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HYDROGEN STORAGE VIA METAL HYDRIDES FOR UTILITY AND AUTOMOTIVE ENERGY STORAGE APPLICATIONS

by

F. J. Salzano, C. Braun, A. Beaufrere, S. Srinivasan
G. Strickland, J. J. Reilly, C. Waide

Department of Applied Science
Brookhaven National Laboratory
Upton, New York 11973

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ABSTRACT

Brookhaven National Laboratory is currently supported by ERDA to develop the technology and techniques for storing hydrogen via metal hydrides. Hydrogen is able to react with a wide variety of metal and metal alloy materials to form hydride compounds of hydrogen and metals. These compounds differ in stability--some are relatively unstable and can be readily formed and decomposed at low temperatures. The use of these systems for hydrogen storage involves the design of heat exchanger and mass transfer systems, i.e., removal of heat during the charging reaction and addition of heat during the discharge reaction. The most notable example of a metal hydride material is iron titanium which shows promise of being economic for a number of near term hydrogen storage applications. Recent work and progress on the development of metal hydrides for hydrogen storage connected with utility energy storage applications and natural gas supplementation are discussed and electric-to-electric storage system is described in some detail.

A system of energy storage involving the electrolysis of hydrochloric acid is described which would utilize metal hydrides to store the hydrogen. In addition, the use of metal hydrides for hydrogen storage in automotive systems is described.

INTRODUCTION

The subject of hydrogen as an industrial fuel or chemical commodity has received considerable attention in recent years.(1-19) Presently, hydrogen is an important industrial commodity, which in terms of resources consumed in the United States corresponds to approximately 1% of the total (~1 x 10^{15} Btu/yr). It is evident that the projected growth of industrial hydrogen demands as given in Figure 1 and based on current trends, are expected to grow, and by the years 1985 and 2000 may reach the level of 1.5 x 10^{15} Btu/yr and 3 x 10^{15} Btu/yr, respectively.(18) Irrespective of whether or not the concept of the so called "Hydrogen Energy Economy" comes to fruition, hydrogen now plays and will continue to play a major role in the energy system. Current hydrogen demands are primarily supplied from natural gas and petroleum resources. These resources are currently in short supply and their availability is expected to decline with a corresponding rise in prices. Eventually these resources will be effectively exhausted. As this trend continues, it is expected that a major fraction of future industrial demands for hydrogen will be supplied from coal; however, as more and more nuclear capacity becomes available, smaller, but significant fractions of the industrial hydrogen requirements could be supplied from these energy sources. Thus, from a utility point of view, hydrogen production is one approach among many, which can help level the output load from nuclear systems and allow maximum utilization of available capital facilities. Unlike other storage options, the hydrogen produced can be used inside, or sold outside of the electric utility system, thus offering versatility and flexibility unavailable with other storage schemes.

The problem of choosing between various storage schemes for a utility system is obviously a complex question in that not only are various technological approaches possible, but there are also nonstorage and nontechnological options which could achieve load leveling of a nuclear electric system to varying degrees. The various storage options to be considered take many forms, each with its own unique characteristics; however, a quality that distinguishes them is the practical and economic residence time periods for the energy stored. Some options such as superconducting magnetic energy and flywheels storage appear best suited for short time periods on the order of minutes or hours. Various battery options appear attractive for daily storage. Pumped storage is presently operated on a weekly cycle with energy added in large quantities on weekends and smaller additions made during the week.

Hydrogen as an energy storage option appears to be unique in terms of the variety of ways in which it can be applied as an energy storage medium. The various modes of application which generally represent long term storage options, i.e., either weekly cycles or longer are listed below.

1) The most widely discussed option is hydrogen electric-to-electric storage system, which unlike the battery options may be attractive for application involving weekly cycles.

2) Hydrogen could simply be produced from excess nuclear capacity and sold as an industrial commodity or injected into existing natural gas pipelines of combination electric-gas utility systems. This associated with the concept of underground seasonal storage has been discussed.

3) It is likely that as a result of storage capacity hydrogen markets will be interruptible and hydrogen production would be possible from nuclear spinning reserve where the electric supply could quickly and easily be shifted from hydrogen production to the existing electric grid to meet peak or unexpected electric demands. Coupling this concept with seasonal storage has some attractive features.

4) At a time when efficient low cost reliable fuel cells become viable electric generating devices hydrogen could be produced to supply supplemental fuel to fuel cells, or hydrogen storage would serve as capacitance to reduce or eliminate the varying load on distillate fuel reformers required by oil fed systems. The prospects for "dual mode" systems in which hydrogen would be produced and distributed to either fuel cells for electric production or injected into the natural gas system has been well discussed by R. Fernandes.(20)

5) The prospects may be attractive for hydrogen and oxygen production and storage at central station nuclear plants in which the hydrogen and oxygen combustion would supply super heat to a low pressure nuclear steam produced in an LWR and subsequently used to generate electricity to meet peak demands in a super heat turbine. Incremental efficiencies for hydrogen oxygen conversion in the range of 50% to 60% appear achievable.

6) And last, but not least, a new concept is being considered at BNL which involves the electrolysis of hydrochloric acid (HCl) in an electrolyzer which serves also as a fuel cell to recombine the H_2 and Cl_2 for electric production. Thus,

this system via storage of H_2 and Cl_2 would serve as an electric-to-electric storage system with an overall efficiency in the range of 70% to 80%. A further advantage is that by supplying pure water to the electrolyzer hydrogen and oxygen would be produced in the same unit, thus reducing the required capital investment. This system would offer great flexibility and allow utilization of available technology from the large-scale electrochemical industry, e.g., for chlorine storage and chlorine electrode systems.

In general, when considering the application of hydrogen as an energy storage system it is desirable to design systems which allow maximum flexibility of operation and thus have high utilization factors for the required capital facilities.

In this paper we discuss hydrogen as an electric-to-electric storage option in detail and present recent cost estimates for such a concept as well as discuss its competitive position and future prognosis relative to the allowed costs. We will also discuss the application of hydrogen production for natural gas injection, and the HCl electrolysis scheme for electric-to-electric storage and hydrogen production.

ELECTRIC-TO-ELECTRIC STORAGE

The Brookhaven National Laboratory with support from the ERDA and with some support from ESEERCO has been developing the technologies required for electric-to-electric storage via hydrogen production storage and reconversion. Work in progress at BNL consists of a variety of efforts ranging from engineering analysis and design of hydrogen storage plants to improvements in the techniques of electrolytic production.(21) This work includes plans to construct a prototype electrolytic hydrogen production and storage facility based on the use of iron-titanium hydride and which could be coupled to a fuel cell for conversion to electric energy.

In the scheme presented below it is assumed that electric energy supplied from a utility network during off-peak hours is used to produce hydrogen which is stored in an iron-titanium hydride compound. During peak-load periods, the hydrogen is released by heating the hydride and used to generate electric power in a fuel cell.

During hydrogen storage (metal hydride formation) energy is liberated and must be removed; during hydrogen release, energy must be supplied. Two methods for removing or supplying the energy have been considered. The first, termed "convective case," involves transferring heat to or from circulating hydrogen which flows through the hydride and heaters or coolers external to the hydride containment vessels. The second, termed "conductive case," involves transferring heat to or from a heat transfer fluid which flows through tubes buried in the hydride internal to the hydride containment vessels. The first approach is less attractive because under long cycling the hydride particles undergo size reduction and would likely exhaust from the storage vessel.

A preliminary plant design and cost estimates were made utilizing a "conductive type" metal hydride hydrogen storage bed. This design was based on chemical characteristics of iron-titanium as determined in the labroatory,(22, 23) small-scale engineering test bed data(24) and on engineering analyses made by the BNL staff and plant designs by its subcontractors.** Technology representative of the current state-of-the-art and advanced technology are separately considered in the cost and performance estimates. The design details presented consider the use of current technology.

PLANT PROCESS AND DESIGN

Figure 2 is a flow schematic for the overall plant process. During the hydrogen charging phase, high voltage, 3-phase, ac power from the utility power network is transformed and rectified by solid state rectifiers to dc. The dc power is supplied to water electrolyzers which are capable of producing 3250 lbm-H_2/hr and 25,800 lbm-O_2/hr, maximum. During normal operation, 2800 lbm-H_2/hr and 22,000 lbm-O_2/hr are produced. The oxygen is released to the atmosphere, while the hydrogen is cooled and passed through a deoxygenator to remove residual oxygen. The hydrogen is then passed through a dryer to remove residual water vapor and the final product hydrogen gas has a dew point of -76^{o}F or less. The dry gas then flows to the combined hydride bed/heat exchangers where it is absorbed and stored.

**Burns & Roe, Inc., Engineers and Contractors, Hempstead, N.Y.

Figure 3 shows pressure-temperature conditions and other characteristics during the hydrogen charging of the combined powdered metal hydride bed/heat exchangers. During charging, the valve downstream of the hydride beds is closed. Cooling water circulates through the heat transfer tubes buried in the metal hydride to remove the heat released as the hydrogen is absorbed and iron-titanium-hydride is formed. The sensible heat in the bed is also removed by this stream. The cooling duty is thus determined by the requirements that 2800 lbm per hour of hydrogen be stored and 6750 Btu be removed for each pound of hydrogen added.

Figure 4 shows pressure-temperature conditions and other characteristics during the discharging (desorption) of the combined hydride bed/heat exchangers. During discharging, the valve between the hydrogen dryer and the hydride beds is closed, and the valve from the beds to the fuel cell packages opened. Water, heated using waste heat from the fuel cell packages circulates through the same heat transfer tubes used during storage, to supply the heat of dehydriding and sensible heat as the hydrogen is released. As the sensible heat energy is small compared to the reaction energy required, it is neglected. The heating duty is thus determined by the requirements that 2800 lbm of hydrogen be released per hour and 6750 Btu be supplied for each pound of hydrogen released.

The general arrangement plan view of a 26MW(e) iron-titanium metal hydride storage (conductive type) electric power plant is shown in Figure 5. The main subsystems of this plant includes a 24 module, Lurgi high pressure (30 atm) water-KOH electrolyzer, 10 iron-titanium hydride hydrogen storage heat-transfer beds, and a 24 module hydrogen-air fuel cell system using phosphoric acid as the electrolyte.

The electric auxiliaries include; an ac-dc rectifier to convert 3-phase, 60 H_Z power from the utility network to operate the electrolyzers, an inverter and transformers to convert the fuel cell 500 volt dc electrical output to 3φ 6.9kV ac bus voltage. Figure 6 shows the hydrogen flow between the major components and the auxiliaries associated with producing and storing the hydrogen including electrolyte separators, hydrogen coolers, water separators, deoxygenators and dryers. Figure 7 is a flow diagram of the process heating and cooling systems. The cooling/heating water auxiliaries include: hydride cooling water-tower system, electrolyzer intercooling system, electrolyzer coolant cooler, and a dehydriding heating water system operated on reclaimed heat from fuel cells. An electrolyte flow diagram is shown in Figure 8. It is to be noted that a plant utilizing an advanced technology electrolyzer and fuel cells of the General Electric solid polymer type require no flowing electrolyte.

Figure 9 is a simplified one-line diagram of the plant's main electrical system. This system is comprised of a 115kV high-voltage substation, four 34 MVA, 115/6.9kV stepdown transformers, 6.9kV switchgear, 24 rectifiers rated at 6.9kV, 3.4MW, and 24 inverters rated at 6.9kV, 1.1MW.

PLANT PERFORMANCE

Figure 10 shows the estimated nominal plant performance. During the hydriding portion of the plant cycle, the gross electrical power input is 72.5MW(e) 3 ϕ ac to the solid state rectifiers. The rectifiers have an estimated conversion efficiency of about 97 percent, so 2.16MW are rejected to the atmosphere as heat and about 70.0MW(e) dc are distributed to the 24 electrolyzers. The electrolyzers convert the 70.0MW(e) into 2800 lbm-H_2/hr with a conversion efficiency of about 72 percent, based on the high heating value of hydrogen (61,000 Btu/lbm). About 20.0MW of heat are rejected directly and through the circulating cooling water system to the atmosphere (see Figure 7). The 2800 lbm-H_2/hr produced by the electrolyzers are stored in the hydride beds at a uniform rate with an assumed efficiency of 100 percent; i.e., with no leakage. The heat of hydriding, 5.54MW, (6750 Btu/lbm), is rejected to the atmosphere by means of the cooling water system, (see Figure 6 and 7). Hydrogen chemical energy is thus stored at the rate of 50.1MW, based on the high heating value of hydrogen, and the nominal hydriding effectiveness for the charging portion of the plant cycle, defined as the ratio of the rate of hydrogen chemical energy stored to the total plant power required, is 69 percent.

During discharging or dehydriding, hydrogen is liberated from the hydride beds at a uniform rate of 2800 lbm-H_2/hr. The heat of hydriding, 5.54MW, is supplied, for normal operation, by utilizing heat rejected by the fuel cell packages, which are assumed to operate with a conversion efficiency of 55 percent, based on the high heating value of hydrogen. In addition, about 0.44MW of heat from the fuel cell packages are also used to preheat the hydrogen before it enters the fuel cells to prevent quenching the electrochemical reactions. From the 50.1MW rate of hydrogen chemical energy input to the fuel cells (2800 lbm-H_2/hr), 27.6MW(e) dc is extracted and 22.6MW is rejected. As noted, 5.54MW and 0.44MW of the rejected power are utilized, while the remainder is transferred directly to the atmosphere. The 27.6MW(e) dc is distributed to the SCR inverters, which have an estimated conversion efficiency of 97 percent, and converted to 26.7MW(e) with about 0.90MW of heat rejected to the atmosphere. About 0.7MW(e) of the 26.7MW(e) is used to power auxiliaries during dehydriding leaving a net plant output of 26.0MW(e) 3 ∅ ac. Thus, the nominal dehydriding effectiveness for the power generation portion of the plant cycle, defined as the ratio of the net plant output to the rate of hydrogen chemical energy available, is 52 percent. For the complete plant operating cycle, therefore, the efficiency or ratio of net plant output to total plant input, is 36 percent. Even with a projected fuel cell conversion efficiency of only 55% and the overall plant efficiency could be improved to a value above 50% with a 90% efficient electrolyzer. The key to greater efficiencies is in the utilization of a conversion device more efficient than the first generation phosphoric acid air fuel cell expected to be available. Alkaline fuel cells involving the use of oxygen do achieve efficiencies as high as 70%(19) which coupled with a 90% electrolytic production efficiency would set 60% as an upper bound for the overall electric-to-electric storage efficiency.

CAPITAL COSTS

The capital cost of the first one-of-a-kind 26MW(e) metal hydride storage electric plant described herein and constructed on an improved building site in the Northeastern part of the United States is estimated at $170/kW(e)-hr for a ten hour charge/discharge cycle. This is considered to be representative of the state-of-the-art and does utilize available components, except for the fuel cell. Thus, this cost estimate serves as a first baseline of comparison with other types of electric storage plants based on available technology and allows judgment regarding the value of advanced technology development and procedures. An advanced technology 1980 demonstration plant with the same storage and process scheme but having higher overall efficiency (50%) is estimated at $66/kW(e)-hr. This higher efficiency is mainly accomplished by operating the electrolyzers at higher temperatures.(21) Table I shows the distribution of costs of this advanced technology plant now under study at BNL and Table II indicates the cost distribution as a percentage compared with the present state-of-the-art power plant described above. By far the greatest cost reduction comes about by the utilization of an advanced technology electrolyzer. Although a very reliable unit of moderate efficiency, the present Lurgi electrolyzer is representative of current technology and market conditions, while the advanced technology electrolyzer now under study at BNL and its subcontractors,(19,21) is capable of operating at much higher current densities as well as consisting of a fewer number of modules. Thus, it will be smaller and lighter which leads to lower costs and will require less floor space and foundation. It also will have lower installation costs as there will be less piping, valves, controls and instruments. The accessory electrical equipment will also be less expensive because there will be fewer number of major modules.

The allowed cost for the introduction of electric storage devices into the national energy system was examined, utilizing the Brookhaven Energy System Optimization Model (BESOM). Allowed cost curves versus distillate oil prices shown in Figures 11 and 12 were reproduced from Reference (25), but put in terms of 1975 instead of 1970 dollars. At the present oil price of approximately $\$2.6/10^6$Btu and at a load factor of 0.1, Figure 11 indicates that the allowed cost, or break-even cost for the advanced technology electric peaking plant with an overall efficiency of 50%, would be about \$500/kW(e). However, if the cost of fuel were to increase to $\$3.9/10^6$Btu, as indicated in Figure 12, the allowed cost would approach the above \$660/kW(e) advanced technology plant cost.

It should be noted from the reference cost curves that allowed capital costs are a strong function of load factor as well as the overall efficiency of the plant. However, the latter effect greatly diminishes when the efficiency is greater than 30 to 50%, where the upper part of this efficiency range is for the higher load factor. Thus, high utilization of a high efficiency plant would be most profitable. For example, at a load factor of 0.25 and at an efficiency of 50%, the estimated allowed capital cost in 1975 dollars would be about \$650/kW(e) at approximate level of present fuel costs.

An approach which would achieve higher plant utilization of a hydrogen production and storage system is to operate in the so called "dual mode."(20) In this case, hydrogen would also be generated from off-peak power, stored, and injected into the natural gas fuel supply system as well as being used to generate electricity during peak-load periods. This hydrogen would be produced by the same equipment as that used for the electrical branch of the system where fuel cells would convert the distillate fuel or hydrogen to electricity on demand. The use of hydrogen in a dual mode plant could greatly increase the utilization of the fuel cells and electrolyzer equipment. Also, the fuel cells would be operated as dual fuel devices, using distillate fuel a major fraction of the time and hydrogen for peaking applications only. In this way the utilization factor for the fuel cells could be as high as 50%. Any system approach which will maximize the utilization of the production and conversion equipment is highly desirable.

HYDROGEN INJECTION INTO THE NATURAL GAS PIPELINES AND "DUAL MODE" CONCEPT

Hydrogen injection into the natural gas pipelines can be considered on its own merits as an end to itself, or it can be carried over to its logical extension within joint electric and gas utilities, which is the "dual mode" concept. Dual mode systems have been referred to in the literature as the "two-way electric-gas transformer" or "dual-input dual-output generating device."(26) A discussion of hydrogen supplementation of natural supplies is now given, followed by consideration of dual mode concepts.

HYDROGEN INJECTION INTO NATURAL GAS PIPELINES

There are two basic incentives for hydrogen injection into the natural gas pipelines: Supplementation of dwindling natural gas supplies and improved utilization of base and intermediate load electric power plants. It is thus evident that hydrogen injection is most attractive to joint electric and gas utilities. Large-scale implementation of this concept, based on possible demand diversity between the electric and gas subsystems can lead to a greater integration of the two components of the joint utility, and in fact to a new definition of the role of such utilities as energy companies. On the technical side, hydrogen injection can lead to implementation of seasonal storage systems, compared with the daily and weekly storage concepts considered so far.

Hydrogen injection schemes involve the utilization of available low cost off-peak electric power (preferably nuclear) to electrolyze water. The product hydrogen is then injected up to a predetermined volumetric flow rate, into the natural gas pipelines. Three production locations can be considered:

1. Electrolyzer banks can be installed within a nuclear central station plant. The electrolytic hydrogen produced with off-peak power is then transmitted into the nearest pumping substation of the natural gas pipeline network.

2. Electrolyzer banks are installed within a natural gas substation. Off-peak electric power from the electric network is transmitted into the natural gas substation, and the product hydrogen is injected directly into the pipeline.

3. Electrolyzer banks are installed as a lightly loaded electric substation, preferably one close to a natural gas valving station. The available off-peak power at the substation in periods of slack demand is utilized for electrolytic hydrogen production. The hydrogen is then transported a relatively short distance to the nearest natural gas pipeline valving station.

The different production schemes have specific importance, when considered in the context of dual mode generating devices, as discussed later.

As can be seen from the above discussion, implementation of hydrogen injection schemes will depend on several factors such as: expected natural gas shortfall, expected availability of off-peak power, electrolyzer availability, hydrogen embrittlement problems and the expected economics of electrolytic hydrogen production. These factors are now discussed, as related to possible near term implementation of injection schemes. Long term considerations are mentioned later.

NATURAL GAS SUPPLY AND CURTAILMENTS

A recent Federal Power Survey report(27) indicates that on a national level the deficiency in natural gas supply is expected to be on the order of 22.1 percent of the projected firm requirements for the twelve month period September 1975 - August 1976. When considering the Northeast U.S. region, which includes approximately the service territories of the New England and New York Power Pools, and the Pennsylvania-Jersey-Maryland Interconnection, the projected natural gas curtailment for the same 12 month period is about 528 Tcf which corresponds to 22.6 percent of the year 1972 supply. These projections are based on Reference (27) data and the Energy Future of the Northeast study now being conducted at Brookhaven National Laboratory (28). No reduction in this level of deficiency can be projected for the Northeast region in the time frame of 1975-1985. Thus, clearly there exists a need to supplement the dwindling natural gas supplies with any additional gas sources.

AVAILABILITY OF OFF-PEAK NUCLEAR POWER

Public attention has recently focused on delays in construction of new nuclear plants. However, several regions of the country which embarked on a nuclear program to lessen their dependence on imported oil as power plants fuel, now find themselves with large nuclear fractions of the total installed capacity and with reduced electric demand due to the recent economic slowdown. Such regions which include the Chicago area (Commonwealth Edison Service area) and New England region may have excess nuclear capacity to serve a lower than expected load growth till 1985. Thus, Commonwealth Edison has recently reported that 51 percent of its electricity generation was from nuclear power plants during November 1975.(29) The installed nuclear capacity now comprises 19.6 percent of the New England Power Exchange capacity, and this fraction is expected to increase to 26.7 percent and 37.7 percent by 1980 and 1985, respectively, according to Brookhaven projections.(28) It is possible to estimate the available off-peak energy as percentage of the total electric system energy production as a function of the system nuclear capacity based on a correlation developed by Public Service Electric and Gas Company.(30) Using data from Reference (30) off-peak power available in New England will be 0.4 and 2.0 percent of total generation in the years 1980 and 1985, respectively. Long term nuclear capacity projections beyond 1985 are quite unreliable in the current situation; however, the Brookhaven study of the Energy Future of the Northeast(28) indicates nuclear fractions of the total installed capacity in the Northeastern United States as 0.39 and 0.48 in the years 1990 and 1995. These nuclear capacity fractions correspond, according to Reference (30), to nuclear off-peak power in the range of 3.5 and 7.0 percent of the total generation in 1990 and 1995. Thus, due to over construction, several regions of the country may have a sufficient amount of off-peak nuclear power in the near term (until 1985), to start modest programs involving electrolytic hydrogen production. Larger amounts of nuclear off-peak power may become available beyond 1985, however, projections beyond 1985 are not accurate. The effects of the off-peak power costs on the cost of the electrolytic hydrogen are shown in Figure 13.

AVAILABILITY OF ELECTROLYSIS EQUIPMENT

Water electrolysis equipment that can be installed on a substation level has been described above in this paper, and in other recent reports such as Reference (31). Current projections indicate that first generation advanced electrolyzers, costing \$100/kW hydrogen output and having conversion efficiencies in the range of 88% will become commercially available during the period 1981-1985. Such electrolyzers using power costing in the range of 10 mills/kWh for off-peak energy (supplied by a mix of fossil and nuclear plants) will produce electrolytic hydrogen in the cost range of \$5-6/10^6Btu.

ECONOMICS OF ELECTROLYTIC HYDROGEN PRODUCTION

As indicated above, the electrolytic hydrogen cost is a function of the electrolyzer capital cost and conversion efficiency and the off-peak electric power cost. Assuming that advanced electrolyzers become available around 1985, with capital cost of \$100/kW electricity input and efficiency range of 0.85-0.90, the expected hydrogen cost will be in the range of 3.5-5.5 \$/10^6Btu which corresponds to off-peak power cost of 5 to 10 mills/kWh. This should be compared with recent Federal Power Commission report which indicated that the cost of interruptible natural gas to New England power plants was \$1.2/10^6Btu and the cost of firm gas supplies to Middle Atlantic utilities was \$1.56/10^6Btu in July 1975. However, as the price of natural gas is further deregulated the future cost of this fuel is expected to be considerably higher than these figures. Current projected prices of coal derived synthetic natural gas are in the range of \$3 to \$4/10^6 Btu. The economics of hydrogen supplementation of natural gas supplies will depend on two factors: (1) the ratio of the cost of hydrogen to the cost of the conventional fuel it is about to replace in the different areas of hydrogen utilization, and (2) the ratio of the cost of hydrogen to other natural gas supplementary fuels. Thus, it is obvious from the above cost data that hydrogen will be much more expensive than current natural gas prices, though this may later change as natural gas prices are deregulated or it becomes more scarce. As an example of these considerations, the allowed cost of the electrolysis plant as the function of natural gas price and device utilization factor are shown in Figure 14.

The cost of hydrogen versus synthetic natural gas or imported liquified natural gas--all of which are possible supplants of the domestic natural gas supply, have to be considered. It can be argued that during the period 1981 - 1985 natural gas shortfalls will increase, the synthetic fuels program will not yet be commercialized, certainly not to supply fuels to Northeastern United States and imported natural gas on top of political and regulatory problems, may be required to supply a minimum amount of gas to firm customers. Hydrogen supplementation of natural gas supplies may become economically attractive.

An initial small scale (regional basis) implementation program for electrolytic hydrogen injection into existing natural gas lines may be tailored to specific localized circumstances. Factors such as local availability of low cost off-peak nuclear power, the existence of economically acceptable advanced electrolyzers could be combined to allow hydrogen injection into natural gas at less than 10 percent volumetric concentrations. This could be done with virtually no changes in gas transmission facilities and no change in end use devices. Such utility or regional based program could be carried out before 1985 at a moderate level and expanded.(32)

"DUAL MODE" ELECTRIC-HYDROGEN GENERATING DEVICES

The key technological development required to make the "dual mode" scheme viable is the availability of commercial fuel cells. Fuel cells development status has been reviewed extensively in References (19, 33).

The simplest concept of a "dual mode" device is a fuel cell that can burn either fossil fuel by first reforming it to hydrogen in an attached reformer, or externally produced and purified hydrogen. The hydrogen source can be either a water electrolysis plant run by an electric utility as described above, or a remote coal gasification plant that produces commercial hydrogen as a prime or by-product. Such a device can be optimized to operate at intermediate or even base load while burning distillate oil or natural gas and electrolytic hydrogen during peak demand periods. The "dual mode" designation refers here both to operation at several load factors and to burning two different types of fuels.

The advantage of burning two types of fuels in the fuel cell is that the relatively low cost fossil fuels can be utilized to supply intermediate or even base load demand and to a lesser degree to keep the reformer operated at steady state conditions for long periods of time. In order to supply cyclic peak load demand and avoid the necessity of starting and shutting down the reformer several times a day, the stored electrolytic hydrogen can be utilized. This type of "dual mode" device can be constructed at central station plants or on a dispersed generation basis, at heavily loaded substation on the transmission network. External source of fossil fuel can be used or natural gas can be withdrawn from the natural gas pipelines. Similarly, any source of hydrogen fuel for peak load power supply can be provided; i.e., electrolytic hydrogen stored in metal hydrides or in the gas transmission pipelines, or coal derived hydrogen stored in high pressure steel bottles.

A more complex "dual mode" scheme involves the combination of a simple output electrolyzer with hydrogen/fossil fuels dual input fuel cell. In this concept, the electrolyzer bank of a standard size 26MW(e) station, as described in Reference (34), produce hydrogen which is stored on-site, and burned by the co-located fuel cells. Distillate oil or natural gas can be burned to supply intermediate electric power, and hydrogen is burned during peak demand periods. This generating concept achieves a greater degree of integration between the electric and the gas sections of large power utilities. A range of allowed costs for this concept as a function of the input fuel mix into the fuel cell are shown in Figure 15.

The most complex form of a "dual mode" generating concept incorporates a dual output electrolyzer with a dual input fuel cell. This makes the operation of the electrolyzer fuel cell combination a completely reversible process that can be run in any direction depending on the diversity of the electric and gas demands. Such concept may also require a large capacity hydrogen storage system and is in fact the vehicle through which seasonal storage may be introduced into the operation of joint electric and gas utilities. A schematic description of this concept is shown in

Figure 16. Two variants of this concept have so far been proposed. One proposal assumes co-location of the main system components--the electrolyzer fuel cell, hydrogen storage and possibly methanator. This concept has been proposed by Public Service Electric and Gas personnel(26) and labelled "Two-Way Electric-Gas Energy Transformer." The other concept proposed by R. Fernandes(20) assumes dispersed location of the electrolyzer and fuel cells along the electric transmission network. The electrolyzers are located at highly loaded substations which are located near to valving substations of the natural gas transmission network. The fuel cells are located at heavily loaded electric transmission substation and augment the electric supply at these points. The advantage of the dispersed generation concept is the ability to utilize the natural gas pipeline network itself as the (possibly seasonal) hydrogen storage system.

In both of these complex schemes the electrolytic hydrogen is either sent to the fuel cells for reconversion to electricity or injected into the natural gas pipelines. At the other extreme point of the "dual mode" concept the fuel cell can burn either electrolytic hydrogen or natural gas-hydrogen mix withdrawn from the natural gas pipelines and sent through reformer banks for complete conversion to hydrogen prior to burning. Given a set of performance characteristics for the fuel cell and the electrolyzer components, the operating parameters that lend themselves to optimization are the fractions of the electrolyzer output that are burned or injected into the natural gas pipelines, and the composition of the input fuels mix into the fuel cell.

HYDROCHLORIC ACID ELECTROLYSIS

Conventional water electrolysis-fuel cell storage systems have the disadvantages of a relatively low electric-to-electric efficiency (~50%) and a high cost, mainly because three major components (water electrolysis cell, metal hydride reservoir and fuel cell) are necessary. The main reason for the inherently lower efficiency of the hydrogen-air system, compared with the other electrochemical systems is the irreversibility of the oxygen electrode reaction. Further, since different electrocatalysts have to be used for oxygen evolution and reduction, two electrochemical systems are necessary instead of one as in the case of a battery.

The proposed electrochemically regenerative closed cycle hydrogen-chlorine fuel cell system(35) involves (1) using off-peak power to electrolyze hydrochloric acid; (2) metal hydride storage for hydrogen and storing of chlorine as a liquid or as the hydrate; and (3) combining the hydrogen and chlorine in fuel cell for peaking operations and storing the hydrochloric acid. The main advantages of such a system are: (1) the electrode reactions of hydrogen and chlorine are quite reversible. Thus, one can expect to achieve an overall efficiency (electric-to-electric) higher than 70%; (2) the same electrodes can be used as electrocatalysts in both modes (chemical and electricity generation). Therefore, the same electrochemical cell can be used for both functions which cuts down the capital costs; (3) it should be possible to use the same cell in a third function for electrolysis of water to produce hydrogen and oxygen at a high efficiency using off-peak power. The hydrogen produced could be used for injection into natural gas pipelines or in chemical industry applications. The hydrogen selling price could be used as a credit against the cost of the hydrogen-chlorine system; (4) the chlorine production and storage technology is well known and developed; (5) the system will operate at low temperatures (<100°C); (6) though HCl and Cl_2 are corrosive chemicals the corrosion problems at less than 100°C should be at least an order of magnitude less than with electrochemical systems involving alkali metals and their salts at temperatures greater than 400°C; (7) the reactants for chemical and electricity generation are stored outside the cell. Thus, the sizes of the electrochemical conversion devices are relatively small compared to batteries, and will scale well for long duty (weekly) cycles; (8) Scaling the hydrogen-chlorine system for intermediate load operation requires only larger reactants storage capacity and cycling rate through the system. This in contrast to other electrochemical storage systems where scaling up requires the installation of a larger capacity (and capital cost) system.

Compared with water electrolysis energy storage systems the hydrogen-chlorine device is expected to have higher allowed break-even costs for a given utilization factor due to the higher projected conversion efficiency and holds promise of reduced overall cost as a result of less equipment requirements and more flexible modes of operation.

THE PROPOSED ELECTROCHEMICALLY REGENERATIVE HYDROGEN-CHLORINE ENERGY STORAGE SYSTEM FOR ELECTRIC UTILITY APPLICATIONS, ITS ADVANTAGES AND DISADVANTAGES

The loss of efficiency in the hydrogen energy storage system is caused by the sluggishness of the O_2/OH^- redox couple. It can be eliminated by replacing it with a Cl_2/Cl^- redox couple. The proposed electrochemically regenerative closed cycle hydrogen-chlorine fuel cell system will thus involve: (i) using off-peak power to electrolyze hydrochloric acid; (ii) metal hydride storage for hydrogen and storage of chlorine as the liquid; and (iii) combining the hydrogen and chlorine in the same electrochemical cell operating in the discharge mode and storing the hydrochloric acid produced, outside the cell. This new system is schematically represented in Figure 17. The main advantages of such a system are: (i) the electrode reactions of hydrogen and chlorine are quite reversible; thus, one can expect an estimated efficiency of over 70%; (ii) the same electrodes can be used as electrocatalysts in both charge and discharge modes. Therefore, the same electrochemical cell can be used for both functions, which cuts down the capital costs; (iii) it should be possible to use the same cell in a third function (see Figure 17) for electrolysis of water, to produce hydrogen and oxygen, using off-peak power. The hydrogen produced could be used for injection into the natural gas pipelines or sold to chemical industries. The hydrogen selling price could be used as a credit against the cost of the hydrogen-chlorine system; (iv) the methods of drying and storing chlorine are well developed. In 1974, the total production of chlorine in the U.S. was about 10 million tons and large quantities were transported safely in trucks, railroad cars and barges; (v) the system will operate at low temperatures (<100°C); (vi) though HCl and chlorine are corrosive chemicals, their corrosion problems at 100°C should be much less than with alkali metals and their salts at temperatures much greater than 400°C; (vii) the reactants for chemical and electricity generation are stored outside the cell. Thus, the sizes of the electrochemical conversion devices are relatively small compared to batteries, and scaling up for long duty (weekly) cycles will pose no problems.

The relative merits of the hydrogen-air and the hydrogen-chlorine systems are presented in Table III. The advantages of electrolysis of HCl instead of water are clearly seen. A calculation was made of the material (fuel, oxidant and FeTi) requirements for a 26 MW output energy storage system based on a 10-hour charge, 10-hour discharge cycle. Results of these calculations along with similar information for a hydrogen-air system are given in Table IV.

THE ELECTROCHEMICALLY REGENERATIVE HYDROGEN-CHLORINE CELL, SYSTEM DEFINITION AND PROJECTED PERFORMANCE

A hydrogen-chlorine cell with a solid polymer electrolyte (e.g., Nafion membrane embedded with catalyst), which is a spinoff from the General Electric fuel cell and water electrolysis cell technology, appears most attractive for an electrochemically regenerative hydrogen-chlorine system. The novel features of this type of cell are: (i) the design of a cell with a solid polymer electrolyte appears to be the most suitable way of cell construction taking into consideration that there is gas generation during the electrolyzer mode and its utilization in the fuel cell mode; (ii) the solid polymer electrolyte is a highly stable perfluorinated-sulfonic acid ion exchange membrane which is not affected by strong acids and chlorine. It acts as a highly conductive electrolyte allowing rapid transport of H^+ ions while the intermixing of gases is prevented; (ii) the device employs porous metal electrodes and low contact resistance bipolar current collectors, thus maintaining a high efficiency to at least 500 ma/cm^{-2}.

The projected performance of the electrochemically regenerative hydrogen-chlorine cell with today's technology and an advanced one that will be developed in a six year program are shown in Figure 18. Experimental results, as those depicted in this figure, show that even at high current densities (500 ma/cm^{-2}), the operating cell potential departs from the reversible value only due to ohmic losses. From the data shown in Figure 18, it appears that the efficiencies for the regenerative hydrogen-chlorine cell should be about 70% at a current density of 300 ma/cm^{-2}. By advancing the state-of-the-art, even higher efficiencies are projected at higher current densities.

AUTOMOTIVE APPLICATIONS OF METAL HYDRIDES

The use of a hydride in an automotive system for hydrogen storage is a considerable departure from conventional power plant and fuel storage systems. The uptake of hydrogen to form a hydride in the fuel tank involves an exothermic reaction and heat must be removed. Heat must be supplied to release fuel to the engine. The combustion of hydrogen in the internal combustion engine is subject to operational considerations not found with conventional fuels. It also offers some unique advantages such as the possibility of lean combustion and reliable startup.

To understand the relationships which exist between the storage unit and the engine, the preparation of a reference design, based on a known engine and a reference hydride is essential. A reference design demonstrates to a large extent the performance capability, in terms of range, speed, response, etc., of the system and in the course of its development indicates research and development directions for the improvement of hydride materials and component designs.

Preliminary vehicle system studies were made using as a basis two hydrides whose properties were relatively well known. While they did not meet the required criteria, they served to demonstrate and compare systems based on first, a lightweight, high equilibrium temperature hydride with a relatively high heat of decomposition (nickel-catalyzed magnesium hydride) and second, iron-titanium hydride which has a low equilibrium decomposition temperature and a low heat of reaction. The properties of the two hydrides are shown in Table V.

The fuel supply system for vehicles utilizing hydride storage beds would vary depending primarily on the characteristics of the hydride used. For a hydride such as magnesium hydride, a high temperature source of heat is necessary to release the hydrogen. Exhaust heat will have to be supplemented by heat supplied from a hydrogen burner fueled from the hydride bed. Approximately 13% of the bed will be utilized for this purpose. A small reservoir of iron-titanium hydride, coupled to the main reservoir, would be required to store hydrogen for starting purposes. This starter would be replenished as soon as the main bed started to deliver hydrogen. A system such as this is shown in Figure 19.

The use of a hydride with properties similar to the iron-titanium hydride would require minimal heating to release the hydrogen. The source of this heat could be either engine coolant, air preheated by heat from the coolant radiator or heat from the exhaust. Hydrogen for startup would be available from the hydride at ambient temperatures. This system is shown schematically in Figure 20.

A comparison of specific energy values for several hydrides, gasoline and the lithium-sulfur battery, as conceived for vehicle use, are presented in Table VI. A set of values is also presented to show the specific energy as utilized. This latter value includes container weight and drive efficiency estimates. It demonstrates two interesting facts in particular. First, the lightest hydride with some immediate promise (MgH_2 catalyzed with Ni) cannot compete on equal terms with gasoline. It will, in fact, add approximately 600 lb. to the vehicle storage unit weight and because of operating temperature, some complexity. The second point is that the heaviest hydride considered, $FeTiH_{1.6}$, is able to compete on a weight basis with advanced battery systems without penalty and with a vehicle size and capability near to existing standard vehicles. It is, as well, a low temperature system as opposed to high temperature battery units. It is far superior to the lead-acid battery.

A major emphasis in the reference design task was characterizing the behavior of storage beds through the use of mathematical modeling techniques. Some general conclusions can be drawn from the modeling work. The rate of hydrogen release for the two hydrides was found to depend upon heat transfer rather than reaction rate. Since release occurs over a narrow band of hydride proceeding from the source of heat, the bed becomes operative as soon as this initial amount of hydride is heated. There is no need to provide massive quantities of heat to bring the entire bed up to operating temperature. For restarts, this is not necessarily true unless the bed is sectionalized or the hydrogen redistributes during cooldown. Future work should be devoted to this area of study as well as to the possibility of using hydrogen, stored as a hydride, as a supplemental fuel along with gasoline or methanol to provide lean operation and lower NO_x emissions, and a clean fuel for startup and engine warmup.

Metal hydride materials do not bring hydrogen into contention as a competitor with gasoline for automotive use; however, a potential for use in limited application or large fleet vehicles does exist. Studies have shown that even heavy hydrides such as the iron-titanium hydride are competitive with advanced battery powered vehicle systems in terms of energy density. Magnesium hydride (nickel catalyzed) still appears to be a good choice for special vehicles. Some magnesium-aluminum alloys with lower hydrogen contents have been identified which might serve in the same way. Hydrides of the iron-titanium type show a strong potential for use in heavier vehicles. Further work in developing lightweight hydrides could have significance in automotive applications and provide a useful alternative or supplement to present day fuel systems for the automobile.

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TABLE I

SUMMARY OF INSTALLED CAPITAL COST ESTIMATES (in 1975 Dollars) OF AN ADVANCED TECHNOLOGY (1980) 26MW(e) METAL HYDRIDE STORAGE POWER PLANT, 10 HOUR CHARGE/DISCHARGE CYCLE

	$/kW(e)hr*	$/kW(e)*
1. Water Electrolyzer, including auxiliaries	14	140
2. Hydride Storage Bed/Heat Exchanger	6	60
3. Iron-Titanium Hydride Powder	11	110
4. Fuel Cell Packages, Including Combined Converter-Inverter	15	150
5. Piping, Valves, Controls and Instruments	10	100
6. Accessory Electrical Equipment	7	70
7. Structures and Foundations	3	30
Total Plant Cost	66	660

*Based on plant electrical output

TABLE II

COST DISTRIBUTION
STATE-OF-THE-ART VS. ADVANCED TECHNOLOGY (1980) OF 26MW(e)
METAL HYDRIDE STORAGE ELECTRIC POWER PLANT
10 HOUR CHARGE/DISCHARGE CYCLE

		Present	Advanced
1.	Water Electrolyzer, including auxiliaries	36%	21%
2.	Hydride Storage Bed/Heat Exchanger, including auxiliary H_2 purification equipment	10%	8%
3.	Iron-Titanium Hydride Powder	11%	17%
4.	Fuel Cell Packages, including Combined Converter-Inverter	12%	23%
5.	Piping, Valves, Controls and Instruments	12%	15%
6.	Accessory Electrical Equipment	11%	11%
7.	Structures and Foundations	8%	5%

Table III

A COMPARISON OF THE ELECTROCHEMICALLY REGENERATIVE H_2-O_2 AND H_2-Cl_2 FUEL CELLS - PERFORMANCE, SAFETY AND STORAGE ASPECTS

		H_2O	HCl
1	Reversible potential (volt)	1.23	1.35
2	Projected lowest potential in electrolysis	1.70	1.50
3	Probable lowest potential in electrolysis	2.00	1.70
4	Projected highest potential in fuel cell	0.80	1.20
5	Probable highest potential in fuel cell	0.65	1.10
6	Projected highest overall efficiency (electric-electric)	50%	80%
7	Probable highest overall efficiency (electric-electric) achieved in the near term	32%	65%
8	Hazardous chemical produced at cathode	yes	yes
9	Hazardous chemical produced at anode	no	yes
10	Methods now available for handling the hazardous chemicals	yes	yes
11	Materials problems for storage of anode product	yes (if pure O_2)	yes (but solved)
12	Energy needed for storage of anode product	High for pure O_2, None for air	Low

Table IV

A COMPARISON OF THE ELECTROCHEMICALLY REGENERATIVE
H_2-O_2 AND H_2-Cl_2 FUEL CELLS - FeTi FUEL AND
OXIDANT REQUIREMENTS BY ELECTRIC UTILITY

	H_2O	HCl
Total energy stored	260 MWH	260 MWH
fuel cell voltage	0.65 Volt	1.10 Volt
weight of hydrogen stored	32.5×10^3 lb	15.2×10^3 lb
weight of TiFe required to store above amount of H_2	2.4×10^6 lb	1.42×10^6 lb
weight of Cl_2 stored	——	0.68×10^6 lb
weight of TiFe per KWh	9.2 lb/KWh	5.5 lb/KWh
weight of H_2 per KWh	0.125 lb/KWh	0.074 lb/KWh
weight of Cl_2 per KWh	——	2.6 lb/KWh

Table V

Hydride Properties

	$FeTiH_{1.6}$		MgH_2	(a)
Hydrogen content (wt %)	1.5		7.3	
Bulk density (lb/ft^3)	220		56	
Heat of dissociation (Btu/lb H_2)	7,250		16,650	
Heat capacity (Btu/lb/°F)	0.15	(b)	0.25	(b)
Thermal conductivity (Btu/Hr-°F-ft)	1.0	(c)	0.3	(c)

a. Mg catalyzed with 5% nickel

b. Estimated

c. Granular solid hydrogen at 1 atm

Table VI

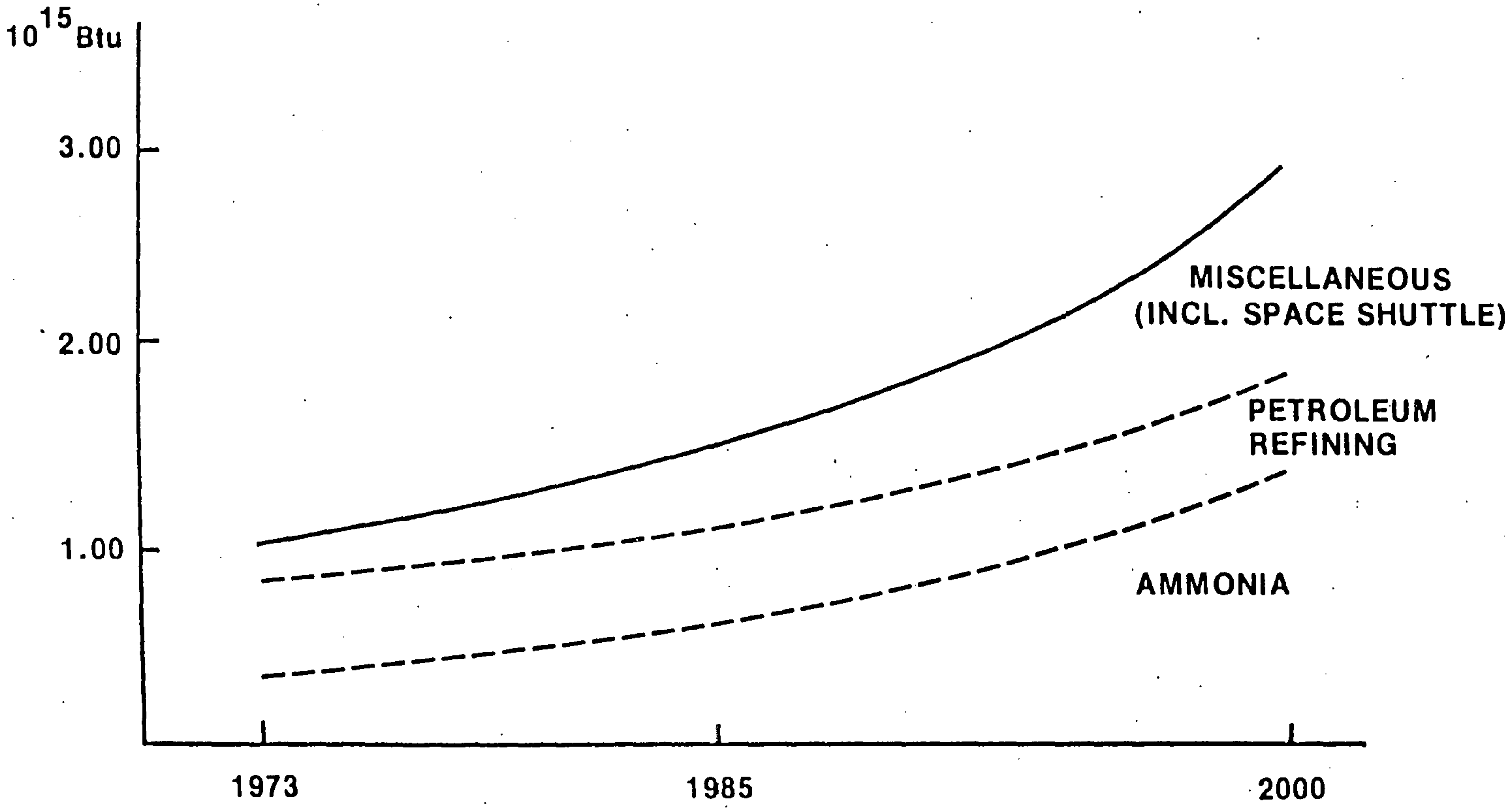
Power Source Energy Density Comparison

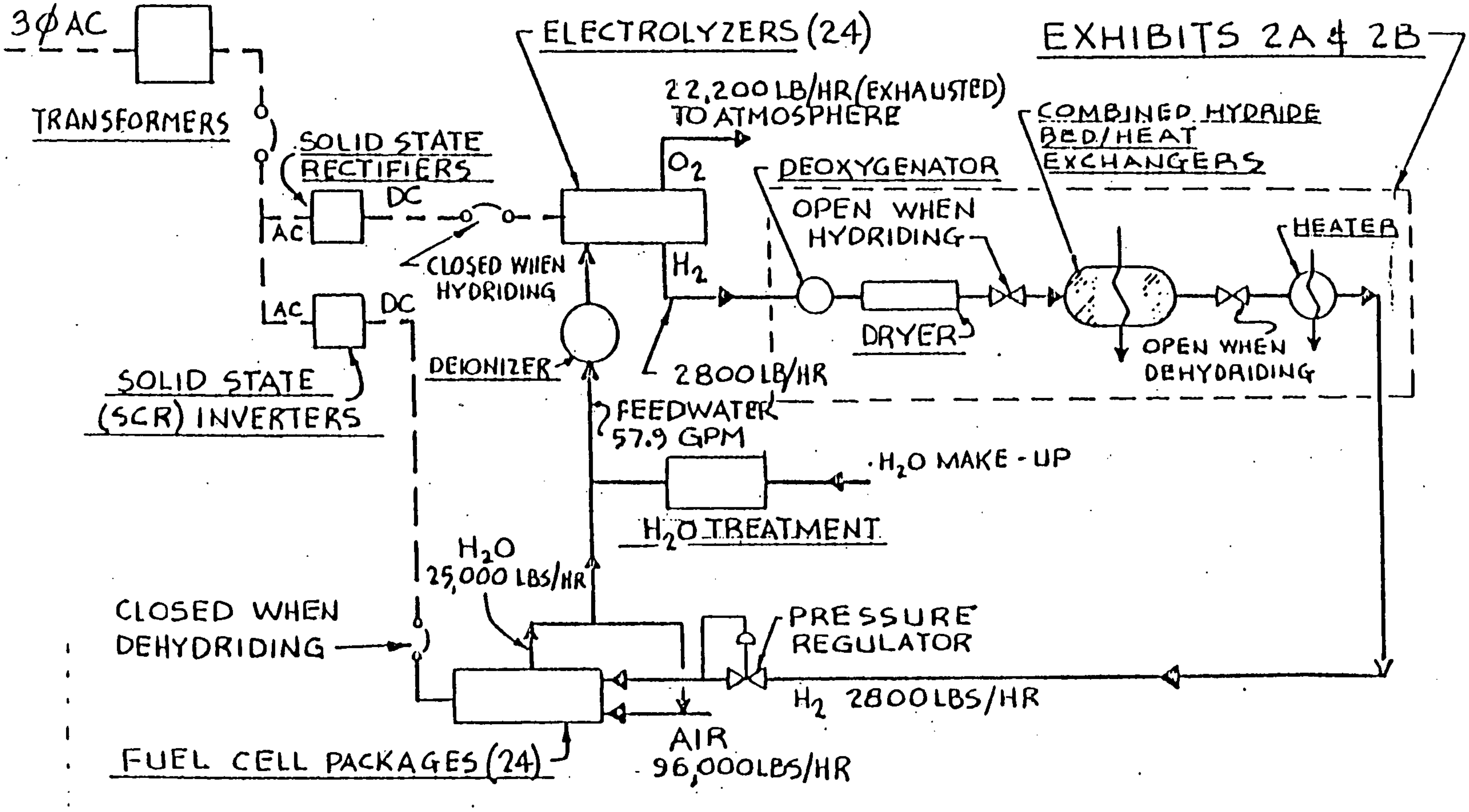
Power Source	Energy Density (w hr/lb)	Energy Density for Propulsion (w hr/lb)
Pb Acid Battery	10	7.1
Li-S Battery	68	48
$FeTiH_{1.6}$	214	53
$FeTiH_{1.9}$	256	64
Mg_2NiH_4	427	109
MgH_2 (5% Ni)	819	179
Gasoline	5570	1100

Note: H_2 utilized at 30% efficiency, gasoline at 23%. $FeTiH_{1.6}$ indicates degree of hydriding reached using a fast recharge. $FeTiH_{1.9}$ is result of overnight recharge.

Figure 1

HYDROGEN - PROJECTION OF CURRENT USES

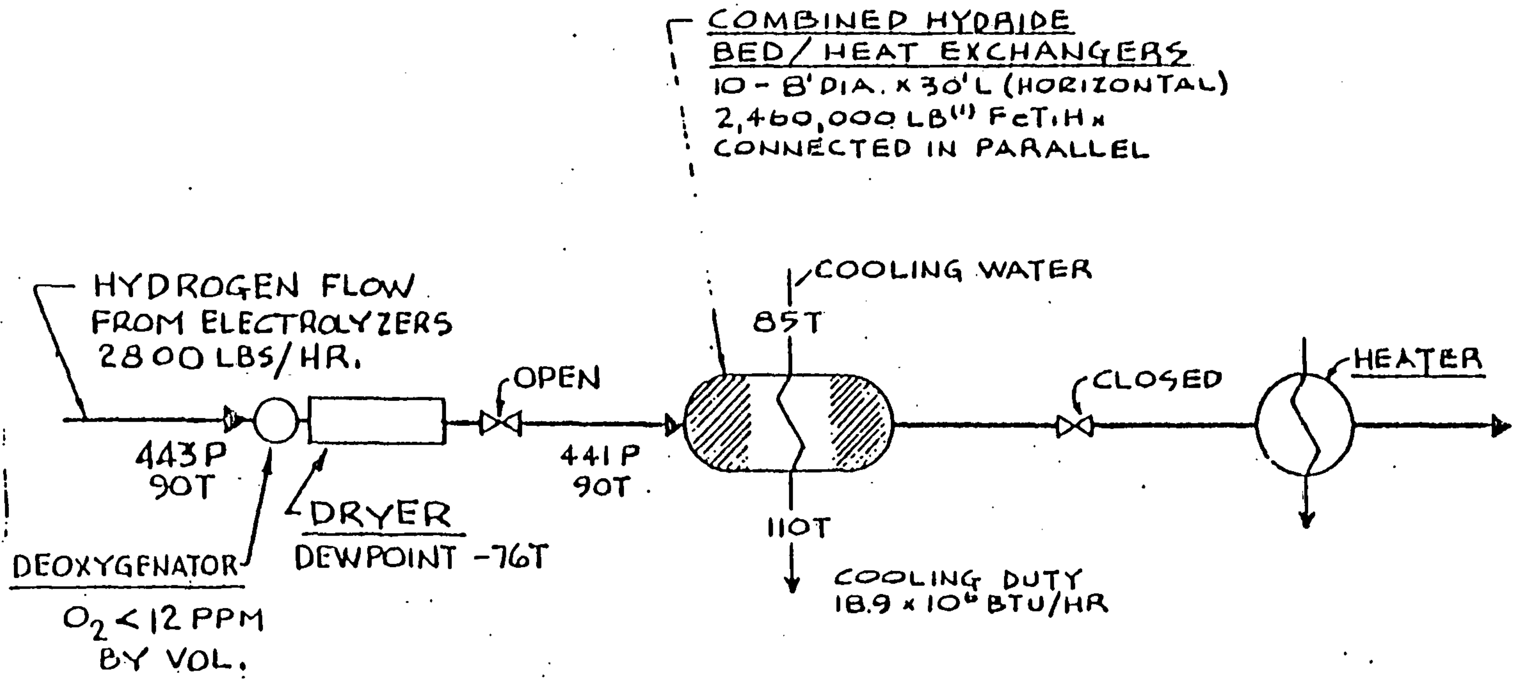




METAL HYDRIDE STORAGE POWER PLANT
PROCESS SCHEMATIC

FIGURE 2

T = TEMPERATURE °F
P = PRESSURE P.S.I.A.



NOTES

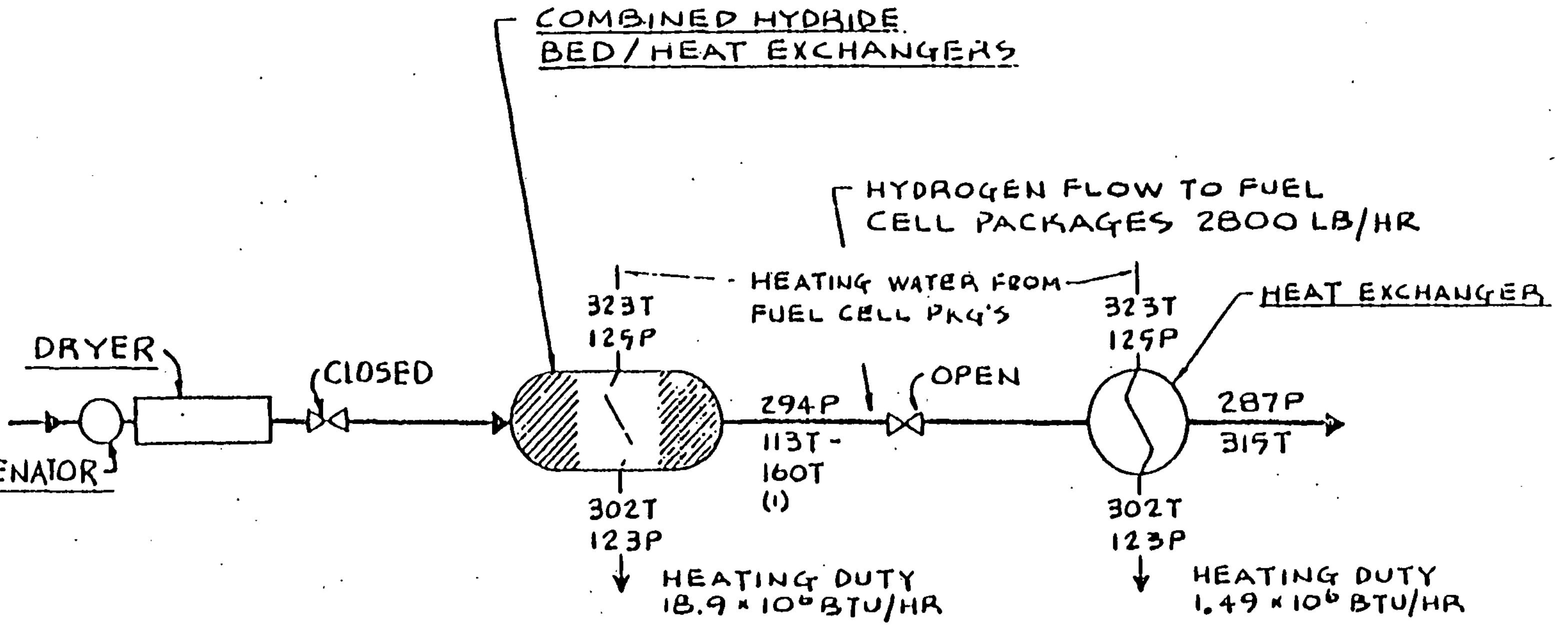
(1) BASED ON HYDRIDING FROM $FeTiH_{0.2}$ TO $FeTiH_{1.4}$

METAL HYDRIDE STORAGE POWER PLANT

HYDRIDING PROCESS SCHEMATIC

FIGURE 3

T= TEMPERATURE °F
P= PRESSURE P.S.I.A.



NOTES
(1) HYDRIDE DISSOCIATION EQUILIBRIUM TEMPS. AT 294 PSIA

METAL HYDRIDE STORAGE POWER PLANT

DEHYDRIDING PROCESS SCHEMATIC

FIGURE 4

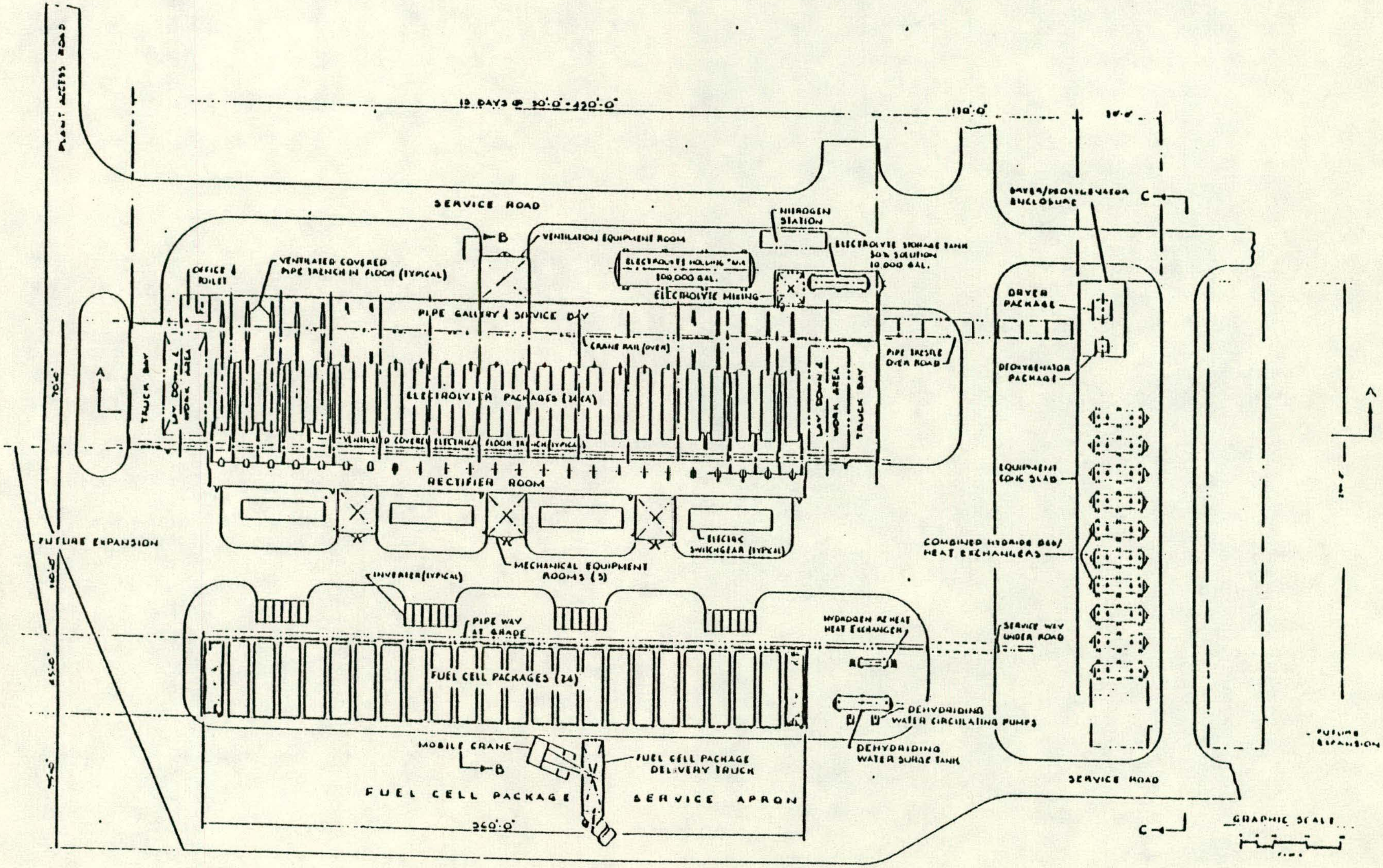


FIGURE 5
Metal Hydride Storage Power Plant - General Arrangement

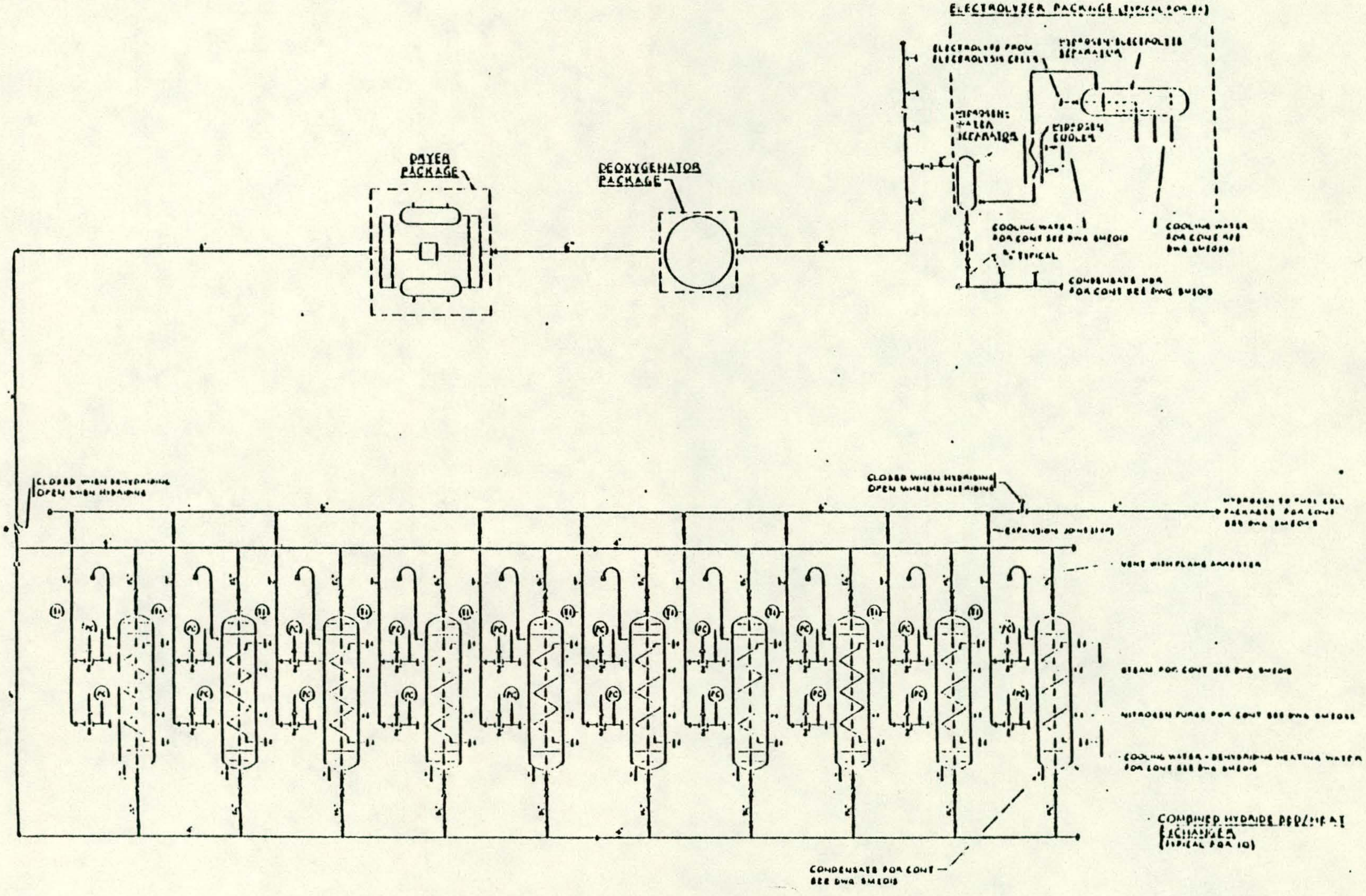


FIGURE 6

Metal Hydride Storage Plant - Hydrogen Flow Diagram

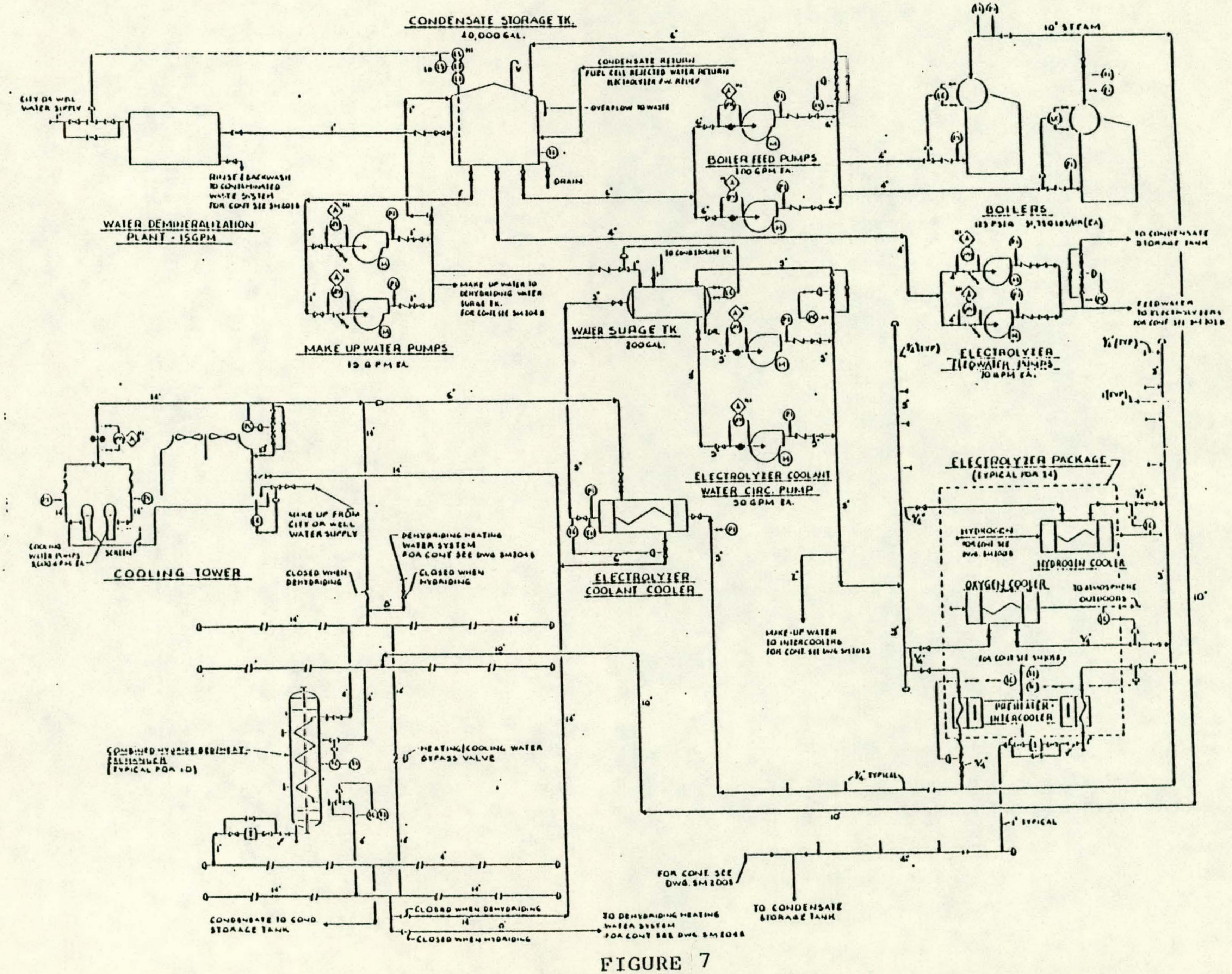


FIGURE 7

Metal Hydride Storage Power Plant - Water and Steam Flow Diagram

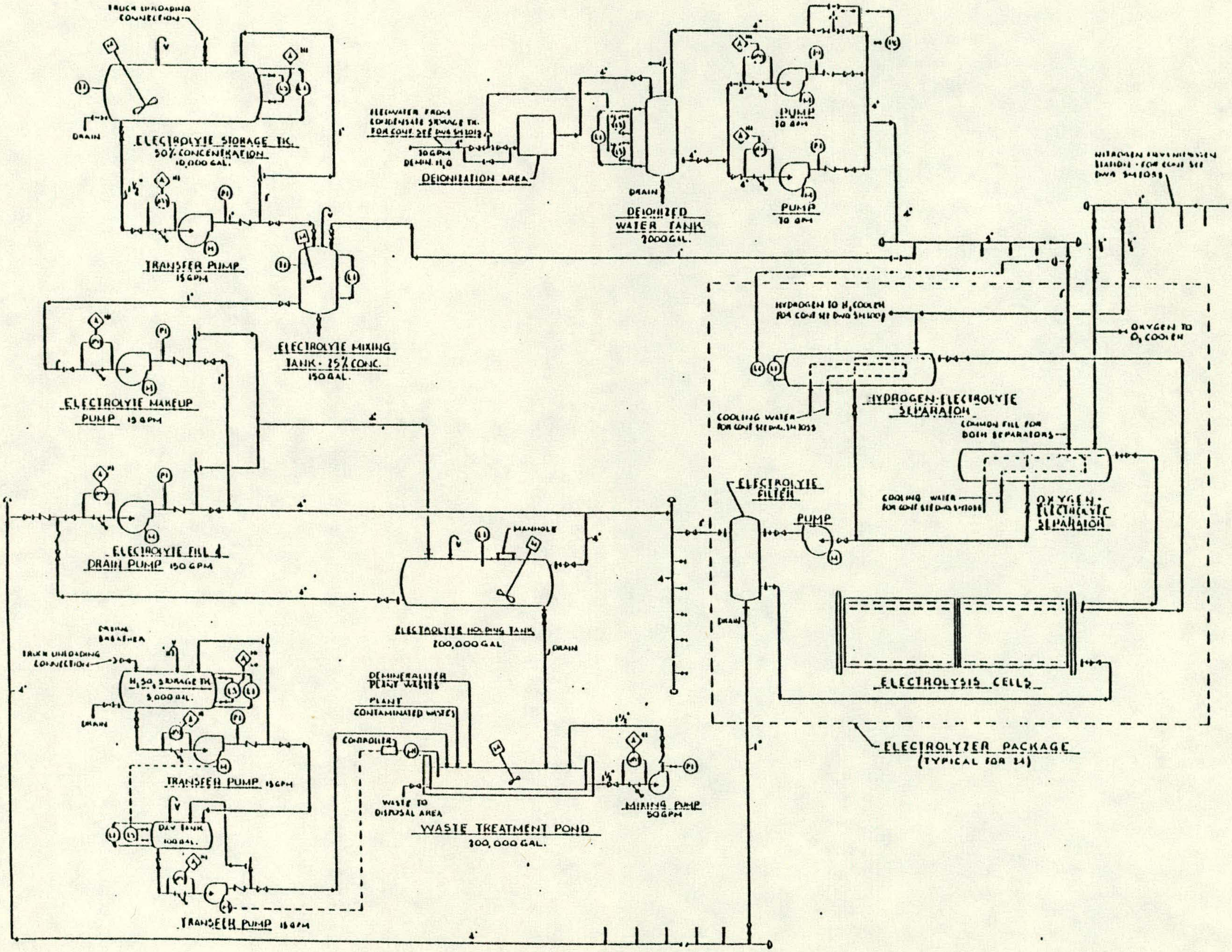


FIGURE 8
Metal Hydride Storage Power Plant - Electrolyte Flow Diagram

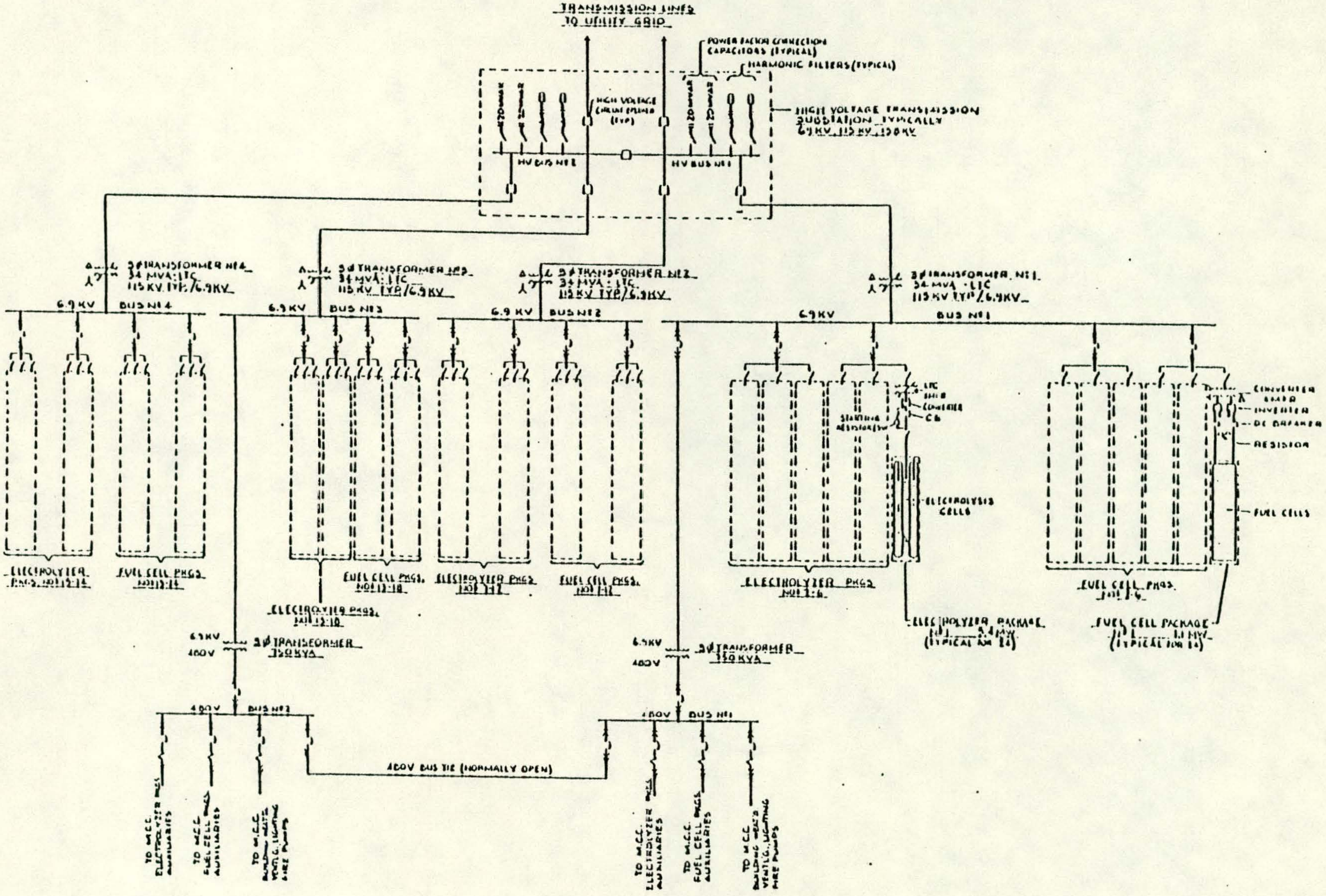
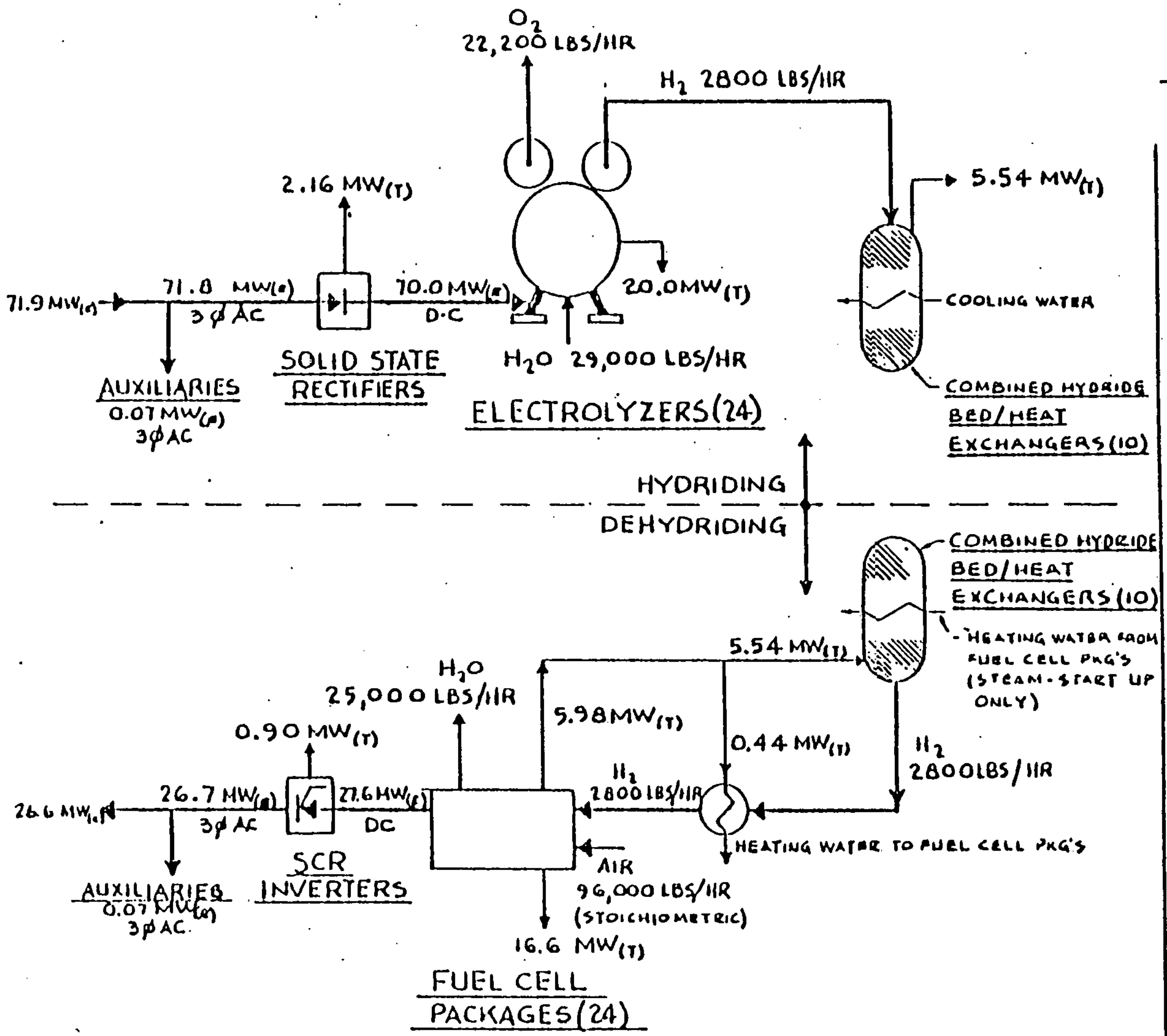


FIGURE 9

Metal Hydride Storage Power Plant - Main Electrical One-Line Diagram



METAL HYDRIDE STORAGE POWER PLANT

ESTIMATED NOMINAL PLANT PERFORMANCE

(CONDUCTION CASE)

HYDRIDING

RECTIFIER INPUT	71.8 MW
AUXILIARIES - (COOLING TOWER PUMPS, OTHER PUMPS, ETC.)	0.07 MW
TOTAL PLANT INPUT	71.9 MW
RATE OF H_2 ENERGY STORAGE (BASED ON HHV OF H_2)	50.1 MW
NOMINAL HYDRIDING EFFECTIVENESS	$\frac{50.1}{71.9} \times 100 = 70\%$

DEHYDRIDING

GROSS PLANT OUTPUT	26.7 MW
AUXILIARIES - (HEATING WATER PUMPS, FUEL CELL EXHAUST FANS, ETC.)	0.07 MW
NET PLANT OUTPUT	26.6 MW
RATE OF H_2 ENERGY AVAILABILITY (BASED ON HHV OF H_2)	50.1 MW
NOMINAL DEHYDRIDING EFFECTIVENESS	$\frac{26.6}{50.1} \times 100 = 53\%$

OVERALL PLANT EFFICIENCY

$(0.70)(0.53) \times 100 = 37\%$

FIGURE 10

Metal Hydride Storage Power Plant - Estimated Nominal Plant Performance

FIGURE 11

THE BREAK EVEN CAPITAL COSTS OF THE BLACK-BOX STORAGE DEVICE, AS A FUNCTION OF THE CONVERSION EFFICIENCY

NOMINAL PEAK LOAD DISTRIBUTION
DISTILLATE FUEL OIL PRICE OF $2.6/10^6 BTU

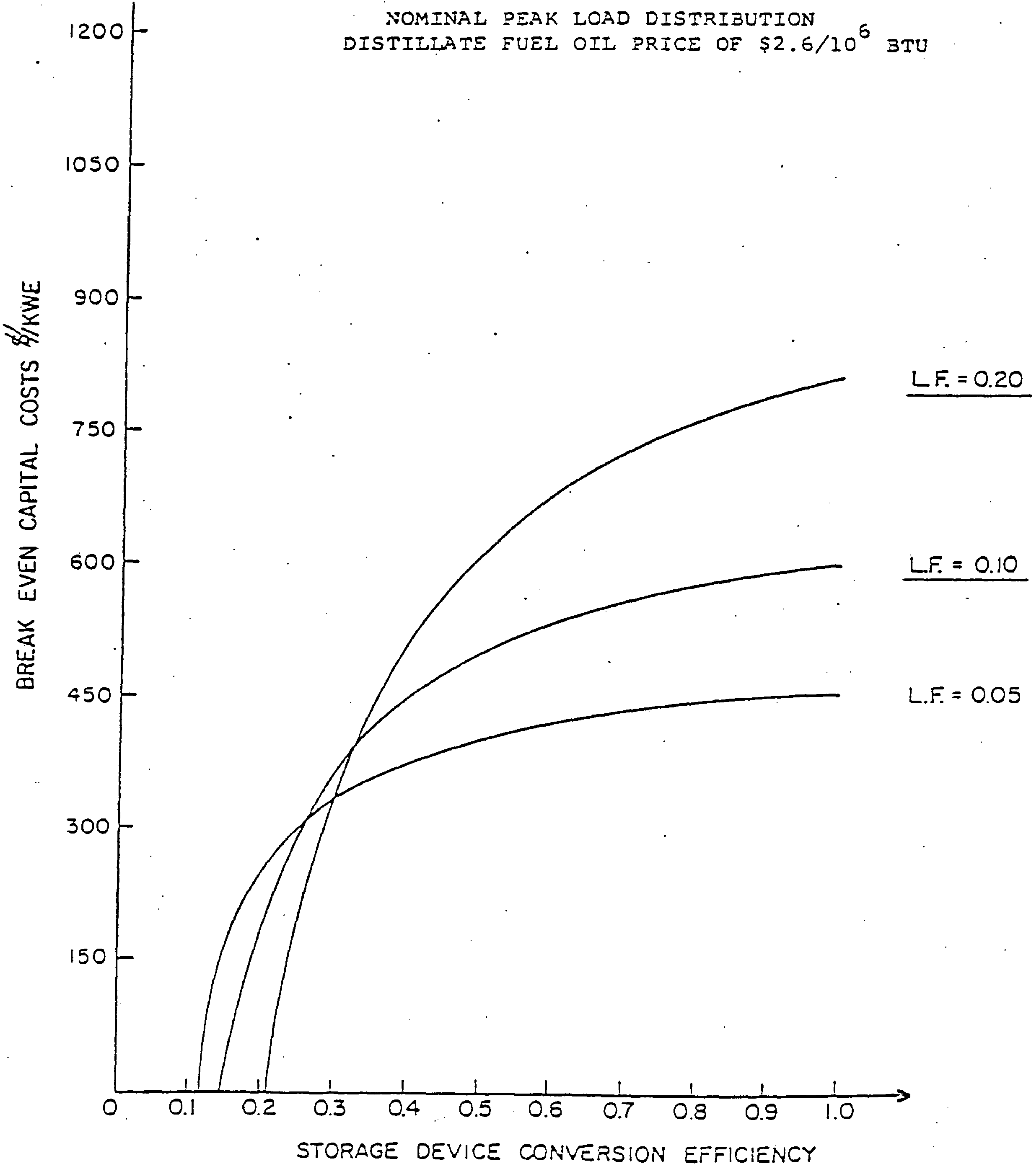


Figure 12

THE BREAK EVEN CAPITAL COSTS OF THE BLACK-BOX STORAGE DEVICE, AS A FUNCTION OF THE CONVERSION EFFICIENCY

NOMINAL PEAK LOAD DISTRIBUTION
DISTILLATE FUEL OIL PRICE OF $3.9/10^6 BTU

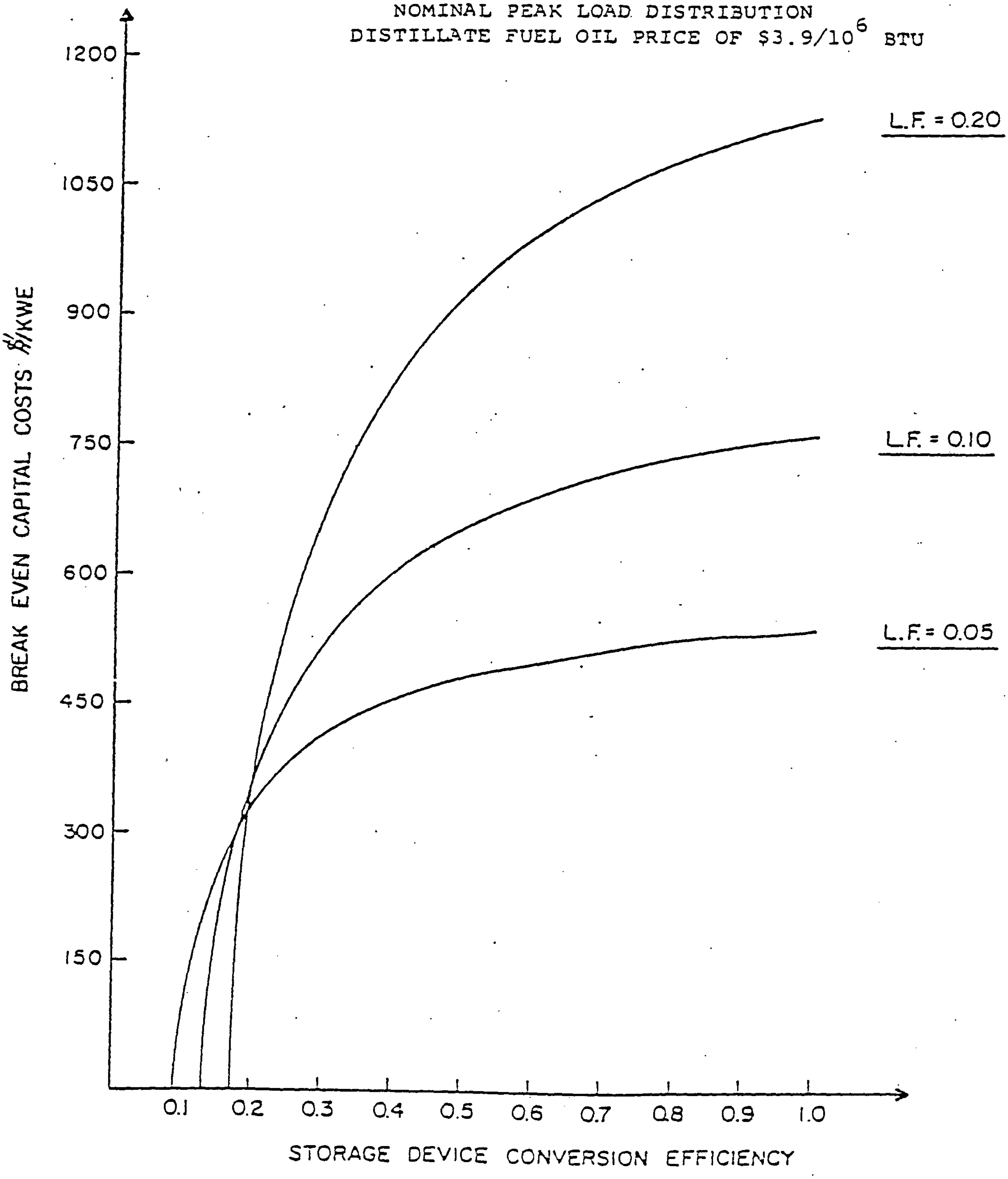
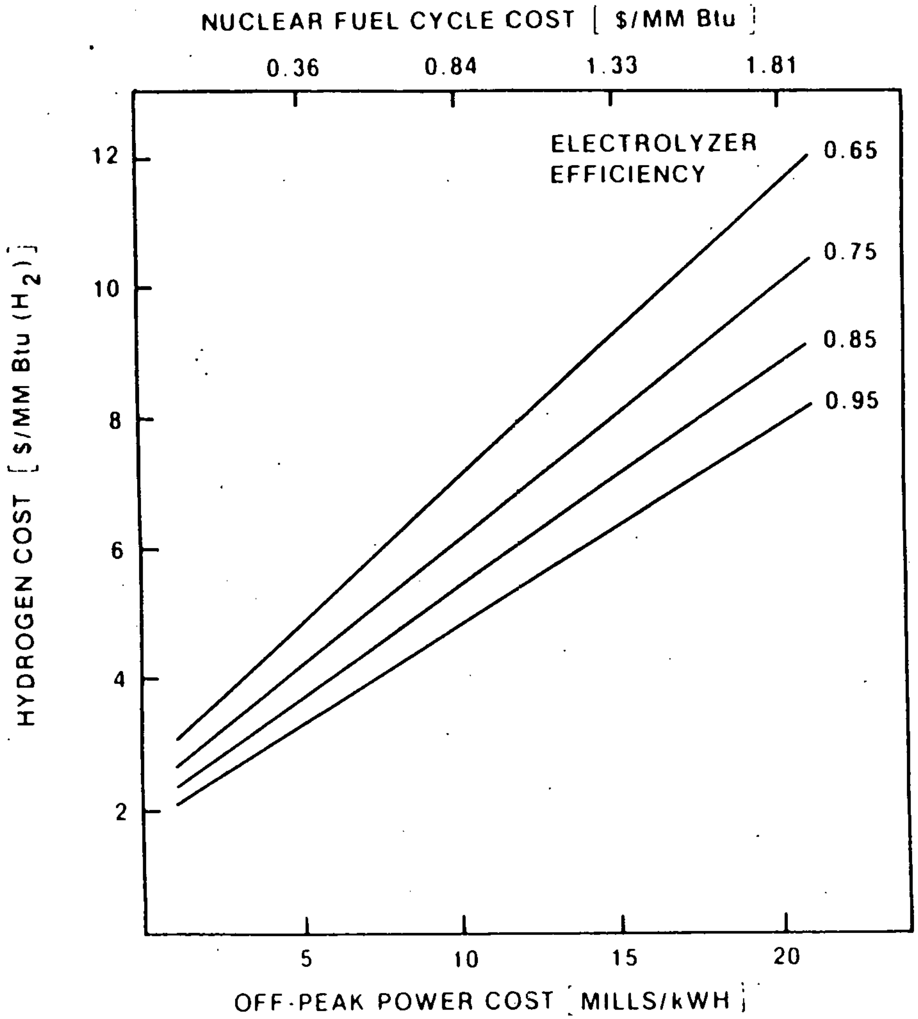


Figure 13

COST OF OFF-PEAK NUCLEAR ELECTROLYTIC HYDROGEN AS A FUNCTION OF THE OFF-PEAK POWER COST, AND THE ELECTROLYZER EFFICIENCY

(YEARS 1985 AND 2000)



ELECTROLYZER COST — $100/kW(e)
O AND M COSTS — 0.37$/MM Btu(e)
NUCLEAR THERMAL EFFICIENCY — 0.33

Figure 14

THE ALLOWED ELECTROLYZER PLANT CAPITAL COST, AS A FUNCTION OF THE NATURAL GAS PRICE AND THE ELECTROLYZER'S ANNUAL AVERAGE LOAD FACTOR

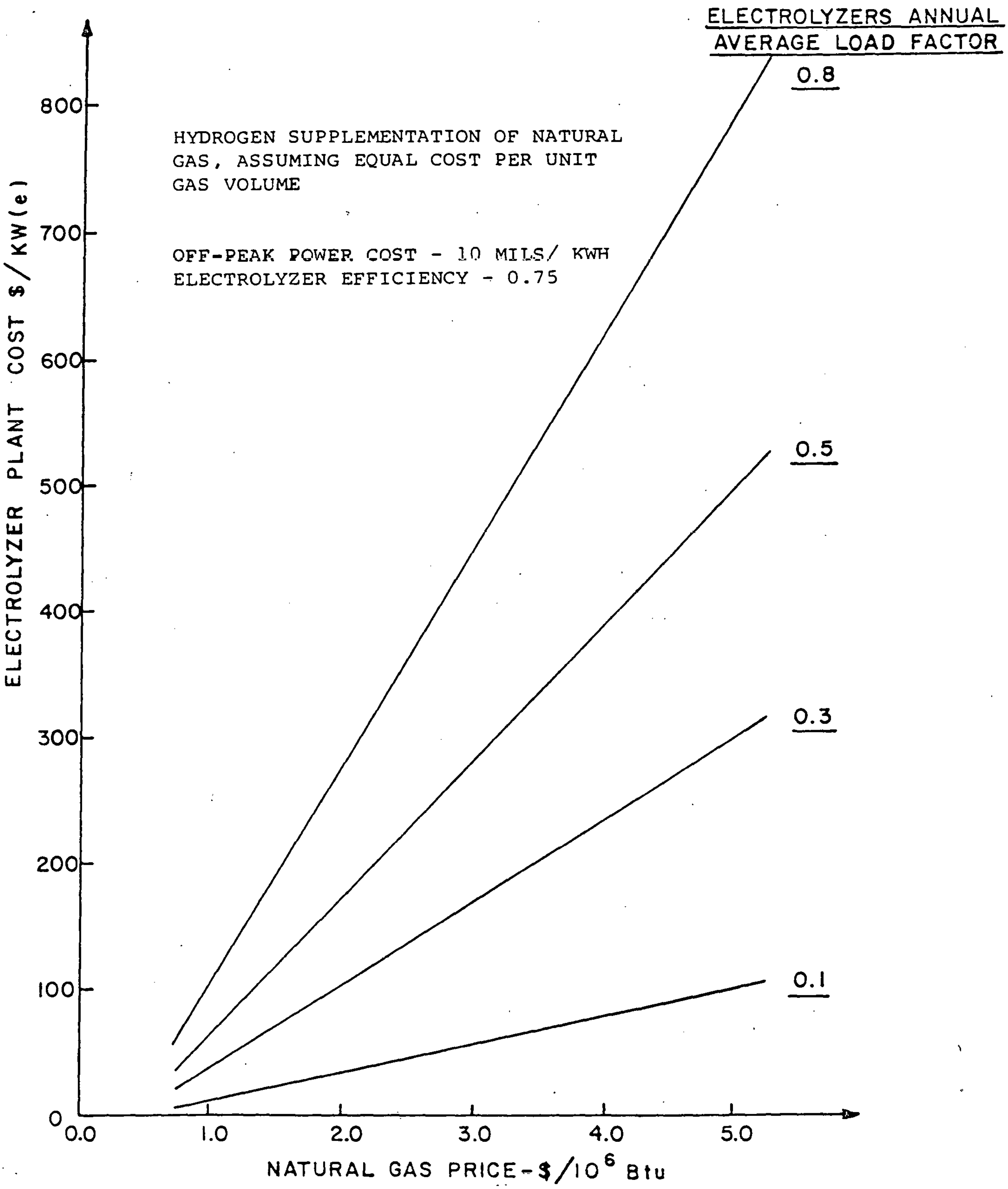


Figure 15

THE BREAK-EVEN CAPITAL COST OF NATURAL GAS/ELECTROLYTIC HYDROGEN DUAL INPUT GENERATING DEVICE, AS A FUNCTION OF THE INPUT FUEL MIX

Natural Gas Price of $0.45/10^6 Btu
Distillate Oil Price of $2.6/10^6 Btu
Electric to Electric Conversion Efficiency - 0.60

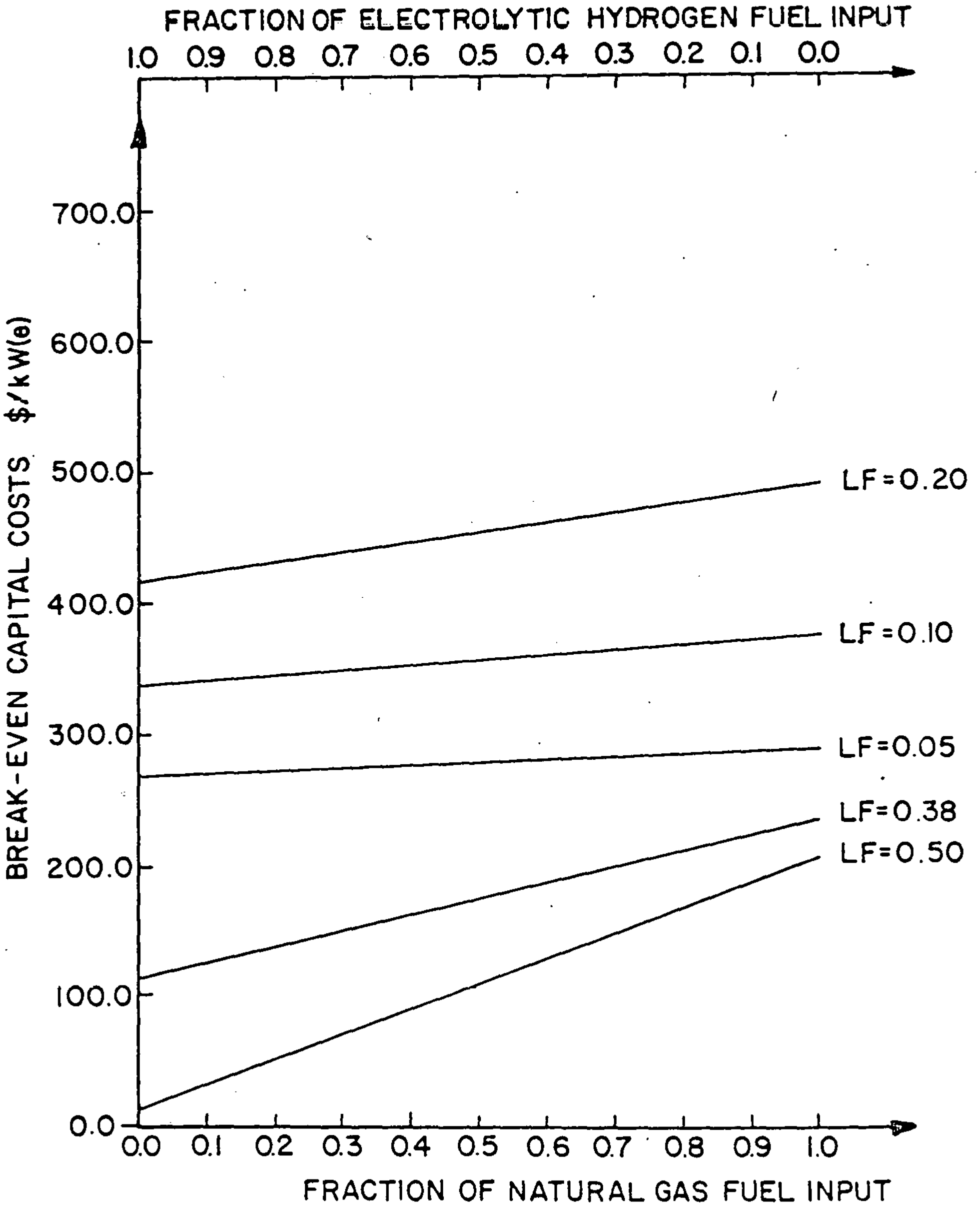
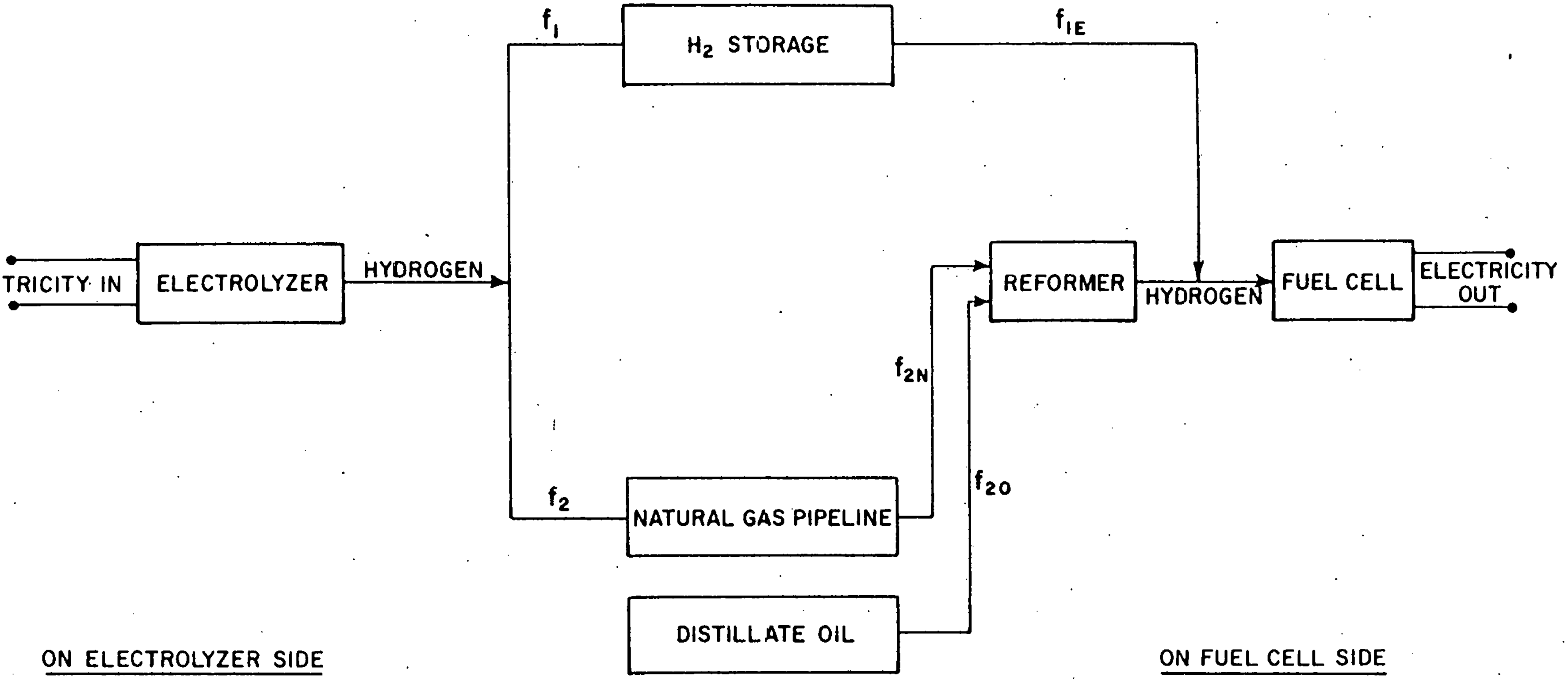


Figure 16

DUAL OUTPUT ELECTROLYZER-DUAL INPUT FUEL CELL

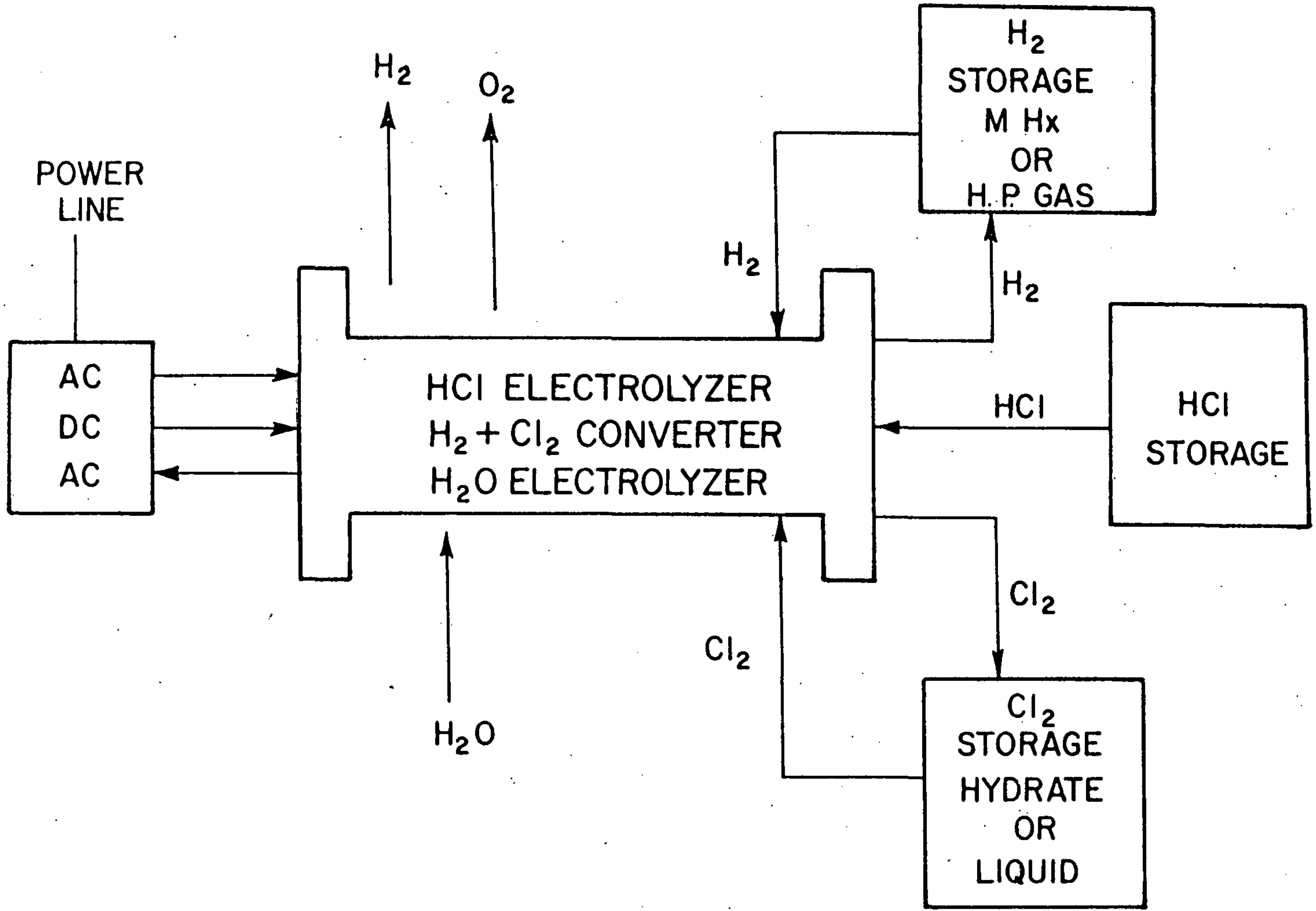


ON ELECTROLYZER SIDE

$f_1 + f_2 = 1.0$

ON FUEL CELL SIDE

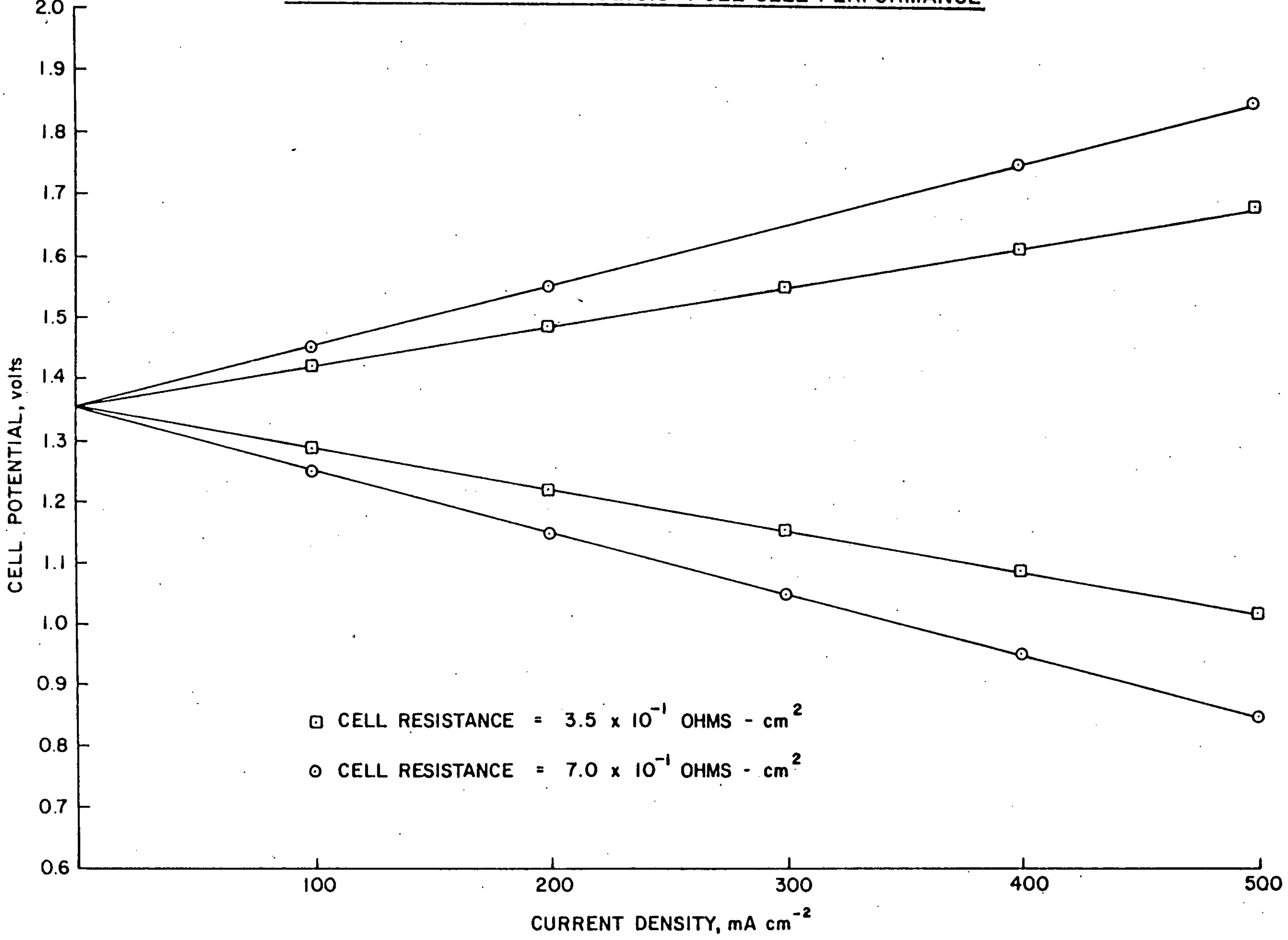
$f_{1E} + f_{2N} + f_{2O} = 1.0$



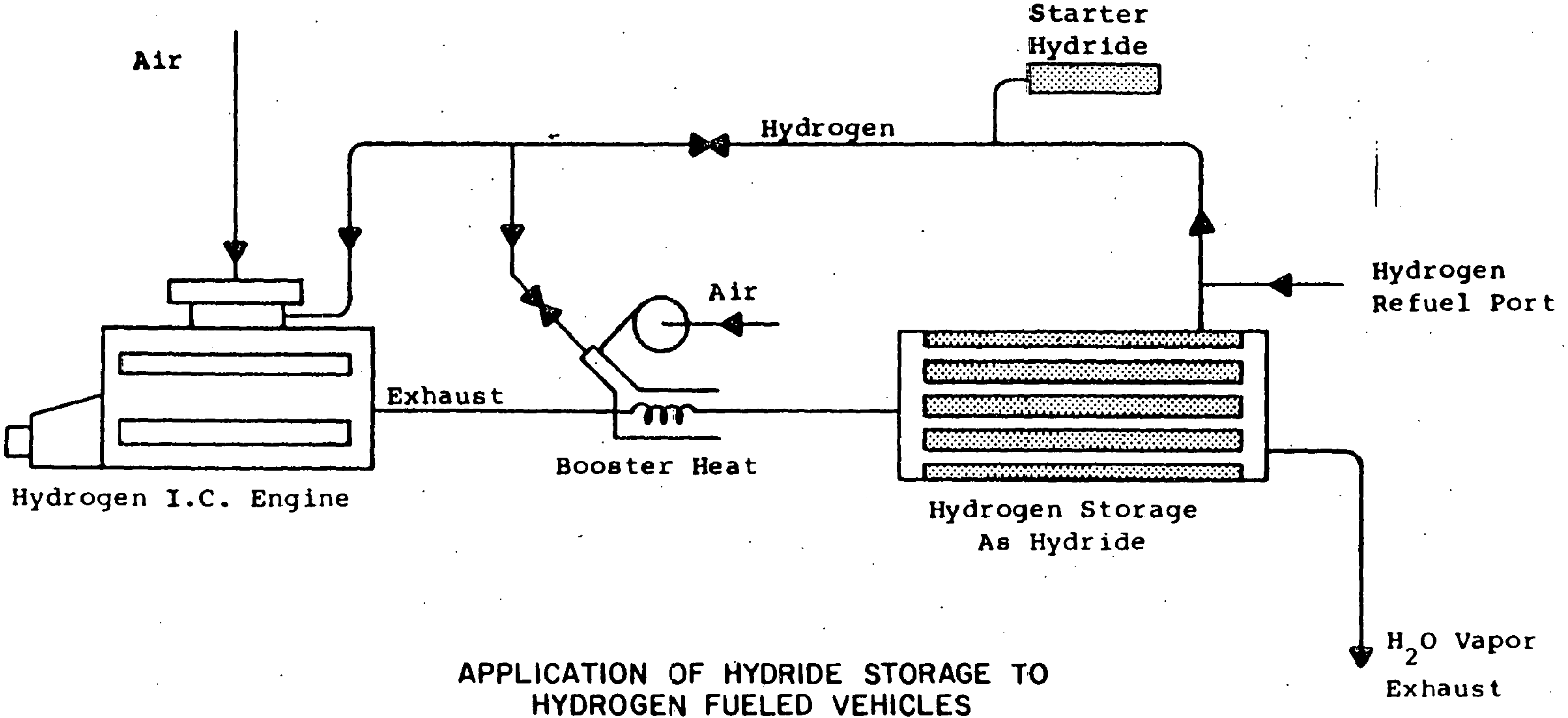
HCl ELECTROLYSIS ELECTRIC TO ELECTRIC STORAGE AND H_2 PRODUCTION SCHEMATIC

Figure 17

Figure 18

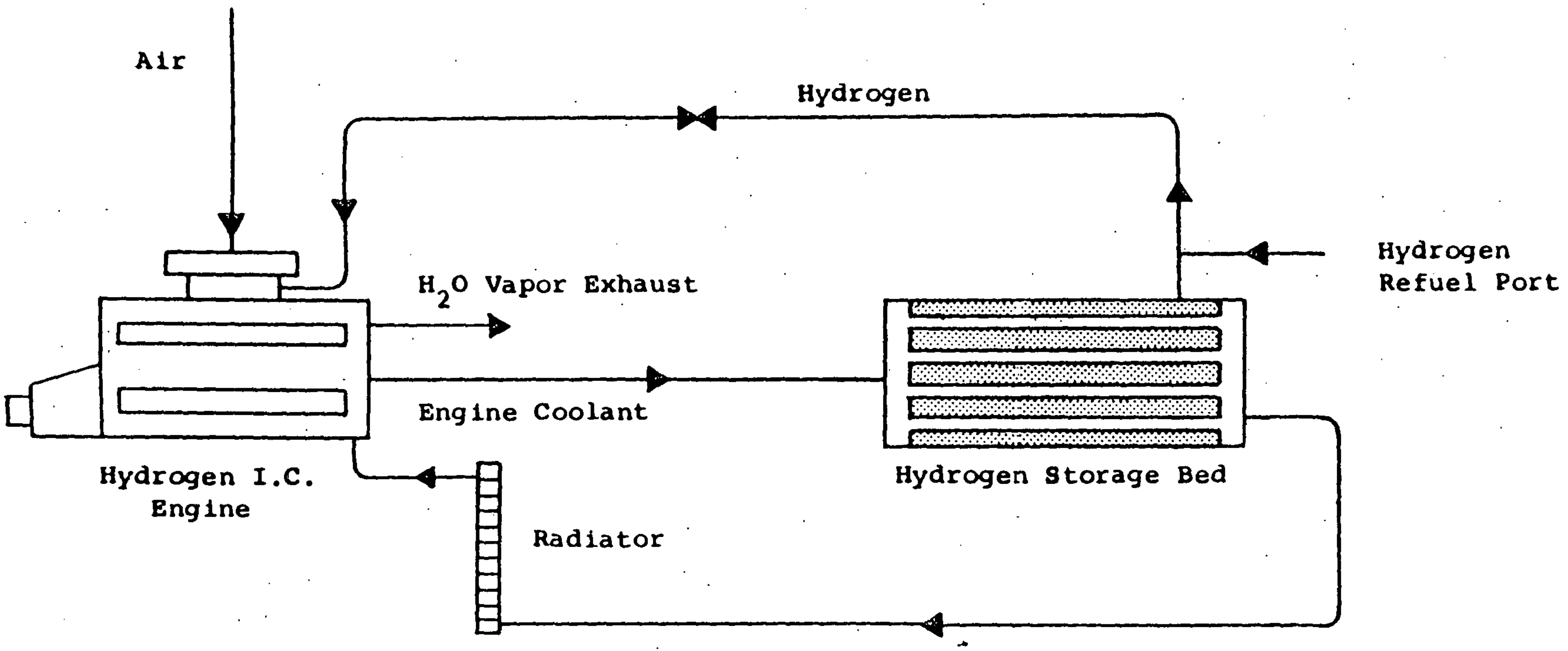


PROJECTION OF HCl ELECTROLYSIS FUEL CELL PERFORMANCE



APPLICATION OF HYDRIDE STORAGE TO HYDROGEN FUELED VEHICLES
(Supplemental Heat Case)

Figure 19



HYDROGEN STORAGE SYSTEM - LOW TEMPERATURE HYDRIDE

Figure 20