prospect in mind, the cryogenic-circuit alternatives were explored in view of the conceptual nature of the study. In addition to consulting the literature, the advisory assistance of the Los Alamos Scientific Laboratory (LASL) researchers working in superconducting electric-transmission systems was obtained.[14]

In view of the generator-to-electrolyzer runs being reasonably short, nominally about 90 m (300 ft), it was determined that water-cooled aluminum busses would provide acceptable costs and power losses. GE has considered this type of bus for use with acyclic generators and suggested a high length/width ratio plate-and-channel weldment of high-conductivity aluminum alloy as being a reasonable approach.[29] The thin, flat channel provides high contact area for heat removal from the conductors.

Cryoresistive and superconducting busses would hold significant advantages over the forced-cooled ambient-temperature units if generator-to-electrolyzer distances became quite significant. They may also be superior, in terms of cost and/or energy dissipation performance in close-coupled arrangements, such as the present concept. But a determination in this area was beyond the scope of the study.

## Electricity-to-Hydrogen Subsystem

### Electrolyzer

Electrolyzer efficiency, capital costs, and hydrogen outlet pressure are the key selection criteria in the context of the advanced facility concept. These have been discussed for the three basic electrolyzer types considered in Section 7.

In narrowing down the candidates for the selected advanced hydrogen-production facility concept, the efficiency and costs presented in Table 7-1 indicated that the unipolar alkaline-electrolyzer type, having the lowest efficiency not compensated by commensurately low cost, would not yield the lowest hydrogen costs. Further, being an ambient-pressure system, it required a maximum of compression investment and energy.

The bipolar alkaline- and solid-polymer-electrolyte (SPE) systems, on the other hand, were found to have more favorable efficiency and cost characteristics. The alkaline-electrolyzer offered a higher efficiency while the SPE system was considerably less expensive. Further, the lack of a mechanical compression requirement with the SPE system adds to its cost characteristics.

When a check on the respective hydrogen production costs of systems using each of the electrolyzer alternatives was made, it became evident that the SPE electrolyzer gave significantly lower costs (by 20%, see Section 9). It was therefore selected for integration into the advanced facility concept.

Based on technical information provided by the General Electric Co. on the SPE electrolyzers, unit sizing was carried out to match the d-c electricity generation equipment as covered above. Twenty units (stacks) are used.

The results are presented in Table 8-3.

### Mechanical-Compression Unit

In view of the SPE-type electrolyzer being capable of 6900 kPa (1000 psia) outlet pressure using pumped feed-water, no further gaseous compression equipment is required in the context of the present study.

Table 8-3 BIPOLAR SOLID-POLYMER-ELECTROLYTE TECHNICAL CHARACTERISTICS

| | |
|---|---|
| Rated Output Pressure | 6900 kPa (1000 psi) |
| Cells per Stack | 588 |
| Cell Stack Voltage | 1000 V d-c |
| Cell Stack Current | 300,000 A d-c |
| Electrolyzer Current Density | 12,900 A/m$^2$(1200 A/sq ft) |
| Cell Stack Efficiency* | 86.5% |
| Electrolyzer-Unit Efficiency* | 86.3% |

* Defined as higher heating value chemical energy of product hydrogen divided by total electrolyzer d-c electrical power input.

System Physical Description

The advanced nuclear-electrolytic hydrogen-production facility is illustrated schematically in Figure 8-1. It is composed of subsystems and component units just described. The system will be briefly further described in this section and overall performance estimated made.

A detailed conceptual design of the facility was beyond the study scope.

The facility is based on a single high-temperature gas-cooled reactor (HTGR) rated at 3000 MWt. Three helium gas turbines are operated in parallel and each drives six 60-MWe acyclic d-c generators. The turbines, recuperator, and pre-cooler heat-exchanger ducts and controls — as well as the reactor unit — are contained within a central prestressed concrete reinforced vessel (PCRV). The double-ended turbine drive shafts pass out of the PCRV at six points to drive the 18 generators, three on each shaft, which are outside the PCRV.

An ammonia Rankine-cycle power loop, located external to the PCRV, receives its heat input via heat-exchange in the pre-cooler with the helium exiting the gas turbines. The ammonia turbine is a symmetrical split-flow design to zero out thrust loads and reduce rotor size. It drives four 60-MWe acyclics on one shaft end and three on the other. A 5-MWe (nominal) a-c generator is added to the latter end. This supplies sub-system ancillary power requirements and general facility house-power. The acyclic generators are electrically connected in series in 5-unit sets.

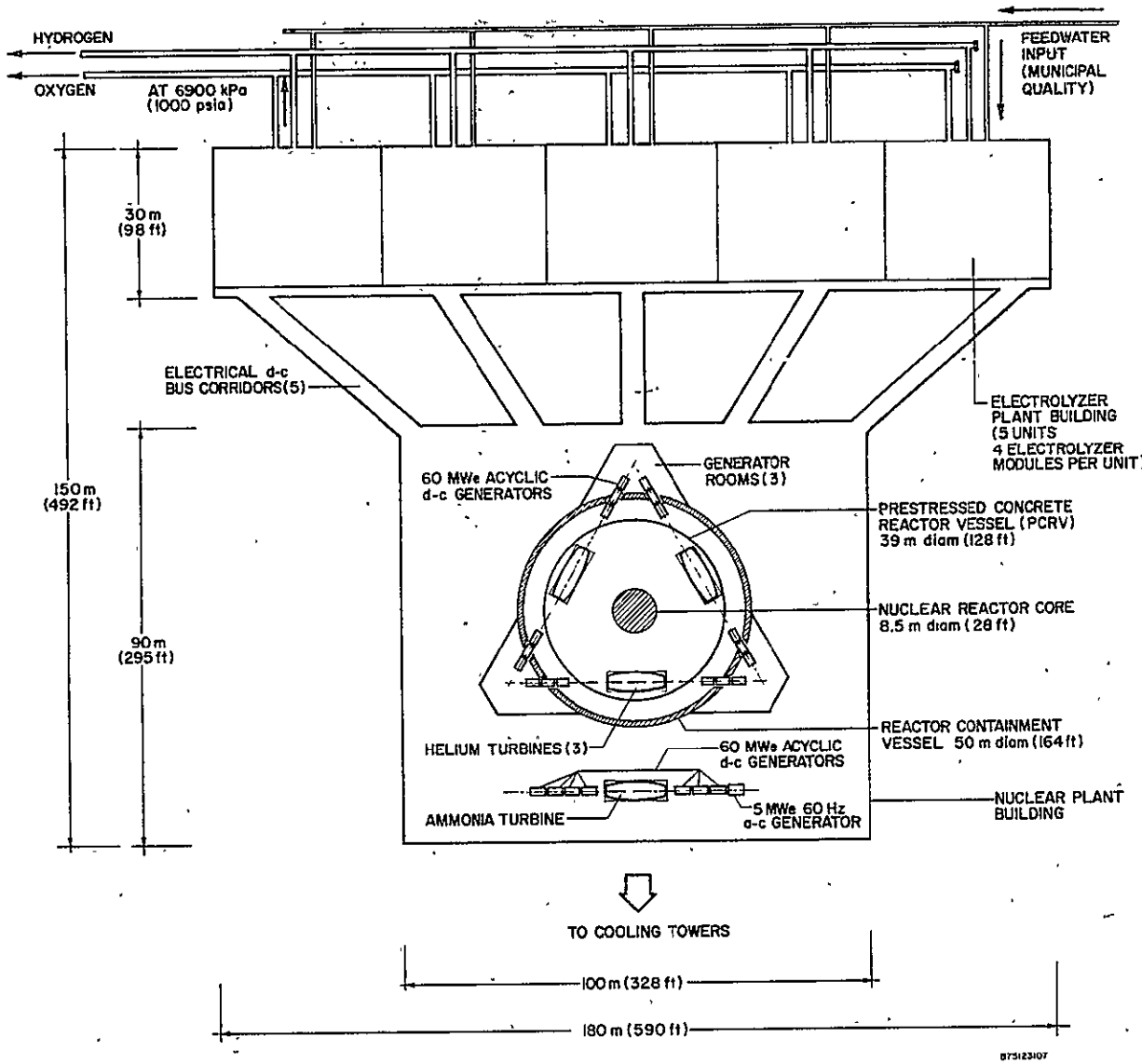


Figure 8-1. CONCEPTUAL LAYOUT OF THE ADVANCED NUCLEAR-ELECTROLYTIC HYDROGEN-PRODUCTION FACILITY

Each of the five 1000-V d-c circuits comprise a pair of aluminum busses connected through circuit breakers that are closed at all times except when anomalous system operation is experienced or an emergency situation exists.

The five circuits each energize four bipolar solid-polymer-electrolyte (SPE) pressure electrolyzers in parallel. Each of these operates at 1000 V and absorbs a rated 75,000 A. The electrolyzers are fed high-pressure feed-water that has been purified to requisite levels.

Hydrogen and oxygen gas are produced at 6900 kPa (1000 psia) and collected in a high-pressure distribution manifold. The hydrogen flow is manifolded through appropriate valving and metering, and fed into a transmission pipeline. The oxygen coproduct can be similarly fed to a second, oxygen-transmission pipeline or it can be vented to the atmosphere. A third alternative is liquefaction of part or all the oxygen for transport by rail cars or other means. Since the oxygen is automatically at elevated pressure, an expander turbine may also be used to recover shaftpower while cooling the oxygen for liquefaction.

System Performance

System performance is reflected in the overall energy- and mass-flow balance presented in Table 9-1.

System throughput efficiency, and costing, is presented in Section 9.

The Multiple-Module Large-Scale Hydrogen-Production Complex

Considering the advanced nuclear-electrolytic hydrogen-production facility concept considered so far in this study (Figure 8.1), when one addresses the potential need for producing very large quantities of hydrogen, as would be required in major hydrogen-energy usage, multiple-system (or module) complexes feeding a large pipeline system would logically be considered.

Such a complex would be akin to the "nuclear park" concept, sometimes referred to as a "Nuplex" (for nuclear-complex), as considered in earlier studies.

A recent study by the Nuclear Regulatory Commission has indicated a number of significant advantages to this "Nuclear-Energy Center" approach that would seem directly applicable to the nuclear-hydrogen facility.

These findings, as cited in an IGT publication, are summarized here:[30]

> "The Nuclear Regulatory Commission will report to Congress January 19 that nuclear energy centers consisting of 10 to 20 commercial plants at a single site can be made "feasible and practical" and will recommend 37 potential sites. The reactors would be located in clusters of four, each group 2 mi apart, to occupy a total area of about 40 sq mi. Additional large tracts of land would be needed for transmission lines running to service areas. Because the centers would dissipate large amounts of waste heat into the atmosphere, they could "substantially modify local meteorology and weather conditions," the study points out. Potential advantages of the centers include savings of up to 15% in construction costs over single-reactor sites and the provision of steady employment for 2 decades at one location. The study finds no significant difference in safety between the centers and dispersed plants. Some Government incentives, such as construction loan guarantees and the use of surplus federal lands, may be needed to encourage the nuclear centers, says the study."

The number of 3000-MWt nuclear-reactor-based "modules" (i.e., the system of Figure 8.1) to maintain full service operation of a large gas transmission pipeline has been estimated for illustration purposes, from an earlier study by IGT.[30]

The following conditions were stipulated, or otherwise selected, to match the study system characteristics:

Table 8-4. CONDITIONS FOR PIPELINE HYDROGEN SYSTEM ILLUSTRATION

| Hydrogen-Production Rate | SI Units | Illustration English Units |
|---|---|---|
| Volume Basis (stream day) | 8.7 million std cu m/day | 325 million SCF/D |
| Energy Basis | 32.5 million GJ/yr | 30.8 trillion Btu/yr |
| Pipeline Diameter | 1.22 m | 48 in. |
| Operating Pressure | 6900 kPa | 1000 psi |
| Pipeline Length | 492 km | 300 mi |
| Hydrogen-Product Cost | $4.15/GJ | $4.38 million/Btu |

For a cost-minimum system, the delivered hydrogen volume estimated from Reference 45's Figure 9 is approximately 248 million GJ/year (235 trillion Btu/yr).

Assuming that the fuel-use of hydrogen to operate the pipeline compressors was negligable (it is a significant transmission cost factor, however), this delivered energy rate can be used to determine the number of modules required.

For the rated module hydrogen production rates it is seen that 8 modules would be required for the assumed 80% capacity factor.*

The minimum transmission cost would be 12.1¢/GJ for 492 km (11.5¢/million Btu for 300 miles). This is about 3% of production cost.

Because it is very considerably less expensive to transmit energy as hydrogen in comparison with electricity,[25] such a "Hyplex" (hydrogen-nuclear complex) could be located much more remotely from the points of use than an equivalent nuclear-electric complex providing conventional electricity.

In view of the difficult siting constraints that have been applied to nuclear systems, this may prove to be a salient advantage for the hydrogen system.

* By the same token, one module would be capable of servicing, on the average, a 0.43 m (17 in.) diameter pipeline at the same conditions.

## 9. ADVANCED-SYSTEM ANALYSIS

### Estimated Facility Energy-Conversion Efficiency

The 980°C (1800°F) helium-temperature HTGR-operated binary power-extraction cycle provides the major share of the marked efficiency gain over the base-line LWR-based system. Directly-generated d-c electricity is transmitted to the electrolyzers with a distribution power loss of only about 0.5%. The high-current-density, SPE pressure electrolyzers produce hydrogen with a net electrolysis efficiency of 86.3%.

Of the initial 3000-MWt reactor heat output, the system yields 1288 MW (8.7 million std cu m/day or 326 million SCF/day) of product hydrogen at pipeline pressure. The overall nuclear-heat-to-hydrogen conversion efficiency, based on the higher heating value of hydrogen, takes place at 42.9%. A tabular energy-flow balance and statement of efficiencies is presented in Table 9-1.

Table 9-1. ADVANCED-SYSTEM ENERGY- AND MASS-FLOW BALANCE

| Input | Processing (Efficiency) | Output |
|---|---|---|
| 3000 MW | Nuclear-Heat to d-c Electricity (0.50) | (1500 MW) |
| (1500 MW) | d-c Electricity Transmission and Control (0.995) | (1493 MW) |
| (1493 MW) | d-c Electricity-to-Hydrogen at Pipeline Pressure (0.863) | 1288 MW |
| 3000 MW, Net Input | | 1288 MW, Net Output |

$$\text{Overall Efficiency} = \frac{1288\ \text{MW}}{3000\ \text{MW}} = 42.9\%$$

$7.0 \times 10^6$ kg $H_2O$/day ($1.6 \times 10^7$ lb/day) for electrolysis, excluding cooling requirements → $7.8 \times 10^5$ kg $H_2$/day ($1.7 \times 10^6$ lb/day) + $6.2 \times 10^6$ kg $O_2$/day ($1.4 \times 10^7$ lb/day)

### Estimated Facility Costs

#### Financing Rules

In developing economic groundrules, attempts were made to be consistent with the model specified by the Atomic Energy Commission (AEC) for previous nuclear process-heat studies.[24,47,49] Some of the guidelines used in this study are at variance with the AEC guidelines in order to simplify

the analysis, or to more accurately reflect post-July 1974 economic conditions. Because of the limited scope of this study, detailed economic analyses, such as those typical of nuclear-fuel-cycle cost calculations, were not performed.

These financing rules were identically applied to the baseline case (see Section 3) and the advanced-system cases. The following summarizes the costing groundrules used:

- All capital and operating costs are in July 1975 dollars
- No escalation of construction or operation costs is considered
- Economic analysis assumes privately-owned utility financing and tax rates
- Annual fixed-charge rate for depreciable investments is 15%
- Investment is depreciated over 30 years straight-line for books and sum of years digits for taxes, annual tax charge is normalized; that is, the present value of the tax payments is converted into an equivalent annual expense for the life of the investment
- Interest during construction is 10% compounded with an outlay schedule to yield 41% of total direct and indirect investment
- Eight-year construction period
- Plant-capacity factor is 80%
- Nuclear-fuel-cost assumptions are derived from GA and the literature
- Cost estimates are made on the basis that the plant is of proven design (that is, it is not the first of its kind or size)
- $15,000/yr labor rate.

Cost of capital was estimated from the following economic parameters:

| | % | 1972 Avg. Yield[18] | New Project Yield |
|---|---|---|---|
| Debt | 53.1 | 5.7 | 8.9 |
| Preferred Stock | 11.8 | 6.1 | 9.0 |
| Common Stock | 35.1 | 11.8 | 12.0 |
| | 100% | 7.9% | 10.0% |

New Project Yield (Cost of Capital): 10%

The fixed charge rate for depreciable plant investment is broken down as follows:

| | |
|---|---|
| Capital Recovery Factor | 10.61% |
| Federal Income Tax (at 48% rate) | 2.29 |
| Interim Replacements | 0.35 |
| Property Insurance | 0.25 |
| State and Local Taxes | 1.50 |
| Fixed Charge Rate | 15.00% |

Capital Costs

By far the greatest portion of the capital investment (90%), is allocated for the nuclear-to-shaftpower subsystem (i.e., the HTGR nuclear facility). A breakdown of its estimated capital costs is given in Table 9-2. Estimates

Table 9-2. SPECIFIC CAPITAL-COST BREAKDOWN OF HTGR NUCLEAR-TO-ELECTRIC PLANT

| Item | $/kWe |
|---|---|
| Direct Costs (Land, Structures, Site, Facilities, and Equipment) | 236 |
| Contingency | 33 |
| Indirect Costs (Engineering and Construction Facilities and Services) | 79 |
| Interest During Construction | 143 |
| Total Capital Cost | 491 |

for the single 1500 MWe unit used in the nominal case were provided by the General Atomic Co. The estimates from GA were expressed in January 1976 dollars and were depreciated at an 8% rate for one-half year to reach July 1975 dollars.

Modification of this estimate to include d-c acyclic generation equipment in lieu of assumed a-c generators was judged not necessary, as both generators are expected to have equal costs as well as to operate at the same efficiency.

The total estimated capital investment required for the nuclear unit in July 1975 dollars is $737 million. This estimate excludes escalation during construction.

Electrical distribution costs were estimated to be $3.60/kW of electric capacity. Capital costs for the water-treatment plant are increased about 50% from the base-case to reflect the larger water flow and increased purification requirements.

The electrolyzer-system cost estimate excluding installation was provided by the General Electric Co., Lynn, Mass. The total installed cost was obtained by multiplying the GE equipment estimate by 1.5.

The total estimated capital investment for the advanced nuclear-electrolytic hydrogen-production facility in July 1975 dollars is $806 million, as summarized in Table 9-3.

Table 9-3. ADVANCED SYSTEM CAPITAL-COST ESTIMATE

| Item | Cost, $ million |
|---|---|
| Nuclear-to-Electric Plant | 737 |
| Electrical Distribution | 5 |
| Water-Treatment Plant | 6 |
| Electrolyzer | 58 |
| Estimated Total Capital Invested | 806 |

It should be recalled that these estimates are intended to reflect anticipated 1985 technology. The research and development monies required to create this technology level are not included.

Fuel, Operating, and Maintenance Costs

Nuclear fuel costs are estimated to be 2.32 mills/kWh of electricity produced, or an annual cost of $24.4 million for a 1500-MWe plant operating at 80% capacity factor.

Annual operating and maintenance costs for the nuclear portion of the plant are estimated at $5.7 million. About 40% of the cost is for plant staff salaries.

The annual costs for the nuclear unit are summarized in Table 9-4.

Table 9-4. NUCLEAR-UNIT FUEL, OPERATING, AND MAINTENANCE COSTS

| Item | Annual Cost, $ million |
|---|---|
| Fuel | 24.4 |
| Operating and Maintenance Cost | 5.7 |
| Subtotal | 30.1 |
| Fixed Capital Charges | 110.6 |
| Total Annual Cost | 140.7 |

Cost of electricity is total annual cost divided by annual production

$$140.7 \times 10^6 \div 1.05 \times 10^{10} \text{ kWh} = 13.4 \text{ mills/kWh}$$

These can be used to estimate a cost for electric production from the HTGR system of 13.4 mills/kWh.

The annual operating and maintenance cost for the electricity-to-hydrogen subsystem is $5.1 million. A breakdown is provided in Table 9-5.

Table 9-5. ELECTRICITY-TO-HYDROGEN SUBSYSTEM OPERATING AND MAINTENANCE

| Item | Annual Cost, $ million |
|---|---|
| Production Materials | 0.2 |
| Water | 0.7 |
| Direct Labor | 1.2 |
| Maintenance | |
| Labor | 0.7 |
| Supplies | 0.7 |
| Supervision | 0.3 |
| Administration and Overhead | 1.3 |
| Subtotal | 5.1 |
| Fixed Capital Charges | 10.4 |
| Total Annual Cost | 15.5 |

Estimated Hydrogen-Production Costs

The estimated cost of hydrogen is determined by dividing the total annual cost of the advanced nuclear-to-hydrogen system by the annual gas production. For the advanced-system nominal case (bipolar SPE electrolyzers) hydrogen cost is $0.062/std cu m ($1.65/1000 SCF) or $4.81/GJ ($5.07/million Btu). The cost estimation is detailed in Table 9-6.

Table 9-6. ESTIMATED ADVANCED-SYSTEM HYDROGEN-PRODUCTION COSTS

| Item | Cost, $ million |
|---|---|
| Annual Nuclear Plant Costs | 140.7 |
| Annual Electricity-to-Hydrogen Plant Costs (Bipolar SPE) | 15.5 |
| Total Annual Cost | 156.2 |

$156.2 X $10^6$ ÷ 2.540 X $10^9$ std cu m = $0.0615/std cu m

$156.2 X $10^6$ ÷ 9.481 X $10^{10}$ SCF = $1.65/$10^3$ SCF

$156.2 X $10^6$ ÷ 3.081 X $10^{13}$ Btu = $5.07/$10^6$ Btu

$156.2 X $10^6$ ÷ 3.248 X $10^7$ GJ = $4.81/GJ

As a variant, were bipolar alkaline-electrolyte electrolyzers used, hydrogen cost is estimated at $0.075/std cu m ($2.01/1000 SCF) or $5.86/GJ ($6.18/million Btu). Using unipolar alkaline-electrolyte electrolyzers, hydrogen cost is estimated at $0.080/std cu m ($2.15/1000 SCF) or $6.27/GJ ($6.61/million Btu). The higher hydrogen costs for these two systems vs. the GE one is chiefly the result of higher electrolyzer capital-cost estimates. The electrolyzer costs and efficiencies used in these estimates appear earlier in Table 7-1.

Oxygen-Byproduct Credit

Hydrogen costs have also been estimated assuming an oxygen-byproduct credit. When oxygen is sold at $10/(short) ton the required hydrogen price is reduced from $4.81/GJ ($5.07/million Btu) to $4.19/GJ ($4.42/million Btu). A parametric variation of oxygen credit and hydrogen cost reduction is plotted in Figure 9-1.

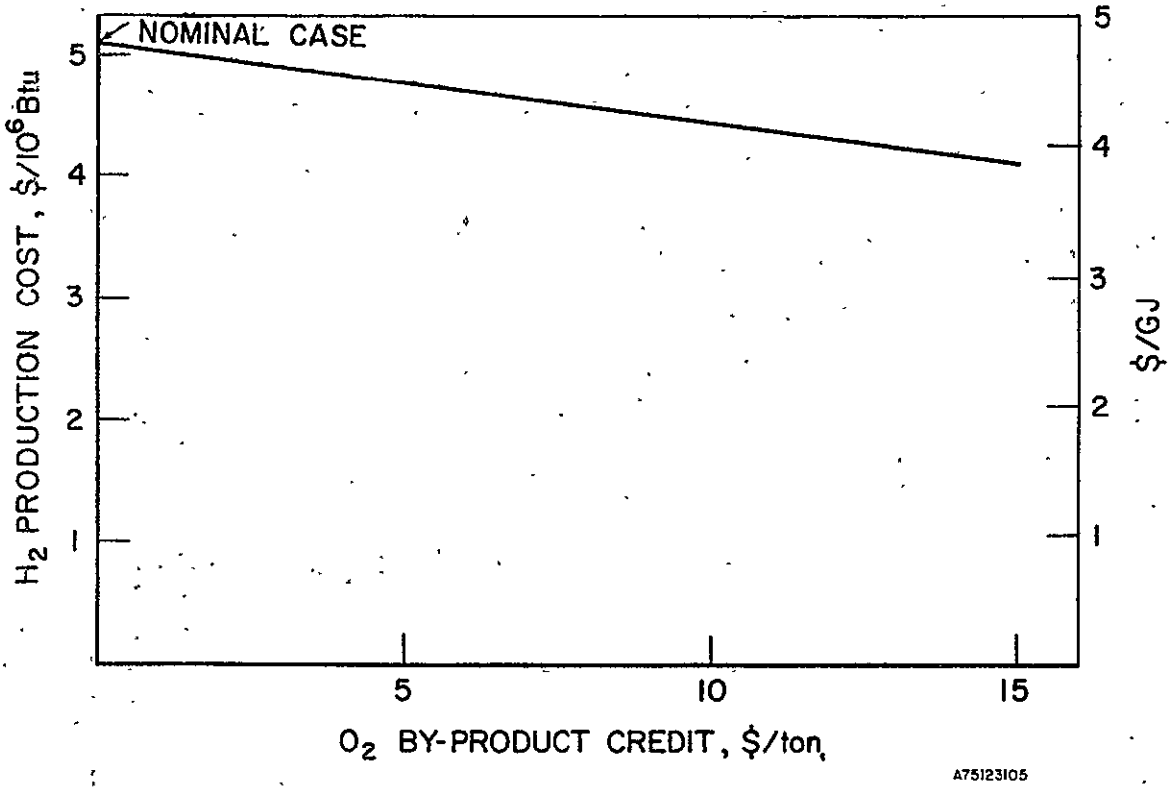


Figure 9-1. OXYGEN CREDIT AND HYDROGEN COST REDUCTION

Plant-Capacity Factor

Hydrogen costs depend fundamentally on the annual capacity factor anticipated for the plant. Obviously, less down-time means more hydrogen production and a larger base over which to recover the system's large capital investment.

As an example, upgrading the capacity factor from 80% to 90% for the advanced system reduces the hydrogen cost from $4.81/GJ ($5.07/million Btu) to $4.37/GJ ($4.61/million Btu). The effect of capacity factor on hydrogen cost is graphed in Figure 9-2.

Construction of Multiple-Nuclear-Units Complex

Because of the high capital intensity of the advanced nuclear-electrolysis system, significant reductions in hydrogen cost could be expected were plant capital costs to be even moderately reduced. Increasing the size of the facility and/or constructing two or more units consecutively are

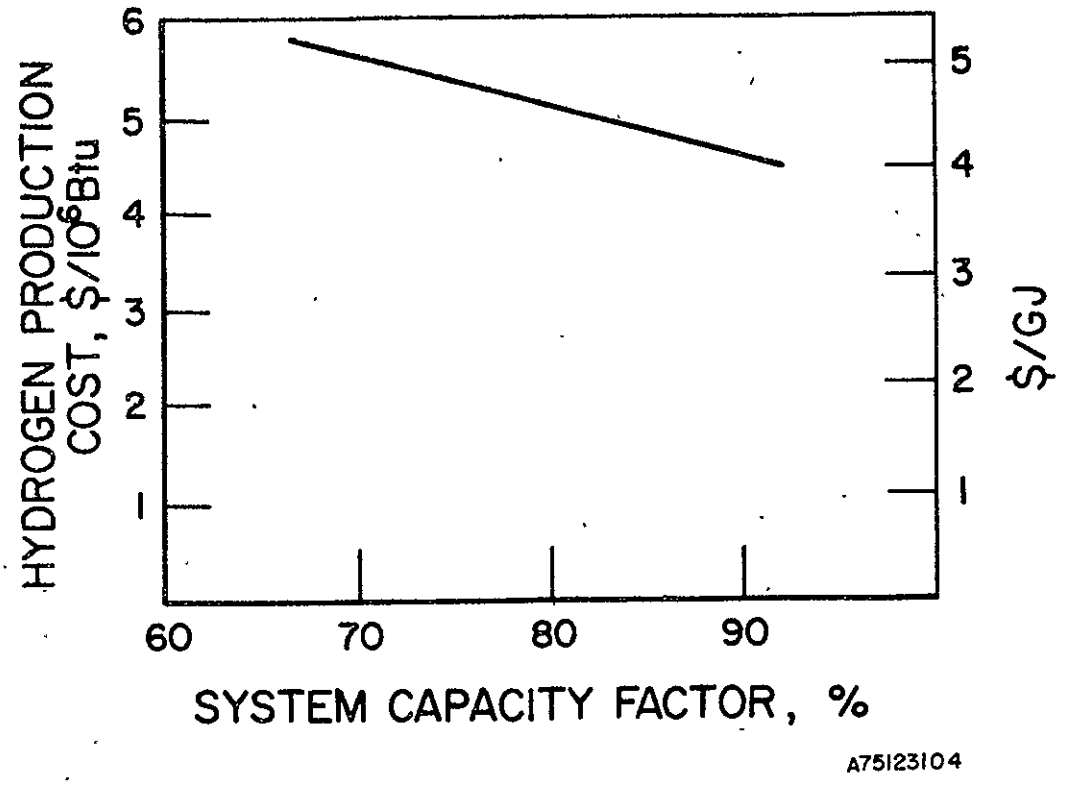


Figure 9-2. EFFECT OF CAPACITY FACTOR ON HYDROGEN COST

demonstrated approaches for such cost reductions. A second unit obtains the benefit of reduced construction costs due to sharing of the engineering, temporary facilities, tooling, and manpower. In view of this, General Atomic Co. has provided a cost estimate for a two-unit nuclear facility. Each unit has the same technical features as the single unit of the nominal advanced case, but a larger thermal rating (4000 MW vs. 3000 MW). This estimate is $279/kWe, again excluding interest and escalation during construction.[12] This estimate is 20% less than the comparable single-unit-only (i.e., nominal case) estimate of $348/kWe. Based on the lower estimate the total annual cost would be reduced from $156.2 million to $134.1 million resulting in hydrogen costs being reduced from $4.81/GJ ($5.07/million Btu) to $4.13/GJ ($4.35/million Btu).

It is obvious that the benefits of oxygen-byproduct credit, improved capacity factor, and multiple-unit complexes can be compounded. For example, assuming an oxygen credit of $10/short ton, a 90% capacity factor, and a twin-unit nuclear installation, hydrogen costs would be projected at about $3.00/GJ ($3.15/million Btu).

## Comparison of Advanced and Baseline Systems

### Technical

Both systems convert nuclear energy to hydrogen energy with an intermediate sequence of electricity generation and water electrolysis. The base-case system is considered to utilize 1975 technology while the advanced system uses technology to be available in 1985. The base-case uses an LWR nuclear plant to generate electricity while the advanced system uses an HTGR, operating at higher turbine-working-fluid temperatures and consequently having a higher overall electrical generating efficiency (50% vs. 33%). Both nuclear reactors have a thermal core rating of 3000 MW. In the advanced case d-c electricity is generated whereas the base-case system produces a-c electricity and rectifies it to dc for use by the electrolyzers. The d-c generation approach results in about a 2% gain in efficiency. In the base-case Lurgi electrolyzers are used to produce hydrogen at 3100 kPa (450 psia). The advanced system's GE-SPE cells electrolyze at higher current densities than the base-case (12,900 A/sq m or 1200 A/sq ft vs. 2150 A/sq m or 200 A/sq ft) and higher net efficiency (86% vs. 78%). The GE cell also produces hydrogen at 6900 kPa (1000 psia) and thus does not require compression equipment. The overall nuclear-to-hydrogen energy conversion efficiency for the advanced case is 42.9%, compared with 24.7% for the base-case.

### Economic

Hydrogen costing for both cases is based on constant 1975 dollars to allow straightforward comparisons. Both systems were designed with the same reactor-core thermal rating (3000 MW) to reduce the economic effects of size scaling. The advanced system can generate hydrogen at a price of $4.81/GJ ($5.07/million Btu) compared to the base-case value of $9.36/GJ ($9.88/million Btu). The large reduction in production cost is due principally to the lower unit capital cost of the electrolyzers and secondarily to the lower unit cost of the nuclear-to-electricity system.

## 10. TECHNOLOGY ASSESSMENT AND RECOMMENDATIONS

### Technology Assessment

"1985 Technology" has been frequently stated to be a criterion of component and subsystem technological development status used throughout the study in connection with the development of an advanced nuclear-electrolytic hydrogen-production facility concept. This has been meant to imply that a maximum of 10 years of nominal research and development would be required to achieve an appropriate "state-of-the-art" upon which the equipment in question could be reasonably predicated. Quite obviously, were there to be inadequate R&D efforts to develop "1985 Technology", those areas thus unsupported would not achieve the efficiency levels, costs, or other principal characteristics stated for them in this study.

Those technical areas that are particularly critical in this regard, and that therefore deserve early attention with reference to the studied advanced-facility concept include —

1. High temperature gas-cooled reactors and components (fuel elements, heat exchangers, turbines, and ducting) capable of sustained long-lived operation at 980°C (1800°F), or thereabouts, at the cost stated.
2. Acyclic generators with the efficiency and cost characteristics cited.
3. High-pressure, high-current-density electrolyzers capable of sustained operation at the efficiency and cost cited.

These areas accord with the three basic subsystems from which the advanced facility concept was synthesized in the present report.

In support of these general observations, and those brought out in the preceding sections, a number of specific areas require early study and appropriate exploratory development. These areas are listed below at both the system and subsystem level in the form of recommended actions to be taken. Such efforts would provide useful information in support of the advanced nuclear-electrolytic hydrogen-production facility concept as a potential project, were this to be undertaken at some point in the future.

## Recommendations

### Systems-Level Recommendations

1. A study at the conceptual design level, including a detailed costing assessment, of the advanced system described in this effort is now needed to verify, revise, and/or refine the technical and economic findings reported here.

2. An assessment of the influence of facility siting and location on the design of the plant is needed, to evaluate the payoff of dedicated production of hydrogen (vs. electricity), to include land, shore-based, off-shore, and deep open-ocean sites.

3. The effect of scale-up of the facility to greater then 3000 MWt reactor sizing, and the cost benefits of multiple-plant (modules), very-large-scale nuclear-electrolytic complexes producing pipeline hydrogen should be explored.

4. The issue of oxygen co-product usage should be explored realistically, but imaginatively, to determine its potential marketability and price potential; if marketable as a credit-byproduct, how much, and in what form and location should it be delivered?

5. Possible synergistic effects for a close-coupled nuclear-electrolytic facility need to be assessed; e.g., waste heat from electrolysis could be used to generate more electricity.

### Subsystem-Level Recommendations

1. Nuclear-to-Shaftpower Subsystem

1.1 The helium/ammonia binary cycle was selected in this study; other high-efficiency shaftpower cycles and various working-fluid combinations should be examined in context for performance, cost, and practicability including single, binary, and ternary cycles.

1.2 The assessment of reactor working-fluid outlet-temperature variation on reactor engineering and associated costs carried out for nuclear process-heat generally (References 24, 47, and 49), should be extended to shaftpower cycles as discussed in item 1.1.

1.3 Employment of a breeder reactor, as opposed to the converter reactor included in this study, should be examined in connection with the subject system application.

1.4 The potential for improvements in plant capacity factor and availability in a dedicated, non-electricity-generating role (such as considered in the study) should be assessed in view of the large effect of these on product cost; advancements in reactor fueling techniques and component designs to minimize outage should be considered.

1.5 Optimization of turbine design and output speed in view of d-c electricity usage should be carried out free of the constraints of producing 60-Hz a-c electricity on which currently available designs are based.

1.6 The fuel of current HTGR reference design is limited to a maximum nominal core temperature of 1400°C (2550°F). This is near the 1450°C (2640°F) required to provide helium at 980°C (1800°F), thus HTGR fuel systems need to be examined to ensure operability at slightly higher temperatures.

2. Shaftpower-to-Electricity Subsystem

2.1 Non-60-Hz a-c generators, d-c generators, and associated power conditioning equipment, should be surveyed broadly, including innovative concepts; technical and cost aspects should be delineated in view of close-coupled electrolyzer demand on one side and shaft-power availability from a high-temperature reactor on the other.

2.2 In view of its basic attractiveness, an expanded preliminary design assessment of the acyclic d-c generator should be carried out to provide a broader, more highly substantiated data-base to support further in-depth systems studies of the advanced nuclear-electrolytic facility concept including that of item 1.5.

2.3 The distribution of high-current d-c power from facility generators to electrolyzers should be studied, and experiments performed as indicated; this should include conventional bussing approaches as well as cryoresistive and superconducting approaches (the latter to date have been directed toward long-distance high-voltage power transmission, both a-c and d-c).

3. Electricity-to-Hydrogen Subsystem

3.1 A comparative technical and cost assessment of all candidate electrolyzer types should be conducted with the present application in view including, as a minimum, the three types examined briefly in this study; innovative concepts should be sought.

3.2 The parallel operation of electrolyzer modules has been questioned by several manufacturers and experts in the field; demonstration of feasibility is required, and methods to accomplish this should be developed.

3.3 Pressure-electrolysis systems must be further explored in terms of both technical and cost aspects in view of hydrogen pipeline requirements, with and without the imposition of mechanical compression systems.

3.4 Very large-flow mechanical compressors for service in advanced hydrogen-production facilities (including non-electrolytic concepts) must be studied to determine applicability, sizing effects, modes for driving, and type.

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