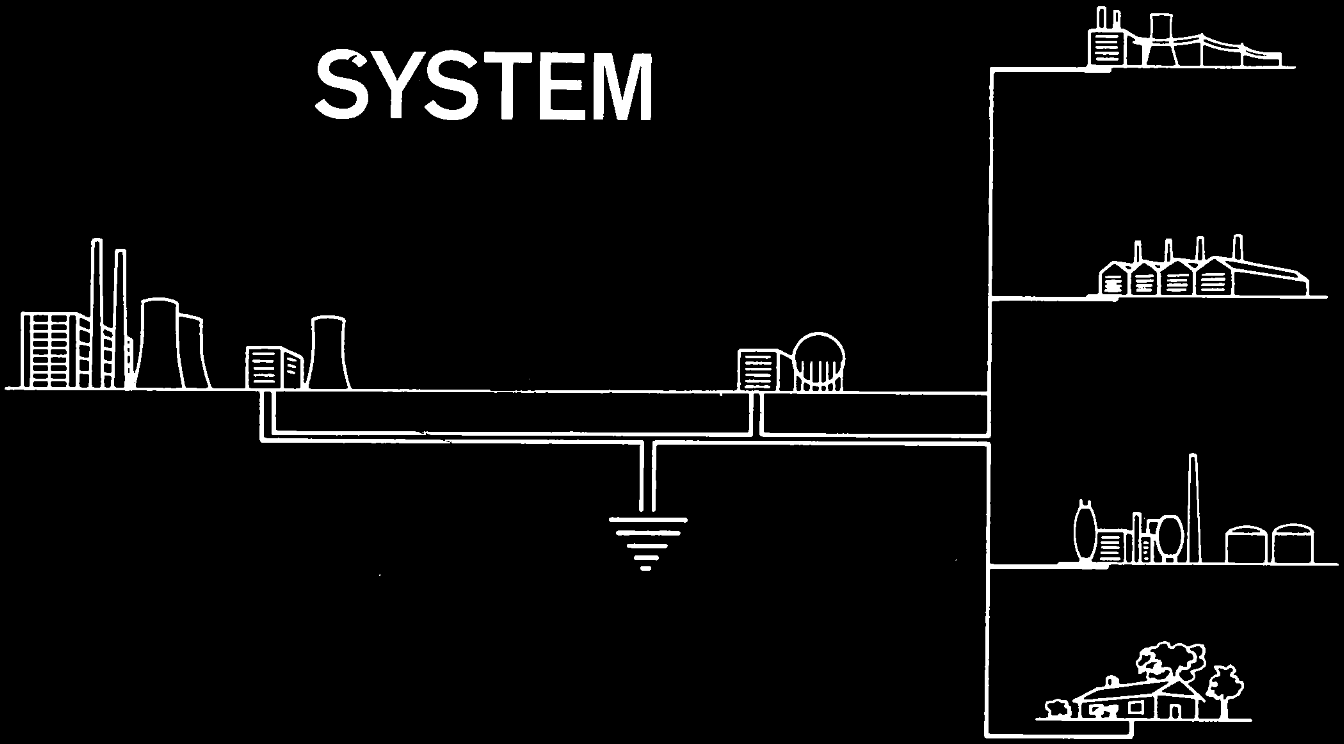
A HYDROGEN - ENERGY SYSTEM



American Gas Association

A HYDROGEN-ENERGY SYSTEM

Prepared for

AMERICAN GAS ASSOCIATION

by

INSTITUTE OF GAS TECHNOLOGY

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PREFACE

This work was sponsored by the American Gas Association and was carried out by the Institute of Gas Technology as A. G. A. Project IU-4-6. The advice and assistance of Dr. A. Flowers, Manager, Residential, Commercial, and Industrial R&E, of A. G. A. and the A. G. A. -appointed project advisers are much appreciated.

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EXECUTIVE SUMMARY

INTRODUCTION

Because of the limited supplies of fossil fuels available, our energy supply pattern will undergo some radical changes in the near future. One change is that energy in any form is going to cost more in proportion to the other things we can buy. Another change is that the sources of energy which we use will have to change and relatively "inexhaustible" supplies such as nuclear energy will have to play an increasing part. These changes will precipitate a number of other radical changes, which themselves will be tempered by our increasing desire to avoid "pollution" or to minimize the effects of our technological progress upon our environment.

One of the changes that is possible is the development of a fuel system based upon a synthetic chemical fuel derived from nuclear energy and fully recyclable materials such as air and water. Of the various fuels that can be considered, the most likely to come into use is hydrogen. An energy industry based upon hydrogen for energy storage, distribution, and utilization has been termed "The Hydrogen Economy." There is growing interest in such a concept on the part of various industrial companies, the U.S. Government, the Atomic Energy Commission, the American Gas Association, and others.

The feasibility and introduction of such a system will not be without major problems, many of which will require fairly long lead times for their solution. Accordingly, the Institute of Gas Technology carried out for the American Gas Association a study of a nationwide hydrogen energy production, transmission, distribution, and utilization system that may ultimately take the place of the present natural gas system when our fossil fuel supplies become scarce. The study was intended to establish the feasibility of such a concept, to identify major problems and timetables involved, and to recommend a plan for further investigations. That study, which is reported here, commenced in June 1971.

The study involved not only the extraction of technical and engineering information from the available literature and preliminary design calculations for hydrogen transmission facilities, but also extensive discussions with representatives of both the chemical industry and NASA, which are users of hydrogen, and the electrical industry, which is facing major problems of energy transmission. Without the cooperation of these people, this study would not have been as comprehensive.

To report the results of this effort, we have chosen to write a detailed volume that can be used as a basic reference for further work. Because of the length of that volume, this summary report has been prepared to cover some of the highlights and conclusions of the study. Inevitably, the summary duplicates some information in the body of the report and treats other items rather briefly. Further details are to be found in the body of the report, which follows the same sequence as this summary report.

I. THE NEED FOR HYDROGEN AS A FUEL IN FUTURE

Many studies have been done of our fossil fuel resources and undoubtedly many more will be done. Although many of these come to differing conclusions, they reach a broad consensus that each of the fuels — gas, oil, shale, and coal — will be produced at increasing rates until they each reach a peak, after which time, the rate of producibility will decline. The peak producibility of natural gas in the lower 48 U.S. states is occurring now. A recent study of the problem on a worldwide basis, carried out by Elliott and Turner of Texas Eastern Transmission Corp., has assumed various models for the rate of development of production and various estimates for the overall fossil fuel resources. In each case they show that peak producibility occurs in the first half of the 21st century, or within 50-80 years from now. That is not to say that all the world's coal, for example, will have been used by then, but that the rate at which all fossil fuels can be produced will be falling off after that time, so that a new energy source must be found to fill the gap.

The only new energy source with which we can "fill the gap," based on present and immediate future technology, is nuclear energy. To produce the vast amounts of energy required in the future, the breeder reactor, and ultimately the fusion reactor, will have to be developed because the natural uranium reserves are themselves limited in quantity. Solar energy may also be harnessed in the future, but advanced developments are necessary. In this study, we confined our consideration of energy sources to nuclear reactors. The most important question is the form in which this nuclear energy is to be delivered to its users.

Most of the current work on nuclear reactor technology is aimed at converting nuclear energy into electrical energy for direct supply to the consumer. As problems of siting nuclear power plants, due to their heat release requirements and safety considerations, become greater, longer transmission lines are becoming required. The optimum size for nuclear power stations is also likely to become very large, about 5000 to 10,000 MW, again requiring large, high-capacity transmission lines. Among recent developments in the nuclear industry is a growing interest in modular floating power stations, built by shipyard techniques and delivered to ocean-cooled offshore sites. Quite recently, Westinghouse-Tenneco have teamed up to enter this field. We foresee the nuclear power stations of the future being large installations, remotely sited along side, or actually in, large bodies of water.

In the U.S., the use of electric energy by the consumer is growing at more than double the rate at which our overall use of energy is growing. The growth rate of electricity now (1970-71) appears to be slowing, but is still predicted to rise considerably faster than the direct use of fossil fuels. The impact of the growth of nuclear electric power stations will assist this trend. On economic grounds, such a trend is surprising because electric energy, on the average, today costs 7-3/4 times as much as natural gas, for example. It is also surprising on conservation grounds because a unit of electrical energy, by the time it reaches the user, has required between 3 and 4 times that amount of fuel energy in its generation and transmission. Thus, energy use patterns are certainly not completely dominated by either cost or a concern for fossil fuel resources.

One of the biggest problems facing the electrical industry is the transmission of the huge quantities of electric power that will be produced by the remotely located generating stations to the concentrated urban areas where the load centers are. Apart from the high cost of transmission equipment and maintenance, there is growing concern for the aesthetic effect of overhead lines. Allied with this problem is one of storage requirements: At present, there is no way of storing large quantities of electrical energy near the consumer sites for peakshaving purposes.

In the fossil fuel industries, we are accustomed to using our fuels as a storage and transmission medium. We take for granted the ability to fill up an automobile gasoline tank for a 200-mile journey. We also take for granted the availability, on demand, of huge quantities of oil or natural gas for winter heating on a severely cold day. Neither of these examples is easily available in an all-electric economy – witness the absence of electric automobiles (and airplanes) and the difficulties experienced in keeping up the electricity supply of, for example, New York City on its peak demand day in summer. The nuclear age will need a synthetic chemical fuel that will make possible –

a. Lower cost transmission
b. Underground or inconspicuous transmission and distribution
c. Storage for peakshaving

Of the various chemical fuels considered, we must confine ourselves to those made from air and water, so that on combustion their products can be deposited into the environment without pollution. Of the choices available to us, hydrogen is the easiest to make and in many ways the easiest to use. Ammonia and hydrazine might be made from hydrogen and atmospheric nitrogen. Methanol or even hydrocarbons might be synthesized from hydrogen and carbon dioxide derived from limestone or from the atmosphere. All of these require hydrogen.

Hydrogen is the cleanest of all fuels, burning to form only water, with the possibility, which may be suppressed, of nitrogen oxides formation from the heated air. Apart from the absence of pollution, water is sufficiently abundant and mobile in the earth's crust that no disturbance would be caused by consuming water at the generating stations and liberating it in the cities.

We can therefore make a strong case for considering hydrogen as a "universal" fuel to replace natural gas and the other fossil fuels as they become scarce or expensive. Let us now look into the technical problems and economics of its production and use.

II. "SCENARIO" FOR THE HYDROGEN ECONOMY

To set the stage for examining some of the problems to be solved, we have attempted to paint a picture of the energy situation 30 to 50 years from now, assuming that a hydrogen energy system was developing. This is the "scenario" technique of technological forecasting and allows one to foresee problems before they actually occur.

In the "Hydrogen Economy," hydrogen will be produced from nuclear energy by today's known technology using water electrolysis. Direct-current electric power from a nuclear power station can be used to electrolyze water into hydrogen and oxygen at efficiencies of about 100% (in comparison to today's figures of between 60 and 70%). New methods will also be developed for water-splitting using the nuclear reactor heat directly.

Hydrogen will be used for all the present applications of natural gas and more. Burners can be designed to handle hydrogen in heating, cooking, and industrial operations. Gas turbines and piston engines will operate better on hydrogen. Fuel cells that use hydrogen as a fuel are simpler and cheaper than those that use hydrocarbon fuels. As we have already mentioned, hydrogen is an extremely clean fuel, the controlled burning of which produces only water. The benefit of such a clean fuel on the environment will be considerable.

Hydrogen will be transmitted from the remote, possibly offshore, power stations in underground high-pressure pipelines similar to those used for natural gas today. In many instances, the same lines can be used, with modifications to the compressor stations. There appear to be no insurmountable problems in doing this. Hydrogen will be distributed in networks similar to those used for today's natural gas. Some extra safety considerations are necessary, but appear to be acceptable.

The cost of delivering energy in a natural gas pipeline distribution system is today far lower than the cost of moving electrical energy. This advantage of gas transmission appears to be retained if we move to hydrogen. Today's costs of installation of gas and electric transmission equipment are shown in Figure 1, which presents data derived from 1970 A.G.A. and FPC reports. The intercepts at the zero-distance axis are

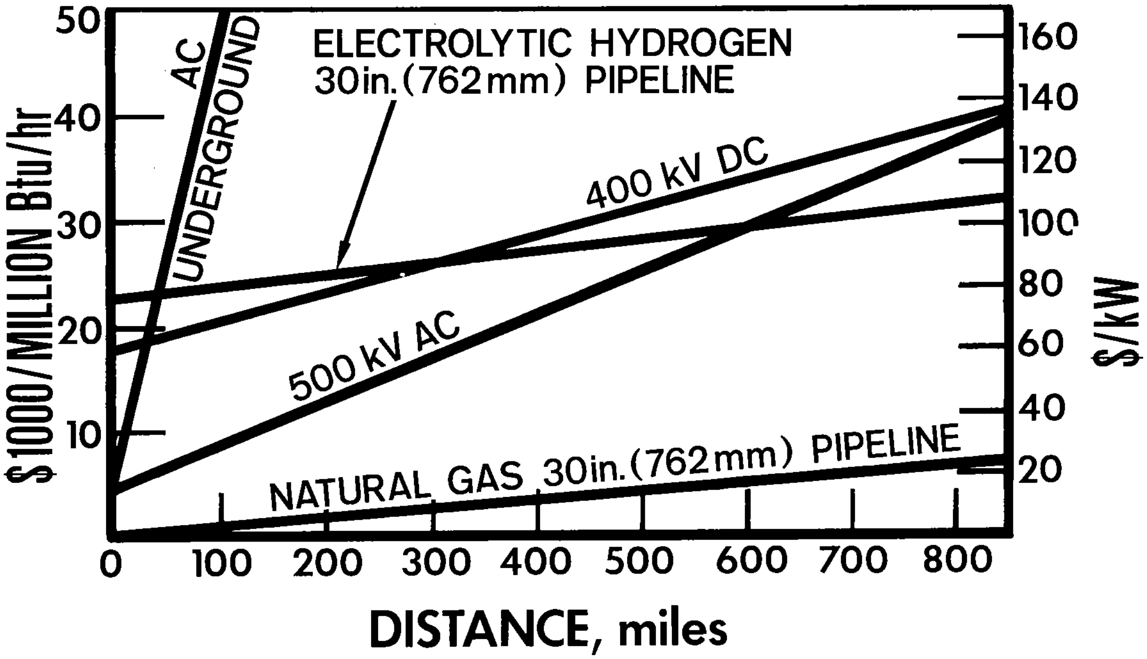

Figure 1. INVESTMENT COSTS FOR ENERGY TRANSMISSION FACILITIES

the combined costs of terminal facilities. Gas compressor costs are included in the pipeline cost per mile. We have estimated the cost of hydrogen production and transmission facilities, using advanced electrolyzer cost data as the "terminal cost" and a factor of 1.33 times the pipeline cost of natural gas to compensate for the increased compressor station capacity required. Converting electricity to hydrogen and delivering it as hydrogen is attractive over distances of a few hundred miles, or even shorter distances if underground electricity transmission is the alternative.

We computed the average 1970 costs of the production, transmission, and distribution of gas and electricity including all amortization, taxes, and profits, from statistical data provided by the FPC and A.G.A. By conventional utility financing techniques, we estimated the cost of production of hydrogen, based on advanced electrolyzer plant costs and the 1970 average U.S. electric power production cost of 9.1 mills/kWhr. We estimated the cost of transmission of hydrogen based on our calculations that optimized hydrogen transmission will cost about 2.6 times that of natural gas, allowing for the increased compressor requirements and hydrogen fuel cost of $3.00/million Btu. Table 1 shows all these data and indicates that even at today's prices, hydrogen energy could be delivered to the consumer more cheaply by underground systems than electricity can be distributed by overhead systems.

Table 1. RELATIVE PRICES OF DELIVERED ENERGY
(Source: 1970 Data From the FPC and A.G.A.)

	Electricity	Natural Gas	Electrolytic Hydrogen
	$/million Btu		
Production	2.67*	0.17	2.95-3.23†
Transmission	0.61	0.20	0.52‡
Distribution	1.61	0.27	0.34
Total	4.89	0.64	3.81-4.09

* Equivalent to 9.1 mills/kWhr.

† Assuming power purchased at 9.1 mills/kWhr.

‡ Assuming pipeline hydrogen, at $3.00/million Btu used for compressor fuel in optimized pipelines compared to natural gas at $0.25/million Btu.

The quantities of hydrogen that will be required for such a concept will be enormous. For example, if we were to produce enough to replace the 1970 natural gas supply, we would require 68 trillion SCF of hydrogen per year. By electrolyzer techniques this will require 1 million MW of electrical power. In comparison, the total U.S. generating capacity in 1970 was 0.36 million MW and was growing at a rate of "only" 6%/yr. Although the amount of water required to produce this quantity of hydrogen will be large, about 1.2 billion gallons/day, this is small in relation to the cooling water requirements of the power stations, 20 billion gallons/day for evaporative cooling towers, or 540 billion gallons/day for direct cooling. Thus, the growth of a hydrogen energy system is very likely to be limited by the rate at which new nuclear power stations can be financed, licensed, and constructed.

Because of the supreme cleanliness of hydrogen as a fuel, consideration might be given to introducing it at an earlier time than that dictated by the relative economics of fossil and nuclear fuel. Hydrogen can be produced from coal, oil, and shale almost as cheaply as can pipeline gas, and we foresee the beginnings of a hydrogen-energy economy relying on gasifying our remaining fossil fuels to a form, hydrogen, that is compatible with future energy forms — nuclear, solar, and geothermal.

III. HYDROGEN PRODUCTION

We examined in detail the present techniques for producing hydrogen from electric power and from thermal energy without the use of fossil fuels. The only such process currently available is that of electrolysis of water. Large-scale electrolysis plants are in operation in many parts of the world where relatively cheap electric power is available, mainly supplying hydrogen to the ammonia and fertilizer industry. None of these plants is as large as we are envisioning, but they are modular in construction and could scale up without problems. Two of the largest plants consume about 90-100 MW, within a factor of 10 of the size we imagine as a suitable unit for fuel production.

The efficiency of present plants is about 60-70%, based on the ratio of the fuel value of hydrogen produced to the electrical input. Because of the special thermodynamic conditions of water electrolysis, it is theoretically possible to operate a cell that absorbs heat from its surroundings and thus produces about 20% more hydrogen energy than the electrical energy supplied. In practice, it should be possible to develop a plant that would operate at an apparent 100% efficiency, based on electrical input, and still allow some irreversible electrode losses. Data from the literature indicate that some laboratory electrolyzers of advanced electrode design, operating under severe conditions, have achieved this condition, but there is a question of both their cost and their longevity. Research directed toward increasing the efficiency and decreasing the capital cost of electrolysis cells appears to be a very worthwhile proposition.

The cost of hydrogen production by electrolysis is markedly dependent on the cost of electric power. Allis-Chalmers and Oak Ridge National Laboratory carried out a design study for large-scale electrolyzers in 1966, and derived a cost for a 44,000 lb/hr plant (about 1000 MW input) of about $40 million. This is about 10% of the cost of the nuclear power stations required to supply it. Their hydrogen production cost was based upon some rather unorthodox financing assumptions and a very low cost of electric power (2.5 mills/kWhr, compared to an average cost of over 9.0 mills prevailing in 1970). This gives a hydrogen production cost of $1.03/million Btu. We revised these calculations and derived a cost range of $2.00-$3.20 if power is available at 4 mills-7 mills/kWhr — figures which we feel are reasonable if continuous operation at uniform loading is achieved.

We then made some assumptions about likely advances in electrolysis technology, including a reduction of 50% in capital cost and an increase of electrical efficiency from 70% to 100%. We justify the first assumption on the basis that half of our previous cost was based on the a-c to d-c conversion equipment, which can be eliminated if an acyclic or homopolar generator is developed, as General Electric Company indicates is possible. The second assumption was justified on the belief that long-term research and development can achieve similar results for electrolysis cells as it already has achieved for fuel cells.

Assuming these advances are made, we derive a cost range for hydrogen of between $1.50 and $2.50/million Btu for power at 4 mills to 7 mills/kWhr and a cost of $2.95 at today's average power production cost. We believe these costs can be met after reasonable development investment.

Another means of producing hydrogen is by thermochemical water-splitting to avoid the costs and inefficiencies of producing electricity. Work on thermochemical water-splitting is in progress at the Euratom Laboratories in Italy and at IGT under a separate A.G.A. contract. By this process, water enters into a series of chemical reactions that consume heat energy directly from the nuclear reactor. Hydrogen and oxygen are among the products of the reaction sequences. All other products are completely recycled within a closed loop. Of the various processes proposed, all appear to require the use of highly corrosive chemicals at high temperatures and pressures. We feel that this area is fertile for further experimentation, but no conclusions can yet be drawn about cost or practical efficiency of such a process. Theoretically, the efficiency of a single thermal water-splitting process can reach 85% and is not subject to the same restrictions that control the efficiency of nuclear-electric power stations.

IV. HYDROGEN TRANSMISSION

Hydrogen is moved in chemical plants in huge quantities through pipes operating at up to 1200 psi. The U.S., Germany, and South Africa operate pipeline systems using pipes up to 12 inches in diameter and pressures up to 450 psi, over distances of 50 miles or more. One network of hydrogen pipelines in Germany totals about 130 miles. As an example of how a light gas, with leakage characteristics similar to hydrogen, is handled, a 425-mile helium pipeline is in operation from Kansas to Texas. We have found no examples of hydrogen lines with intermediate compressor stages in them.

We find no reason to suppose that existing pipeline materials are not compatible with hydrogen. Hydrogen intergranular embrittlement does not occur at the typical temperatures and pressures experienced by pipelines, except in the presence of "atomic hydrogen" produced, for instance, by corrosion processes. Molecular hydrogen under pressures of up to 2000 psi at room temperature does not affect carbon steels at room temperature. We found reference to a new phenomenon, known as "environment embrittlement," observed and being studied by NASA's research laboratories. This is a surface-fracture phenomenon associated with the presence of very high purity hydrogen at high pressures on a steel surface subject to yielding stress. Whether or not this is cause for concern to pipeline design requires further study, but it does not appear to have caused problems, for instance, with the either U.S. or German hydrogen pipeline systems, the latter having been in continuous operation since 1940.

We determined the energy-carrying characteristics of an existing natural gas pipeline if it were converted to hydrogen. Because of the different compressibilities of hydrogen and natural gas, the capacity ratio of the pipe itself varies with pressure, but is only slightly less for hydrogen than for natural gas at 750 psi. The existing compressor capacity would be inadequate to handle the extra volume required to carry the same energy; the pumping horsepower would also have to be increased. In summary, an existing line, without modification, operated on hydrogen would carry only 26% of the energy, but would require only 10% of the compressor horsepower, as with natural gas. To carry the same energy content as hydrogen, at the same pressure of 750 psia, the compressor capacity must be increased by 3.8 times and the horsepower by 5.5 times. Considerable advantages, especially in horsepower requirement, result from operation at increased pressures.

We then carried out a detailed design optimization of a single compression section of pipeline, at an arbitrary length of 65 miles, for operation on hydrogen. This design was not completely optimized for hydrogen because it would require prolonged repetitive calculations, but we derived the necessary equations and physical data to allow this to be done. Our preliminary conclusions are that the cost of hydrogen transmission at 750 psia is between 3¢ and 5¢/million Btu per 100 miles compared to current costs for natural gas of about 1¢ to 1.5¢/million Btu per 100 miles, at throughputs of 300 to 500 trillion Btu/year and assuming a $3.00/million Btu cost of hydrogen as compressor fuel. Increasing the pipeline pressure to 2000 psia significantly reduces the fuel consumption. The overall costs are from 2.5¢ to 3¢/million Btu per 100 miles. These data are summarized in Figure 2.

Compressors specifically designed for hydrogen will be rather different from those for natural gas. Achieving a high enough compression ratio in a single-stage radial compressor will present a problem. Multistage compressors with about eight stages are probably optimum. Axial turbocompressors are attractive for very large volumes. The screw compressor, not normally used at high pressures, would combine the benefits of positive displacement with high throughput and low capital cost.

An interesting possibility exists for combining a liquid-hydrogen transmission pipeline with a superconducting cable carrying electric power. Liquid-hydrogen transmission alone appears to be prohibitively expensive, as does a helium-cooled superconducting power line, but, as a long-term possibility, a combination of the two may have merit.

The estimated costs of moving energy by hydrogen pipeline between 2.5¢and 5.0¢/million Btu per 100 miles compared very favorably with the average costs of overhead electrical transmission, which range between 10.0¢ and 30.0¢/million Btu per 100 miles.

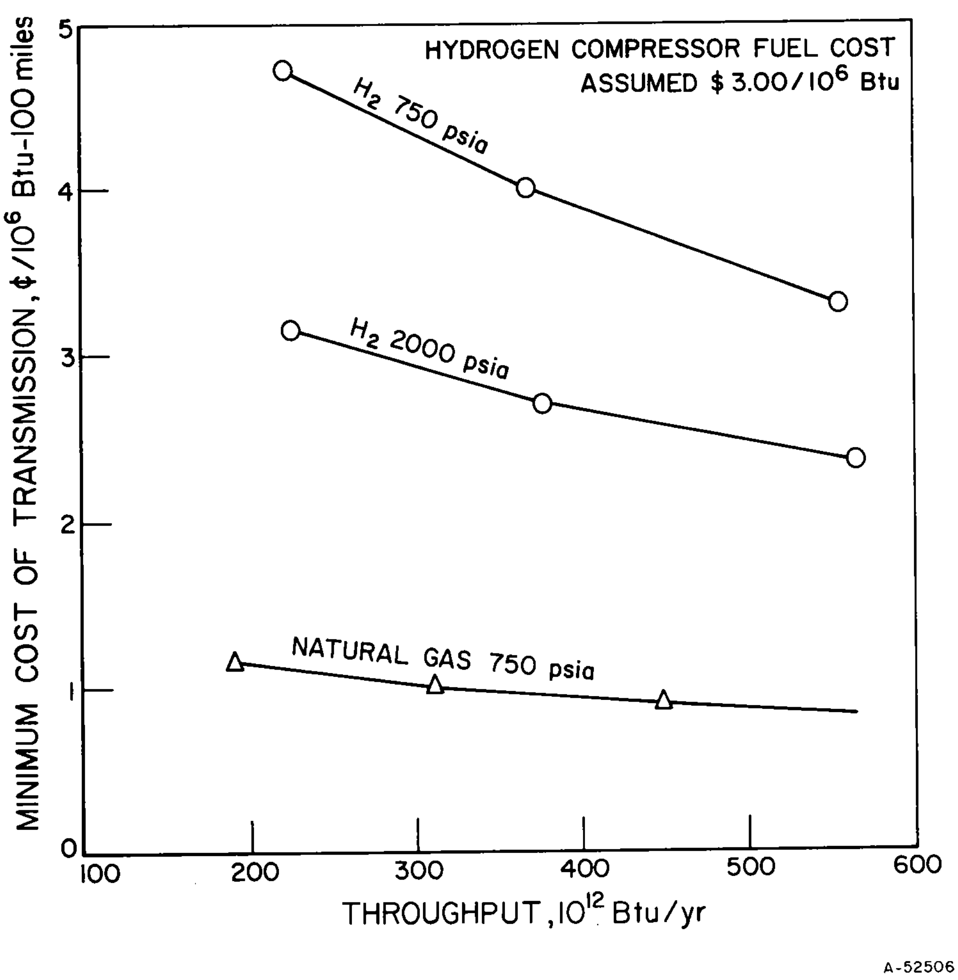

Figure 2. OPTIMIZED TRANSMISSION COSTS FOR HYDROGEN COMPARED TO NATURAL GAS

V. HYDROGEN STORAGE

One of the great advantages of the hydrogen energy form over electrical energy is its capability of storage on a large scale, as is required for peakshaving on a daily and seasonal basis. Line-packing will probably be unimportant as a storage technique for hydrogen because the pipeline will contain only about one-quarter of the energy as a natural gas line at the same pressure. Compressed gas storage appears to be prohibitively expensive on all but the smallest scale. In addition, liquid-hydrogen technology has grown rapidly as part of the space program. On the other hand, underground storage of hydrogen in depleted oil and gas fields, in aquifer storage, and in mined caverns all appear to be economical and practical. We have created an analogy between liquid-hydrogen storage and liquid-natural-gas storage.

Because of the much lower boiling point of hydrogen (—423°F), considerably more cost is involved in liquefying and storing it than natural gas. Ratios for hydrogen to natural gas handling costs are shown below:

	LH_2/LNG, $ ratio for same Btu
Liquefaction Plant	2.8
Liquefaction Energy	2.0
Storage Tank*	4.8

* Based on 0.4 X 10^{12} Btu capacity and highly insulated; probably smaller ratio for much larger tanks with higher boil-off rate allowed.

The largest liquid-hydrogen tank in the world is at Cape Kennedy and stores about 1 million gallons, or 38 billion Btu, of hydrogen. Impressive as this is, it is still small compared with a typical LNG peakshaving tank containing about 2000 billion Btu, although it is comparable in energy storage capacity with the world's largest electrical storage system — the pumped hydroelectric plant at Ludington, Michigan (51 billion Btu). Liquid hydrogen for peakshaving storage appears to be a technical certainty, but could cost over double the present costs of LNG storage.

As already mentioned, underground storage of hydrogen in depleted gas and oil fields or in aquifer storage appears to be technically and economically feasible. If these fields are gas-tight for methane, they will be gas-tight for hydrogen, as the seal is accomplished by a water capillary effect and is independent of the nature of the gas. Large volumes of coke-oven manufactured gas containing hydrogen were stored for many years at Beynes, near Paris, for peakshaving duty in aquifer storage of 12 billion SCF capacity. Underground storage operating at about 700 psia will contain only about one-quarter of the energy with hydrogen as with natural gas.

Thirty billion SCF of helium is now in storage in the Cliffside field near Amarillo, Texas.

If hydrogen is to be considered as a vehicle or aircraft fuel, small-scale portable storage is required. Liquid-hydrogen storage is certainly technically feasible, but safety considerations involving both fueling and accident conditions should be considered further. Under controlled conditions, both transfer operations and over-the-road trucking are carried out today on a routine basis.

The great bulk of hydrogen in liquid form is a major disadvantage over hydrocarbon fuels, but its very high energy-to-weight ratio (2.6 times that of gasoline) partially compensates. An equal energy content of hydrogen occupies 4 times the bulk but weighs only 0.38 times as much as gasoline. While the low density may be a problem in ground transportation, the low weight is of dramatic advantage in aircraft design.

Chemical storage as hydrides – either as ammonia or as metal hydrides – can be considered. Ammonia can cause toxicity and pollution problems if it is not completely decomposed when hydrogen is withdrawn. Metal hydrides are, at present, still rather a heavy way of storing hydrogen. Small research programs are in progress at Brookhaven National Laboratory and at N.V. Philips in The Netherlands, but should be augmented.* New storage schemes, such as underwater containers with pressure equilization, suggested for natural gas should be equally applicable to hydrogen.

VI. HYDROGEN DISTRIBUTION

A public distribution system for pure hydrogen does not exist at present, although the vast experience with manufactured gas, which contains up to 50% hydrogen, is valuable and suggests that the concept is feasible. Because operation is at relatively low pressure and flows are laminar rather than turbulent, the increased requirements of a transmission system do not apply to a distribution system. With hydrogen, the capacity of an existing system operating with the same pressure drops would be within 6% of its capacity with natural gas. Most existing materials are compatible with hydrogen. Although the permeability of plastic pipes is from 5 to 85 times higher for hydrogen than for methane, according to materials, the absolute loss rates are insignificantly small, from both a cost and a safety consideration. In this respect, PVC and polyethylene pipe are superior to ABS and CAB.

Safety is a major consideration. It appears essential to add an odorant and possibly a flame illuminant to hydrogen to allow leaks to be detected easily. This presents no problems other than the possible poisoning of catalytic burners, which is discussed later. A new form of sulfur-free odorant might be considered to give hydrogen its own characteristic smell and eliminate this catalyst problem.

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* So far, the metal hydrides considered have all been too heavy and the heats of dissociation too great to permit their immediate use in practical systems.

Existing codes for gas distribution systems will apply equally to hydrogen systems, with the exception of one of the National Fire Codes, which prohibits the use of cast iron pipe for hydrogen service.

VII. HYDROGEN UTILIZATION

Hydrogen will be primarily used to produce heat by combustion. We have reviewed the combustion characteristics of hydrogen and compared them with those of methane. The most dramatic differences are in 1) flame speed, 2) ignition energy, and 3) upper flammability limit with air. The first of these differences requires that the burners now in use for natural gas must be modified, but the extent of the required modifications can be accurately predicted, and the feasibility of modifying each type of burner can be evaluated in advance. The second difference results in easier ignition systems, more stable flames, and a somewhat greater safety hazard in the event of leakage. The third makes little difference to most applications, but renders operation of engines on hydrogen rather easier than on methane because engines will operate smoothly over a wide range of fuel-air mixtures.

The type of burners used for manufactured gas will be useful with hydrogen. The conversion of natural gas burners may be more difficult than the earlier conversion in the reverse direction because port sizes must be made smaller, whereas before they were enlarged. Experimental study of the various types of domestic and industrial burners is essential to determine the extent to which hydrogen can be added to natural gas before problems appear and to determine the most practical and economical way of carrying out a conversion operation. There is already enough data to broadly design the required changes.

Hydrogen offers a great opportunity for novel appliance concepts because it is admirably suited to catalytic combustion. At temperatures from 100^0F upward, hydrogen will oxidize in air completely on a catalyst surface. Catalytic radiant and convective heaters are possible. The cleanliness of the fuel allows its combustion without a flue. At the lower temperatures of catalytic combustion, no nitrogen oxides can be formed, so water is the only product. Novel domestic heating concepts can be devised, using a single ventilator in the house to control the overall humidity produced by individual heating devices in each room. Much higher efficiencies than conventional gas burners are thus available. Research is needed to develop these catalytic burner concepts into useful hardware, especially in the area of inexpensive catalysts and ignition systems.

Of the other equipment on the customers' premises, only the meter needs modifying, as it will have to carry 3 times the volume of gas. It may also be necessary to close the vent orifices on some regulators for safety reasons.

Hydrogen has been used successfully to operate aircraft gas turbines with very little modification. Several projects are now under way to operate piston engines on hydrogen. Modification of the carburetor appears necessary, together with adjustment of ignition timing and increasing the crankcase ventilation. Diesels should be easier to convert, as their fuel injection is probably ideally suited to operation on hydrogen. Limited data so far suggest that gasoline engines operating on hydrogen produce only about one-tenth, or less, of the usual nitrogen oxides pollutants and no other emission other than water vapor. Thus, the need to develop an adequately small and light hydrogen "fuel tank" for a vehicle is great, if an abundant and universal supply of pure hydrogen is assumed. Considerable study has already been done for aircraft hydrogen fuel systems. A hydrogen-fueled aircraft flew in 1957. Hydrogen fuel is essential for hypersonic transports and is likely to be seriously reconsidered by NASA for wide-bodied subsonic transports in future.

As an industrial raw material, hydrogen is already very important and is certain to remain so. Its use in upgrading of remaining fossil fuels to gasoline and pipeline gas is likely to increase, as is its use as a direct reductant in the steel industry. It could easily replace fossil fuels as a general source of heat for the process industry.

Hydrogen can be used as a fuel for local electricity generation when the economics of transmission from the power station dictate that pipeline hydrogen should be preferred. Conventional steam stations can readily be converted to hydrogen or can be designed to use it as a fuel. The required design data are available. If it is economical to pipeline the oxygen too, there are exciting prospects for direct hydrogen-oxygen steam-generation devices to operate conventional turbine equipment at high efficiency and with zero pollution. Hydrogen gas turbine-generators are practicable for peaking duty. Most important of all is the fuel cell, which becomes technically far easier, and at a much lower cost, if pure hydrogen is available as a supply. Hydrogen-air cells should have a 55% overall efficiency; hydrogen-oxygen cells, over 60%.

The vast amount of oxygen produced as a by-product in hydrogen manufacture has not been credited to the economics in our study, and we have given little attention to its use. Nevertheless, oxygen is vitally important to the steel industry and is of great use to water treatment and sewage disposal processes. Further consideration must be given to developing markets for this new product of the gas industry.

VIII. HYDROGEN SAFETY

The most controversial subject concerning the use of hydrogen as a fuel is its safety. We have examined this in considerable detail and have compared its hazardous properties with those of natural gas. Our conclusion is that, because of the hazard, so much work has gone on in industrial hydrogen safety that we now know how to achieve the same safety standards as we obtain with natural gas.

In fact, several features of hydrogen make it safer than some of the materials we handle routinely today. Its low density and high diffusivity ensure that leaking hydrogen diffuses quickly. Its low heating value means that the energy buildup in a confined space is less than that of methane or propane. Extra precautions must be taken, however, to seal small leaks because hydrogen leaks through a given opening at about 3 times the rate of natural gas. There are well-established and rigid codes of practice for hydrogen handling, both as a gas and as a liquid. In the liquid form, it does not appear to be significantly more hazardous than LNG, with the exception of the possibility that air or oxygen from the air could condense on poorly insulated surfaces, thus creating a fire hazard. Proper design of equipment eliminates this possibility.

We believe that a proper education and public relations program will be required to condition the public, who still remember the *Hindenburg* accident, to the use of hydrogen. An analogy here is the Cleveland LNG accident, which received widespread publicity and acted against the installation of LNG facilities in other areas for several years, but was overcome by effective public relations.

IX. CONVERSION AND IMPLEMENTATION

We have considered two ways to convert from natural gas to hydrogen. A gradual "mixed gas" approach, with increased additions of hydrogen into the existing distribution system, appears to be unacceptable because of the wide disparity in heating values (325 and 1025 Btu/SCF) and because of the need to repeatedly modify burners. A once-and-for-all change on a regional basis is to be preferred. The technique for doing this must be planned well in advance; much experience is available from prior conversions both in the U.S. and elsewhere. Several electric utilities are showing interest in using hydrogen gas for energy transmission; cooperating with these projects will yield benefits.

The offtake of hydrogen from the "power lines" for purposes other than regeneration of electricity should be possible. There is a clear basic advantage here for the gas industry to be involved with the running and operating of these lines because this type of operation may well act as the nucleating center for regional conversion.

X. ALTERNATIVES TO THE HYDROGEN ENERGY SYSTEM

Assuming a widespread increase in nuclear-electric generating facilities in the future, we have examined in broad outline the alternatives facing us in delivering this energy to the consumer. The future expansion of overhead a-c and d-c transmission systems is severely limited because of high cost and because of environmentalist opposition, yet the same environmental pressures are forcing the remote location of the generating stations. Advancing technology in overhead power transmission appears to offer little hope of significantly reducing costs.

Considerable efforts are going on in the field of underground transmission; however, it is at least 10 times more expensive than overhead, and what work is going on will not reduce its cost by an order of magnitude. Efforts at cryogenic cooling of conductors and of superconducting cables are under fairly intense funding, but the objectives of these programs are to bring the costs of underground transmission down only into the region of existing overhead lines and not below. There seems little to suggest that the cost of electric transmission can be brought down to the levels we have predicted for hydrogen pipelines.

The need for storage is acute in the electric industry. Research projects are under way to develop bulk storage batteries, but we consider the chances of success to be unlikely. The only large-scale storage means for electricity now in use is pumped hydroelectric storage. We examined the largest pumped hydroelectric installation in some detail. Its cost is extremely high, both in dollars and in the land occupied, in comparison with conventional gas storage techniques. In addition, such systems can be built in only limited geographical areas. Electrical energy storage, by either battery or pumped hydroelectric power, thus appear to have no chance of being built economically on the scales already required by the gas energy industry, and achieved by underground and cryogenic techniques. Some new approaches are being made toward the possibility of compressed air storage in underground caverns, but none are yet in use.

Considerable effort has already been spent on electric vehicles, but rechargeable batteries suitable for high-performance cars, trucks, trains, and ships are still in the early stage of laboratory development. An electric airplane appears to offer no prospects at all. Transportation in general then has a long-lasting need for a chemical fuel. Hydrogen is a superior fuel for aircraft.

Ammonia can be produced from hydrogen as a storable and chemical fuel. The toxicity and pollution problems inherent with its use must, however, be weighed against the problems associated with the direct use of hydrogen. They appear to be equal in magnitude. Synthetic methane, methanol, and gasoline-like hydrocarbons can be made from hydrogen and carbon dioxide, derived either from the atmosphere or from limestone. These fuels would do nothing to alleviate today's pollution problems, but otherwise could be used directly. Since all of these synthetic fuels require hydrogen, the "Hydrogen Economy" is still a basic part of their production cycle. Further attention should nonetheless be given to the technical problems associated with extracting carbon from the atmosphere or limestone.

XI. RECOMMENDATIONS

We recommended that further serious consideration be given to the development of a hydrogen energy economy for the future because it appears to have many advantages, both in economics and in environmental attractiveness, over the alternatives.

Rather than wait for the time when fossil fuel costs become too high and a substitution of nuclear-derived hydrogen can be wholly justified on economic terms alone, we should consider committing the U.S. gas industry, or the U.S. energy industry, to such a course in the future and begin to prepare for it now. In this context, the conversion of coal and other "low-grade" fuels to hydrogen, and the creation and expansion of a hydrogen distribution and utilization network in the very near future can be justified.

The following research objectives should be established, some of which can be delayed for attention at a later date:

1. Production
   - a. Increased efficiency of electrolysis cells
   - b. Decreased cost of electrolysis cells
   - c. Systems optimization of nuclear-electric-electrolysis power stations
   - d. "Prospecting" research on new thermochemical water-splitting processes
   - e. Engineering studies of practical means to harness solar energy to make hydrogen
2. Transmission
   - a. Detailed pipeline optimization studies aimed at identifying compressor design requirements
   - b. Compressor development for optimum hydrogen service
   - c. Study of the "hydrogen environment embrittlement" phenomenon under conditions associated with transmission pipeline operation
   - d. Preliminary design and cost studies on liquid-hydrogen pipelines carrying cryoresistive or superconducting electric cables

3. Storage

   a. Detailed operational plan for a pilot scheme for underground storage of hydrogen in a depleted gas field or in aquifer storage

   b. Basic research on metal hydrides, with special regard for reducing the heat transfer load during charge and discharge

   c. Engineering-economic studies on integrated hydride storage systems to allow use of the hydride heat energy released on charge

   d. Investigation of the practical feasibility of constructing large-scale cryogenic hydrogen tanks without vacuum insulation

   e. Investigation of means to reduce the cost of hydrogen liquefaction and storage

4. Distribution

   a. Experimental studies of pipe-sealing materials in hydrogen environments

   b. Experimental tests of leakage characteristics from various types of pipe failures including joints, corrosion pits, and fractures in pipes carrying hydrogen

   c. Life tests for possible degradation and permeability checks on plastic pipe in hydrogen service

   d. Selection of suitable odorants and leak detectors for hydrogen

   e. Selection of suitable flame illuminants for hydrogen

5. Utilization

   a. Experimental survey of existing domestic and industrial burners converted to hydrogen service

   b. Experimental development of inexpensive catalysts and catalytic appliances for domestic and industrial use

   c. Development of appliances not using catalytic burners that are fueled with hydrogen

   d. Investigation of feasibility of converting existing meters to operate at 3 times the volume flow rate

   e. Analysis of an inexpensive and efficient hydrogen-air fuel cell

   f. Engineering design of a large passenger-carrying aircraft fueled by hydrogen

   g. Detailed market study for tonnage amounts of oxygen

   h. Cost and feasibility studies for transmission of oxygen by pipeline from the generating station to the point of use

6. Safety

   a. Construction of suitable demonstration systems for –

      1) Demonstration to visitors, such as government regulatory officers

      2) Demonstration to potential users

      3) Demonstration to potential equipment manufacturers

   b. Use of demonstration equipment by gas company maintenance crews to explore problem areas and to create confidence

   c. Use of demonstration equipment to test new equipment

   d. Preparation of Hydrogen Safety Manual for use by gas industry personnel

   e. Production of promotional and public relations materials such as movies

   f. Review of existing local and national codes to determine if they are strict enough to ensure safe operation on hydrogen

7. Systems Studies

   a. Design of a hydrogen-oxygen twin pipeline system for electric power transmission, feeding substation-sized fuel cell or gas or steam-turbine-generator

   b. Construction of large-scale demonstration energy transmission system, using commercial electrolyzer, commercial pipeline components, modified "commercial" electric generator, and other hydrogen-using equipment

   c. Long-term use of a hydrogen pipeline/compressor/distribution equipment sequence in a closed-loop operation to demonstrate experience and confidence in handling hydrogen

I. THE NEED FOR HYDROGEN AS A FUEL IN THE FUTURE

A. Introduction

In this section, we first examine the future trends likely to occur in the overall energy supply and distribution area, and we observe a number of results of these trends which have relevance to the future use of hydrogen as a fuel. Such an energy "overview" is important if we are to understand the need for a new transportable and storable energy form. Then we look at the alternatives before us in selecting a synthetic nonfossil fuel and find that we can make an almost overwhelming case for hydrogen as the fuel of the future. Finally, we make the point that tomorrow's fuel can be integrated with today's energy system in a very dramatic way.

B. Outlook for Fossil Fuels

The total reserves of fossil fuels of all kinds are, of course, finite. Many experts have made estimates of the various natural resources, both in the U.S. and on a worldwide basis, as well as forecasts of our energy (and therefore fuel) demands. Although these forecasts and estimates vary from expert to expert, the overall message is clear: We are using our fuel resources at a rapidly increasing rate, and we can only supply our needs by increasing our production and importation of fuels.

Some facts of relevance to this study are summarized as follows:

a. Natural gas demand far outstrips the rate at which it can be produced domestically; importation alone cannot fill the deficiency.

b. Domestic coal reserves are far greater than those of oil or gas, but the demand for coal for fuel use is relatively small. This has led to the development of processes for the conversion of coal into oil and gas. Moreover, the reserves of economically recoverable coal are probably far smaller than the huge reserve figures frequently quoted.

c. As more of the known fuel reserves are used, the cost of exploration and extraction rises, leading to higher fuel costs. This trend is seen clearly for coal, oil, and gas.

d. Worldwide fossil fuels are being produced at such an accelerating rate that we will reach the peak producibility in 30-80 years, after which time the expected increase in our energy consumption on a worldwide basis will have to be met from nonfossil sources.

The point in time at which fossil fuel production cannot meet energy demands is of considerable importance to the energy industry. A study by Dr. Martin Elliott of Texas Eastern Transmission Corporation (Reference 2) suggests that we may reach the point of maximum producibility of the U.S. fossil fuels by the year 2050 — or sooner if the rate of fossil fuel consumption continues to grow. When the producibility declines, it could be associated with a marked increase in fuel cost if the demand continues to grow. Because of the importance of imported fuels, one should really be considering worldwide fossil fuel reserves, rather than only U.S. reserves.

In a more recent paper,[3] M. A. Elliott and N. C. Turner of Texas Eastern Transmission Corporation have estimated the future rate of production of the world's fossil fuels. They applied several empirical relationships of fossil fuel resources ranging from 85 X 10^{18} to 226 X 10^{18} Btu. Regardless of which assumption is made, the maximum rate of production of the world's fossil fuels is projected to occur some time in the first part of the next century, i.e., between 30 and 80 years from now. Note that these predictions apply to world resources, not the U.S. alone, and assume no environmental or economic brake on the rate at which coal mining capacity can be developed. Figures I-1 and I-2, taken from Elliott and Turner's paper, illustrate how this peak production rate is relatively independent of both the resource base and the assumptions made on the rate of production.

These facts lead us to the clear observation that the prices of fossil fuels will continue to increase at a rate greater than normal inflation rates. It is almost impossible, however, to make reliable forecasts of the rate and price increase beyond a few years hence because so many unknown factors prevail.

We have attempted to make price projections for the various fossil fuels for the period up to 1985 and beyond. Projections of fuel availability exist for up to 1985, but beyond this date we can only speculate. Not only will fuel prices depend on the availability of fuel and on the economics of its production and distribution, but they will be strongly influenced by many additional and unforecastable factors such as government policy, public acceptance of industrial practices, pollution regulations, and availability of capital.

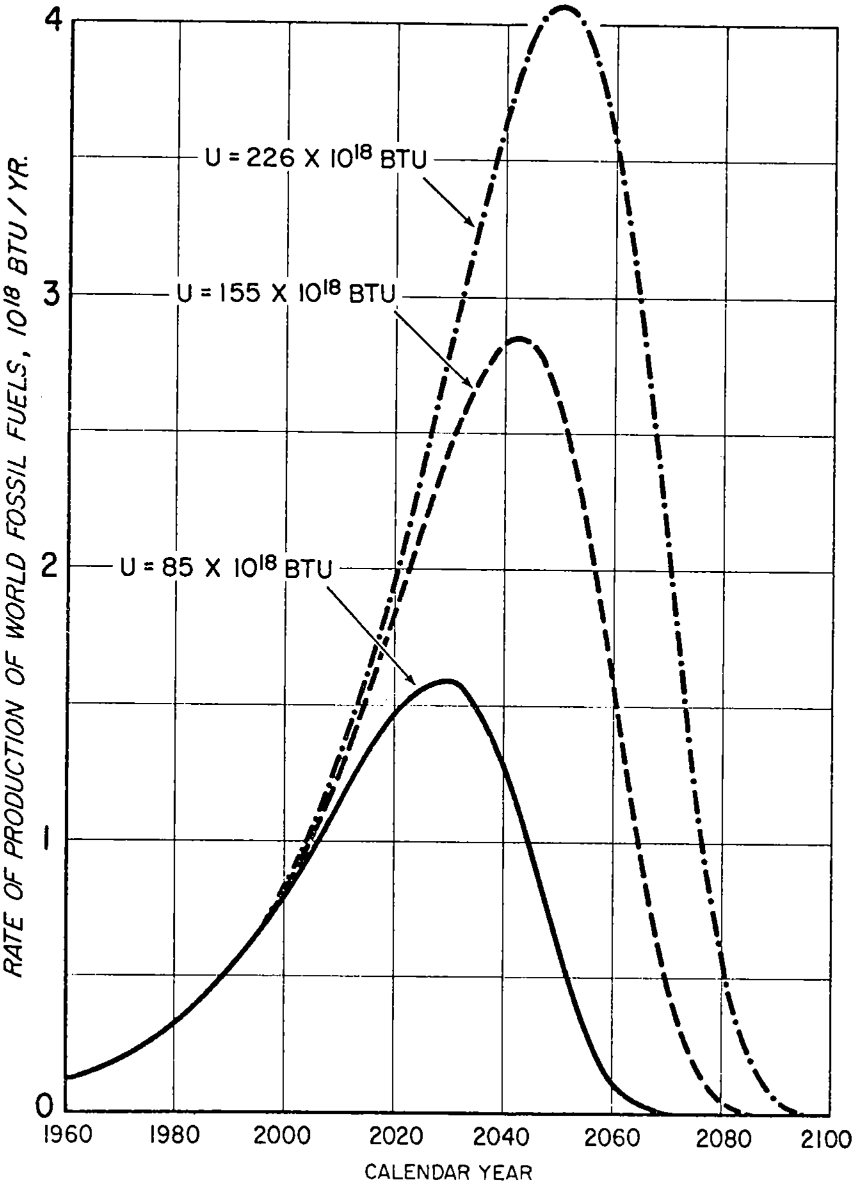

Figure I-1. EFFECT OF RESOURCE BASE ON PROJECTED RATE OF PRODUCTION OF WORLD FOSSIL FUELS USING FUNCTION TYPE II[3]

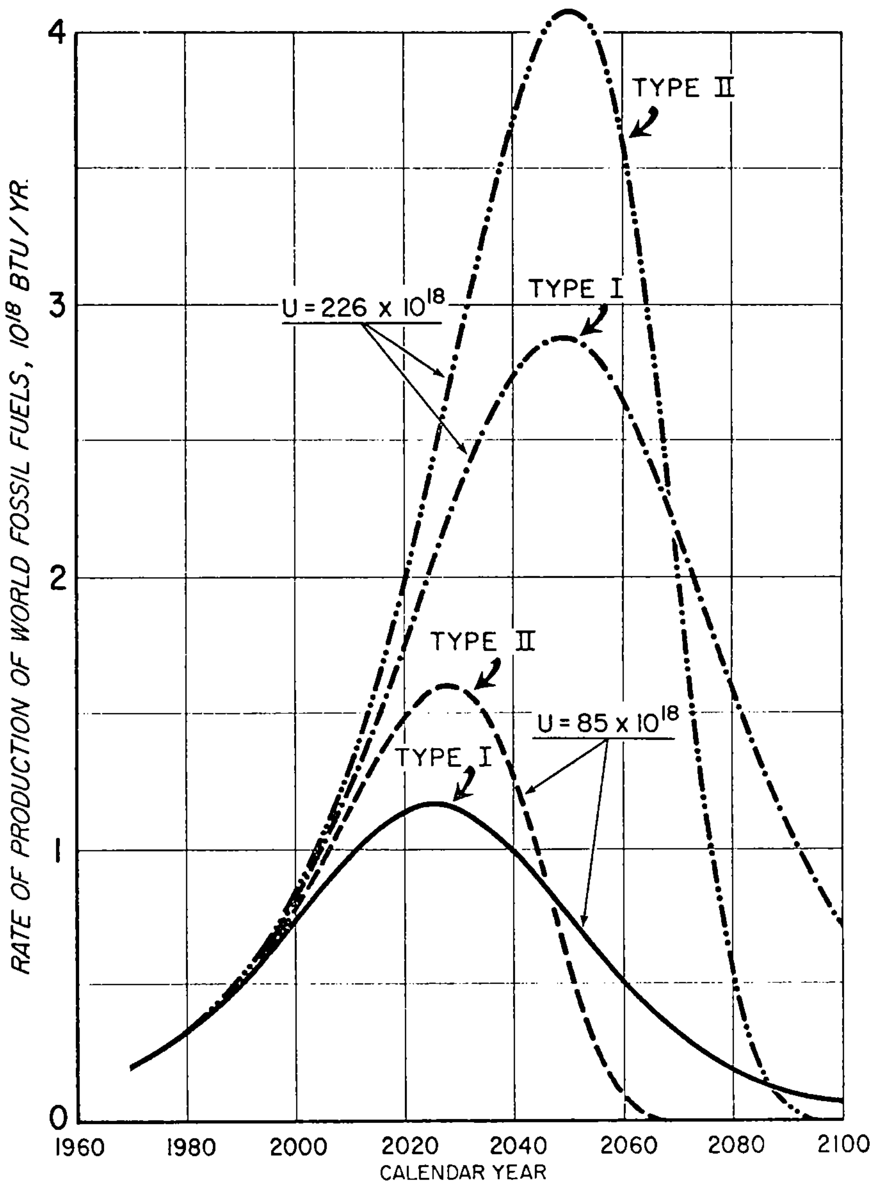

Figure I-2. EFFECT OF TYPE OF FUNCTION USED ON THE PROJECTED RATE OF PRODUCTION OF WORLD FOSSIL FUELS (Each Equation Contains Four Parameters.)[3]

We assumed an escalation in all energy costs of 2.5-3.2% to account for increasing costs of capital equipment and labor. Any variation in this figure will affect the total costs, but will not significantly change the relative prices of different fuels.

During the past 2 decades, both the price of coal and total annual production of coal in the United States have remained remarkably stable. During this period, the average price of bituminous coal ranged between $4.50 and $5.00/ton. However, the passage of the Mine Health and Safety Act of 1969, the enforcement of air pollution control regulations, and the recent tightness of fossil fuel supplies of all kinds brought about a sharp escalation in coal prices during 1969 and 1970: The wholesale coal price index published by the Bureau of Labor Statistics jumped about 50% during 1969 and 1970. Thus, the average price of coal was around 28¢/million Btu at the end of 1970.

In projecting future coal prices, we have relied heavily on the work of Louis Hauser of the Westinghouse Electric Co.[5, 6] Hauser predicts further escalation in the price of coal, although at much lower rates than the sharp rise of the past 2 years. He estimates that labor costs will escalate at about 5%/yr over the long term, while materials and supplies escalate at approximately 3%/yr. We have used Hauser's rate of escalation in the period from 1970 to 1976 and, in fact, have raised it somewhat to accommodate the sharp increase in 1970, which is not fully accounted for in Hauser's projections.

The observation that coal prices have, in fact, continued to rise more rapidly than Hauser predicted, even in the short time since his prediction was made, is important. The reason for this unforecast increase is probably a continuation of effects such as social pressures for increased mineworkers' safety, air pollution regulations, and land conservation. We have no way of forecasting the effects of these factors in the future, but they can only cause coal prices to rise.

However, in the period from 1976 to 1995 an increasing proportion of Western coal will be used. Western coals are generally strip-mined and have a mine-mouth price averaging 7¢ or 8¢/million Btu below the U.S. average coal price. Thus, with an increasing proportion of Western coal, the average coal price escalates less rapidly, going from a price of 40¢/million Btu in 1975 to 50¢/million Btu by 1995 (Table I-1).

Table I-1. PROJECTED AVERAGE MINE-MOUTH BITUMINOUS COAL PRICES

Year	¢/10^6 Btu
1970	28.0
1975	39.0
1980	42.0
1985	44.0
1990	47.0
1995	50.0

Commercial shale oil production is expected to begin in the early 1980's and to grow rapidly through the remainder of the century. Production costs of crude shale oil are estimated at about \$4.35-\$5.30/bbl.[8] This would be competitive with domestic oil; thus shale oil can be considered as a source of feedstocks for gas production. In Elliott's projections, including all available shale, tar sands, etc., peak producibility was still estimated in 2050.

Since the mid-1950's, the price of residual oil has been declining gradually from a peak of close to 50¢/million Btu in 1957 to about 37¢/million Btu in New York Harbor in 1969. However, as with coal, the average price of residual oil in New York Harbor increased about 50% during 1969 and 1970.

The price of imported oil cannot increase very much without stimulating the development of the shale oil industry. However, low foreign oil prices could serve to delay the development of our own synthetic oil resources. Whether they are permitted to do this would depend on government policy regarding the importation of foreign crude and residual oils. While government policies are difficult to predict, we have assumed that such policies will permit the importation of foreign oil in quantities necessary to make up energy deficiencies in our economy, but not large enough to seriously delay or impair the development of shale oil or synthetic gas and oil from coal.

We have thus projected the price of residual oil to remain competitively priced and to escalate along with the increasing prices of coal and synthetic gas at rates that will approximate the 3%/yr escalation that we have used for capital equipment and labor costs. Our own extension of the consumption of energy presented in Reference 8 estimates that the rate of importation of foreign oil will peak some time about 1990 and will gradually decline from then on as our own synthetic oil and gas production increases and an increasing proportion of our energy consumption takes the form of nuclear electricity.

The recent history of natural gas prices is well known; indeed, we are currently witnessing an attempt to increase the regulated prices of natural gas at the wellhead. Predicting how soon and how much the wellhead price will be increased during the next several years is difficult.

We have assumed that, at some point in the distant future, the price of synthetic gas made from coal, shale oil, or other hydrocarbons will effectively set the wholesale price of pipeline gas. We have also assumed that natural gas cannot be found at any price in quantities sufficient to make supplementary sources of natural gas unnecessary. This means that the market value of the wellhead price of natural gas will be that price that would bring natural gas to market at prices comparable with synthetic pipeline gas.

We also assumed that a) the price of imported LNG will gradually escalate but will remain below the price of synthetic gas and b) as the volume of synthetic gas grows and the volume of additional natural gas supplies increases, the price of imported LNG will gradually fall below the average wholesale price of gas in the market place, even though it is still increasing in price. This condition will be necessary for imported LNG to compete with adequate sources of domestic pipeline gas.

On this basis, we have estimated the price of synthetic gas by a) using the best available estimates for the cost of synthetic gas, b) escalating gas processing and transportation costs at a rate of 5%/yr through 1975, and c) adding coal prices estimated for Western coal in the preceding discussion for the appropriate years. These costs were then further escalated at 4%/yr through 1980 and 3%/yr thereafter to the year 2000. This provides a measure of the maximum gas prices to be anticipated.

We then assumed that the average wellhead price will escalate sharply to about 40¢/million Btu by 1975 and 50¢/million Btu by 1980. The average transmission cost was then added to these wellhead prices to obtain an average wholesale natural gas price, which increases from about 68¢/ million Btu in 1975 to about approximately $1.00/million Btu by 1980. This price is then gradually escalated and more nearly approaches the synthetic gas price, so that the average overall wholesale pipeline gas price is $1.25/million Btu in 1985, $1.50 in 1990, $1.70 in 1995, and approximately $2.00 in the year 2000. See Figure I-3.

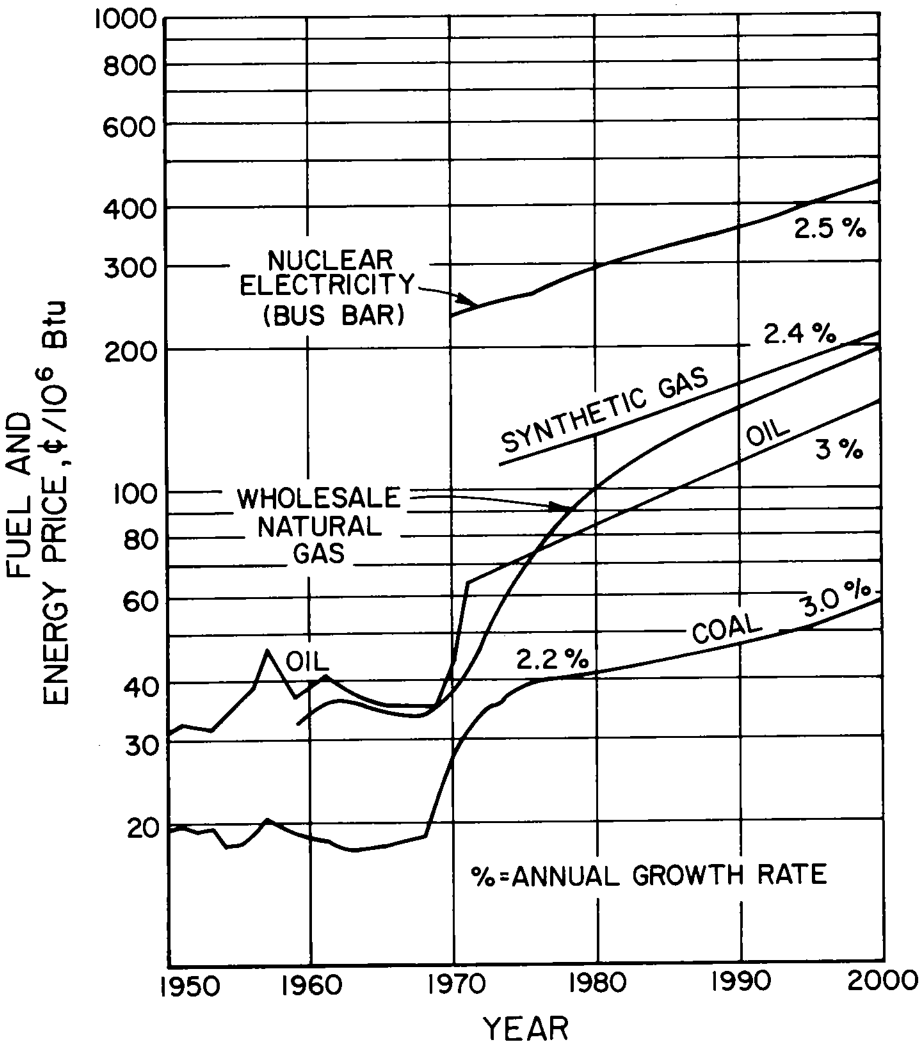

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Figure I-3. PROJECTED FUEL AND ENERGY PRICES

C. Outlook for Nuclear Energy

Present nuclear power stations use the uranium 235 fission reaction as their source of energy. Uranium 235 is in limited supply. Hopefully, an economical "breeder reactor" can be developed which is capable of transforming the U^{238} isotope into a fissionable fuel at the same time it is producing energy from the fissionable isotope. Much research and development is going on within the AEC and elsewhere to develop a commercial breeder reactor. A recent study concluded that "... the differences between a breeder and present day converter reactors are more of degree than of radically different operating principles. There is no doubt of their practicality since operating prototypes for several different breeders exist and large-scale versions are under construction in several countries."[4]

The importance of the breeder reactor may be realized when one considers that only 0.7% of natural uranium is the fissionable U^{235} isotope. The remaining 99.3% is useless in present reactors, but may be converted and ultimately used in the breeder. Even more important are the limited present U.S. uranium reserves; without the breeder reactor, these reserves would only supply the expected nuclear generation load for 25 years.[7]

Fusion reactors will produce energy from the fusion of light atoms, deuterium or tritium, to produce helium. Research in this area has progressed to the point where the problems of maintaining the reactants at extremely high temperatures, about 100 to 500 million degrees centigrade, can be clearly defined, but have by no means been solved. Nobody in the business is talking about a development period of less than 20 years. Although some energy from fusion reactors is released in the form of high-energy charged particles, useful for producing electricity directly, most of the energy will be produced as heat by the absorption of neutrons in the thermal blanket; thus, the normal Carnot cycle limitations are to be expected. Fuel supplies for the fusion reactor are virtually unlimited, as there is enough deuterium in 1/2 cubic mile of seawater to produce all the energy used by man to date.[4]

Perhaps the most critical obstacle currently facing the development of nuclear power stations is the concern over their environmental effects and the resultant difficulties in finding suitable sites for them. Because nuclear plants are rather less efficient than fossil plants and consequently reject more of their waste heat into cooling water streams, the thermal pollution problem of nuclear plants has been stressed. Since the optimum generating capacity of nuclear plants is likely to be larger than that of the fossil plants, local thermal rejection loads will be very high.

In addition, serious concerns have been expressed over the inherent safety of nuclear power stations. Although no nuclear accidents have occurred, a strong body of opinion opposes the construction of nuclear plants at all, and an even stronger body of opinion holds that such plants should not be sited in densely populated areas. Needless to say, these opinions are not shared by the Atomic Energy Commission, which, nevertheless, may be forced to give way to public opinion.

The problem of disposal of radioactive wastes from nuclear fuel reprocessing is another controversial issue that can slow down the rate at which new plants are licensed. This factor, however, seems to have little bearing on the siting of future plants.

Selection of sites and the subsequent approval of operating licenses for today's plants have presented as many problems as to create a lag of at least 2-3 years in the planned installation program, and are expected to get worse unless remote or offshore locations are selected. The importance to this study of this expected trend in nuclear plant size and location will become clear when we consider the allied problems of moving the energy to the load centers.

D. Outlook for Solar and Other Energy Sources

In comparison with nuclear and fossil fuel energy research, development of solar and alternative energy sources is proceeding at a very low level of effort; thus we have not concerned ourselves with these sources in this study. Two important observations can be made, however:

a. A growing tide of public opinion favors attempting to exploit solar energy rather than face the environmental risks thought to be associated with nuclear power.

b. Solar, wind, and tidal energy sources are available only periodically, and are geographically limited. Because of this, any utilization system for these energy sources must incorporate an economical transmission and storage capability. The importance of this observation to this study will become clear.

E. Trends Toward Electric Energy Use

In the U.S., total electric energy generation is growing at a considerably more rapid pace than the overall consumption of energy. In other words, we as a nation are not only using more energy each year, but we are using a greater proportion of it as electricity. This trend is clearly illustrated in Figure I-4, which shows historical data and forward predictions made for total energy consumption and total electricity generation.

Clearly, forward logarithmic projections made in this way must be inaccurate,* but we know of no better way to forecast these figures. One can draw the following conclusions from these data:

a. The present trend in the U.S. is toward greatly increased use of electricity.

b. The proportionately larger increase in the use of electrical energy implies a relative loss of importance of oil and gas in the ultimate energy market.

c. The high future growth rate of electric power will be encouraged because nuclear power, at present synonymous with electric power, will be used to fill a large portion of the overall energy demand growth in the future.

We believe that these conclusions are probably wrong because it is not at all clear that the ultimate user of energy really prefers to receive all of his power requirements as electrical energy. At present, only about 15% of the U.S. energy use is as electric power; the remainder is the direct combustion of fossil fuels by the ultimate user. A ratio approximating the present situation can be maintained for the benefit of the consumer by providing more energy in the form of a combustible fuel rather than taking up the increase with electricity.

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* Inaccurate because ultimately the lines cross over, which is meaningless.

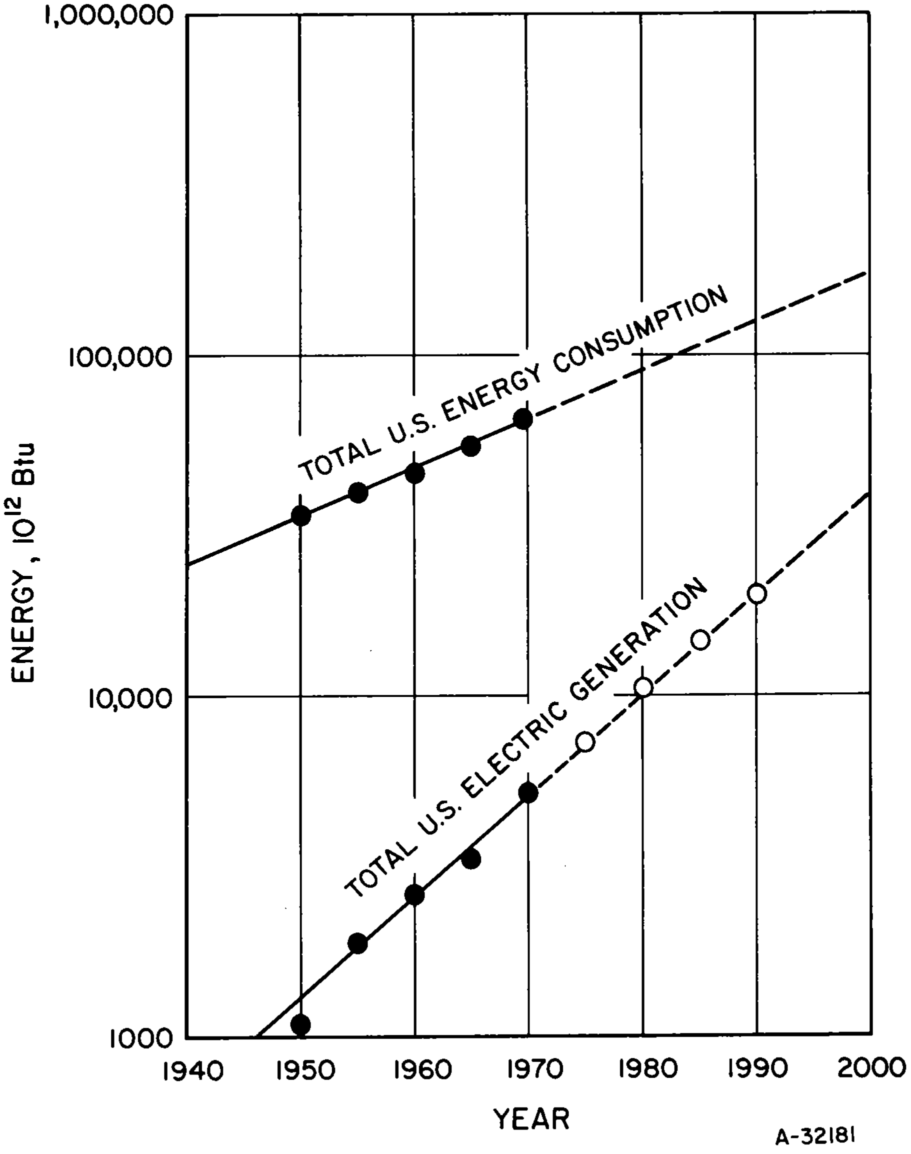


Figure I-4. ELECTRIC ENERGY AND OVERALL ENERGY USE

In making our analysis of the cost of electricity we used the bus-bar cost of electricity as being most closely analogous to the city-gate price of gas and the wholesale price of oil and coal. Data presented by Electrical World in its 16th and 17th Steam Station Cost Survey[10] were used to provide the basis for current fossil fuel power plant bus-bar costs. These data show that the bus-bar generating cost of a selected number of large, modern fossil fuel power plants reached a minimum in about 1966 and increased by 1968 to 6.04 mills/net kWhr. A steep upturn is noted in the following 2 years,[10] reaching 7.20 mills/net kWhr by 1970. This is approximately $2.11/million Btu.

The cost of bus-bar electricity from a nuclear power plant was also projected. A capital cost of $300/kW was used for 1970 and escalated at approximately 2-1/2%/yr. Nuclear fuel costs were assumed to remain constant at 1.5 mills/kWhr.

Since some difference of opinion exists as to the projected prices of nuclear fuel, we have chosen to use a constant fuel price that, by the year 2000, will amount to only 10% of the total bus-bar cost and that is not a large factor in the relative energy costs which are being compared in this analysis. Under this assumption, we project that in 1975 and beyond, the bus-bar cost of nuclear power will be less than that of fossil fuel power, primarily because nuclear generating plants are not subject to the same sharp escalation in fossil fuel costs that we are currently experiencing in oil and coal and because they do not require the additional sulfur-removing facilities.

Our projections for bus-bar nuclear electricity prices are incorporated in Figure I-3.

F. Trends in the Electrical Generation and Transmission System

Base-load electricity generating stations are tending to use bigger units, with overall plant capacities in the 1000-2000 MW range becoming typical. It is forecast that nuclear plants will be optimized in even larger sizes (e.g., the Quad Cities Plant of Commonwealth Edison Company and the Iowa-Illinois Gas and Electric Company, due to operate in 1972, is 1600 MW, and the Greenwood Energy Center plant of Detroit Edison Company, due to operate in 1979, is 2300 MW). Fusion plants will probably be upward of 10,000 MW in a single unit. Because of the size of modern plants, with the associated problems of fuel supply and waste-heat removal, a trend has developed to install them at locations optimized for cooling, and for fuel supply in the case of fossil fuel stations, rather than close to the load center. This implies longer transmission distances for the power produced. Suitable sites for power stations of all types are becoming difficult to find. Offshore locations are proposed, and modular floating power stations are being designed by Westinghouse Electric Corporation and Tenneco Inc.

Because of the larger sizes of base-load plants and the lead time required for their construction, the popularity of the smaller "peaking" units has risen. These units are usually modular collections of engine-driven generators that are located close to the load centers and capable of operating on short notice. Because such units are cheap to build and expensive to operate, they are only used for peaking duties. This trend toward the use of peaking generators is expected to continue.

As a result of the rapidly increasing electrical demand and the trend toward remote, large base-load stations, transmission line length and capacity in the U.S. have been growing and are expected to continue to grow. As the "blocks of power" have become larger and distances have increased, the use of higher transmission voltages has also become desirable. From the 230-kV lines first used to transmit power, we now have a family of transmission voltages of 230, 345, 500, and 765 kV each with progressively lower costs per unit of energy transmitted, but requiring larger blocks of power for transmission.

Very long distance transmission over a-c lines results in unacceptable impedance losses so that d-c lines have been considered. To date, only one long, overland d-c line has been constructed, from Oregon to southern California, but more are expected once this first one has proved itself.

Very considerable resistance is mounting to the construction of overhead power lines. Duplication of lines along the same right-of-way results in the appearance of "wire-scapes" similar to Figure I-5, with the obvious reaction from land conservationists. In 1972, we saw the first refusal of a construction permit for an overhead transmission line[1] on esthetic grounds. We also observed several legal steps concerning the

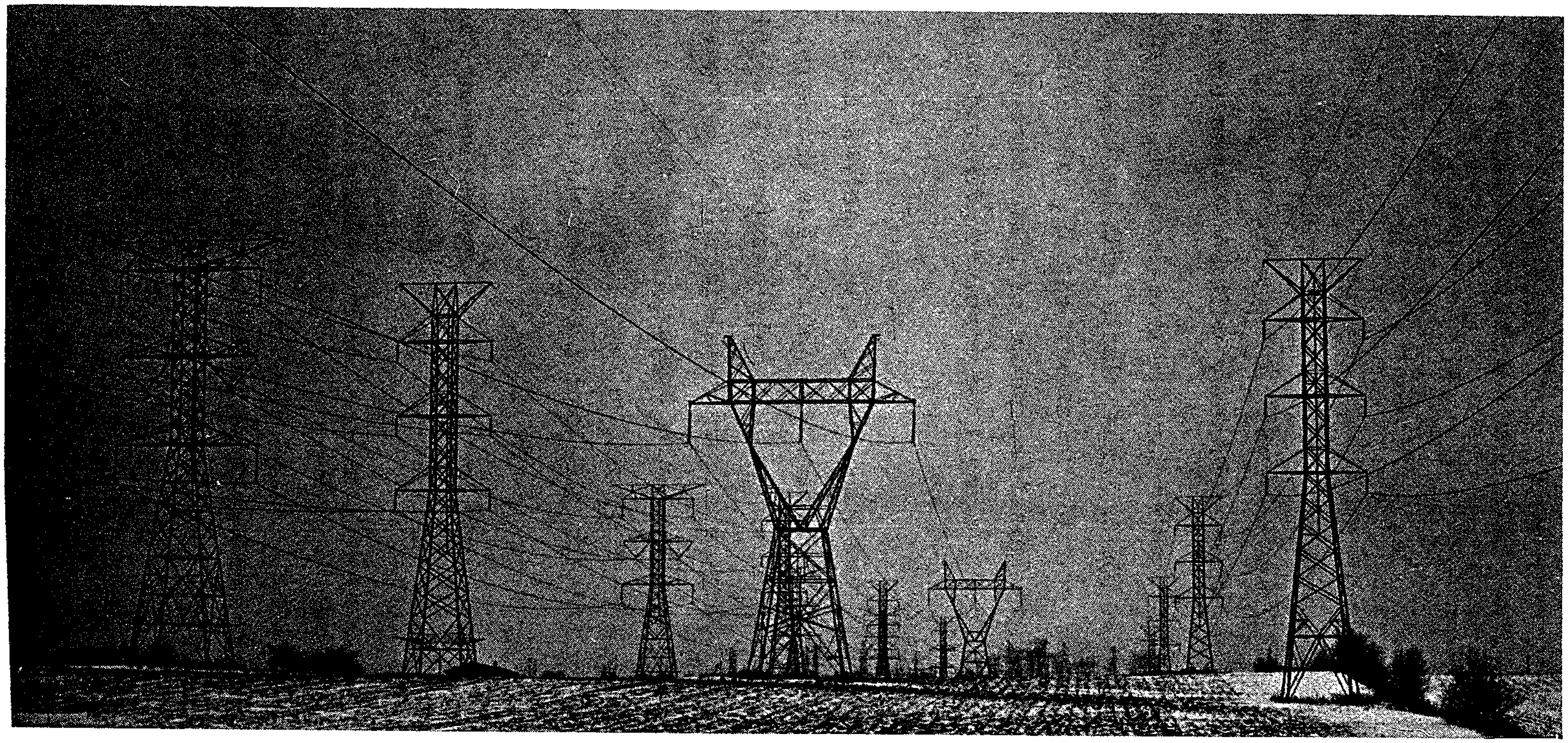


Figure I-5. CONGESTION OF OVERHEAD POWER LINE RIGHT-OF-WAY use of overhead electric distribution. New York State[11] now prohibits the supply of electricity to new multifamily dwellings (four or more) by overhead cable, while California[9] has prohibited the use of overhead distribution lines within sight of state scenic highways. These are examples of pressures being applied to the electric industry to "go underground." The cost of underground cable is very high (estimated by the Federal Power Commission to be from 10 to 40 times the cost of overhead lines of similar capacity), although much development work is going on to reduce the cost. The status of this technology will be discussed in Section X.

In summary, the trend is toward larger base-load plants with correspondingly larger transmission lines. The plants will be located remotely from load centers, wherever suitable locations can be found for cooling. Public opinion will try to force undergrounding of transmission and distribution lines, but the enormous extra cost involved will act against it.

G. Need for Energy Storage

In the use of fossil fuels, we use the fuels themselves as a convenient means of storing energy until it is needed. In the gas industry, the need for energy storage on a very considerable scale has been recognized because it allows the production and transmission facilities to operate at a fairly even rate while the customers are supplied at a rate that fluctuates widely on a 24-hour cycle, a weekly cycle, and a seasonal basis. Because of the impact of energy storage on the load factor of the transmission system, storage close to the load center is desirable.

On the other hand, large blocks of electric energy can be stored only as unconverted fuel — that is, the fuel that is burned to produce electricity in the first place. This means that both the generating and transmission facilities have to be sized to cope with the maximum demand rather than the average demand. In an attempt to alleviate this problem, several schemes for storing energy close to the load center have been investigated. The only one that appears economically promising so far is the pumped-hydroelectric system, which is further discussed in Section X. Suitable sites at which pumped hydroelectric stations can be built are strictly limited in number and in capacity.

H. Need for Synthetic Chemical Fuels From Nonfossil Sources

The development of nonfossil energy sources is following a course aimed at converting these energy sources into electricity. This is true of the nuclear breeder, nuclear fusion, and solar, wind and tide, and geothermal energy in general. Nuclear stations are most economical if they operate at a constant power level, while solar, wind, and tidal stations will operate intermittently. Since our need for energy is concentrated in local areas and is on a periodic basis which does not conform to the periodicity of the intermittent sources, storage and transmission must be available. We are accustomed to using fossil (chemical) fuels as energy storage and transportation media. Thus, a synthetic fuel is needed that is made from a nonfossil energy source that would be easy to store in relatively large quantities and that would be easy and cheap to transport to wherever its energy is required.

In the special case of nuclear energy, with which we are concerned in this study, the only alternative to a synthetic chemical fuel is a complex electrical transmission and distribution system, sized to carry the peak, rather than the average load, coupled to a series of large nuclear generating stations also sized to deliver peak consumption demands, since electrical energy cannot be directly stored in large quantities.

A synthetic chemical fuel can be stockpiled to ensure against temporary shutdown of the power stations. It can be moved to wherever it is needed to take care of local irregularities in demand.

I. Alternative Synthetic Fuels

The primary criterion for a synthetic fuel is that, given unlimited energy, it must be available in unlimited quantity. It must therefore be synthesized from abundant materials, which by definition within this study excludes the fossil fuels. A secondary criterion, but almost as important, is that it should be capable of being used (burned) without the production of a noxious effluent, and a third is that the products of combustion must be assimilated into the environment at the point of use, without having to be recycled to the generating station.

To meet these criteria, we can only consider using the components of the atmosphere and the oceans as sources in order to carry out the return cycle. It may be possible to consider carbon dioxide, which is a low-concentration component of the atmosphere (0.4%), as a source of carbonaceous fuel, but it is more realistic to consider only oxygen, nitrogen, and water.

Typical synthetic fuels that can be made from these materials are —

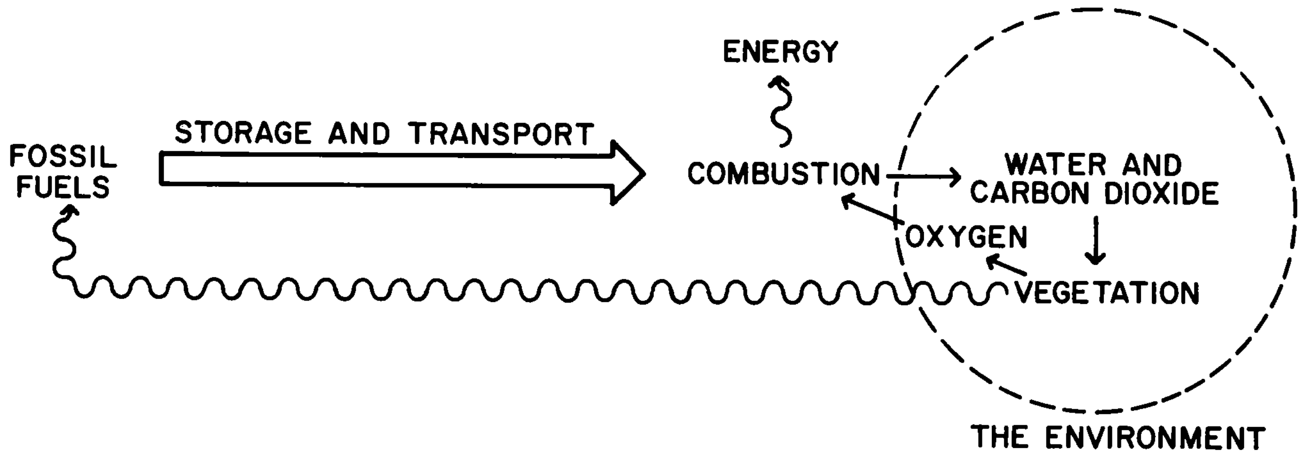
- Hydrogen (from water)
- Ammonia (from hydrogen and nitrogen)
- Hydrazine (from ammonia and nitrogen)
- Methanol (from hydrogen and carbon dioxide)
- Other hydrocarbons (from hydrogen and carbon dioxide)

Notice that all of these fuels require the production of hydrogen. Thus, large-scale hydrogen manufacture will be required in any case.

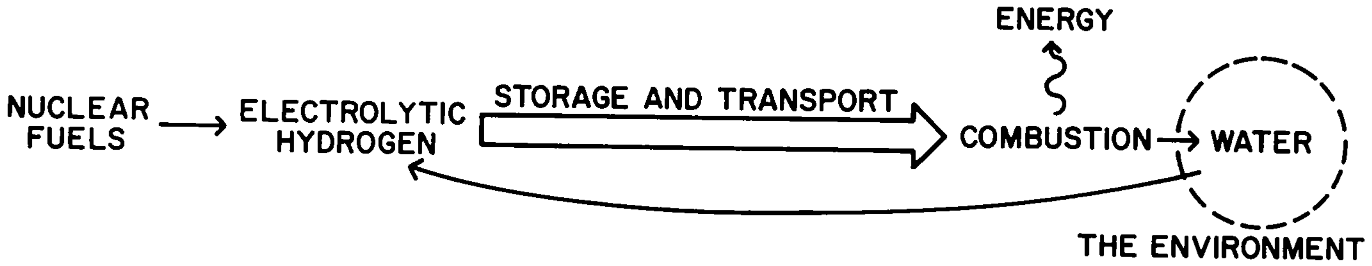
J. The Case for Hydrogen

Hydrogen is the easiest of the synthetic fuels to make, and all the other candidates require the previous production of hydrogen. Thus, if we can use "plain" hydrogen, it would be preferable. Hydrogen is the cleanest of all fuels, producing only water vapor as a combustion product: It is impossible to form carbon dioxide or monoxide, solid particulates, or hydrocarbons by the combustion of hydrogen. Nitrogen oxides formation, due to the heating of air in the flame, can be suppressed by lowering the combustion temperature. Hydrogen is much in demand as a chemical raw material. A large portion of today's natural gas market goes toward the production of hydrogen, so this would be a natural "product" for tomorrow's gas industry.

The amount of water required for electrolysis is only 0.2% of the cooling water requirement of the power station, and the process of making hydrogen from water at the power stations and of burning it at the load centers can have only an insignificant, temporary effect on the environment because of the abundance and high mobility of water in the earth's crust. Figure I-6 shows a comparison of the present fossil fuel cycle, which takes millions of years to complete and results in environmental pollution at one end and resource depletion at the other, with the



a) THE PRESENT ENERGY CYCLE



b) THE HYDROGEN ENERGY CYCLE

Figure I-6. THE ENVIRONMENTAL EFFECTS OF THE FOSSIL FUEL AND HYDROGEN FUEL CYCLES

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proposed hydrogen fuel cycle, which can be completed rapidly and cannot cause either environmental damage or resource depletion.

Hydrogen will be easy to use as a fuel. Apart from its nonpolluting advantage already mentioned, which eliminates the need for flues in many appliances, it is easily ignited and burns smoothly and evenly in properly designed open-flame burners, both on a small, domestic scale and in large industrial-size furnaces. Moreover, hydrogen is particularly suited to catalytic oxidation, for which a flameless heating source can be conceived, which should be admirably suited to space heating and other purposes. Hydrogen has been used to power reciprocating and gas turbine engines of conventional design and does so extremely well; hydrogen-oxygen fueled steam generators can be built at a size and cost that compare very impressively with conventionally fired burners.

Hydrogen is clearly the favorite contender for the fuel of tomorrow. However, hydrogen can also be considered as the ultimate fuel of today's fossil age. Today, hydrogen is made from natural gas in huge quantities. It can be made from coal and oil; indeed, it is as cheap to make hydrogen from coal as to make methane from coal. Hydrogen thus offers the prospect of a bridge from the fossil fuel age to the nuclear power age. Thus, today we could think about converting our energy system to a hydrogen base, feeding it with fossil fuel hydrogen, and, over the next century or so, phasing out fossil fuels and phasing in nuclear power. If and when we harness solar energy, nuclear fusion, and other energy forms, they could all be integrated into the hydrogen system. The beauty of this concept is that the energy user will be able to develop his end use of energy steadily, without interruption, and independently of the radical changes that will inevitably be made in the ultimate energy sources.

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II. A "SCENARIO" FOR THE HYDROGEN ECONOMY

A. Introduction

In this section, we attempt to prophesy. In the words of Alvin Toffler author of Future Shock, "In dealing with the future, it is more important to be imaginative and insightful than one hundred percent right." He uses as an example the early mapmakers, who by today's standards were hopelessly inaccurate, but without their maps, the New World would not have been discovered.

This section then is such a "map." Not to be taken as an accurate forecast, it should nonetheless prove valuable for planning purposes. This is the "scenario" technique of technological forecasting.

To attempt to draw up a system plan for a nationwide hydrogen energy system would be as difficult as attempting, back in 1945, to draw 1971's natural gas transmission line map and put throughput numbers against each line.

To paint the picture, we have assumed a time about 30-50 years hence when there will be a growing, comprehensive hydrogen transmission and distribution network. Fossil fuels will still be very much in the picture, but we will be preparing to phase them out by the increasing use of nuclear energy. Solar power will be beginning to come onto the scene.

B. Sources of Hydrogen

In the "Hydrogen Economy," hydrogen will be produced at large generating stations operating on nuclear energy. Because of thermal dissipation problems, these nuclear power stations will have to be sited in open country or on shorelines where deepwater cooling is available. Many of these stations will probably be on offshore floating platforms, as already under serious study by Westinghouse-Tenneco.[4] Those power stations that can be located relatively close to the cities will produce electric power.

Within 30 years, the earliest large-scale hydrogen production plant will have been built to operate on coal, oil shale, or heavy oil to provide commodity hydrogen delivered in pipeline systems to industrial users. A second development will have been the incorporation of off-peak hydrogen production plants into both fossil fuel and nuclear power stations. As the use of hydrogen becomes more widespread, the first generation of nuclear plants designed for the exclusive production of hydrogen will appear. It will use electrolyzers operating from steam-driven d-c generators. The second generation of nuclear-hydrogen plants will use the heat from the nuclear reactor directly to decompose water in a multistep chemical process that will be more efficient than the combination of electricity generation and electrolysis. The growing market for hydrogen, for use as a fuel, will have encouraged the development of production plants of all the types described above.

As new technology develops to harness solar and other energy sources, they will also be integrated into the hydrogen production and pipeline network.[2]

C. End Uses of Hydrogen

Hydrogen will be delivered by underground pipeline to all those users of today's natural gas and to more besides. It will be used to generate electricity onsite in locations where it is impractical to supply all the electricity needs from the central generating station. Such generators may be fuel cells or steam turbine stations of advanced design and may be located on individual properties or in "substation" locations. By doing this, it should be possible to meet tomorrow's greatly increased electrical consumption (variously estimated at 8-10 times the present level by the year 2000) without correspondingly large increases in the electrical transmission capacity.

Hydrogen will be supplied to industry as a heating fuel and as a reducing gas. In those many instances where today natural gas is used for production of a hydrogen-rich atmosphere, hydrogen can be used directly. For industrial process heat, hydrogen can be burned. In both applications, cleaner operation of the industry will be achieved. We can imagine, for example, the steel, ceramic, and cement industries consuming large amounts of fuel hydrogen.

Hydrogen is already a valuable raw material for the chemical industry. It is used for the production of rubbers, plastics, drugs, detergents, foodstuffs, etc., usually in conjunction with petroleum or vegetable products.

This use will continue. If synthetic liquid fuels become necessary to drive our cars and airplanes, such compounds as methanol would be ideal. The synthesis of such fuels could still use hydrogen as an intermediate.[5]

Hydrogen can be used in the home to heat and to cook. Because of the ease with which catalytic combustion takes place with hydrogen, revolutionary changes are likely in the design of both space heating and cooking appliances. Because of the nature of the effluent (only water), flueless appliances may become practical and "decentralized" heating may become preferred, since a chimney or flue for each appliance will not be necessary.

Hydrogen will find use as a transportation fuel if the problems of handling it and storing it on a small scale are solved. Both piston and gas-turbine engines operate well on hydrogen; it is possible to conceive of vehicles and aircraft using liquid-hydrogen tankage or some form of metal hydride as a "fuel tank."

D. Transmission, Storage, and Distribution

Hydrogen will be transmitted from the generating plants to the load centers in underground pipelines similar to the natural gas lines used today. Certain modifications in design, mainly associated with compressor stations, will have to be made. Existing lines may not be situated in the new, required locations, but where they are, they can be used.

Hydrogen will be stored, for seasonal and diurnal peakshaving purposes, as a gas in underground systems and as a liquid in tanks. A liquid-hydrogen plant may be operated on the line or as a satellite system using road-tanker delivery.

Hydrogen will be distributed within an urban center in an underground system just as natural gas is handled today. Certain modifications to pipes and other equipment may be necessary, but much existing equipment will be used.

E. Interrelation With Electric Utility Industry

Because hydrogen will be generated at large nuclear plants, the experience of the electric industry in planning and designing — perhaps even operating — these plants would be useful. In the same way, the experience of the gas industry in transmitting energy in gas pipelines will be useful to the electric industry. Both industries will thus have a common interest in the use of hydrogen.

F. Relative Costs of Delivered Energy

It is hard to predict what the cost of delivered hydrogen will be in the future and equally hard to predict corresponding future costs of natural or synthetic gas or electricity. We can carry out an exercise using today's prices, however, which is useful in making comparisons, and can then project how these costs will change in the coming years.

Details of a calculation procedure used to derive comparative cost figures for the gas and electric industry, and hence for the "hydrogen-energy industry," are given in Appendix II-A. This procedure is summarized here, together with its conclusions.

The latest available statistics for both the gas and the electric industries in the same year are for 1970. For that year, we can determine the average selling prices for gas and electricity for all customers in the U.S. and can break down these prices into their components relating to production, transmission, and local distribution of sales.

For the gas industry, the calculation is quite simple because the production, transmission, and distribution companies' financial statistics are reported separately.[1] Using the total sales of gas to ultimate customers, the revenues of the distribution, transmission, and production companies, and the average wellhead price, we obtain the figures shown in column 1 of Table II-1.

For the electric industry, however, no breakdown of overall financial statistics into these three categories is available, but data published by the Federal Power Commission[3] allow us to carry out the necessary calculations. Using the total number of kWhr sales to ultimate customers, the industry's breakdown of operating costs between generation, transmission, and distribution, and apportioning the capital costs of the three

Table II-1. RELATIVE PRICES OF DELIVERED ENERGY
(Source: 1970 Data From the FPC and A. G. A.)

	Electricity	Natural Gas	Electrolytic Hydrogen
	$/million Btu		
Production	2.67[*]	0.17	2.95-3.23[†]
Transmission	0.61	0.20	0.52
Distribution	1.61	0.27	0.34
Total	4.89	0.64	3.81-4.09

[*] Equivalent to 9.1 mills/kWhr.

[†] Assuming power purchased at 9.1 mills/kWhr.

[‡] Assuming pipeline hydrogen at $3.00/million Btu used for compressor fuel in optimized pipelines, compared to natural gas fuel at $0.25/ million Btu.

sectors in proportion to their relative capital investment, we obtain the second column of Table II-1. The average generating cost, derived from these figures, of $2.67/million Btu corresponds to 9.1 mills/kWhr. This, at first sight, appears a little high when compared with figures of 6-7 mills being quoted for modern steam station costs. However, when we realize that this figure includes all generation, even the older stations only used in peak conditions, and all the gas turbine peaking units, it appears reasonable — a view which has been checked out with and agreed to independently by two major electric utility companies.

To estimate the comparative costs for hydrogen, we assumed the existence of large electrolytic hydrogen generators as described in the Allis-Chalmers and AEC reports reviewed in Section III. The operating costs of these plants are highly sensitive to power costs. Instead of the unrealistically low figure of 2.5 mills/kWhr used by the AEC, we used the 9.1 mills/kWhr power cost derived above to calculate a hydrogen cost. We believe this cost to be pessimistically high for this application. We then derived an average transmission cost for hydrogen based upon the available statistics for natural gas transmission, increasing the overall costs for natural gas transmission by a factor of 2.6 times as derived in Section IV for the relative costs of optimized hydrogen and natural gas lines of high throughput, using the increased cost ($3.00/million Btu) of hydrogen fuel used for the compressors.

This clearly is a very artificial number, for it assumes that the hydrogen would be produced at the same locations as today's major gas fields and that no extra pipeline capacity would need to be laid. In fact, average transmission distances for hydrogen will almost certainly be far less than average transmission distances for natural gas. Further cost savings might be achieved by designing pipelines to operate at higher pressures than now. Thus, the hydrogen transmission figures presented here are probably pessimistically high.

Lastly, we calculated distribution costs for hydrogen, assuming that all the commercial costs for this sector of the industry will remain unchanged and that only the actual piping operating and depreciation costs will go up. Because we are unsure what the real effect of hydrogen would be, we arbitrarily doubled this portion of the cost, which we consider to be pessimistically high. Even so, it makes only a small change in the overall distribution cost.

These hypothetical costs for hydrogen are shown in column 3 of Table II-1.

The most important thing we notice in this table is that the difference between average transmission and distribution costs of natural gas and electricity, which is in favor of gas transmission, still exists when we look at the projections for hydrogen. We should bear in mind that the gas transmission is underground, while the electricity transmission is overhead.

Secondly, we observe somewhat surprisingly that even today we should be able to deliver hydrogen energy to the average customer more cheaply than we could deliver electricity: The savings in transmission and distribution more than make up for the extra cost of converting the electricity into hydrogen. This favorable comparison does not hold if we factor in the cost of reconverting the hydrogen to electricity at the user's end, but there would be a large and ready market for hydrogen to use as a heating fuel.

Electrolytic hydrogen at this price, however, would not find an immediate market for many uses already met by natural gas as long as natural gas is as cheap as it is. Thus, we may assume that, at these 1969 prices, it is not worth considering large-scale delivery of electrolytic hydrogen as a fuel. Hydrogen made from fossil fuels, especially from coal and heavy oil, would be very considerably cheaper than the prices shown above and could well find an important place in a developing hydrogen transmission system, especially if we look ahead and commit ourselves well in advance to widespread use of hydrogen fuel in the future.

Now let us project into the future. Undoubtedly, all fossil fuel prices, including that of natural gas, will increase because of the shortage of supply. Our attempts (in Section I) to predict the prices of coal, oil, natural gas, and synthetic gas for more than 10 years ahead are unreliable because we can have no accurate idea of the real availability of these fuels in the U.S. that far ahead. We know that a) the users are willing to convert from one fuel to another, as the relative prices change, if enough notice is given; b) technology is developing that will enable interfuel conversion on the part of the producer — for example, coal to oil, coal to gas; c) exploration and production costs for oil and gas are increasing because all the "easy" fuel has already been extracted; d) productivity per man in the coal industry is falling because of recent safety legislation; and e) an enormous capital investment must be made in the coal industry to increase production rates to the required levels. All of these factors will increase the price of fossil fuels. Since most electricity is produced from fossil fuels today, it will inflate in price at a corresponding rate. However, today's insignificant 1.6% of electricity generation from nuclear sources is expected to grow very rapidly, to over 25% in the next 30 years. If the production of electrolytic hydrogen is accepted, a growth of nuclear power at many times this rate is anticipated. Nuclear power is not severely resource-limited, once the breeder reactor becomes economical. There is adequate government-funded R&D going on to ensure this. Thus, although nuclear breeder electricity generating costs are predicted to be at least as high as today's base-load fossil fuel electricity costs (6-8 mills/kWhr), they should not escalate because of a decrease in fuel supply. Similar considerations apply to the fusion reactor — if and when they are developed. The operating cost of fusion reactors will be extremely small compared to their capital costs, so electricity costs should remain in line with the prevailing costs of capital amortization, and not be subject to increase because of fuel shortage.

The costs of transmission and distribution will increase for both gas and electric energy because both are sensitive to manpower costs. Since overhead electric transmission requires a great deal of maintenance, its cost will escalate even faster. Underground electric transmission, prohibitively expensive today, will become cheaper if superconducting cables are developed, but will always be more costly than overhead, and will thus be far more costly than underground gas. (See Section X.)

We can predict then, that the average price of delivered natural gas will climb steadily, at a rate greater than inflation rates. Synthetic gas from coal and oil will join this upward climb as their resource bases become depleted. Nuclear-based hydrogen should escalate in price only at normal inflation rates, as there will be no resource limitation. We cannot predict at what time hydrogen will become economically competitive with natural gas because too many independent and unforecastable factors are at work. Perhaps the most important factor will be the environmental benefits to be gained from the use of a completely nonpolluting fuel, transmitted through "invisible" underground pipelines. No dollar value can possibly be assigned to these benefits, but there are plenty of precedents for actions that cannot be economically justifiable being taken in order to achieve a situation desirable to the populace.

G. Projected Scale of Hydrogen Production

The concept of a hydrogen-energy system replacing the present fossil fuel energy system requires the production of hydrogen on an unprecedented scale. Because the nation's energy demands are rising rapidly and the split between electrical and nonelectrical energy demands is changing, it is difficult to carry out meaningful forecasts of the amount of hydrogen required. To meet the projected needs of the U.S. over the next 30 years, an increase of electrical generation capacity of from 8 to 10 times present levels is predicted. If, in addition to this, there are further economic incentives to switch from the direct use of fossil fuels to electrical energy, even greater increases of electrical plant capacity will be necessary.

To arrive at some figures required to indicate the necessary scale of hydrogen manufacture, we have considered the case in which today's natural gas energy supply is replaced by hydrogen. This still leaves the remainder of the present fossil fuel supply — oil and coal. Such an arbitrary division is, of course, hypothetical and only serves to illustrate the scale. We shall see that the magnitude of plant investment and conversion is of the same order, or greater, than that involved in installing coal gasification equipment.

How much hydrogen would have to be made if the whole U.S. gas industry were to operate on synthetic hydrogen rather than natural gas or manufactured pipeline gas? The U.S. now produces about 22 trillion CF of gas per year. This gas has an energy content equivalent to a steady electrical load of 730,000 megawatts. About 20% of today's gas is used for electricity generation, but we can safely assume that the nonelectric demand for gas 20 or more years from now will be at least equal to today's total demand. This means that the supply of hydrogen having a total energy content equal to today's natural gas supply (68 trillion CF/year of hydrogen) would require a nuclear energy generating capacity of between 0.7 and 1.0 million megawatts if hydrogen generation were at a constant rate year-round and significantly more than this if a load factor other than 1.0 is assumed.

In comparison, the 1970 total U.S. electricity generation of 1638 billion kWhr corresponds to a steady load of "only" 0.19 million MW. To provide this load, the electricity industry had a total generating capacity of 0.36 million MW. In other words, a complete change from today's gas supply to an equivalent electrical supply would require a six- to tenfold increase in electricity generation. The electricity demand in the U.S. is already rapidly increasing at a growth rate ranging from 6 to 9%/yr over the past 10 years, representing a doubling time of about 7 years. Thus, to provide 1970's gas energy as electrical energy, we would use the entire generating capacity planned for 1990.

To provide for both the present predicted expansion of electrical demand and the replacement of gas energy, the electrical industry will have to double its capacity every 5 years, corresponding to about a 15% growth rate. These figures apply whether or not we consider a "Hydrogen

Economy." If we begin to replace our fossil fuel energy supplies by nuclear electric supplies, we have to expand the electric industry at this kind of rate. The figures are conservative; they do not take account of the share of the energy supply currently obtained from oil or coal, nor do they consider the realistic expansion of gas energy demand.

Clearly, we cannot expect a rapid "overnight" switch from a fossil fuel economy to a nuclear hydrogen economy, but the scale of electrical plant installation necessary will clearly require years of planning and construction. We have serious concern over the availability of capital for the necessary plant construction and anticipate that very serious plant siting problems will arise for the numbers necessary. Nevertheless, power stations or other energy plants will have to be installed on this scale in the future if we are to use energy at even today's rate, whether or not we choose to use hydrogen as our energy-delivery means.

To take care of peak demands, the installed generating capacity in the U.S. is about 50% greater than the average year-round electrical load. With proper planning and design, this off-peak generating capacity could be used to produce hydrogen for storage. We could already consider feeding this into our gas supply reservoirs mixed with methane. In the long run, with an all-hydrogen fuel system, the storage capability of hydrogen will have a marked effect in reducing the amount of "redundant" generating capacity required.

Another way of looking at the scale of hydrogen generation operations is to consider the size of present electrical generating plants. A typical "large" power station has a capacity of about 1000 MW. Larger plants of 2000 MW have been constructed, especially in Europe, and plants of 4000 and 5000 MW are projected for the future. The trend in the U.S. has been to construct many plants in the 500-800 MW range. Present technology limits the capacity of a single generating machine to about 1000 MW (e.g., "Big Allis" in New York), but most power stations use multiple generators.

Let us assume, then, a "typical" power station size of 1000 MW. To provide today's gas energy demand we will need between 700 and 1500 extra power stations of this size! Again, whether or not we use hydrogen as a delivery means, if nuclear energy is to take the place of fossil energy to any reasonable extent in the future, huge numbers of power stations will be needed. The cooling loads on nuclear stations alone will restrict their siting to remote coastal or offshore areas, increasing the transmission distance to the load centers and making the cheaper hydrogen transmission method more attractive. A 1000-MW nuclear power station providing the whole of its electrical output to a "perfect" water electrolyzer will produce 310 million SCF/day of hydrogen with a fuel value of 100 billion Btu/day.

Thus, if the whole U.S. gas industry were to operate on synthetic hydrogen, 68 trillion SCF/year of hydrogen would have to be made. This would require about 1.0 million MW of electricity, or an increase in the present plant capacity of over 6 times, just to maintain the status quo of 1971. Increases of generating plant capacity of this scale are inevitable and are already forecast by the electricity industry over the next 20 years or so.

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Appendix II-A. Comparison of Energy Transportation and Distribution Costs

A. Summary

Using 1970 figures wherever possible, we have derived the relative costs for the transmission and distribution of gas and electricity. The sources of data used were confined to publications of the Atomic Energy Commission,[2] Federal Power Commission,[3-5] or A.G.A.'s Gas Facts.[1]

Two approaches were made: One was to take the overall industry composite income accounts, which show breakdowns of operating expenses by classes of production, transmission, and distribution and relate these costs to the amount of energy sold to ultimate customers. This gives inclusive industry costs of production, transmission, and distribution of energy — including returns to stockholders and payment of taxes. The other approach was to relate the actual cost per mile of long-distance transmission equipment installed in 1970 to the energy-carrying capacity of the system. This gives a comparison of the cost of installing transmission facilities.

The cost of generating hydrogen from electricity and the cost of transmitting and distributing hydrogen were derived by combining the natural gas and electricity figures obtained above with data published by Allis-Chalmers and Oak Ridge National Laboratory[2] in 1967. We made three assumptions of our own: One was that technological improvements that we can foresee will reduce the cost projected by Allis-Chalmers for an electrolyzer plant by a factor of between 0 and 1/2. Another is that the cost of transmission of hydrogen will be greater than that for natural gas, by the factors derived by Von Fredersdorff.[6] We have modified his numbers to account for an increased cost of hydrogen used as compressor fuel. Our third assumption is that, because of additional safety requirements, both the operating and installation expenses for distribution systems will be doubled. We assumed that all other costs, including commercial costs, taxes, returns to stockholders, etc., would be unaffected by a change to hydrogen.

The comparative cost, or, more accurately, "price" figures derived are shown in Table II-1 of Section II and Figure II-A1 of this appendix.

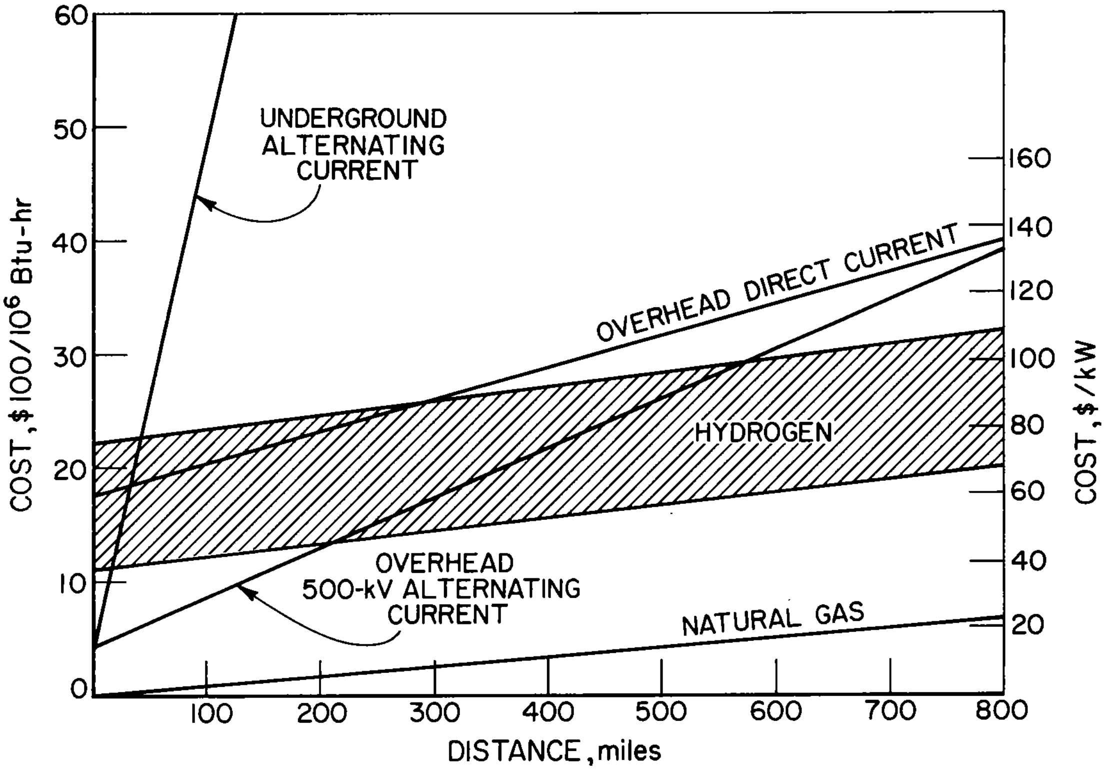

Figure II-A1. RELATIVE COSTS OF INSTALLING ELECTRICITY AND GAS TRANSMISSION FACILITIES

The prices of delivered energy given in Table II-1 include fuel, maintenance, and administration expenses, depreciation, all taxes, and profits. For the electric utility industry, we have taken the FPC published breakdown of operating costs for the three categories of production, transmission, and distribution and have allocated the depreciation, taxes, and profits in the proportion of plant investment in these categories. The gas industry figures are also inclusive of taxes and profits, as they are derived from overall operating revenues of the three sectors of the industry.

B. 1970 Gas Costs

Average production, transmission, and distribution costs were derived from published tables in 1971 Gas Facts,[1] which presents 1970 data. "Production" cost is obtained directly from the wellhead price. "Transmission" cost is obtained by difference from the revenue of the pipeline companies, less the price which they paid for the gas at the wellhead. "Distribution" cost is obtained by difference from the total revenue of all gas utility companies, less the price paid to the pipeline companies. The data are shown in Table II-1A. Lines f, i, k, and l are used for Table II-1.

C. 1970 Electricity Costs

The Federal Power Commission statistics show revenues, operating costs, and investments of the electricity industry broken down by classes of production, transmission, distribution, customer accounts, sales, and administration. Table II-A2 shows how we adjusted the operating cost figures to relate to revenues from ultimate customers instead of gross revenues, and how the fixed operating costs were then reallocated to production, transmission, and distribution in the ratio of total investments. Table II-A3 shows how the operating costs and reallocated fixed costs have been summed for each category.

In Table II-A4, the fixed costs relating to customer accounting, sales, and administration have been reallocated to production, transmission, and distribution in the correct proportion, and in Table II-A5, operating cost of administration is also reallocated, while the operating costs of customer accounting and sales are added completely to "distribution." This gives a breakdown in Table II-A6 of total operating costs, classified into three categories only: production, transmission, and distribution.

From the figures in Table II-A6, we see that the production cost of electricity appears as 0.91¢/kWhr, while the FPC average figure for generating cost is 0.476¢/kWhr. Reference 4, Table 21, shows that the 0.476¢/kWhr is obtained by dividing the direct operating expenses of production only by the total energy sold; this does not include the reallocation of investment costs and administration costs as we have carried out above. This accounts for the discrepancy between these figures.

D. Adjustment of Gas Transmission and Distribution Costs for Hydrogen

Data from A.G.A. Gas Facts[1] show operating expenses and plant investments of the gas industry, broken down into categories of production, storage, transmission, distribution, customer accounts, sales, administration, and depreciation.

In Table II-A7, the expenses of depreciation were allocated to the operating expenses in the ratio of the investment amounts, so we arrive at a total operating plus depreciation cost for transmission and distribution.

Notice that the figures derived in Table II-A7 for operating costs are considerably less than the costs shown in Table II-A1, lines h and j, because they do not contain such items as return to investors and Federal taxes. We consider that a changeover to hydrogen would not affect these other costs at all.

Because of the combination of hydrogen's lower heating value (325 Btu/SCF compared to 1033 Btu/SCF for natural gas) and its different physical properties, we have modified the compressor cost and pumping energy for hydrogen, based on Von Fredersdorff's calculations[6] for a 500-mile, 20-inch pipeline. While Von Fredersdorff used a value of $0.75/million Btu for the cost of hydrogen used to drive the compressors, we have modified his calculation, using a $3.00/million Btu figure for hydrogen, based on the electrolytic production cost derived in Table II-A12.

In the distribution networks, it is possible that safety limitations will require a "pipe-within-a-pipe" concept. This is a pessimistic assumption, and results in doubling both operating and depreciation costs. We have therefore increased these costs by a factor of 2.0. These conversions are made in Table II-A8. Lines Z and DD from this table have been used for Table II-1.

E. Cost of Installing Electricity Transmission Equipment

The FPC 1971 report, Transmission of Electric Power,[5] provides data on the actual installation cost, including right-of-way of EHV power lines built since 1969. We took the 500-kV line figures and disregarded one line built in urban areas, which was outstandingly high in right-of-way cost (thus giving a benefit to the electricity cost figures because it is in these urban areas that they are really in trouble in acquiring rights-of-way). Within the text of this report, we found references to the typical power transmission capacities of these EHV lines, relative costs and capacities of d-c overhead lines, and relative costs of underground EHV lines. We also found reference to typical substation costs. These values allowed us to derive generalized costs for various power transmission systems.

From the figures derived in Table II-A9, the plot of Figure II-A1 was made, assuming that the d-c and 500-kV a-c lines need two terminals, regardless of length, and that the terminal costs of underground lines are equal to a-c terminal costs. Note that these figures apply only to long-distance bulk power transmission, averaged over the country, and not to local distribution, which is much more expensive and is built underground in larger proportion. The average transmission distance in the U.S. is about 200 miles.

F. Cost of Installing Gas Transmission Equipment

The FPC report, Cost of Pipelines and Compressor Station Construction in Fiscal Year 1970,[3] shows the actual costs of installing various types of pipeline and compressors, including land and rights-of-way. We used the data for a 30-inch pipeline. The typical energy transmission capacity of a 30-inch pipeline was obtained from a Pipeline Industry article, and typical compressor station spacing and horsepower were obtained from the Gas Engineers Handbook.

We derived the combined cost of compressor stations and pipelines in terms of ¢/mile for unit transmission of energy. These data are derived in Table II-A10, and are then plotted as a line in Figure II-A1.

For hydrogen transmission, we have assumed that the increased capital cost factor for hydrogen over natural gas also held true for the 30-inch line analyzed above. We applied this factor to the cost of a natural gas line in order to obtain the cost of a hydrogen line. These data are also derived in Table II-A10.

G. Cost of Production of Electrolytic Hydrogen

Table II-A11 shows the derivation of data for the cost of electrolytic hydrogen. The Allis-Chalmers report to Oak Ridge National Laboratory[2] gives its estimates of the cost of constructing a large-scale hydrogen electrolyzer plant, based on 1966 technology. We have increased this cost estimate to allow for a return on investment and to pay Federal income taxes, as these were not included in the original Allis-Chalmers calculations.

Allis-Chalmers' calculations[2] assumed an operating efficiency of 85%. We believe that by increasing the operating temperature, efficiencies approaching 100% are achievable, and this has, in fact, been demonstrated in the Allis-Chalmers Laboratory. We therefore used an optimistic, but we feel realistic, 100% electrical efficiency figure. The Allis-Chalmers cost assumed that half the plant cost was in a-c to d-c rectification equipment. We feel that this cost, and also that of the remainder of the plant, is high by a factor of up to 2.0 times, if 1980-1990 technology is assumed. However, because of the uncertainty of this assumption, we used a spread of data covering Allis-Chalmers' original costs, reducing these by half.

Table II-A12 shows how we obtained costs of electrolytic hydrogen. We added the plant cost, expressed in terms of the hydrogen output, to an assumed figure for the cost of electricity. We took as our electricity generation cost 9.1 mills/kWhr.

The data from Table II-A11 were used in Figure II-A1 as the "terminal cost" for hydrogen transmission lines. One terminal per line was assumed, so that energy is delivered to the end point in the form of compressed hydrogen, not as electricity. Using the spread of data for terminal costs and the slope of the line, the derived pipeline cost from Table II-A10, the shaded area in Figure II-A1, results. The data of lines nn and oo in Table II-A12 are used for Table II-1.

H. References Cited

1. American Gas Association, 1971 Gas Facts: A Statistical Record of the Gas Utility Industry in 1970. Arlington, Va., 1972.
2. Costa, R. L. and Grimes, P. G., "Electrolysis as a Source of Hydrogen and Oxygen," Chem. Eng. Progr. Symp. Ser. 63, No. 71, 45-58 (1967).
3. Federal Power Commission, Cost of Pipeline and Compressor Station Construction in Fiscal Year 1970. Washington, D. C.: U.S. Government Printing Office, 1970.
4. Federal Power Commission, "Statistics of Privately-Owned Electric Utilities in the United States, 1970," FPC Report S-214. Washington, D. C.: U.S. Government Printing Office, 1971.
5. Transmission Technical Advisory Committee for the National Power Survey, The Transmission of Electric Power. Washington, D. C.: Federal Power Commission, 1971.
6. Von Fredersdorff, C. G., "Relative Costs of Transmission of Pipeline Gas," in American Gas Association Operating Section Proceedings — 1959, CEP-59-18.

Table II-A1. 1970 GAS COSTS[1]

Item	Data	Value Assumed	Source*
a	Total all-gas utility revenues	$\$10,283 \times 10^6$	Table 81
b	Total revenue — investor-owned pipeline companies	$\$5928 \times 10^6$	Table 143
c	Average wellhead price	17.1¢/1000 CF	Table 24
d	Total gas utility sales	$16,043 \times 10^{12}$ Btu	Table 68
e	Average heating value	1033 Btu/CF	
f	Unit production cost	$\$0.165/10^6$ Btu	c/e
g	Total production cost	$\$2647 \times 10^6$	f × d
h	Transmission cost	$\$3281 \times 10^6$	b — g
i	Unit transmission cost	$\$0.204/10^6$ Btu	h/d
j	Distribution cost	$\$4355 \times 10^6$	a — b
k	Unit distribution cost	$\$0.0271/10^6$ Btu	j/d
l	Average unit revenue	$\$0.640/10^6$ Btu	a/d

* The tables listed below are from Reference 1.

Table II-A2. ELECTRICITY REVENUES AND FIXED COSTS[4]

Identification	m	o	p	q	r
Item	Operating Cost	Ultimate Customer Share of Operating Cost	Investment	% Investment	Allocation of Fixed Costs in Proportion to Investment, $\$10^6$
Source	Ref 4, Table 5	m X n*	Ref 4, Table 6		p X s†
		$\$10^6$			
Production	6144	5622	33,035	40.2	4063
Transmission	291	266	15,444	18.8	1890
Distribution	1253	1146	31,329	38.1	3853
Customer Accounts	502	459			
Sales	306	280	2400	2.9	295
Admin. and General	1163	1064			
Total	9659	8837	82,208	100	10,101
Fixed	10,132	9261			
Revenue (Ref 11, Table 4)	19,791	18,098			

* n. $\frac{\text{Revenue From Ultimate Customer}}{\text{Gross Revenue}} = \frac{\$18,098 \times 10^6}{\$19,791 \times 10^6} = 0.915$ (Ref 4, Table 3)

† s. Fixed Charges as % of Investment $\frac{\$10,132 \times 10^6}{\$82,208 \times 10^6} = 0.123$

Table II-A3. ELECTRICITY OPERATING COSTS AND REALLOCATION OF FIXED COSTS[4]

Identification	o		t	u	v	w
Item	Ultimate Customer Share of Operating Cost		Ultimate Customer Share of Fixed Cost	Total Cost	¢/kWhr	\$/10^6 Btu
Source	o		r X n	t + o	u/x*	u/y†
	\$$10^6$		\$$10^6$	\$$10^6$		
Production	5622		3718	9340	0.86	2.53
Transmission	266		1729	1995	0.18	0.53
Distribution	1146		3525	4671	0.43	1.26
Customer Accounts	459	1803	270	2073	0.19	0.56
Sales	280					
Admin. and General	1064					
Total	8837		9242	18,079	1.667	4.89

* x. Sales to ultimate customers: 1083 X 10^9 kWhr/yr (Ref 4, Table 4)

† y. Sales to ultimate customers: 3696 X 10^{12} Btu.

Table II-A4. "OTHER" FIXED COST REALLOCATION

Identification	t	z	A	B	C
Item	Ultimate Customer Share of Fixed Costs	Fixed Costs	Fixed Costs, %	"Other" Costs	Fixed Costs
Source	t			% X 270	z X B
	$\$10^6$	$\$10^6$		$\$10^6$	$\$10^6$
Production	3718	3718	41.4	111.8	3830
Transmission	1729	1729	19.3	52.1	1781
Distribution	3525	3525	39.3	106.1	3631
Other	270				
Total	9242	8972	100.0	270	9242

Table II-A5. REALLOCATION OF "OTHER" OPERATING COST

Identification	o	D	E
Item	Operating Cost	Admin. and General Cost	Total Operating Cost
Source	o	1064 X A	D + o
		$\$10^6$	
Production	5622	440	6062
Transmission	266	205	471
Distribution	1146		
Customer Accounts	459	418	2304
Sales	280		
Admin. and General	1064	--	
Total	8837	1064	8837

Table II-A6. SUMMARY OF OPERATING AND FIXED COSTS

Identification	E	C	F	G	H
Item	Operating Cost	Fixed Cost	Total Cost	Total Cost, ¢/kWhr	Total Cost, $\$/10^6$ Btu
Source	E	C	C + E	F/x	F/y
	$\$10^6$				
Production	6062	3830	9892	0.91	2.67
Transmission	471	1781	2252	0.21	0.61
Distribution	2304	3631	5935	0.55	1.61
Total	8837	9242	18,079	1.67	4.89

Table II-A7. REALLOCATION OF OPERATING EXPENSES FOR GAS INDUSTRY

Identification	I	J	K	L	M	N
Item	Operating Expenses, 10^6	Operating Expenses, %	Plant Investment, 10^6	Investment, %	Depreciation as % Investment	Total Operation Plus Depreciation Costs
Source	Ref 1, Table 144	Ref 1, Table 152	Ref 1, Table 149		L X O*	I + M
					10^6	
Production and Purchasing	9021	77.5	3,657	9.2		
Storage	104	0.9	1,816	4.5		
Transmission	507	4.3	17,188	43.1	474	981
Distribution	723	6.3	15,056	37.7	415	1138
Customer Accounts	336	2.9	--			
Sales	209	1.8	--			
Admin. and General	735	6.3	2,197	5.5		
Total	11,635	100.0	39,914	100.0		

* O. Depreciation (Ref. 1, Table 142) $1101 X 10^6$.

Table II-A8. CONVERSION OF GAS DISTRIBUTION COSTS TO HYDROGEN

Assumptions:

U Overall hydrogen transmission cost increases by factor of 2.6 (Section IV, Figure IV-9).
V Hydrogen distribution operating cost increases by factor of 2.0.
W Hydrogen distribution depreciation cost increases by factor of 2.0.

Identification	Data	Value Assumed	Source
X	Total H_2 transmission	$3281 x 10^6	h
Y	New total transmission cost	$9187 x 10^6	X x 2.6
Z	New unit transmission cost	$0.52/$10^6$ Btu	Y/d
AA	New distribution, operation, and depreciation cost	$2276 x 10^6	N x 2.0
BB	Increase in distribution, operation, and depreciation cost	$1138 x 10^6	AA – N
CC	New total distribution cost	$5493 x 10^6	BB + j
DD	New unit total distribution cost	$0.342/$10^6$ Btu	CC/d

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Table II-A9. ELECTRICITY TRANSMISSION COSTS[5]

Identification	Data	Value Assumed	Source*
EE	Average cost of five 500-kV lines built since 1969 – Includes right-of-way, excludes the cost of one urban line	\$130,000/mile	p. 23
FF	Cost of d-c line at 0.65 times the cost of comparable a-c line	\$84,500/mile	EE × 0.65
GG	Typical power capability of 500-kV line	900,000 kW	p. 25
HH	Typical a-c terminal cost	\$8/kW	p. 115
II	Typical d-c terminal cost	\$30/kW	p. 115
JJ	Average 500-kV overhead line cost	\$0.144/kW-mile	EE/GG
KK	Average 500-kV overhead line cost	\$42.32/10^6 Btu-hr-mile	
LL	Average d-c overhead line cost	\$0.093/kW-mile	FF/GG
MM	Average d-c overhead line cost	\$27.50/10^6 Btu-hr-mile	
NN	Cost of two terminals for ac	\$16/kW	HH × 2
OO	Cost of two terminals for ac	\$4687/10^6 Btu-hr	
PP	Cost of two terminals for dc	\$60/kW	II × 2
QQ	Cost of two terminals for dc	\$17,580/10^6 Btu-hr	
RR	Cost ratio of underground to overhead power transmission	10:1 to 40:1	p. 123
SS	Cost of underground line	\$1.44/kW-mile	JJ × 10
TT	Cost of underground line	\$423.2/10^6 Btu-hr-mile	KK × 10

* The page numbers refer to specific pages of Reference 5.

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Table II-A10. GAS TRANSMISSION INSTALLATION COSTS[3]

Identification	Data	Value Assumed	Source
UU	Average cost of 30-in. pipelines laid in fiscal 1970 (includes materials, labor, right-of-way, surveys, etc.)	$181,569/mile	
VV	Total compressor stations built in 1970	134,676 hp	
WW	Total compressor station cost, 1970	$41,297,704	
XX	Average compressor cost	$307/hp	WW/VV
YY	Transmission capacity of 30-in. line (from Pipeline Industry, Jan. 1966, p. 45)	600 X 10^9 Btu/day (25 X 10^9 Btu/hr)	
ZZ	Typical compressor station location for 30-in. line (From Gas Engineers Handbook)	9000 hp/100 miles	
aa	Average compressor cost for 30-in. line	$2.76 X 10^6/100 miles	ZZ times XX
bb	Average compressor cost for 30-in. line	$107/$10^6$ Btu per hp-100 miles	aa /YY
cc	Average pipeline cost for 30-in. line	$720/$10^6$ Btu per hr-100 miles	UU/YY
dd	Total natural gas pipe + compressor cost	$827/$10^6$ Btu per hr-100 miles	bb + cc
ee	Estimated compressor cost for hydrogen	$142/$10^6$ Btu per hr-100 miles	bb X 1.327*
ff	Total hydrogen gas pipe and compressor cost	$862/$10^6$ Btu per hr-100 miles	cc + ee

*1.327 Factor derived from reference 6

Table II-A11. COST OF INSTALLING HYDROGEN GENERATION CAPACITY

Identification	Data	Value Assumed	Source
ff	Pipeline and compressor costs for hydrogen	$862/10^6 Btu-100 miles	Table II-A10
gg	Allis-Chalmers plant capacity	13×10^9 Btu/day; 540×10^6 Btu/hr	Reference 2
hh	Allis-Chalmers plant cost estimate	$\$12 \times 10^6$	Reference 2
ii	Unit plant cost	$\$22,200/10^6$ Btu-hr	hh/gg
jj	Lowest estimate of unit plant cost	$\$11,000/10^6$ Btu-hr	jj/2

Table II-A12. COST OF GENERATING HYDROGEN

Identification	Data	Value Assumed	Source
kk	Allis-Chalmers plant operating cost, less electricity	$0.12/1000 SCF $\$0.37/10^6$ Btu	Reference 2
ll	Allis-Chalmers plant operating cost, revised by IGT assuming utility financing, less electricity	$0.18/1000 SCF $\$0.56/10^6$ Btu	
mm	Optimistic estimate of plant cost	$\$0.28/10^6$ Btu	ll/2
G	Average production cost of electricity	9.1 mill/kWhr	Table II-A6
H	Average production cost of electricity	$\$2.67/10^6$ Btu	Table II-A6
nn	Hydrogen production cost range — Upper	$\$2.95/10^6$ Btu	mm + H
oo	Lower	$\$3.23/10^6$ Btu	ll + H

III. HYDROGEN PRODUCTION

A. Introduction

Hydrogen is produced in huge quantities today for use as a major intermediate in chemical and petrochemical manufacture. Between 1960 and 1968, the total U.S. hydrogen production rose from 722 to 2280 billion CF/yr. Only about 5% of this quantity was sold as hydrogen, the remainder being consumed, for example, in the manufacture of such chemicals as ammonia and methanol.

Today by far the major proportion of this hydrogen is made from natural gas by reaction with steam and some oxygen or air. Where large quantities of hydrogen are needed, it is more economical to build a natural-gas- or oil-fed hydrogen plant onsite than to become involved with storage or transportation of hydrogen.

These generalizations, however, are by no means universal; in several instances where alternative means of hydrogen production are involved, economics dictate remote siting of production and use facilities. For example, at several locations where cheap hydroelectric power is available, very large electrolytic hydrogen plants exist. Also, several hydrogen users in the Houston area purchase bulk hydrogen from an underground pipeline system operated by Air Products & Chemicals, Inc., from a central natural-gas-fueled plant. Almost every power station in the country requires a small but reliable supply of hydrogen as a coolant for the generator. Hydrogen is chosen because its low viscosity decreases "windage" losses inside the generator. This hydrogen is usually provided by an onsite electrolyzer.

Thus, even today, when cheap natural gas is almost universally available, alternative sources of hydrogen are sometimes justified. Basically, however, there are only two prime sources of hydrogen in the enormous quantities required for our "Hydrogen Economy": One is from fossil fuel hydrocarbons, which can be ruled out as an indefinitely economic source in the "nuclear age," and the other is from water. Half of the hydrogen produced from steam reforming of methane is really derived from the water (or steam).

Water can be split up into its elements, hydrogen and oxygen, without the use of fossil fuels by the injection of an amount of energy equal to the combustion energy of hydrogen. This can be achieved in three ways:

1. Electrolytically
2. Thermally
3. Thermochemically

The first process is relatively simple and provides automatic separation of the products; however, it requires electrical energy for operation. But the generation of electrical energy from nuclear fission is, by today's technology, an inefficient process: The best nuclear power stations operate at about 33% thermal efficiency. Thus, even though we have available the technology to obtain electrolytic hydrogen, its overall efficiency is low.

The second process requires very high temperatures and results in the formation of a mixture of hydrogen and oxygen that will recombine as the temperature is lowered. It appears to be an impractical process for hydrogen production, although some schemes to make it operable have been proposed recently.[8]

In concept, the third type of process is a series of two or more chemical reactions by which water reacts with an intermediate to form products that may be thermally decomposed a) to produce hydrogen and oxygen in separate reaction stages, and b) to regenerate the original intermediate compound. In this way, the thermal energy of the nuclear reaction can be made directly available to the process, and the separation of the hydrogen and oxygen products can be achieved. No technology is in practical operation today for a process of this type, but the concept holds out the promise of "thermal water-splitting" at a higher practical efficiency than the overall electrical route and is therefore worthy of study.

Our study explores the technical and economic backgrounds of the electrochemical process for hydrogen production and the technical status of the thermal water-splitting process.

B. Electrolytic Production of Hydrogen

1. Theoretical Limitations of Electrolysis

An electrolytic process is one made to occur by passing a direct electric current between two electrodes immersed in an electrolyte. Endothermic, or energy-consuming, processes can be carried out by this method, the required energy being provided by the electric current. Many simple chemical compounds are broken down into their elements by this process. For water, the products are hydrogen and oxygen.

Since the overall process of water electrolysis is the reverse of the combustion of hydrogen, the energy required per unit quantity of hydrogen produced is the same as the heat of combustion, or calorific value, of hydrogen. Each hydrogen molecule is formed by the addition of two electrons to two hydrogen ions in solution, so that a direct relationship exists between the current passed (rate of passage of electrons) and the rate at which hydrogen is produced. A water electrolysis cell has a current efficiency, in practice, of almost 100%, corresponding to a release of 6.95 cu cm/min of H_2 per ampere, or 15.6 SCF/1000 A-hr.* A perfectly efficient cell would require 79 kWhr of electrical energy for each 1000 SCF of hydrogen produced. Since this energy input to the cell is measured by the product of current and voltage, each electrolytic process has a theoretical voltage corresponding to the energy required for the reaction to proceed.

This situation is not quite as simple as described above, however, because only the free energy of reaction can be interchanged with electrical energy. The difference between free energy change and the total energy change (enthalpy) is accounted for by a change of entropy in the process. This entropy change cannot be converted to electricity; it must be supplied or liberated as heat.

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* The electrochemical equivalent of current is 96,500 A/equiv/second. At 32°F and 1 atm this is 6.95 cu cm/min/A. The SCF values are corrected to 60°F, the standard industry temperature of measurement.

We can calculate that for a water electrolysis cell the voltage corresponding to the enthalpy change, or heat of combustion of hydrogen, is 1.47 volts at 25°C, while the cell voltage corresponding to the free energy change is only 1.23 volts. This difference is important because it is a factor that works in favor of electrolyzers and against fuel cells.

In an ideal case, then, a voltage of 1.47 volts applied to a water electrolysis cell at 25°C (77°F) would generate hydrogen and oxygen isothermally — that is, at 100% thermal efficiency with no waste heat produced. However, a voltage as low as 1.23 volts would still generate hydrogen and oxygen, but the cell would absorb heat from its surroundings. The electrical energy required for the process is only 83.7% of the combustion energy of the hydrogen produced, the other 16.3% being supplied as heat. Another way of expressing this is that the fuel value of the hydrogen produced is 120% of the heating value of the electrical energy put in.

In marked contrast to a hydrogen fuel cell, therefore, we see that a water electrolyzer can have a theoretical "electrical" efficiency of up to 120%, while a perfect fuel cell is limited to an "electrical" efficiency no greater than 83.5%, if it operates at 25°C (77°F).

The free energy change voltage, or "reversible" voltage as it is called, varies with temperature as shown in Figure III-1. We can see that raising the temperature lowers the voltage at which water can be decomposed. Again, this factor operates in favor of electrolysis cells because at higher temperatures the electrode processes proceed faster, with lower losses, while the required energy input is less. This is in contrast to fuel cells; their available energy output falls as the temperature is raised.

The voltage corresponding to enthalpy change, or, as we shall term it, the "thermoneutral voltage," varies only slightly with temperature from 1.47 volts at 25°C (77°F) to 1.50 volts at 340°C (644°F). This is also shown in Figure III-1. We can therefore identify three areas in which 1) no hydrogen is evolved, 2) hydrogen is made at greater than 100% electrical efficiency, and 3) hydrogen is made at less than 100% efficiency with production of waste heat.

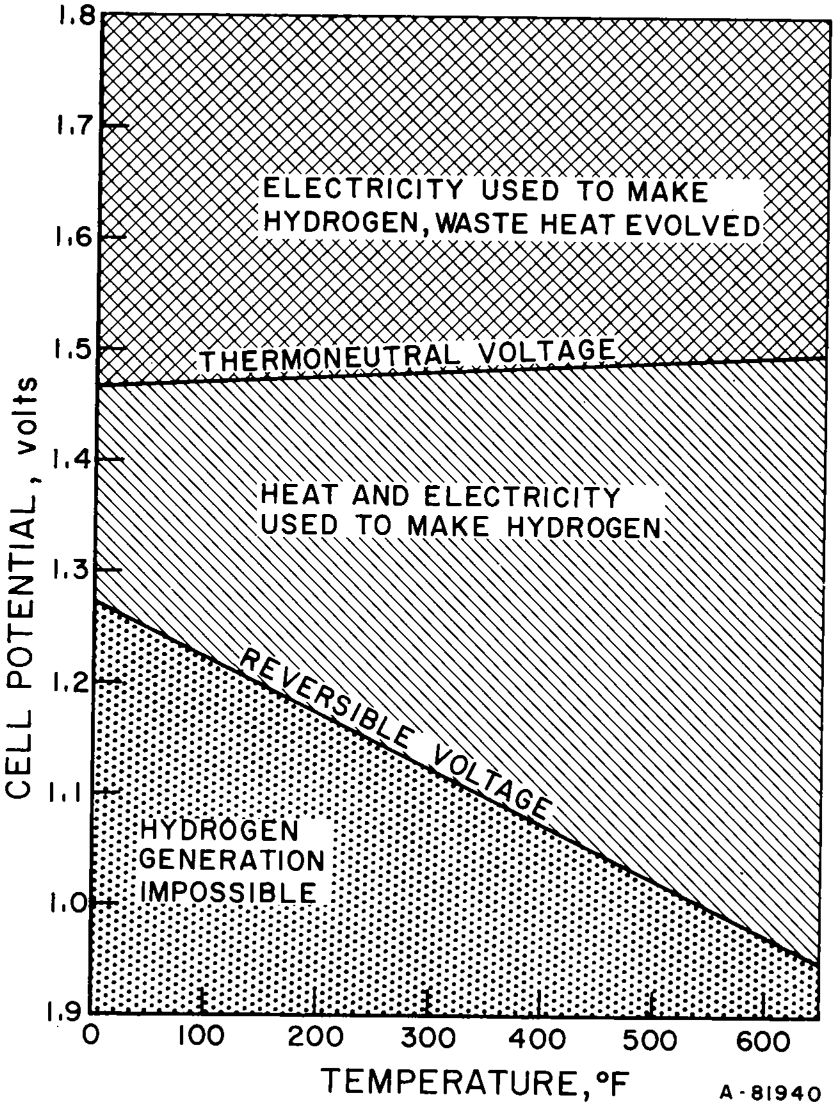


Figure III-1. IDEALIZED OPERATING CONDITIONS FOR ELECTROLYZER

2. Design Optimization

In practice, an electrolyzer does not operate at the theoretical "reversible voltage" because at this voltage the rates of the electrode processes are zero. To promote the decomposition of water, a voltage higher than the reversible value must be applied. The excess voltage necessary is termed "overvoltage" or "polarization" and is related to the current that passes through the cell. Higher currents per unit area of electrode require higher overvoltages and hence lower efficiencies. The size of the cell, and thus the capital cost of the cell, is reduced if it is designed to operate at a high current density, but at the expense of energy input or efficiency. Overvoltages are reduced by increasing the operating temperature, by the proper design of the electrode structures, and by the incorporation of catalysts into the electrodes. Other factors contributing to cell inefficiency are those that influence the electrical resistance of the cell. Resistance losses may be reduced by optimizing the design.

3. Criteria for Evaluating Electrolyzer Cells

In evaluating the relative merit of different electrolyzer cells and in comparing them with alternative systems, it is important to know what characteristics to measure. Since the cost of the hydrogen production will be influenced by both capital and operating costs, both of these are important.

The operating cost of an electrolyzer is dominated by its efficiency. Since current efficiencies are, in general, very high, the operating cell voltage gives a direct measure of the energy efficiency. Although most voltage comparisons in the literature are made with the "reversible" voltage of 1.23 volts, we feel it is more meaningful to compare practical voltages with the "thermoneutral" voltage of 1.47 volts to indicate an electrical efficiency, defined by the ratio:

$$\frac{\text{Heating Value of } H_2 \text{ Output}}{\text{Electrical Energy Input}}$$

Any deviation from 100% electrical efficiency is a direct measure of the heat energy to be removed from or supplied to the cell. Another useful efficiency criterion is to compare the power requirement of the cell with the theoretical power requirement of 79 kWhr/1000 SCF at 25°C.

The capital cost of the cell is dominated by the size and the unit cost of the electrodes. To achieve maximum hydrogen output, the cell can be operated at very high current density (current per unit area of electrode). However, to do this, higher voltages are needed, and the efficiency falls off. Increased current density is also obtained by using more expensive (precious metal) catalysts or by going to extremely complicated, and thus costly, electrode construction. A degree of optimization is thus required; the resulting choice will vary according to the cell's application, the prevailing cost of power, and other individual factors.

The principal difference between the old, established electrolyzers and the advanced concepts is in the electrodes. The development of fuel cells has introduced a better understanding of porous electrode design and fabrication, and the use of catalysts. Most of the advanced cells use highly porous, high-surface-area metal electrodes carrying a highly developed nickel, silver, or, in some cases, platinum catalyst. Filter-press bipolar construction is usually employed. Cell resistance is minimized by the use of thin, uniform sheets of asbestos or similar material of "fuel cell" grade. The most successful of the advanced electrolyzers still operate with aqueous alkaline electrolyte at modest temperatures. Alternative electrolytes, including ion-exchange membranes and high-temperature oxides, have been considered. Thus far, only one U.S. manufacturer, Teledyne Isotopes, has ventured into the market with an advanced type of electrolyzer design.

4. Types of Electrolyzer Designs

Each of the many existing commercial electrolyzers can generally be classified according to two constructional techniques — tank-type electrolyzers and filter-press electrolyzers. In the tank-type electrolyzer, a large vat, usually iron, holds the alkali electrolyte. Electrodes with alternate polarity are suspended in the vat. The electrodes consist of flat sheets of mild steel, welded to bus bars of steel. Plates are heavily nickel-plated; the cathodes are left plain. Usually, a bag or skirt of asbestos is used as a diaphragm to maintain separation between the hydrogen, which is generated at the cathode,[5] and the oxygen, which is generated at the adjacent anodes. In electrolyzers of this type, each tank operates as one cell. Although it may carry thousands of amperes, only about 2 volts are applied. Thus, in small sizes this type of electrolyzer operates at high current and low voltage, resulting in an awkward electrical rectification problem. Larger units in series can accept higher voltages.

Connecting individual tanks in a series raises the voltage of the system, but increases the total power that must be handled by the switchgear. Compared to the filter-press electrolyzers, some designs of tank-type units are wasteful of floor space and require more maintenance. Nevertheless, the outage of a single tank does not cause a significant operational problem as it can easily be "bypassed."

The filter-press-type electrolyzer is constructed with alternate layers of electrodes and diaphragms, much the way a filter press is built. The electrodes are solid metal and are bipolar: One side of the electrode is the cathode of one cell, while the opposite side is the anode of the adjacent cell. With construction of this type, the individual cell voltages are additive within a stack. With electrolyzers of this type, if an individual asbestos diaphragm is torn, a significant rebuilding job is necessary for renovation of the unit and production potential is thus lost. Nevertheless, this type of electrolyzer appears to be more efficient in voltage requirements. However, as the filter-press electrolyzers usually cost more to construct, they are generally operated at higher current densities in order to generate more hydrogen per square foot. Thus, the usual operating voltages of both tank-type and polar electrolyzers are about the same.

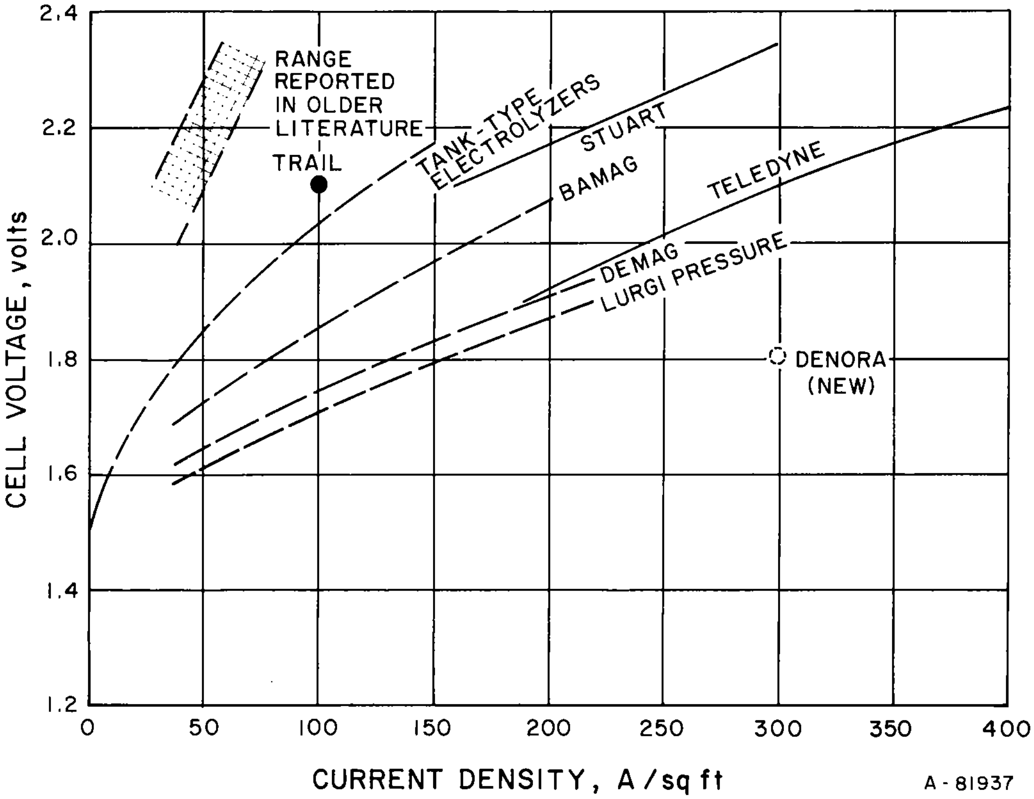
Tank-type cells operate at almost 100% efficiency. Because of the bypass currents in their common electrolyte, filter-press-type cells have a current efficiency of about 95%. Usually, the bipolar construction is more expensive than the tank-type construction for a given hydrogen production, even if the bipolar cell is operated at the same voltage as the tank-type cell. It is noteworthy that commercial tank-type electrolyzers are said to have a life of greater than 25 years and to be maintenance-free for over 10 years. At that time, only an electrolyte change is necessary.

Appendix III-A is a review of modern electrolyzer technology[20] by A. K. Stuart, president of the Electrolyser Corporation Ltd., Toronto, Canada, and is a very up-to-date (1972) account of the electrolyzer scene as viewed by a large manufacturer.

5. Manufacturers and Current Performance

There are two major electrolyzer manufacturers in North America. The Electrolyser Corporation Ltd. of Toronto, Canada, manufactures cells for a wide variety of applications, mainly custom-designed. This is an old, established company. It built the original cells for the large installation at Trail, B. C., in the 1930's. A new entry to the field is Teledyne Isotopes of Baltimore. This company acquired the Allis-Chalmers fuel cell and electrolyzer technology in the late 1960's and is now offering for sale both a range of small electrolysis plants in the 10-100 CF/hr range and custom design services. Specifications and descriptions of some of Teledyne's systems are shown in Appendix III-B.

Figure III-2 shows a comparison of the cell performances of a number of cell types that we have studied.



Figures III-2. OPERATING CHARACTERISTICS OF VARIOUS COMMERCIALLY AVAILABLE ELECTROLYZER PLANTS

Points or solid lines represent information from primary literature sources or personal contact. Dashed lines are values taken from secondary literature where primary information is not yet available. Most of these electrolyzer manufacturers are in Europe; the usual European reluctance about releasing equipment operating performance probably explains the lack of primary data.

The German manufacturer Lurgi produces pressure-type electrolyzers, but has been extremely reluctant to provide us with information. We experienced similar difficulty with De Nora of Milan, which has claimed impressive performance figures. It is likely De Nora will provide design figures if it receives specifications for an actual installation.

Comparison of cell types and manufacturers is difficult; even the secondary literature does not agree upon electrolyzer operating performance for individual cell brands. In addition, a cell comparison based upon voltage-current relationships is meaningless unless cell cost is included.

Although the process for electrolytic manufacture of hydrogen is old, well established, and centered primarily in Europe, space and military applications have caused an increase of interest in electrolyzer technology within the last decade in the United States. This has led to a number of advanced technical concepts for electrolyzer design and construction, which have not yet reached commercial application, but which promise to reduce the likely cost of hydrogen manufactured by this process.

The primary military application was the "energy depot program."[19] Because of logistics, the cost of energy on the battlefield is high. In this concept, a nuclear power plant, an electrolytic hydrogen plant, an air liquefaction plant, and an ammonia plant would be flown in and assembled behind the lines to chemically manufacture ammonia to be used as a fuel for internal combustion engines, fuel cells, and heaters. As electrolytic hydrogen manufacture was an integral part of this program, and improved electrolyzers should be possible as a spin-off from advanced fuel cell technology, a significant effort was expended in advancing electrolyzer technology.

Further improvements in electrolyte technology have been spurred by the Atomic Energy Commission in its study of "nuplexes" — agricultural-industrial complexes supplied by seawater and nuclear energy. Nitrogen-based fertilizer manufactured from electrolytic hydrogen is a key feature of most of the nuplex studies.[18]

Electrolyzers have also benefited from space research. One of the problems with longer duration manned space flight is the reclamation of waste products for use in the life cycle. One of the primary problems has been the recovery of breathing oxygen. In most of the regenerative processes that have been developed, electrolysis of water is required to recover this oxygen. Consequently, electrolyzer technology has also been enhanced by this effort.

A small number of large electrolyzer installations are of interest, although none are as big as will be required for hydrogen production on a massive scale.

Table III-1 lists four large electrolyzer installations with their capacities as determined from the literature. The electrical requirements of these plants range from 75 to 400 MW. The plants produce billions of cubic feet per year of electrolytic hydrogen for the production of ammonia. Also included on Table III-1 are the outputs of these plants in terms of the heating value of the hydrogen produced, indicating the relative size of these plants in comparison with gas industry needs.

These four electrolysis plants have one factor in common: They are all located at a source of inexpensive hydroelectric power. The Trail, British Columbia, facility of Cominco Ltd. was built in the 1930's (before air reduction was common) to provide oxygen for metallurgical operations. The hydrogen is now converted, via ammonia, to fertilizer. The tank-type cells used in this electrolysis operation were quite advanced for their time and featured rugged construction, simplified operation, and ease in maintenance. Nevertheless, this cell design requires much floor space. The hydrogen cell room of Cominco Ltd. contains over 3200 electrolyzer tanks (Figure III-3). The building covers over 2 acres. About 90 megawatts of power are consumed to produce 36 tons/day of hydrogen.

Table III-1. LARGE ELECTROLYSIS INSTALLATIONS

Location	Cell Type	Power Requirements, 1000 kW	Hydrogen Output, 10^9 CF/yr	Heating Value of Hydrogen Produced, 10^9 Btu/day
Trail, B.C., Canada	Trail (Kent)	90	4.9	4.3
Nangal, India	DeNora	125	7.8	7.0
Aswan, Egypt	Demag	~75-100	~6	~5
Norsk Hydro, Norway	Pechkranz	400	28	25

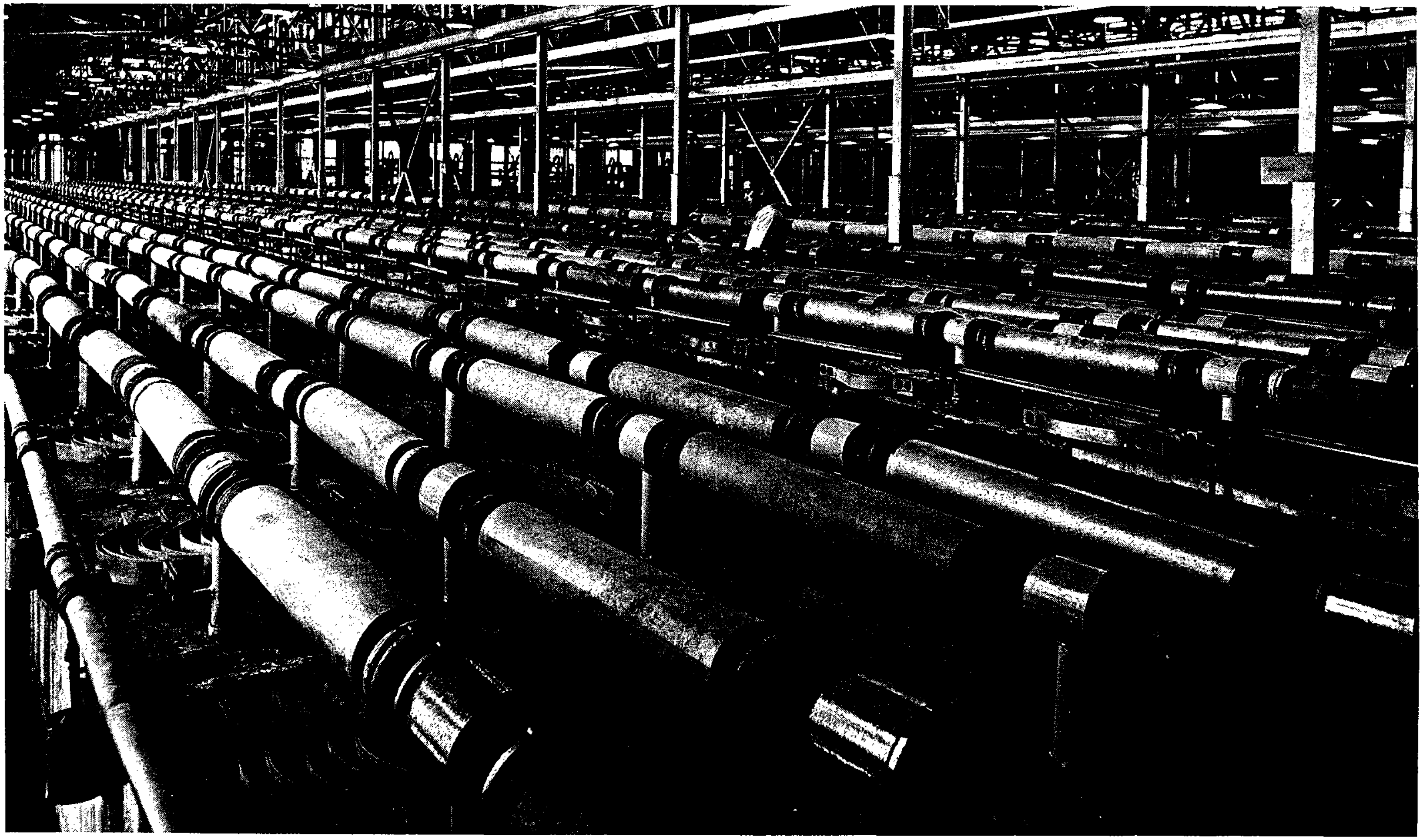


Figure III-3. LARGE ELECTROLYTIC CELLS FOR HYDROGEN PRODUCTION AT COMINCO LTD.'s TRAIL, B.C., INSTALLATION

During World War II the Trail plant was operated to produce heavy water for the Manhattan project. This is an interesting by-product of electrolytic hydrogen; heavy water can be produced in reasonable concentrations by staging the electrolyte flow to the cells at a slight loss of hydrogen production efficiency. Heavy water will be required as a "fuel" for fusion reactors.

Of the first three large fertilizer facilities in India, only the Nangal plant uses electrolytic hydrogen. (The others partially oxidize wood.) At Nangal 60, electrolyzer units produce 880, 000 CF/hr of hydrogen with a daily heating value of 7. 0 billion Btu. The total current through all the cells adds up to 60 million amperes. This installation is relatively new (1959). The cells were furnished by De Nora of Milan, which is also one of the world's larger manufacturers of electrolytic chlorine cells. The Nangal plant produces 15 tons/yr of heavy water, for a by-product credit (at $28. 50/lb) of nearly $1 million annually.

The Aswan Low Dam project in Egypt was built in the late 1950's with about 100 MW of hydrogen generation capacity for eventual use in fertilizer production. The literature on this project is sparse, but we understand that this plant uses about 75-100 MW for a daily output of 5 billion Btu equivalent in hydrogen.

The Norsk Hydro facility in Norway was started before World War II. This plant was the object of the famous commando raids to destroy the German heavy-water capability. With subsequent additions, this plant produced 28 billion CF of hydrogen in 1963, indicating a plant size of 400 MW with a daily output of 25 billion Btu equivalent in hydrogen.

The plants listed in Table III-1 are those known to exist; however, a plant of about 165 MW (10 billion Btu/day) capacity is the subject of rumors in the industry. It will be supposedly built in Rhodesia. The electrolyzer section of this plant is now out for bid. Other, smaller electrohydrogen plants are used for making fertilizer in Italy, Japan, Portugal, New Zealand, Spain, and Switzerland.

A listing of electrolytic hydrogen plant equipment prepared by Teledyne Isotopes is given in Table III-2.

Table III-2. SUMMARY OF ELECTROLYTIC PLANT EQUIPMENT (Prepared by Teledyne Isotopes, Inc.)

				Cell Design					Experience		
	Company/ Location	Cell Name	Type	ASF amp/ft^2	Volts/ Cell	Module Size lb H_2/day	Pressure psig	No. of Plants	Largest Size lb H_2/day	Earliest Plant year	Best Known Plant year
A.	Norsk Hydro Notodden, Norway	Hydro-Pechkranz	Filter Press	140	1.773	1800	1	3	284,000	1927	Rjakon, Norway 1965
B.	Lurgi Frankfurt, Germany	Zdansky-Lonza	Filter Press	200	1.832	4200	440	32	22,000	1955[1]	Cuzco, Peru 1958
C.	DeNora Italy	DeNora	Filter Press	280	2.00[2]	4100	1	2	110,600	1958	Nangal, India 1958
D.	Pintsch-Bamag Germany	Bamag	Filter Press	230	1.788	2600	13.5	200	UNK	1935	UNK
E.	Electrolyzer Corp. Canada	Stuart	Tank	200	2.04	40	.03	1000	1,130	1930	Teledyne Wah Chang, Alabama, USA 1971
F.	Cominco Canada	Trail	Tank	80	2.142	38	.1	1	77,000	1939	Trail Canada 1939
G.	Teledyne Isotopes USA	EGGS	Filter Press	400	2.1	65	70	2	50	1968	Teledyne Isotopes USA 1972
H.	Demag Elektro-metallurgic GMBH Duisburz, Germany	Demag	Filter Press	92 to 280	1.75 to 1.95	900	1.	57	177,000	1945	Aswan Dam Egypt 1960
I.	Electric Heating Equipment Co. USA	Kent	Tank	115	2.2	28	.1	100	1,610	1920	Hobart, Tasmania 1949
	Cells Being Developed										
J.	Teledyne-Isotopes USA	----	Filter Press	400	1.65	13	2000		Designed for military aircraft application		
K.	Teledyne Isotopes	----	Filter Press	250	1.64	94	3000		Designed for nuclear submarine application		
L.	General Electric	---	Solid Electro-lyte	3260	1.2 to 1.8	--	1		2000°C not now under development		
M.	Westinghouse	---	Solid Electro-lyte						Used for CO_2 electrolysis in spacecraft atmosphere control system.		

---

[1] First Zdansky-Lonza Plant

[2] DeNora has indicated an ability to achieve 1.61 volts on new cells.

In general, the existing, large-scale electrolyzer plants are all operated at current densities of about 100-200 mA/sq cm (1 mA/sq cm $\cong$ 1 A/sq ft) and at voltages of about 2.0 ± 0.1 volts. Present producers and users of large-scale electrolyzers are skeptical about being able to reduce the cost and raise the efficiency sufficiently to allow hydrogen from electrolyzers to be used as a fuel gas.

6. Advanced Concepts

The "advanced" electrolyzer concepts offer the most promise for production of "fuel hydrogen."

Table III-3 presents the characteristics of the advanced electrolyzer technology which we have reviewed. This review was either through personal contact or the study of primary literature with reanalysis to determine cell operating efficiency and cost on a consistent basis. Similarly, Figure III-4 presents the reported cell operating performance characteristics for a number of electrolyzers. The new data in Figure III-4 are superimposed on the earlier data reported in Figure III-2. They indicate the improved operation of the advanced electrolyzers over existing equipment. In this graph, the solid lines and data points were used to present the data that we have reviewed; dashed lines depict data from secondary literature sources. In the case of the dashed lines, we have been unable to check the primary literature to determine that operation of the device as an electrolyzer rather than as a fuel cell was specifically studied. (Often, in theoretical fuel cell studies, the electrodes are driven to the opposite polarity to determine voltage-current characteristics. Although this approximates electrolyzer operation, it cannot be termed an electrolyzer study because in-depth analysis of operating conditions, materials of construction, and corrosion is not attempted.)

a. The Allis-Chalmers Cell

The advanced electrolyzer concept that is closest to an economic reality is the Allis-Chalmers cell. This electrolyzer is the spin-off of various Allis-Chalmers contracts for the Army and Air Force, and was developed under the energy depot and nuplex programs. This electrolyzer uses potassium hydroxide electrolyte with advanced porous nickel electrodes at moderate temperatures of 250^{0}F. The cell is constructed on

Table III-3. ADVANCED ELECTROLYZER TECHNOLOGY

		Operating Conditions								
							Installed Cost			
Organization	Description	Temp, °F	Press., psi	Current Density, A/sq ft	Voltage, volts	Efficiency,* %	†	‡	Date	Present Status
Allis - Chalmers (Now, Teledyne Isotopes)	Similar to A-C fuel cell. KOH matrix, porous electrodes, no noble metal	250	300	800	1.78	83	3.8	9.3	1966	Research stopped 1967; technology sold to Teledyne Isotopes, which is commercializing.
General Electric	Similar to GE high-temp fuel cell, solid oxide	~2000	0	3260	1.33	111	2.6	7.3	1966	Research stopped 1968.
General Electric	Similar to Gemini fuel cell, acid ion-exchange memb; designed for space life support, not optimized for commercial	190		200	1.59	93	30 (Catalyst)	40	1971	Continuing on space life support; little work toward commercialization.
Battelle	Alkaline matrix cell with Pd-Ag diffusion cathode, space application	335	0	75	1.6	92	High (Pd-Ag)		1966	--
Westinghouse	High-temp solid oxide space application	2000	0	300	1.65	89	--		1966	Fuel cell research discontinued in 1971.

* Efficiency based on supplying entire standard enthalpy for formation (ΔH_f^o) by electricity. This is approximately equal to converting the heat equivalent of electricity into higher heating value of Hg.

† Estimate of installed cost of electrolyzers only, \$ 10^6/10 billion Btu/day capacity.

‡ Estimate of total plant cost including piping, water conditioning, electrical conditioning, etc.

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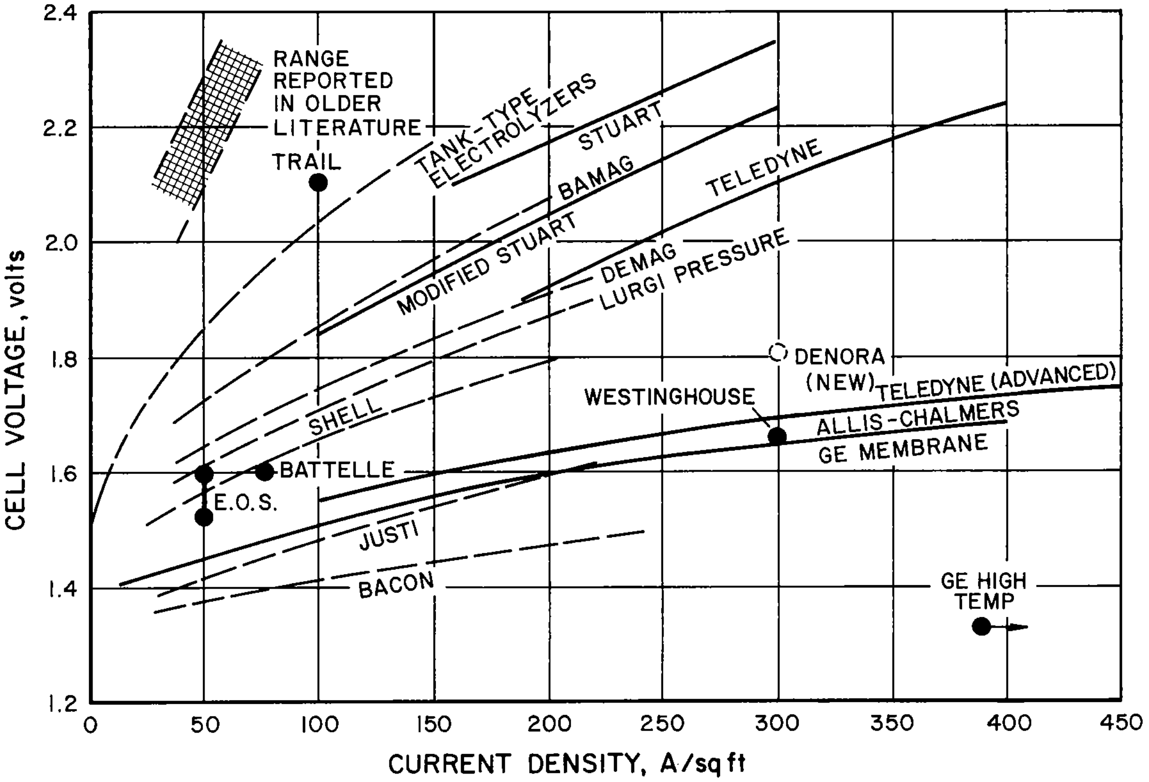

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Figure III-4. CELL OPERATING PERFORMANCES OF VARIOUS ADVANCED ELECTROLYZERS

the filter-press basis and contains no precious metal catalysts. Each cell consists of two porous electrodes separated by a porous, insulating diaphragm. Current is passed between the electrodes, where hydrogen and oxygen are evolved. The aqueous potassium hydroxide electrolyte is circulated through the cell, carrying off the hydrogen and oxygen into gas-liquid separators, where they are separated from the electrolyte. The electrolyte also serves as a cell coolant. Many cells are connected electrically in series to form a battery or "stack" of electrolyzers.

With this electrolyzer, current densities up to 1600 A/sq ft are possible at reasonable voltages. Individual cells up to 4 sq ft have been operated, as have multiple-cell stacks, which confirm the above operating conditions. In addition to an expansive test program, Allis-Chalmers undertook a detailed economic analysis of electrolytic hydrogen plant operations. (See Section III-B7.) For these reasons, we have chosen the Allis-Chalmers cell as the primary device in our studies of electrolytic hydrogen manufacture.

Allis-Chalmers ceased its fuel cell and electrolyzer R&D in 1967. The technology was sold to Teledyne Isotopes, which has already gone onto the market with a number of electrolyzer cells. Teledyne furnished us with laboratory data for advanced cells not yet in commercial production.

b. General Electric High-Temperature Cell

General Electric Company has developed an electrolyzer concept based upon its high-temperature fuel cell technology. Only small, individual cells have been operated, so the scale-up to large installations is tentative. In addition, much of the data that have been presented are based upon anticipated results of research in reducing electrolyte thickness and resistance. Yet, this system might be attractive for the long run because of the high current densities and low voltages achievable, and because thermal efficiencies greater than 100% are practicable.

This GE cell operates at about 2000° F using a conductive solid oxide as an electrolyte. The cell area is small because the fragile electrolyte must be made in a small-diameter tube to have mechanical strength. Although the high-temperature fuel cell concept has the best theoretical potential for electric power generation, funding has been discontinued by the Government because of the materials problems involved; all experimental development has ceased. The same problems will be experienced with electrolyzer operation. Electrical costs for generating hydrogen would be about 35% lower with this cell than with the Allis-Chalmers cell. This concept provides the bench mark for electrolyzer operating costs that might be achieved with sufficient fruitful research. The likelihood for success in this field, however, is doubtful, so the concept has a low priority for further research.

c. General Electric Ion-Exchange Membrane Cell

General Electric has developed a second electrolyzer using an ion-exchange membrane for operation up to 190^0F. The cell is similar to the General Electric fuel cell used in the Gemini spacecraft, although it uses a new and more rugged type of ion-exchange membrane. GE claims that if this membrane had been available at the time of the Gemini program, the national fuel cell development program would now be based on that concept. At present a small amount of laboratory work is still in progress at GE aimed at electrolyzer development for the spacecraft use.

The performance characteristics of this cell are identical to those of the Allis-Chalmers alkaline cell as presented in Figure III-4. The higher efficiency quoted in Table III-3 results from the lower current density (and lower voltage) selected by GE for space operation.

We asked GE to estimate a likely production cost for this type of cell. The cost figures that it supplied were over 3 times higher than Allis-Chalmers', but are directly competitive with existing electrolyzers. However, these costs are not subject to reduction (as are existing electrolyzers due to quantity construction and changes in operating conditions) because the GE membrane cells contain noble metal catalysts. Indeed, the noble metal requirement for this type of cell would limit its application because of the limited availability of platinum. Further research on this type of cell would not be warranted for our purposes, although it is interesting to note that a single cell of this type has been operating at the Air Force Propulsion Laboratory in Dayton, Ohio, for 18,000 hours continuously, at 150 A/sq ft and at a very encouraging voltage of 1.62 volts (compare 2.1 volts for commercial electrolyzers) corresponding to an electrical efficiency of 90% and a thermal efficiency of 76%.

d. Battelle Cell

Battelle Memorial Institute has proposed an electrolyzer construction for space applications which uses a palladium-silver cathode that is permeable to hydrogen diffusion. The cell operates at relatively high temperatures of 335°F for a minimum polarization. The Pd-Ag electrode is used primarily as a technique to separate the hydrogen in a weightless operating condition; the probable high cost of the cell because of these noble metals makes this approach unattractive for commercial applications.

e. Westinghouse High-Temperature Cell

Westinghouse Corporation has published data on its solid-oxide, high-temperature fuel cell operated as an electrolyzer for space applications. Compared to the GE high-temperature cell, relatively high voltage at low current was reported. However, this work was not an extrapolation of existing data and represents the practical performance obtainable from a high-temperature cell. The problems inherent to the high-temperature GE cell operation as discussed above are also present with the Westinghouse cell.

f. Other Advanced Electrolyzers

Figure III-4 presents operation data for three European fuel cells in the electrolyzer mode, but we have been unable to check the original literature. The Shell fuel cell uses acid electrolyte, which causes the appreciably higher voltage reported for this cell as an electrolyzer.

The Bacon fuel cell was the first fuel cell to be fully engineered and has been used for all of the Apollo spaceflights. Because of its high temperature (500^0F) and use of concentrated electrolyte, its oxygen electrode performance is uniquely efficient. Its reported operation as an electrolyzer is promising. Because of the high efficiency obtained and because the cell contains no precious metal catalysts, the Bacon cell warrants further study as an electrolyzer.

The "Justi" cell is a laboratory development of Professor E. W. Justi of Braunsweig Technical University in Germany. The reported performance of this cell[7] is most significant because it is the best performance seen at relatively low temperatures. The cell construction is similar to that of the Allis-Chalmers cell, but uses porous electrodes containing highly active Raney nickel and Raney silver catalysts.

Other cell types were not included in Table III-3 because insufficient data were available. Electro-Optical System (E.O.S. in Figure III-4) is developing for aerospace use an electrolyzer-fuel cell combination in which the electrolyzer product gas is compressed and stored for return to the system in the fuel cell mode of operation. Pratt & Whitney Aircraft is also developing a similar system. Allison Division of General Motors has operated electrolyzers with Raney nickel electrodes; Allison's reported data superimposes the Shell cell line in Figure III-4.

7. Hydrogen Costs Predicted by Allis-Chalmers

In our opinion, the Allis-Chalmers cell design is a satisfactory bench mark for the determination of the economics of hydrogen manufacture using advanced electrolyzer techniques.

The Allis-Chalmers Manufacturing Company was the first of the fuel cell laboratories to publish the results of applying advanced technology to electrolysis cell construction. This discussion is based upon Allis-Chalmers' published work and conversations with Dr. P. G. Grimes, who was associated with that project when it was active up to 1966.

a. Operating Data

The Allis-Chalmers fuel cells used alkaline electrolyte. This electrolyte has also historically been favored by electrolysis cell manufacturers because of its lower voltage requirements. It was only logical, therefore, that Allis-Chalmers would use this electrolyte in its advanced electrolyzer concepts. The major disadvantage of alkaline electrolyte for fuel cell work is that it is not compatible with CO_2, either in the air or in the fuel. Since this problem does not arise in electrolyzers, there is little justification in considering acid electrolytes, which are the present trend in fuel cell technology. Water alone gives too great an overvoltage to be used as an electrolyte.

Allis-Chalmers operated test cells varying in size from 4 sq in. to 4 sq ft over a wide range of temperatures, pressures, and electrolyte concentrations. The larger cells were made of plastic and were therefore only operated at ambient conditions to check the scale-up from the small-cell data. The smaller cells, up to 36 sq in., were more ruggedly constructed for a greater operating range. We believe that data taken on cells of this size are a reasonable approximation of the performance that can be expected in even larger sizes, given sufficient engineering development.

The performance of the Allis-Chalmers electrolysis cell is presented in Figure III-5, a plot of cell voltage as a function of current density at various temperatures. Two types of lines are presented: The solid lines represent data taken with electrodes containing 0.3 mg/sq cm of platinum-palladium catalyst on nickel electrodes and the dashed lines

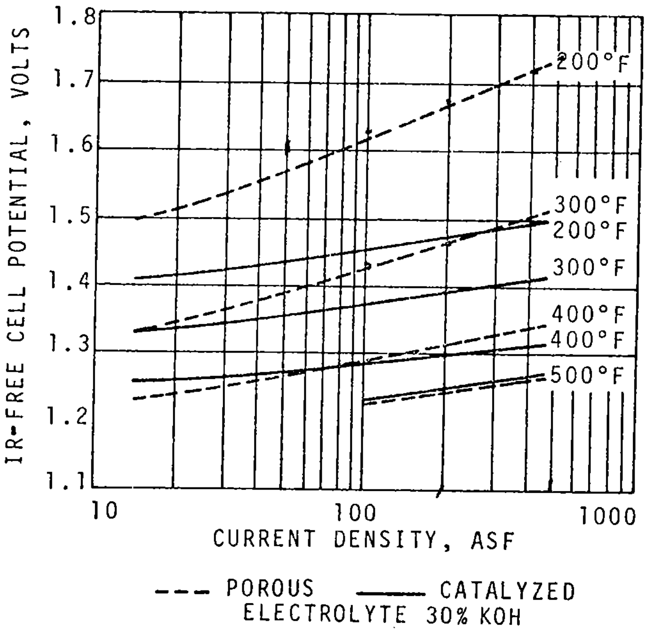

Figure III-5. EFFECT OF TEMPERATURE AND CATALYTIC ACTIVITY ON CELL POTENTIAL[3]

represent the performance from uncatalyzed nickel electrodes. The noble metal catalyst becomes unnecessary at higher temperatures and probably could not pay for itself at reduced temperatures. Note that Figure III-5 presents the cell potential on an IR-free basis: The voltage due to the internal resistance of the cell has been determined by current interruption techniques and subtracted from the overvoltage. Therefore, the true cell polarization is determined independent of ohmic effects, which are functions of the "engineering" geometry of the cell.

The overvoltage above the reversible voltage is about 300 mV at 250°F using a catalyst. This value is similar to the polarization experienced on a well-engineered alkaline fuel cell, from which, theoretically, similar polarization values are expected; thus this observation lends credibility to the Allis-Chalmers data and indicates a measure of the degree of development of that system.

Allis-Chalmers designed and operated a four-cell test module with a 30-sq-in. electrode size at a temperature of 200°F. The performance of this module is the same as the performance of the single-cell tests with a 90-mV ohmic polarization at 400 A/sq ft. The test module was not long-lived. The Allis-Chalmers report blamed the short life on corrosion of stainless steel parts, but Dr. Grimes has recently ascribed the deterioration to leaching of sulfur from rubber seals and subsequent poisoning of the electrodes.

The problem of cell lifetime may be accentuated by the matrix configuration of the cell. To keep the electrodes from touching, they were separated by an asbestos diaphragm, which had to be kept wet with electrolyte. We know that water balance is very difficult to achieve in fuel cells of this design, but in the Allis-Chalmers electrolyzer, electrolyte was circulated in both anode and cathode compartments to overcome the problem. Longevity of an electrolyzer of this type depends on both the materials of construction and the system control, both of which seem to require further development at this stage.

The performance of an experimental module at 200°F was extrapolated by Allis-Chalmers to 250°F based upon single-cell polarization data and improvements in electrolyte conductivity with temperature. The predicted cell performance at 250°F is presented in Figure III-6.

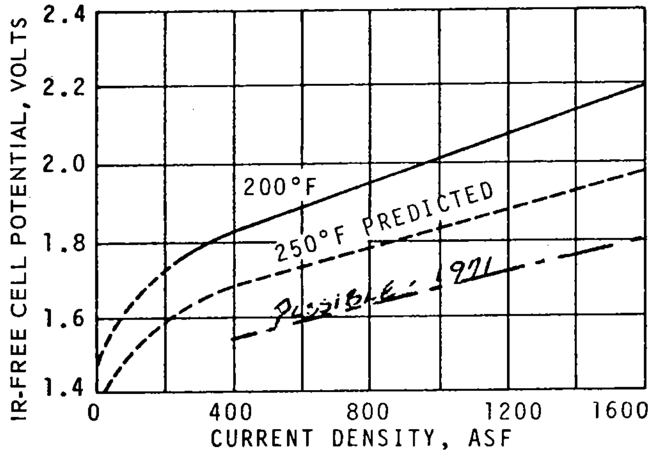

Figure III-6. DESIGN PERFORMANCE OF MULTICELL ELECTROLYSIS MODULE[3]

We have also included a line in Figure III-6 depicting the performance that we think might now be achieved based on improvements in fuel cell technology over the past 5 years. We note, however, that the performance curves provided by Teledyne in 1972 are poorer than the 200°F line shown in Figure III-6. In other words, Teledyne has not been able to achieve the earlier optimism shown by Allis-Chalmers.

b. Economics

Allis-Chalmers prepared a conceptual design for 1000-volt modules of electrolysis cells with about 30-inch effective cell diameters. The appearance of such a module is presented in Figure III-7; the basic operating characteristics are listed in Table III-4.

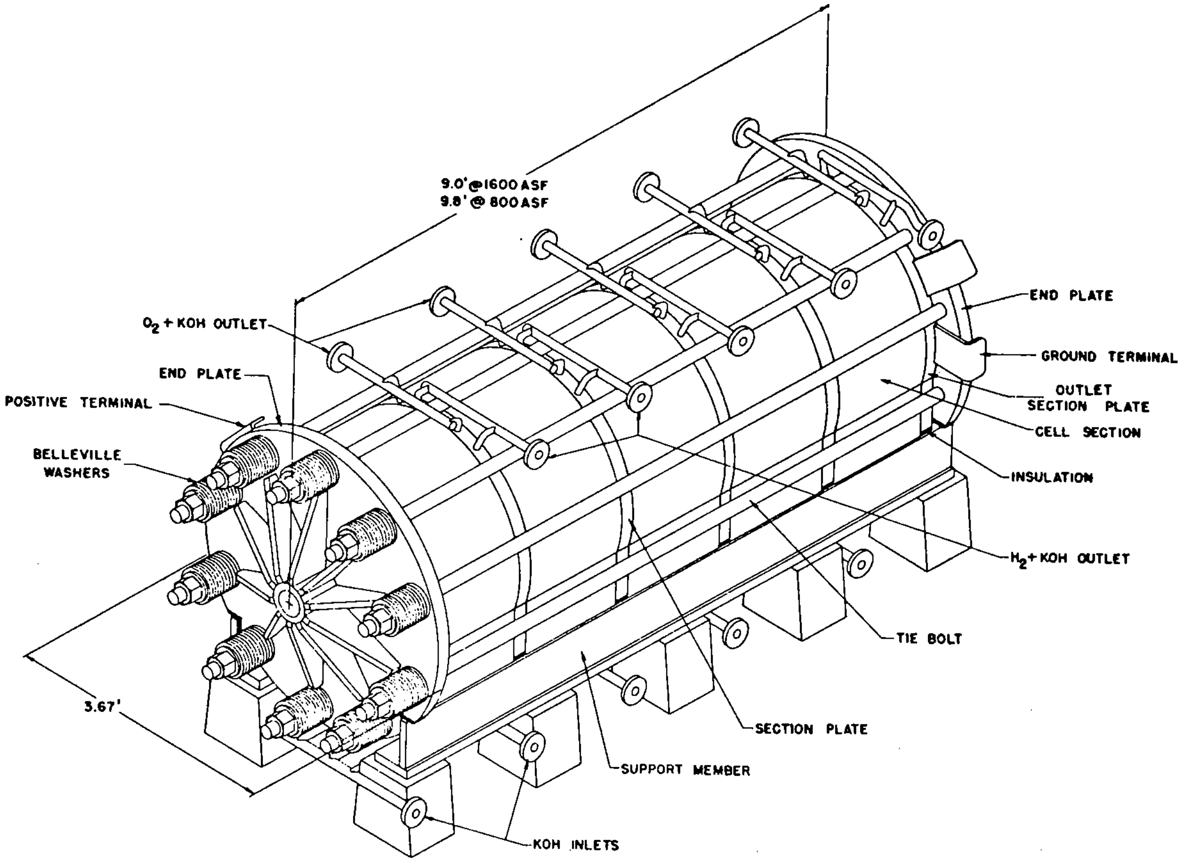

Figure III-7. ALLIS-CHALMERS' ELECTROLYSIS MODULE FOR HYDROGEN PRODUCTION[3]

We notice that this module design is similar to those used in the Allis-Chalmers fuel cell work, both having a close spacing of the cells (6.5 cells/inch).

Table III-4. BASIC ALLIS-CHALMERS MODULE CHARACTERISTICS

(Temperature 250°F, Pressure 300 psig)

Electrode Current Density, A/sq ft	800	1,600
Hydrogen Output, lb/hr	183	314
Current Input, A	4,030	8,110
Module Terminal Potential, volts	1,000	955
Overall Module Length, inches	118	108
Module Weight, Pounds: Dry	16,245	15,205
With KOH	18,800	17,495
Single-Cell Active Area (Each Electrode), square feet	5.0	5.0
Cell Potential, volts	1.78	1.99
Number of Cells per Inch	6.25	6.25
Total Number of Cells Per Module	560	480
Total Active Cell Area Per Module, sq ft	2,800	2,400
Power Input, MWe	4.03	7.75

Allis-Chalmers then prepared detailed cost estimates on each module. These costs varied from $80,000 to $94,000 per module, depending upon quantity and stack surface area. These prices were for installed costs and correspond to $33-$37/sq ft of installed electrolyzer area. On a weight basis, the installed costs of a module are about $5-$6/lb. Based on past experience with fuel cell component costs, we think that the installed cost of about $35/sq ft seems optimistic; however, large industrial chemical processing equipment can often be installed for $2.50/lb for mild steel construction and $3.50-$4.00/lb for stainless. Considering that some nickel would also be used in this design, the cost of $5-$6/lb seems reasonable.

Using these module characteristics, Allis-Chalmers designed electrolyzer plants under three assumptions of plant size and operating characteristics. The plant costs are tabulated in Table III-5. Note that the major item in each of these plants is "electrical," i.e., power conditioning and switchgear equipment. As Allis-Chalmers is a major manufacturer of such equipment, these costs should be reliable. The basis for these costs was the use of technology available in 1966; consequently, Allis-Chalmers assumed rectification and control of 20-kV a-c current rather than generation of direct current.

When Oak Ridge[17] evaluated the Allis-Chalmers data, it added an increased cost factor of 9% to the plant capital requirements. We could not rationalize this increase; perhaps it was for land, offsite facilities, or interest during plant construction. Our own refinements of the Allis-Chalmers cost figures are discussed in Section III-B8.

Note that the largest of the three plants considered by Allis-Chalmers requires a power input of approximately 1000 MW. This is a relatively large electrical generating station by today's standards. Such a nuclear power plant would require a capital investment of $250-$300 million in today's money market. Yet, the electrolyzer cost would only be about $40 million. Therefore, a significant change in the electrolyzer plant cost would not cause a great variation in the price of the hydrogen output; the cost of building the electrical generating facility overshadows the electrolyzer capital cost.

For its study of a 40 million SCF/day hydrogen plant, Oak Ridge National Laboratory derived the operating cost breakdown shown in Table III-6.

This estimated manufacturing cost of 33.6¢/1000 SCF, corresponding to $1.03/million Btu, has been widely used in AEC cost studies. However, it is based on an unrealistically low electric power price of 2.5 mills/kWhr, compared to an average generating cost today of about 8 mills/kWhr. On the other hand, it does not take into account certain optimistic assumptions that we feel can be justified based on the prospects for electrolyzer development.

Table III-5. INSTALLED COST OF ALLIS-CHALMERS' PLANTS

	Assumptions					
	4,400 lb/hr at 800 A/sq ft		4,400 lb/hr at 1,600 A/sq ft		44,000 lb/hr at 1,600 A/sq ft	
	$	% of Total	$	% of Total	$	% of Total
Mechanical, Instrumentation, Processing, Piping, and Structures	962,000	17.6	958,000	20.7	5,413,000	14.4
Electrical	2,261,000	41.3	2,327,000	51.6	21,018,000	56.0
Modules	2,246,000	41.1	1,254,000	27.7	11,109,000	29.6
TOTAL	5,469,000	100.0	4,539,000	100.0	37,540,000	100.0

Table III-6. ESTIMATED MANUFACTURING COSTS FOR HYDROGEN FROM ADVANCED-TYPE ELECTROLYTIC CELLS[a]

Item	Cost of Porous-Electrode Cell, ¢/1000 SCF/H_2
Utilities[b]	29.5
Maintenance and Operating Supplies	4.2
Labor at $4/hr	0.5
Overhead at 60% of Labor	0.3
Fixed Charges[c]	7.6
Gross Manufacturing Cost	42.1
By-product O_2 Credit	(8.5)[d]
Net Manufacturing Cost	33.6
Capital Investment, $$10^6$	11.8

[a] Based on hydrogen production, 40 million standard cubic feet; hydrogen delivery pressure, 1700 psig; fixed charges, 9%.

[b] Electric power cost: 2.5 mills/kWhr.

[c] Depreciation, 6.7%; local taxes and insurance, 2.3%.

[d] Oxygen delivered at 300 psig, $4/ton.

A. K. Stuart[20] of The Electrolyser Corporation Ltd. compares the Mrochek Oak Ridge cost figures[17] with costs "which may be achieved in the near future by moderate adaptation of existing uni-polar industrial electrolyzers."

> For very large installations, following the trend in both brine and aluminum electrolysis, significant reductions in capital cost and floor space can be obtained by building uni-polar cells to much higher d-c current rating. Such cells, with a capacity of 40 million cubic feet of hydrogen per day, can be accommodated in a room 60,000 square feet in area. Using the same nuclear power rate as Mrochek (2.5 mills/kWhr), gross manufacturing cost would be 49.3¢/1000 SCF, before by-product credits. This corresponds to the Mrochek gross manufacturing cost of 42.1¢ estimated for porous electrode cells, including depreciation, insurance, and local taxes on a comparable basis.

The value of the by-product oxygen taken at $4.00/ton (17¢/1000 SCF) would reduce net hydrogen cost in both cases by 8.5¢ to 40.8¢ and 33.6¢ respectively. In addition, heavy water by-product would be recoverable by known technology from the uni-polar cells in a quantity of approximately 30 tons/yr. Assuming a price of $20.00/lb, less 50% recovery cost, there would be a further credit of 4.3¢ and net hydrogen cost would then become 36.5¢/1000 SCF ($1.13/million Btu).

In conclusion, it would appear that, while more intensive development of cells is needed and will be carried out, sufficient established technology already exists for the electrolytic production of hydrogen in very large quantities, at a production cost in the same order of magnitude as that estimated for advanced cells. The key is the availability of low cost nuclear power.

8. IGT's Revised Cost Analysis of the Allis-Chalmers Electrolyzer

Allis-Chalmers carried out a cost assessment of its electrolyzer system for three different sizes or operating conditions. AEC's Oak Ridge National Laboratory, for which the electrolyzer work was done, used these data in its studies of a nuclear-industrial complex.

When we examined the derivation of the hydrogen production cost carried out and published by J. Mrochek of ORNL[17] using Allis-Chalmers' capital costs, we found that ORNL had not included provisions for profit, for the cost of borrowed money, or the payment of Federal income taxes, though it had added an arbitrary 9% to Allis-Chalmers' plant cost.

We feel that a more realistic estimate for the hydrogen production cost can be obtained using utility financing, assuming 7% return, and 5% interest on debt (65% debt) with 48% Federal income tax. (Use of 8% rate of return and 8% interest does not significantly increase costs because of tax credits.)

Mrochek[17] used a cost of electric power of 2.5 mills/kWhr. Almost any number for bulk power generation between 1 and 10 mills/kWhr can be justified, depending on the assumptions made. We prefer to express our cost data as made up of two components: a fixed plant cost independent of electric power, to which is added a variable cost proportional to power costs.

Figure III-8 shows our revised value of the hydrogen produced (i.e., the price at which it can be sold at a reasonable profit) as a function of purchased electricity price. The ORNL data are shown as a single point at $0.44/1000 CF at 2.5-mill power. Our data are shown as a line with a slope that represents the electric power cost portion of the hydrogen value, including the 15% inefficiency of the plant assumed by Allis-Chalmers. The line intersects the vertical axis at $0.18/1000 CF ($0.56/million Btu), which is the basic value of the plant itself without running costs.

We then made some further calculations based on different assumptions, illustrated in Figure III-9. The top line on Figure III-9 presents the cost of hydrogen as calculated in Figure III-8 and assumes that the performance of the cell is that demonstrated by Allis-Chalmers in 1966. Another line drawn through the same intercept ($0.56/million Btu) indicates the cost of hydrogen at the theoretical decomposition voltage and the same plant costs. This line indicates the improvement in cost that might be achieved if research could result in an electrochemically perfect electrolysis cell operating without polarization. (This is impossible in practice, but indicates an upper limit.)

Another series of lines in Figure III-9 has an intercept of $0.28/million Btu as the nonelectrical operating cost. To arrive at this, we assumed that the electrolysis plant cost can be halved by development of both the cells and the electrical equipment. The slopes of these two lines correspond to electrical efficiencies of 85%, demonstrated by Allis-Chalmers, and 120%, the theoretical upper limit.

The heavy line in Figure III-9 is simply the heat equivalent of electricity, or 3412 Btu/kWhr. A cell operating at the thermoneutral voltage, which we feel is a reasonable goal, would operate at 100% electrical efficiency and would therefore correspond to a line on Figure III-9 having the same slope as the heavy line, but passing through an intercept corresponding to the nonelectrical part of the plant cost. Such a line is shown in Figure III-10. This, we propose, is a reasonable target for development, requiring a halving of the plant costs assumed by ORNL in 1966 and operation at a performance demonstrated in Allis-Chalmers' laboratory in 1966 under extreme conditions, and by Justi[7] in 1971 under more mild conditions.

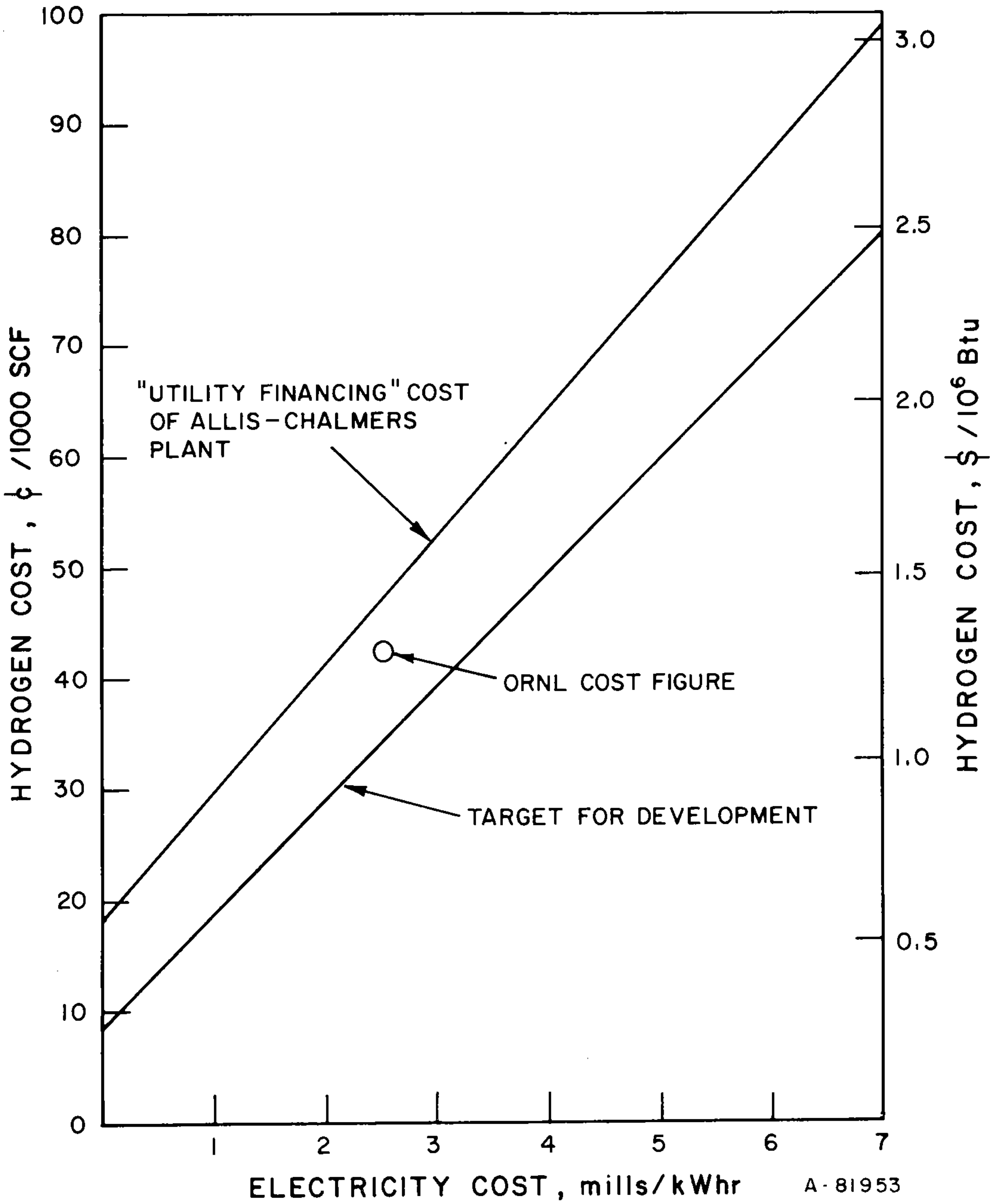

Figure III-8. COST OF HYDROGEN AS A FUNCTION OF PURCHASE PRICE OF ELECTRICITY

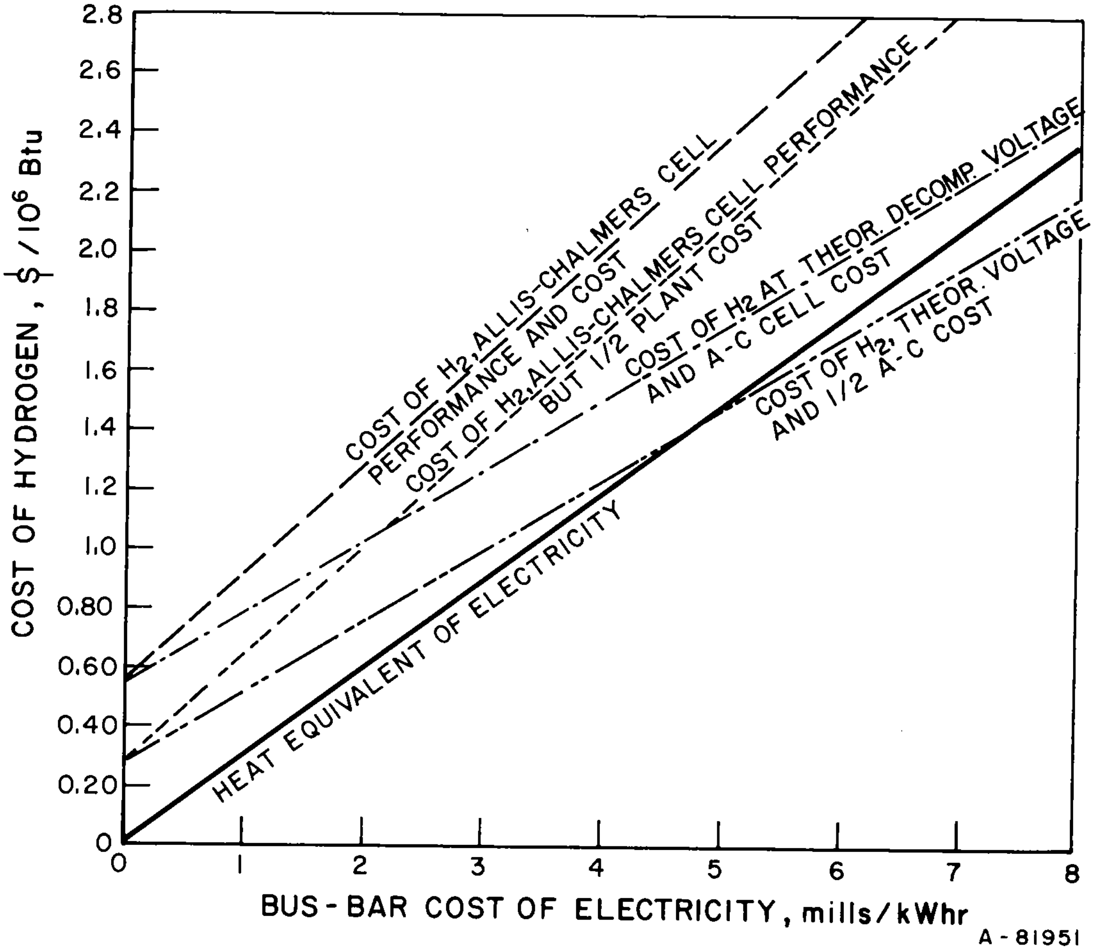

Figure III-9. COST OF HYDROGEN AS A FUNCTION OF ELECTRICITY PRICE, SHOWING THE EFFECT OF VARIOUS CELL EFFICIENCIES

The costs of hydrogen production should range from \$1.50 to \$2.50/ million Btu if these goals can be met and if power is available at a price between 4 and 7 mills/kWhr, which seems reasonable. Decreased costs of hydrogen could be obtained if off-peak electric power is used.*

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* Breakdown of 1970 nuclear power costs indicates that off-peak power cost is only 2.0 mills/kWhr, corresponding to \$0.85/million Btu for hydrogen.

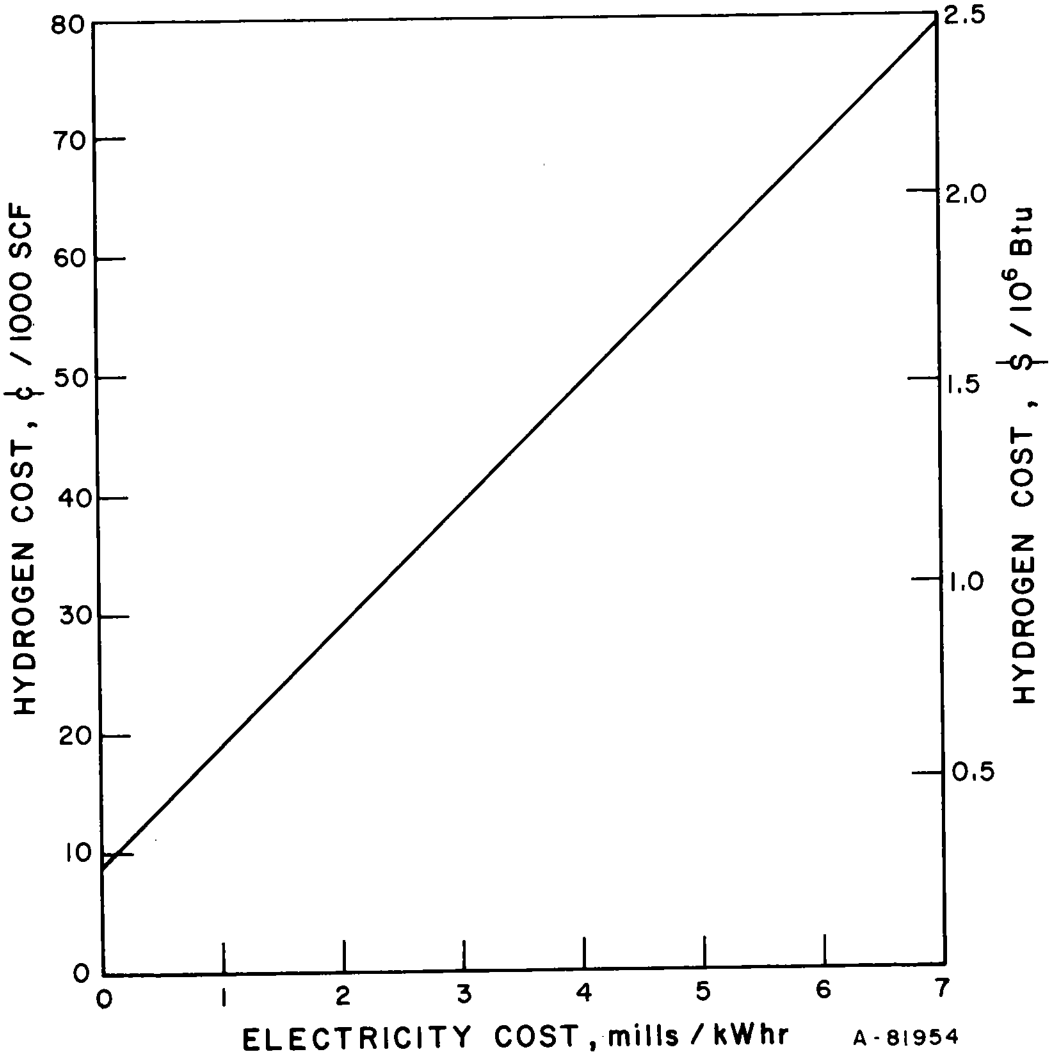

Figure III-10. TARGET FOR DEVELOPMENT OF ELECTROLYZER OPERATING COST

These figures do not take into account credits that may be obtained from the sale of oxygen or heavy water, both of which would be produced as by-products. However, the quantities of oxygen and heavy water that will be produced will be large compared to the estimated market; thus a value cannot be readily placed upon these materials. Conceivably, these credits could reduce the price of manufactured hydrogen by about 25¢/million Btu.

The above discussion illustrates that electrolytically manufactured hydrogen must carry a price tag that is similar, on a Btu basis, to its chief utility competition, which is in the form of electricity. The benefits of hydrogen will be regained when transmission and distribution costs are considered. Although the hydrogen will be produced from water, the cost of water makeup is expected to add little to the overall cost.

High-purity water is desired so that poisons do not build up within the electrodes, increasing the cell voltage and forcing premature cell failure. Boiler feedwater quality is recommended.

For the hypothetical 1.25 million SCF/hr plant (10 billion Btu/day), the theoretical water requirement is 125 gpm. In addition to the water that is decomposed into hydrogen, some water vapor is lost as humidity in the exiting gases; therefore, the water requirement for a practical installation of this size is about 140 gpm. This compares to approximately 25 gpm of boiler feedwater which would be required for the power station that would generate enough electricity for these cells, and this power plant will also require a makeup of 3500 gpm of high-quality cooling water to offset the losses in the cooling towers on the recirculating coolant water circuit.

If the electrolyzer makeup water cost is assumed at 50¢/1000 gallons, the cost of the water adds 1¢/million Btu of hydrogen heating value.

To put the estimated costs derived in this report into perspective, we compared the capital costs assumed for the Allis-Chalmers system with some capital costs for other installations and electrolyzers.

The capital costs of electrolytic hydrogen installations used in our overall cost estimates were extracted from the open literature by R. E. Blanco[2] for the Oak Ridge nuplex studies on ammonia manufacture. Figure III-11 was drawn from the results of these studies, with additional data added.

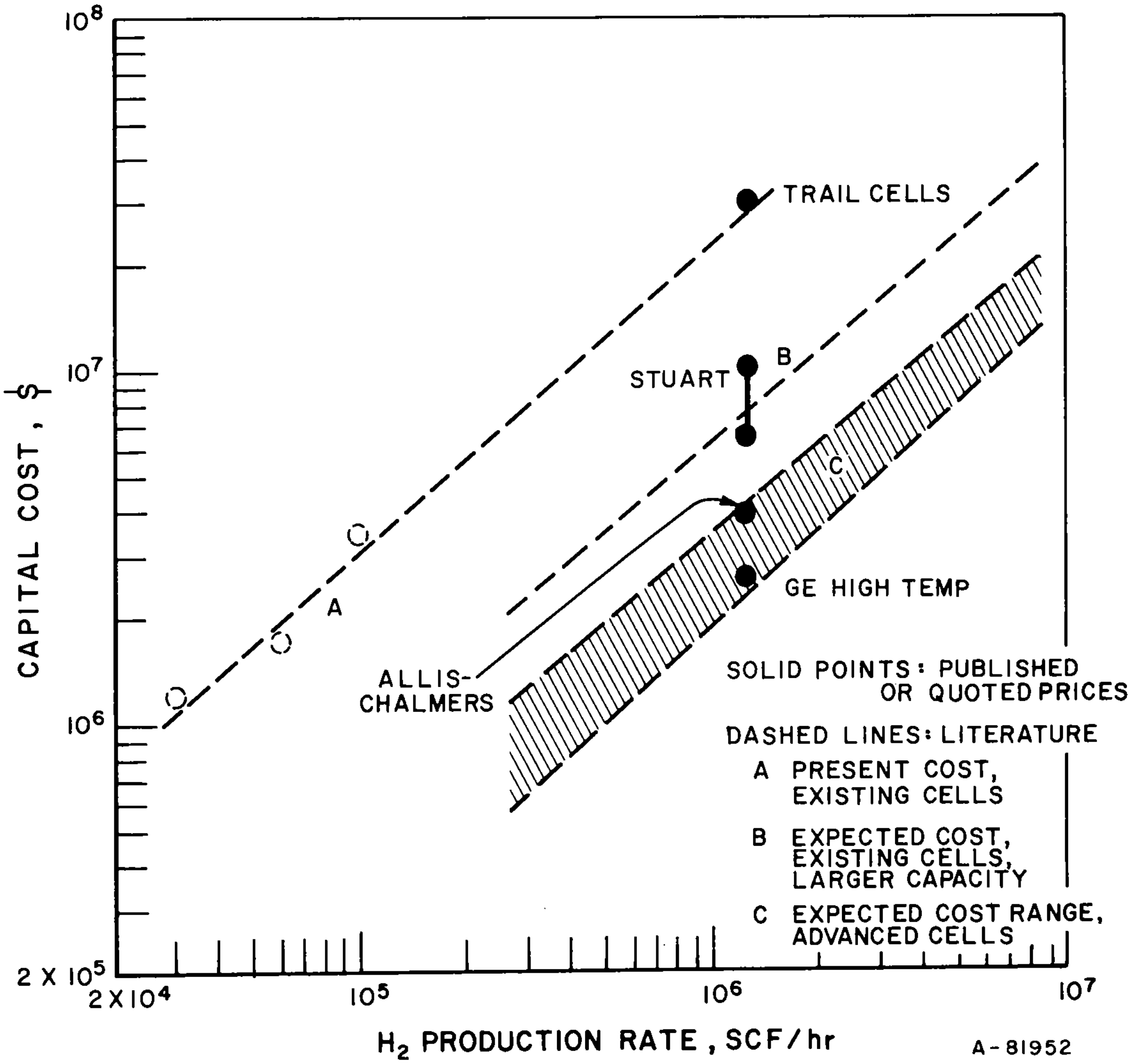

Figure III-11. CAPITAL COSTS OF ELECTROLYTIC HYDROGEN INSTALLATIONS

Line A on this graph presents the costs of known installations. Blanco's references were checked, and the data points for line A are from these sources. Line A stops at a hydrogen capacity of about 200,000 CF/hr because this is the limit of present electrolytic hydrogen plants in this country.

Line B is Blanco's estimate of the capital cost requirement for the electrolyzers in larger installations. This line is based upon driving the cells at higher current densities because he assumed low-cost nuclear energy would be available.

The operating range C was predicted for advanced cells based upon cost estimates derived from the Allis-Chalmers electrolyzer and the GE high-temperature cell.

We asked some established electrolyzer manufacturers to estimate the plant costs for a hypothetical 10 billion Btu/day operation. These costs are shown as points in Figure III-11. The licensed manufacturer of the Trail cells quoted a price for multiple standard units of $30 million. This cost falls on a direct extrapolation of the data for existing smaller installations.

As already explained in Section III-B5, cost estimates have not been received for the Lurgi high-pressure cell or the De Nora high-efficiency cell.

The exhaustive cost information prepared by Allis-Chalmers was interpolated to the 1.25 million SCF/hr (10 billion Btu/day) production rate to yield that data point, as were the GE data. As the report was based upon these data, they were expected to fall within the range for advanced cells.

The data in Figure III-11 are for the installed cost of the electrolyzer section of the electrolysis plant. The ac-to-dc conversion equipment and switchgear are not included, nor is the electrical generation facility. Based upon data in the Allis-Chalmers report, the power handling equipment for this plant should cost about $4.5 million, based on 1966 technology. With improvements in d-c switchgear and the possibility of direct-current generation, this cost should be reduced.

9. Potential for Advances in Electrolyzer Technology

In deriving the cost goals shown in Figure III-10, we made some optimistic assumptions that the cost of the electrolyzer cells and the electrical equipment could be halved from the figures used by Allis-Chalmers. We also assumed that the cells' "electrical" efficiency would be 100%. These assumptions are justified below.

A halving of the capital cost of the cells is achieved by a doubling in current density, effectively doubling the hydrogen production rate for a given cell. By analogy with the advances made in fuel cell development during the time when this technology was receiving major R&D funding, we think this is a reasonable expectation. For example, fuel cells operating with aqueous alkaline electrolytes in the laboratory in the last 1950's were scarcely able to achieve 100 mA/sq cm at reasonable voltages. During the mid-1960's, Allis-Chalmers had developed electrodes and cell separators that allowed current densities of 400 mA/sq cm to be achieved regularly. Some of the latest space-type cells at Pratt & Whitney Aircraft are capable of operating at over 1000 mA/sq cm. In view of this, we feel that assuming a doubling of the 1966 Allis-Chalmers electrolyzer current density is reasonably safe.

A halving of the cost of electrical equipment is assumed because of two developments that have occurred since the 1966 Allis-Chalmers study.[1] It assumed rectification of 20-kV a-c current, and assumed a price for this equipment of $20/kW. Advances in d-c switchgear associated with the introduction of bulk power d-c transmission lines are tending to reduce costs, although reduction in rectifier costs below this figure are hard to visualize. However, significant development efforts are going on in acyclic generators, otherwise known as homopolar generators, which produce low-voltage direct current at very high currents. The following is an extract from a letter received from the Product Planning Department of General Electric Co., December 15, 1971:

> The high-speed acyclic generator with liquid-metal collector has been developed by General Electric Company as a practical new tool in generating high-current, low-voltage d-c power in large capacity. Four large units have been in service at the Arnold Engineering Development Center, Tullahoma, Tenn., for over 10 years. These supply a pulse of over a half-million amperes per generator. A much smaller unit is installed at Argonne National Laboratory, Chicago, capable of about 20,000 amperes at 5 volts continuous. The acyclic generator is limited on available rating variations. The optimum speed, voltage, and ampere ratings are held in fixed relationship. This limitation has been the major barrier to date in industrial application of the acyclic generator. The economic evaluation frequently becomes unfavorable when the application requirement does not match the acyclic generator capability.

The acyclic generator could be utilized with single-unit capability over the range of ratings as indicated below. (Other ratings are possible – these are considered optimum):

Rated rpm	3600	down to	1800
Power	10-30 MW	up to	100 MW
Amperes	100-150 kA	up to	250 kA
Volts	100-200	up to	400
$/kW*	$18-$9	down to	$7
Total Weight (lb)	30,000-52,000	up to	210,000

* Price projections for mature product. Additional required development cost estimated at $1 million over 3-4 years.

It is, of course, possible to connect multiple units in tandem from one prime mover and thereby increase the flexibility of choice of rated speed, voltage, and amperes. The space and weight factors would, of course, be different.

Costs of the generator, both alternating and direct current, and the converter apparatus (for the a-c systems) were also provided in communications from General Electric:

Plant Size	Up to 50 MW $/kW	100 MW $/kW
a-c Generator	10	10
a-c—d-c Converter	60 30	30-50 25 (later information)
d-c Acyclic Generator	9	7

As this table shows, the cost of a-c generators plus converters is $35-$40/kW, whereas the d-c acyclic generator costs $7-$9/kW, for a saving of $28-$31/kW. This is deemed significant when compared with the estimate of $40/kW for the entire electrolyzer at the 1000-MW size* implied in the Phase 1 Report (page 39). Thus the potential for the acyclic generator appears quite interesting for this application.

In conclusion –

- The acyclic generator offers significant cost advantages over the a-c conversion approach in capital equipment costs of about $30/kW differential. This does not include any research and developments costs for the acyclic generator; little if any is assumed to be needed for the a-c converter approach.

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* Electrolyzers, being "modular buildups," seem to be fairly flat in cost with power level.

- The rectifier costs projected in the Phase 1 report of \$10-\$15/kW appear optimistic by comparison with GE's best numbers of \$25-\$30/kW.
- A saving of \$30/kW in the power supply, or power station cost, by the use of a d-c generator should be compared with the earlier estimated cost of the electrolyzer plant of about \$40/kW input. It thus appears that the capital costs of a nuclear power station providing hydrogen as a product and one providing conventional a-c power as a product are comparable, and certainly closer than the 10% difference noted in the previous section.

This new information on the acyclic generator makes it apparent that the halving of the electrical cost is indeed a realistic and not an optimistic assumption. The assumption that the "electrical efficiency" of the cell can be increased from the present 60% or so to 100% is justified on the basis of information from the literature on advanced cells operating with highly developed electrodes.

The GE ion-exchange membrane cell, operating on the laboratory bench at the Air Force Propulsion Laboratory, uses a voltage of 1.62 volts corresponding to a 90% "electrical" efficiency. This cell contains platinum catalysts, which cannot be considered for our application. Justis' cell, in a recent publication,[7] achieved 100 mA/sq cm at a voltage of only 1.57 volts at 60°C without the use of platinum. This corresponds to an electrical efficiency of 94%. At current densities below 30 mA/sq cm, his cell operates at voltages below the 1.4-volt potential corresponding to efficiencies greater than 100%.

We believe that it will be possible to achieve 100% or greater efficiencies on more highly developed cell systems by operating them at temperatures higher than are conventionally used. Figure III-12 shows the Allis-Chalmers 1966 cell data plotted on a voltage-temperature chart. The thermoneutral potential corresponds to an electrical efficiency of 100%. At a 400 mA/sq cm current density, with "noncatalyzed" (i.e., nickel) electrodes, 100% efficiency was achieved between 300°and 400°F. The "Bacon" cell, operating at about 500°F using only nickel as a catalyst, was able (Figure III-4) to achieve greater than 100% efficiency (less than 1.47 volts) at current densities up to 200 mA/sq cm.

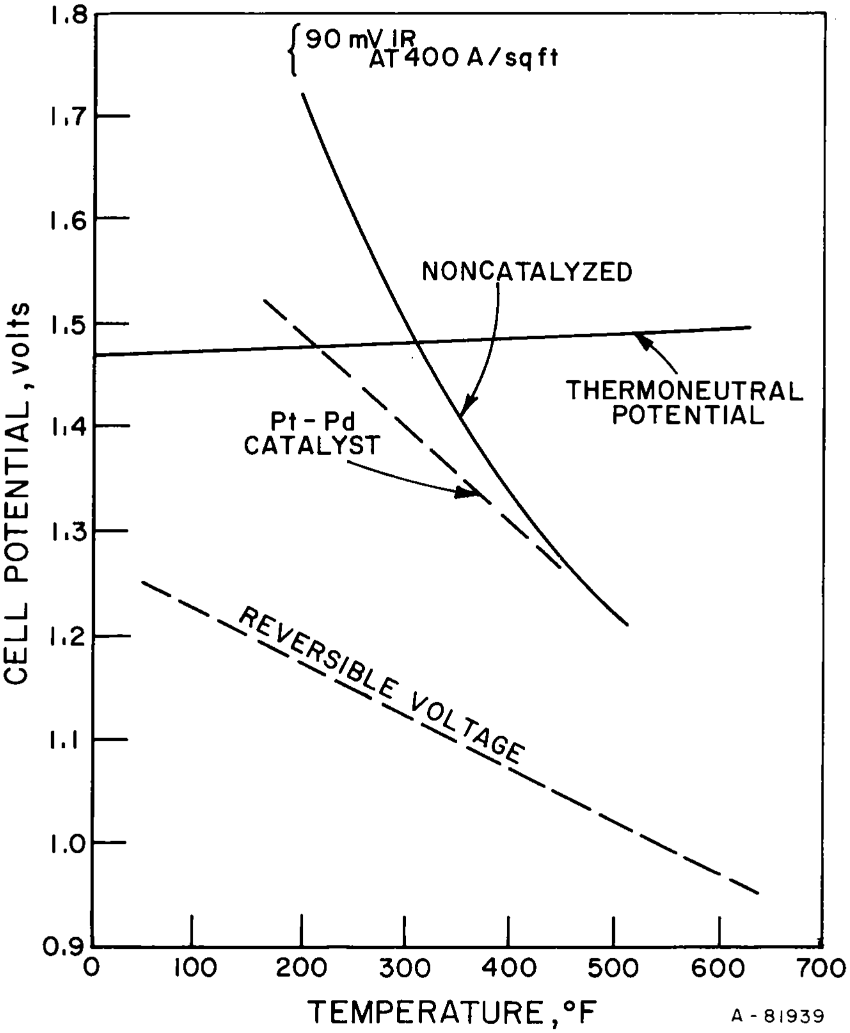

Figure III-12. PERFORMANCE OF ALLIS-CHALMERS ELECTROLYZER CELL AT 400 A/sq ft WITH IR DROP ELIMINATED

Therefore, several different cell types have demonstrated the ability to operate without precious metals at 100% or greater electrical efficiencies. No information is available on cell life under the extreme temperature conditions, or with the highly active forms of nickel and silver catalysts used. Much R&D is undoubtedly necessary, but the goals appear to be realistic.

C. Thermal Water-Splitting for Hydrogen Production

1. Introduction

An alternative to the electrolytic method of generating hydrogen from nuclear energy exists. In principle, water may be split into its components, hydrogen and oxygen, by heating it to a sufficiently high temperature and separating the constituents before they have had a chance to recombine. This process has been termed "thermal water-splitting."

The theoretical efficiency of splitting water depends on the temperature at which heat is supplied and rejected, and is the same as that of electricity generation followed by electrolysis. However, the practical efficiencies obtained by the electrical production of hydrogen are far lower than theoretical. Thus, it may be feasible to develop a thermal water-splitting process with a higher practical efficiency and a lower equipment cost than the electrical process.

The concept of thermal water-splitting is not new. It was investigated by Funk and Reinstrom[10, 11] as part of the "energy depot" study carried out in the 1960's by Allison Division of General Motors Corporation. Since that time, Marchetti[4, 5, 15] and others at the Euratom Laboratories in Italy have discussed the concept and have carried out experimental work on a system intended to achieve practical hydrogen production.

Water splits to form hydrogen and oxygen if it is heated to a temperature in the region of 4000°C. Such a temperature is not available from conventional nuclear power reactors, which are currently limited by their materials of construction to maximum temperatures of 540°-700°C (1000°-1300°F). Even if the constraints of finding materials compatible with a steam-raising function are removed, it is unrealistic to believe that sufficiently high temperatures for direct water-splitting will ever be achieved. At conventional nuclear reactor temperatures, about 1% of the water would be dissociated, but the hydrogen thus formed is so dilute and at such a low pressure that recovery becomes economically impossible.

Funk and Reinstrom[10] considered the use of multistep processes in which water reacts with another material, for example, a metal, to produce hydrogen and a metal oxide. Subsequent thermal decomposition of the oxide would recycle the metal for repeated use. This technique has been termed "thermochemical water splitting." They were, however, unable to find any suitable two-stage reactions that would occur at temperatures within reach of nuclear reactors. They went on to consider three-, four-, and five-step processes that were theoretically feasible, but they were pessimistic about the processes' ultimate efficiencies. In contrast, Marchetti[5] is far more optimistic about the overall efficiency of his four-step process, anticipating practical efficiencies of about 50% from a cycle that can be, theoretically, about 85% efficient.

We made an analysis of a variety of methods for producing hydrogen without using electricity or using significantly decreased quantities of electricity. Several of these offer the promise of producing low-cost hydrogen whereas others lack technical or economic feasibility. Specific conclusions, made in September 1971, were —

- A purely thermal process for splitting water to produce H_2 and oxygen would require temperatures in excess of 3500°F, clearly above the range feasible with thermal fission reactors or with modern chemical engineering technology. Furthermore, thermodynamic constraints make it highly improbable that a simple two-step process such as —

$$H_2O + X \rightarrow XO + H_2$$

$$XO \rightarrow X + {}^1/_2O_2$$

or

$$H_2O + Y \rightarrow YH_2 + {}^1/_2O_2$$

$$YH_2 \rightarrow Y + H_2$$

can be feasible. It is theoretically possible, however, to split water in multistep processes.

- At least three such processes have been proposed in the literature: In these processes water could be split to H_2 and O_2 by nonelectrolytic means. All three appear to be technically feasible, but it is too early to assess their potential economic feasibility.

    a. The Marchetti Process[4, 5, 15] (Euratom) is a purely thermal four-step process, utilizing fission heat and based on the splitting of HBr produced by the hydrolysis of $CaBr_2$. All steps in the sequence can be carried out at temperatures at or below 730°C (1350°F). A preliminary analysis indicates that technically feasible processes for all reactions should be possible with current chemical engineering technology. The reaction sequence is cumbersome, however, and the attainment of an economically feasible process may be difficult. The development of the Marchetti "Mark I" Process is currently being pursued at Euratom. Marchetti claims that laboratory work to date indicates that an overall efficiency of 50% should be possible.

b. The Von Fredersdorff Process (IGT)[21] is based on the conventional steam-iron-carbon monoxide process with the product CO_2 being split to regenerate the carbon monoxide and produce O_2. The latter step, which has been demonstrated in the laboratory, is carried out at low temperatures (600°F) by the use of ionizing radiation from a chemonuclear reactor. The technical and economic feasibility of the process therefore depends strongly on the development of chemonuclear reactor technology.

c. The Vanadium Chloride Process (Allison Division of General Motors)[11] splits water by the following sequence of reactions:

$$H_2O(g) + Cl_2(g) \rightarrow 2HCl(g) + 1/2O_2(g) \quad 1340^0F$$

$$2HCl(g) + 2VCl_2(s) \rightarrow 2VCl_3(s) + H_2(g) \quad 77^0F$$

$$4VCl_3(s) \rightarrow 2VCl_2(s) + 2VCl_4(g) \quad 1340^0F$$

$$2VCl_4(g) \rightarrow 2VCl_3(s) + Cl_2(g) \quad 77^0F$$

Theoretical calculations by Funk[9] indicate that an overall energy efficiency of only 18% would be obtainable. This is less than the 21-25% obtainable by current, feasible fossil fuel electric generation and electrolysis technology.

Our exploratory analysis has suggested other potentially feasible processes that could split water by either nonelectrolytic methods or by electrolysis with substantially reduced electric power requirements.

a. More than one process can be conceived based on the reverse Deacon Process:

$$H_2O(g) + Cl_2(g) \rightarrow 2HCl(g) + 1/2O_2(g)$$

The HCl produced can then be further split to $H_2 + Cl_2$. Several possibilities are —

1) Electrolysis of HCl at a reduced electric power cost

2) Either a thermal or a hybrid thermal-electrolytic process based on —

$$2HCl(g) + 2CuCl(s) \rightarrow 2CuCl_2(s) + H_2(g)$$

$$2CuCl_2(s) \rightarrow 2CuCl(s) + Cl_2(g)$$

3) Similar processes based on variable-valence elements other than copper and vanadium, for which the valence state of the metal halide can be controlled by manipulating the kinetic variables or by the use of suitable ligands or coreactants. This area is largely unexplored at present.

The electrolysis of HCl is of proved feasibility and has been used on a small commercial scale. The other reaction sequences have been demonstrated only on a laboratory scale, but appear to have a potential as great as that of the Marchetti Process.

b. Literature data[16] suggest that a process similar to the Von Fredersdorff Process[21] and based on ultraviolet or electric discharge radiations should be possible. If so, the need for the development of chemonuclear technology could be circumvented. More data from either the literature or the laboratory would be required to assess the potential of such a process.

- The future development of the fusion reactor technology would greatly enhance the possibility of the chemonuclear-type processes because most of the energy from such reactors is produced in a form usable for radiation chemistry.
- The empirical exploration of other possible water-splitting processes reported here is based on a brief study. We feel that further exploratory work in this area would be very rewarding.

On the basis of these conclusions, drawn in September 1971, an experimental project was commenced at IGT, under A. G. A. sponsorship, in January 1972. This project ran concurrently with the final stages of the study reported here, so progress during the first few months of 1972 on the experimental project is not included in this report. The reader is referred to the progress reports of A. G. A. Project IU-4-14.

2. Thermodynamic Limitations

Using electrolysis as a reference process, Funk and Reinstrom[10, 11] (Allison Division, General Motors Corporation) have analyzed from a thermodynamic point of view, the problem of the energy requirements for producing H_2 from water. For any process that is reversible and operated at constant temperature and pressure, the work (W) and heat requirements (q) for each gram-mole of H_2O decomposed are —

$$W = \Delta F$$
$$q = T \Delta S$$

where ΔF and ΔS are the Gibbs free energy change and the entropy change per gram-mole of H_2O. For the reaction

$$H_2O\ (g) \rightarrow H_2\ (g) + {}^1/_2\, O_2\ (g)$$

at 25°C and 1 atm, these requirements are —

$$W = \Delta F = 54.64 \text{ kcal/g-mole}$$

$$q = T \Delta S = 298\ (10.6) = 3.16 \text{ kcal/g-mole}$$

$$W + q = \Delta H = 57.80 \text{ kcal/g-mole}$$

Thus, for electrolysis at room temperature, most of the energy for water-splitting must come from useful work (i.e., electric power). The only way to decrease the amount of electric power required is to increase temperature (i.e., $T \Delta S$). Electric power requirements can thus be reduced by electrolyzing at elevated temperature. However, to reduce the electric power requirements to zero would require a temperature above 4000°C.

On the other hand, Funk and Reinstrom's[10, 11] analysis indicates that it should be possible, at least in theory, to develop multistep processes for which the power requirements are essentially reduced to zero at a technically feasible temperature (i.e., 2000°F). For the simplest case of a two-step process two possibilities exist:

<u>Oxide Reactions</u>

$$H_2O + X \rightarrow XO + H_2$$
$$XO \rightarrow X + {}^1/_2\,O_2$$

<u>Hydride Reactions</u>

$$H_2O + X \rightarrow XH_2 + {}^1/_2\,O_2$$
$$XH_2 \rightarrow X + H_2$$

The specifications for the relationship between compound X and its oxide or hydride required for the two-step process to be feasible at temperatures no higher than 2000°F (1100°C) were then defined in terms of free energy change at 25°C and the absolute entropy. On this basis, Funk and Reinstrom made a systematic search of the elements and their monoxides and hydrides. They concluded that: "No compounds which would yield an efficient two-step process were found. Furthermore, based on semi-empirical correlations, it appears unlikely that a compound exists, or can be synthesized, which will yield a two-step chemical process superior to water electrolysis. The general question of the existence of any process having a higher thermal energy efficiency than water electrolysis still remains, but the possibility appears to be remote." If such a conclusion is valid, the development of nonelectrolytic water-splitting would require either going to a temperature higher than 1100°C (2000°F) or to a process employing three or more steps. The further possibility always exists that, in spite of poor thermodynamic equilibria, some reactions may be found that can be carried out efficiently by a) kinetically displacing the equilibrium by continuous separation of one of the products or b) quenching.

3. Published Processes — 1972

a. Marchetti (Euratom)

Marchetti and his colleagues at Euratom[4, 5, 15] have proposed two multistep processes that are theoretically feasible. Although they do not discuss at length the theoretical constraints on the development of such a process, their proposals illustrate the potential for meeting practical temperature limitations by the use of multistep processes.

With the following four-step process (Mark 1), the splitting of water to hydrogen and oxygen is theoretically feasible with a maximum temperature of 730°C (1350°F):

1. $CaBr_2(s) + 2H_2O(g) \rightarrow Ca(OH)_2(s) + 2HBr(g)$
   T = 730°C
   P = 50 atm

2. $2HBr(aq) + Hg(l) \rightarrow HgBr_2(aq) + H_2(q)$
   T = 250°C (480°F)
   P = 25 atm

3. $HgBr_2(aq) + Ca(OH)_2(aq) \rightarrow CaBr_2(aq) + H_2O(l) + HgO(s)$
   T = 200°C (390°F)
   P = 10 atm

4. $HgO(s) \rightarrow Hg(s) + {}^1/{}_2O_2(g)$
   T = 600°C (1110°F)
   P = 10 atm

The sum of these reactions is —

$$H_2O \rightarrow H_2 + {}^1/{}^2\,O_2$$

The technical feasibility of developing a process based on this reaction sequence is currently being investigated by Euratom on laboratory and engineering calculation levels.

A second process scheme proposed by Marchetti[4, 5, 15] achieves a simpler reaction sequence by increasing the maximum temperature limitations to 1400°C (2550°F):

1. $C(s) + H_2O(g) \rightarrow Co(g) + H_2(g)$
   T = 700°C (1300°F)

2. $CO(g) + 2Fe_3O_4(s) \rightarrow C(s) + 3Fe_2O_3(s)$
   T = 250°C (480°F)

3. $3Fe_2O_3(s) \rightarrow 2Fe_3O_4(s) + 1/2O_2(g)$
   T = 1400°C (2550°F)

This process, although thermodynamically feasible, is apparently not being pursued currently because of the high temperature required.

Marchetti[15] has sent us a very preliminary report of progress through December 1970 which we have reviewed, and he and his co-worker, De Beni, visited us at IGT in April 1972. Laboratory work to define the kinetics and thermodynamics of each of the reactions is far from complete. As engineering design is still in the conceptual stage, the studies on the optimization of process variables have not yet begun. Marchetti has a team of 25 people on this project, which has been in progress for 4 years.

A schematic flow diagram of the overall process is reproduced from that report as Figure III-13. The four principal reactions involved correspond to units 10, 20, 30, and 40. The material flows are expressed as moles per mole of H_2 produced. Marchetti's description of the process follows:

> Calcium bromide and water vapour react in [Unit] 10, producing calcium hydroxide and hydrobromic acid with excess steam. Hydrobromic acid is concentrated by distillation..., and then fed into 20 where it reacts with mercury.
>
> After the reaction we have a mixture of hydrobromic acid, water, mercury, mercurous bromide, mercuric bromide and hydrogen. The gases are separated from the liquid and washed to produce pure hydrogen. Mercury and mercurous bromide

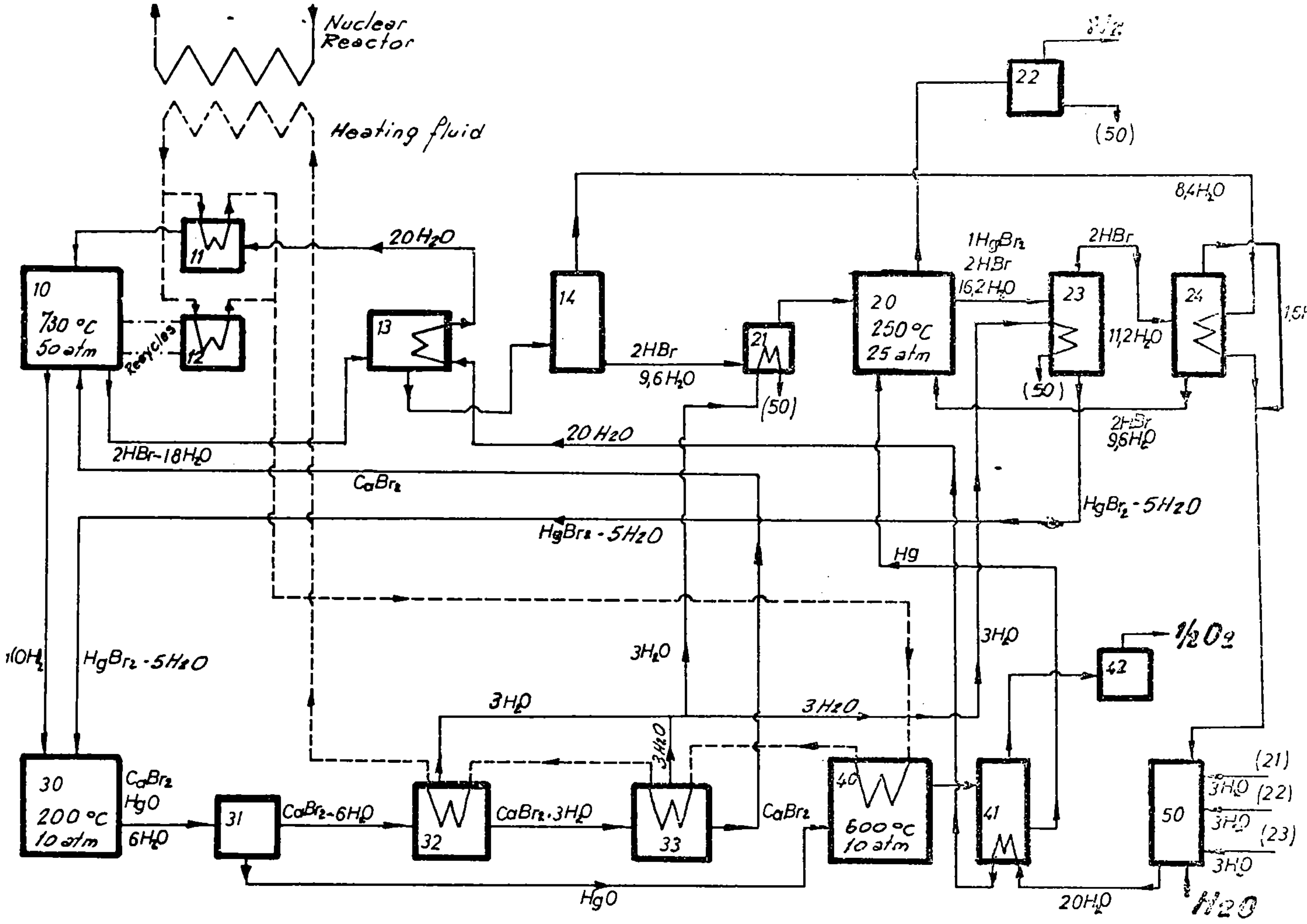

Figure III-13. SCHEMATIC DIAGRAM OF OVERALL EURATOM WATER-SPLITTING PROCESS

> are fed back into 20; the remaining solution is stripped to separate most of the hydrobromic acid which is sent to the concentration column 24. The solution of mercuric bromide is fed into 30 together with the calcium hydroxide coming from 10.
>
> After this reaction we have a solution of calcium bromide which is easily separated from the mercuric oxide precipitate.
>
> This solution of calcium bromide is concentrated before going to the reaction 10. Mercuric oxide is fed into 40, where it is thermally dissociated. The mercury produced in this reaction returns to 20 to react with hydrobromic acid.
>
> The cycle is thus completed and the global result is an output of hydrogen and oxygen from an input of water (and heat).

Although it is not possible to critically evaluate the feasibility of the process in its present state of development, certain observations can be made. All unit processes involved should be achievable with current engineering technology. The chemistry also should be adaptable to conventional engineering techniques.

The question then is whether the metallurgical, kinetic, heat and materials transfer, and safety problems can be solved to achieve an economical process.

This flow diagram (Figure III-13) is still in the conceptual stage as many of the process units have not been defined. As of December 1970, only "three process units have been considered" from the point of view of preliminary design and technological feasibility.[15]

1) Hydrolysis of $CaBr_2$ (Unit 10, Figure III-13)

The report states that: "A simplified model of the reaction chamber has been defined in order to study the handling and the mixing of the reactants (solid-gas or liquid-gas) at high temperature and the separation of the products (solid-gas)." The report does not state what type of reactor is to be used nor what the phase relationships will be.

The problems in reactor design stem basically from the thermodynamics of the reaction and the phase relationships involved.

The reactions involved include —

$$CaBr_2 + 2H_2O \rightarrow Ca(OH)_2 + 2HBr$$

and

$$CaBr_2 + H_2O \rightarrow CaO + 2HBr$$

The first of these is preferred because this reaction, which is already highly endothermic, is 15 kcal/g-mole less than for this second reaction. Since the dehydration of $Ca(OH)_2$ to CaO is thermodynamically favored at the temperatures of interest, the reaction must be carried out at a pressure of about 750 psi.

The equilibrium conversions for the hydrolysis are strongly temperature-dependent and become of interest far above the critical point of water. The reaction therefore will be a heterogeneous one involving either gas-solid contact below 760^0C (1400^0F) (melting point of $CaBr_2$) or gas-liquid contact above 760^0C. Marchetti and his associates tentatively elected to operate at 730^0C (1350^0F), just below the melting point.

Thus the reactor design must provide not only for intimate contact between solid and gaseous reactants but also for continuous or semicontinuous separation and transport of the solid $Ca(OH)_2$ product to the regenerating reactor. Because of the intimate gas-solid contact required and the particle transport problem, a fluidized particle reactor would appear to be desirable. However, the operation of a fluidized particle system so close to the melting point may be difficult. Any misoperation will result in an agglomerated, plugged bed. On the other hand, operation at lower temperatures further removed from the melting point of $CaBr_2$ will further dilute the aqueous HBr product, which already requires considerable concentration.

The alternative of working in a liquid-gas system above the melting point of $CaBr_2$, however, would appear to be much less attractive: Molten $CaBr_2$ can be anticipated to present severe corrosion problems and the conversion of $CaBr_2$ to $Ca(OH)_2$ involves a phase change from liquid to solid. To avoid handling such a phase change in the process will require limiting the conversion to maintain liquidity. This in turn will require either separation of the two phases or recycling rather large amounts of $CaBr_2$ to the next reactor. The latter is highly undesirable as it will tend to suppress the next reaction in the scheme:

$$Ca(OH)_2 + HgBr_2 \rightleftarrows CaBr_2 + HgO + H_2O$$

2) Decomposition of HgO (Unit 40, Figure III-13)

Both the thermodynamic equilibrium and the kinetics of the decomposition appear to be adequate at 600°C (1110°F) and 20 atm. Basic process design should present no undue difficulties. The main problems will be concerned with the safety hazards and leak-proofing associated with handling mercury at 600°C.

3) Heat Transfer Units (Several Units, Figure III-13)

Marchetti and his colleagues indicate that, of the several heat transfer units shown in Figure III-13, "some will be critical to the efficiency for the process. A survey has been started on the possibility of using advanced heat transfer units, like fluidized beds and metal boiling heat exchangers."

The only other engineering studies that have been made concern the overall thermal balance for the process, upon which a tentative heat flow sheet has been constructed. The coupling of the process with the thermal fission reactor has also been considered. As they point out: "It is interesting to note that the total heat produced by the nuclear reactor can be utilized in the chemical plant, so that dual purpose plants are not necessary."

Work on the other steps of the process has not progressed beyond the laboratory stage.

4) Reacting Mercury With HBr

Concentrated aqueous HBr reacts with mercury at reasonable rates only at temperatures above 200°C (390°F). Thus, operation must be under a pressure of about 375 psi. Preliminary laboratory data indicate the rates of reaction are highly dependent on the surface area of mercury and the concentration of HBr solution, and only moderately dependent on temperature (activation energy = 14.9 kcal/g-mole).

The HBr concentration is important because of thermodynamic considerations. Although the reaction of gaseous HBr with mercury is exothermic ($\Delta H_{298} = -23.2$ kcal/g-mole), the reaction becomes endothermic when concentrated solutions are used ($\Delta H_{298} = +10$ kcal/g-mole). Furthermore, the endothermicity increases with increasing dilution. Thus, even though the hydrogen is removed continuously, the rate appears to be limited by the equilibrium, at least under 10 atmospheres H_2 pressure. The process consequence of this will be that considerable volumes of dilute HBr must be recycled to the distillation unit.

The principal problem in process design will be to provide adequate mercury surface area for contact.

5) Overall Process Evaluation

Although a determination of the overall efficiency or economic feasibility of this process on the basis of the data published to date is not possible, in his last communication[5] Marchetti indicated that sufficient progress has been made so that thermal efficiencies of about 50% should be attainable; that is, the heat consumed in the processing is only 50% of the net heating value of the H_2 produced.

b. Von Fredersdorff (IGT)

Another conceptual, multistep process for splitting water without electrolysis was proposed by C. G. Von Fredersdorff of the Institute of Gas Technology in 1959.[21] The overall process scheme involves the following simplified reaction scheme:

Steam-Iron Process

$$\begin{array}{c} Fe(s) + H_2O(g) \rightarrow FeO(s) + H_2(g) \\ 3FeO(s) + H_2O(g) \rightarrow Fe_3O_4(s) + H_2(g) \\ Fe_3O_4(s) + CO(g) \rightarrow 3FeO(s) + CO_2(g) \\ FeO(s) + CO(g) \rightarrow Fe(s) + CO_2(g) \\ \hline 2H_2O + 2CO \rightarrow 2H_2 + 2CO_2 \end{array}$$

Chemonuclear Reactor

$$2CO_2(g) \rightarrow 2CO(g) + O_2(g)$$

Oxygen Separation

$$\begin{array}{c} 2Hg(l) + 2CO(g) + O_2(g) \rightarrow 2CO(g) + 2HgO(s) \\ 2HgO(s) \rightarrow 2Hg(g) + O_2(g) \end{array}$$

The heart of the scheme, of course, is the production of H_2 by the steam-iron process, a process of proved feasibility. Instead of being vented to the atmosphere, the by-product CO_2 is decomposed to CO and O_2 in a chemonuclear reactor at 600^0F. Oxygen in the effluent from the chemonuclear reactor is separated by reaction with elemental mercury to form mercuric oxide. Recovery of oxygen is then accomplished by thermal decomposition of the HgO:

$$HgO(s) \rightarrow Hg(g) + 1/2 O_2(g)$$

The process scheme must also provide for the recovery and removal of minor quantities of radioactive gases from the decomposed CO_2 stream. After the removal of oxygen and radioactive gases, a portion of the CO_2 decomposition stream, comprising mostly CO, is recycled to the reducing section of the steam-iron process.

As indicated above, the feasibility of the steam-iron process portion of the overall scheme has already been proved. Furthermore, although oxygen separation and recovery with mercury has never been commercially developed, current chemical engineering technology indicates that such a process is feasible. The critical part of the process is the CO_2 decomposition in the chemonuclear reactor.

The proposed process does, however, call for decomposition of CO_2 under conditions that are highly unfavorable thermodynamically. Nevertheless, the proposal is based on an actual laboratory demonstration by Harteck and Dondes of decomposition under these conditions.[12]

The unfavorable thermodynamic equilibrium is circumvented by the ingenious use of nitrogen oxides as inhibitors for the back reaction. There is ample evidence that the reaction —

$$CO_2 \rightleftarrows CO + 1/2 O_2$$

can occur at low temperatures under the influence of various ionizing radiations, electric discharges, or ultraviolet radiation. But, as the reaction is reversible, little net reaction tends to occur under ordinary conditions. Harteck and Dondes[12] found that the reoxidation of carbon monoxide to carbon dioxide during irradiation was a considerably more complex process than generally assumed. The mechanism involved carbon atoms and carbon suboxides. Furthermore, they showed that the process could be inhibited by the addition of nitrogen dioxide.

The eventual commercial feasibility of such a process cannot be assessed at this time. The laboratory data suggest that adequate conversions per pass will be achievable. The major obstacles to the development of the process will be the development of the chemonuclear reactor itself.

Juppe[13] has described some of the technical problems facing the development of chemonuclear reactors. Most of the available energy of the fission process (84%) is released in the form of the kinetic energy of the fission particles. In the conventional thermal fission reactor this kinetic energy is converted directly to thermal energy by interaction with the material of the reactor. Only 8% of the total energy is of a kind that can penetrate the reactor and be made available for radiation chemical purposes.

In a chemonuclear reactor, the conversion of the kinetic energy of the fission fragments must be prevented so that it can be used at least partially for promoting a suitable chemical reaction. Since the average fission fragment's track length is only 2-2.5 cm (about 1 inch) in gases (only 5-25 microns in liquids), very close contact between a large surface area of the nuclear fuel and the reacting chemical system will be required. Thus, the fuel must be provided in a high-surface-area form such as extremely thin foils, probably of honeycomb structure for mechanical strength. U^{235}-impregnated glass fiber systems have been used, but tend to powder because of flexing, thus providing the possibility of a severe nuclear hazard. Another problem is the spallation effect: A fission fragment passing through the fuel tends to eject fuel atoms from the matrix. This results not only in the loss of fuel and the attendant increase in radioactivity of the product but also in the mechanical disintegration of the fuel element. The latter effect would be especially severe with the thin foil arrays.

A second technical problem is the decontamination. Although modern technology can provide effective methods for decontamination, the cost may be high.

The third and probably the major obstacle facing the development of commercial chemonuclear reactors is economics. The capital costs of both the reactor itself and its decontamination equipment are high. In addition, the radiation chemical yields will be an important economic factor. According to Juppe[13] "... the radiation chemical yields observed up to now for fissiochemical syntheses are not yet sufficient to make these processes competitive with conventional processes."

Yields are expressed in terms of G-values, i.e., the number of molecules formed per 100 electron volts of radiation energy absorbed. A high G-value indicates that little radiation energy is required to produce a lot of product. Harteck and Dondes[12] obtained G-values as high as 8.5 for the CO_2 decomposition. If we assume a G-value of 10 and if the energy deposition efficiency of 50% could be achieved, a 2-MW chemonuclear reactor would be capable of decomposing about 10 tons of CO_2 per day. This is roughly equivalent to 350,000 SCF of H_2 produced. This is obviously not currently competitive with electrolysis. (A 2-MW thermal fission reactor should produce about 620,000 SCF of H_2 by electrolysis.)

However, the theoretical maximum G-value for the CO_2 decomposition is considerably higher than 10. (G_{max} equals 48 for gamma radiation and may be higher for fission fragment energy.) Therefore, it may be possible to vastly improve the radiation yields and thus the economics of the chemonuclear process.

Further development of the Von Fredersdorff Process consequently depends on the further development of chemonuclear reactor technology and radiation chemistry.

4. Other Process Concepts

We have approached the development of a new thermochemical process through an empirical technique. In the first place we have listed all the obvious types of elements or compounds that might be used to split water. We then studied the thermodynamic feasibility of the splitting reaction as well as the feasibility of regenerating the splitting agent and producing either H_2 or O_2 in a second step. Secondly, we have tried a) to list the product compounds from which the potential splitting agent can be regenerated by thermal decomposition and b) to visualize reaction sequences that will produce these compounds. In this way, we get a direct empirical evaluation of the negative conclusion arrived at by Funk and Reinstrom.[10, 11] In addition, however, the intimate knowledge developed of the thermodynamics and properties of the products of the splitting reaction sets the stage for visualizing multistep processes that are potentially feasible.

In evaluating the thermodynamic feasibility of the splitting and regenerating reactions, thermodynamic data from Bureau of Mines Bulletins Nos. 601[14] and 605[22] were used. These data permitted the rapid estimation of Gibbs' free energy changes ($\Delta F_T o$) for the reactions at 298.1°K and at 1000°K (1000°K = 727°C = 1340°F), which was used as the upper limit because data at that temperature are available for most chemicals of interest and because it is close to the upper temperature limit that can be achieved in a thermal fission reactor. Reactions showing free energy changes less than about +10,000 cal/g-mole were considered potentially feasible, although negative free energies are preferred.

Scanning of the periodic table reveals relatively few general (or simple) types of elements or compounds that might be considered as potential reducing or splitting agents for water. The most obvious potential splitting reactions found are as follows:

$$C + 2H_2O \rightarrow CO_2 + 2H_2 \quad (1)$$

$$CO + H_2O \rightarrow CO_2 + H_2 \quad (2)$$

$$C + H_2O \rightarrow CO + H_2 \quad (3)$$

$$M(\text{metal}) + aH_2O \rightarrow MO_a + aH_2 \quad (4)$$

$$MO_a + bH_2O \rightarrow MO_{a+b} + bH_2 \quad (5)$$

$$Cl_2 + H_2O \rightarrow 2HCl + {}^1/{}_2O_2 \quad (6)$$

$$2MCl_a + aH_2O \rightarrow M_2O_a + 2aHCl \quad (7)$$

$$3S + 2H_2O \rightarrow SO_2 + 2H_2S \quad (8)$$

$$MS_a + aH_2O \rightarrow MO_a + aH_2S \quad (9)$$

$$MC_2 + H_2O \rightarrow MO + C_2H_2 \quad (10)$$

$$MN + H_2O \rightarrow MO + NH_3 \quad (11)$$

The potential candidates for Reactions 4 and 5 include all of the metallic and some of the nonmetallic elements and their lower oxides. The only nonmetallic elements included are carbon, sulfur, and the halogens. Other nonmetallic elements (such as group VA: nitrogen, phosphorus, arsenic, antimony, and bismuth, and selenium, tellurium, and polonium in group VIA) were excluded on a cost and availability basis.

In general, our analysis indicates that the conclusions of Funk and Reinstrom[10, 11] are valid if the reactions can go to equilibrium. Those agents capable of splitting water (carbon, carbon monoxide, sulfur, chlorine, many metals, and the lower oxides) produce products which are stable enough so that regeneration is unlikely at temperatures below 1000°K (1340°F). For those reactions that would produce products capable of regenerating the original splitting agent thermally at temperatures less than 1000°K, the splitting reaction itself tends not to be thermodynamically feasible. The latter category includes the reactions involving the following conversions: $Hg \rightleftarrows HgO$; $BaO \rightleftarrows BaO_2$; $CaO \rightleftarrows CaO_2$; $Cr_2O_3 \rightleftarrows 2CrO_3$; $3CoO \rightleftarrows Co_3O_4$; $3PbO \rightleftarrows Pb_3O_4$; $2MnO \rightleftarrows Mn_2O_3$; $Cu_2O \rightleftarrows CuO$; $SO_2 \rightleftarrows SO_3$; $S \rightleftarrows H_2S$; $Br_2 \rightleftarrows 2HBr$; and $I_2 \rightleftarrows 2HI$. Some other compounds, particularly the oxides of some of the transition elements having several higher valent oxides, such as manganese, molybdenum, vanadium, chromium, the rare earths, and the metal sulfides, may have better characteristics.

A two-step process might be possible a) if the temperature differential between the water-splitting and regeneration steps could be increased by increasing the temperature of the regeneration above 1000°K (1340°F) or b) if the water-splitting could be carried out at or near room temperature. For example, the carbon—steam-iron process could work if the decomposition of Fe_2O_3 to Fe_3O_4 could be carried out at 1200°-1400°C (2200°-2550°F) as proposed by Marchetti:

$$C(s) + H_2O(g) \rightarrow CO(g) + H_2(g) \qquad 700^{\circ}C\ (1300^{\circ}F)$$

$$CO(g) + 2Fe_3O_4(s) \rightarrow C(s) + 3Fe_2O_3(s) \qquad 250^{\circ}C\ (480^{\circ}F)$$

$$3Fe_2O_3(s) \rightarrow 2Fe_3O_4(s) + {}^1/_2O_2(g) \qquad 1400^{\circ}C\ (2550^{\circ}F)$$

Several two-step reaction schemes would be thermodynamically feasible if the splitting reaction could be made kinetically feasible at or near room temperature. An example of such schemes is —

$$H_2O(l) + 2MnO(s) \rightarrow H_2(g) + Mn_2O_3(s)$$

$$\Delta F_{298} = +19,570 \quad \text{cal/g-mole}$$

$$Mn_2O_3(s) \rightarrow 2MnO(s) + 1/2O_2(g)$$

$$\Delta F_{1000} = +12,350 \quad \text{cal/g-mole}$$

Although the thermodynamic equilibria is poor for both steps, the reaction could be pushed to completion by continuous separation of the H_2 or O_2 if the kinetics were sufficiently rapid. Speeding up the kinetics might be accomplished by catalysis or the use of ultraviolet or ionizing radiation. However, no such data are currently available.

Another general method of getting around the thermodynamic constraints on the two-step process is to circumvent the thermodynamics by kinetic means. The Von Fredersdorff Process discussed above is an example of this. In that case, CO_2 was decomposed at a temperature where the thermodynamic equilibrium is almost nil by the use of ionizing radiation in the presence of an agent that inhibits the back reaction until stable product molecules are formed and quenched. It might be similarly possible to accomplish the decomposition of metal oxides, such as Fe_2O_3, to oxygen and the lower oxide at low pressures or in the presence of an inhibitor. However, so far no references to such reactions have been found, although our literature coverage in this area is far from complete.

In considering possible multistage processes, no theoretical analytical approach has been devised. Instead, one starts with a splitting reaction of known feasibility and tries to visualize multistep reaction schemes by which the splitting agent can be regenerated, or alternatively, one may start with a product from which O_2 or H_2 can be generated and work backward by visualizing splitting-reaction sequences by which they can be generated. Hopefully, the feedback from evaluation of the feasibility of these schemes will suggest further improvements.

a. Processes Based on the Reverse Deacon Process

Among the most promising approaches are those based on the following water-splitting reaction:

$$H_2O(g) + Cl_2(g) \rightleftharpoons 2HCl(g) + 1/2O_2(g)$$

In this way oxygen is released in the water-splitting step and the problem becomes one of generating hydrogen and regenerating chlorine from HCl. This reaction is the reverse of the well-known commercially developed Deacon Process for producing Cl_2 from HCl. The reaction is completely reversible and the production of HCl and O_2 is highly favored at temperatures between 800° and 1000°K (980°-1340°F). Such a process is definitely technically feasible.[6] It turns out that splitting HCl is easier than splitting water. The free energy of formation of 2HCl is less than that of water at room temperature ($\Delta F_{298} = -45,500$ cal/2 g-mole versus $-56,750$ cal/g-mole for water). Thus the electric power required for the electrolysis of HCl will be less than that required for the electrolysis of water. Furthermore, the saving in power will be greater due to the lower polarization expected at the chlorine electrode compared to an oxygen electrode. The electrolysis of HCl to produce H_2 and Cl_2 has been carried out commercially on a small scale.

The overall reaction scheme then becomes —

$$\begin{array}{c} H_2O(g) + Cl_2(g) \rightarrow 2HCl(g) + {}^1/{}_2O_2(g)\text{: } T = <1000^0K\ (1340^0F) \\ \underline{2HCl(l) \rightarrow H_2(g) + Cl_2(g)\ \text{(Electrolysis): } T = 300^0K\ (80^0F)} \\ H_2O \rightarrow H_2 + {}^1/{}_2O_2 \end{array}$$

A further reduction in power might be accomplished by the following scheme:

$$\begin{array}{c} H_2O(g) + Cl_2(g) \rightarrow 2HCl(g) + 1/2O_2(g)\text{: } T = <1000^0K \\ 2Hg(l) + 2HCl(aq) \rightarrow 2HgCl(aq) + H_2(g)\text{: } T = <600^0K \\ \underline{2HgCl(l) \rightarrow 2Hg(g) + Cl_2(g)\ \text{(Electrolysis): } T = 800^0K\ (980^0F)} \\ H_2O \rightarrow H_2 + {}^1/{}_2O_2 \end{array}$$

The free energy of formation of 2HgCl at 800°K is only −22,700 cal/2 g-mole. Thus the electric power for electrolysis of HgCl would be about half that for HCl.

Although the development of a purely thermal process for splitting HCl may be possible, it will not be as simple as electrolysis. In the first place, the development of a two-step process of the type –

$$HCl + M(\text{metal}) \rightarrow MCl + {}^1/{}_2 H_2$$

$$MCl \rightarrow M + {}^1/{}_2 Cl_2$$

faces the same problems as in the splitting of water: Those metallic elements that react with HCl to release H_2 give metal chlorides which cannot be thermally decomposed below 1000^0K to regenerate the metal. Conversely, the elements (or compounds) which give chlorides that are decomposable to the element and chlorine at temperatures below 1000^0K will not react with HCl. These include carbon, gold, platinum, and rhenium (also NO and SO_2).

On the other hand, it may be possible to devise a feasible system based on the oxidation-reduction couples involving higher and lower valent chlorides of some of the transition elements. Perhaps the closest to feasibility is the following:

$$H_2O(g) + Cl_2(g) \rightarrow 2HCl(g) + 1/2O_2(g)$$

$$2HCl(g) + 2CuCl(s) \rightarrow 2CuCl_2(s) + H_2(g)\text{: } \Delta F_{298} = +8000 \quad \text{cal/g-mole}$$

$$\underline{2CuCl_2(s) \rightarrow 2CuCl(s) + Cl_2(g)\text{: } \Delta F_{800} = +5500 \quad \text{cal/g-mole}}$$

$$H_2O \rightarrow H_2 + {}^1/{}_2 O_2$$

The dissociation pressure of Cl_2 over $CuCl_2$ increases to above 250 mm at the melting point ($498^0C = 930^0F$). Therefore, a viable process for the 3rd step should be possible.

The second reaction in the sequences –

$$HCl + CuCl \rightarrow CuCl_2 + {}^1/{}_2 H_2$$

appears not to have been demonstrated in the laboratory. However, the following reactions have been demonstrated:

$$2CuCl(aq) \rightarrow Cu(s) + CuCl_2(aq) \text{ (in dilute HCl)}$$

$$2HCl(g) + Cu(s) \rightarrow CuCl_2(s) + H_2(g)\text{: } T = 230^0C \; (440^0F)$$

Thus, it should be possible to drive the second reaction to completion, although laboriously, at least by a two-stage process. Furthermore, it seems probable that the addition of a suitable ligand such as ammonia or ethylenediamine, by thermodynamically stabilizing the cupric state, may allow the reaction to proceed in one step as follows:

$$CuCl(aq) + HCl(aq) + 2en(aq) \rightarrow Cu(en)_2Cl_2(aq) + {}^1/{}_2H_2(g)$$

Alternatively, it should also be possible to carry out the second reaction ($CuCl + HCl \rightarrow CuCl_2 + {}^1/{}_2 H_2$) by electrolysis at a substantially reduced electric power cost (ΔF_{298} = +5500 cal/g-mole versus ΔF_{298} = +22,750 cal/g-mole for the electrolysis of HCl). The trade-off, of course, would be the relative cost of electric power compared to capital costs in a complex process.

A similar system based on the ferrous chlorides may also be possible:

$$H_2O(g) + Cl_2(g) \rightarrow 2HCl(g) + {}^1/{}_2O_2(g)$$

$$2HCl(g) + 2FeCl_2(g) \rightarrow 2FeCl_3(g) + H_2(g);\ \Delta F_{1000^0K} = +12,500 \text{ cal/g-mole}$$

$$\underline{2FeCl_3(s) \rightarrow 2FeCl_2(s) + Cl_2:\ \Delta F_{500^0K} = +2300 \text{ cal/g-mole}}$$

$$H_2O \rightarrow H_2 + {}^1/{}_2 O_2$$

Neither of the reactions involving the iron chlorides has particularly good thermodynamic equilibria, but the conversions might be driven to completion by recycling the manipulation of the kinetic parameters, or the use of ligands to stabilize the ferric state. A thermodynamic assist for the decomposition of $FeCl_3$ can be obtained by the addition of nitric oxide according to the following reaction, which occurs at room temperature:

$$FeCl_3 + NO \rightarrow FeCl_2 + NOCl$$

NOCl is easily decomposable at moderate temperatures to regenerate NO and Cl_2. However, the volatility of $FeCl_3$ (boiling point = 315°C = 600°F) will present process design difficulties.

An electrolytic process for the reaction —

$$FeCl_2 + HCl \rightarrow FeCl_3 + {}^1/{}_2 H_2:\ \Delta F_{298} = +15,300 \text{ cal/g-mole}$$

should also be feasible. Electric power requirements would be only 67% of that required for electrolysis of HCl and only 54% of that for the electrolysis of H_2O.

Other potential candidates for similar sequences based on the reverse Deacon Process include any of the elements having variable-valent halides (i. e., the transition elements). Since the IU-4-6 Phase 1 Final Report, we have learned that the Allison Division of General Motors has looked at several of these candiates including mercury, tantalum, bismuth, and vanadium chlorides. The process based on the vanadium chlorides, which appears to be the most feasible, was described by Funk as follows:

$$H_2O(g) + Cl_2(g) \rightarrow 2HCl(g) + 1/2O_2(g):\ T = 1340^0F$$

$$2VCl_2(s) + 2HCl(g) \rightarrow 2VCl_3(s) + H_2(g):\ T = 350^0F$$

$$4VCl_3(s) \rightarrow 2VCl_4(g) + 2VCl_2(s):\ T = 1340^0F$$

$$2VCl_4(l) \rightarrow 2VCl_3(s) + Cl_2(g):\ T = 350^0F$$

b. Processes Based on Carbon Cycles

Another basic water-splitting reaction that should be of primary interest is that based on reduction of H_2O with carbon — either in elemental form or as carbon monoxide:

$$H_2O(g) + C(s) \rightarrow CO(g) + H_2(g)$$

$$\underline{H_2O(g) + CO(g) \rightarrow CO_2(g) + H_2(g)}$$

$$2H_2O + C \rightarrow 2H_2 + CO_2\ (\text{yield} = 2H_2/CO_2)$$

H_2 production processes based on these reactions have already been proved to be commercially feasible. If we start with one or both of these reactions for splitting water, the problem then becomes whether a method for splitting of CO or CO_2 can be conceived which is easier than the splitting of water.

One approach, which should be considered in the long run, is to use the product CO_2 in the production, by photosynthesis, of carbohydrate, which could be decomposed to H_2O and carbon for recycle. It could also be used as food and ultimately be recycled to the process in the form of pyrolyzed garbage. Although we have not made the necessary material balance calculations, it seems probable that only a fraction of the carbon recycle could be obtained by garbage recycle and that one or more splitting processes would be needed. However, to the extent that the CO_2 can be used in some such fashion, the burden on the splitting process could be relieved.

One of the attractive features of the use of carbon as the splitting agent is that the hydrogen can be produced in the form of liquid hydrocarbons, methanol, or a wide variety of organic chemicals as well as the elemental form. However, in all cases, 1 mole of carbon dioxide is produced for every 2 moles of H_2 in whatever form it is produced. Especially then the CO_2 must be either used or split.

Thermodynamically, the splitting of CO is unfavorable at any temperature from absolute zero to far above 4000°K (6750°F). Temperatures above 2750°K (4530°F) would be required to decompose CO_2 into CO and O_2 in reasonable yields. Furthermore, a two-step process for splitting CO_2 to CO and $^1/_2\,O_2$ is just as unfavorable as is the two-step process for H_2O. Those elements or compounds capable of reducing CO or CO_2 below 1000°K cannot be regenerated below 1000°F and vice versa. Theoretically, multistep processes should be possible, but would probably have no advantage over multistep splitting processes for water and would be more circuitous.

Thus the Von Fredersdorff approach, in which the unfavorable thermodynamics of the reaction –

$$CO_2 \rightarrow CO + {}^1/_2\,O_2$$

are circumvented by carrying out the reaction in the presence of an inhibitor for the back reaction, appears to be the only approach so far conceived which will permit the development of a self-contained process based on the splitting of H_2O with carbon or carbon monoxide. As indicated before, the Von Fredersdorff Process appears to be feasible, but would require considerable development of chemonuclear technology. However, the same splitting reactions can be carried out without nuclear radiation techniques – namely, with ultraviolet radiation or with electric energy in the form of corona discharge or silent electric discharge.

The decomposition of CO_2 by electric sparks was observed as long ago as 1788.[16] Nevertheless, the extent of decomposition tends to be quite small because the electric spark energy also promotes the back reaction. On the other hand, Holt[16] found that the decomposition of CO_2 can be considerable (48%) at low pressure (30 mm) under the influence of silent electric discharge. The formation of solid carbon suboxide has also been noted. Thus fairly high conversions can probably be achieved by thermal quenching of the products alone. The addition of nitrogen or nitric oxide presumably would inhibit the back reaction of the oxygen atoms and prevent the formation of solid carbon suboxide.

It was also found that the number of coulombs required to decompose 1 gram equivalent of CO_2 is only 2610, which shows that the decomposition is not a direct electrolytic process. However, it was also shown that only about 1% of the total electrical energy supplied was converted to chemical energy.[16] Unless the overall electrical efficiency is greater than 80% (i.e., 80% of the total Faradays supplied produce the decomposition of at least 1 mole of CO_2), the process has no advantage over electrolysis of water in terms of electric power requirements.

Since we have not reviewed the modern literature in this area, we are in no position to evaluate what overall electrical efficiencies might be expected for the decomposition of CO_2 by electric discharge. We therefore suggest that if a thorough evaluation of the literature indicates the possibility of achieving reasonable efficiencies, a laboratory investigation of the decomposition of CO_2 by silent electric discharge could accomplish two objectives:

- The results would allow us to evaluate directly the technical feasibility of a process based on silent electric discharge.
- Since the two processes are similar in many respects, the results would permit at least a preliminary evaluation of the overall Von Fredersdorff Process without involving the use of chemonuclear techniques.

c. Other Exploratory Systems

Some attention has also been given to the conception of multistep processes based on splitting reactions other than those based on Cl_2 or carbon, so far without much success. However, the process of conceiving such reactions is a highly empirical one and depends on a detailed knowledge of the extensive chemistry of the compounds involved. We feel that the further exploration of these areas could be fruitful.

We would also like to point out that the promotion of splitting reactions by nuclear radiation or electric discharge might be applicable for materials other than CO_2, including SO_2 (the product from splitting H_2O with sulfur) and water itself.

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Appendix III-A. "Modern Electrolyser Technology"*

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* Excerpt from Reference 20.

MODERN ELECTROLYSER TECHNOLOGY IN INDUSTRY

A. K. Stuart

Extent of Use

Electrolysis of water is familiar to high school students of chemistry throughout the world; but the extent of its application in industry today may come as a surprise to many. One reads statements in the technical literature such as "the electrolytic process for producing hydrogen is now generally considered too costly for practical purposes". Such statements apply to large plants, except in low cost power areas, but do not adequately reflect what has in fact been happening in the field. Total figures are not available but there are many hundreds of electrolytic plants in operation today throughout the world and a considerable number are being built every year.

The capacities in industrial use range from as little as 500 cubic feet per day, absorbing perhaps 3 kw, to over 40 million cubic feet per day, absorbing 240 thousand kw. The sizes most common in metallurgical and chemical processing are between 10 thousand and 500 thousand cubic feet per day. The very large installations exist at low cost hydro-electric sites where hydrogen is used for the manufacture of synthetic ammonia for nitrogen fertilizer. Examples of such plants are in Norway, India, Egypt, Japan, Peru, Korea, Canada and Australia.

The uses of electrolytic hydrogen plants in North America and abroad are as diverse as are the uses of hydrogen itself. The principal present applications are indicated in Table I.

TABLE I

Hydrogenation of fats and oils for shortening, margarine and soap

Production and sintering of metal powders and compacts (iron, tungsten, cobalt, molybdenum, etc.)

Bright annealing of stainless steel

Preparation of semi-conductor materials

Television and radio tube and lamp manufacture

Grain orientation of transformer steel

Inflation of weather balloons

Compressed industrial gas manufacture for distribution

Cooling of electric generators at thermal power stations

Uranium extraction and processing

Chemical synthesis (Examples nylon and polyurethene intermediates, sorbitol, etc.)

Nuclear power stations - recovery of radioactive emissions; graphite reactor core corrosion control

Float glass manufacture

By-product oxygen (purity 99.6 to 99.7%) is recovered, where a market exists, for use in cutting and welding and in chemical and metallurgical processing, electronics manufacture, etc. In these applications the value is from $1.00 to $3.00 per 1000 SCF. Future uses will probably include treatment of sewage and industrial effluent to reduce biological and chemical oxygen demand.

The Electrolysis Reaction

Before discussing the equipment details, some simple data concerning the electrolysis reaction may be useful (Table II).

TABLE II

TYPICAL OPERATING DATA FOR MOST INDUSTRIAL ELECTROLYSERS

$2\ H_2O$	+	Electric Power $\longrightarrow$	$2H_2$ (gas)	+	O_2 (gas)
6.7 U.S. gals. (distilled or demineralized)		120 - 140 kwh (D.C.)	1000 SCF (99.7 to 99.9%)		500 SCF (99.3 to 99.7%)

Electrolyte - pure KOH solution, strength 25% to 28%

Operating Temperatures - 60° C. to 90° C.

Cooling Water @ 30° C. - 200 to 300 U.S. gals. per 1000 SCF H_2

Production per 1000 amperes - 15.9 SCF H_2 and 7.95 SCF O_2 per Hour at 100% current efficiency (c.e.)

(or 63,000 amperes per 1000 SCFH approx.)

Specific Power Consumption (in kwh per SCF H_2)

$$= \frac{\text{Cell Voltage} \times \text{Amperes} \times 10^{-3}}{\text{Amperes} \times 10^{-3} \times 15.9 \times \text{c.e.}}$$

$$= \frac{\text{Cell Voltage}}{15.9 \times \text{c.e.}}$$

Current Efficiency (c.e.) - 96% to 99.9% according to cell design and condition.

The electrolyte most commonly used is potassium hydroxide solution of low chloride grade at a strength of 28% for maximum conductivity. Higher strengths may be used to reduce loss of feed water by evaporation when operating at high temperatures; in cells of open construction, where the electrolyte can absorb carbon dioxide from the surrounding atmosphere, sodium hydroxide may be preferred in spite of lower conductivity as it costs less to replace. In sealed cells, the original electrolyte charge normally is used for more than ten years. Periodic make-up is required to replace mechanical losses.

Due to the absence of side reactions, current efficiency in most types of electrolyser is close to 100% (actually 96 - 99.9% depending on design) and production rate is therefore 15.9 SCF/hr hydrogen per 1,000 amperes, representing the electrochemical equivalent. As may be seen in Table II, at any given current efficiency, specific power consumption is in direct proportion to cell voltage and, conversely, energy efficiency is in inverse proportion to cell voltage. Cell design and operating methods are accordingly directed toward achieving a minimum cell voltage consistent with economical capital and maintenance costs, and equipment service life.

Overall cell voltage includes the components given in Table III.

TABLE III

CELL VOLTAGE COMPONENTS

$$E_{\text{Cell}} = E_{\text{Rev.}} + E_{\text{A}} + E_{\text{C}} + IR$$

E_{Cell} - Voltage at cell terminals

$E_{\text{Rev.}}$ - Reversible decomposition voltage

E_{A} - Overvoltage at Anode

E_{C} - Overvoltage at Cathode

IR - Loss due to ohmic resistance of electrolyte and cell parts

The reversible decomposition voltage at atmospheric pressure and 25° C. is 1.23 volts; between 1.23 volts and 1.48 volts the applied energy is absorbed to maintain cell temperature; above 1.48 volts, energy is released as excess heat. The decomposition voltage plus a degree of overvoltage must be applied before current begins to flow. The ohmic or IR resistance losses within the cell are minimized by careful design of the conducting paths and choice of diaphragm material, by maintaining electrolyte strength at the point of maximum conductivity and by operating the cell at the highest possible temperature (about 80° C. in present practice) compatible with the materials of construction.

The anode and cathode overvoltage phenomena are themselves made up of a number of individual losses not fully understood. Overvoltages and the residual losses are affected by the choice of electrode material, the mechanical condition of the surface, the current density, the temperature of operation, the presence of impurities and/or catalysts and the adequacy of electrolyte circulation.

Types of Electrolyser

Electrolysers presently available for industrial use are in one of two basic classifications - uni-polar or bi-polar. The distinction is illustrated in Fig. 1. In the uni-polar electrolyser, each electrode has the same polarity on both surfaces and carries out a single electrode process (i.e. either hydrogen evolution or oxygen evolution). A single cell contains a number of electrodes and all electrodes of like polarity are connected electrically in parallel. The result is that overall cell voltage is equivalent to that of one pair of electrodes or approximately 2 volts. High total currents per cell may be carried at this low voltage potential, by increasing the number of electrodes in the cell tank. A sufficient number of cells are then connected electrically in series by bus bars to form a cell battery of the desired hydrogen output capacity.

The bi-polar electrolyser installation, frequently called the filter-press electrolyser, on the other hand consists of a single assembly of a relatively large number of electrodes, each of which is cathodic on one side and anodic on the other. The assembly is held together by longitudinal tie bolts in a manner similar to that of the plate and frame filter-press. Each electrode is insulated from, and electrically in series with, its neighbour; and each pair of electrodes forms an individual cell unit. The direction of current flow is from one end of the cell mass to the other. A bi-polar electrolyser may thus contain from 30 to several hundred individual cells in series at approximately 2 volts each, so that the corresponding applied voltage ranges from 60 to 1200 volts DC approximately, depending upon output capacity.

There are, as may be expected, advantages and disadvantages inherent in each approach. With bi-polar construction, intercell bus bar connections are eliminated and floor space is reduced in comparison to older uni-polar cells. The series arrangement of the electrodes results in a higher voltage and lower current requirement for a given hydrogen output which, in smaller plants, can mean lower rectifier cost.

A bi-polar electrolyser is illustrated in Fig. 2. Inherent in bi-polar design is a multiplicity of contact surfaces which require manufacture to close tolerances and careful sealing and insulating to prevent leakage of gas, electrolyte and electric power. Because of the relatively high DC voltage applied, care is taken to avoid short circuit currents, which can affect both current efficiency and gas purity. The electrolyte is recirculated from gas separating tanks to the electrolyser by an external pumping system, which includes cooling and filtration.

Uni-polar electrolysers, of which an example is illustrated in Fig. 3, require heavy interconnecting DC bus bars and, in some cases, greater floor space. They have however the advantage of greater simplicity in design; this is mainly because of the low DC voltage per unit and the relatively few contact surfaces requiring insulation and sealing. In general, appropriate welding shop techniques are sufficient for high quality production of uni-polar cells. Because of economy in manufacture, uni-polar cells may be economically operated at lower current density and high electrical efficiency, if preferred. The operating condition of an individual uni-polar cell (for example, hydrogen and oxygen gas purities) can be checked and if necessary a single cell removed for repair without significant interruption of hydrogen plant output. This is an important advantage where high continuity of hydrogen supply is essential. Under normal conditions, modern uni-polar cells can be expected to operate in excess of ten years before removal for cleaning or overhaul; and repair of individual cells may be readily carried out at site using spares on hand.

As indicated in Fig. 5, in terms of building requirements high current uni-polar cells are now available which, in comparison to bi-polar cells, require comparable or less total floor space for installation, when aisles and space for auxiliary equipment are included.

In industrial electrolysers of both types, hydrogen and oxygen compartments are separated by a woven asbestos cloth diaphragm, made to precise specifications to minimize diffusion of the product gases without impeding ionic conductivity. These diaphragms are in some instances reinforced by cotton or wire. Under proper conditions of application, the diaphragms will last well in excess of 20 years.

The uni-polar cell illustrated in Figure 3 is of a type in common use which contains 19 electrodes (10 cathodes and 9 anodes); the cell is capable of operating at DC currents to 20,000 amperes or higher on overload. The cover and interior of the cell tank are of nickel-plated steel; the copper electrode terminals are silver-plated to minimize contact resistance. Electrolyte level is maintained automatically by an external float valve and temperature of the cell is thermostatically controlled by regulating water flow through a cooling jacket mounted on the rear of the cell tank. The product gases are cooled in individual separators, returning condensate and electrolyte entrainment to the cell through an overflow connection. A heavy sponge nickel plate is applied to the anodes and the cathodes are treated to obtain a more active surface for electrolysis. A number of such uni-polar electrolysers are connected electrically in series to form a cell battery as illustrated in Fig. 4. This small battery has an output capacity of 4,000 cubic feet of hydrogen per hour. The cells occupy approximately 120 square feet, to which is added approximately an equal amount to allow for aisles and end spaces.

Pressure Electrolysis

Pressure electrolysers have been the subject of study and development for more than fifty years and are now available with a capability of delivering gases at a pressure of 30 atmospheres.[3] Operation at pressure requires that a very close balance be maintained at all times between hydrogen and oxygen chambers, to avoid failure of the relatively weak asbestos diaphragm and consequent hazardous mixing of the hydrogen and oxygen product. External auxiliary systems, which form part of the gas separation and electrolyte recirculation systems, are used to maintain the pressure balance required. The electrolyte is circulated by pumping and is carefully filtered to avoid any blockage of the small passages within the electrolyser unit by corrosion products or other impurities. Feed water must of course be introduced under pressure and rate of load change carefully regulated. In spite of added complexity and cost, there are obvious advantages to deriving both gases at a pressure sufficient for storage and pressure electrolysers represent an engineering development of interest.

Electrical Efficiency

Fig. 6 illustrates a typical voltage-current/hydrogen output curve for uncatalysed bi-polar and uni-polar cells. Hydrogen output commences at an impressed voltage of approximately 1.5 volts DC; small increments of voltage result in relatively large increments of current or hydrogen output. The rectifier voltage control therefore provides a precise means for regulation of gas production. It is apparent that, unlike many processes, there is a gain in efficiency at lower levels of output. On the other hand, operation at low current density requires more or larger electrolysers and therefore increases capital cost. Every make of electrolyser possesses a unique investment/efficiency characteristic and, for each hydrogen project, an optimization study is obviously needed based on the power cost and other conditions prevailing at site.

Operating Economics

At one time electrolytic plants consisted of large numbers of relatively low amperage hydrogen cells requiring hand feeding, continuous operator attendance and a good deal of space. Modern design has reduced both capital and operating costs substantially. The guiding principles for economy are as follows:

1. Operation should be entirely automated, with remote indication and remote or automatic output control as desired.

2. Operation should be integrated fully with an existing electrical load (either company or central station) using an automatic modulating control to avoid imposing new peak power demands. A large number of electrolytic installations on this continent operate in this manner and power cost for electrolysis is reduced thereby to two-thirds or one-half of plant average power cost.

3. Capital investment should be minimized by packaged construction and by utilizing the inherent overload capability of electrolytic cells (with some designs, up to 200% of normal). Recurring peak hydrogen demands, or variable power availability, may thus be accommodated with a less than proportionate impact on capital cost.

4. Design and construction of the electrolytic cells should be sufficiently rugged to provide the above operating flexibility, and to assure long service life at good performance with a minimum of administrative and maintenance attention.

5. Opportunities for the disposal or use of by-product oxygen should be fully exploited.

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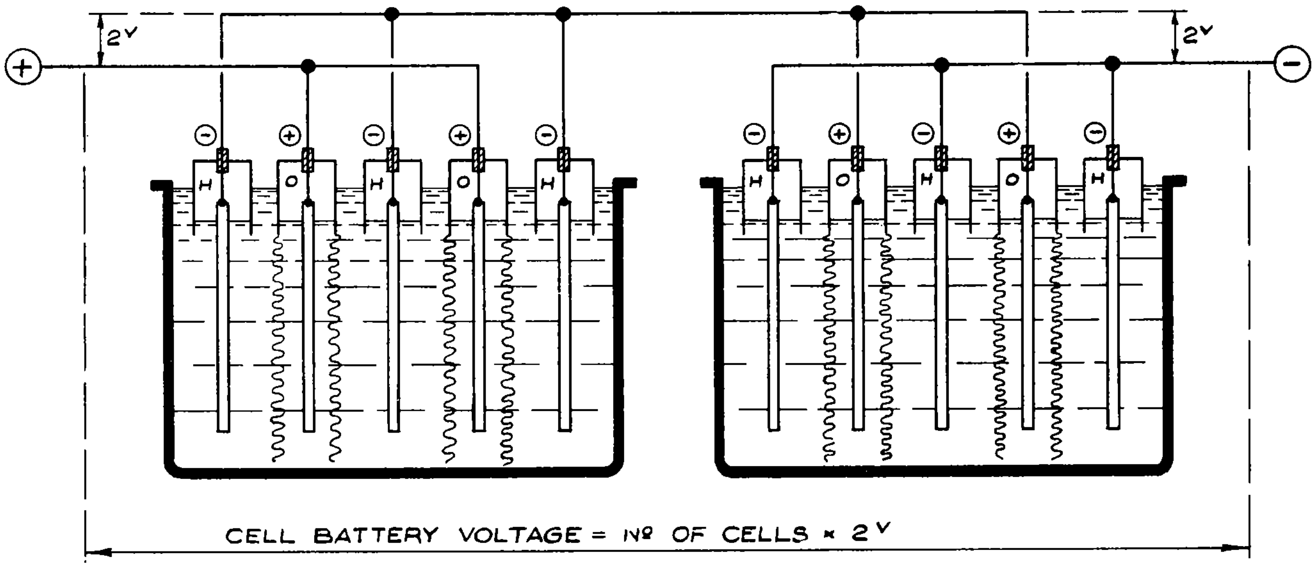
UNIPOLAR CELL CONSTRUCTION



BIPOLAR CELL CONSTRUCTION

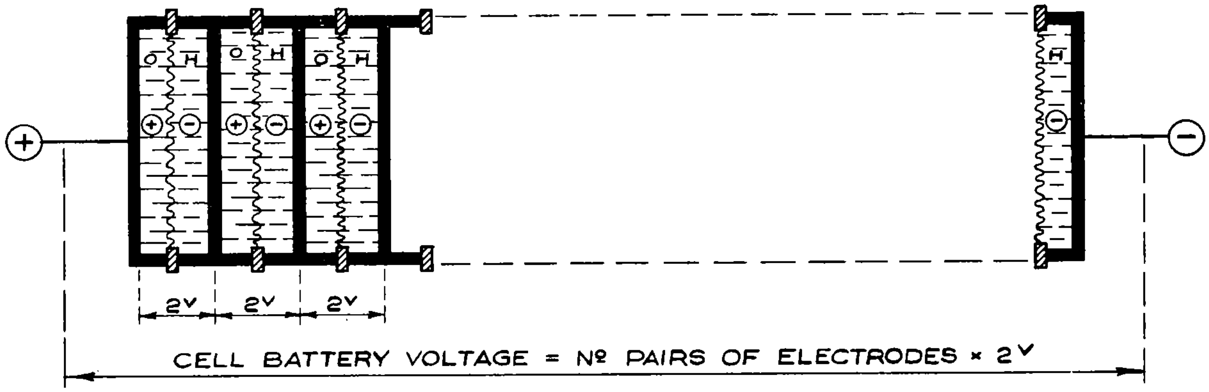
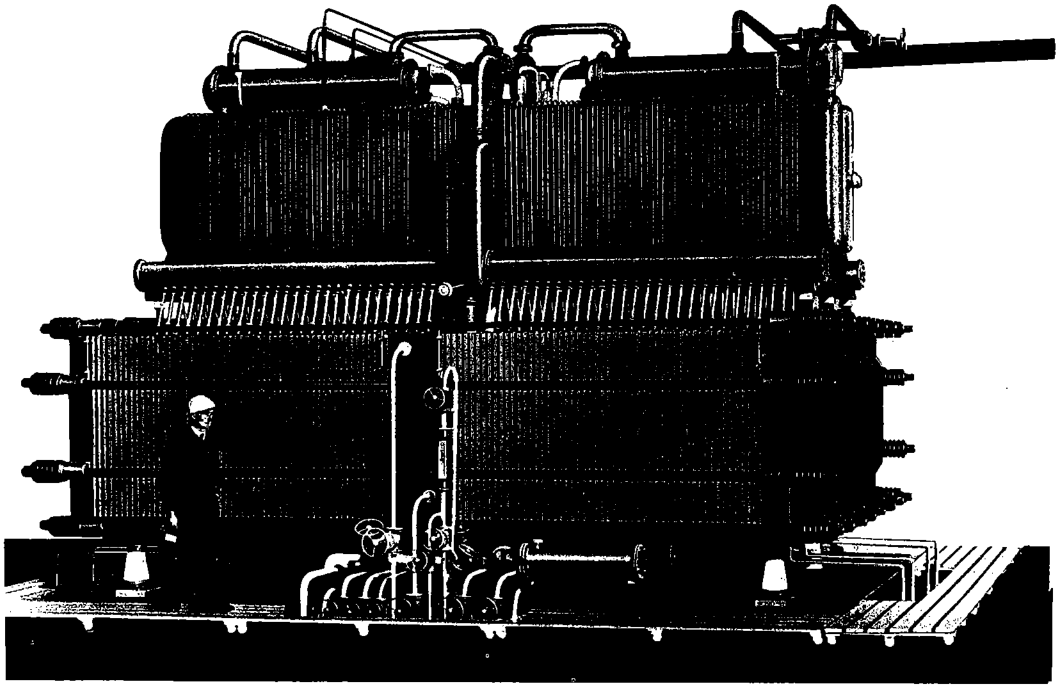


FIGURE 1

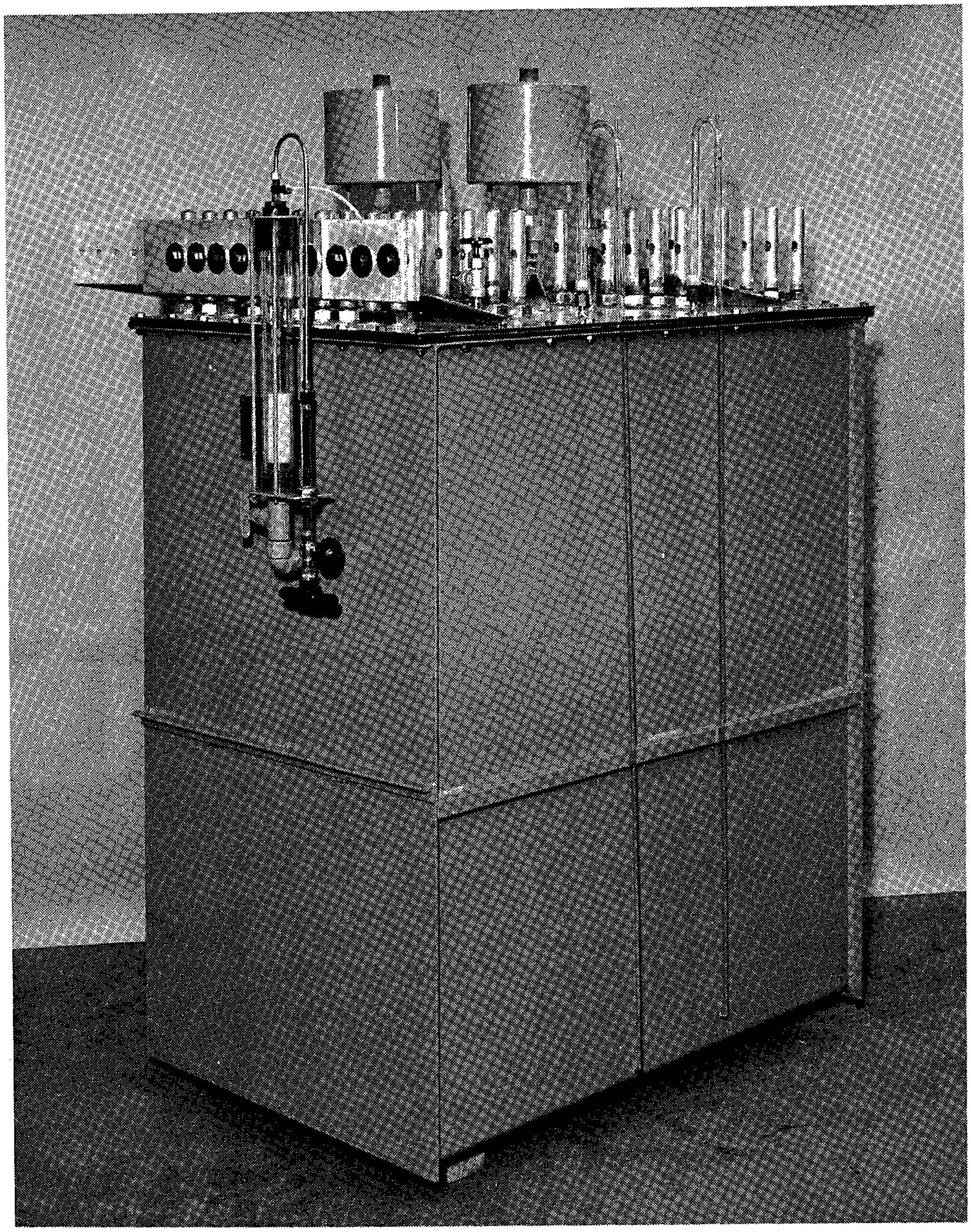
THE ELECTROLYSER CORPORATION LTD.



LARGE BI-POLAR ELECTROLYSER

TYPE - DE NORA • 10,000 Amperes D.C.

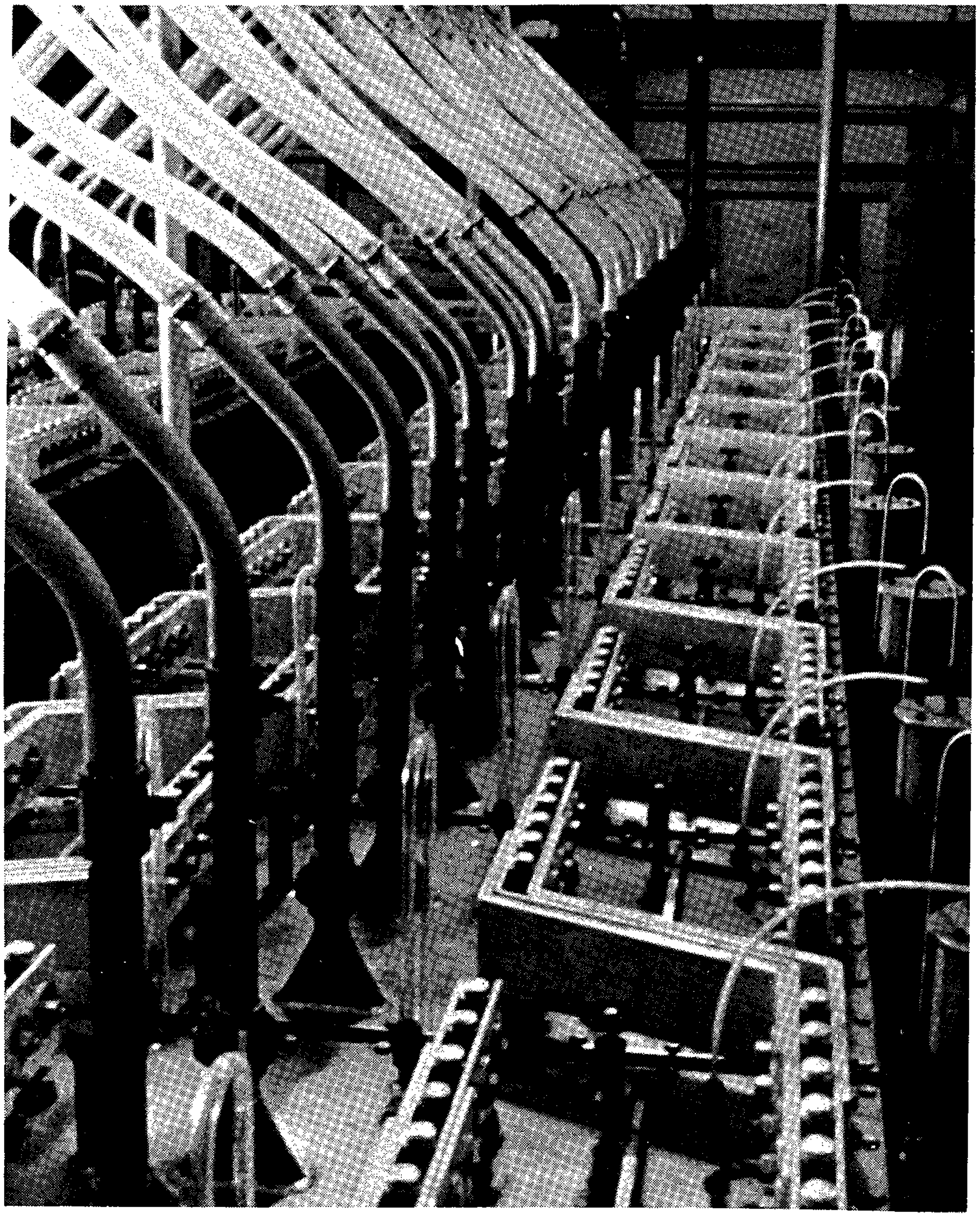
FIGURE 2



UNI-POLAR ELECTROLYSER

Type-STUART – 20,000 Amperes D.C.

FIGURE 3



UNI-POLAR CELL BATTERY

CAPACITY 4,000 CFH H_2

FIGURE 4

FIGURE 5

SPACE COMPARISON

BI-POLAR and UNI-POLAR CELLS · Capacity 14,300 SCFH H_2

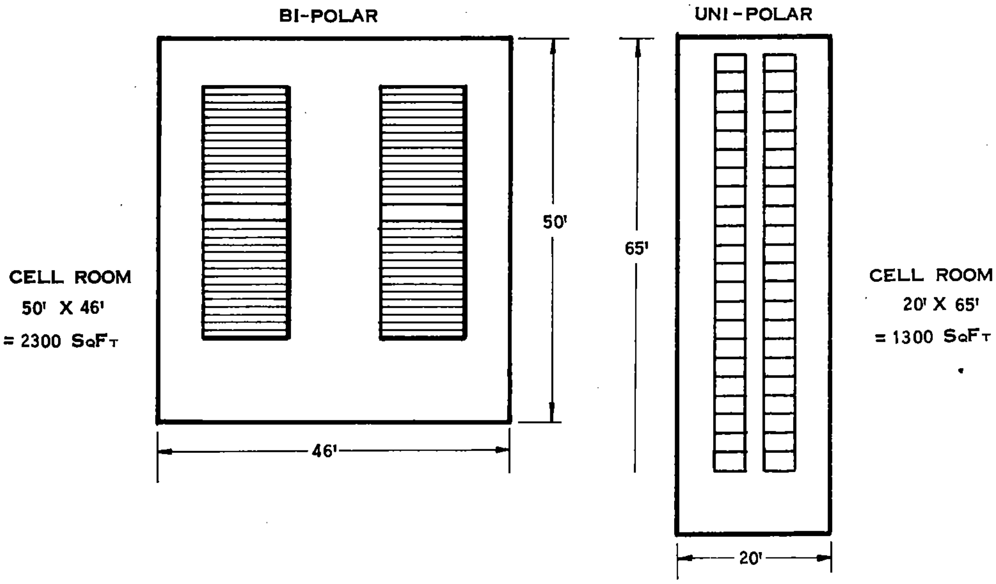
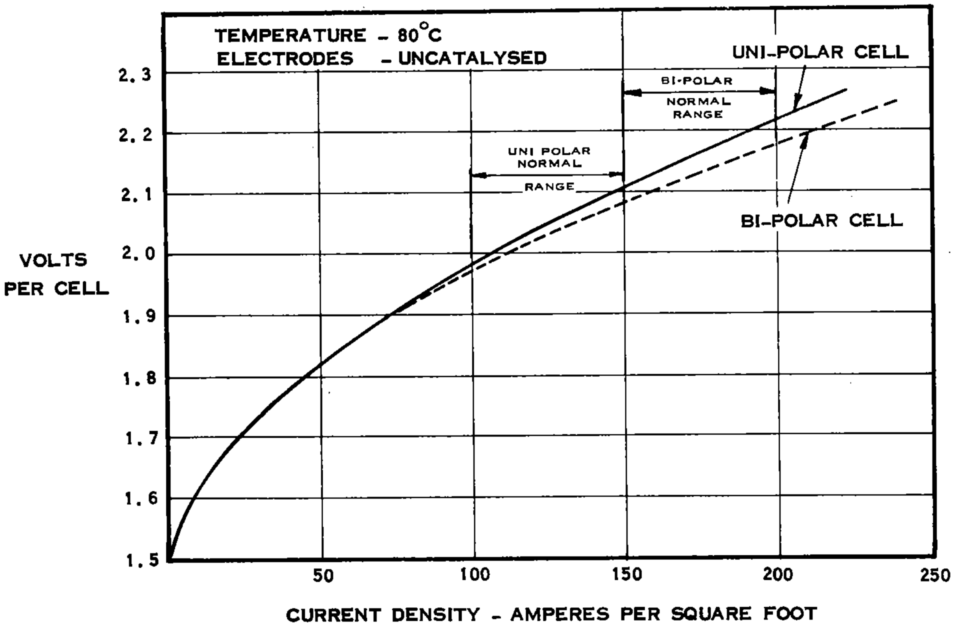


FIGURE 6

TYPICAL PERFORMANCE CURVES



Appendix III-B. Specifications and Descriptions of Some of Teledyne Isotopes' Electrolyzer Systems

The three basic models available in this series vary in hydrogen delivery rates as shown in the table below. Specifications for the units are included below as an example. The flexibility of these systems enables them to be easily adapted to match generating station constraints, such as hydrogen requirements, cooling water temperature, floor space availability or generator locations. The total cost at a generating station to operate the systems will range between $.10 to $.15 per hundred cubic feet of hydrogen. Electric power is used at the rate of 19 kWh per hundred cubic feet of hydrogen.

SPECIFICATIONS

	MODEL 5 SLM	MODEL 20 SLM	MODEL 50 SLM
Hydrogen Production			
(SLM)	5	20	50
(SCFH)	11	41	106
(SCFD)	250	1000	2550
Hydrogen Delivery Pressure (PSIG)	90-100	90-100	70-100
Oxygen Production			
(SCFH)	5	20	50
(PSIG)	80-90	80-90	60-90
Electrical Input			
VAC (60 Hz)	220 ± 5%	220 ± 5%	460 ± 5%
Phase	1	1	3
KVA	3	8	20
Amp. Service	25	50	50
Make-up Water (Distilled or equivalent) (GPD)	3	12	20
Cooling Water (GPM @ 60°F)	-	-	1.2
Ventilating Air (CFM @ 40°C max.)	1000	1000	1000
Electrolyte (KOH) (Wt. %)	20	20	20
Inventory (GAL)	2.0	2.0	2.1
Cabinet Dimensions (ft.)			
L.	5	5	6
W.	2	2	3
H.	6	6	5
System Weight (lb.)	800	1200	1500

SYSTEM DESCRIPTION

The Teledyne Isotopes gas generation system operates on the well-established principle of water electrolysis which uses electric power to reduce water to its basic constituents - hydrogen and oxygen. Unique features of the Teledyne Isotopes system include the design and construction of the electrolysis module, the controls, and the ability to deliver high purity hydrogen. This design is the result of 15 years of research and development on electrical systems. It can be considered a potential base load builder for application in many processing industries.

The basic system consists of two separate sections - the power conditioning and controls section and a gas generating section. The smaller, air-cooled units feature these partitioned sections within one cabinet whereas the water cooled, 50 SLM generator is a two cabinet design. When the cabinet is energized from a main disconnect switch, full hydrogen generation is automatically attained within 10 minutes. The system automatically responds to the small daily variations in make-up hydrogen requirements and requires only routine monthly maintenance involving semi-skilled personnel. The design and performance of the unit will satisfy most local safety and fire insurance code requirements.

IV. HYDROGEN TRANSMISSION

A. Introduction

The gas industry has a very important asset in its natural gas transmission system. The movement of energy in pipelines is acknowledged to be one of the cheapest ways of energy transmission. In addition, because the system is buried underground, it does not arouse the criticism of those environmentalists who are attempting to eliminate some of the more unattractive visible evidence of modern technology from the landscape. Transmission of hydrogen by underground pipelines can be a valuable factor in justifying a hydrogen energy economy. The comparison we must draw is with electrical transmission because we are considering the use of hydrogen derived from nuclear energy rather than the direct use of nuclear-based electricity. We have already seen that the trend in nuclear plants will be to construct larger single plants or agglomerates and to site them remotely from the load centers because of the safety and cooling requirements. In this section, we examine the technology that already exists in hydrogen pipelining and the application of natural gas pipeline technology to hydrogen transmission, and derive some estimated costs of transmission of large quantities of hydrogen over long distances. We also consider the possibility of liquid-hydrogen transmission systems.

B. Need for Bulk Transmission

At present, all indications are that miniature nuclear power generators for single customer use or even substation use will not be possible. Once the smallest economical size of generator reaches a few hundred megawatts, removal of the waste heat becomes a significant local problem and forces the location of the plant into specific areas. Again, the economy of scale takes over, and we find that nuclear-electric plants of 1000 MW (3.4 billion Btu/hr) output are becoming typical now, with figures of up to 10 times this amount predicted for the future. Since the siting of such nuclear plants on large bodies of water is almost mandatory for cooling purposes, we begin to observe that our energy production sites will be large and remote.

Our energy load centers are also large and concentrated, so an immediate problem arises of transmitting energy from the concentrated production site to the concentrated utilization site from whence more diffuse distribution occurs. Thus, the concept of bulk energy transmission, already needed for natural gas and electricity, will also be even more necessary for hydrogen.

A national energy grid offers a considerable advantage. Apart from boosting the reliability of the system by linking in more generation points and more routing options, thus cutting down some need for redundancy of both generating and transmitting equipment, such a system will allow some evening out of peakload demand from one area to another. Because of the large distances involved in the U.S., a national electricity grid does not exist, but area power pools have been formed with similar objectives. In smaller countries with a higher population density, such as Great Britain, national electric grids are operating. Although the U.S. has a comprehensive gas transmission network, it is by no means a national grid because most lines are directly routed from supply sources to individual load areas. Interconnections do occur, however, but the need for a greatly interconnected system for reliability is less acute in an underground system than in a more vulnerable overhead system.

We may ask whether natural gas pipeline routes today would be in the right locations for hydrogen supply. If we wished to make use of existing pipeline equipment, it would be reasonable to attempt to locate the hydrogen generating stations along the existing routes. In some cases, this will be ideal; in others, some spur lines will have to be laid. In general, we can expect the majority of our generating stations to be offshore, with only those in the Gulf area being able to fully utilize existing transmission line routes. A detailed generating station siting survey should be undertaken in order to consider the many factors, such as proximity to large-scale hydrogen customers, oxygen customers, cooling water, and existing pipelines that would affect the choice.

C. Present Status of Hydrogen Pipeline Technology

The transmission of hydrogen under pressure in large quantities is an established industrial practice, but it is normally carried out over very small distances. In many thousands of chemical plant and refinery installations, hydrogen is piped from one plant to another in large-diameter high-pressure pipes. So far there has been little need or incentive to move hydrogen over great distances this way, but our investigation brought some interesting installations to light.

Air Products & Chemicals, Inc., is building up the business of supplying many industrial gases, including hydrogen, by pipeline to a customer from an offsite plant. The following is extracted from Air Products & Chemicals' 1970 Annual Stockholders' Report:

> Industrial gases are produced and marketed throughout most of the United States, the United Kingdom, Belgium, The Netherlands, Germany, and France. Distribution to a part of the industrial gas market, particularly the steel and chemical industries, is accomplished by locating a plant near the customer and distributing gases through pipelines.
>
> Large volumes of oxygen, nitrogen, hydrogen, and carbon monoxide in a gaseous state are delivered by pipelines to industrial plants located within relatively short distances from the Company's plants. These sales are made under contracts varying in length from 5 to 20 years which require the Company to have available minimum stated quantities and which provide, in most cases, for minimum monthly payments.
>
> During 1970 the Company brought on-stream a record capacity of new gas generating facilities, representing an investment of more than $30 million. Much of this new capacity has been sold under long-term contracts to customers by direct pipeline.
>
> Growth in the sales of hydrogen and carbon monoxide pipeline gases from the Houston plant necessitates the expansion of this facility by early 1972 to more than twice its present capacity. The Company is exploring other opportunities to expand its production of these important basic gases for the process industries.
>
> New long-term contracts were signed for onsite pipeline sales of industrial gases at the Europort area of Rotterdam, The Netherlands. Construction is proceeding on a large industrial gas complex for the manufacture of oxygen, nitrogen, hydrogen, and carbon monoxide to supply these and other pipeline customers and The Netherlands merchant market.

We discussed the subject of pipelining hydrogen with Air Products, which went on record with the following statement:

> Air Products uses pipelines to supply customers with hydrogen, oxygen, nitrogen, and carbon monoxide. The piping of hydrogen is handled in the same manner as the other gases with no special precautions being practiced specifically because it is hydrogen. The longest hydrogen pipeline Air Products has in use is approximately 12 miles and is an 8-inch line operating at a pressure of 200 psi. This is in the Houston area. In our system we have in excess of 20 miles of hydrogen pipelines of various sizes.

We also discussed the same topic with Linde Division of Union Carbide Corporation. Linde told us that hydrogen gas pipelining in the 50 tons/day scale for 1-2 miles is in current use. It foresees no problems in extending the distances to the 50-100 mile range. The company proposed at one time to pipe bulk hydrogen from Texas to the White Sands proving grounds in New Mexico. The system was designed, but not constructed. At present, Linde has pioneered a nationwide liquid-hydrogen "transmission" system using rail and road tank cars; this will be described later.

A comprehensive hydrogen pipeline network in the Ruhr area of Germany is operated by Chemische Werke Huls AG and has a total length of about 130 miles. An interesting account of the development history of this network is given by Isting[6] and is extracted below:

> In 1937, the availability of the necessary raw materials was one of the controlling factors in Huel's selection of the location at Marl on the northern border of the Ruhr area. At this second German plant for the manufacture of synthetic rubber, the hydrocarbons required for producing acetylene and ethylene had to be made available in adequate amounts over as short a supply route as possible. These requirements could be met by the neiboring Scholven Chemie hydrogenation plants of Bergwerksgesellschaft Hibernia (now Veba-Chemie AG, Gelsenkirchen-Buer plant) and Gelsenberg Benzin AG in Gelsenkirchen, where fuels were manufactured by coal hydrogenation with the formation of large amounts of off-gases containing methane and ethane (which can be cracked in the electric arc to yield acetylene and ethylene).
>
> Another controlling factor in the selection of Marl was the presence in the Ruhr area of various coking plants producing coke-oven gas, from which ethylenes could be obtained in Linde-type gas separation units.

Production at Huels started in 1940. Coincident with the erection of the plant units, installation of the pipelines needed for cooperation with the neighboring plants had been started in 1938. Lines of 400 mm and 300 mm nominal sizes to carry hydrogenation off-gases from the Schloven and Gelsenberg hydrogenation plants to Huels were laid over a total length of 23 km.

Only a very small proportion of the hydrogen also produced in the electric arc process is needed for captive use at Huels, whereas the hydrogenation plants do need large quantities. Pipelines of 300 mm and 200 mm nominal size were therefore laid from Huels to Scholven and Gelsenberg to route this hydrogen.

Because the amounts of ethylene available to Huels were not sufficient, the firm erected its own coke-oven gas separation unit to recover ethylene for itself. The necessary gas was received from the Scholven hydrogenation plant through a 300-mm 11-km pipeline, as well as from the Gewerkschaft Auguste Victoria coal mine at Marl-Huels, and from Ruhrgas AG through 300-mm 4-km line. The fuel gas required by Huels was supplied by Gewerkschaft Auguste-Victoria through another 300-mm pipeline.

All the pipelines mentioned so far were built between 1938 and 1940. An exception is the crude-ethylene pipeline from Castrop-Rauxel to Marl, which was constructed in 1943.

After this development, the network totaled 347 km, and there was an interchange of 12 different materials.

At Huels there was only a slight demand for the by-product hydrogen mentioned earlier. Part of this hydrogen went to the Gelsenkirchen-Buer plant of Veba-Chemie and to Gelsenberg-Benzin AG in Gelsenkirchen. To dispose of the excess hydrogen, a systematic expansion of the hydrogen network was started in 1954 with the object of connecting further consuming plants. In the same year, Gewerkschaft Victor at Castrop-Rauxel was connected up through a 200-mm 23-km pipeline. In the ensuing years, pipeline connections to existing hydrogen lines were laid to Henkel in Dusseldorf to Farbenfabriken Bayer at Krefeld-Uerdingen, and at Leverkusen (150 mm) to Ruhrchemie at Oberhausen-Holien (300 mm) as well as to Veba-Chemie West at Wanne-Eickel (200 mm).

It was not long before further plants were tapped into the system. The Esso refinery at Cologne-Meikenich also had hydrogen at its disposal, and so joined the hydrogen network by installing a connecting line of 80 to 100 mm.

> In all, the expansion increased the length of the hydrogen pipeline network by 165 to 204 km, and the total Huels grid to 512 km. Eighteen plants were linked and the number of materials being transported by pipeline was 12.

From correspondence with Chemische Werke Huls we determined that the pipeline, with diameters from 6 to 12 inches, is designed for a pressure of 240 psig and operates at a supply pressure of 150 psig. The throughput of the system in February 1972 was 875 million SCF, corresponding to an annual throughput of 10.5 billion SCF/yr or 3.4 trillion Btu/yr. The pipeline system has no compressors along the pipeline and is not equipped with any safety features in addition to those used in the company's natural gas lines. The pipe is of seamless construction and uses steel of the St. 35.29 grade, which corresponds to SAE 1015 or 1016. A map of the system is shown in Figure IV-1.

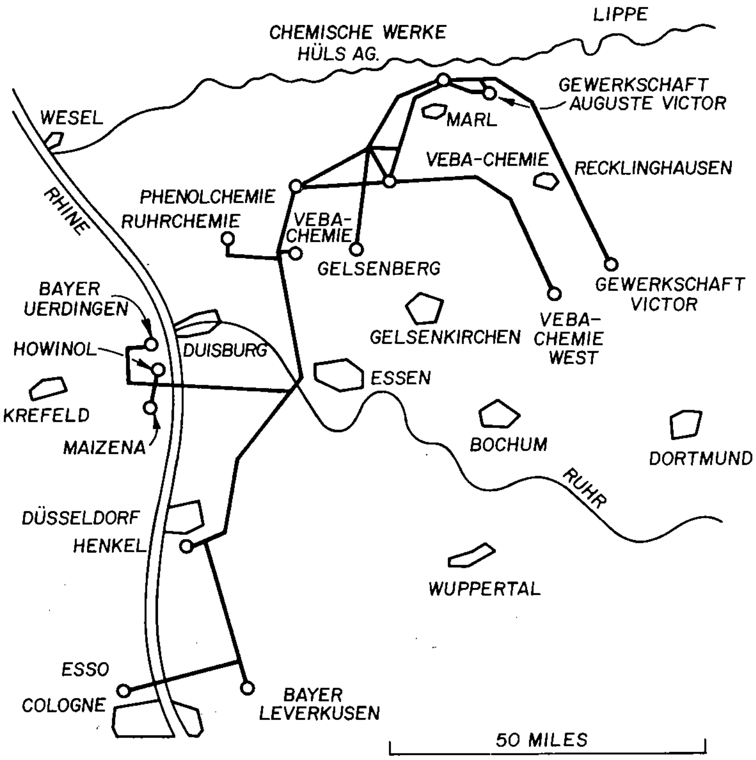


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Figure IV-1. HYDROGEN PIPELINE GRID OF CHEMISCHE WERKE HULS AG IN GERMANY, 1970[6]

Another hydrogen pipeline located in Johannesburg, South Africa, is about 50 miles long.

Interestingly, none of the hydrogen pipelining systems that we have found are long enough to require compressor stations along the line. Although experience in design and operating the lines themselves already exists, there is little precedent for compressor staging from which we can observe typical design parameters, such as optimum pressure ratios and spacings. We may observe, however, that pipelining hydrogen over reasonable distances is already an active and growing practice. Some of the pipelines pass through populated or commercial areas; suitable codes of practice have been devised to allow this to be done safely, with the approval of local authorities.

The question of the increased "leakiness" of hydrogen over natural gas is a possible cause for concern. We have an analogy here with the handling of helium, which is a low-density gas with diffusivity and leakage properties similar to those of hydrogen. Although helium is not a hazardous gas, it is valuable enough that leakage cannot be tolerated.

As part of the U.S. Helium Conservation Program, a helium pipeline has been in operation connecting a number of helium extraction plants in Kansas and Oklahoma with the Cliffside storage field, near Amarillo, Texas.[12] The pipeline is 425 miles long, is 2 inches in diameter, and operates at 1800 psi. The Bureau of Mines, which owns and operates the line, told us it had experienced no major difficulties in the operation or maintenance of the system, which went into operation in December 1962 and has been in continuous service ever since. It is to be assumed that helium leakage rates from this line have been reduced to small, acceptable levels because of the value of the helium itself.

D. Materials for Hydrogen Pipelines

Recent trends in chemical engineering technology have made increasing use of hydrogen under high pressures and at elevated temperatures. Because of this, results of tests on materials compatibility have been collected and published.[10] These data can be used to establish practical limits for the use of many carbon and alloy steels.

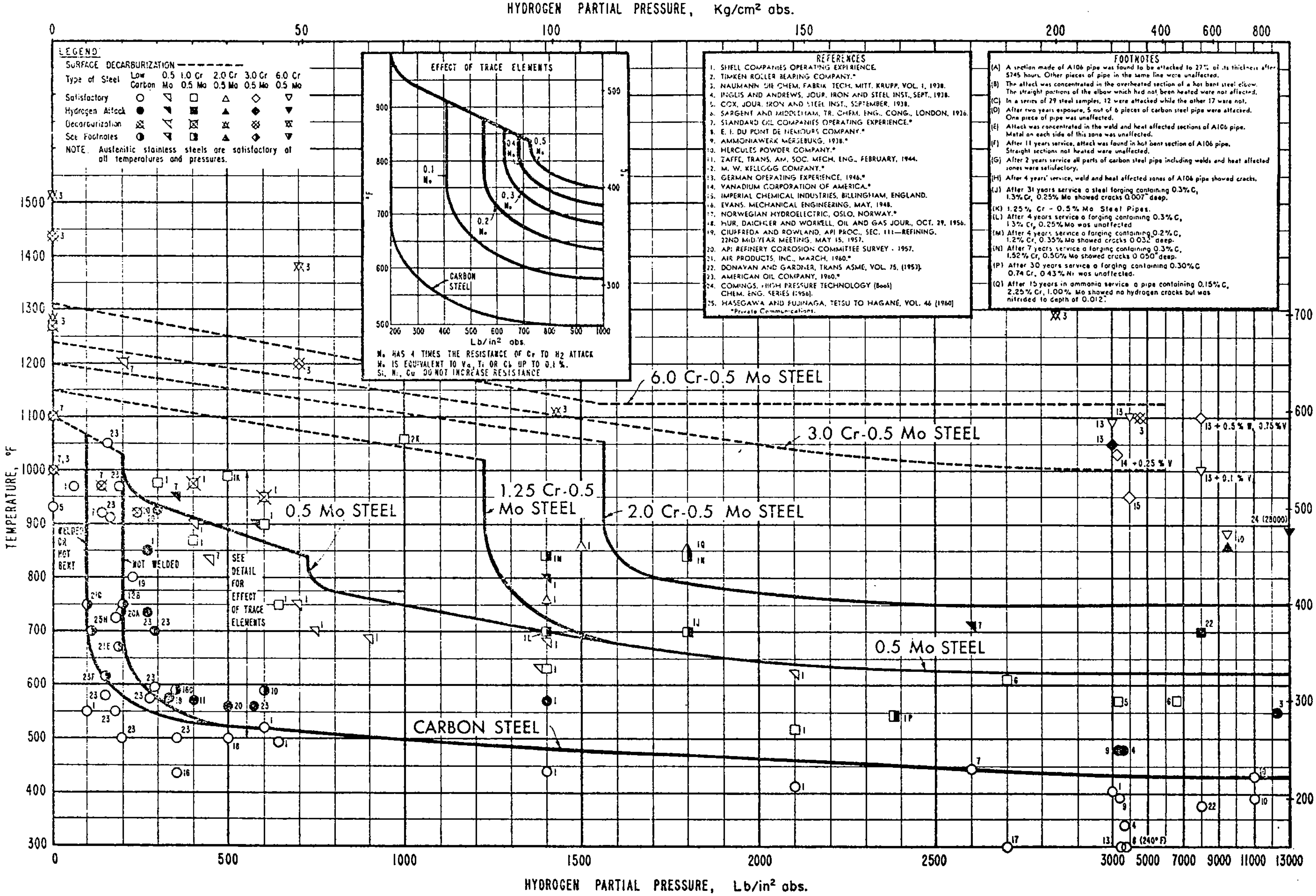
Figure IV-2 indicates the service life data for a number of steels at various conditions of exposure to hydrogen. It indicates that, over a very wide range of hydrogen pressures, hydrogen exposure does not present problems below 400^{0}F, even for carbon steels.

Existing hydrogen lines constructed of mild steels have not exhibited hydrogen embrittlement problems. Hydrogen embrittlement does cause troubles with conventional natural gas pipelines under conditions of corrosive attack. In these cases, "atomic hydrogen" formed at the corrosion site can and does penetrate into the lattice structure of the steel. On the other hand, molecular hydrogen inside a pipe will be unable to penetrate at normal operating temperatures and pressures (below 2000 psia) and presents no additional problems in causing intergranular embrittlement.

However, in examining this question of materials compatibility with hydrogen, an area of concern was identified and looked into in preliminary detail. A relatively recently observed phenomenon, under present investigation by the National Aeronautics and Space Administration (NASA), has been termed "hydrogen environment embrittlement."

The term "environment" is used because the phenomenon under study relates to the effect of hydrogen on the surface of materials. This is as opposed to other embrittlement phenomena, better known than this environmental effect, in which hydrogen presence within the material is the cause of difficulties in some materials. This latter could be referred to as "classical embrittlement."

Over the period of the last 5 or 6 years, various NASA facilities experienced a rash of failures in high-pressure hydrogen storage vessels which were operating well within design limits. In every case the hydrogen was of high purity, typically derived as boil-off from liquid hydrogen, which is at very high purity as a result of the low cryogenic temperatures at which all possible contaminants (with the exception of helium) have been removed as solids. These failures were frequently in the welded sections of vessels that were made up of assembled sections, such as cylindrical sections plus end pieces with fabricated bosses. (This is a significant point because the normal, commercial high-pressure steel "bottle" is typically a one-piece, forged unit; so far, these vessels have not experienced the hydrogen environment embrittlement failures.



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FOOTNOTES

(A) A section made of A106 pipe was found to be attacked to 27% of its thickness after 5745 hours. Other pieces of pipe in the same line were unaffected.
(B) The attack was concentrated in the overheated section of a hot bent steel elbow. The straight portions of the elbow which had not been heated were not affected.
(C) In a series of 29 steel samples, 12 were attacked while the other 17 were not.
(D) After two years exposure, 5 out of 6 pieces of carbon steel pipe were attacked. One piece of pipe was unaffected.
(E) Attack was concentrated in the weld and heat affected sections of A106 pipe. Metal on each side of this zone was unaffected.
(F) After 11 years service, attack was found in hot bent section of A106 pipe. Straight sections not heated were unaffected.
(G) After 2 years service all parts of carbon steel pipe including welds and heat affected zones were satisfactory.
(H) After 4 years' service, weld and heat affected zones of A106 pipe showed cracks.
(J) After 31 years service a steel forging containing 0.3% C, 1.3% Cr, 0.25% Mo showed cracks 0.007" deep.
(K) 1.25% Cr - 0.5% Mo Steel Pipes.
(L) After 4 years service a forging containing 0.3% C, 1.3% Cr, 0.25% Mo was unaffected
(M) After 4 years service a forging containing 0.2% C, 1.2% Cr, 0.35% Mo showed cracks 0.032" deep.
(N) After 7 years service a forging containing 0.3% C, 1.52% Cr, 0.50% Mo showed cracks 0.050" deep.
(P) After 30 years service a forging containing 0.30% C 0.74 Cr, 0.43% Ni was unaffected.
(Q) After 15 years in ammonia service a pipe containing 0.15% C, 2.25% Cr, 1.00% Mo showed no hydrogen cracks but was nitrided to depth of 0.012".

Figure IV-2. OPERATING LIMITS FOR STEELS IN HYDROGEN SERVICE[10]

Based on these incidents, NASA Headquarters initiated an inter-Center study of the hydrogen environment embrittlement failure mechanism several years ago. Both contracted efforts and NASA in-house investigations were launched, and are continuing at Marshall Space Flight Center, Huntsville, Ala.; Lewis Research Center, Cleveland, Ohio; and the Ames Research Center, Mountain View, Calif.; and under contract by the Rocketdyne Division of North American Rockwell and the Pratt & Whitney Aircraft Division of United Aircraft Corporation. A previously published report by Rocketdyne[7] was found to be very helpful in obtaining background information.

We discussed the problem with NASA Headquarters, Marshall Space Flight Center, and the Lewis Research Center. We were shown a specimen of high-strength pressure vessel material, A-302, Grade B, which demonstrated the surface cracking mode of failure under tension. This sample showed a great number of circumferential cracks in the area where the cross section had been reduced. The tension specimen tested in 10,000-psi pure hydrogen failed because of cracking. A similar specimen subjected to tension in a high-pressure air environment showed no cracks, failing in simple tension at considerably higher levels of induced stress.

NASA indicated that the failed pressure vessels noted earlier all had similar surface cracking in the vicinity of the ultimate failure. However, the specific mechanism for cracking has apparently not yet been identified. A rough correlation has been achieved, however, between the appearance of the cracked area and the degree of severity with which a given material is attacked. A ranking of "extremely, severely, moderately, etc.," is used to denote this degree of severity by the research personnel.

Where a case of "extreme" hydrogen attack is noted, as for certain high-strength Maraging steels, only a few very large cracks are usually noted, with one of these developing into a tensile fracture. On the other hand, "moderately" attacked metals such as the metastable stainless steels of the austenitic family, e.g., SS-304, 305, and 310, show a large number of shallow cracks under hydrogen exposure.

A listing of a number of materials grouped by the degree of severity of the hydrogen environment is presented in Table IV-1.

Table IV-1. MATERIALS GROUPED BY SUSCEPTIBILITY TO HYDROGEN ENVIRONMENT EMBRITTLEMENT

(Source: H. Gray, Materials and Structures Division, NASA Lewis Research Center)

Extremely Susceptible to Attack	High strength steels Maraging 410, 440C, 430F H-11, 4140 17-4PH, 17-7PH
Severely Attacked	Nickel and nickel alloys Nickel 200, 270 Inconel 625, 70, 718 Rene 41 Hastelloy X Waspalloy, Udimet 700
	Titanium alloys Ti-6Al-4V Ti-5Al-2.5Sn
NOTE: The performance of pipeline steels of the X42... X65 series with 0.26-0.31% C is anticipated to be in this grouping. →	Low-strength steels Armco Iron, HY-100 1042, A-302, A-517
	Cobalt alloys S-816, HS-188
Moderately Attacked	Metastable stainless steels 304L, 305, 310
Not Attacked	K-Monel Be-Cu Alloy 25 Pure titanium Aluminum and copper alloys Stable austenitic stainless steels 316, 347, A-286

Note that typical low-strength steels (as used in pipelines) are listed as "severely attacked." However, it should be emphasized that the actual conditions for hydrogen environment embrittlement should be further examined in order to determine whether or not they exist in typical pipeline operation.

Limited work on hydrogen environment embrittlement has been noted in mild carbon steels used in gas pipelines. Some German work[4] limited to studies of ductility loss (reduction in area) dealt with steels of this class and reported effects on hydrogen environment embrittlement. More work focused on the specific pipeline conditions and materials is needed.

In the contacts with NASA, and as derived from Reference 7, a number of conditions are seen which characterize the failures. Among these are the following:

- Temperature: Room temperature hydrogen is the most severe case; the problem does not occur at cryogenic temperatures, nor above about 1200°F.
- Pressure: Failures are more severe at high pressure, with one correlation attempted showing a pressure to the one-half power relationship with attack severity.
- Hydrogen Purity: Hydrogen of high purity appears to offer the worst condition for attack. Oxygen as an impurity at 0.6-0.7% and even lower concentrations has been noted to completely inhibit hydrogen attack by preferential combination with any freshly yielded metal areas. Moisture has a similar effect, but is far less effective than oxygen.

Another condition that appears to be necessary for hydrogen environment embrittlement to occur is that the metal must undergo local or general yielding in the presence of hydrogen. That is, failures have not been experienced in cases of elastic straining of pressure vessels and test specimens. In the case of the pressure vessels that initially failed, causing attention to be given to the problem, it is suspected that local inelastic straining in the areas of discontinuities and weld-associated induced stresses had occurred in the regions of materials failure.

This observation suggests that it may be the welded joints of pipelines where a close examination for susceptibility of hydrogen environment effects should be made in future work.

Hydrogen environment embrittlement has thus been identified as a potential problem that must be addressed in future study of the hydrogen-energy transmission concept. Although materials of construction currently used in pipelines and in the many other components that must be considered in view of their potential exposure to hydrogen once in service have been demonstrated to be susceptible to this mode of metal failure, whether this is a "real" problem of concern or not is unclear at this moment. Consider the very large amount of hydrogen containers and processing pipeline that has survived many years of service without failures being noted. Neither Linde Division of Union Carbide Corporation nor Air Products & Chemicals, Inc., has expressed evidence or concern that hydrogen environment embrittlement in hydrogen equipment is a problem. Indeed, the German hydrogen pipeline system referred to earlier has operated without failure since 1940.

What is suggested is a deepening of the preliminary inquiry made so far into the potential problem area. Some simple materials testing of pipeline steel, both parent and welds (both weld body and heat-affected zones) could be examined in the hydrogen environment in a simple apparatus. This phenomenon is under active study by NASA. A parallel study to ensure that typical pipeline conditions and materials are included is required.

E. Compressor Design

Three types of compressors are applicable for service in hydrogen pipelines:

1. Piston, or reciprocating compressors
2. Radial turbocompressors or centrifugal compressors
3. Screw compressors

Axial turbocompressors might become worth considering if very large volumes are handled.

All of these types can handle hydrogen without significant changes from the basic design used for natural gas, but limits are imposed by the capacity requirements, operating pressures, pressure ratios, and pressure differences.

Reciprocating compressors present the simplest case. No problems are anticipated in operating them at any pressure, but because they are positive-displacement machines, their size must be increased in the inverse ratio of the volumetric heating value of the gas at the operating pressure to deliver the same energy content. For hydrogen, this nearly fourfold increase might be uneconomical. Existing reciprocating compressors will be too small to handle the same energy throughput of hydrogen as they carry with natural gas. They will deliver 26% of the energy capacity at 750 psi.

Because no special design changes are required for natural gas reciprocating compressors converted to hydrogen service, we can make a good comparison of their behavior when handling the two different gases. After lengthy calculations, which appear in Appendix IV-A, we concluded that —

a. For the same pressure ratio, the volumetric efficiency will not change appreciably.

b. The relative volumetric efficiency will improve for hydrogen if the compressor is operated at lower pressure ratios.

c. The adiabatic efficiency on hydrogen will be higher than on natural gas at the same pressure ratio, while at lower pressure ratios, the adiabatic efficiencies on hydrogen and natural gas will be equal.

For radial turbocompressors, the limiting factor is the pressure ratio achievable in one stage. This is because this type of machine converts kinetic energy into a pressure head, and the pressure ratio is directly proportional to the rotor tip speed and dependent on a) the physical properties of the gas and b) the rotor and diffuser geometries. For such a light gas as hydrogen, achievable pressure ratios are far lower than obtainable with natural gas at the same tip speed. The maximum tip speed is limited by the mechanical properties of the rotor.

A radial turbocompressor designed to handle natural gas at a pressure ratio of 1.3 at a rotor tip speed of 800 ft/s would only generate a pressure ratio of 1.027 on hydrogen. If the rotor tip speed could be increased, for example, to 1300 ft/s, a pressure ratio of only 1.075 could be reached. To achieve a pressure ratio of 1.3, a tip speed of about 2500 ft/s is required; even with complete redesign, this is not attainable.

One way of achieving higher pressure ratios is to construct a multistage compressor. Pressure ratios of 1.3 would require seven or eight stages at conventional speeds. However, until complete pipeline optimization studies are completed, it is not clear that such high pressure ratios are optimum for hydrogen, as they are for natural gas. Because the volume of gas handled by a turbocompressor is fixed by the blade geometry and rotation speed, the volume capacity of a given machine will be the same for both gases, so the energy throughput on hydrogen is smaller than that on natural gas in inverse proportion to the gas heating values. The maximum energy throughput on hydrogen will be 26% that of natural gas at 750 psi. Because of the lower density of hydrogen, it will tend to leak back around the rotor; thus, the efficiency of a compressor designed for natural gas, when operated on hydrogen, is expected to decrease. Nevertheless, properly designed compressors for hydrogen service should have efficiencies as high as those for natural gas.

Screw compressors have not been used in very high-pressure applications (above about 600 psi). However, they combine the valuable features of both positive-displacement and dynamic machines, and are "oil free." Therefore, if developed for higher pressure application, they could be valuable for hydrogen pipeline service.

F. Hydrogen Pipeline Design

A thorough search of the available literature failed to identify a design system for a hydrogen pipeline analogous to those in use for natural gas today. We know of only one theoretical paper[13] which deals with the capacity and pumping energy of a hydrogen pipeline, but this is not devoted to hydrogen transmission specifically, and is restricted to dealing with a 20-inch pipeline. We therefore had to carry out our own calculations from first principles in order to compare the capacities and costs of hydrogen and natural gas transmission lines.

We set out first to determine the behavior of an existing natural gas pipeline if it were converted to carry hydrogen. We wanted to know the capacity of the line with no mechanical modifications and the effect of the conversion on capacity of various possible modifications to compressor equipment. We carried out these calculations on a "compression section" (a length of pipeline between two compressor stations) in a hypothetical pipeline. We then carried out a brief cost analysis of such a compression section, with cooperation from a pipeline company (Natural Gas Pipeline Company) and a compressor manufacturer (Ingersoll-Rand Company) and were able to estimate the costs of constructing and operating such a pipeline.

The calculations required to carry out the exercises outlined above were lengthy and detailed. They are summarized here very briefly, and worked through in more detail in Appendix IV-A.

At the outset of the study, we used data taken from Reference 13 which suggested that, for natural gas pipelines, compressor pressure ratios of about 1.3 are normally used. Applying this figure to data provided by Natural Gas Pipeline, which indicated that typical pressure drops were about 3 psi/mile and typical average operating pressures were about 750 psig, we determined a compressor station spacing of 65 miles. Thus, our assumed reference conditions for the natural gas compression section are —

Pressure Ratio, π_{NG}	1.3
Average Pressure Drop, ΔP	3 psi/mile
Average Pressure, P_{avg}	750 psig
Average Temperature, T_{avg}	520^0R
Average Compression Section Length, L	65 miles

Other reference data we assumed are given in Table IV-2.

In subsequent discussions we observed that many natural gas pipeline compressors are operated at pressure ratios of about 1.5. With the same average pressures and pressure drops as noted before, this requires a compressor spacing of about 100 miles. For hydrogen, optimum pressure ratios and spacings are unlikely to be the same as for natural gas, but we have been unable to optimize them within the scope of this study. Meanwhile, our calculations are based upon an actual compression section of 65 miles. We have extrapolated data, where necessary, to yield figures appropriate to a 100-mile distance.

To evaluate the comparative throughput capacity of a compression section on hydrogen and natural gas, we had to make assumptions about the relative volumetric efficiencies of the compressors operating on each gas. For reciprocating compressors, we assumed the identical machine, running at the same speed, would be used; after a lengthy calculation, we determined that the volumetric efficiencies were 90% and 89% on natural gas and hydrogen if the pressure ratios were the same. For radial turbocompressors we observed that the efficiency was determined by the matching of the tip speed with the physical characteristics of the gas and that inferior performance would be obtained if a compressor

Table IV-2. REFERENCE DATA FOR NATURAL GAS PIPELINES

	Pipeline Diameters, in.			
	24	30	36	42
Gas Flow Rate at 14.62 psia, 60^0F, 10^6 CF/day (See Appendix IV-A.)	285	525	860	1280
Btu Flow Rate (Gross), 10^9 Btu/yr	109,162	201,206	325,080	490,560
Station Capacity (V_2) at Standard Conditions, SCF/min	197,916	364,583	597,222	888,888
V_2 at Suction Conditions, CF/min	3,934.6	7,248	11,872.9	17,671.2
Power Input (W) (Station Without Auxiliaries), hp	3,703.5	6,822	11,175	16,633
Power Input (W), Btu/min	157,176	289,525	474,267	705,914
Fuel Flow Rate (V_{2f}), SCF/min	373	687	1,125	1,674
Net Gas Flow Rate (Standard Conditions) ($V_{2_{net}}$), SCF/min	197,543	363,896	596,097	887,214
Net Gas Flow Rate (Inlet Conditions) ($V_{2_{net}}$), CF/min	3,927.2	7,234.3	11,850.5	17,638

Other Assumptions:

Total adiabatic efficiency of compressors: $\eta_{tad} = 0.8$

Total engine efficiency: $\eta_E = 0.4$

designed for natural gas were operated on hydrogen. We therefore assumed that a radial turbocompressor would be replaced by one designed expressly for hydrogen and would then have the same efficiency. Thus, we assumed that the compressor efficiencies would be the same for both gases in all cases.

Using the basic flow equations for a pipeline, we calculated the volumetric flow capacity of the compression section for natural gas and hydrogen. In order to determine the relative energy transmission capacity (the Btu/hr transmitted), we had to consider the relative heating values (Btu/CF) of the two gases. At atmospheric pressure, these are roughly in the hydrogen/natural gas ratio of 1:3. However, due to the different compressibility factors, this ratio changes as the pressure is increased. We determined the appropriate ratio at different pressures; at 750 psig it is 1:3.83. We also required data on the specific heat ratio for hydrogen over a wide pressure range and extrapolated to high pressures the data we could find in the literature, which were confined to below 100 atm.

The results of these calculations are displayed in Figure IV-3, which shows the relative energy delivery rates on hydrogen and natural gas of pipelines operating at different average pressures. Two sets of curves are superimposed: One set shows the effect of varying the compressor capacity (i.e., the swept volume of the compressor) while the other shows the effect of varying the compressor input horsepower. Both of these values are given as relative numbers, referred to 1.0 as the standard condition for the original pipeline.

From this curve we can interpolate the relative energy carrying capacities of pipeline sections at any given pressure from 100 to 6000 psia if no changes are made to compressor capacities. We can also determine a) what would be the effect of changing either the engine horsepower or the compressor swept volume and b) what changes in compressor equipment are needed in order to give the pipeline its original energy-carrying capacity.

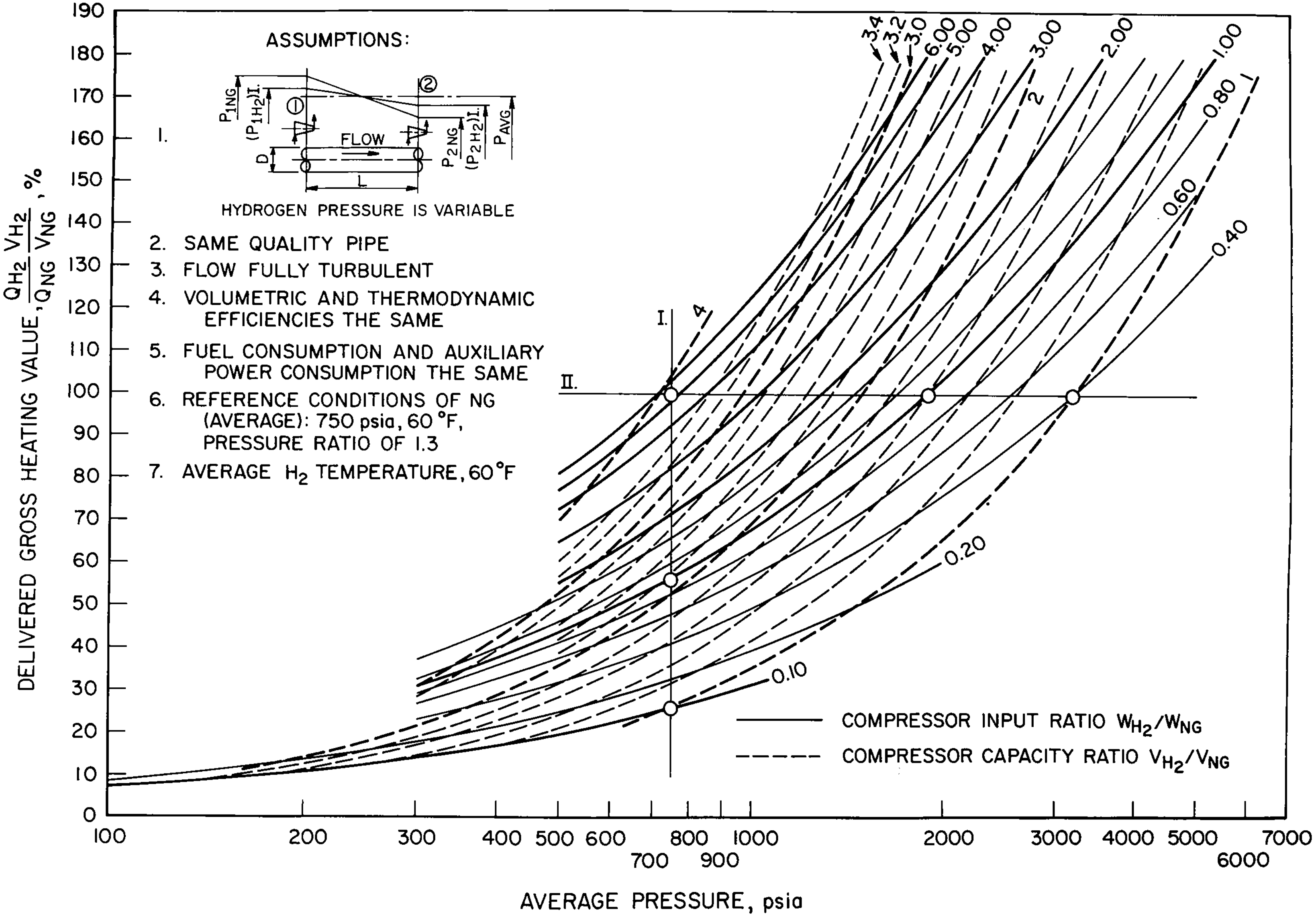

Figure IV-3. RELATIVE ENERGY TRANSMISSION CAPABILITY AND REQUIRED COMPRESSOR CAPACITY AND HORSEPOWER OF A HYDROGEN PIPELINE AT VARIOUS PRESSURES COMPARED WITH NATURAL GAS AT 750 psia, 60°F, AND COMPRESSOR SPACING CORRESPONDING TO THE PRESSURE RATIO π_{NG} = 1.3:1

Some points of interest are summarized in Table IV-3, which indicates that an unmodified natural gas line would be severely reduced in capacity, to about 26% of its original value, if hydrogen was to be substituted without modification.

Table IV-3. RELATIVE CAPACITY OF TRANSMISSION LINE ON HYDROGEN AND NATURAL GAS AT 750 psia

Gas	Compressor Capacity	Compressor Horsepower	Energy Delivery Rate
Natural	1.0	1.0	1.0
Hydrogen	1.0	0.1	0.26
	2.1	1.0	0.56
	3.8	5.5	1.0

Note that these figures relate to the assumption that compressor efficiency is unchanged, valid only for reciprocating compressors and not for radial turbocompressors. Table IV-3 also indicates that modifications in both the compressor and the engines must be made in order to recover the original capacity of the line. In this case, turbocompressors would be replaced with custom-designed equipment intended for hydrogen service. Considerable benefit would result from operating the line at a higher pressure, but this is considered impracticable for existing pipelines.

We calculate that a turbocompressor operating at its original fixed speed would deliver a pressure ratio of only 1.027. Assuming that the reduced flow rate does not in turn reduce this ratio still further and neglecting the lower efficiency anticipated with hydrogen, the capacity of the pipeline would thus be reduced to 24% or less if no modifications were made.

Nothing can be learned from Figure IV-3 about the effect of adding extra compressor stations at intermediate points, which must be studied separately, or of increasing the number of parallel pipelines between existing compressor stations. In the latter case, we were able to calculate the changes in compressor capacity and engine input required in order to deliver the original energy capacity of the pipeline, using one, two, three, or four parallel lines of the same diameter as the original. The use of multiple pipelines has the effect of reducing the pressure ratio at the compressors, clearly an advantage if turbocompressors are used. These data are summarized in Figure IV-4. At 750 psia, we

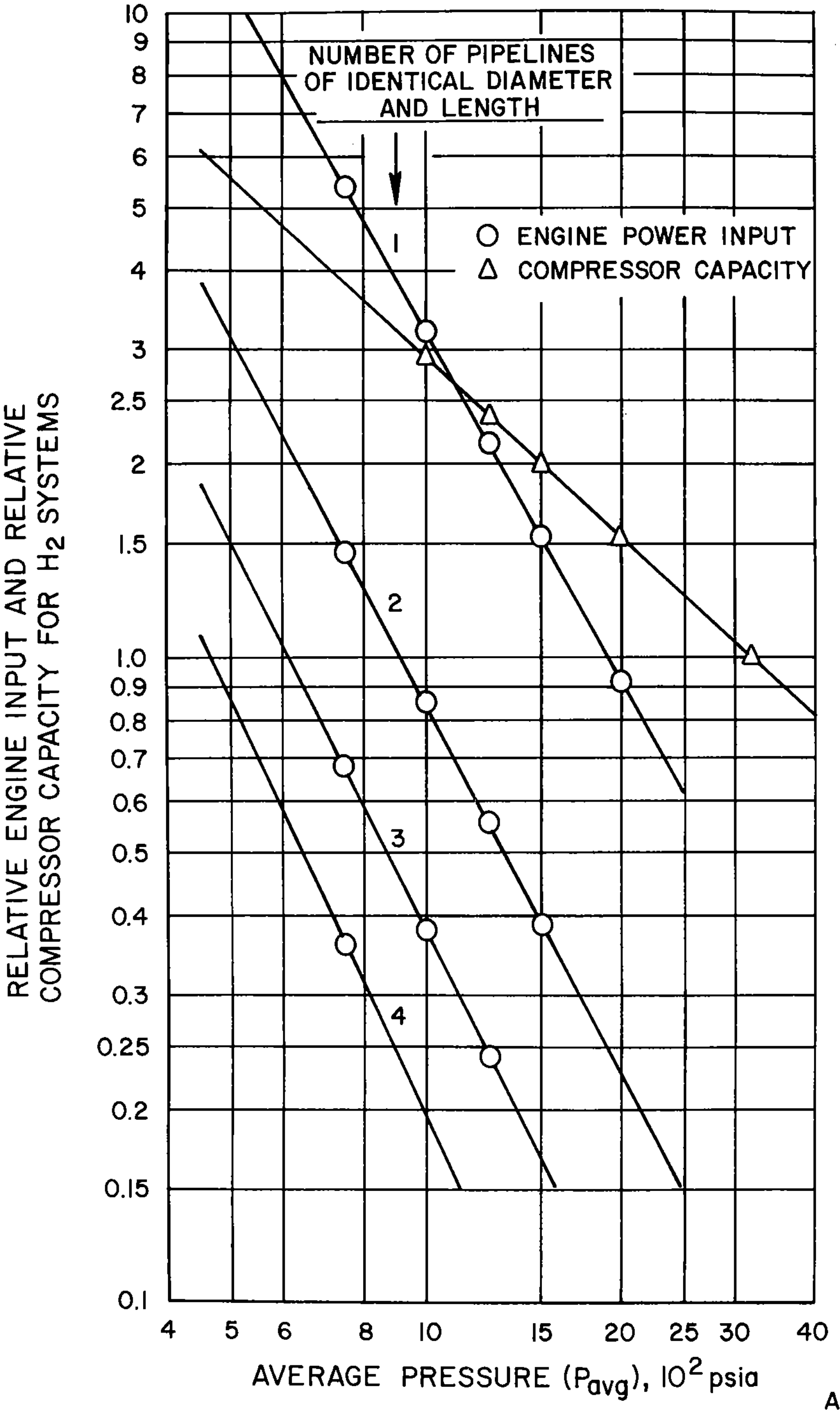

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Figure IV-4. RELATIVE CHARACTERISTICS OF HYDROGEN TRANSMISSION LINE COMPRESSOR SECTION DELIVERING 100% OF GROSS HEATING VALUE OF THE COMPARATIVE NATURAL GAS SYSTEM note that very considerable reduction in compressor horsepower is obtained if more than one parallel line is used, though the compressor swept volume requirement is unchanged.

Further analysis of the preferred changes in an existing pipeline necessary to operate it on hydrogen must be carried out for each system on a custom design basis. The basic equations required to do this are now available in Appendix IV-A. We can summarize our findings so far in the following way:

- Reciprocating compressors will operate satisfactorily on hydrogen.
- Radial turbocompressors will not operate properly on hydrogen and must be replaced with turbocompressors specifically designed for hydrogen service.
- Without modifications, an existing natural gas pipeline equipped with reciprocating compressors will exhibit a marked reduction in capacity on hydrogen on an energy basis.
- To restore the original energy capacity of such a pipeline, both the compressors and their engines will have to be augmented.
- The addition of extra pipelines in parallel will allow the same engine horsepower to be used, with extra compressor capacity still being required.

The existing transmission systems for natural gas have been optimized for operation on a very cheap fuel, and therefore we have observed that the design is such that capital or installation costs are kept to a minimum. If we substitute hydrogen, at a cost of \$3.00/million Btu for natural gas at a cost of, say, \$0.25/million Btu as a compressor fuel, the optimization becomes very sensitive to fuel costs, and the actual capital costs are likely to be somewhat higher in a fully optimized system.

Thus, very misleading and pessimistic results are obtained if we try to calculate the operating costs of existing pipeline systems converted to natural gas simply by modifying the compressor stations. It is very important to recalculate from first principles the actual costs of moving hydrogen in a pipeline system fully optimized for hydrogen, in which the compressor stations, the station spacing, the pipe diameters, and the number of parallel pipes are all variable.

Evidently then, to take greatest advantage of the potentially low transmission cost of hydrogen, a new, specially designed system is required. In many cases, parts of an existing system will be useful, augmented by extra equipment in an appropriate way. We carried out a cost analysis of a compressor section optimized for operation on hydrogen, but staying with the basic assumptions of compressor spacing assumed before. To carry out a full optimization in which these variables too are optimized, a long iterative calculation is necessary, requiring feedback of compressor design data. Such computations were outside the scope of the present study.

We calculated the compression section transmission cost from data and methods suggested by Natural Gas Pipeline Company, using its suggested pipeline materials costs and depreciation rates, and its station operating cost. We assumed properly designed radial turbocompressors and gas turbines for hydrogen service, and obtained cost estimates for these from Ingersoll-Rand. We assumed the cost of hydrogen to be used as a fuel for the compressor engines would be \$3.00/million Btu, but also carried out calculations for \$1.00 and \$2.00/million Btu fuel costs to determine the sensitivity of costs to this rather uncertain variable. The costs were calculated for pipe sizes of 24, 30, 36, and 42 inches, and were carried out for one, two, three, and four parallel pipelines — corresponding to a reduction in the operating pressure ratio, using a figure of 1.3 for a single pipe as a reference point.

The results are tabulated in Table IV-4 and are plotted in Figures IV-5 to IV-8 for each of four operating pressures. To summarize all these results, we plotted the minimum of these curves, or minimum transmission costs, for pressures of 750 and 2000 psia, based on a fuel cost of \$3.00/million Btu, against the maximum throughput of the pipeline to which the cost referred. To obtain comparative units, we linearly extrapolated our cost data for a 65-mile section to a "cents per million Btu per 100 mile" basis. These data are shown in Figure IV-9. In comparing these data with typical natural gas transmission costs, we encountered difficulty in obtaining up-to-date figures. An average current value for natural gas for a high-throughput line is about 1.5¢/million Btu per 100 miles. We also obtained some 10-year-old transmission cost data[5] from the Natural Gas Pipeline Company (Figure IV-10), and

Table IV-4. HYDROGEN TRANSMISSION COST BREAKDOWN AT AVERAGE PRESSURES OF 750, 1000, 1500, AND 2000 psia

			AVERAGE OPERATING PRESSURE, psia															
			750				1000				1500				2000			
	Cost Item		PIPE DIAMETER (D), in.															
			24	30	36	42	24	30	36	42	24	30	36	42	24	30	36	42
NUMBER OF PARALLEL LINES			$\$/10^9$ Btu (GROSS HEATING VALUE)				$\$/10^9$ Btu (GROSS HEATING VALUE)				$\$/10^9$ Btu (GROSS HEATING VALUE)				$\$/10^9$ Btu (GROSS HEATING VALUE)			
D	$\frac{\text{13\% OF STATION \& LABOR COSTS}}{\text{DELIVERED HEATING VALUE / yr}}$		4.480	3.850	3.510	3.270	2.800	2.140	1.960	1.850	1.660	1.230	0.960	0.870	1.160	0.880	0.690	0.570
	$\frac{\text{13\% OF PIPELINE MATERIAL \& LABOR COSTS}}{\text{DELIVERED HEATING VALUE / yr}}$		11.920	8.950	6.940	5.290	13.550	10.160	7.880	6.050	15.790	11.970	9.330	7.320	16.030	12.430	9.620	7.630
	$\frac{\text{OPERATING COST / yr}}{\text{DELIVERED HEATING VALUE / yr}}$		2.520	2.260	2.070	1.920	1.520	1.360	1.250	1.150	0.860	0.700	0.640	0.600	0.610	0.480	0.400	0.370
	SUBTOTAL		18.920	15.060	12.520	10.480	17.870	13.660	11.090	9.050	18.310	13.900	10.930	8.790	17.800	13.790	10.710	8.570
	$\frac{\text{TRANSMISSION COST OF FUEL / yr}}{\text{DELIVERED HEATING VALUE / yr}}$		0.310	0.246	0.205	0.171	0.160	0.123	0.100	0.081	0.074	0.056	0.044	0.035	0.041	0.032	0.025	0.019
	TRANSMISSION COST WITHOUT FUEL		19.230	15.306	12.725	10.651	18.030	13.783	11.190	9.131	18.384	13.956	10.974	8.825	17.841	13.822	10.735	8.589
	$\frac{\text{FUEL IN } (10^9 \text{ Btu / yr}) \times (1000\ \$ / 10^9 \text{ Btu})}{\text{DELIVERED HEATING VALUE IN } 10^9 \text{ Btu / yr}}$		16.184	16.184	16.184	16.184	8.953	8.953	8.953	8.953	4.004	4.004	4.004	4.004	2.296	2.296	2.296	2.296
	TRANSMISSION COST FOR THE FUEL COST OF	$\$1/10^6$ Btu	35.414	31.490	28.909	26.835	26.983	22.736	20.143	18.084	22.388	17.960	14.978	12.829	20.137	16.118	13.031	10.885
		$\$2/10^6$ Btu	51.598	47.674	45.093	43.019	35.936	31.689	29.096	27.037	26.392	21.964	18.982	16.833	22.433	18.414	15.327	13.181
		$\$3/10^6$ Btu	67.782	63.858	61.277	59.203	44.889	40.642	38.049	35.990	30.396	25.968	22.986	20.868	24.729	20.710	17.623	15.477
2D	$\frac{\text{13\% OF STATION \& LABOR COSTS}}{\text{DELIVERED HEATING VALUE / yr}}$		1.610	1.220	0.950	0.880	1.080	0.860	0.690	0.590	0.690	0.530	0.430	0.370	0.530	0.390	0.310	0.260
	$\frac{\text{13\% OF PIPELINE MATERIAL \& LABOR COSTS}}{\text{DELIVERED HEATING VALUE / yr}}$		23.840	17.900	13.880	10.580	27.100	20.320	15.760	12.010	31.580	23.940	18.660	14.640	32.060	24.860	19.240	15.260
	$\frac{\text{OPERATING COST / yr}}{\text{DELIVERED HEATING VALUE / yr}}$		0.830	0.660	0.600	0.560	0.580	0.460	0.390	0.350	0.360	0.290	0.220	0.200	0.250	0.200	0.170	0.140
	SUBTOTAL		26.280	19.780	15.430	12.020	28.760	21.640	16.840	12.950	32.630	24.760	19.310	15.210	32.840	25.450	19.720	15.660
	$\frac{\text{TRANSMISSION COST OF FUEL / yr}}{\text{DELIVERED HEATING VALUE / yr}}$		0.098	0.073	0.057	0.045	0.060	0.046	0.035	0.027	0.033	0.025	0.019	0.015	0.018	0.014	0.011	0.009
	TRANSMISSION COST WITHOUT FUEL		26.378	19.853	15.487	12.065	28.820	21.686	16.875	12.977	32.663	24.785	19.329	15.225	32.858	25.465	19.731	30.823
	$\frac{\text{FUEL IN } (10^9 \text{ Btu / yr}) \times (1000\ \$ / 10^9 \text{ Btu})}{\text{DELIVERED HEATING VALUE IN } 10^9 \text{ Btu / yr}}$		3.738	3.738	3.738	3.738	2.151	2.151	2.151	2.151	0.994	0.994	0.994	0.994	0.562	0.562	0.562	0.562
	TRANSMISSION COST FOR THE FUEL COST OF	$\$1/10^6$ Btu	30.116	23.591	19.225	15.803	30.971	23.837	19.026	15.128	33.657	25.779	20.323	16.219	33.420	26.026	20.293	16.231
		$\$2/10^6$ Btu	33.854	27.329	22.963	19.541	33.122	31.689	21.177	17.279	34.651	26.773	21.317	17.213	33.982	26.588	20.855	16.793
		$\$3/10^6$ Btu	37.592	31.067	26.701	23.279	35.273	28.139	23.328	19.430	35.645	27.767	23.311	18.287	34.544	27.150	21.417	17.355

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Table IV-4, Cont. HYDROGEN TRANSMISSION COST BREAKDOWN AT AVERAGE PRESSURES OF 750, 1000, 1500, AND 2000 psia

NUMBER OF PARALLEL LINES	Cost Item		AVERAGE OPERATING PRESSURE, psia															
			750				1000				1500				2000			
			PIPE DIAMETER (D), in.															
			24	30	36	42	24	30	36	42	24	30	36	42	24	30	36	42
			$/10⁹ Btu (GROSS HEATING VALUE)				$/10⁹ Btu (GROSS HEATING VALUE)				$/10⁹ Btu (GROSS HEATING VALUE)				$/10⁹ Btu (GROSS HEATING VALUE)			
3D	13% OF STATION & LABOR COSTS / DELIVERED HEATING VALUE / yr		0.960	0.750	0.610	0.520	0.680	0.520	0.438	0.370	0.460	0.330	0.260	0.220	0.390	0.270	0.200	0.170
	13% OF PIPELINE MATERIAL & LABOR COSTS / DELIVERED HEATING VALUE / yr		35.760	26.850	20.820	15.870	40.650	30.480	23.640	18.158	47.370	35.910	27.990	21.960	48.090	37.290	28.860	22.890
	OPERATING COST / yr / DELIVERED HEATING VALUE / yr		0.500	0.400	0.330	0.300	0.350	0.280	0.230	0.200	0.210	0.160	0.140	0.120	0.150	0.120	0.100	0.090
	SUBTOTAL		37.220	28.000	21.760	16.690	41.680	31.280	24.300	18.720	48.040	36.400	28.390	22.300	48.630	37.680	29.160	23.150
	TRANSMISSION COST OF FUEL / yr / DELIVERED HEATING VALUE / yr		0.063	0.048	0.037	0.028	0.042	0.031	0.024	0.019	0.019	0.015	0.011	0.009	0.012	0.009	0.007	0.006
	TRANSMISSION COST WITHOUT FUEL		37.283	28.048	21.797	16.718	41.722	31.311	24.324	18.739	48.059	36.415	28.401	22.309	48.642	37.689	29.167	23.156
	FUEL IN (10⁹ Btu / yr) x (1000 $ / 10⁹ Btu) / DELIVERED HEATING VALUE IN 10⁹ Btu / yr		1.671	1.671	1.671	1.671	0.956	0.956	0.956	0.956	10.426	0.426	0.426	0.426	0.249	0.249	0.249	0.249
	TRANSMISSION COST FOR THE FUEL COST OF	$1/10⁶ Btu	38.954	29.719	23.468	18.389	42.678	32.267	25.280	19.695	48.485	36.841	28.827	22.735	48.891	37.938	29.416	23.405
		$2/10⁶ Btu	40.625	31.390	25.139	20.060	43.634	33.223	26.236	20.651	48.911	37.267	29.253	23.161	49.140	38.187	29.665	23.654
		$3/10⁶ Btu	42.296	33.061	26.810	21.731	44.590	34.179	37.192	21.607	49.337	37.693	29.679	23.587	49.389	38.436	29.914	23.903
4D	13% OF STATION & LABOR COSTS / DELIVERED HEATING VALUE / yr		0.680	0.510	0.430	0.370	0.490	0.360	0.290	0.250	0.360	0.240	0.190	0.150	0.320	0.210	0.150	0.120
	13% OF PIPELINE MATERIAL & LABOR COSTS / DELIVERED HEATING VALUE / yr		47.680	35.800	27.760	21.160	44.200	40.640	31.520	24.200	63.160	47.887	37.320	29.280	64.120	49.720	38.480	30.520
	OPERATING COST / yr / DELIVERED HEATING VALUE / yr		0.335	0.267	0.222	0.192	0.230	0.180	0.150	0.130	0.130	0.110	0.090	0.080	0.100	0.080	0.065	0.055
	SUBTOTAL		48.695	36.577	28.412	21.722	54.920	41.180	31.960	24.580	63.650	48.230	37.600	29.510	64.540	50.010	38.695	30.695
	TRANSMISSION COST OF FUEL / yr / DELIVERED HEATING VALUE / yr		0.044	0.033	0.026	0.019	0.027	0.021	0.016	0.012	0.013	0.0096	0.0075	0.0059	0.008	0.006	0.005	0.004
	TRANSMISSION COST WITHOUT FUEL		48.739	36.610	28.438	21.741	54.947	41.201	31.976	24.592	63.663	48.2396	37.6075	29.5159	64.548	50.016	38.700	30.699
	FUEL IN (10⁹ Btu / yr) x (1000 $ / 10⁹ Btu) / DELIVERED HEATING VALUE IN 10⁹ Btu / yr		0.906	0.906	0.906	0.906	0.487	0.487	0.487	0.487	0.285	0.2850	0.2850	0.2850	0.124	0.124	0.124	0.124
	TRANSMISSION COST FOR THE FUEL COST OF	$1/10⁶ Btu	49.645	37.516	29.344	22.647	55.434	41.688	32.463	25.079	63.868	48.4446	37.8125	29.7209	64.672	50.140	38.824	18.084
		$2/10⁶ Btu	50.551	38.422	30.250	23.553	55.921	42.175	32.950	25.566	64.073	48.6496	38.0175	29.9259	64.696	50.264	38.948	30.947
		$3/10⁶ Btu	51.457	39.328	31.156	24.459	56.408	42.662	33.437	26.053	64.278	48.8546	38.2225	30.1309	64.920	50.388	39.072	31.071

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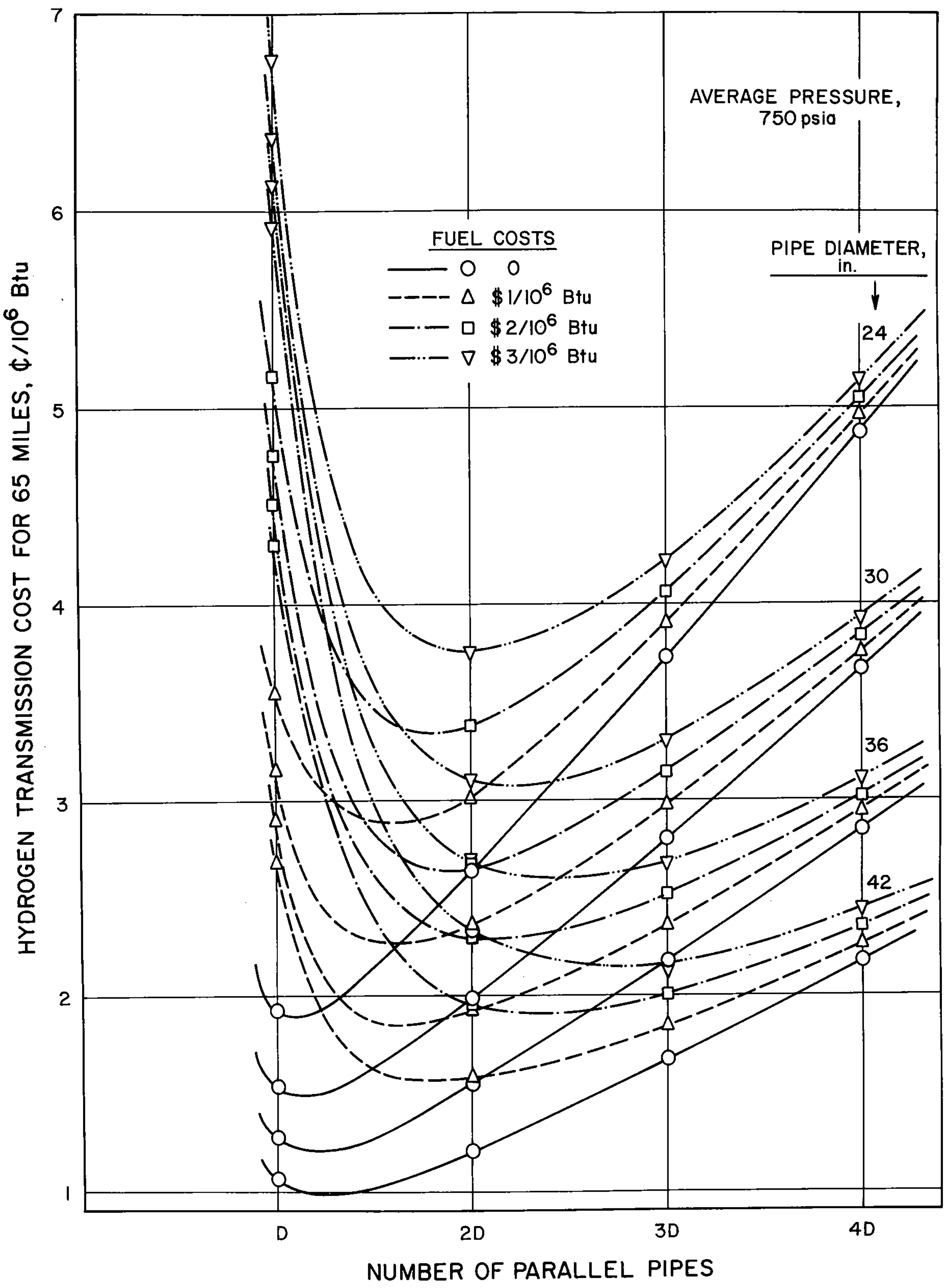

Figure IV-5. HYDROGEN TRANSMISSION COST FOR AVERAGE PRESSURE OF 750 psia

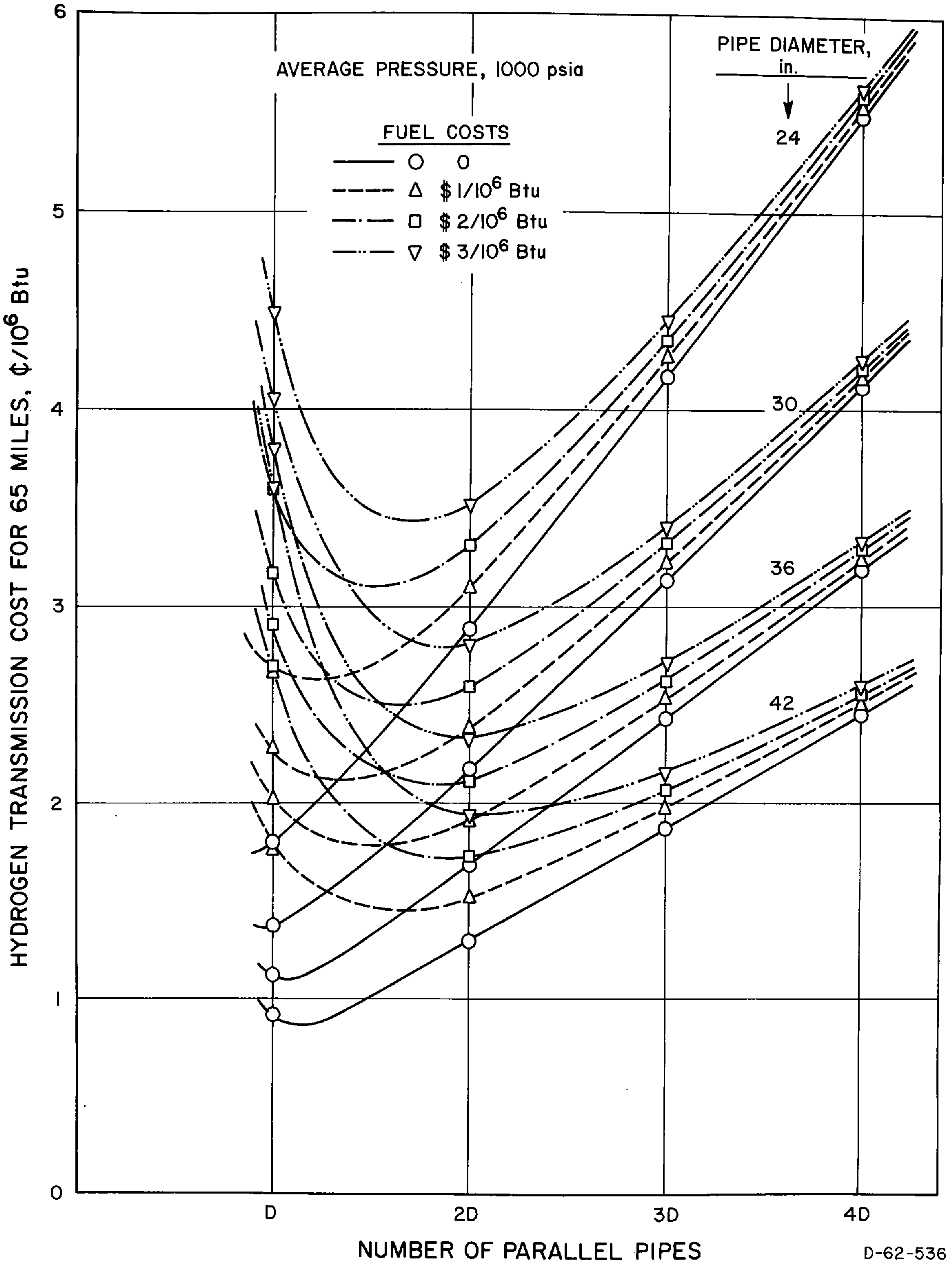

Figure IV-6. HYDROGEN TRANSMISSION COST FOR AVERAGE PRESSURE OF 1000 psia

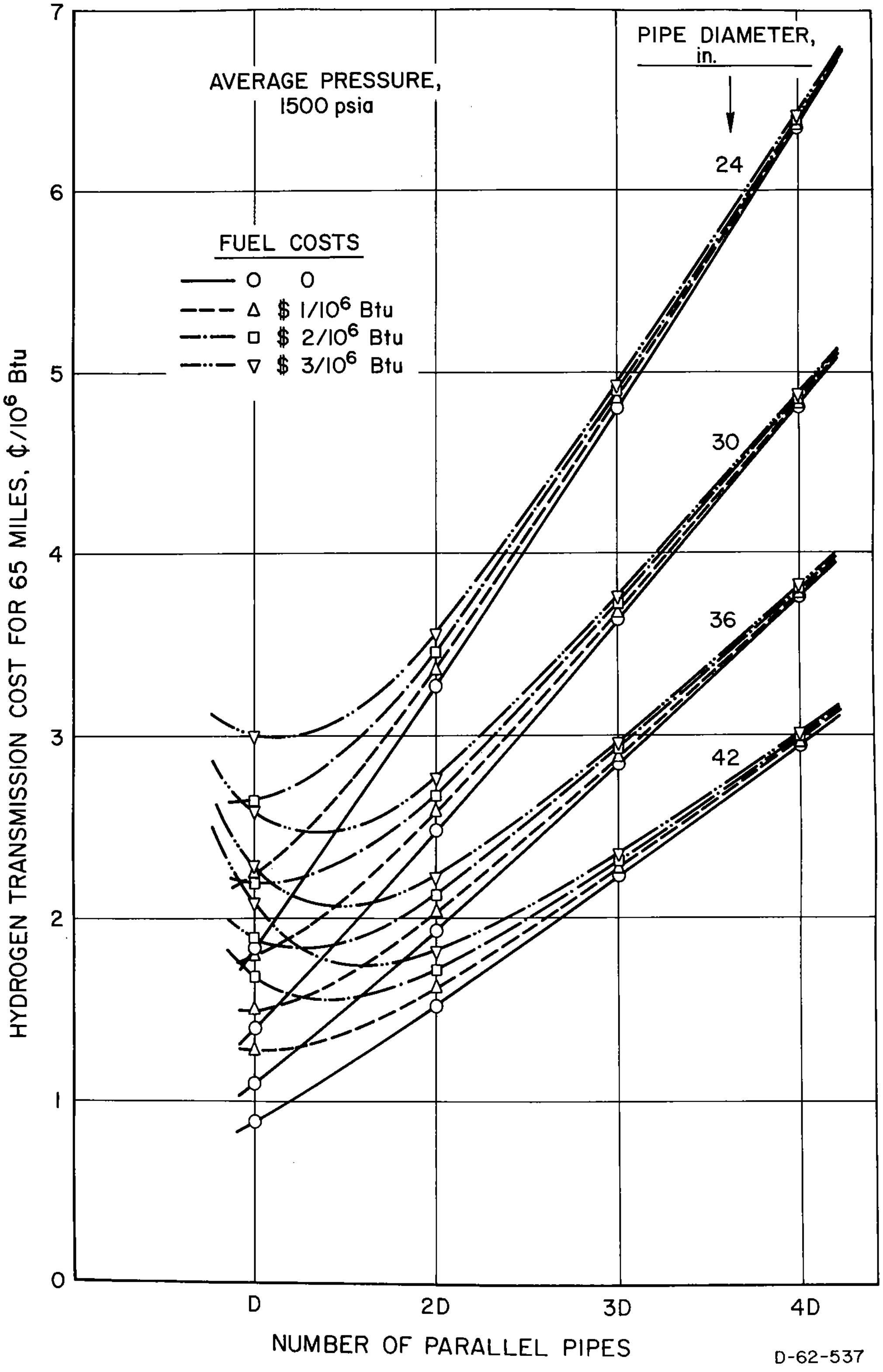

Figure IV-7. HYDROGEN TRANSMISSION COST FOR AVERAGE PRESSURE OF 1500 psia

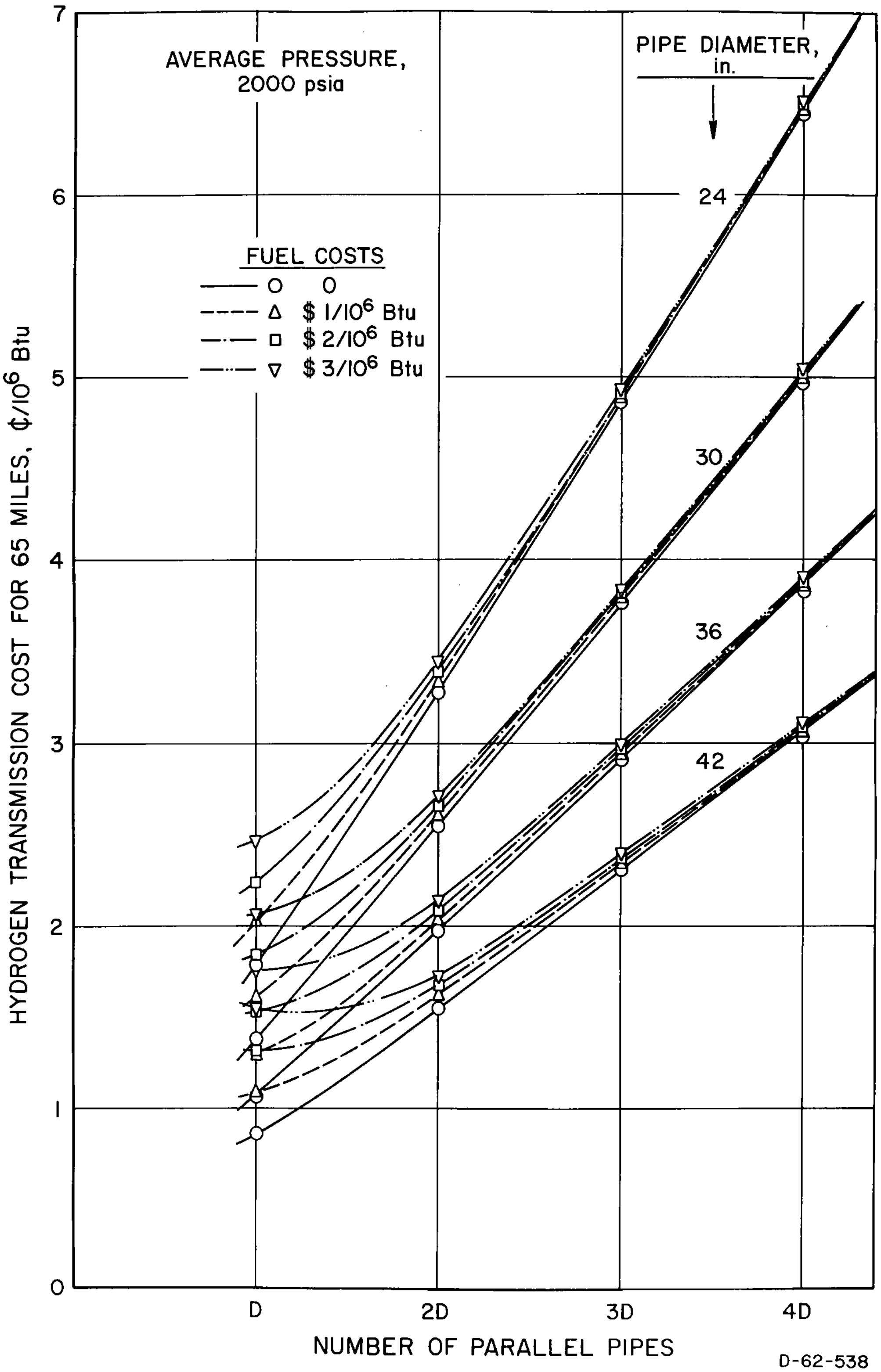

Figure IV-8. HYDROGEN TRANSMISSION COST FOR AVERAGE PRESSURE OF 2000 psia

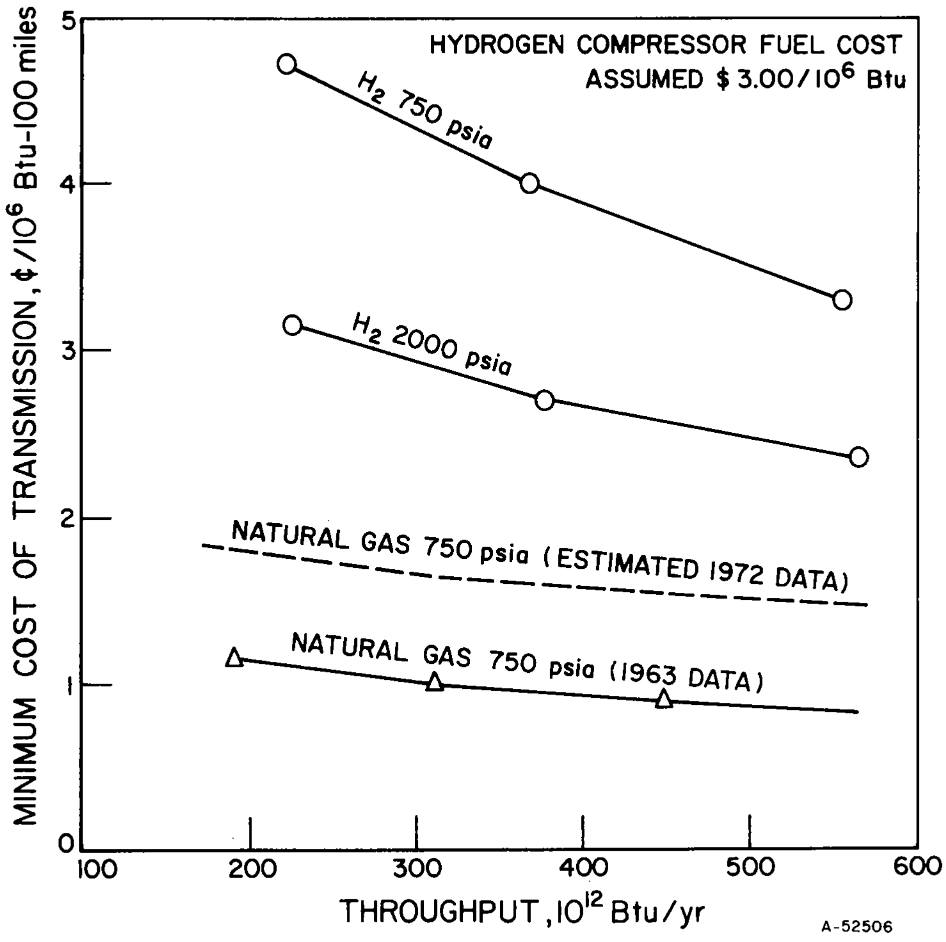

Figure IV-9. OPTIMIZED TRANSMISSION COSTS FOR HYDROGEN COMPARED TO NATURAL GAS

plotted these in Figure IV-9, which serves to show the trend of transmission cost with throughput. From this we can make a rough estimate of 1972 natural gas transmission cost.

Because the data in Figure IV-9 were not optimized for compressor station spacing or pressure ratio, we conclude that the cost of transmission of hydrogen in completely optimized systems will fall on or below the lines shown, which at an average operating pressure of 750 psig range between 3.5¢ and 4.5¢/million Btu per 100 miles. This is a factor of 2 to 3 times the cost of today's natural gas transmission costs. A considerable reduction in cost (about 30%) will result if operating pressures as high as 2000 psi can be considered.

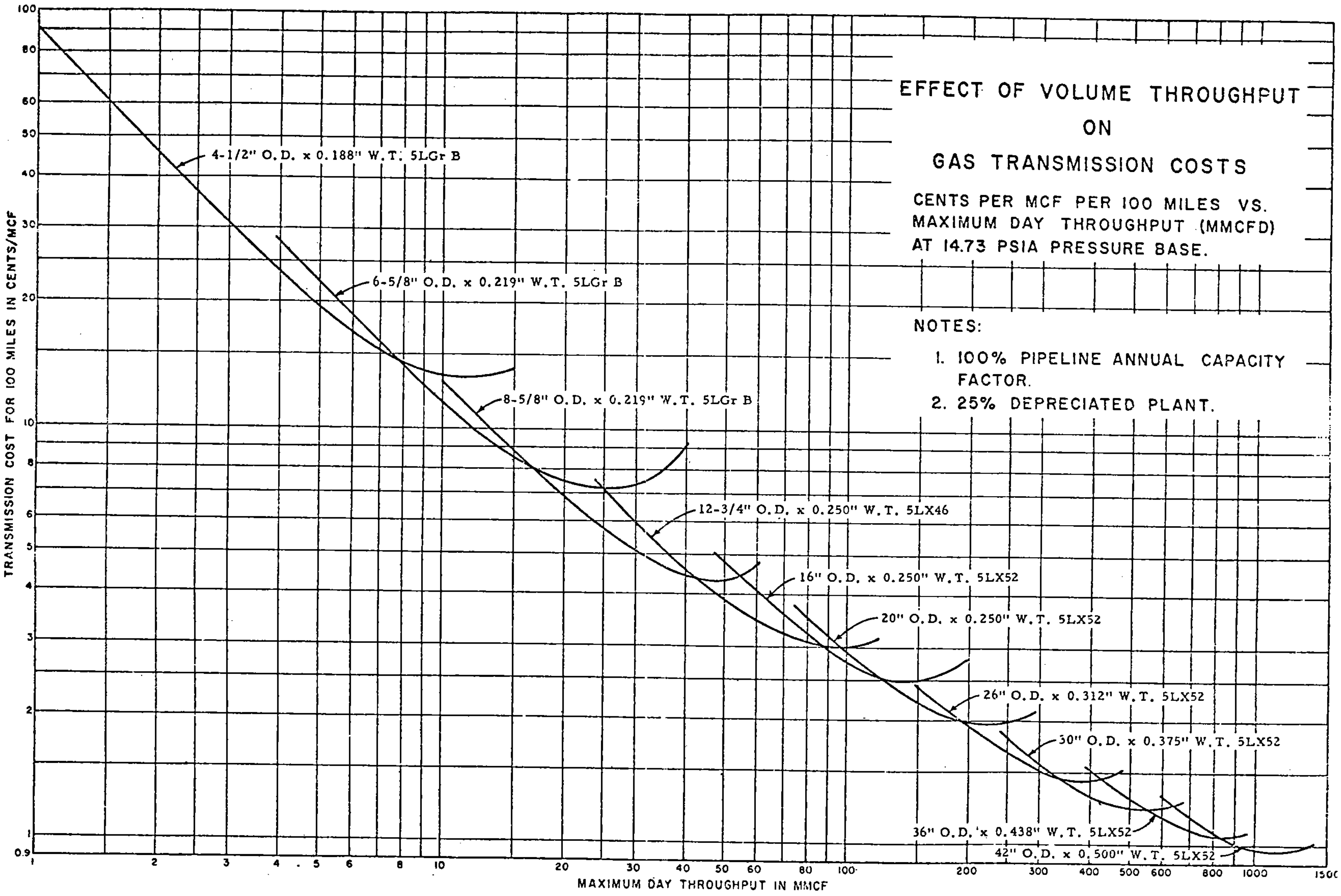

Figure IV-10. EFFECT OF VOLUME THROUGHPUT ON GAS TRANSMISSION COSTS

G. Possibility of Liquid-Hydrogen Transmission

1. Introduction

An alternative to gaseous hydrogen transmission, as discussed above, is transmission of the cryogenic liquid form of hydrogen, with liquefaction being considered an adjunct to production. An analogy with liquefied natural gas (LNG) can be considered relevant for this concept, as a number of studies of LNG pipeline transmission have been carried out in the past (for example, Reference 2).

Pipelining the liquid phase of a gas such as methane offers both a number of advantages and several distinct drawbacks. Among the advantages of liquid transmission are —

a. Much smaller pipelines and lower pumping power (as measured by the amount of the gas consumed at pumping/compressor stations) are needed.

b. Storage requirements near the distribution end of the pipeline may be considerably eased (particularly when there is no readily available underground storage capability).

c. The liquid form may be more suitable for some utilization modes, for example, transportation.

Disadvantages for cryogenic transmission include the much larger capital and operating costs associated with a given diameter pipeline because of the need for liquid containment and temperature maintenance. On the other hand, much more energy can be transmitted as a liquid. These high capital and operating costs arise from the need for a) good thermal insulation and b) materials that are compatible with the low temperatures of liquefied gases. Refrigeration stations along the pipeline are also likely to be required if liquid delivery is desired at the terminal end of the line.

A possible exception to a liquid delivery system, which is essentially an isothermal transmission approach, is "dense-phase transmission" in which a progressive warm-up of the gas is permitted along the pipe. In this instance, as reviewed for LNG in Reference 8, no refrigeration may be required. Thus, only part of the line may handle the cryogenic liquid phase, the remainder of the warming-up gas being transmitted in uninsulated (or at least less sophisticated) pipeline to the point(s) of delivery. Such an approach would apply, as it does for LNG, where cryogenic liquid is available at the production point — or more realistically, at a port where it is received as a shipment having been put into the cryogenic form to achieve transportability — and a gaseous product is desired at the terminal end of the pipeline. Whether such a set of circumstances will ever exist for a hydrogen-energy transmission system remains to be seen.

Especially when compared with natural gas, the major cost of hydrogen liquefaction is in terms of additional production capital equipment and energy requirements. This cost increment would seem to be the most significant drawback for a liquid-hydrogen transmission system to effectively compete with conventional gas transmission. However, three major reasons for further consideration of this prospect are —

1. Cryogenic liquid hydrogen may be the desired end-use form of hydrogen, as for transportation usage; hence, liquefaction will be necessary at some point along the logical path of production to distribution.
2. The trade-off of liquid transmission and storage costs with the conventional gas alternatives could possibly be sufficiently favorable economically to dictate the cryogenic system as an economic choice, especially if refrigeration energy can be reclaimed efficiently in the vaporization of the hydrogen for distribution (where the gaseous form is wanted).
3. The distinct possibility exists that an "energy-pipe" concept will be pursued in which not only hydrogen but also electricity will be transmitted through a common "pipeline"; in this case, the very low temperature of hydrogen liquid (−423°F normal boiling temperature) will provide an environment for "cryocooled" electrical conductors and an opportunity for the gas and electric utility industries to share constructing and operating such a line.

With these considerations in mind, we feel it is worthwhile to review the possibility of liquid-hydrogen transmission in at least some depth in the present report.

2. Technological Status of Liquid Hydrogen

Reference 11 reviews the technology of cryogenic hydrogen from the standpoint of the early to mid-1960's. It describes the relatively broad and successful use of liquid hydrogen in the nuclear and high-energy physics fields, and in some early liquid-hydrogen-fueled aircraft and space vehicle engines. (See also Section VII of this report.) Since the publication of this reference, liquid hydrogen has been produced and used to an even greater degree in support of the space program, particularly the Apollo lunar exploration effort.

In support of this space effort, several 20-30 tons/day and one 60 tons/day LH_2 production facilities were put on-line in this country. Transportation of the cryogenic hydrogen produced has been carried out by truck-trailers with capacities up to 16,000 gallons and by railroad tank cars with capacities up to 34,000 gallons. Pipelining of hydrogen has been limited to short runs at the production plants, and somewhat longer lines at the test and launch facilities. The largest scale of liquid-hydrogen piping and associated storage capacity is found at the NASA Kennedy Space Center's Launch Complex 39, from which the Saturn 5 moon mission vehicles are launched. NASA buys approximately 1 million gallons of liquid hydrogen to support the Apollo program annually. From consultation with NASA personnel we learned that approximately 340,000 gallons of liquid hydrogen are loaded into the Saturn 5 vehicle for each launch operation and about an additional 60,000 gallons are lost as vapor in chilldown and boil-off in the facility equipment and in the vehicle tankage. No efforts are made to capture the gaseous hydrogen escaping. About 100 tons of liquid hydrogen are contained in the vehicle at lift-off, and provide much of the energy for the flight to the moon. (The first-stage rocket, and those of the command-service and lunar modules use storable or room-temperature liquid fuels; the second and third stages of the launch vehicle use liquid hydrogen.)

Developments accompanying and paralleling the space mission utilization of liquid hydrogen have produced a substantial technological base from which new applications for liquid hydrogen can proceed. A great number of liquid-hydrogen components and systems are now available routinely and at competitive costs. Distinctly missing, however, is any substantial large-scale liquid-hydrogen pipeline technology, probably because, to date, the space effort has had no call for large, efficient hydrogen pipelines. The largest pipelines used, namely those at Cape Kennedy, are about 10 inches in diameter and, although of conventional vacuum-jacketed construction, are otherwise not sophisticated in terms of potential improvements in insulation capability — that is, use of multilayer radiative shielding or "superinsulation" techniques.

In summary, although a considerable technological foundation for constructing a liquid-hydrogen pipeline system now exists, largely because of progress in the space sector, no significant effort to date has been devoted to truly large-scale and well-insulated liquid-hydrogen pipelines. The most comprehensive study effort noted to date, and this was limited to considerations of 16-mile pipeline lengths, is that done by Air Products & Chemicals, Inc., for NASA in 1968.[3] The problem Air Products addressed here was the fueling of projected hydrogen-fueled hypersonic transports for a number of global locations. It found that liquid-hydrogen pipelining is technically feasible to the extent that the subject as considered is applicable to truly long-distance energy pipelining.

Considerations of storage vessels for liquid-hydrogen and other system components will be presented in Section V, "Hydrogen Storage." Of particular applicability to the question of pipelining liquid hydrogen is the overall problem of liquefying the hydrogen once it has been produced. Liquefaction of hydrogen requires much more energy than the liquefaction of natural gas, which will be a fundamental disadvantage to the prospect of a liquid-hydrogen transmission system.

Figure IV-11 is a schematic diagram of a liquid-hydrogen transmission system. Liquefaction following production of hydrogen (e.g., from the electrolyzer) is noted, with initial pumping up to initial line pressure through a cryogenic pumping plant. A considerable technology in large liquid-hydrogen pumps of both centrifugal (single and multistage) and axial-flow types exists as a result of progress in liquid-hydrogen rocket engine development. Units as large as 70,000 hp producing liquid-hydrogen pressures above 1000 psi have been demonstrated.

Underground pipeline construction is noted in Figure IV-11 to be of vacuum-jacketed, multilayer, radiative-shielded design to minimize heat leak. Alternative methods of construction are possible and should be more thoroughly explored to determine an economically optimum design. Periodically, as pressure losses become substantial and/or the liquid hydrogen heats up sufficiently, repumping and refrigeration stations must be positioned along the pipeline just as recompression stations are required in conventional natural gas pipelines. The capabilities and spacing along the pipeline of the repumping and/or refrigeration units must be

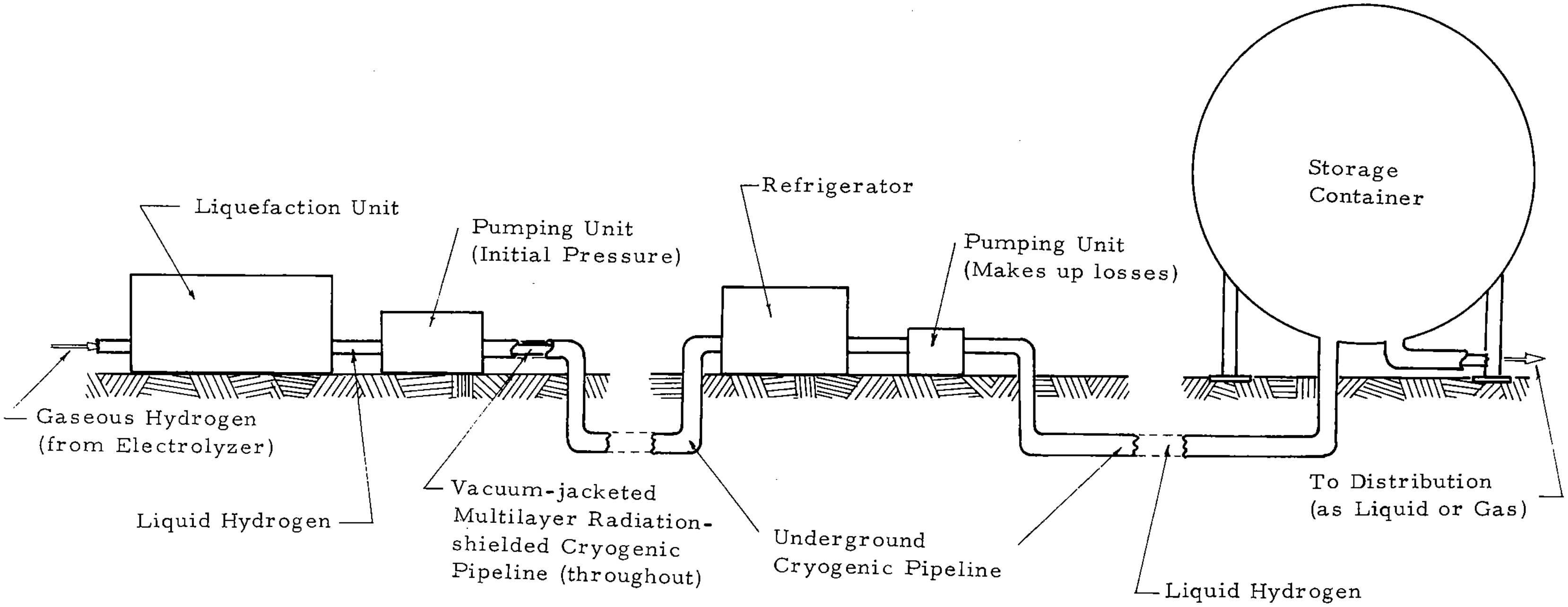

Figure IV-11. CRYOGENIC LIQUID-HYDROGEN TRANSMISSION AND STORAGE SYSTEM determined in an overall system economics assessment, not yet attempted for hydrogen. (Reference 8 notes repumping for LNG at the usual 100-mile intervals.)

At the terminal end of the pipeline in Figure IV-11, an aboveground liquid-hydrogen storage container is noted. As already noted, storage of cryogenic hydrogen is discussed in Section V.

Where hydrogen gas is wanted for distribution periodically down the pipeline, refrigeration requirements along the line could be partially met by the energy sink represented by the vaporizing hydrogen, which could serve to effectively minimize the additional mechanical refrigeration energy that would otherwise be needed.

The electrical utility industry is striving to demonstrate underground cryocooled transmission systems involving the use of cryogens such as liquid nitrogen, hydrogen, and helium. These systems are generally of one of two possible types: cryoresistive or superconducting. The first of these capitalizes on the gains in conductivity of normal conductive metals, for example, copper and aluminum, with a reduction in metal operating temperatures. Reference 1 is a typical description of a cryoresistive test installation by authors from the General Electric Research and Development organization. Liquid nitrogen is used as the coolant in this case. Superconductive transmission necessitates much lower temperatures and the selection of special superconductive metals or alloys, usually those containing niobium. Reference 9 is an assessment of this transmission system which emphasizes the superconductive approach with a liquid-helium coolant and refrigeration system.

With the great pressures bearing on the electric community to diminish its use of overhead transmission cables, particularly near urban areas, because of limited availability of right-of-way, land value, and general "visual pollution" problems, cryogenic underground transmission is expected to receive increasing interest in the years ahead.

Liquid hydrogen has excellent properties for the cryoresistive approach, being grossly superior to liquid nitrogen, but the electrical investigators have tended to shy away from hydrogen despite its technical superiority, probably for fear of the attendant hazards and the increased sophistication required for the conduits and refrigeration apparatus. Thus Reference 1 describes only liquid-nitrogen experiments.

Cryogenic hydrogen can also ameliorate rather substantially the constraints associated with liquid helium in superconducting systems, acting either as a low-temperature sink for the helium refrigeration systems, or for directly cooling superconductive material.

The upshot of the foregoing research and study has led to consideration of the "energy-pipe" concept, in which transmission of liquid hydrogen and electrical power in a single conduit is envisioned, with a synergistic engineering and economic benefit being achieved; that is, the physical gains of liquid-hydrogen transmission (over gaseous) are achieved, with the additional cost of refrigeration and probable higher line costs being shared with the electrical utilities. The electrical community might achieve, at the same time, an efficient long-distance underground transmission net operating in parallel with gas energy distribution.

Though obviously intriguing, the "energy-pipe" concept is not without its technical and economic questions. The very concept of a shared gas/electrical transmission system poses fundamental problems, not the least of which is the traditional organization of and roles played by the two energy industries. Nevertheless, a further study, including an economic assessment, should be made of the concept. This study will require inputs from both the gas and electrical communities to identify points of infeasibility/feasibility.

As a corollary to the concept, consideration of a special form of liquid hydrogen should be given. This is the <u>subcooled liquid</u>, usually created in the form of a "slush" solid/liquid mixture at essentially triple-point conditions. Liquid hydrogen is cooled from its boiling point of 36^0R to about 25^0R where solidification commences. Slush mixtures of 50% or higher solids content are readily achieved. The space research field has examined slush hydrogen rather extensively. Study of a tonnage-capacity slush facility is under way at the Marshall Space Flight Center, Alabama.

Compared with normal-boiling liquid hydrogen, slush hydrogen offers a number of important potential advantages in considering the "energy-pipe" concept and also for "straight" liquid transmission systems. Among these are —

- An increase in density of about 15-20% over the boiling (conventional) hydrogen is gained.
- A very significant additional heat sink capability is gained in the fluid, which will tend to minimize the amount of refrigeration required in the pipeline and/or minimize the effect of heat leakage into the pipeline.
- With reference to the "energy-pipe" idea, slush hydrogen is capable of directly superconducting at least one Type-2 material, for example, niobium-tin; this suggests the possibility of eliminating the liquid-helium system altogether, usually assumed to be an inherent concomitant in superconductive systems.

Clearly, although the research accomplished to date reflects the basic feasibility of slush-hydrogen production, pumping, measurement of qualities, etc., much further systems analyses and focused hardware efforts will be needed before a judgment can be made on the viability of the slush-hydrogen system approach in this context of hydrogen transmission.

Recommendations relative to liquid-hydrogen transmission systems will be provided in the recommendations section at the conclusion of the report. The reader is again directed to the part of Section V on liquid-hydrogen storage for additional discussion of the cryogenic-hydrogen system potential.

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Appendix IV-A. Calculation Procedures for Hydrogen and Natural Gas Pipeline Characteristics

A. Introduction

It is of interest to compare the characteristics of pipeline transmission of hydrogen and natural gas. To do this, we derived some basic equations concerning the flow of hydrogen in pipelines with compressors. We then calculated some ratios and compared hydrogen and natural gas. The results are presented in the text of Section IV. Because these calculations are of significant importance to future work in hydrogen pipeline optimization, they are recorded in detail in this appendix.

B. Problem Definition

We set out to compare the energy transmission capability of a typical, modern natural gas pipeline, as it exists today, operating on hydrogen and on natural gas. To make this comparison, we calculated the cost of transmission of hydrogen through a pipeline in which the compression ratio, pipe diameter, and number of pipes had been optimized.

We consider one section of pipeline of length L between two compressors stations, one having a delivery pressure to the section of P_1 and the other receiving gas from the pipeline at P_2. The average pressure in the pipeline section (defined as arithmetic mean) is P_{avg}; the pipe diameter is D. Data for natural gas are subscripted $_{NG}$ and for hydrogen $_{H_2}$. The basic scheme is shown in Figure IV-A1.

C. Governing Equations

1. Basic Thermodynamic Relationship for Local Pipeline Capacity

One of the important values used in pipeline design is its capacity or operating volume flow rate at a given station (point):

$$V = \frac{mzRT}{P} \tag{1}$$

where

V = volume flow rate, CF/min
m = mass flow rate, lb/min
z = compressibility factor
R = gas constant, (ft-lb)/lb-^{0}R
T = absolute temperature at a given station, ^{0}R
P = absolute pressure at a given station, lb/sq ft

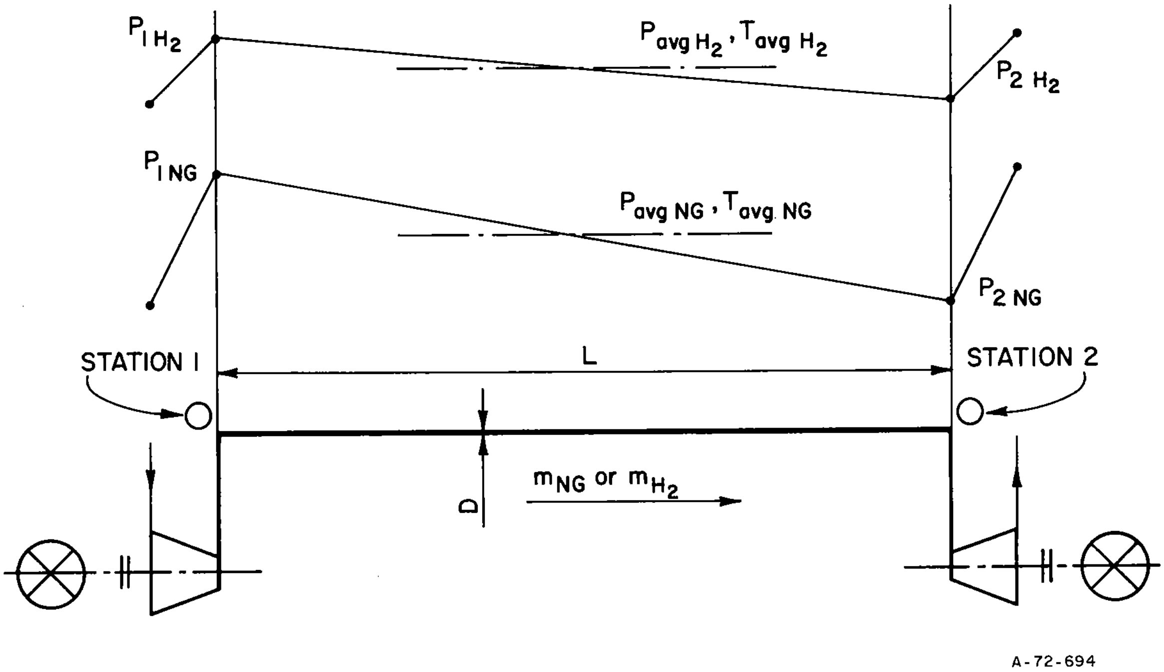

Figure IV-A1. COMPRESSION SECTION USED IN THE TRANSMISSION STUDY

A comparison of the hydrogen and natural gas volume flow rates through a given pipeline at conditions corresponding to those of the compressor inlet would be of particular interest. Assuming that this is the station 2 in Figure IV-A1, the volume flow rate ratio is —

$$\frac{V_{2H_2}}{V_{2NG}} = \frac{(mz_2RT_2)_{H_2}}{(mz_2RT_2)_{NG}} \cdot \frac{P_{2NG}}{P_{2H_2}} \tag{2}$$

2. Heating Values of Transmitted Gases

To introduce the heating values of transmitted gases, the following relationship is used:

$$mq = VQ \tag{3}$$

where —

q = mass heating value, Btu/lb
Q = volumetric heating value, Btu/CF

Particularly,

$$\frac{V_{2H_2}}{V_{2NG}} = \frac{(mq)_{H_2}}{(mq)_{NG}} \cdot \frac{Q_{2NG}}{Q_{2H_2}} \tag{4}$$

To obtain the ratio of volumetric heating values as a function of thermodynamic states, we shall combine Equations 2 and 4. The mass flow rates cancel, and we get —

$$\frac{Q_{2H_2}}{Q_{2NG}} = \frac{q_{H_2}}{q_{NG}} \cdot \frac{P_{2H_2}}{P_{2NG}} \cdot \frac{(z_2RT_2)_{NG}}{(z_2RT_2)_{H_2}} \tag{5}$$

3. Pipeline Flow Capacity

The objective of the analysis is to determine the ratio of the delivered heating values $(\frac{Q_{2H_2}}{Q_{2NG}} \frac{V_{2H_2}}{V_{2NG}})$ or the mass flow rate ratio at given conditions, as given by Equation 4. Therefore, the flow capacity of a pipeline has to be calculated.

Assuming that the constant-temperature flow in all cases is fully turbulent, the flow capacity of a pipeline at standard (base) conditions is[8] —

$$V_b = 38.77(\frac{T_b}{P_b})(\frac{1}{f})^{0.5} \cdot \frac{D^{2.5}}{L^{0.5}} \cdot [\frac{D_1^2 - P_2^2}{GT_{avg}\, z_{avg}}]^{0.5} \tag{6}$$

where the friction factor corresponding to the rough-pipe law —

$$(\frac{1}{f})^{0.5} = 4 \log(\frac{3.7D}{k_e}) \tag{7}$$

is independent of the Reynolds number and thus simplifies the comparison, and where —

V_b = volumetric flow rate at base conditions (14.73 psia, 60°F), SCF/day

D = internal pipe diameter, inches

L = line length, miles

G = gas gravity (air = 1)

k_e = effective or operating roughness

b = standard (or base) conditions (14.73 psia, 60°F)

avg = average conditions

[Note: arithmetic mean (average) conditions are assumed throughout the calculation, disregarding the effect on accuracy.]

Referring to the conditions at station 2 in Figure IV-A1, the volume flow rate is —

$$V_2 = V_b\left(\frac{z_2 T_2}{z_b T_b}\right)\left(\frac{P_b}{P_2}\right) = 38.77\left(\frac{z_2}{z_b}\right)\left(\frac{T_2}{P_2}\right)\left(\frac{1}{f}\right)^{0.5} \cdot \frac{D^{2.5}}{L^{0.5}} \cdot \left(\frac{P_1^2 - P_2^2}{GT_{avg}\, z_{avg}}\right)^{0.5} \qquad (8)$$

Then, the ratio of the volume flow rates is —

$$\frac{V_{2H_2}}{V_{2NG}} = \frac{\left[\frac{z_2}{z_b} \cdot \frac{T_2}{P_2} \cdot \left(\frac{P_1^2 - P_2^2}{GT_{avg}\, z_{avg}}\right)^{0.5}\right]_{H_2}}{\left[\frac{z_2}{z_b} \cdot \frac{T_2}{P_2} \cdot \left(\frac{P_1^2 - P_2^2}{GT_{avg}\, z_{avg}}\right)^{0.5}\right]_{NG}} \qquad (9)$$

To calculate the compressor energy input ratio, the pressure ratio (π) must be introduced. Therefore, let us further assume —

$$\frac{P_1 + P_2}{2} = P_{avg} \qquad P_2 = \frac{2\, P_{avg}}{\pi + 1}$$

$$\frac{P_1}{P_2} = \pi \qquad P_1 = \frac{2\pi}{\pi + 1} P_{avg} \qquad (10)$$

From there —

$$P_1^2 - P_2^2 = 4\left(\frac{\pi - 1}{\pi + 1}\right)(P_{avg})^2 \qquad (11)$$

Introducing Equation 11 into Equation 9, and putting $T_2 = T_{avg}$, we get —

$$\frac{V_{2H_2}}{V_{2NG}} = \frac{\left\{\frac{z_2}{z_b}\left[\frac{T_{avg}}{Gz_{avg}}(\pi^2 - 1)\right]^{0.5}\right\}_{H_2}}{\left\{\frac{z_2}{z_b}\left[\frac{T_{avg}}{Gz_{avg}}(\pi^2 - 1)\right]^{0.5}\right\}_{NG}} \qquad (12)$$

This ratio would be identical to the ratio of displacement volumes or impeller volumes only if the fresh inlet gases were not heated by walls and internal leakage losses, if there were no internal or external leakage losses or inlet and outlet throttling, and if the compressor had no dead volume. Also, so far we have not considered the amount of fuel required to pump the gas from one compressor station to the other. Therefore, to evaluate the actual compressor sizes, we will have to introduce the overall volumetric efficiency and the fuel factor and recognize the operating differences between the positive-displacement, or reciprocating, compressors and radial turbocompressors.

Generally, the overall volumetric efficiency (η_{vo}) and the fuel factor (η_f) will be defined as –

$$\frac{V}{V_2} = \frac{\eta_f}{\eta_{vo}} \tag{13}$$

where –

V = theoretical compressor capacity, CF/min, or a cylinder volume, cu ft

V_2 = actual compressor capacity less the volume of fuel, CF/min, or an actual cylinder capacity less the volume of fuel, cu ft, at compressor inlet conditions

Comparatively –

$$\frac{V_{H_2}}{V_{NG}} = \frac{\eta_{f\,H_2}}{\eta_{f\,NG}} \cdot \frac{\eta_{voNG}}{\eta_{voH_2}} \cdot \frac{\left\{\frac{z_2}{z_b}\left[\frac{T_{avg}}{Gz_{avg}}(\pi^2 - 1)\right]^{0.5}\right\}_{H_2}}{\left\{\frac{z_2}{z_b}\left[\frac{T_{avg}}{Gz_{avg}}(\pi^2 - 1)\right]^{0.5}\right\}_{NG}} \tag{14}$$

We must now determine whether there will be a significant change in the fuel factor and the volumetric efficiency of a compressor if it is operated on hydrogen rather than natural gas. We discuss, in turn, each type of compressor: For reciprocating machines we assumed the same design for both gases; for turbocompressors we assumed a design optimized in each case for natural gas or for hydrogen, for reasons stated later; and for rotary machines we also assumed individually optimized designs.

4. Fuel Factor and Overall Volumetric Efficiency of Reciprocating Compressors

To make calculation reasonably simple, one following basic assumption is made for the derivation of the overall volumetric efficiency and fuel factor ratios: The hydrogen (H_2) compressor and natural gas (NG) compressors are identical and operate at the same speed.

Obviously, this is strictly applicable only within the limits of maximum allowable crank mechanism loads and operating pressures. Also, it is necessary to keep in mind that a compressor designed specifically for hydrogen would have slightly different characteristics, especially if the operating pressure levels differ greatly from the reference NG compressor. It would also probably operate at a different speed. However, we are assuming that the consequent influence of these factors on the calculated ratios of efficiencies and fuel factors is of secondary importance.

Additional assumptions will be referred to during the derivation.

a. Compressor Power Input and Fuel Requirement

The compressor input (shaft horsepower) for a single-stage positive-displacement compressor, using the handled gas as a fuel, is given by —

$$W = 4.363 \text{ X } 10^{-3} \cdot \frac{1}{\eta_{tad}} \cdot \frac{z_1 + z_2}{2z_2} \cdot \frac{\gamma}{\gamma - 1} \cdot (P_2)(V_2 + V_{2_f})(\pi^{\frac{\gamma - 1}{\gamma}} - 1) \qquad (15)$$

where —

W = compressor power input, bhp

$\eta_{tad} = \eta_{ad} \cdot \eta_{mech} = \frac{W_{ad}}{W}$ = total adiabatic efficiency

$\eta_{ad} = \frac{W_{ad}}{W_i}$ = adiabatic efficiency

$\eta_{mech} = \frac{W_i}{W}$ = mechanical efficiency

$W_{ad} = 4.363 \text{ X } 10^{-3} \cdot \frac{\gamma}{\gamma - 1} \cdot (P_2)(V_2 + V_{2_f})(\pi \frac{\gamma - 1}{\gamma} - 1)$ = adiabatic power input, bhp

$W_i = 4.363 \text{ X } 10^{-3} P_{im} \cdot AlN$ = indicated power input, bhp

P_{im} = mean effective pressure found from an indicator diagram, psig

A = piston area, sq ft

l = piston stroke, ft

N = speed, rpm

P_2 = compressor inlet pressure, psia

V_2 = actual compressor capacity, less the volume of fuel, CF/min

V_{2_f} = fuel volumetric flow rate, CF/min

π = external pressure ratio (internal losses being included in η_{ad})

γ = $\frac{c_p}{c_v}$ = specific heat ratio

$\frac{z_1 + z_2}{2z_2}$ = factor, which averages the compressibility change during the compression; used only when large variation in compressibility can be expected. (Note: At all conditions, including inlet conditions, $V_{real} = zV_{ideal}$, so the factor changes the real volume into the ideal volume on the average basis.)

For the sake of a clear understanding of these definitions, let us note that the difference between the indicated power input and adiabatic power input is due to –

- Flow resistances of valves, valve chambers, and piping with accessories
- Heating of the gas after suction into the cylinder
- Deviations of the polytropic curves of compression and expansion from the isentropic ones caused by such irreversibilities as heating, reheating, and mixing with leaking gas
- Mass change due to leakages

The fuel flow rate is –

$$V_{2_f} = m_f v_2 = 42.44 \cdot \frac{1}{\eta_E} \cdot \frac{W}{q} \cdot \frac{z_2 R T_2}{P_2} \qquad (16)$$

where –

m_f = mass fuel flow rate, lb/min

v_2 = specific volume of the fuel at the compressor inlet, CF/lb

η_E = engine overall efficiency

Defining the fuel factor as –

$$\eta_f = \frac{V_2 + V_{2_f}}{V_2} \qquad (17)$$

and combining Equations 15, 16, and 17, we shall get –

$$\eta_f = \frac{1}{1 - 1.286 \times 10^{-3} \cdot \frac{z_1 + z_2}{2z_2} \cdot \frac{1}{q\eta_E\eta_{tad}} \cdot \frac{\gamma}{\gamma - 1} \cdot z_2 R T_2 \left(\pi^{\frac{\gamma - 1}{\gamma}} - 1\right)} \qquad (18)$$

Consequently, the compressor power input gets its final form —

$$W = 4.363 \times 10^{-3} \cdot \frac{1}{\eta_{tad}} \cdot \frac{z_1 + z_2}{2z_2} \cdot \frac{\gamma}{\gamma - 1} \cdot \eta_f P_2 V_2 (\pi^{\frac{\gamma-1}{\gamma}} - 1) \qquad (19)$$

For exact evaluation of hydrogen and natural gas compressors as to their absolute or relative power consumption, the power efficiencies η_E and η_{tad} would have to be measured. However, for the first approximation certain constant values derived from experience can be assigned to both cases and will give good accuracy of relative power values. Also, measured characteristics can be extrapolated as to their capacity and/or pressure range. This is even more true for computation of the fuel factor because it generally influences only a relatively small amount of the handled gas (in other words, $\eta_f V_2 \approx V_2$). Finally, the compressor power input ratio is —

$$\frac{W_{H_2}}{W_{NG}} = \frac{(\eta_{tad}\, z_b)_{NG}}{(\eta_{tad}\, z_b)_{H_2}} \; \frac{\{\eta_f\, P_{avg} \frac{\gamma}{\gamma - 1} [\frac{T_{avg}\, z_{avg}}{G} \cdot \frac{\pi - 1}{\pi + 1}]^{0.5} (\pi^{\frac{\gamma-1}{\gamma}} - 1)\}_{H_2}}{\{\eta_f\, P_{avg} \frac{\gamma}{\gamma - 1} [\frac{T_{avg}\, z_{avg}}{G} \cdot \frac{\pi - 1}{\pi + 1}]^{0.5} (\pi^{\frac{\gamma-1}{\gamma}} - 1)\}_{NG}} \qquad (20)$$

where it is assumed that $\frac{z_1 + z_2}{2} = z_{avg}$, which is used in combination with Equations 10, 12, and 19.

For all practical purposes, $\frac{z_{bNG}}{z_{bH_2}} \approx 1$. Also, we can assume the same average temperature of the two gases and write —

$$\frac{W_{H_2}}{W_{NG}} = \frac{\eta_{tad\ NG} \; \{\eta_f P_{avg} \frac{\gamma}{\gamma - 1} [\frac{z_{avg}}{G} \; \frac{\pi - 1}{\pi + 1}]^{0.5} (\pi^{\frac{\gamma-1}{\gamma}} - 1)\}_{H_2}}{\eta_{tad\ H_2} \; \{\eta_f P_{avg} \frac{\gamma}{\gamma - 1} [\frac{z_{avg}}{G} \; \frac{\pi - 1}{\pi + 1}]^{0.5} (\pi^{\frac{\gamma-1}{\gamma}} - 1)\}_{NG}} \qquad (21)$$

To find the relative values of η_{tad} when no measured data are available, η_{ad} can be used, assuming that the mechanical efficiencies are an invariable constant of the compared compressors (e.g., $\eta_{mech} = 0.95$). The adiabatic efficiency (η_{ad}) can be then calculated, neglecting the effects of heating (and cooling) and leakages on the compression and expansion curves and compressed mass. Such an efficiency would reflect the most important effect of variable flow resistances within a typical compressor pumping different gases. For our purposes the calculation has been performed according to Reference 15 (pp. 51 and 318)*; the results are presented in Figure IV-A2 and Table IV-A1.

Table IV-A1. ADIABATIC EFFICIENCIES OF RECIPROCATING COMPRESSORS AS CALCULATED ACCORDING TO THE REFERENCE 15

	Pressure Ratio (π)				
	1.05	1.1	1.2	1.4	1.6
	η_{ad}				
Hydrogen $G = 0.0696$ $\gamma = 1.4065$	0.794	0.884	0.932	0.961	0.972
Natural Gas $G = 0.641$ $\gamma = 1.26$	0.293	0.447	0.605	0.735	0.793

* Data obtained from more modern equipment were not available, but should ideally be used. The data used here were published in 1961.

b. Overall Volumetric Efficiency

The overall volumetric efficiency of a reciprocating compressor is a ratio of the mass of fluid discharged during one revolution of the compressor shaft to the mass of fluid that, at suction line conditions, would occupy a volume equal to the total displacement during one revolution.

Allowing for the flow resistances, heating of the inlet gas, and the leakage losses, the basic volumetric efficiency, which accounts for the relative clearance volume only, will assume in close approximation the form:

$$\eta_{vo} = \left[(1 + \epsilon)\left(\frac{P_{II}}{P_2}\right)^{\frac{1}{n}} - \epsilon\left(\frac{P_I}{P_2}\right)^{\frac{1}{m}}\right] \frac{T_2}{T_{II}} - \zeta \qquad (22)$$

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* Data obtained from more modern equipment were not available, but should ideally be used. The data used here were published in 1961.

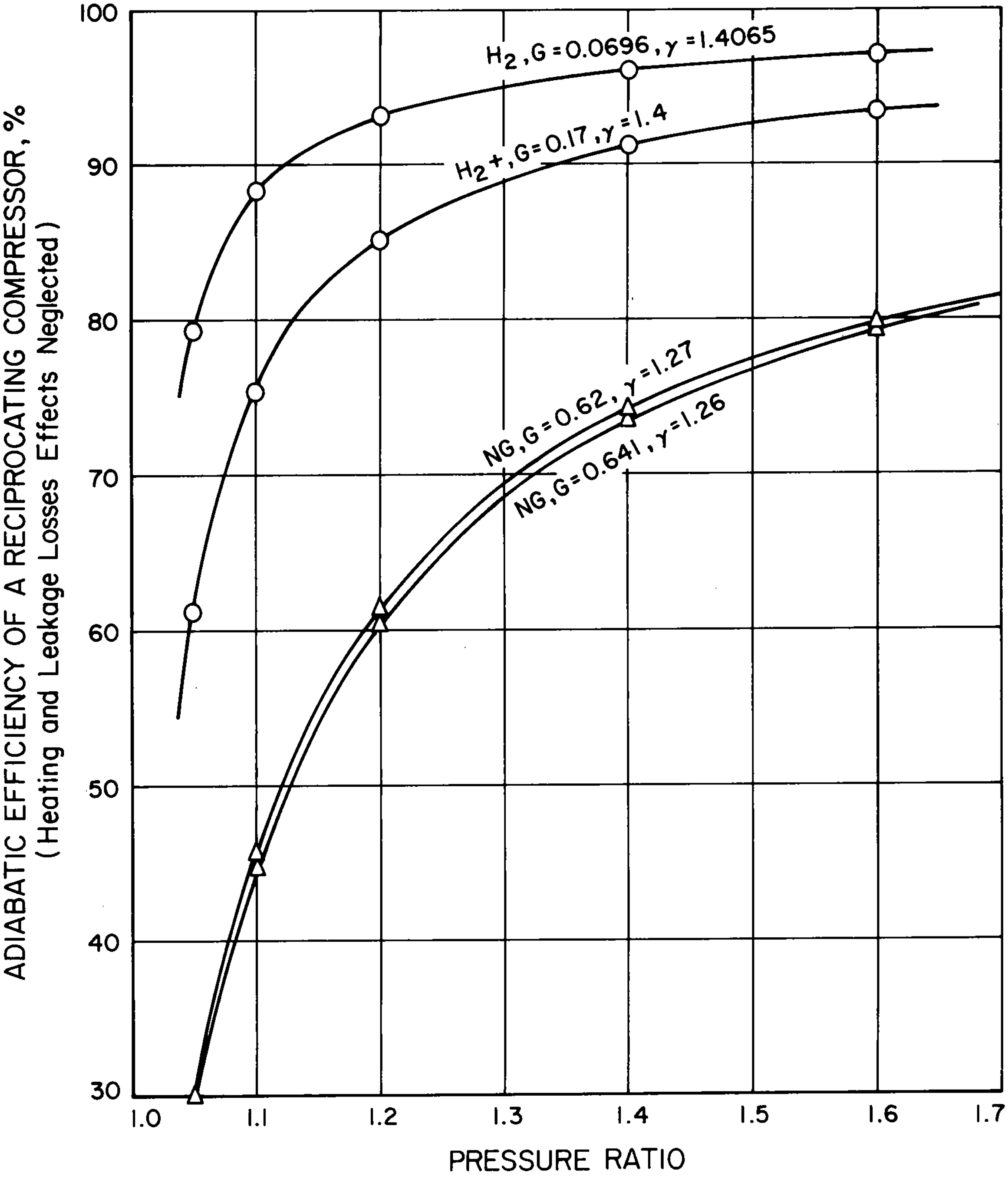

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Figure IV-A2. ADIABATIC EFFICIENCIES OF RECIPROCATING COMPRESSORS AS CALCULATED ACCORDING TO REFERENCE 15 where —

ϵ = relative clearance volume
n = exponent of polytropic compression
m = exponent of the polytropic expansion (from the clearance volume)
ζ = relative leakage loss factor (leakages past the piston, valves, and stuffing boxes)

Roman numerals subscripts indicate the initial and final stages of compression, and arabic subscripts indicate the states at the compressor flanges, as shown in Figure IV-A3.

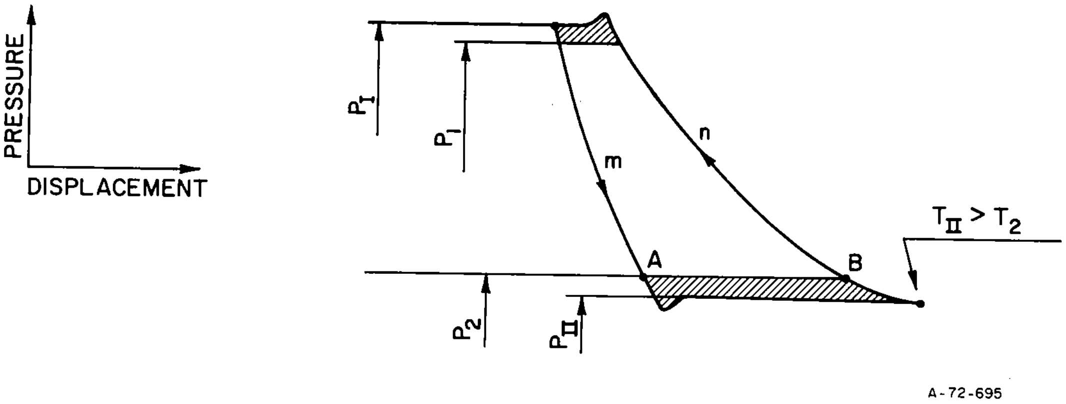


Figure IV-A3. REAL INDICATOR DIAGRAM OF A RECIPROCATING COMPRESSOR

Without a significant error, we can put —

$$n = m = \gamma$$

Also,

$$\frac{P_{II}}{P_2} = \frac{P_{II}}{P_{II} + \Delta P} = \frac{P_{II}}{P_{II} + \theta G P_{II}} = \frac{1}{1 + \theta G} \qquad (23)$$

and

$$\frac{P_I}{P_2} = \frac{P_1 + \Delta P}{P_2} = \frac{P_1 + \theta G P_1}{P_2} = \pi(1 + \theta G) \qquad (24)$$

where θ is the flow resistance factor through valves and valve chambers; it is a constant for certain valve geometries and speeds.[15]

In addition, heating of the inlet gas can be assumed to be proportional to the capacity of the heat source (heat capacity of cylinder and duct walls). For dry jackets or inlet cooling water temperatures higher than the inlet manifold gas temperatures, such an assumption has become a common practice.[6,10] This is because all the phenomena resulting in the gas temperature increase during the suction stroke were found to be satisfactorily described by the empirical relationship[3]:

$$T_{II} - T_2 = 0.2(T_w - T_2) \qquad (25)$$

Rearranged,

$$\frac{T_2}{T_{II}} = \frac{5/4}{1/4 \, \frac{T_w}{T_2} + 1} \qquad (26)$$

where T_w is the average cylinder wall temperature, approximated in practice by the inlet water temperature.

This relationship holds very well for $T_w - T_2 \approx 30^0\text{-}50^0$F and apparently for a range of low pressure ratios. It also reflects the small influence the nature of the gas has upon the magnitude of the inlet heating.

This has been verified in the following way[2]: Let us assume a steady-state heat balance for the suction stroke, defined by a description of the path leading to the final suction temperature and pressure (B). Namely —

$$m_B h_B \approx m_A h_A + (m_B - m_A)\, h_2 + Q_w + W_{ts} \qquad (27)$$

where —

m = mass of gas in a cylinder at particular state, lb/stroke

h = corresponding enthalpy, Btu/lb

Q_w = heat transferred into the gas from the cylinder, chamber, and piston walls, Btu/stroke

W_{ts} = suction throttling work transferred as heat to the inlet gas, Btu/stroke

See also Figure IV-A3.

This identity can be useful only when accompanied by another analytical or empirical description of the physical phenomenon giving the same results. As of now, only a few approximate measurements that can be used for the above heat balance are known, so the relationship has to be considered empirical.

Expression 27 can be rewritten in the following way:

$$m_B c_p (T_B - T_2) \approx m_A c_p (T_A - T_2) + Q_w + W_{ts} \qquad (28)$$

Both sides of the identity represent the overall amount of heat transferred to the fresh charge of the inlet gas thus increasing its temperature from T_2 to T_B and correspondingly decreasing the capacity of the compressor. Assuming that the overall effect has been measured, the question remains, "What were the actual contributions of the individual terms?" Analyzing them, we can reasonably predict the response of the same compressor when handling a different gas.

The first term of Identity 28 (the heat from the gas that reexpanded from the clearance volume) is derived next, with the help of basic thermodynamic relations:

$$\frac{T_B}{T_{II}} = \left(\frac{P_2}{P_{II}}\right)^{\frac{n-1}{n}}$$

$$\frac{T_I}{T_B} = \left(\frac{P_I}{P_2}\right)^{\frac{n-1}{n}} \qquad (29)$$

$$\frac{T_I}{T_A} = \left(\frac{P_I}{P_2}\right)^{\frac{m-1}{m}}$$

These, combined with definitions used in Equations 23 and 24, give —

$$T_A = T_{II}\, \pi^{\left(\frac{n-1}{n} - \frac{m-1}{m}\right)} \left(\frac{1 + \theta G}{1 - \theta G}\right)^{\frac{n-1}{n}} \left(\frac{1}{1 + \theta G}\right)^{\frac{m-1}{m}} \qquad (30)$$

The mass of the gas in the cylinder at piston position A is —

$$m_A = \frac{V_A}{v_A} = (V_A)\left(\frac{P_2}{z_A R T_A}\right)$$

where volume V_A could be expressed with help of the definition of the clearance volume, V_o:

$$\frac{V_o}{V - V_o} = \epsilon \qquad (31)$$

Also,

$$\frac{V_o}{V_A} = \left(\frac{P_2}{P_I}\right)^{\frac{1}{m}} \qquad (32)$$

Then,

$$m_A = \frac{P_2}{Rz_A T_A} \cdot \frac{\epsilon}{1 + \epsilon} \cdot V\pi^{\frac{1}{m}} (1 + \theta G)^{\frac{1}{m}} \qquad (33)$$

Combining Equations 30 and 33, we get —

$$m_A c_p (T_A - T_2) = 144 \cdot \frac{c_p}{z_A R} \cdot \frac{\epsilon}{1 + \epsilon} (1 - \theta G) P_2 V \pi^{\frac{1}{m}} \frac{(1 + \theta G)^{\frac{1}{m}}}{1 - \theta G} - \frac{T_2}{T_{II}} \cdot \pi^{\frac{1}{n}} \left(\frac{1 + \theta G}{1 - \theta G}\right)^{\frac{1}{n}}, \text{ Btu/min} \qquad (34)$$

The second term of Identity 28 expresses the heating effect of the walls and, as such, depends on the heat transfer characteristics of the gas flowing into the cylinder. The amount of heat transferred per suction stroke is —

$$Q_{ws} = \frac{1}{120N} hA(T_{II} - T_2), \text{ Btu/stroke} \qquad (35)$$

where —

h = film heat transfer coefficient, Btu/hr-sq ft-^{0}F

A = total heat transfer area, sq ft

For Reynolds numbers $Re > 10^4$,

$$h = 0.023 \, Re^{0.8} \, Pr^{0.4} \frac{k}{d_h}$$

where –

$Re = \frac{c\rho d_h}{\eta g}$ = Reynolds number

$Pr = \frac{3600\ c_p \eta g}{k}$ = Pradtl number

c = velocity of the gas, ft/s

ρ = specific weight of the gas, lb/CF

d_h = characteristic dimension, ft

η = dynamic viscosity of the gas, lb-s/sq ft

g = gravitational acceleration, ft/s^2

k = thermal conductivity of the gas, Btu/hr-ft-^{0}R

Assume further –

$$c = \frac{VN}{30\ A_{ff}} \text{ and } d_h = \frac{4\ A_{ff}\ell}{A} \rightarrow cd_h = \frac{4}{30}\ \frac{VN\ell}{A}$$

where

A_{ff} = free flow area, sq ft

ℓ = free flow path, ft

Two other characteristic constants have to be preselected from experience as follows:

$$cd_h = 10 \text{ sq ft/s}$$

$$\ell / d_h = 10$$

Taking V in CF/min, the heat transferred from walls will be –

$$Q_w = NQ_{ws}$$

$$Q_w = 2 \times 10^{-5} \cdot T_{II} k Re^{0.8} Pr^{0.4} V \left(1 - \frac{T_2}{T_{II}}\right), \text{ Btu/min} \tag{36}$$

The third term of Identity 28 – the throttling work rate – is approximately –

$$W_{pts} \approx \left(\frac{\gamma}{\gamma - 1}\right) 1.286 \times 10^{-3} \cdot 144\ P_{II} V \left[\left(\frac{P_2}{P_{II}}\right)^{\frac{\gamma - 1}{\gamma}} - 1\right] \tag{37}$$

Using the previous relations and definitions,

$$W_{pts} \approx 144 \frac{c_p}{R}(1 - \theta G)\, P_2 V\left[\left(\frac{1}{1 - \theta G}\right)^{\frac{\gamma - 1}{\gamma}} - 1\right], \text{ Btu/min} \tag{38}$$

Now, we can evaluate the right-hand side of Identity 28 for certain reference conditions which are typical for present natural gas transmission systems. We assume the following case:

a. The compressor handles natural gas or pure molecular hydrogen at $P_{avg} = 750$ psia, $\pi = 1.3$, $P_2 = 652.2$ psia, suction manifold temperature of $T_2 = 60^0$F, and average wall temperature or inlet water temperature of $T_w = 100^0$F. The compressor has the relative clearance volume of $\epsilon = 0.1$ and a hydraulic loss factor $(\theta) = 0.09$.

b. Thermodynamic and thermophysical constants (at average pipeline conditions where they apply) are presented in Table IV-A2. (See Section D for nonreferenced properties.)

For the same temperature rise given by Equation 26 –

$$\frac{T_2}{T_{II}} = \frac{5/4}{1/4 \cdot \frac{T_w}{T_2} + 1} = 0.986$$

Identity 28 gives the following values for the individual terms:

$m_B c_p (T_B - T_2) \approx$	$\underline{m_A c_p (T_A - T_2)}$	$\underline{+ Q_w}$	$\underline{+ W_{ts}}$
Natural Gas	140.4 V	+ 28.2 V	+ 472.4 V
Hydrogen	42.8 V	+ 23.9 V	+ 46.5 V

This example shows that only about one-sixth of the heat flux existing at the natural gas compressor is enough to raise the suction temperature of the hydrogen compressor to the same level as it would occur in the natural gas compressor. In other words, the suction temperature of hydrogen compressors is liable to be increased more readily compared to that of natural gas compressors, provided the clearance volume, size, clearances, and the average wall temperature are the same. Because of this, the assumption of equal temperature rise is clearly incorrect for a hydrogen compressor. Rather, it would be logical to assume that the first term of Identity 28 would contribute equally to the total heat flux. (The second term does not influence the whole amount too much; the third term is independent of the temperature ratio, T_2/T_{II}.) In that case, solving Equation 34 for the ratio T_2/T_{II} in the form –

Table IV-A2. THERMODYNAMIC AND THERMOPHYSICAL CONSTANTS USED FOR THE EVALUATION OF THE OVERALL VOLUMETRIC EFFICIENCY OF RECIPROCATING COMPRESSORS

Constant	Unit	Natural Gas	Hydrogen
G	--	0.6410	0.0696
c_p	Btu/lb-^{0}R	~0.60 (for 85% CH_4 mixture) (Ref 16)	3.46
γ	--	1.260 (Refs 4 and 13)	1.414
R	(ft − lb)/lb-^{0}R	83.2	767 (Ref 12)
k	Btu/hr-ft-^{0}R	~0.0225 (for 94% CH_4 mixture) (Ref 5)	0.1030 (Ref 2)
η	lb-s/sq ft	2.4012×10^{-7} (Ref 1)	1.782×10^{-7} (Ref 2)
z_{avg}	--	0.8685	1.030
z_2	--	0.885	1.026
Calculated Values:			
Pr	--	0.742	0.694
$Pr^{0.4}$	--	0.887	0.864
ρ_2	lb/CF	2.454	0.229
Re	--	3.174×10^6	4×10^5
$Re^{0.8}$	--	1.590×10^5	3.031×10^4
Combined Values:			
$(\gamma - 1)/\gamma$	--	0.2064	0.2930
$1/\gamma$	--	0.7937	0.7072
$\epsilon/(1 + \epsilon)$	--	0.0909	0.0909
$1 + \theta G$	--	1.0577	1.0063
$1 - \theta G$	--	0.9423	0.9937

$$140\ V = \{144 \cdot \frac{c_p}{z_A R} \cdot \frac{\epsilon}{1+\epsilon}(1-\theta G)\ P_2 V[\pi^{\frac{1}{m}} \cdot \frac{(1+\theta G)^{\frac{1}{m}}}{1-\theta G} - \frac{T_2}{T_{II}}\ \pi^{\frac{1}{n}}\ (\frac{1+\theta G}{1-\theta G})^{\frac{1}{n}}]\}_{H_2} \qquad (39)$$

we get,

$$(\frac{T_2}{T_{II}})_{H_2} = 0.95$$

and correspondingly $T_{II} = 547.3^0 R$.

Although this merely indicates the higher significance of suction period heating with hydrogen compressors, we assume that the previous example of heat flux distribution is the most probable, then –

$$(\frac{T_2}{T_{II}})_{H_2} \approx 0.964 \frac{5/4}{1/4 \frac{T_w}{T_2} + 1} \qquad (40)$$

The reliability of this expression can be proved only by experiment.

The last term in the overall volumetric efficiency equation (Equation 22) is the relative leakage loss factor (ζ). Below we derive its value by using empirical data and adiabatic flow relationships.

Adiabatic mass flow rate through an orifice is –

$$m_{or} = \text{const}_1 \frac{cP_1}{\sqrt{z_1 R T_1}}),\ \text{lb/stroke} \qquad (41)$$

where

$$c = (\frac{2}{\gamma+1})^{\frac{1}{\gamma-1}} \sqrt{2g \frac{\gamma}{\gamma+1}} \qquad (42)$$

The corresponding volume flow rate is –

$$V_{or} = \text{const}_1 (\frac{cP_1}{\sqrt{z_1 R T_1}})\ v_1 \qquad (43)$$

$$V_{or} = \text{const}_1 (c\sqrt{z_1 R T_1}),\ \text{CF/stroke} \qquad (44)$$

To comply with the definition of volumetric efficiency, the relative leakage loss factor is expressed as a function of V_{or}:

$$\zeta = \text{const}_2\left(\frac{V_{or}}{V}\right) \tag{45}$$

$$\zeta = \text{const}_3\left(c\sqrt{z_1RT_1}\right) \tag{46}$$

When handling gases with physical properties similar to air, large compressors with relatively small pressure ratios have an $\zeta \approx 1\text{-}2\%$.

Assuming $\zeta \approx 0.01$ and $C = 2.07$ for $\gamma = 1.26$

$$P_1 = 847.8 \text{ psia}$$

$$T_1 = T_2\, \pi_{NG}^{\frac{\gamma - 1}{\gamma}} = 520 \text{ X } 1.3^{0.20646} = 548.9^0\text{R}$$

$$z_1 \approx 0.885$$

Equation 46 yields the constant const_3 to about –

$$\text{const}_3 \approx 2.403 \text{ X } 10^{-5}$$

For the same compressor, this would also be valid for other gases, so in the case of hydrogen –

$$\zeta_{H_2} = 2.403 \text{ X } 10^{-5} \left[c\sqrt{z_1RT_1}\right]_{H_2} \tag{47}$$

As an example, for the same pressure ratio and T_2 as above –

$$\zeta = 2.403 \text{ X } 10^{-5} \text{ X } 2.15\sqrt{1.03 \text{ X } 767 \text{ X } 561.2} = 0.034$$

Summarizing all we have learned about volumetric efficiency, we can now express Equation 22 in terms of variables that depend on the physical properties of handled gas:

$$\eta_{vo} = \left\{(1 + \epsilon)\left(\frac{1}{1 + \theta G}\right)^{\frac{1}{n}} - \epsilon\left[\pi(1 + \theta G)\right]^{\frac{1}{m}}\right\} K_1\left(\frac{1}{\frac{1}{4}\frac{T_w}{T_2} + 1}\right) - K_2\sqrt{z_1RT_1} \tag{48}$$

For computation, the exponents can be simplified by assuming the $n = m = \gamma$, and the constants K are –

	K_1	K_2
Natural Gas G = 0.641	1.25	$4.974 \text{ X } 10^{-5}$
Molecular Hydrogen	1.205	$5.166 \text{ X } 10^{-5}$

As an example, let us calculate the overall volumetric efficiency of a reciprocating compressor for which the following is given:

Natural Gas: $G = 0.641$, $\gamma = 1.26$, $R = 83.2$ (ft-lb)/lb-^{0}R

$\pi = 1.3$, $P_{avg} = 750$ psia, $T_2 = 520^0$R, $T_w = 560^0$R

$\epsilon = 0.1$, $\theta = 0.09$

$$(\eta_{vo})_{NG} = \{1.1(\frac{1}{1 + 0.09 \times 0.641})^{\frac{1}{1.26}} - 0.1[1.3(1 + 0.09 \times 0.641)]^{\frac{1}{1.26}}\}[\frac{1.25}{0.25(\frac{560}{520}) + 1}] - 4.974 \times 10^{-5} \sqrt{0.885 \times 83.2 \times 548.9}$$

$$(\eta_{vo})_{NG} = 90\%$$

Molecular Hydrogen: $G = 0.0696$, $\gamma = 1.41$, $R = 767$(ft-lb)/lb-^{0}R

all the other conditions same as above

$$(\eta_{vo})_{H_2} = \{1.1(\frac{1}{1 + 0.09 \times 0.0696})^{\frac{1}{1.41}} - 0.1[1.3(1 + 0.09 \times 0.0696)]^{\frac{1}{1.41}}\}[\frac{1.205}{0.25(\frac{560}{520}) + 1}] - 5.166 \times 10^{-5}\sqrt{1.03 \times 767 \times 561.2}$$

$$(\eta_{vo})_{H_2} = 89\%$$

From this example we can conclude that for the same pressure ratio, the volumetric efficiency will not change. Also we can speculate that a hydrogen compressor would operate economically at lower pressure ratios than 1.3 (unlike a natural gas compressor) and that under these conditions it will have a higher overall volumetric efficiency.

5. Fuel Factor and Overall Volumetric Efficiency of Radial Turbocompressors

Since dynamic machines are sensitive to the differences between the operating and design conditions, they are predominantly "made to measure." Therefore, it would be highly improper to assume (as in the previous case) that the same size turbocompressor operating at the same speed could compress natural gas and hydrogen over the same pressure ratio. Here, another variable influences the comparison — namely, the rotor tip speed as dictated by the specific thermodynamic properties of the gas and the pressure ratio.

However, as the internal compressor geometry is assumed for this analysis to be of secondary importance, the same characteristics could be used for hydrogen and natural gas.

a. Compressor Power Input and Fuel Requirement

For turbocompressors it is customary to use the polytropic reference process for calculating the power input compared to the isentropic reference change of state (mostly referred to as adiabatic change) used with reciprocating compressors. The difference between these two approaches will become clear by defining the corresponding efficiencies[11,17]:

$$\eta_{pol} = \frac{RT_1 \cdot \frac{n}{n-1}\left[\left(\frac{P_2}{P_1}\right)^{\frac{n-1}{n}} - 1\right]}{RT_1 \cdot \frac{\gamma}{\gamma-1}\left[\left(\frac{P_2}{P_1}\right)^{\frac{n-1}{n}} - 1\right]} = \frac{n}{n-1} \cdot \frac{\gamma-1}{\gamma} \qquad (49)$$

and

$$\eta_{ad} = \frac{RT_1 \cdot \frac{\gamma}{\gamma-1}\left[\left(\frac{P_2}{P_1}\right)^{\frac{\gamma-1}{\gamma}} - 1\right]}{RT_1 \cdot \frac{\gamma}{\gamma-1}\left[\left(\frac{P_2}{P_1}\right)^{\frac{n-1}{n}} - 1\right]} = \frac{\left(\frac{P_2}{P_1}\right)^{\frac{\gamma-1}{\gamma}} - 1}{\left(\frac{P_2}{P_1}\right)^{\frac{n-1}{n}} - 1} \qquad (50)$$

Here only subscripts 1 and 2 refer to the initial and final states of compression.

Accepting the polytropic change as a reference process, Equation 18 will become —

$$\eta_f = \frac{1}{1 - 1.286 \times 10^{-3} \cdot \frac{z_1 + z_2}{2z_2} \cdot \frac{1}{g\eta_E\eta_{tpol}} \cdot \frac{n}{n-1} \cdot z_2RT_2\left(\pi^{\frac{n-1}{n}} - 1\right)} \qquad (51)$$

and the power input (Equation 19) will change to —

$$W = 4.363 \times 10^{-3} \cdot \frac{1}{\eta_{tpol}} \cdot \frac{z_1 + z_2}{2z_2} \cdot \frac{n}{n-1} \cdot \eta_f P_2V_2\left(\pi^{\frac{n-1}{n}} - 1\right) \qquad (52)$$

where —

$$\eta_{tpol} = \eta_{pol}\eta_{mech}$$

and

$$\eta_{mech} = \frac{1}{1 + \Sigma a_i}$$

The power input (W) is also expressed as —

$$W = \frac{W_{pol}}{\eta_{pol}} + \Sigma a_i \frac{W_{pol}}{\eta_{pol}} = \frac{W_{pol}}{\eta_{pol}} (1 + \Sigma a_i) \qquad (53)$$

where a_i is the individual percentage of power loss, which consists of the seal horsepower loss, the bearing horsepower loss, and the balance piston horsepower loss (usually taken as $0.015 \times \frac{W_{pol}}{\eta_{pol}}$).

To evaluate the polytropic efficiency (η_{pol}) and the individual power loss factors (a_i), the empirical characteristic data, such as presented in Table IV-A3 and Figures IV-A4a-4f, could be used, provided the internal geometry corresponds to these characteristics.

Table IV-A3. CASING SELECTION FOR INGERSOLL-RAND CENTRIFUGAL COMPRESSORS

Casing Size		**Capacity**		**Max. Stages At Rated Speed***	**Rated Speed (rpm)**
(inches)	**(mm)**	**(cfm)**	**(m³/ min.)**		
24	610	5400	153	9	10,000
33	838	7500	212	9	10,000
42	1070	12,000	339	9	7900
52	1320	23,000	651	8	7000
65	1650	30,000	850	7	5170
77	1950	42,000	1190	7	4650
87	2210	57,000	1610	7	3800
100	2540	75,000	2120	6	3320
112	2840	110,000	3120	6	3100
124	3150	140,000	3960	6	2865
140 124	3555 3150	200,000	5660	6	2865

***NOTE: For each side stream or re-entry connection for more than 10% of flow, deduct one stage from maximum number of stages.**

(Source: Ingersoll-Rand Company)

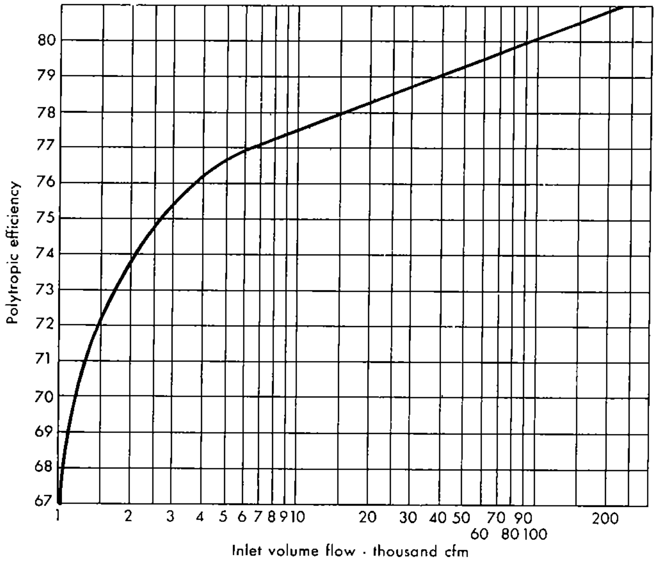


Figure IV-A4a. POLYTROPIC EFFICIENCY VERSUS INLET VOLUME FLOW FOR INGERSOLL-RAND CENTRIFUGAL COMPRESSORS (Source: Ingersoll-Rand Company)

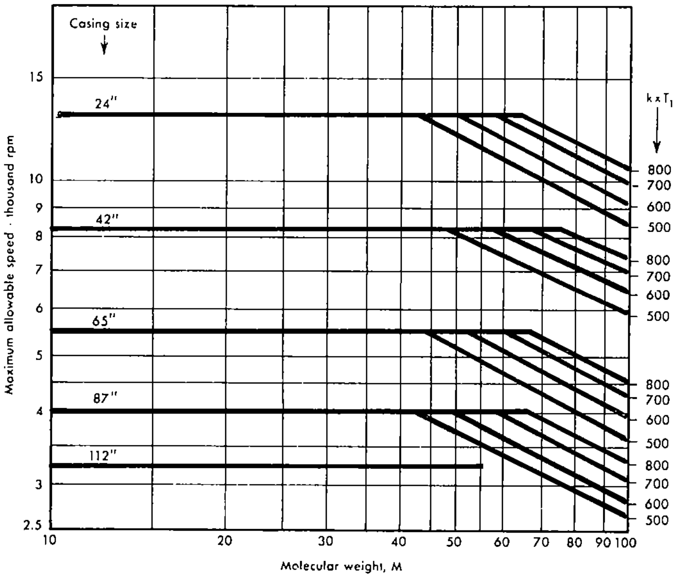


Figure IV-A4b. MAXIMUM ALLOWABLE SPEED FOR INGERSOLL-RAND CENTRIFUGAL COMPRESSORS (Source: Ingersoll-Rand Company)

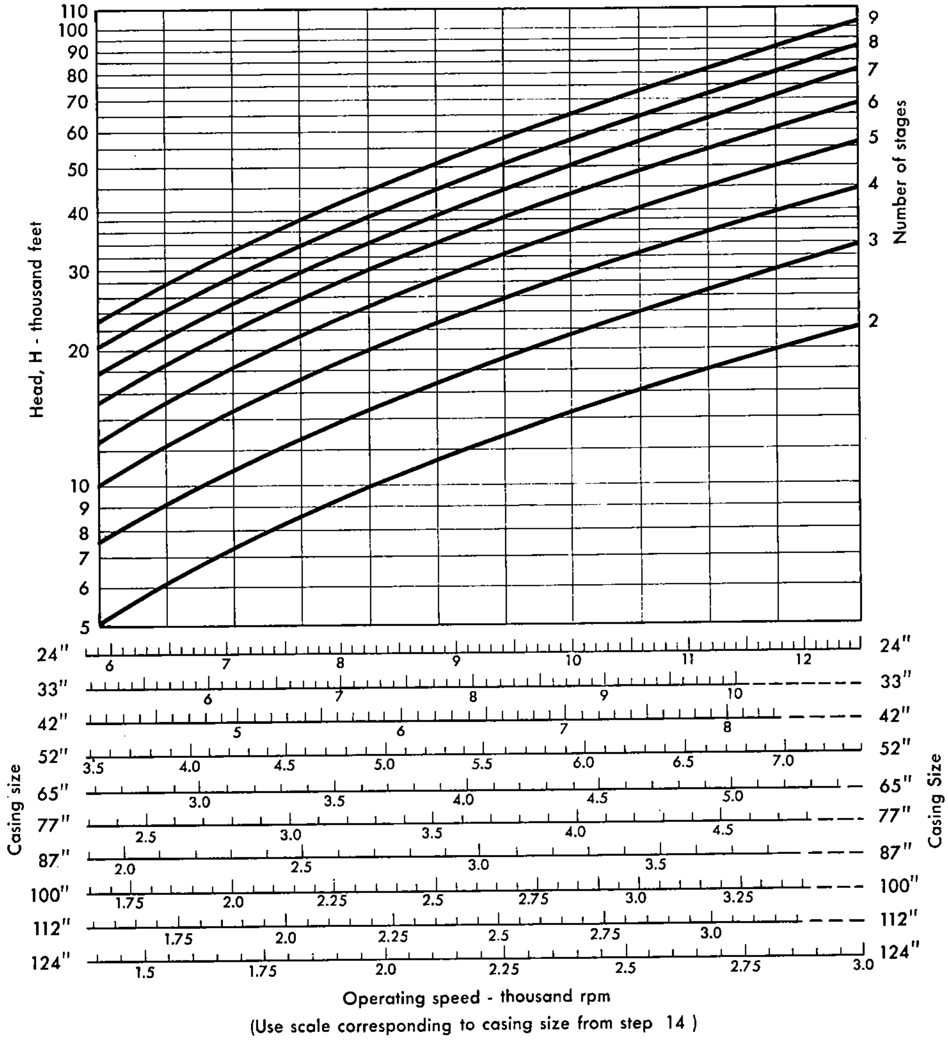
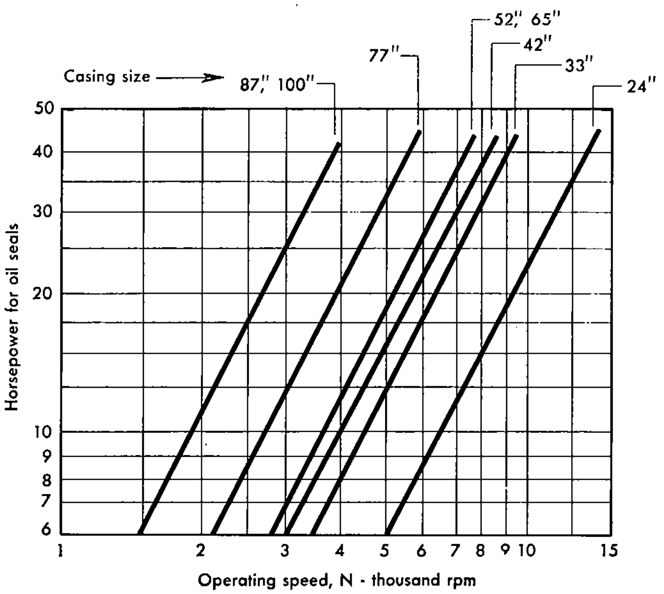
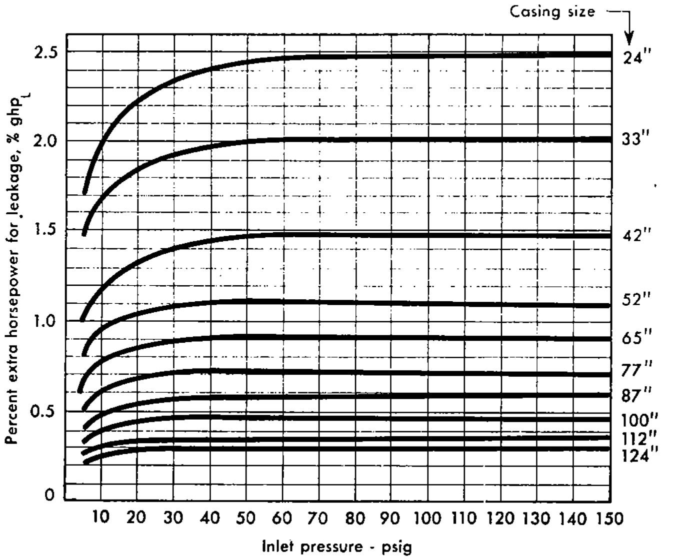


Figure IV-A4c. OPERATING SPEED AND NUMBER OF STAGES FOR INGERSOLL-RAND CENTRIFUGAL COMPRESSORS (Source: Ingersoll-Rand Company)



NOTE: Do not use this chart for labyrinth-type seals.

Figure IV-A4d. HORSEPOWER FOR OIL SEALS VERSUS OPERATING SPEED FOR INGERSOLL-RAND CENTRIFUGAL COMPRESSORS (Source: Ingersoll-Rand Company)



NOTE: Do not use this chart for oil seals.

Figure IV-A4e. EXTRA HORSEPOWER FOR LABYRINTH SEALS VERSUS PRESSURE FOR INGERSOLL-RAND CENTRIFUGAL COMPRESSORS (Source: Ingersoll-Rand Company)

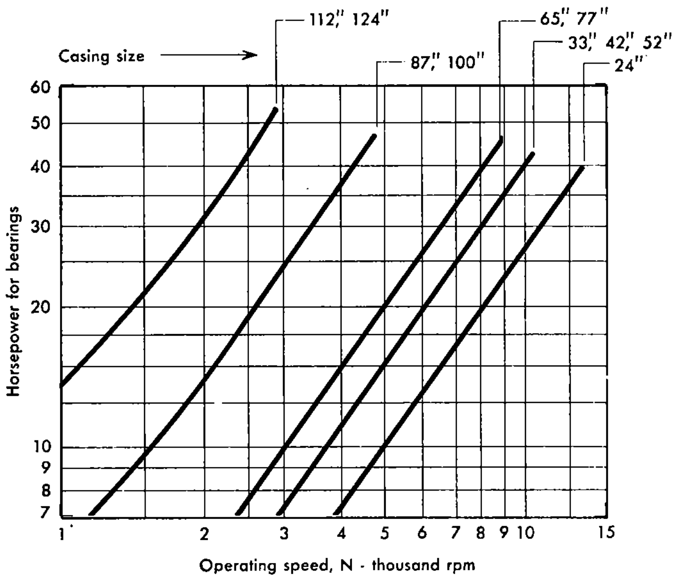


Figure IV-A4f. HORSEPOWER FOR BEARINGS VERSUS OPERATING SPEED FOR INGERSOLL-RAND CENTRIFUGAL COMPRESSORS (Source: Ingersoll-Rand Company)

b. Overall Volumetric Efficiency

Having in mind that a hydrogen radial turbocompressor must be a specially designed machine, the volumetric efficiency can be considered to be mainly a function of the size of the compressor, provided the required design improvements to minimize the internal and external losses are within the practical limits. The compressor size is controlled mostly by the leakage losses. Not only do they directly increase the necessary rotor size but they also, as a source of heat transferred to the inlet gas, decrease the compressor's suction mass capacity. For a good design, the leakage losses should approach only about 2% and the overall volumetric efficiency should be between about 90 and 98%, depending on the size of the compressor (lower value for smaller machines). The approximate dependence of radial turbocompressor capacity on leakage losses is shown in Figure IV-A5.

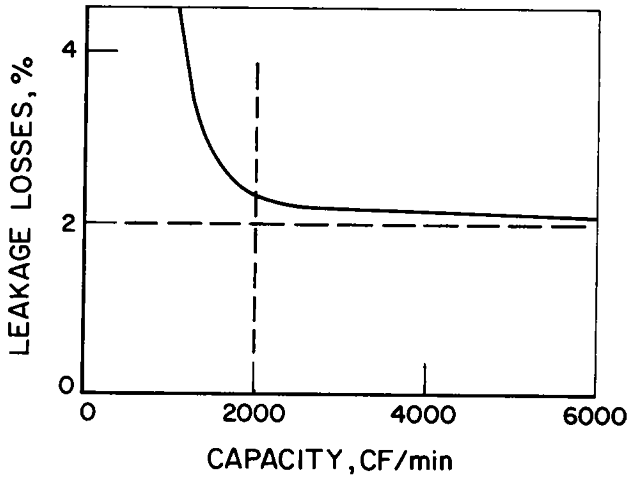


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Figure IV-A5. APPROXIMATION OF DEPENDENCE OF SIZE OF RADIAL TURBOCOMPRESSORS ON LEAKAGE LOSSES

An additional aspect has to be kept in mind in evaluating a dynamic machine such as a radial turbocompressor: The number of stages necessary to accomplish the overall compression depends on the physical properties of the gas and the rotor's tip speed. In practice, the maximum rotor tip speed is dictated by the allowable stresses on the rotor. Therefore, for every gas, there is a pressure ratio limit for a single stage. For example, to achieve the same pressure ratio for the two different gases (e. g., natural gas and hydrogen) in a single stage and with geometrically similar rotors, the ratio of the tip speeds is —

$$\frac{u^2_{NG}}{u^2_{H_2}} = \frac{\left[R \frac{\gamma}{\gamma - 1} \left(\pi^{\frac{\gamma - 1}{\gamma}} - 1\right)\right]_{NG}}{\left[R \frac{\gamma}{\gamma - 1} \left(\pi^{\frac{\gamma - 1}{\gamma}} - 1\right)\right]_{H_2}} \tag{54}$$

For $\pi = 1.3$, this will be —

$$\frac{u_{H_2}}{u_{NG}} = 3.03 \approx 3$$

If the speed exceeds the allowed limit, staging is necessary. Currently, compressors have been built to operate at 1200 ft/s and turbines, at 1500 ft/s. The latter seems to be a practical limit.

Thus, radial compressors will have to be designed specifically for hydrogen service. Data for carrying out this design are available. Practical limitations of rotor tip speeds require lower pressure ratios are used for hydrogen than for natural gas or that multistage compressors are used.

6. Power and Overall Volumetric Efficiency of Rotary Compressors

Another type of compressor, i.e., the screw compressor, should be considered as a potential candidate for hydrogen transmission. As to the technical characteristics of these machines we refer to Reference 2. Without going into the details, we will discuss their efficiencies below.

a. Compressor Power Input

The rotary compressor is a positive-displacement machine. Yet, its compression change follows the pattern of turbocompressors rather than that of reciprocating ones because its compression is relatively fast and its hydraulic losses account for the reheating effects typical of dynamic machines. Power efficiency is usually defined in reference to the isentropic change; it is the function of the pressure ratio, pressure difference, the physical properties of gas, and the size of the machine. Characteristic efficiency curves should be commercially obtainable, but were not available for use in this report. The values can go as high as an adiabatic efficiency (η_{ad}) about equal to 85%.

b. Overall Volumetric Efficiency

What has been said about the volumetric efficiency of turbocompressors applies generally to screw compressors, too. However, the effect of internal losses upon the power input and capacity is much more pronounced. Whether or not the hydrogen transmission operating conditions (mainly the pressure level and pressure difference) would not be detrimental to the compressor performance remains to be determined.

D. Thermodynamic and Thermophysical Properties of Natural Gas and Hydrogen

The typical composition of the natural gas chosen for the study is given in Table IV-A4. Its gas constant (R) is 83.2 (ft-lb)/lb-°R, its specific gravity (G) is 0.641, its gross volumetric heating value (Q) is 1054 Btu/CF at standard conditions, and its gross mass heating value (q) is 21,500 Btu/lb. The compressibility factors for this natural gas were obtained by interpolation from charts in Reference 4, pp. 34-57, 34-58. They were tabulated (together with hydrogen compressibilities and gross volumetric heating value ratios for equal conditions) and are presented in Table IV-A5.

The ratios of the gross heating values contained in a given volume of hydrogen and natural gas at various pressures are presented in Figure IV-A6. The other natural gas reference properties, namely, the specific heat ratio (γ), specific heat at constant pressure (c_p), thermal conductivity (k), and dynamic viscosity (η), were taken from references specified in Table IV-A2 of this study.

The following basic properties of pure molecular hydrogen are used in this study:

- Gas constant (R) = 767 (ft-lb)/lb-°R
- Specific gravity (G) = 0.0696
- Gross mass heating value (q) = 61,100 Btu/lb
- Gross volumetric heating value at standard conditions (Q) = 325 Btu/CF.

The compressibility factors obtained from Reference 4, chart on page 34-32, are also presented in Table IV-A5.

The specific heat ratio (γ) is given in Figure IV-A7, where the values of c_v above 100 atm had to be extrapolated on the basis of curves obtained from the National Bureau of Standards Circular 564, November 1955.[12] The extrapolation is shown in Figure IV-A8. Checking the extrapolated c_v points by finding the slopes $(\frac{\partial v}{\partial T})_p$ and $(\frac{\partial D}{\partial T})_v$ to satisfy the equation —

Table IV-A4. COMPOSITION OF A NATURAL GAS WITH A SPECIFIC GRAVITY OF 0.641 AND A 1054 Btu/CF GROSS VOLUMETRIC HEATING VALVE AT STANDARD CONDITIONS

Component	% by Volume	Spec. Volume, CF/lb	Spec. Weight, lb/CF	weight/volume lb/volume	Gas Constant (R), (ft-lb)/lb-°R	Molecular Weight	R X Weight
CO_2	0.34	8.548	0.117	0.0003980	35.1	44.01	0.013960
O_2	0.04	11.819	0.08461	0.0000338	48.3	32	0.001633
CH_4	85.86	23.565	0.04243	0.0364000	96.3	16.041	3.505000
C_2H_6	5.96	12.455	0.08029	0.0047900	51.5	30.067	0.247000
C_3H_8	2.05	8.365	0.1196	0.0024500	35.1	44.092	0.069800
n-C_4H_{10}	0.58	6.321	0.1582	0.0009180	26.6	58.118	0.024450
C_5H_{12}	0.14	5.252	0.1904	0.0002780	21.45	72.144	0.005970
N_2	4.74	13.443	0.07439	0.0035300	55.2	28.016	0.194900
He	0.21	94.91	0.01054	0.0000221	386.0	4.002	0.008540
Hexane+	0.08	~4.398	~0.2274	~0.0001820	17.95	~86.169	0.003265
	100.00			Σ = 0.0490019 lb/cu ft			Σ = 4.074518

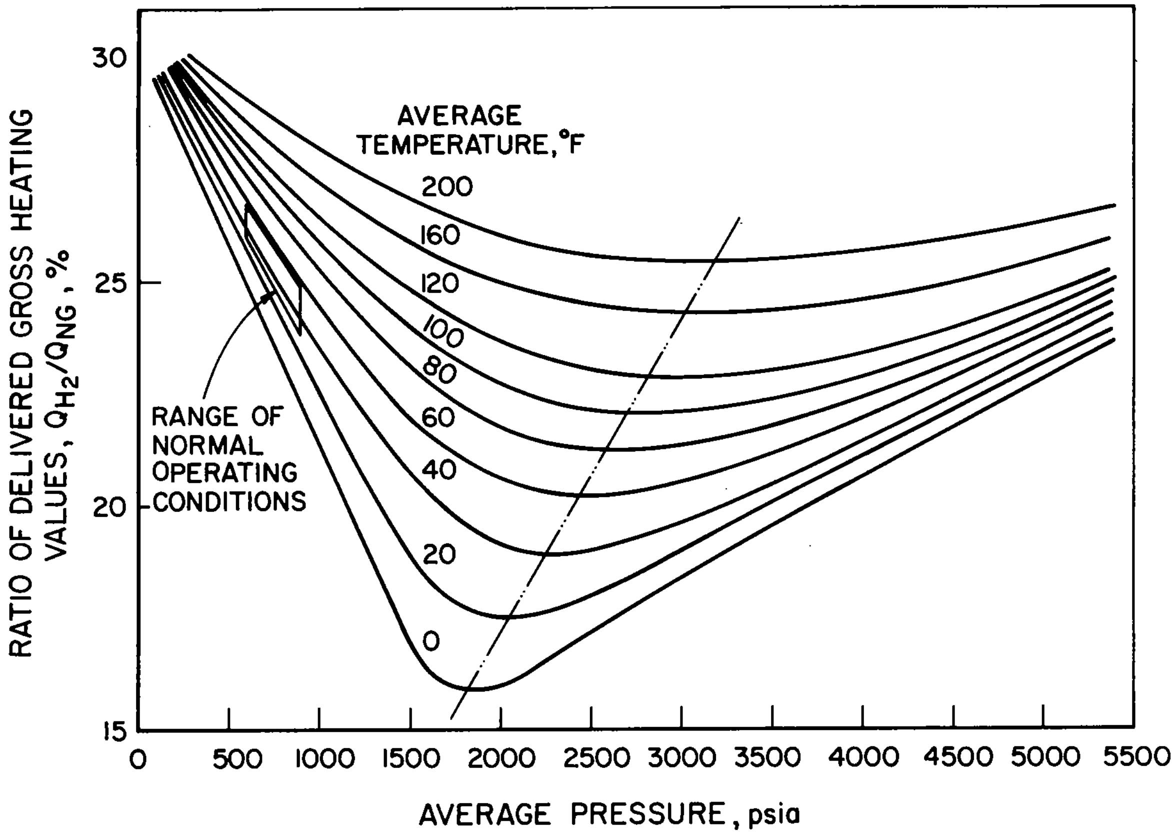

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Figure IV-A6. RELATIVE ENERGY TRANSMISSION CAPABILITIES OF HYDROGEN AND NATURAL GAS PIPELINES AS A FUNCTION OF TEMPERATURE AND PRESSURE AT WHICH THEY OPERATE

$$c_p - c_v = T\left(\frac{\partial v}{\partial T}\right)_p \left(\frac{\partial P}{\partial T}\right)_v \tag{55}$$

was not successful because it was extremely difficult to obtain proper values of $\left(\frac{\partial P}{\partial T}\right)_v$ from the tables available. The obtained c_v values scattered all over the investigated range of c_v; thus the extrapolated curves were adopted as the most probable ones.

Other properties, namely, thermal conductivity and dynamic viscosity, can be obtained from References 2 and 12 and are shown in Figures IV-A9 and IV-A10.

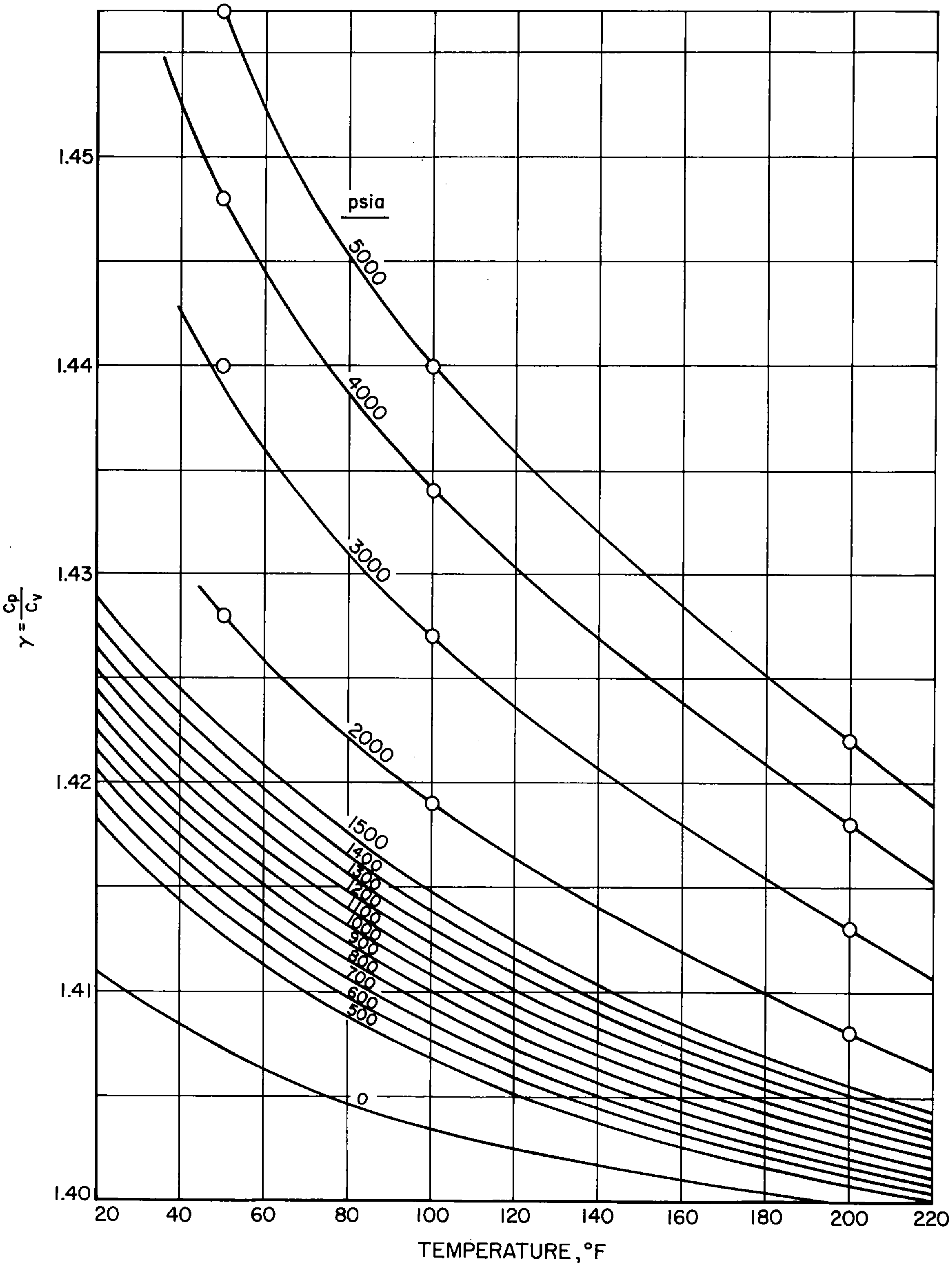

Figure IV-A7. SPECIFIC HEAT RATIO ($\gamma = \frac{c_p}{c_v}$) FOR MOLECULAR HYDROGEN (c_p Taken From Reference 18; c_v Extrapolated From Reference 12)

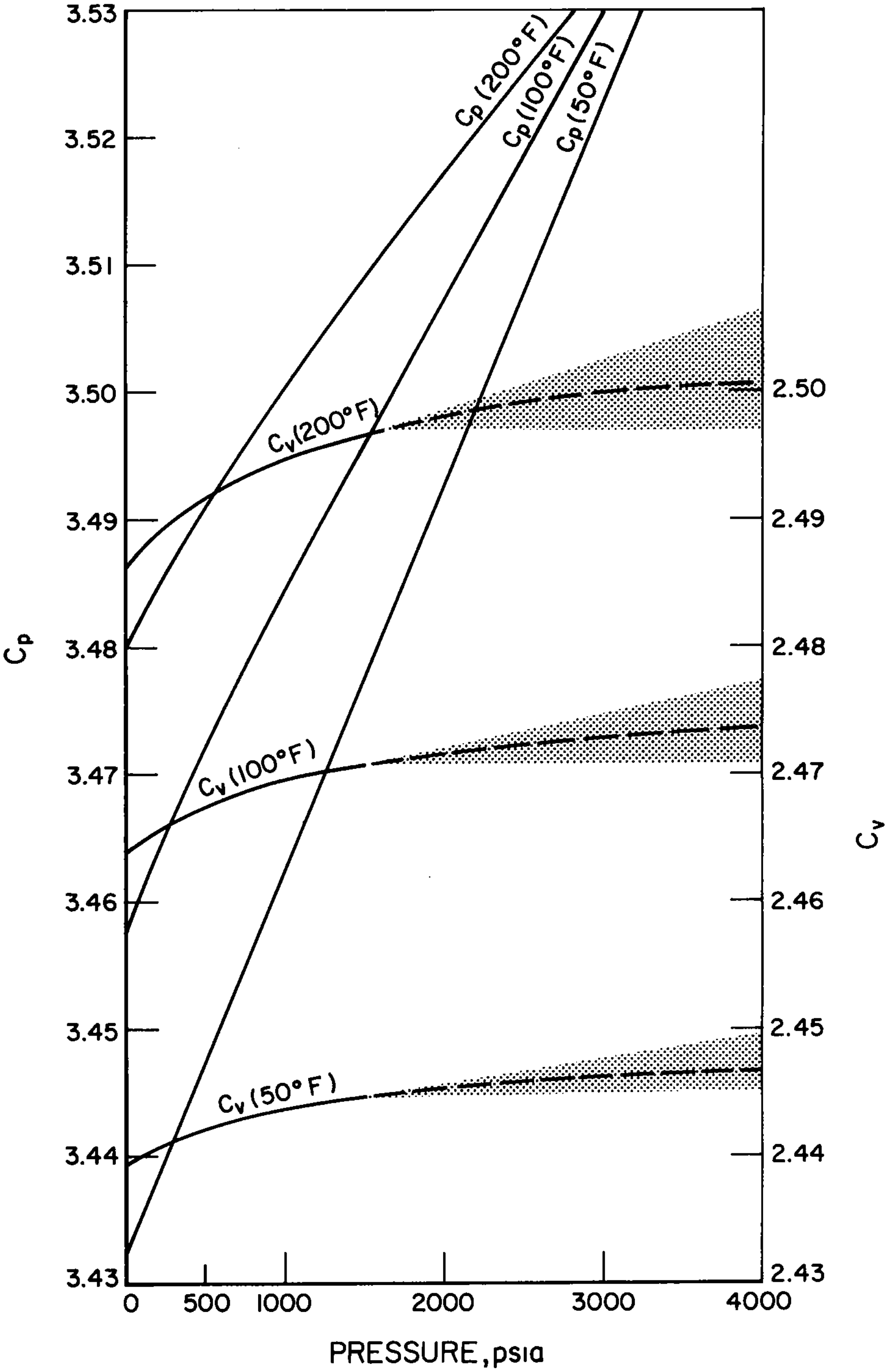

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Figure IV-A8. SPECIFIC HEATS c_p AND c_v FOR MOLECULAR HYDROGEN

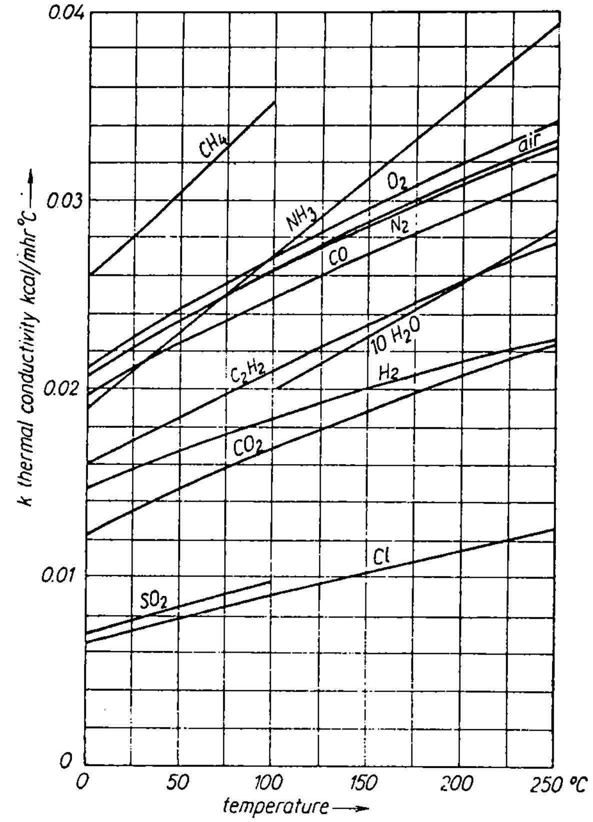

Figure IV-A9a. VARIATION OF THERMAL CONDUCTIVITY (k) OF GASES WITH TEMPERATURE AT 1 atm[2]

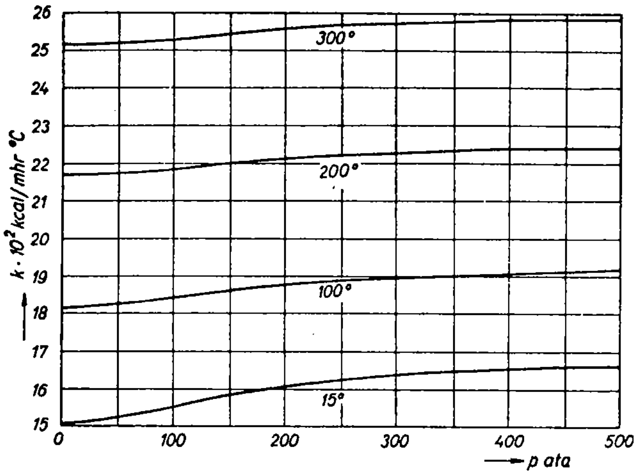

Figure IV-A9b. EFFECT OF PRESSURE ON THERMAL CONDUCTIVITY OF HYDROGEN AT SEVERAL TEMPERATURES[2]

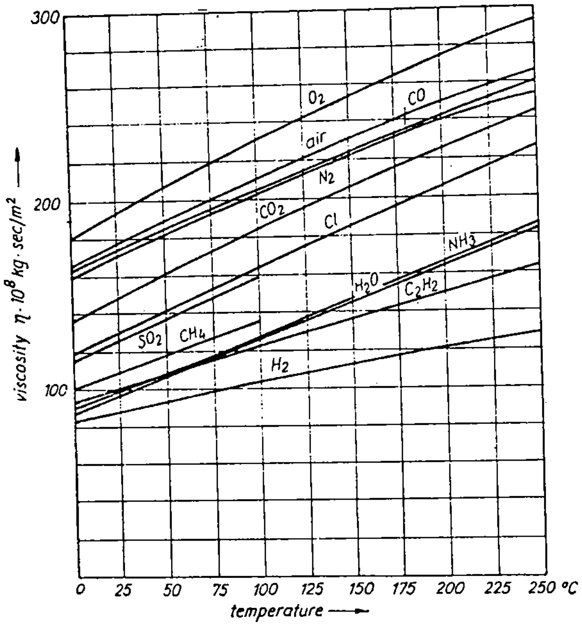

Figure IV-A10a. DYNAMIC VISCOSITY OF VARIOUS GASES AT 1 atm[2]

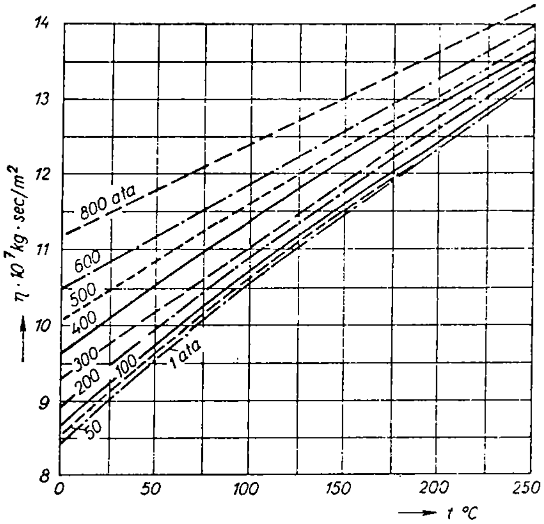

Figure IV-A10b. EFFECT OF TEMPERATURE ON DYNAMIC VISCOSITY OF HYDROGEN[2]

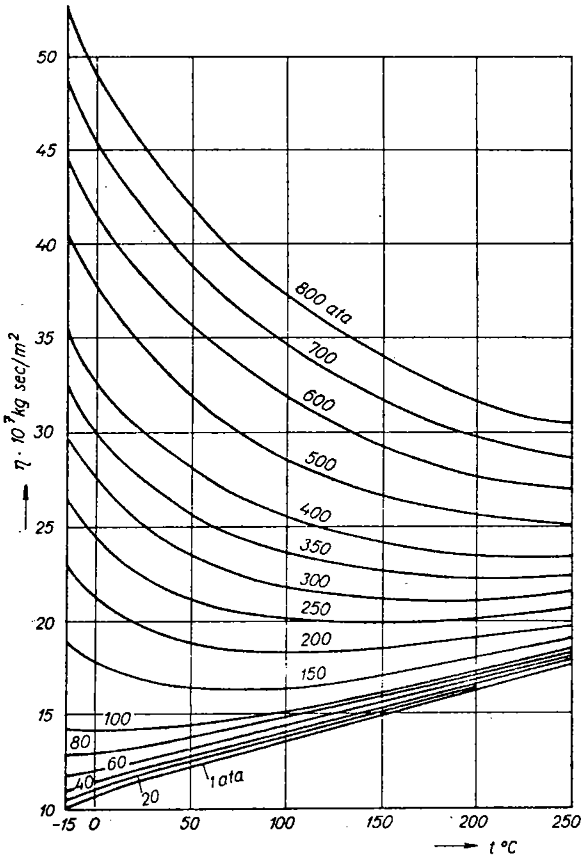

Figure IV-A10c. EFFECT OF TEMPERATURE ON DYNAMIC VISCOSITY OF METHANE[2]

E. Sample Calculations

1. Calculation Method

The method suggested in this report for calculating the hydrogen transmission cost gives the compression section transmission cost values relative to the transmission costs of a selected reference compression section handling natural gas at given conditions. As such, this method can minimize the cost of each compression section in a relative way, but it does not seek the combination of all the minimized compression sections that would result in the lowest overall system cost. (See Reference 9 for this method of optimization.)

To minimize the compression section transmission cost of hydrogen, it is necessary to optimize the section for various reference sections handling natural gas and thus to follow the individual points in the optimization diagram (Figure IV-A11).

2. Selection of Reference Points for Sample Calculations

There is no reason to assume that the optimal compressor station spacing and the optimal section operating conditions would be identical for natural gas and hydrogen. Also in this study we had to assume an idealized transmission line that disregards the geographic conditions and the load factor. Therefore, the first approach to selecting a reference compression section is rather arbitrary and should be followed by a series of repeated calculations for different reference points.

For our calculation we selected the following reference natural gas compression section:

- Pressure ratio (π_{NG}) = 1.3
- Average pressure (P_{avg}) = 750 psia
- Average temperature (T_{avg}) = 520°R

The recommended[14] pressure drop (Δ P) for optimal compressor spacing chosen is 3 psi/mile.

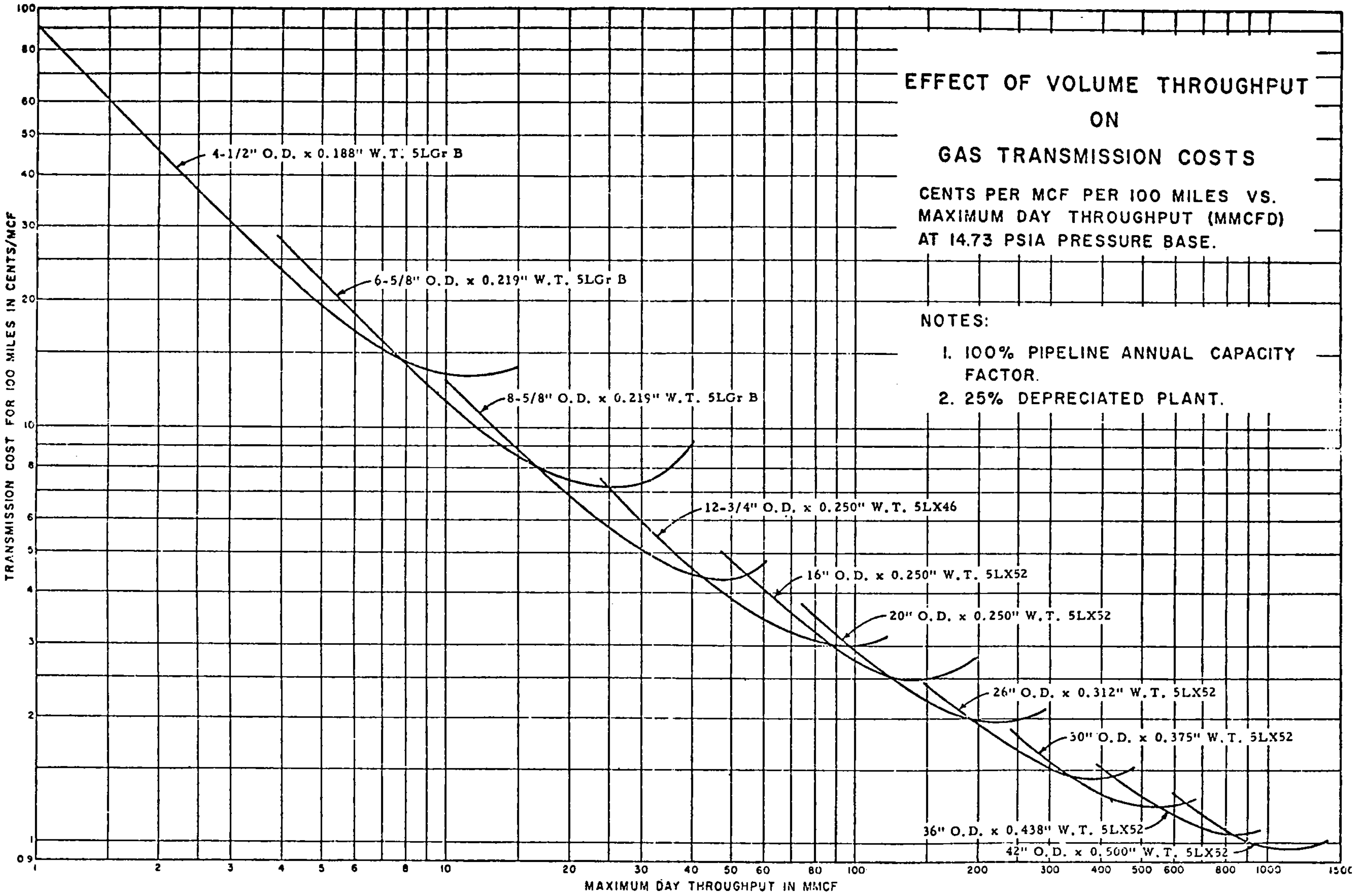

Figure IV-A11. EFFECT OF VOLUME THROUGHPUT ON GAS TRANSMISSION COSTS[7]

Table IV-A7. CAPACITIES AND DESIGN DATA FOR HYDROGEN PIPELINES

NO. OF PARALLEL LINES*	z_{avg}	z_2	z_{avg}/z_2	γ	π	P_2, psia	input factor	Q, Btu/CF	PIPE DIAMETER, in.					
									24					
									V_2		W,† hp	3/2 X V_{2f}‡		V_{2net},
									CF/min	10^{-9} Btu/yr		CF/min	10^{-9} Btu/yr	10^{-9} Btu/yr
P_{avg} = 750 psia, capacity factor = 3.830														
1	1.0300	1.0244	1.0054	1.414	~1.45	612.2	5.35	13,184	15,069	104,417	19,855 19,814	240	1663	102,754
2		1.0286	1.0013		1.095	716.0	1.46	15,356		121,622	5418 5407	56.1	453	121,169
3		1.0294	1.0006		1.042	734.6	0.68	15,743		124,690	2500 2518	25.2	208	124,482
4		1.0296	1.0003		1.022	741.7	0.36	15,891		125,861	1361 1333	13.6	114	125,747
P_{avg} = 1000 psia, capacity factor = 2.920														
1	1.0401	1.0359	1.0041	1.417	1.233	895.6	3.200	19,073	11,489	115,174	12,174 11,851	102.0	1022	114,152
2		1.0390	1.0010		1.053	973.9	0.850	20,677		124,861	3208 3148	24.7	268	124,593
3		1.0396	1.0004		1.023	988.4	0.378	20,973		126,648	1444 1400	11.0	121	126,527
4		1.0399	1.0002		~1.012	994.0	~0.193	21,087		127,336	744 715	5.6	62	127,274
P_{avg} = 1500 psia, capacity factor = 1.975														
1	1.0620	1.0589	1.0029	1.421	1.099	1429.2	1.525	29,775	7771	121,616	5816 5648	31.00	485	121,131
2		1.0612	1.0007		1.024	1482.2	0.385	30,811		125,846	1496 1426	7.70	125	125,721
3		1.0617	1.0003		~1.010	1492.5	0.167	31,012		126,667	630 620	3.30	54	126,613
4		1.0618	1.0001		~1.005	1492.3	~0.081	31,085		126,966	316 300	1.60	26	126,940
P_{avg} = 2000 psia, capacity factor = 1.530														
1	1.0827	1.0805	1.0021	1.426	1.055	1946.5	0.9200	39,741	6020	125,744	3456 3407	13.80	288	125,456
2		1.0822	1.0005		1.013	1986.6	0.2275	40,496		128,133	876 843	3.40	72	128,061
3		1.0825	1.0002		~1.006	1994.0	~0.094	40,635		128,574	392 348	1.50	32	128,542
4		1.0826	1.0001		~1.003	1997.0	~0.044	40,693		128,756	197 163	0.76	16	128,740

NO. OF PARALLEL LINES*	PIPE DIAMETER, in.																	
	30						36						42					
	V_2		W,† hp	3/2 X V_{2f}‡		V_{2net},	V_2		W,† hp	3/2 X V_{2f}‡		V_{2net},	V_2		W,† hp	3/2 X V_{2f}‡		V_{2net},
	CF/min	10^{-9} Btu/yr		CF/min	10^{-9} Btu/yr	10^{-9} Btu/yr	CF/min	10^{-9} Btu/yr		CF/min	10^{-9} Btu/yr	10^{-9} Btu/yr	CF/min	10^{-9} Btu/yr		CF/min	10^{-9} Btu/yr	10^{-9} Btu/yr
P_{avg} = 750 psia, capacity factor = 3.830																		
1	27,760	192,357	36,575	441	3056	189,301	45,473	315,096	59,914	723	5010	310,086	67,681	468,982	89,173	1077	7463	461,519
2		224,051	9981	103.5	835	223,216		367,013	16,349	169.5	1368	365,645		546,254	24,333	252	2034	544,220
3		229,704	4065	46.5	385	229,319		376,272	7544	76.5	633	375,639		560,035	11,228	113.6	940	559,095
4		231,860	2506	25.5	213	231,647		379,805	4106	41.1	343	379,462		565,293	6111	61.5	514	564,779
P_{avg} = 1000 psia, capacity factor = 2.920																		
1	21,164	212,164	22,427	187.5	1880	210,284	34,669	347,549	36,737	306.0	3068	344,481	51,600	517,278	54,678	456.0	4571	512,707
2		230,007	5910	45.5	494	229,513		376,776	9681	74.6	811	375,965		560,780	14,409	111.0	1206	559,574
3		233,299	2660	20.2	223	233,076		382,171	4358	33.0	364	381,807		568,808	6486	49.2	542	568,266
4		234,567	1371	10.0	111	234,456		384,248	2246	17.0	188	384,060		571,900	3343	25.2	279	571,621
P_{avg} = 1500 psia, capacity factor = 1.975																		
1	14,315	224,030	10,714	57.30	897	223,133	23,449	366,977	17,550	93.70	1466	365,511	34,901	546,200	26,121	140.00	2191	544,009
2		231,821	2756	14.20	230	231,591		379,740	4515	23.40	379	379,361		565,198	6720	34.60	560	564,638
3		233,334	1161	6.00	98	233,236		382,218	1902	9.75	159	382,059		568,885	2832	14.50	236	568,649
4		233,885	583	3.00	49	233,836		383,120	955	5.00	82	383,038		570,228	1421	7.35	120	570,108
P_{avg} = 2000 psia, capacity factor = 1.530																		
1	11,089	231,624	6366	25.50	533	231,091	18,166	379,446	10,428	42.00	877	378,569	27,037	564,741	15,520	62.20	1299	563,442
2		236,024	1614	6.30	134	235,890		386,654	2643	10.30	219	386,435		575,469	3934	15.40	328	575,141
3		236,837	723	2.80	60	236,777		387,987	1184	4.60	98	387,889		577,452	1762	6.90	147	577,305
4		237,172	362	1.40	30	237,142		388,535	593	2.30	49	388,486		578,268	882	3.40	73	578,195

* NUMBER OF PARALLEL PIPELINES OF THE SAME DIAMETER, OR EQUIVALENT INCREASE IN PIPE DIAMETER AS IT WOULD BE GIVEN BY EQUATION 6. THE COST CALCULATION HAS BEEN PERFORMED FOR THE FORMER CASE.

† THE TOP VALUES OF THE POWER INPUTS WERE CALCULATED DIRECTLY BY USING FORMULA 19 WITH η_{tad} = 0.8 AND η_f = 1. (THIS CORRESPONDS FOR P = 750 psia AND SINGLE LINE TO η_{pol} = 0.85, η_{mech} = 0.95, n = 1.525). THE BOTTOM VALUES WERE OBTAINED BY APPLYING THE POWER INPUT FACTOR. THE VALUES FOR 30-42 in. ARE THE SAME AS THE TOP VALUES FOR 24 in.

‡ THE FACTOR 1.5 COVERS THE AUXILIARY POWER AND STATION LOSSES.

- 750 psia, 100% of the diagram value
- 1000 psia, 100% of the diagram value
- 1500 psia, 105% of the diagram value
- 2000 psia, 110% of the diagram value

Except for assumption c, the same applies to gas turbine costs, which are given in Figure IV-A17.

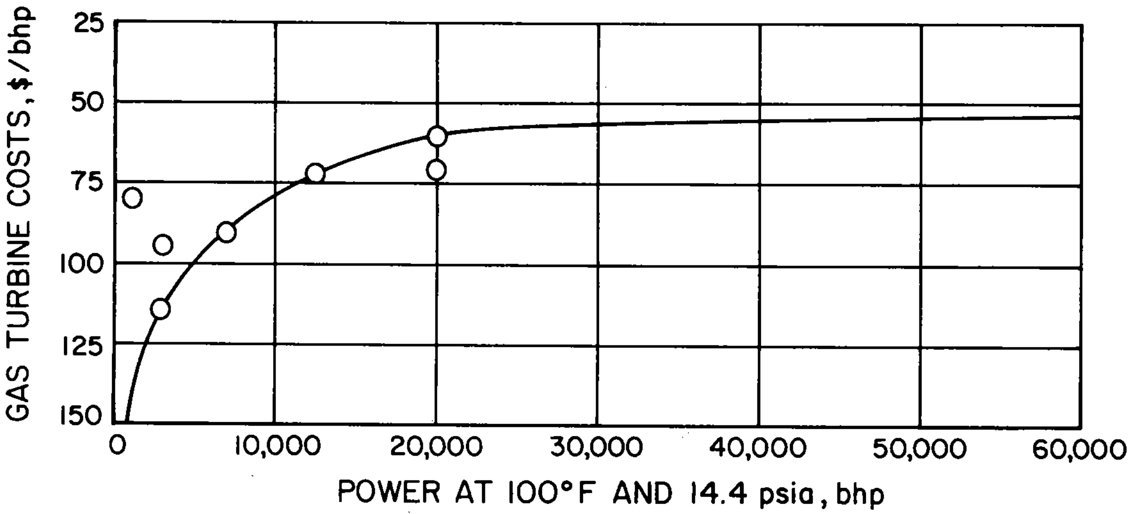

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Figure IV-A17. COSTS OF TURBINES USED AS PRIME MOVERS FOR HYDROGEN TRANSMISSION (Source: Ingersoll-Rand Company)

The labor cost to install the units is assumed to follow the trend of the station's first equipment cost rather than to be a constant for all cases. As a close approach, it is actually taken to be equivalent to the compressor and turbine first cost, so the station's first cost and the labor cost contribution to the transmission cost is equal to —

$$\frac{2 \times 0.13 \times (\text{compressor + turbine cost})}{\text{delivered heating value/year}}$$

These values are summarized in Table IV-A8.

2) Pipeline Material and Labor Costs

Typical onshore pipeline construction costs are presented in Figure IV-A18; graphically smoothed costs are presented in Table IV-A9. One manufacturing company disclosed that a new technology is about to be available for rolling 36-42 inch diameter pipes that can operate at a

Table IV-A8. COMPRESSOR STATION'S FIRST EQUIPMENT COST AND LABOR COST

No. of Parallel Lines		Pipeline Diameter, in. 24	30	36	42
		750 psia			
D	Compressor Cost, $	580,000	760,000	1,015,000	1,350,000
	Turbine Cost, $	1,190,000	2,045,000	3,170,000	4,460,000
	Total, $	1,770,000	2,805,000	4,185,000	5,810,000
	$\frac{\text{13\% of the investment + labor}}{\text{delivered heating value/yr}}$, $\$/10^9$ Btu/yr	4.48	3.85	3.51	3.27
2D or Equivalent	Compressor Cost, $	225,000	275,000	305,000	435,000
	Turbine Cost, $	528,250	778,520	1,030,000	1,400,000
	Total, $	753,250	1,053,520	1,335,000	1,835,000
	$\frac{\text{13\% of the investment + labor}}{\text{delivered heating value/yr}}$, $\$/10^9$ Btu/yr	1.61	1.22	0.95	0.88
3D or Equivalent	Compressor Cost, $	165,000	190,000	230,000	280,000
	Turbine Cost, $	293,750	472,000	648,800	842,100
	Total, $	458,750	662,000	878,800	1,122,100
	$\frac{\text{13\% of the investment + labor}}{\text{delivered heating value/yr}}$, $\$/10^9$ Btu/yr	0.96	0.75	0.61	0.52
4D or Equivalent	Compressor Cost, $	145,000	160,000	190,000	220,000
	Turbine Cost, $	187,140	294,500	431,100	574,400
	Total, $	332,140	454,500	621,100	794,400
	$\frac{\text{13\% of the investment + labor}}{\text{delivered heating value/yr}}$, $\$/10^9$ Btu/yr	0.68	0.51	0.43	0.37
		1000 psia			
D	Compressor Cost, $	350,000	430,000	540,000	695,000
	Turbine Cost, $	882,600	1,301,000	2,057,300	2,952,600
	Total, $	1,232,600	1,731,000	2,597,300	3,647,600
	$\frac{\text{13\% of the investment + labor}}{\text{delivered heating value/yr}}$, $\$/10^9$ Btu/yr	2.80	2.14	1.96	1.85
2D or Equivalent	Compressor Cost, $	175,000	200,000	230,000	280,000
	Turbine Cost, $	360,900	561,500	764,800	979,800
	Total, $	535,900	761,500	994,800	1,259,800
	$\frac{\text{13\% of the investment + labor}}{\text{delivered heating value/yr}}$, $\$/10^9$ Btu/yr	1.08	0.86	0.69	0.59
3D or Equivalent	Compressor Cost, $	135,000	157,000	175,000	205,000
	Turbine Cost, $	195,000	308,600	453,200	596,700
	Total, $	330,000	465,600	628,200	801,700
	$\frac{\text{13\% of the investment + labor}}{\text{delivered heating value/yr}}$, $\$/10^9$ Btu/hr	0.68	0.52	0.43	0.37
4D or Equivalent	Compressor Cost, $	128,000	136,000	155,000	172,000
	Turbine Cost, $	113,500	188,500	274,000	371,100
	Total, $	241,500	324,500	429,000	543,100
	$\frac{\text{13\% of the investment + labor}}{\text{delivered heating value/yr}}$, $\$/10^9$ Btu/yr	0.49	0.36	0.29	0.25
		1500 psia			
D	Compressor Cost, $	215,250	241,500	283,500	330,750
	Turbine Cost, $	558,300	814,300	1,088,100	1,488,900
	Total, $	773,550	1,055,800	1,371,600	1,819,650
	$\frac{\text{13\% of the investment + labor}}{\text{delivered heating value/yr}}$, $\$/10^9$ Btu/yr	1.66	1.23	0.98	0.87
2D or Equivalent	Compressor Cost, $	136,500	154,350	170,100	184,800
	Turbine Cost, $	199,000	319,700	462,800	614,900
	Total, $	335,500	474,050	632,900	799,700
	$\frac{\text{13\% of the investment + labor}}{\text{delivered heating value/yr}}$, $\$/10^9$ Btu/yr	0.69	0.53	0.43	0.37
3D or Equivalent	Compressor Cost, $	126,000	132,300	142,800	157,500
	Turbine Cost, $	97,700	163,700	239,600	322,800
	Total, $	223,700	296,000	382,400	480,300
	$\frac{\text{13\% of the investment + labor}}{\text{delivered heating value/yr}}$, $\$/10^9$ Btu/yr	0.46	0.33	0.26	0.22
4D or Equivalent	Compressor Cost, $	120,750	126,000	134,400	147,000
	Turbine Cost, $	53,800	91,800	140,400	191,900
	Total, $	174,550	217,800	274,800	338,900
	$\frac{\text{13\% of the investment + labor}}{\text{delivered heating value/yr}}$, $\$/10^9$ Btu/yr	0.36	0.24	0.19	0.15
		2000 psia			
D	Compressor Cost, $	173,800	192,500	203,500	236,500
	Turbine Cost, $	383,600	588,900	808,200	1,008,800
	Total, $	557,400	781,400	1,011,700	1,245,300
	$\frac{\text{13\% of the investment + labor}}{\text{delivered heating value/yr}}$, $\$/10^9$ Btu/yr	1.16	0.88	0.69	0.57
2D or Equivalent	Compressor Cost, $	134,200	143,000	148,500	159,500
	Turbine Cost, $	129,200	209,800	306,600	420,900
	Total, $	263,400	352,800	455,100	580,400
	$\frac{\text{13\% of the investment + labor}}{\text{delivered heating value/yr}}$, $\$/10^9$ Btu/yr	0.53	0.39	0.31	0.26
3D or Equivalent	Compressor Cost, $	126,500	132,000	137,500	143,000
	Turbine Cost, $	66,600	110,600	166,900	225,500
	Total, $	193,100	242,600	304,400	368,500
	$\frac{\text{13\% of the investment + labor}}{\text{delivered heating value/yr}}$, $\$/10^9$ Btu/yr	0.39	0.27	0.20	0.17
4D or Equivalent	Compressor Cost, $	121,000	126,500	132,000	137,000
	Turbine Cost, $	35,400	63,400	93,400	130,100
	Total, $	156,400	189,900	225,400	267,100
	$\frac{\text{13\% of the investment + labor}}{\text{delivered heating value/yr}}$, $\$/10^9$ Btu/yr	0.32	0.21	0.15	0.12

Table IV-A9. TYPICAL ONSHORE PIPELINE CONSTRUCTION COSTS (Graphically Adjusted)

Pressure, psia		Pipeline Diameter, in. 24		30		36		42	
		$/mile	$ 10^6/65 miles*	$/mile	$ 10^6/65 miles*	$/mile	$ 10^6/65 miles*	$/mile	$ 10^6/65 miles*
750	Labor Cost	100, 000		125, 000		149, 000		171, 000	
	Material Cost	54, 000		88, 000		118, 000		136, 000	
	Total Cost	154, 000	10. 01	213, 000	13. 85	267, 000	17. 36	307, 000	19. 96
	$\frac{13\% \text{ of Total Cost}}{\text{Throughput in } 10^9 \text{ Btu/yr}}$		(11. 92)		(8. 95)		(6. 94)		(5. 29)
1000	Labor Cost	100, 000		125, 000		149, 000		171, 000	
	Material Cost	75, 000		117, 000		154, 000		180, 000	
	Total Cost	175, 000	11. 38	242, 000	15. 73	303, 000	19. 70	351, 000	22. 82
	$\frac{13\% \text{ of Total Cost}}{\text{Throughput in } 10^9 \text{ Btu/yr}}$		(13. 55)		(10. 16)		(7. 88)		(6. 05)
1500	Labor Cost	100, 000		125, 000		149, 000		171, 000	
	Material Cost	104, 000		160, 000		210, 000		254, 000	
	Total Cost	204, 000	13. 26	285, 000	18. 53	359, 000	23. 34	425, 000	27. 63
	$\frac{13\% \text{ of Total Cost}}{\text{Throughput in } 10^9 \text{ Btu/yr}}$		(15. 79)		(11. 97)		(9. 33)		(7. 32)
2000	Labor Cost	100, 000		125, 000		149, 000		171, 000	
	Material Cost	138, 000		215, 000		282, 000		338, 000	
	Total Cost	238, 000	15. 47	340, 000	22. 10	431, 000	28. 015	509, 000	33. 085
	$\frac{13\% \text{ of Total Cost}}{\text{Throughput in } 10^9 \text{ Btu/yr}}$		(16. 03)		(12. 43)		(9. 62)		(7. 63)

* Number in parentheses is in $/$10^9$ Btu/yr.

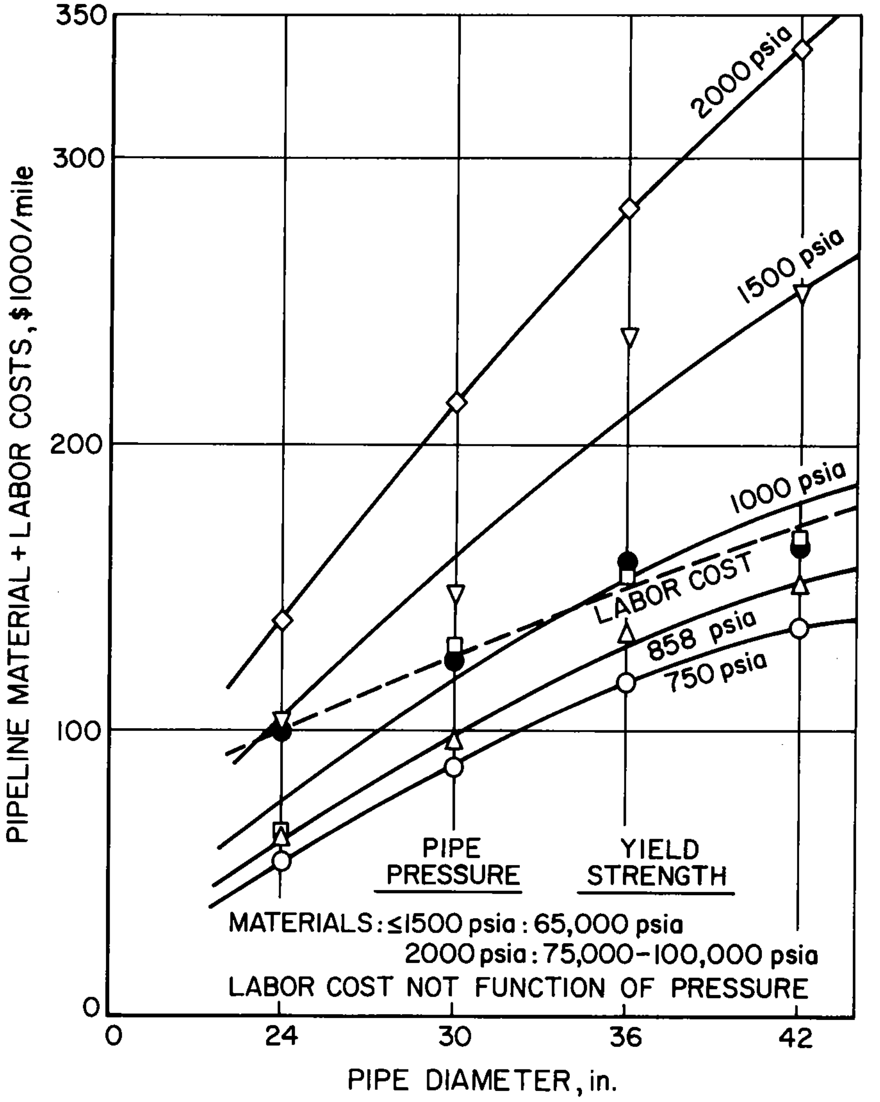

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Figure IV-A18. TYPICAL ONSHORE PIPELINE CONSTRUCTION COSTS
(Source: Natural Gas Pipeline Company of America)

2000-psia pressure level from materials with a yield strength of 75,000-100,000 psia. The company estimated that the cost will be about 33% higher than the cost of pipes capable of operation at 1500 psia.

3) Operating Costs

The operating costs less the costs of the primary and auxiliary fuel and less the station fixed costs (taken as the percentage of the station investments) are tabulated in Table IV-A10 on the basis of Figure IV-A19. The diagram is constructed according to the Reference 13.

Table IV-A10. OPERATING COSTS LESS THE COSTS OF PRIMARY AND AUXILIARY FUEL AND LESS STATION FIXED COSTS AS A PERCENTAGE OF STATION INVESTMENT

No. of Parallel Lines		Pipeline Diameter, in.			
		24	30	36	42
		750 psia			
D	Power Input, hp	19,855	36,575	59,914	89,174
	Yearly Operating Cost, \$/hp-yr	13.05	11,70	10,70	9,95
	Relative Operating Cost, $\$/10^9$ Btu	2.25	2.26	2.07	1.92
2D	Power Input, hp	5,418	9,981	16,349	24,333
	Yearly Operating Cost, \$/hp-yr	18.5	14.7	13.5	12.5
	Relative Operating Cost, $\$/10^9$ Btu	0.83	0.66	0.60	0.56
3D	Power Input, hp	2,500	4,605	7,544	11,282
	Yearly Operating Cost, \$/hp-yr	24.75	19.7	16.4	14.4
	Relative Operating Cost, $\$/10^9$ Btu	0.50	0.40	0.33	0.30
4D	Power Input, hp	1,361	2,506	4,106	6,111
	Yearly Operating Cost, \$/hp-yr	31	24.7	20.5	17.7
	Relative Operating Cost, $\$/10^9$ Btu	0.335	0.267	0.222	0.192
		1000 psia			
D	Power Input, hp	12,174	22,427	36,737	54,678
	Yearly Operating Cost, \$/hp-yr	14.25	12.75	11.70	10.80
	Relative Operating Cost, $\$/10^9$ Btu	1.52	1.36	1.25	1.15
2D	Power Input, hp	3,208	5,910	9,681	14,409
	Yearly Operating Cost, \$/hp-yr	22.5	18	15	13.75
	Relative Operating Cost, $\$/10^9$ Btu	0.58	0.46	0.39	0.35
3D	Power Input, hp	1,444	2,660	4,358	6,486
	Yearly Operating Cost, \$/hp-yr	30.5	24.25	20,2	17.25
	Relative Operating Cost, $\$/10^9$ Btu	0.35	0.28	0.23	0.20
4D	Power Input, hp	744	1,371	2,246	3,343
	Yearly Operating Cost, \$/hp-yr	39	31	25.75	22.25
	Relative Operating Cost, $\$/10^9$ Btu	0.23	0.18	0.15	0.13
		1500 psia			
D	Power Input, hp	5,816	10,714	17,550	26,121
	Yearly Operating Cost, \$/hp-yr	18	14.50	13.3	12.45
	Relative Operating Cost, $\$/10^9$ Btu	0.86	0.70	0.64	0.60
2D	Power Input, hp	1,496	2,756	4,515	6,720
	Yearly Operating Cost, \$/hp-yr	30	24	18.5	17.20
	Relative Operating Cost, $\$/10^9$ Btu	0.36	0.29	0.22	0.20
3D	Power Input, hp	630.5	1,161	1,902	2,832
	Yearly Operating Cost, \$/hp-yr	41.3	33	27.5	23.5
	Relative Operating Cost, $\$/10^9$ Btu	0.21	0.16	0.14	0.12
4D	Power Input, hp	316.5	583	955	1,421.5
	Yearly Operating Cost, \$/hp-yr	53.5	42.5	35.5	30.5
	Relative Operating Cost, $\$/10^9$ Btu	0.13	0.11	0.09	0.08
		2000 psia			
D	Power Input, hp	3,456	6,366	10,428	15,520
	Yearly Operating Cost, \$/hp-yr	22	17,5	14.55	13.6
	Relative Operating Cost, $\$/10^9$ Btu	0.61	0.48	0.40	0.37
2D	Power Input, hp	876	1,614	2,643	3,934
	Yearly Operating Cost, \$/hp-yr	36.5	29.25	24.35	20.75
	Relative Operating Cost, $\$/10^9$ Btu	0.25	0.20	0.17	0.14
3D	Power Input, hp	392	723	1,184	1,762
	Yearly Operating Cost, \$/hp-yr	49.5	38.75	32.6	28.25
	Relative Operating Cost, $\$/10^9$ Btu	0.15	0.12	0.10	0.09
4D	Power Input, hp	196.5	362	593	882
	Yearly Operating Cost, \$/hp-yr	~65	51	42.3	36.5
	Relative Operating Cost, $\$/10^9$ Btu	0.10	0.08	0.065	0.055

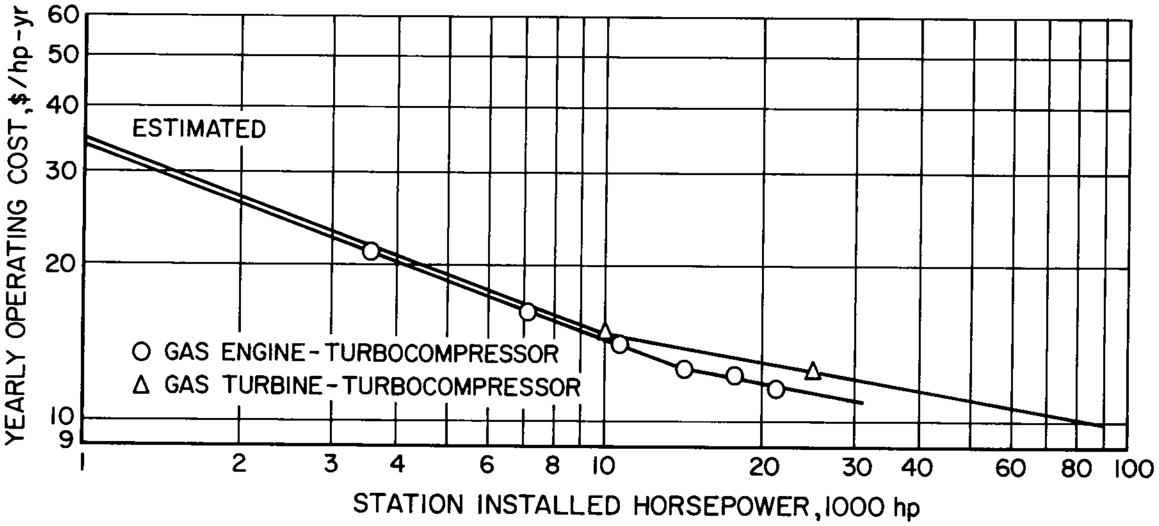

Figure IV-A19. COMPRESSOR STATION OPERATING COSTS (Costs Less Primary and Auxiliary Fuel and Less Fixed Costs as Percentage of the Station Investment)

4) Transmission Cost of Fuel

The transmission cost of the primary and auxiliary fuel is to be understood as an additional part of the fuel cost. The fuel cost (next subsection below) does not have the transmission charges included; therefore, this increase intends to account for the fact that each compression section has to take care of its fuel supply. It is computed as —

$$\left(\frac{V_{2_f}}{V_2} + 1\right) \cdot \frac{V_{2_f}}{V_2} \cdot \Sigma(\alpha, \beta, \gamma), \quad \$/10^9 \text{ Btu} \qquad (56)$$

and is tabulated in Table IV-A11.

5) Cost of Fuel

The production (generation) cost of hydrogen has been assumed to be either $1.00, $2.00, or $3.00/million Btu. From Table IV-4 of the main text of Section IV, we can see how important a part the generation cost of hydrogen plays in the total cost of the fuel, especially for the lower pressure levels, mainly 750 psia.

Table IV-A11. APPROXIMATION OF FUEL (Primary and Auxiliary) TRANSMISSION COSTS

		Pipeline Diameter, in.			
		24	30	36	42
No. of Parallel Lines	V_{2_f}/V_2, %	Cost, $/$10^9$ Btu	Cost, $/$10^9$ Btu	Cost, $/$10^9$ Btu	Cost, $/$10^9$ Btu
750 psia					
D	1.61	0.310	0.246	0.205	0.171
2D	0.37	0.098	0.073	0.057	0.045
3D	0.17	0.063	0.048	0.037	0.028
4D	0.09	0.044	0.033	0.026	0.019
1000 psia					
D	0.89	0.160	0.123	0.100	0.081
2D	0.21	0.060	0.046	0.035	0.027
3D	0.10	0.042	0.031	0.024	0.019
4D	0.05	0.027	0.021	0.016	0.012
1500 psia					
D	0.40	0.074	0.056	0.044	0.035
2D	0.10	0.033	0.025	0.019	0.015
3D	0.04	0.019	0.015	0.011	0.009
4D	0.02	0.013	0.0096	0.0075	0.0059
2000 psia					
D	0.23	0.041	0.032	0.025	0.019
2D	0.056	0.018	0.014	0.011	0.009
3D	0.025	0.012	0.009	0.007	0.006
4D	0.012	0.008	0.006	0.005	0.004

c. Resulting Transmission Cost

The cost of pure molecular hydrogen transmitted through a distance of 65 miles is presented in Table IV-4 of the main text. The values are plotted in Figures IV-5, 6, 7, and 8 of the main text for pressures evaluated as functions of the cost of fuel, pipeline diameter, and number of parallel lines of the same diameter. The last independent variable represents the pressure ratio dependence because, from the fluid flow point of view, changing the number of parallel lines is equivalent to a change in the diameter of a single pipe with a change in pressure drop, although, economically speaking, this equivalence fails because two pipes are more costly than a single pipe of equivalent diameter.

d. Cost Optimization for a Compression Section

Figures IV-5, 6, 7, and 8 show minimum costs for certain pressure ratios. Plotting these minimum points, we constructed a diagram analogous to Figure IV-10 (natural gas transmission cost) in such a way that the hydrogen curves correspond to a curve that would connect all the minimums in the reference natural gas chart, Figure IV-10.

The optimum hydrogen transmission cost chart presented in Figure IV-A20 can be used directly for comparisons, keeping in mind, of course, that it does not represent the optimum spacing. Assuming, for example, the linear extrapolation of the hydrogen transmission cost as to distance,* the following comparison can be made:

Pipeline Diameter, in.	NG (100 miles)	H_2 (65 miles)	H_2 (extrapolation) (100 miles)
	¢/10^6 Btu		
30	~1.14	2.05	3.15
36	~1.00	1.16	2.71
42	~0.91	1.54	2.37

For this comparison the hydrogen data are taken at 2000 psia and at a fuel cost of $3/million Btu.

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* From Table IV-4, we can see that this would be a justifiable assumption because, especially at higher pressures, the only major contributor to the transmission cost is the pipeline investment.

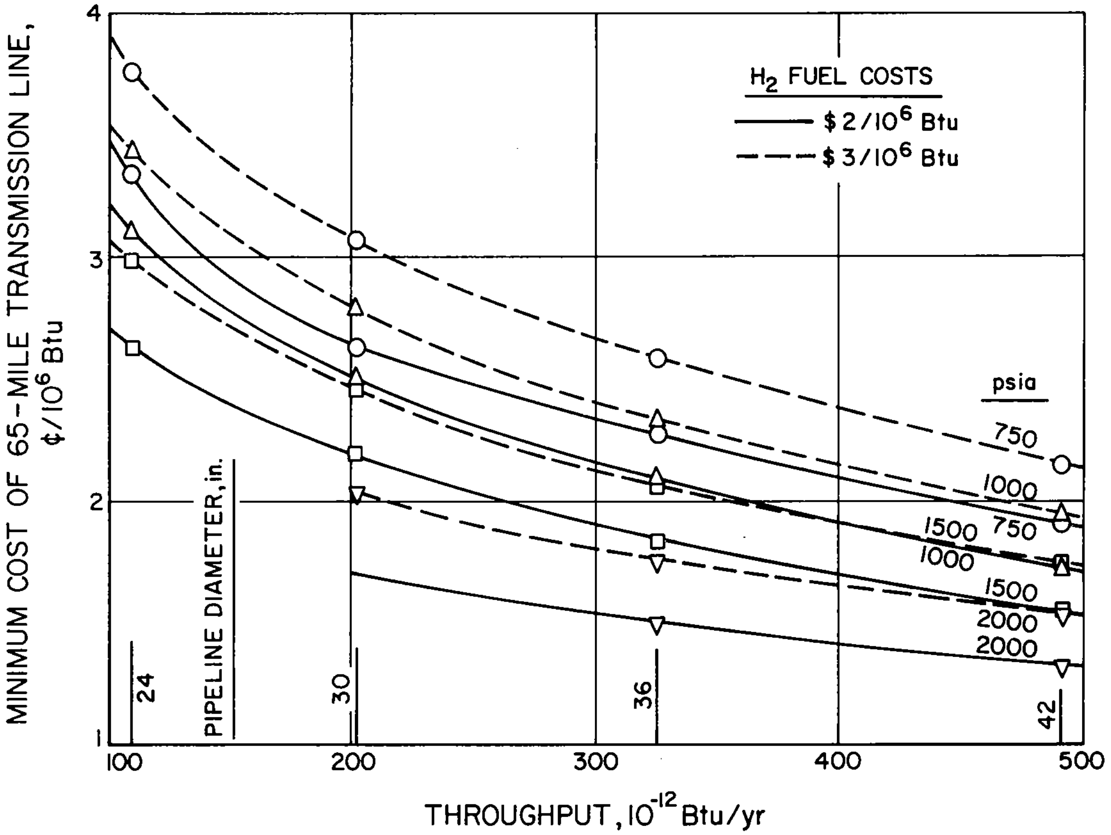

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Figure IV-A20. OPTIMUM COST FOR 65-MILE HYDROGEN TRANSMISSION LINE

F. Conclusions

It has been possible, therefore, to calculate from "first principles" the estimated transmission costs of hydrogen in partially optimized pipelines, but without optimizing the compressor station spacing. To compare these estimated hydrogen transmission costs with today's costs for natural gas transmission on equal terms, a similar "first principles" derivation should be made for natural gas using the same initial assumptions. It was not possible to do this during this study, but it should be done later. Instead, we used the only optimized detailed cost data we could obtain, Reference 7, and plotted them as Figure IV-9 of the main text. Because these data are about 9 years old, significant increases in transmission costs can be assumed to have occurred since that time. An average figure in the range 1.5¢-1.7¢/million Btu per 100 miles seems to be a reasonable consensus. This indicates that, at a $3.00/million Btu fuel cost for hydrogen, hydrogen transmission costs will be 2-3 times greater than those for natural gas at conventional pressures, but will be significantly reduced if hydrogen operating pressures can be increased into the 2000-psia region.

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V. HYDROGEN STORAGE

A. Introduction

Storage is needed in an energy delivery system for two fundamental reasons: 1) to match variations in demand with the economic requirement for the virtually steady rate of production and transmission necessary to maintain a high-load factor in facilities, and 2) to accommodate temporary interruptions in production and transmission and the inability to make accurate short-term forecasts of demand.

It is for these reasons that means for storage are incorporated in all natural gas energy systems and that the same capability must be provided in a hydrogen-energy transmission system. The specific types of storage approaches to be selected will be determined by various local requirements and constraints.

In this section we discuss the practicability and likely costs of storing hydrogen in systems analogous to those at present used or contemplated for natural gas. First, we discuss the storage of gas in general terms in order to expose some of the constraints already imposed on natural gas storage, so that the possibility of storage of hydrogen can be better evaluated.

B. Gas Storage Needs

Categories normally considered in natural gas storage are seasonal, daily, and hourly. Since the same categories will apply to the hydrogen system storage problem, they are discussed below.

1. Seasonal Needs

Storage of gas is required to even out the variation in demand for energy for space heating and related operations between winter and summer. The amount of the "seasonal swing" depends on the severity of the winter and the relative dependence on gas for home and commercial heating in comparison with nonwinter needs. Consumers Power Company serving the mid-Michigan area reports a typical demand of 2.24 billion SCF/day in the February time period, compared to 300 million SCF/day in July.

This is a seasonal variation factor of approximately 7 that must be accommodated, in this case, by dependence on depleted-field underground storage, in which the gas from transmission lines is injected at 2000-3500 foot depths during the nonheating periods of the year.

2. Daily Needs

In most gas distribution systems there are brief periods of yearly maximum demand, which may last for 1 to 3 days. Instead of sizing the main source of supply to accommodate these peaks, it is more economical to introduce supplementary supplies located close to the load centers. Typical forms of peakshaving used in the gas industry are provision of storage facilities for either natural gas, for example, as liquefied natural gas, or for propane, used mixed with air to produce "substitute natural gas."

3. Hourly Needs

Depending on such factors as the extent of industrial load in a gas system, an hourly variation in gas demand occurs. This can be portrayed[5] by a plot of hourly sendout across the hours of the day, or as a cumulative percentage of daily sendout plotted against the hours of the day (total for the day equal to 100%). Traditionally, when town gas (manufactured gas) was utilized, diurnal storage was handled by the familiar large low-pressure gas holders. With the advent of high-pressure natural gas and the resulting increase in usage, much greater storage capacity was needed. Compared to the old low-pressure gas holders, this storage capacity can be provided less obtrusively at a lower cost by other means to be discussed.

4. Security Needs

Storage capability is insurance that demand can be met by a system in cases of temporary loss of supply to the system or failures within the system, such as a break in a line. But, by its nature, the "cost of insecurity" must be thought of in terms of averages over a period of time and would include loss of revenue, cost of reconnection, and deeper ramifications to the system being served with gas. The storage capability that a system has to handle,its seasonal, daily, and hourly storage needs,will contribute therefore to ensuring a minimum of customer interruptions on a nonscheduled basis.

C. Methods of Gas Storage

A number of specific methods for storing gas to meet the objectives just discussed are available. The specific method or combination of methods will depend on each unique system under consideration, and on its intertie to gas production and transmission facilities. This section gives a brief description of the leading storage methods for natural gas — which by and large will be applicable to hydrogen.

1. Depleted Gas and Oil Fields

In the United States during the past 2-1/2 decades, the development of underground storage of natural gas has reached the point where it is by far and away the largest storage capability in use. At the end of 1970 there were 325 gas storage fields in operation in 26 states. Those under the jurisdiction of the Federal Power Commission[3] (57% of these) provided a total storage capability exclusive of native gas of about 2.7 trillion CF [about 2.7 quadrillion (10^{15}) Btu]. A maximum deliverability of 18.4 billion CF/day is available from these fields (about 18.4 trillion Btu).

Original underground storage projects were located in depleted gas or oil reservoirs — locations well proved as being capable of retaining hydrocarbon fluids under pressure. For the U.S., Figure V-1 reflects the geologic constraints that determine the amenability of a region for underground storage. Since porous permeable rocks, usually associated with sedimentary formations, are necessary for both depleted fields and aquifers (to be discussed) to exist, certain areas of the country are geologically favorable, and others are not, as shown by the various hatched areas on the map. For example, New England is constituted geologically of igneous formations with few sedimentary structures; therefore, underground storage in natural formations is highly unlikely. Other areas such as Pennsylvania, Michigan, and Ohio are well supplied with depleted field possibilities. Still other areas, although not endowed with productive gas fields for hydrocarbons, have the possibility of aquifer development for gas storage.

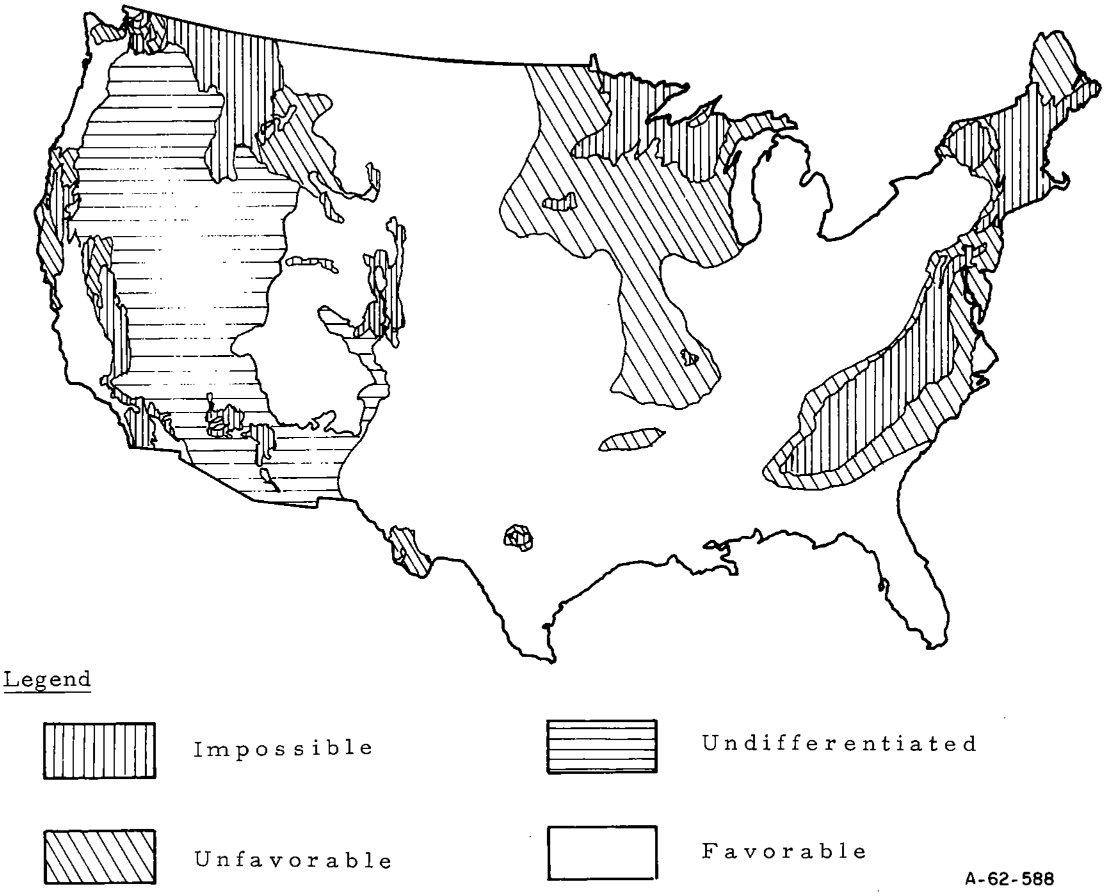

Figure V-1. U.S. REGIONAL DISTRIBUTION OF AREAS AMENABLE AND NONAMENABLE TO UNDERGROUND STORAGE OF GAS IN POROUS ROCK[13]

A singular development in underground storage of gas is the technique of "overpressuring" over that originally present in the native gas field to increase storage capacity. Figure V-2 relates typical discovery pressures to reservoir depth. It is generally accepted that pressurizing a field to the limit of the 1 psi/ft line on the figure is sufficient to lift the caprock and overburden, thus opening fractures and compromising the field's integrity for holding gas. With this as a rough limit on pressure, there is typically a significant incremental pressure increase over discovery pressure which can be used to substantially augment the amount of gas which can be stored over that originally produced.

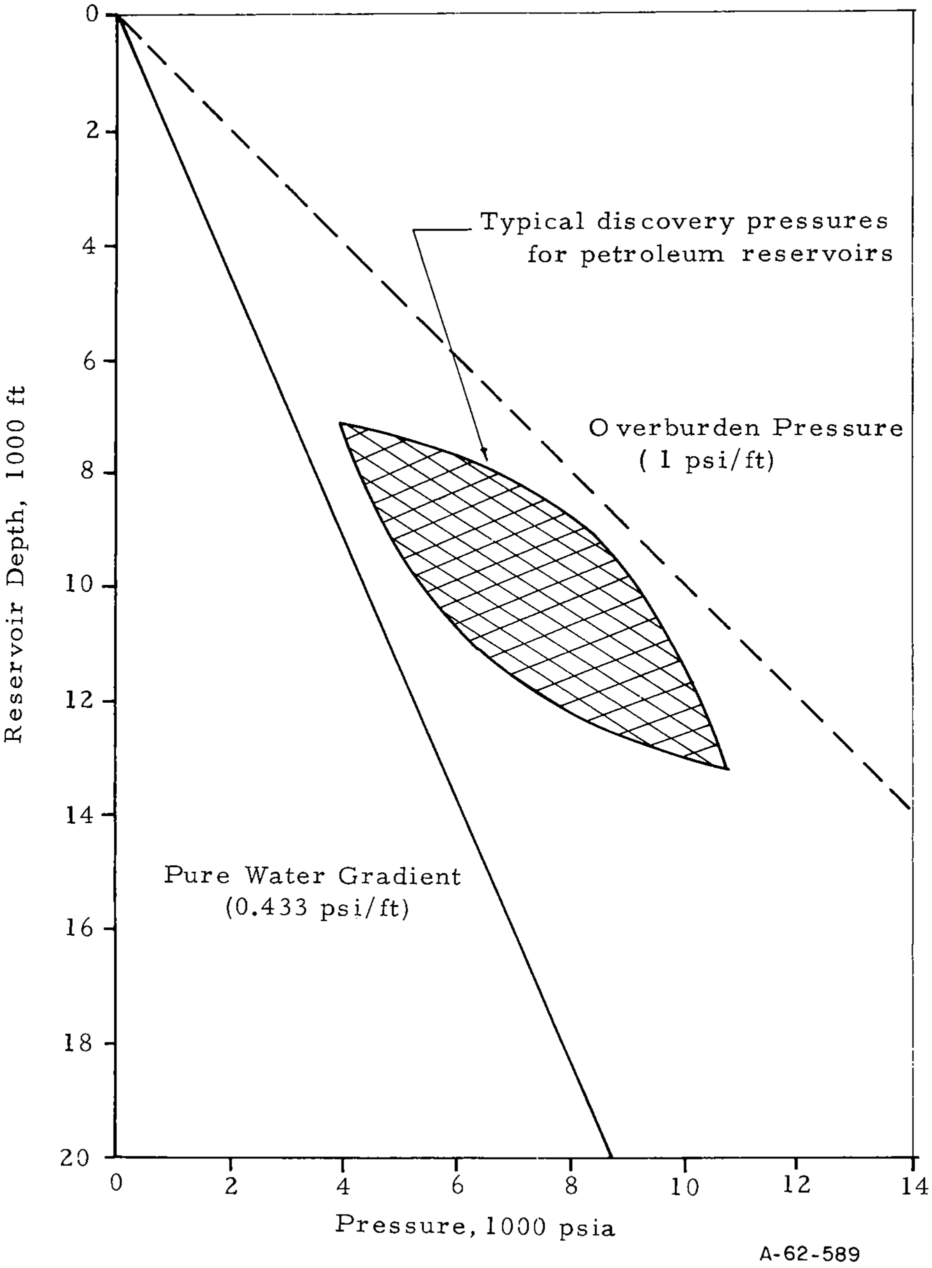

Figure V-2. DEPTH-PRESSURE RELATIONSHIPS FOR UNDERGROUND RESERVOIRS[13]

The gas stored in a field is divided into active working gas and "cushion gas." The latter is inactive base gas not recoverable at acceptable withdrawal rates, but necessary by way of an "initial investment" to place a field into storage service. The ratio of working to cushion gas varies rather widely from one reservoir to another, but is typically in a 1:1 relationship.

2. Aquifer Storage

The development of the overpressuring technique for augmenting the capacity of depleted fields and a better understanding of the behavior of water in contact with stored gas allowed the development of the aquifer storage approach. This permits underground storage in sedimentary structures that have suitable caprock containment even though native gas or oil is not present. In effect, the injected gas displaces the native water in the pores of the rock to form an artificial storage volume for gas storage. Depending on the porosity and permeability of the sedimentary rock structure, a certain "threshold pressure" must be reached by the gas before the water will start to be displaced. The movement of the gas-water interface is generally quite slow. At the end of the filling season, the gas pressure will exceed the formation water pressure and the interface will be gradually receding. At the end of the winter season the gas pressure will be below the water pressure and the interface will gradually return. Once the storage "bubble" is created, it must not be lost while the aquifer is in service, which is why a minimal amount of gas (the cushion gas) must always remain in storage.

The essentials for an aquifer, or any underground storage unit for that matter, are these:[9]

- "A stratum of water-bearing porous rock, usually sand or sandstone, at a depth of, say, 500 to 2000 ft below the surface."
- "An impervious caprock of adequate thickness. (This may be from 20 to 200 ft or more.)"
- "A suitable geological structure, for example, an anticline, which varies in intensity of folding along its axis and therefore usually forms a dome-shaped feature...."

The porosity of the sandstone or sand must be sufficiently high to provide a reasonable void space in an aggregate sense to yield an economically acceptable storage volume. The permeability must be high enough to provide an adequate rate of inlet flow (injection) and outlet transmission injection (withdrawal). On the other hand, the caprock structure must be reasonably impermeable if it is to contain the gas. (Some leakage can be tolerated. It is collected and recycled from shallow wells.)

An important point to note regarding the performance of the caprock structure is the mechanism involved in "sealing" the top of the underground reservoir, either a depleted field or an aquifer. This sealing occurs because of water capillary action, in which water fills all the voids of the caprock structure and must be expelled by sufficiently high pressure to overcome the capillary resistance (the threshold pressure of the caprock). Below this incremental pressure, the caprock will act as an effective barrier to the passage of any gas. This incremental or threshold pressure and the effectiveness of the sealing action is independent of the nature of the gas because it is a water-rock capillary effect. This is an important observation in that it indicates that hydrogen in underground storage will behave like natural gas insofar as integrity against leakage is concerned. In other words, the experience to date with natural gas in the large number of serviceable underground storage reservoirs (325 in the U.S.) is directly applicable to hydrogen storage inasmuch as gastightness is concerned.

3. Mined Caverns and Salt Cavities

Where previously mined cavities are available which are, or can be made, gastight, an opportunity to use these as artificial underground storage structures for gas storage is presented. A special case is the use of salt caverns, particularly in naturally occurring salt domes, which make the best storage areas. Salt caverns have been used for the storage of liquefied petroleum gases such as propane and butane for over 15 years.[13]

Unlike depleted field and aquifer storage systems, which store gas in porous rock formation, cavern/cavity storage involves large open, void spaces to be filled with gas. Therefore, a more complex structural analysis is required to establish feasibility. For example, if the pressure in the cavity is allowed to drop significantly below ambient pressure, a collapsing stress situation is created which might result in loss of structural integrity of the storage volume. One approach considered is to replace the gas drawn off with pumped-in water so that the cavity pressure is maintained.

M. R. Tek et al.[13] report the case of gas storage in a salt cavern in Marysville, Michigan, which had been previously washed out by a salt company and was, in 1960, developed for storage of natural gas by Southeastern Michigan Gas Company. This development answered many questions concerning issues of gas leakage and dissolution in brine. But it posed new questions, such as the possible loss of structural integrity through continuous leaching of the adjacent salt structure.

In regions of impervious rock formation, i.e., the "impossible" zones on the map in Figure V-1, mined caverns may provide a means of underground gas storage otherwise not available.

4. High-Pressure Holders

Storage of gas at relatively high pressure (typically, 60 to 2240 psia) in special vessels or lengths of transmission-type pipe assembled for this purpose offers certain advantages, the most significant ones being the ability to concentrate storage by design at the load center and thus have the gas available above system pressure, which eliminates the send-out compressor. In modern systems, high-pressure storage has pretty much supplanted low-pressure gas holders for reasons of pressure availability and the elimination of the accompanying "visual pollution."

The principal drawback of high-pressure holding systems lies in their cost. There are also the unresolved questions of fatigue resulting from the effect of repeated cycling of vessel pressure levels, particularly for hydrogen service.

5. Linepack

If the throughput of a transmission system is lower than the maximum of which it is capable, the average pressure of the system will rise and gas will be stored as a result. The quantity of gas so stored is known as linepack. The linepack storage capacity of a system is a complex function of system volume capacitance, pressure ratings, provision of additional compressors, and many other aspects that may be peculiar to a given system. It is thus not feasible to generalize on either the cost of linepack storage or its relative advantages over other alternative storage measures. Only a detailed network transient flow analysis can assess linepack capacity in a given system.

6. Liquefied Gas (Cryogenic) Storage

The LNG Information Book, prepared by the American Gas Association,[1] points out the rather long history of the development of liquefied natural gas (LNG), especially noting the accelerating tempo of activity over the past several years. LNG, a cold or cryogenic liquid form of natural gas at -260^0F, provides a very compact form of gas. Maintaining a pressure of 1 atm, lowering the temperature of natural gas at standard conditions to -260^0F results in a volume reduction of over 600 times as the "compacting" factor. For hydrogen this factor is approximately 850.

LNG contributes to overall gas system capability in two fundamental areas: peakshaving, where convenience of storage is important, and base-load supply, particularly that supplied by ship from overseas. Storage of LNG is important to both areas. Well-insulated above- and belowground tanks, typically of the "flat-bottom" configuration, are used. Both areas of application also use liquefaction and revaporization equipment. For base-load applications, plant facilities at both the producing and the receiving terminal, plus a means of transportation — usually a ship fitted out with cryogenic storage tanks of one type or another — must all be accounted for in the economic design and operation of a system.

Some consideration has been given to transmitting LNG in a pipeline. There is an advantage in delivering gas along the pipeline (as opposed to a single receiving terminal), in which case the heat sink provided in vaporization of the local sendout gas would greatly assist in the refrigeration of the liquid that will move further along the pipeline. "Dense phase" transmission has been described[10] in which the gas is allowed to warm up along the pipeline, with a net improvement of transmission economics. Liquid-hydrogen transmission is considered in some detail in Section IV.

7. Unconventional Gas Storage

Tek *et al.*[13] list "new concepts" in storage of natural gas, which might also apply to hydrogen. Among these are storage in underground cavities created by nuclear detonations and underwater storage in anchored pressure-balanced containers in the depths of the ocean or large lakes. If feasible for natural gas, these and other unconventional methods should be applicable to hydrogen, observing that hydrogen characteristically will require 3-4 times the volume as natural gas for the same net energy storage. Hydrogen unconventional storage is discussed in further detail later in Section V, H.

An unconventional storage scheme that is unique to hydrogen involves the preparation of metal hydrides in which the hydrogen storage volume is about that of the liquid form, but the storage weight is significantly higher. The hydrogen is released when the hydride is heated, which poses certain problems to be addressed later.

D. General Comparison of Hydrogen and Natural Gas Storage

To those in the gas industry, hydrogen is known as a "low-Btu gas." In contrast, in those industries involved with fueling energy-conversion devices operating as prime movers, such as aircraft power plants (where the *gravimetric* or mass heating value is of dominant concern, as opposed to the volumetric heating value), hydrogen is known as a "high-energy fuel." This particular superiority of hydrogen led to its selection as a principal rocket fuel for the Apollo program.

Nevertheless, as shown in the comparison of physical and chemical characteristics of hydrogen and natural gas (taken as methane) presented in Table V-1, hydrogen's heating value of 325 Btu/SCF is only 32% of the 1013 Btu/SCF heating value of natural gas. In fact, the large fraction of hydrogen in manufactured gas (about 50% or so) is what caused it to have a low heating value, along with the presence of carbon monoxide and nitrogen.

Hydrogen's low volumetric heating value tends to worsen compared to that of natural gas as the pressure is increased because of the divergent compressibility factors for the two gases (bottom of Table V-1) with increasing pressure. Table V-2 presents several useful comparison ratios between the two fuels, as both cryogenic liquids and as gases at several pressures. Note that where the heating value (volumetric) of hydrogen is

Table V-1. SOME DENSITY, HEATING VALUE, AND COMPRESSIBILITY FACTOR COMPARISONS BETWEEN NATURAL GAS (Taken as Methane) AND HYDROGEN

	Natural Gas (as methane)	Hydrogen
Gas Density at 70^0F and 1 atm, lb/CF	0.0416	0.0052
Gas Specific Gravity	0.555	0.0695
Liquid Density (Normal Boiling), lb/CF	26.49	4.42
Liquid Specific Gravity (Normal Boiling)	0.425	0.071
Heating Value (Liquid), Btu/lb		
Higher (HHV)	23,880	61,030
Lower (LHV)	21,520	51,570
Heating Value (Gas), Btu/SCF		
Higher (HHV)	1,013	325
Lower (LHV)	912	275
Compressibility Factor at —		
1 atm	1.00	1.00
500 psia	0.935	1.020
1000 psia	0.873	1.065

Table V-2. SOME USEFUL RATIOS FOR HYDROGEN/ NATURAL GAS STORAGE CONSIDERATIONS

Btu/Liquid Volume (Cryogenic)

$$\frac{\text{Heating Value of Hydrogen}}{\text{Heating Value of Methane}} \times \frac{\text{Density of Hydrogen}}{\text{Density of Methane}}$$

$$\frac{61{,}030\ \text{Btu/lb}}{23{,}880\ \text{Btu/lb}} \times \frac{4.42\ \text{lb/CF}}{26.49\ \text{lb/CF}} = 0.426$$

Thus, a given volume of liquid hydrogen will contain approximately 40-45% of the heating value of the same volume of LNG.

Btu/Gas Volume (at 70^0F)

$$\frac{\text{Heating Value of Hydrogen}}{\text{Heating Value of Methane}} \times \text{Differential Compressibility Factor, } CH_4/H_2$$

$$\text{At 1 atm, } \frac{325\ \text{Btu/SCF, } H_2}{1013\ \text{Btu/SCF, } CH_4} \times 1.00 = 0.32$$

$$\text{At 1000 psia, } 0.32 \times \frac{0.873}{1.065} = 0.262$$ (Compressibility factors from Reference 15)

$$\text{At 2400 psia, } 0.32 \times 0.654^{*} = 0.208$$

Thus, a given volume of gaseous hydrogen will contain 32, 26.2, and 20.8% of the heating value of the same volume of natural gas (as methane) at 1 atm, 1000 psia, and 2400 psia.

* Factor at 2400 psia is a linear extrapolation of that at 1000 psia.

about 32% that of natural gas at atmospheric pressure, the fraction falls to about 26% at 1000 psi and becomes as low as 21% at about 2400 psi – the pressure range now normally used in gaseous hydrogen commercial delivery and storage service. This compressibility effect increases the storage volume required for hydrogen at elevated pressure, as in underground storage, in any comparison with natural gas.

Further ramifications of hydrogen's low volumetric heating value show up in transmission system requirements as discussed and quantified in Section IV. Other factors must be accounted for too, such as the effect of hydrogen's low molecular weight on compressor designs. For centrifugal compressors, for instance, rotors with very high tip speeds will be necessary to produce the stage-pressure ratios currently developed by natural gas compression machines. Its low molecular size contributes to hydrogen's reputation for being a "leaky gas," a reputation it shares with helium (a point of significance in demonstrating the amenability of hydrogen to underground storage, which will be discussed in Section V, E).

Table V-2 also compares liquid hydrogen, as a cryogenic fluid, with liquefied natural gas or LNG. At 42.6% of the volumetric heating value of LNG, liquid hydrogen is seen to be a closer match than the previously described gaseous comparison. However, hydrogen has a normal boiling point of 36°R (–423°F), which is much lower than that of natural gas as LNG of 200°R (–258°F). Thus hydrogen forms a significantly "deeper" cryogenic liquid than natural gas, a fact that complicates both the storage vessels considered for it and the liquefaction and revaporization equipment needed to operate in a potential peakshaving mode with hydrogen.

As will be discussed in the liquid-hydrogen storage section (Section V, G) roughly 4 times the refrigeration energy per unit weight is required in liquefying hydrogen gas from ambient temperature as is needed for natural gas.

On the plus side for hydrogen, since it is a synthetic fuel produced through electrolysis or thermochemical methods (discussed in "Hydrogen Production," Section III), hydrogen is expected to be essentially a pure substance and thus "cleaner" than natural gas as produced from a well. This suggests the alleviation or elimination of many of the cleanup steps needed for natural gas, although dehydration and odorant removal will still be required prior to liquefaction.

Another comparison area of interest is with the Joule-Thomson inversion point for hydrogen, which is well below room temperature. This is the temperature above which expansion of hydrogen in an expander or a throttling orifice leads to <u>heating</u> of the gas rather than cooling, as is experienced in natural gas expansion processes. In natural gas systems this expansion cooling effect leads to a number of problems such as freezing of earth around piping downstream of a pressure reduction which may cause frost heaving and other problems in pipeline components. These effects will be compeltely avoided in a hydrogen system.

On the other hand, hydrogen's low Joule-Thomson inversion temperature precludes use of any expansion-cooling effect in the liquefaction equipment. Rather, direct heat-transfer based refrigeration is usually employed down to the region of liquid-nitrogen temperatures (–320°F). Below that, the hydrogen can be further cooled by expansion through a "Joule-Thomson valve."

In summary, gaseous hydrogen provides only 20-32% of the volumetric heating value of natural gas, depending on the comparison pressure. (The comparison is more disadvantageous to hydrogen as pressure increases.) In a cryogenic liquid comparison, liquid hydrogen provides about 43% of the heating value per unit volume, compared to LNG.

Thus, hydrogen storage systems in general will be significantly larger than those for natural gas on an equal stored-energy basis. As noted, for gaseous storage systems, relatively more volume will be required for hydrogen as the storage pressure is increased. Cryogenic liquid storage volumes approaching about 2-1/2 times those for LNG will be necessary for the same number of Btu's of liquid hydrogen.

E. Underground Storage of Hydrogen

Storage of hydrogen in depleted gas and oil fields or in aquifers appears to be technically feasible. Depending on storage pressure within the reservoir, which is largely a matter of depth below the surface, 4-5 times the volume, and possibly more for very deep reservoirs, will be required for storing the same energy content of hydrogen as of natural gas. This is a function of the differential compressibility factors of the two gases as discussed previously. (See Table V-1.)

Concern about hydrogen's greater "leakiness" than methane (generally, a molecular size phenomenon) permitting it to escape from underground storage at a correspondingly higher rate can be allayed. The basic phenomenon of caprock penetration by the stored gas has been shown to be dependent on the capillary action of the water in the rock. Essentially, the same caprock threshold pressure (that is, pressure differential at which the gas will just begin to displace the water or dry out the caprock) exists for hydrogen as for natural gas. By the same token, the overpressuring techniques for augmenting storage capacity of an underground reservoir practiced with natural gas storage will also be available for hydrogen.

A convincing demonstration of this fact comes from underground helium storage. The Division of Helium of the Department of the Interior is engaged in a helium conservation program, using a depleted natural gas field for helium storage.[12] The Cliffside field near Amarillo, Texas, used for crude helium (50% helium and 80% nitrogen, with small amounts of methane and hydrogen) injection and storage has given completely satisfactory results.

Crude helium is transmitted through a Government-owned 425-mile pipeline operating at pressures up to 1800 psi and leading from mid-Kansas to the storage field, from which some natural gas is still being removed. Five private-industry groups operating under contracts for helium conservation and three "helium activity" helium plants are tied together by the pipeline and deliver helium to Cliffside for injection. By 1964, a total of 53 billion CF of natural gas had been produced from the field since its discovery in 1924. At that time, the rate of helium injection was greater than the rate of gas production and reservoir pressures began increasing, but since a ground rule was set not to exceed the discovery pressure of 817 psi, even more natural gas has to be produced to provide "room" for the conservation helium.

Gradually, wells adjacent to the helium injection well have been "invaded" by helium, with the result that the gas-producing wells are then relocated toward the periphery of the field. Information from this program is being carefully documented and should be quite helpful in further considerations of hydrogen underground storage.

If hydrogen is to be injected into an existing, partly depleted natural gas field for storage, a technique for making the transition from natural gas to hydrogen extraction from storage must be worked out. Otherwise, if a "step-function" change from natural gas to hydrogen is required, separation facilities will be required to achieve hydrogen production from the gas mixture.

One of the three aquifer storage areas in France, the one at Beynes near Paris, was used for over 10 years to store town gas. It has a storage volume of 7 billion CF and can accommodate an additional 6 billion CF of cushion gas.[9] Plans to progressively convert the storage reservoir to natural gas by "sweeping" the field of the town gas (high hydrogen content) have been published.[2] Since such a conversion is directly relatable to a future conversion from natural gas to hydrogen, the activity at Beynes should, therefore, be reviewed in detail.

On the other hand, if new aquifer storage of hydrogen is to be initiated, there need be no concern with the "transition problems" met in converting an existing underground storage reservoir. In one sense, any problems met in conversion of existing facilities to hydrogen storage may, in the end, be bypassed by creating new aquifer storage for hydrogen.

Hydrogen will pose some need for storage field equipment modifications and/or replacements such as compressors, filtration units, dehydration facilities, and other gas-treating operating equipment. This will affect overall investment analyses and, no doubt, ultimate decision-making regarding the choice of the specific underground storage facility.

Although the propensity of hydrogen for leaking at a higher rate than methane does not affect the tightness of the caprock, many items in a storage field area may pose hydrogen leakage problems that are potentially more serious than those experienced with methane or natural gas. Among these are well plugs and active wellhead components such as valves, meters, and observation instrumentation. Leakage characteristics of hydrogen are discussed in Section VIII. In general the leak-tightness of the storage field will probably have to be considerably monitored and possibly upgraded upon conversion over to hydrogen storage.

A preliminary analytical evaluation of hydrogen conversion of an existing storage facility should be possible, probably with the aid of an analog computer for simulation of such operations as "field sweeping." At a certain point, field-testing will be necessary to demonstrate feasibility and uncover and quantify the numerous problem areas that cannot be foreseen at the present time.

Once again, the prospect for underground hydrogen storage in depleted gas or oil fields or in aquifers appears to be highly plausible.

F. Linepack and High-Pressure Holder Storage of Hydrogen

Linepack storage plays a role varying from significant to minor in various transmission systems, according to the particular characteristics of the individual system. For example, from discussions with the Natural Gas Pipeline Company of America, we learned that linepack storage plays a very secondary role in meeting its system storage demands compared to underground storage facilities, which are rated for that company at about 1400 million SCF/day (two aquifers and a depleted oil field). In many distribution systems, linepacking plays an important role in providing hourly storage needs.

If the hydrogen transmission system uses conventional pipeline sizes and numbers in looping arrangements, comparable to those used in natural gas systems, linepack storage will probably play a smaller, minor role with hydrogen because of its low volumetric heating value compared with natural gas. On the other hand, if hydrogen pipeline sizes and/or numbers of pipes in the transmission trunk are significantly increased for compressor economy or other reasons, linepack storage could gain significance as a storage measure.

High-pressure holders for hydrogen service do not look especially attractive for hydrogen storage except in special circumstances. Not only are the economics unfavorable (as will be discussed), but especially at higher storage pressures (about 3000 psi and above), the effects of hydrogen environment embrittlement must also be considered. This phenomenon might be aggravated, if present, by multiple cycling of the pressure vessels involved as they are filled and emptied into the system. This hydrogen-embrittlement problem is discussed in Section IV.

Also, the previously discussed compressibility factor divergence between hydrogen and natural gas makes very high pressure storage of hydrogen that much more demanding of volume for a given energy storage requirement.

G. Liquid-Hydrogen Storage

Generally, liquid cryogenic hydrogen and liquefied natural gas or LNG can be viewed as analogous forms of the two gases being compared for storage considerations. LNG's use in peakshaving is likely to correspond to liquid hydrogen's role in a hydrogen-energy distribution system. Base-load use of LNG, involving as it does the transportation of the cryogenic product from production facility to a using sector, typically by ocean-going tanker, relates to the hydrogen case in a less obvious way, if at all. Were there to be a need for remote siting of the hydrogen production point involving the nonpipeline transportation of hydrogen to "market," the conversion of produced gas to liquid for bulk transportability might possibly be pursued. This would be despite the relatively high energy costs involved in manufacturing the cryogenic form of hydrogen.

Figure V-3 attempts to relate the energy requirements needed to convert natural gas and hydrogen from gas to a liquid. The figure, a temperature-enthalpy diagram referenced to the normal boiling liquid in both cases, shows that to convert hydrogen to a cryogenic liquid requires the extraction of about 4 times more Btu's per pound through refrigeration than to convert natural gas. Note that the additional energy for conversion of the hydrogen from the normal (25% para-75% ortho) to the para-molecular form to produce a stable (thermally) liquid is not accounted for in the diagram. (See note in Figure V-3.)

Not only is 4 times more heat removal required to produce the hydrogen as liquid, but the refrigeration processes must also operate at much lower temperatures, resulting in significantly lower process efficiencies. References 7 and 11 describe liquefaction of hydrogen in considerable detail.

For an actual large-scale liquefaction operation, and assuming some technological advancements over the present "state of the art," Reference 7 states that approximately 4.5 kWhr/lb H_2 will be required to liquefy and convert the hydrogen to the stable para form. For an ideal refrigeration cycle, Reference 11 indicates approximately 1.5 kWhr/lb. A "present-day" value of about 6.0 kWhr/lb has been noted.

From Reference 1, we can derive a figure of approximately 1.1 kWhr/lb LNG for the liquefaction of natural gas. This is roughly a factor of 4 or 25% less than the hydrogen liquefaction requirement (i.e., of 4.5 kWhr/lb), but is based on present operating equipment. Technological improvements in LNG equipment (as assumed in Reference 7 for hydrogen) would widen the process energy gap to some extent.

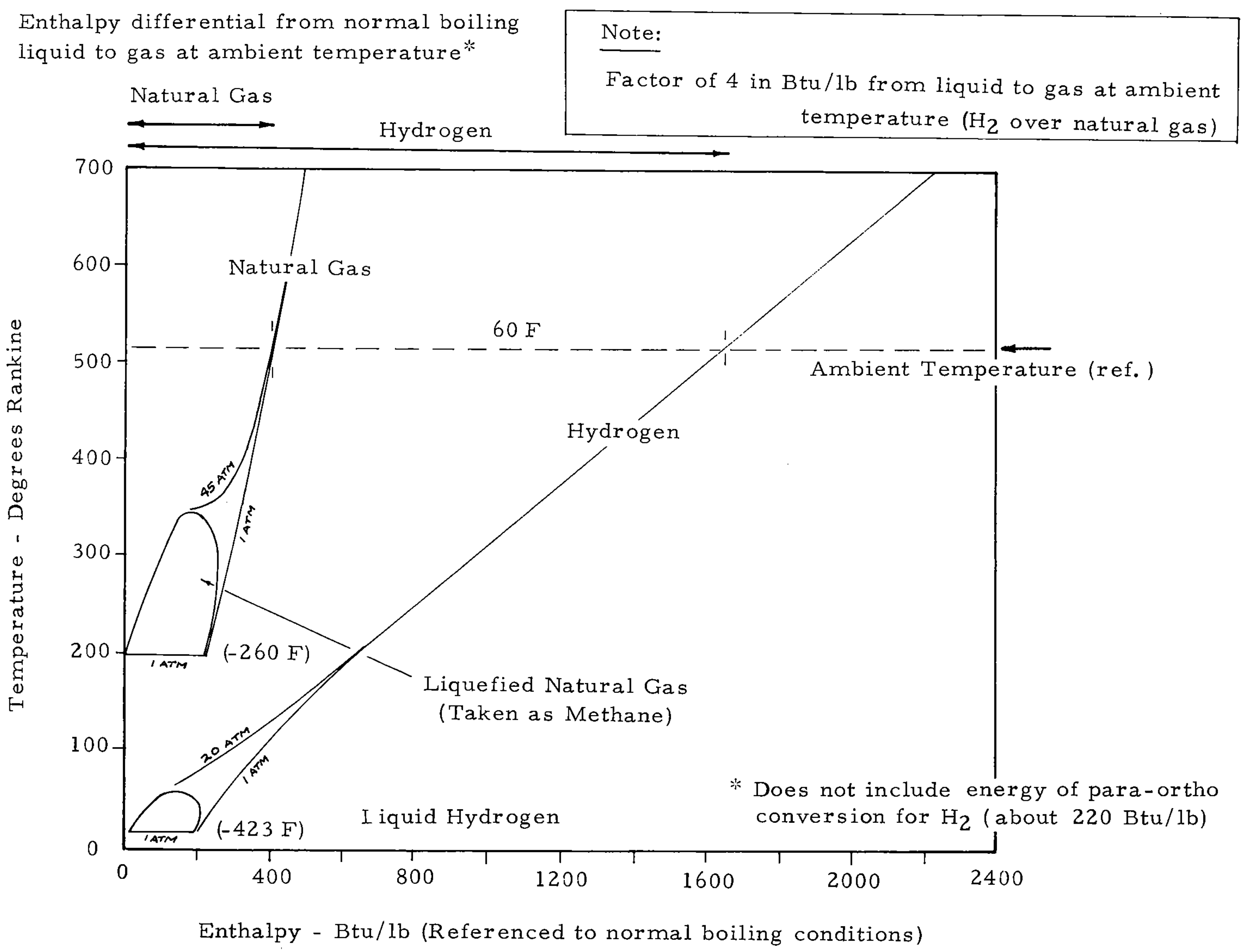

Figure V-3. COMPARISON OF ENERGY CONTENT FROM LIQUID TO AMBIENT GAS FOR HYDROGEN AND NATURAL GAS

On a kWhr/Btu (HHV) basis, since the ratio of gravimetric heating values is 2.56 in favor of hydrogen, the factor of 4 advantage of LNG on a per-pound basis is reduced to about 1.5. Thus, hydrogen liquefaction energy requirements are about 50% higher. Allowing for the mismatch in technology assumptions as noted, the applicable process energy ratio between hydrogen and natural gas is judged to be about 2.0.

Hydrogen liquefaction plant capital cost information from Reference 7 was compared with that for LNG from Reference 1. Per 1000 Btu (HHV)/day as fuel-energy-value liquid production, the hydrogen equipment costs $1.05 and the natural gas facility costs $0.275, which is a ratio of about 3.8 in favor of the LNG facility.

Storage of liquid hydrogen has been carried out in spherical vacuum-jacketed containers up to 900,000 gallons (38 billion Btu). Two such containers are employed at the NASA Kennedy Space Center Launch Complex 39 (Apollo) facility. Figure V-4 is a photograph of one of these units, and Figure V-5 is a sketch of a typical large liquid-hydrogen tank of the type used at the Space Center and elsewhere. The spherical shape is dictated by the structural design constraints posed by the vacuum-jacketed insulation system. This results in daily boil-off losses from the tank of about 0.05%. Materials compatible with liquid-hydrogen temperatures, such as stainless steel (300 series, typically) or aluminum alloys, must be used in the inner liner.

Spherical tank designs of this type are estimated to be limited to practical sizes in the vicinity of 3 million gallons, roughly 3 times the capacity of the Kennedy Space Center tank (References 4 and 6). Unfortunately, such tank designs cost considerably more than the much larger "flat-bottom" tanks used for LNG service. These do not require vacuum-jacketed insulation, but rather use a dry gas-purged perlite (powdered insulation) in the jacket. Figure V-6 illustrates this type of tank design as projected for hydrogen. LNG tanks of about 25 million gallon (600,000-bbl) capacity have been constructed, providing over 25 times the capacity of the largest hydrogen tank (Figure V-4).

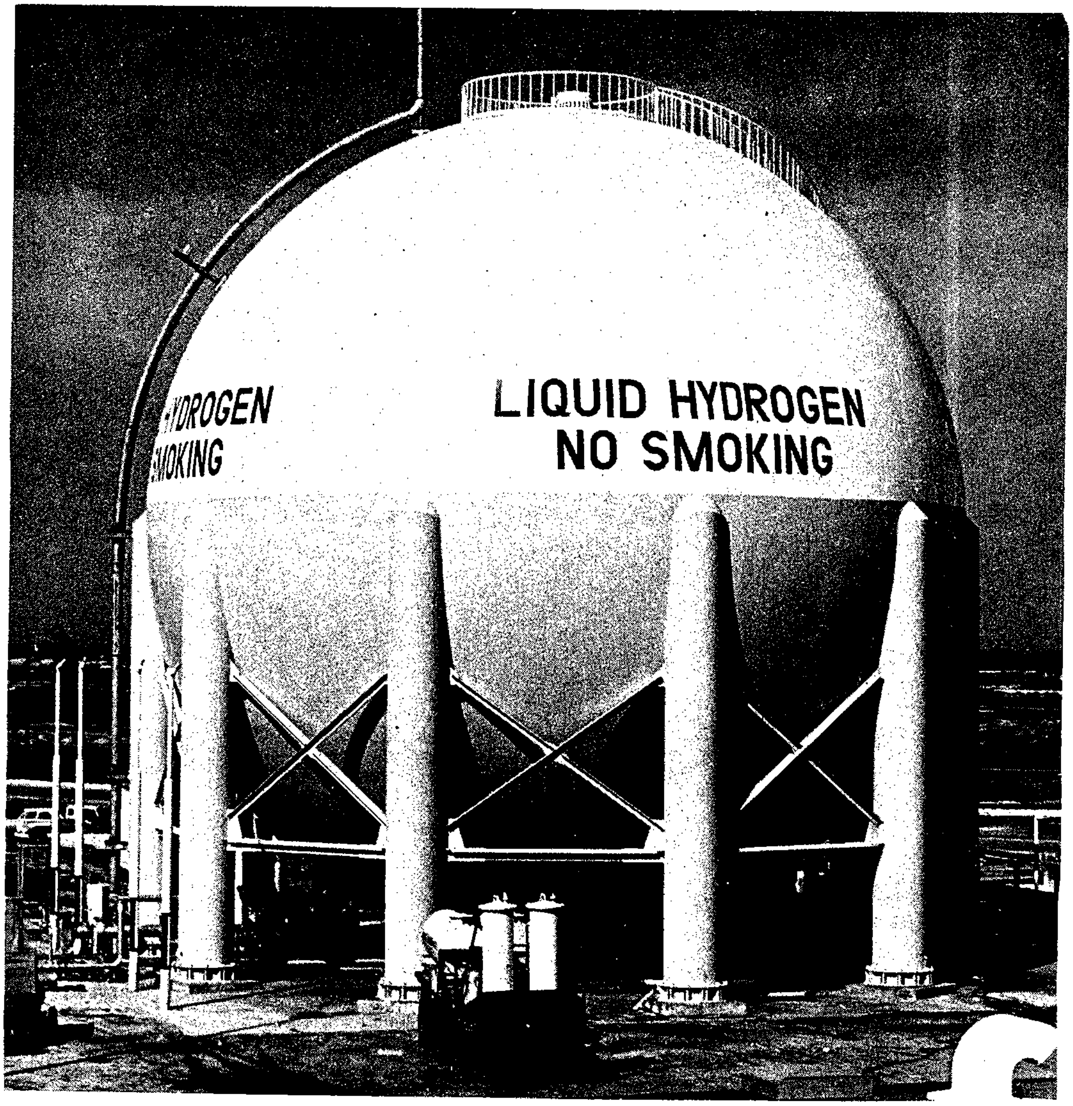

Figure V-4. LIQUID-HYDROGEN TANK

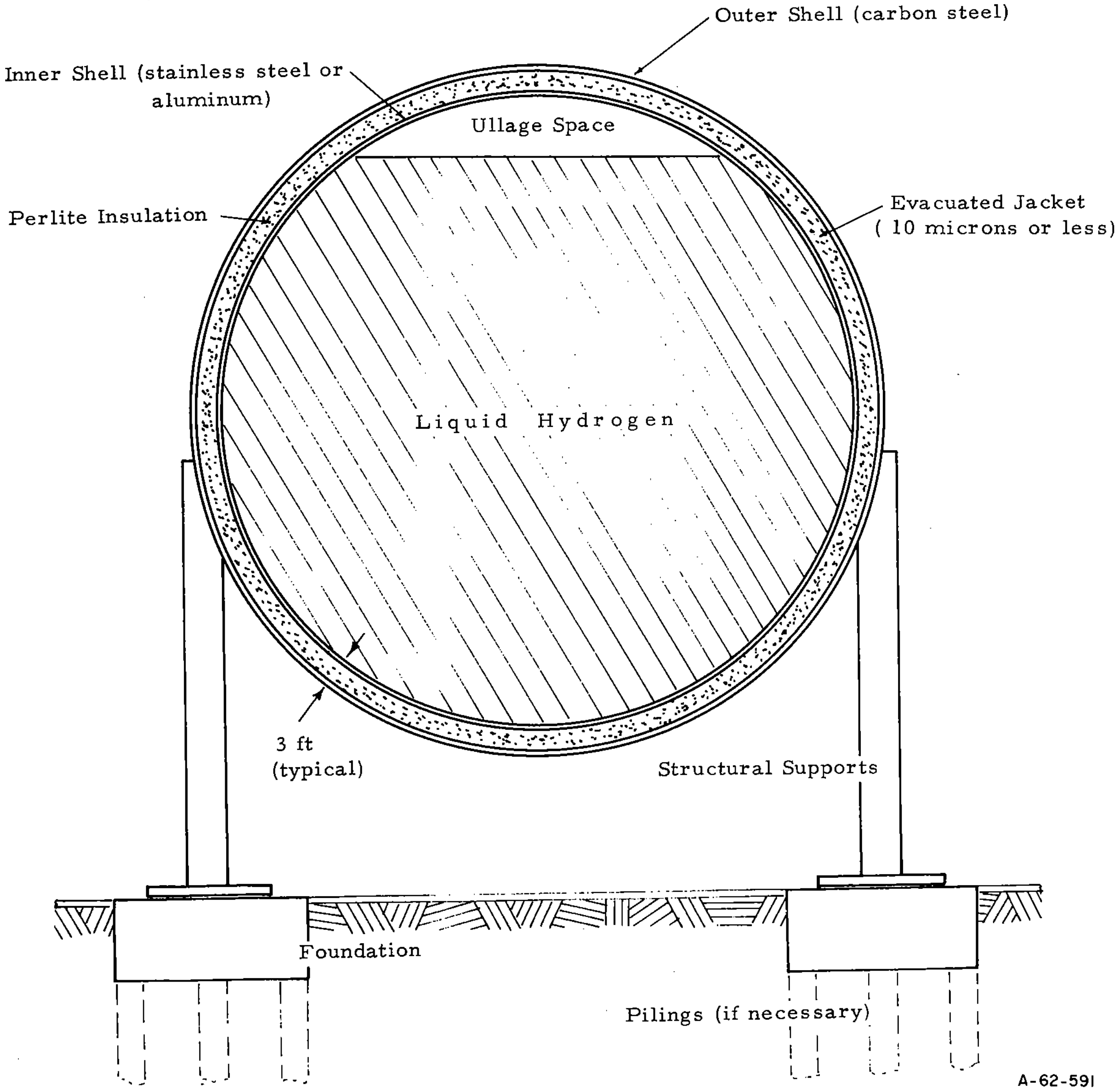

Figure V-5. CONVENTIONAL LIQUID-HYDROGEN STORAGE CONTAINER

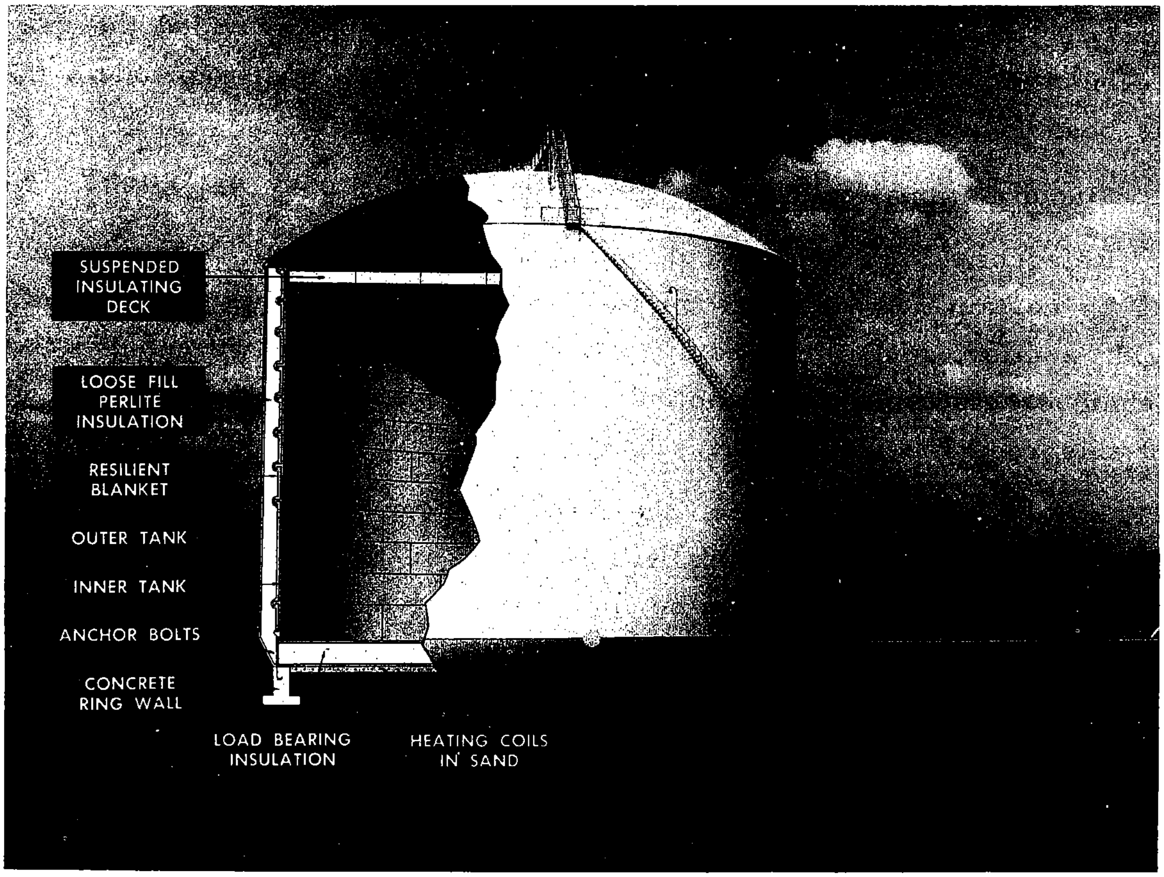

Figure V-6. PROJECTED FLAT-BOTTOM STORAGE TANK FOR LIQUID-HYDROGEN STORAGE
(Source: Chicago Bridge & Iron Company)

Achieving a low boil-off liquid-hydrogen tank without dependence on a vacuum-jacketed design appears to be the key to a) reducing cost for liquid-hydrogen storage and b) achieving much larger sizes than are practical with the present spherical design. Unfortunately, the only atmosphere that can be used in contact with a metal tank inner liner that also contacts liquid hydrogen is either helium or hydrogen gas. Other gases would be liquefied against the liner, setting up a "heat-pipe" system, which would provide a tremendous heat leak in the system. Unless recirculated and thereby not lost, helium would tend to be too expensive. Hydrogen is a more likely candidate. Unfortunately, both of these gases are higher conductivity fluids, which tends to reduce the overall tank insulation efficiency.

Thus considerable ingenuity needs to be used in creating a really large and efficiently insulated tank for the liquid-hydrogen service. Also, apparently unexplored so far in the hydrogen case is the concept of allowing the hydrogen boil-off to be high (relatively), provided the gas can be profitably used. This would relax the tank design problem that has been faced so far by space-type applications.

H. Unconventional Storage of Hydrogen

Reference 13 is a study of methods of underground storage of natural gas by certain new concepts as well as by improvements in depleted gas field, aquifer, and mined-cavity storage technologies. In general the techniques studied appear applicable to hydrogen as well as natural gas, but this requires further investigation.

For hydrogen especially, the field of unconventional storage methods may be quite significant. As will be noted in the next subsection of this report, hydrogen is going to be more expensive, and sometimes more difficult technically to store on an energy basis, than natural gas. We will therefore have a somewhat greater incentive to investigate unconventional hydrogen storage.

One approach treated by Reference 13 is underwater storage of gas in hydrostatically balanced, anchored storage vessels of one type or another. Figure V-7 illustrates this concept for an open-bottomed type and a flexible-membrane-type vessel. The latter type would eliminate the direct water-gas interface in case this proved to be troublesome (excess loss in solution, hydriding reaction, etc.). Storage volume and buoyancy forces were determined for gases ranging in specific gravity from 1.0 to 0.6. Optimum depth minimums can be inferred from the plots presented for natural gas and heavier gases, but not for hydrogen (specific gravity of approximately 0.07).

Considerations of artificial cavities for gas storage created by nuclear explosives may or may not hold for hydrogen. The issue would seem to pivot on the mechanism for sealing the storage volume. If water/rock capillary action established the seal as in aquifers, hydrogen would tend to behave like natural gas. On the other hand, if dry overburden or other dry seal material were to be used, hydrogen might leak prohibitively, even though the situation would be acceptable for natural gas.

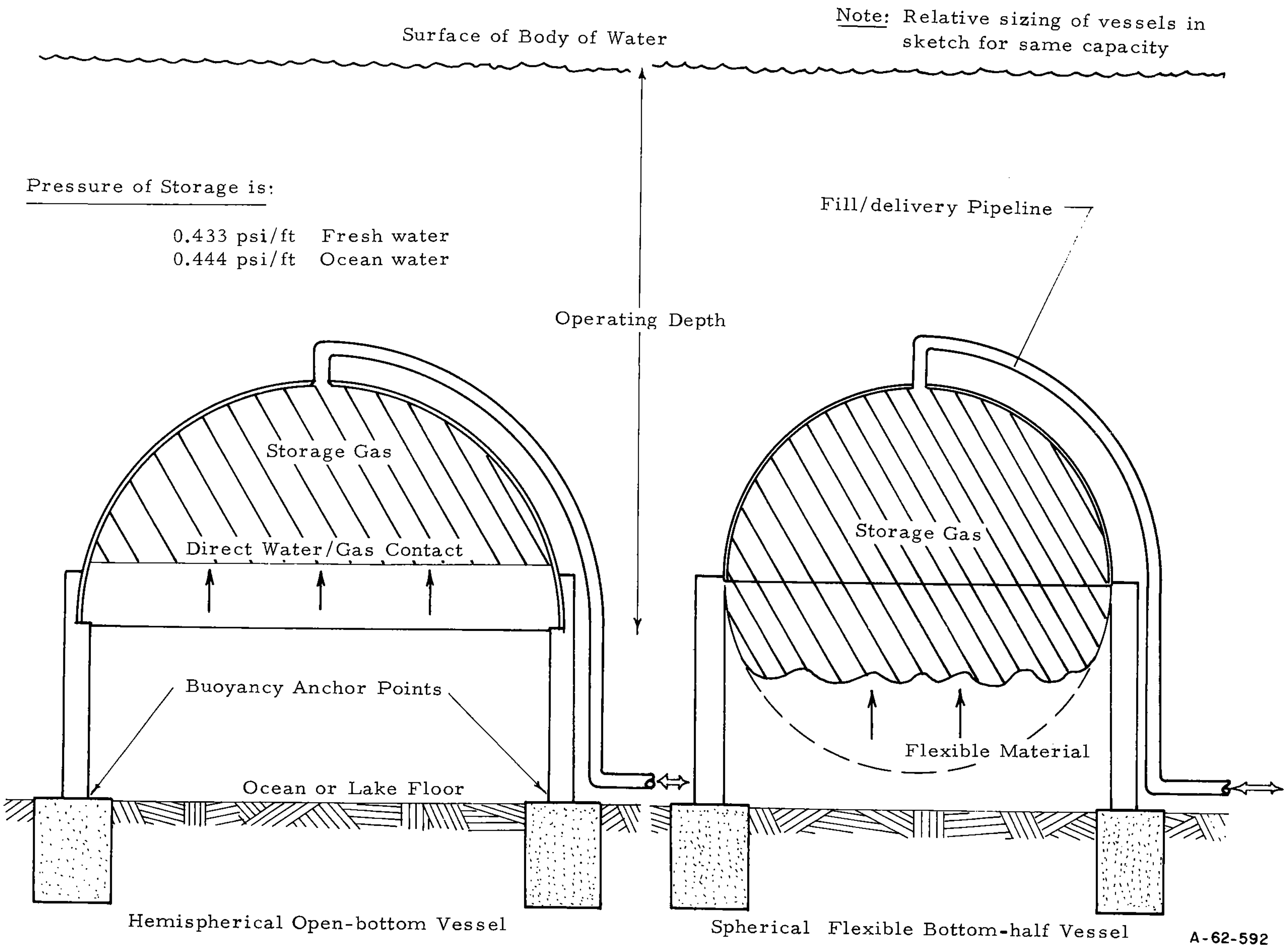

Figure V-7. TWO UNDERWATER STORAGE SCHEMES FOR GASES

Storage of hydrogen in metal hydrides is an intriguing concept being studied by Brookhaven National Laboratory[8] and others, typically for small-scale vehicle storage. Reversible reaction of hydrogen with such metals as magnesium-nickel and magnesium-copper can be obtained so that heating the formed hydride will liberate the hydrogen at a controlled rate. When the metal bed is "charged," it gives off the heat of dissociation in returning to the hydride form. For the metal combinations mentioned, the heat of dissociation is quite high, about 14,000-16,000 Btu/lb of hydrogen. This is about 25% of hydrogen's higher heating value and suggests that a careful matching of the energy conversion unit (exhaust heat) and the metal bed must be achieved.

Hoffman et al.[8] of Brookhaven National Laboratory report the following storage comparison for 45 pounds of H_2, equivalent roughly to a tank of gasoline for a passenger car:

Storage System (H_2)	Weight (Carrier + Fuel), lb	Contained Volume, cu ft
Gas at 2000 psi	2250	66
Cryogenic Liquid	353	10.2
Magnesium Hydride (40% voids)	692	10.8

Thus, the hydride storage method provides for about the same volume for storage as does cryogenic liquid storage, at an additional overall weight. Brookhaven is researching other candidate metal hydrides including those of vanadium and certain ternary mixtures. N.V. Phillips[14] of The Netherlands has reported that lanthanum, a rare earth, in combination with nickel provides outstanding hydrogen storage properties. Additional work is required to determine the applicability of hydride storage to large-scale systems.

In a sense a variant on hydride storage of hydrogen using metals, ammonia as the "hydride of nitrogen" can serve as a "carrier" for hydrogen. Ammonia storage and handling is well developed, as a fertilizer, for instance. After storage, ammonia can be decomposed into its constituents, thus freeing hydrogen for use in various systems.

I. Cost Comparisons for Hydrogen and Natural Gas Storage

Because of the heating value differences already noted, hydrogen storage will typically cost more than natural gas storage to the extent that storage volume requirements control capital and operating costs for storage. In addition, and especially in the case of liquid cryogenic storage, there may be certain premium cost differentials on top of the basic volume-difference controlled costs.

Table V-3 attempts to present a summary comparison of natural gas and hydrogen storage costs as derived from a number of sources (listed). Both gaseous and liquid cryogenic storage are included, with other-than-tank costs listed in the latter case for completeness in considering the liquefaction aspect.

With the background of the previous parts of this section, a number of general conclusions can be tentatively reached in examining Table V-3. Some of these are brought out below.

Underground storage of hydrogen in depleted gas and oil fields and in aquifers remains for hydrogen, as for natural gas, by far the least costly method of large-scale gas storage. Underground storage appears to be very considerably less expensive than the next lowest cost alternative (dissolved-salt-cavern storage). Hydrogen storage is more expensive than natural gas storage by approximately the volumetric heating value difference taken at the storage pressure. Additional costs for hydrogen — unique equipment modifications or replacements — or for the cost of field conversion to hydrogen ("sweeping," etc.) have not been taken into account in this comparison.

High-pressure gas storage in seasonal quantities is generally too expensive for both hydrogen and natural gas, except possibly where underground or liquid storage is not available. Also, a considerable range of costs were noted in the literature for this method. Linepack storage is not included in the cost comparison because deriving a cost evaluation for it is extremely complex and a strict function of the specific nature of a given system. In general, linepack is not expected to be a major (seasonal) storage approach unless larger than usual transmission pipeline volume is provided.

Table V-3. SOME COMPARISONS OF STORAGE COSTS FOR NATURAL GAS AND HYDROGEN [Estimated Capital Costs for Storing 1 Million Btu (HHV) of Gas or Liquid]

	Natural Gas	Hydrogen
Gaseous Storage		
Underground Storage (Depleted field, aquifer) (1000 psi)	$0.79[1]	$3.04*
Dissolved-Salt Cavern (1000 psi)	$2.25[2]	$8.65*
Mined Cavern (1000 psi)	$4.50[2]	$17.30*
Steel Pipe (Local or as Auxiliary Transmission System) (1000 psi)	$48.00[2]	$185.00*
High-Pressure Bottle Storage (2400 psi)	$150[3]	$720*
Aboveground Pressure Vessel Storage (1000 psi)	$227[2]	$870*
Liquid Cryogenic Storage		
Flat-Bottom Tank With Perlite Insulation, Purged	$2.50[4]	No designs
Spherical Tank With Perlite Insulation, Purged	$17 (0.20%/day boil-off loss)[5]	Boil-off considered too high
Spherical Tank With Vacuum-Perlite Insulation	$22 (0.01%/day boil-off loss)[5]	$42 (0.05%/day boil-off loss)[5]
Liquefaction Plant	$0.275/1000 Btu-day[7]	$1.05/1000 Btu-day[6]
Liquefaction Energy	1.1 kWhr/lb[8]	4.5 kWhr/lb[6] 6.0 kWhr/lb (with present systems)[3]

* Hydrogen costs based on natural gas costs multiplied by the volumetric heating value rates (Btu/CF) at the operating pressure: 3.84 for 1000 psi and 4.76 for 2400 psi.

Sources:

1. Based on depreciated storage plant investment of all fields reported to the Federal Power Commission in: Bureau of Natural Gas, Underground Storage of Natural Gas by Interstate Pipeline Companies for A. Calendar Year 1970, B. Winter 1970-1971. Washington, D.C.: U.S. Federal Power Commission, December 1971.
2. Based on mid-range data in: Katz, D. L. et al., Handbook of Natural Gas Engineering. New York: McGraw-Hill, 1959.
3. Estimate by J. E. Johnson, Linde Division, Union Carbide Corporation, May 1972.
4. Based on 1 billion SCF in one tank from: American Gas Association, LNG Information Book, 133. New York (Arlington, Va.), 1968.
5. Estimate by the Chicago Bridge & Iron Company, November 1971.
6. Hallett, N. C., "Cost and System Analysis of Liquid Hydrogen Production," Air Products & Chemicals, Inc., NASA Contractor Report CR 73,226. Washington, D.C.: National Aeronautics and Space Administration, June 1968.
7. Based on 40 million SCF/day rate, from same source as 4, p. 131.
8. Same source as 4, p. 141.

Not included in the comparison of Table V-3 are three unconventional storage approaches: underwater, nuclear-energy developed underground cavities, and metal hydride (or ammonia) storage approaches. Costing of these undeveloped techniques would be premature before additional studies were performed.

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4. Clapp, M. B., Chicago Bridge & Iron Company, private communication, November 1971.

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9. Jones, H., "The Storage of Gas Underground in Aquifers," Int. Gas Eng. J. 3, 257-67 (1963) May.

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11. Scott, R. T. et al., Eds., Technology and Uses of Liquid Hydrogen. New York: Pergamon Press, 1964.

12. Tade, M. D., Jr., "Helium Storage in Cliffside Fields." Paper presented at the Society of Petroleum Engineers Regional Meeting, Amarillo, Texas, October 27-28, 1966.

13. Tek, M. R. et al., New Concepts in Underground Storage of Natural Gas, Monograph on Project PO-50 at the University of Michigan. New York (Arlington, Va.): American Gas Association, 1966.

14. van Vucht, J. H. N., Kuijpers, F. A. and Bruning, H. C. A. M., "Reversible Room Temperature Absorption of Large Quantities of Hydrogen by Intermetallic Compounds," Philips Research Reports 25, 133-40. Eindhoven, The Netherlands: Philips Research Laboratories, April 1970.

15. Von Fredersdorff, C. G., "Relative Costs of Transmission of Pipeline Gas," in American Gas Association Operating Section Proceedings — 1959, CEP-59-18.

VI. HYDROGEN DISTRIBUTION

A. Introduction

We have been considering the use of hydrogen as a fuel gas and as a chemical raw material, much in the same way as natural gas is used today. To this end, we must deliver it to the various customers in a safe, reliable, and inconspicuous way. In this section we discuss the application of present natural gas distribution techniques to pure hydrogen. Safety aspects are briefly referred to here, but are more widely discussed in Section VIII.

B. Types of Customer

Hydrogen must be delivered to a variety of types of customers. These include the large-scale industrial user, which requires hydrogen service for chemical feedstocks as well as for process heat or for use as a reducing gas in metallurgical processes; the intermediate-scale commercial user, which will use hydrogen primarily as a fuel gas; and the residential customer, who will use hydrogen entirely as a fuel for heating, cooling, and cooking. Service will also be required to supply electricity at relatively large substations. For most of these customers, extreme purity limits of hydrogen are not critical, as long as the combustion properties are not significantly altered. The chemical users, and those who use the gas for reduction or for inert atmospheres, however, may be very concerned with even the quite low impurity levels resulting from the incorporation of odorants.

C. Present Status of Low-Pressure Hydrogen Distribution

Hydrogen is widely used in many different industries for a wide variety of purposes. Where huge quantitites are required, a plant is set up to generate hydrogen onsite. It is then piped, usually at high pressure, to the required location within the plant. Many more users, however, do not require a sufficient quantity to justify an onsite plant; hydrogen is delivered to them either as compressed gas in cylinders or tube-trailers, or as a liquid in vacuum-insulated tanks. This hydrogen is then piped, often at fairly low pressures, to the required plant location. Such a system is the nearest operational analogy to a gas distribution system operating on pure hydrogen. It is an everyday, current procedure for which codes of practice and safety codes have been well established. Normally, these distribution pipes do not extend beyond the users' premises or pass over public right-of-way, but this does sometimes occur with the full cooperation of local authorities.

The other most similar analogy to a pure hydrogen distribution system is the large number of systems used to distribute manufactured gas, which contains up to 50% of hydrogen by volume. As natural gas has become almost universal in the U.S. gas industry, the total mileage of gas main, both transmission and distribution, used for "manufactured gas" has fallen from 72,000 miles in 1945 to only 500 miles in 1970. In Europe, a similar changeover is now in progress, but far more recent experience in distributing gas containing hydrogen is available. Similarly, the Japanese and Hawaiian gas industries have current experience in handling such gases. As we have discussed elsewhere in this report, the combustion properties and the safety hazards of hydrogen-containing manufactured gas are more similar to those of pure hydrogen than they are to those of natural gas. In general, the materials and equipment used in these manufactured gas distribution systems will be compatible with pure hydrogen.

D. System Design

In this study we have not devoted a great deal of time to the specific design of distribution systems because of the very diversified range of materials and techniques already in use for natural gas and because of the wide range of individual requirements for each specific distribution system. Rather, we have looked into the compatibility with hydrogen of some modern materials and equipment now in use, and have considered the safety and maintenance differences that would occur if hydrogen were handled.

The capacity of an existing system will be almost the same for hydrogen as it is for natural gas, on a delivered-Btu basis. The higher heating value (gross value) for hydrogen is 325 Btu/SCF, only 0.31 times the value for a typical (1050-Btu) natural gas. Unlike the situation in a high-pressure transmission line, however, we do not have to take into account the different compressibility factors of hydrogen and natural gas for pressures up to, say, 100 psig, and we can assume this rate of 0.31 will hold throughout the distribution system. Also, since such systems operate in laminar rather than in turbulent flow, a different flow formula is used. Because of the far lower density and viscosity of hydrogen, a pipe of a given diameter, with the same pressure drop, will handle, within 6%, the same quantity of energy with hydrogen as with natural gas. The existing pipes, therefore, will have adequate capacity for conversion to hydrogen.

One unique feature of hydrogen is the reversed Joule-Thomson heating effect on pressure change. When most gases, including natural gas, are expanded, they cool down considerably. At city-gate regulator stations, the effect of the cooling, which accompanies the reduction of pressure from transmission levels to distribution levels, can be severe enough to cause frost-heaving of soil downstream from the regulator station. In some cases heating has to be applied to prevent damage. For hydrogen, on the other hand, expansion at normal temperatures causes a heating of the gas, so no frost damage can occur and no auxiliary heating is required. The heating effect should not be severe enough to cause compatibility problems with pipe materials, but detailed calculations and experiments should be carried out for specific installations to ensure this, especially if plastic pipe is to be used immediately following large pressure reductions.

With hydrogen, district regulators will have to handle about 3 times the volume flow as they do with natural gas. As with flow-through pipes, the flow characteristics of hydrogen will compensate for this extra flow; thus the existing regulators will suffice.

The possible effect of hydrogen on rubbers and other organic seals and diaphragm is also a cause for concern. Hydrogen itself is not expected to cause deterioration, but, since some degree of swelling might already exist, brought about by the effect of hydrocarbons in natural gas, some shrinkage or loss of flexibility might occur. This can only be determined by actual testing.

E. Materials

Cast iron and steel pipes are, for all normal purposes, almost impermeable to both hydrogen and natural gas at ambient temperatures. In fact, even though the permeability rate of hydrogen is higher than that of natural gas, it is still so small as to be insignificant. Similar reasoning should apply to sealing materials, but, to be sure, experimental, confirmatory tests should be carried out on typical seals.

The permeability of plastic pipes to hydrogen, however, is high enough to warrant further consideration. Some permeability measurements on typical plastic piping compounds have been made. In these studies the ratio of permeability of hydrogen to natural gas varies widely – between 5.0:1 for polyethylene and 88:1 for ABS. Table VI-1 shows some relative permeability data measured by Battelle.[4]

Table VI-1. PERMEABILITY OF PLASTIC PIPING COMPOUNDS[4]

Material	Methane	Hydrogen	Relative Permeability, hydrogen/methane
	Gas Permeability, 10^{-3} CF mil/sq ft-day-atm		
Acrylonitrite-Butadiene Styrene, ABS-1-2	0.59	51.71	87.6
Cellulose Acetate-Butyrate, CAB-MH	11.8	157.0	13.3
Polyethylene PE II-3	4.2	21.0	5.0
Polyethylene PE III-3	2.4	15.7	6.5
Polyvinyl Chloride, PVC-II-1	0.2	13.7	68.5

How serious is the loss of hydrogen by this route? In the case of PVC pipe, the loss of hydrogen will be 6-8 times the loss of natural gas on a volume basis, but in absolute terms this amounts to only 83.8 SCF/yr per mile of 4-inch pipe having a wall thickness of 0.33 inch and operated at 1 atmosphere or 15 psig pressure. In comparison, Heath Survey Consultants[3] reports a typical leakage rate of existing gas systems is between 100,000 and 400,000 SCF/yr per mile of 3-inch equivalent pipe, while figures obtained from England indicate that leakage rates from cast iron main carrying manufactured gas (50% hydrogen) at 6 inches of water column pressure are typically 20 SCF/hr per 1000 yards of main, or approximately 800,000 SCF/yr per mile. These leakage rates are apparently tolerated and make the diffusion rate of hydrogen through PVC pipes completely insignificant.

Losses of hydrogen by diffusion through other plastic materials are higher than through PVC. Losses through CAB and ABS will be 11 and 4 times as great, respectively. In the latter case, the loss will be over 3000 SCF/yr per mile of 4-inch pipe. Before we can conclude that these leakage rates are absolutely without hazard, experimental measurements should be made on the rate of diffusion of hydrogen through a backfilled trench, and especially under pavement or under frozen ground. It appears that PVC and polyethylene are to be preferred over ABS and CAB. Further experimental testing of actual pipe sections under service conditions, for long periods of time, would, however, be worthwhile carrying out to get practical proof of their suitability.

Some concern exists over the possibility of hydrogen embrittlement, but it is not thought to be a major problem. It is discussed fully in Section IV.

F. Leakage

The rate of loss of hydrogen through physical leaks, whether fractures, corrosion pinholes, or leaky seals, is about 3 times greater on a volume basis than that of natural gas. The safety aspects of this effect are discussed in Section VIII. In summary, the rate of energy loss through the leak is about the same as for natural gas, and in a confined space the lower flammable limit will be reached in a quarter of the time required for natural gas. Hydrogen's rapid diffusivity, 2.8 times as fast as natural gas, will allow it to permeate rapidly through dry soil and crushed rock, and therefore escape from the point of leakage. Once it reaches the air, its low density will cause it to rise rapidly.

The detection of leaks in industrial hydrogen systems is carried out by combustible-gas detectors. One unique hazard of hydrogen leaks in aboveground hydrogen pipework is that occasionally the leaking gas ignites because of a spark or static friction caused by the leak, and the resulting "invisible" flame cannot be seen in daylight. Because of this problem, flame detectors[6] have been developed for hydrogen systems.

Such a situation could create difficulty for a gas distribution system, and an appropriate mode of leak detection must be chosen. There appears to be no reason why an odorant could not be added to hydrogen to assist in the detection and location of leaks.

Conventional combustible-gas detectors operate just as well on hydrogen as they do on methane or other gases; they simply need recalibration to hydrogen. A dual calibration for methane and hydrogen for use in systems undergoing changeover would appear to be quite satisfactory. For more sensitive detection, since the commonly used flame ionization detector will not detect hydrogen, an alternative method would have to be used. Hydrogen is one of the easier gases to detect by other means.

The safety aspects of maintenance of distribution systems are discussed briefly in Section VIII. New techniques may have to be established for working on a leaking system, especially in a confined space such as an excavated hole. The use of spark-proof tools alone will probably not be sufficient to eliminate such ignition sources as static electricity sparks. Even the clothing worn by maintenance crews may have to be strictly selected to prevent accidental ignition. Further consideration has to be applied to the whole problem of maintenance. Much information could be best obtained from the controlled operation of a model distribution system into which deliberate, known failures are introduced.

An area for serious concern is the purging requirements for pipes, both when bringing new main into service and when repairing existing main. Use of an inert gas to sweep out the air, or to sweep out the gas already in a used main, may be necessary because the wide flammability limits of hydrogen (4-75%) compared to natural gas (5-15%) would make a hazardous condition in the main more common. With natural gas, welding operations can be carried out when the gas-air mixture in the line is above 15% gas. But, with hydrogen, one would have to ensure that the hydrogen/air ratio was safely above 75%. Use of some form of oxygen-level indicator may be necessary to ensure that adequate purging has been obtained. Purging procedures will have to be established by experiment.

Most of the serious gas leaks in distribution systems are caused by damage to mains by contractors. With plastic pipe, severing the line is common, while steel pipes are normally only damaged or fractured. A fire resulting from such an accident is relatively uncommon. With hydrogen, however, a fire will almost certainly occur if an ignition source is present. Static charges built up on the inside of plastic pipes are known to be a common occurrence; the fracture of a metal pipe will most certainly be accompanied by friction sparks. Thus, we might expect a higher frequency of fires caused by accidental damage to hydrogen pipes. In a way this may be considered as fortunate because a fire burning at a pipe fracture cannot lead to a buildup of explosive mixtures, as can happen in unignited leaks. However, different operational practices may have to devised to cope with this feature.

G. Odorants and Illuminants

As far as is known, the sulfur compounds now used to odorize natural gas are compatible with hydrogen and would be perfectly satisfactory. Odorants have to be added on a volume basis. Thus, since 3 times the volume of hydrogen is to be used, 3 times the quantity of odorant will be required,although its actual percentage level will be the same. This will be burned at the appliance. However, this should present no pollution problem. The added cost will be insignificant.

When an odorant is being introduced into the gas, the simultaneous addition of an illuminant, which would make the hydrogen flame visible, would also be worth considering. This would facilitate its use in open-flame appliances and assist in the adjustment of burners and pilots. No suitable illuminant has yet been identified, but two classes of materials are appropriate. One is a small amount of an aromatic-type organic material that would burn with a yellow flame; the other is a trace of a volatile organometallic sodium compound that would give the flame the characteristic sodium-yellow color. Experimental study is required to determine whether either of these approaches would be useful and to determine the optimum quantitites to be added, bearing in mind their cost and their pollution characteristics when burned.

The addition of any foreign material, especially sulfur-bearing odorants, could cause considerable problems when hydrogen is used in catalytic processes. Air Products & Chemicals, Inc., told us that it had considered odorizing hydrogen in its Houston transmission line, but that several industrial users could not tolerate the presence of even traces of sulfur compounds. Similar considerations may apply to the use of hydrogen in catalytic burners. (Discussed in Section VII.) It is possible to remove the odorant immediately before the catalytic bed, but in some applications this would be inconvenient and would add cost. (Suflur removal traps are used in the TARGET fuel cell system, upstream of the reformer catalyst.) An alternative, worthy of consideration for future experimental work, is to develop an odorizing material that does not contain sulfur and does not interfere with catalysts. It may be appropriate to introduce such a "new smell" with the introduction of the "new, clean gas" to the public, in which case, a suitable odorant must be ready for application as soon as the first general use of hydrogen is introduced.

H. Codes

We surveyed the established codes that would apply to the use of hydrogen. Both the U.S.A. Standard Code for pressure piping [1] (USAS B31.8-1968) and the minimum safety standards for transportation of natural and other gases by pipeline of the Department of Transportation[2] are believed to be directly applicable to hydrogen distribution systems. In both standards, although the inclusion of gaseous hydrogen is not explicitly spelled out, it is believed to be included on the basis of the standards' definition of "gas." In USAS B31.8, gas is defined as any gas or mixture of gases suitable for domestic or industrial fuel and transmitted or distributed to the user through a piping system. In DOT's standard, gas means natural gas, flammable gas, or gas that is toxic or corrosive. Since these two standards are the primary codes for natural gas distribution, hydrogen systems seem well covered by the existing specifications and regulations.

The National Fire Code,[4] however, has a special section covering the standard for gaseous hydrogen systems at consumer sites. Although the standard does not cover the distribution piping systems and is only specified for hydrogen systems where the hydrogen is delivered by mobile equipment, it is not clear if the standard applies to systems where the hydrogen is delivered to the consumer premises by pipeline. One concern is that in piping, tubing, and fitting design, the standard specifically indicates that cast iron pipe and fittings are not to be used. (The other two national standards contain no such specification.) However, cast iron is not often found in systems to which the National Fire Code applies.

Because of concern over the safety and reliability aspects of hydrogen, particularly in the older sections of distribution systems, the prospect of inserting new plastic pipe through the bore of the existing main, which would act as a conduit, should be considered. Such a technique, already wide in use for renovating natural gas main, would be equally applicable to hydrogen service. To prevent the buildup of leaked hydrogen, it may be desirable to deliberately fracture the outer casing, to ventilate the annulus, or, better still, to fill the main around the plastic pipe with some fluid such as water or a gelling agent. Because the costs of such a system are very speculative, they were not considered here.

I. References Cited

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2. Department of Transportation, Hazardous Materials Regulations Board, "Transportation of Natural Gas and Other Gas by Pipeline: Minimum Safety Standards," Fed. Regist. 35, No. 161, Part II (1970) August 19.

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4. Kuhlmann, H. W. et al., "The Development of Improved Plastic Pipe for Gas Distribution Purposes," A. G. A. Catalog No. M40515. New York (Arlington, Va.): American Gas Association, 1968.

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6. Rosen, B., Dayan, V. H. and Proffit, R. L., Hydrogen Leak and Fire Protection, A Survey (Prepared under contract NAS8-5604). Washington, D. C.: Technology Utilization Division, Office of Technology Utilization, National Aeronautics and Space Administration, 1970.

VII. HYDROGEN UTILIZATION

A. Introduction

Hydrogen gas can be used as a fuel for all of the applications met by natural gas today, and more. It is also a valuable raw material for the petrochemical industry and is used as a reducing gas in the metallurgical industry. If hydrogen is to play a major part in replacing fossil fuels as a whole, then we must also consider whether or not hydrogen is amenable to those fuel uses not conventionally met by natural gas, such as vehicle and aircraft propulsion. In this section we discuss the combustion characteristics of hydrogen and review how these characteristics affect the design of burners, especially as compared with natural gas. We also consider the possible use of catalytic burners and their adaptation to novel types of gas appliances. The suitability for hydrogen service of existing gas-fired equipment and the auxiliary gas metering and regulating equipment that goes with it are also reviewed. We include in our review the potential use of hydrogen in internal and external combustion engines and discuss the use of these prime movers and fuel cells both for transportation and for secondary electricity generation.

B. Types of Usage

Hydrogen's primary use will be as a fuel for heating and cooking. In this application it will be combusted with air to release its energy as heat. There are essentially two types of combustion. One is homogeneous or gas-phase combustion in which high local temperatures are achieved. Depending upon the burner design, heat can be transferred by radiation from the hot gases or from the burner and by convection from the exhaust gases. The other type of combustion is catalytic or surface combustion, which can operate below the normal flame temperature and can therefore avoid or reduce the formation of nitrogen oxides. A catalytic combustor either can be a radiant heat source or provide useful heat by convection from its flue gases.

Hydrogen can be used in three different modes to generate shaft power. One is by direct combustion with air in a conventional engine, which could be either a reciprocating engine, a gas turbine, or a steam engine. Another is by direct reaction with pure oxygen in a rocket-type combustor. By injecting water into the burner, steam at almost any desirable temperature and pressure can be generated in a completely closed, no intake-no exhaust system (except for the water formed by combustion). The third is by direct electrochemical conversion, in a fuel cell, of hydrogen to electrical energy, which is then converted to shaft power by a conventional motor.

Hydrogen will find increasing use in the petrochemical industry as a refinery feedstock, especially for processes involving the conversion of heavy fuels, such as residual oil, shale oil, and coal, to lighter, more useful fractions, including pipeline gas and gasoline. Hydrogen is also a valuable feedstock in the rubber, plastics, pharmaceuticals, and foodstuffs industries.

As a reducing gas, hydrogen is valuable to the metallurgical industry, both in the primary metals industry, where hydrogen can be used for the original reduction of metallic ores, and in the secondary industry, where atmospheres containing hydrogen are used to prevent oxidation in heat-treating and scrap recovery processes.

C. Homogeneous Combustion

1. Combustion Characteristics

Most uses of a gaseous fuel involve open-flame combustion. Hydrogen burns readily and evenly in air with a very hot, nonluminous, almost invisible flame. Primary air may be mixed with hydrogen to levels above the lower flammable limit without flashback, if the gas velocities through the burner ports are kept higher than the flame velocity or if the burner ports themselves are made smaller than the quenching distance. Thus, hydrogen can be burned in a properly designed burner as safely as methane or other fuel gases.

A comparison of the combustion data for hydrogen and natural gas is interesting. Since much research work has been carried out on hydrogen, most of the required properties are known and are documented. In fact, because hydrogen is an invariant, pure material, it does not suffer from the slight uncertainties of properties associated with natural gases of differing compositions.

Two important reference works are a) "Survey of Hydrogen Combustion Properties," published by NACA (forerunner of NASA) in 1958[4] and b) the Bureau of Mines Bulletin on "Limits of Flammability of Gases and Vapors."[3] The former document was prepared as a review of all combustion information related to research and development of hydrogen-fueled aircraft engines, while the second is more generally oriented. Both of these references are rather old, and some of the missing data which they comment on may now be available. An up-dating of the review of Drell and Belles[4] is outside the scope of this study, but would be worthwhile considering for a future program.

One of the most important factors that characterize and influence combustion behavior in any fuel-oxidant system is the flame temperature. Flame temperature as defined here refers to the temperature of flames burning at constant pressure with no external heat losses or gains (adiabatic flames). Such flame temperatures can be calculated and have been measured experimentally. Usually, practical flames will fail to reach the full theoretical temperature. Drell and Belles[4] give theoretical and experimental hydrogen-air flame temperatures in Figure VII-1 and state that for hydrogen-oxygen flames the calculated temperatures are 3080°K (5085°F) at stoichiometric conditions (exact proportions of fuel and oxygen) compared with maximum temperatures of 2403°K (3866°F) calculated for hydrogen-air and only 3484°F for methane-air. The flame temperature is very dependent upon the fuel/air ratio. The composition of the burned gas may be calculated for an adiabatic hydrogen-air flame, for which the theoretical flame product ratios are shown in Figure VII-2. The burning velocity of hydrogen is very high, about 10 times that for methane, and has been variously measured. A consensus of experimental data is shown in Figure VII-3. The burning velocity is highly dependent on the fuel-air mixture and reaches a maximum at about 40-45% hydrogen. NACA has assumed a mean value of burning velocity at a 43% H_2 concentration of 310 cm/s. The burning velocity is sensitive to changes in initial gas temperature, reaching 800-1000 cm/s if the gas mixture is preheated to 700°K (800°F). The apparent burning velocity in turbulent flames is somewhat higher than the above data, which are for laminar flow.

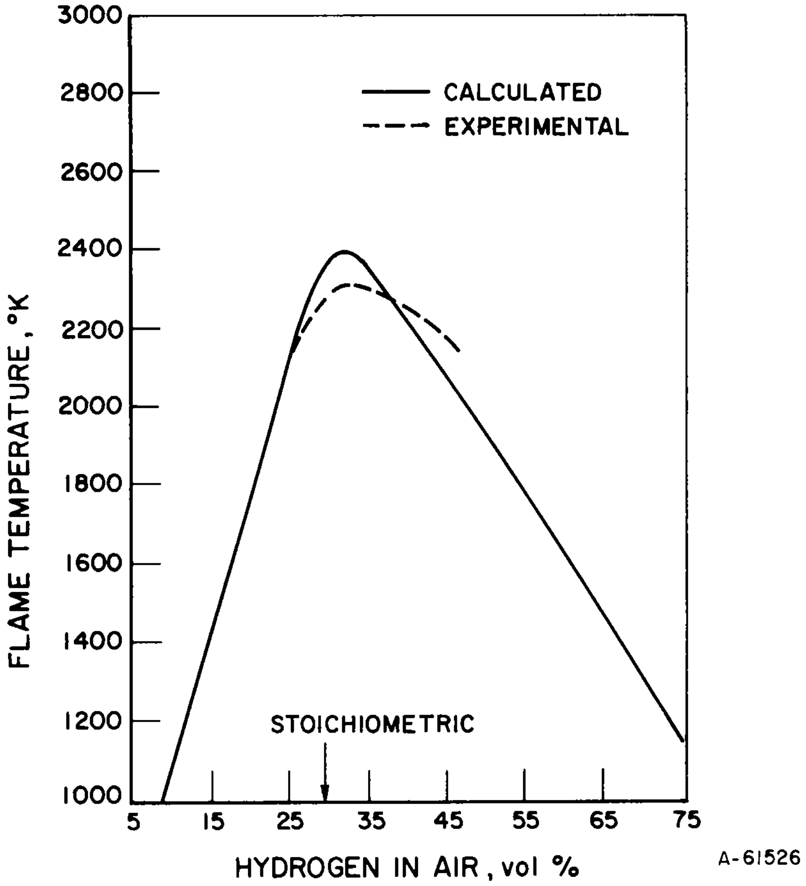

Figure VII-1. THEORETICAL AND EXPERIMENTAL HYDROGEN-AIR FLAME TEMPERATURES

The quenching distance, representing the minimum size of the opening through which a flame will not pass, is smaller for hydrogen than for methane and is sensitive to both the fuel/air ratio and the pressure. Data are shown in Figure VII-4. Assumedly, quenching distance decreases with increasing temperature, but no data are given in Reference 4. One interesting observation was made by Friedman,[10] who investigated the quenching effect of an orifice lined with platinum — a good catalyst for combustion of the hydrogen-air mixture; no effect on quenching was noted. This is important in the design of catalytic burners* because it implies that if the pores of a catalytic burner are kept below the quenching distance (i.e., about 1/2 mm), no flame ignition can occur.

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* See later.

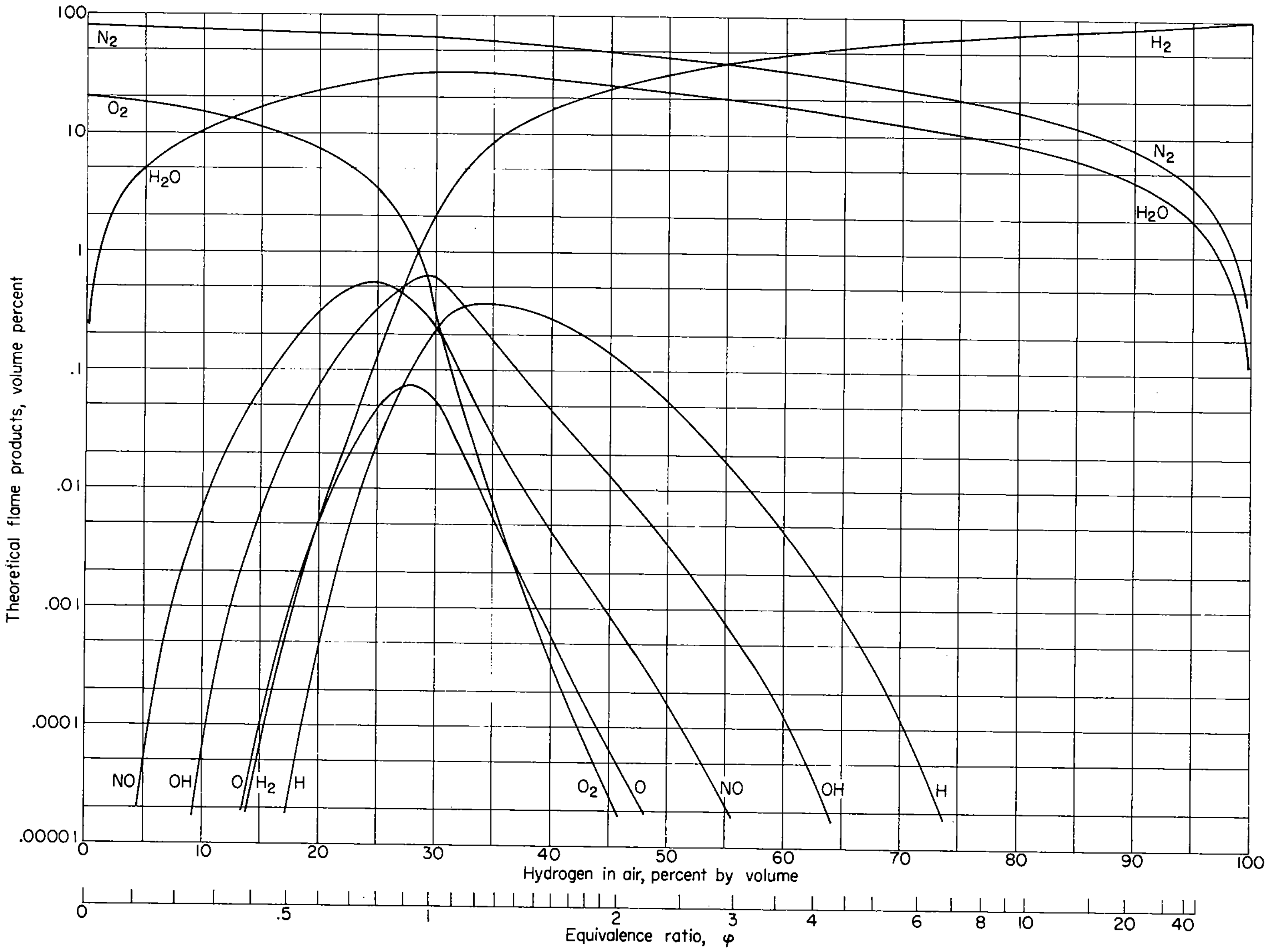


Figure VII-2. THEORETICAL ADIABATIC FLAME COMPOSITION FOR HYDROGEN-AIR MIXTURES. PRESSURE, 1 ATMOSPHERE; INITIAL MIXTURE TEMPERATURE, 298.16°K[4]

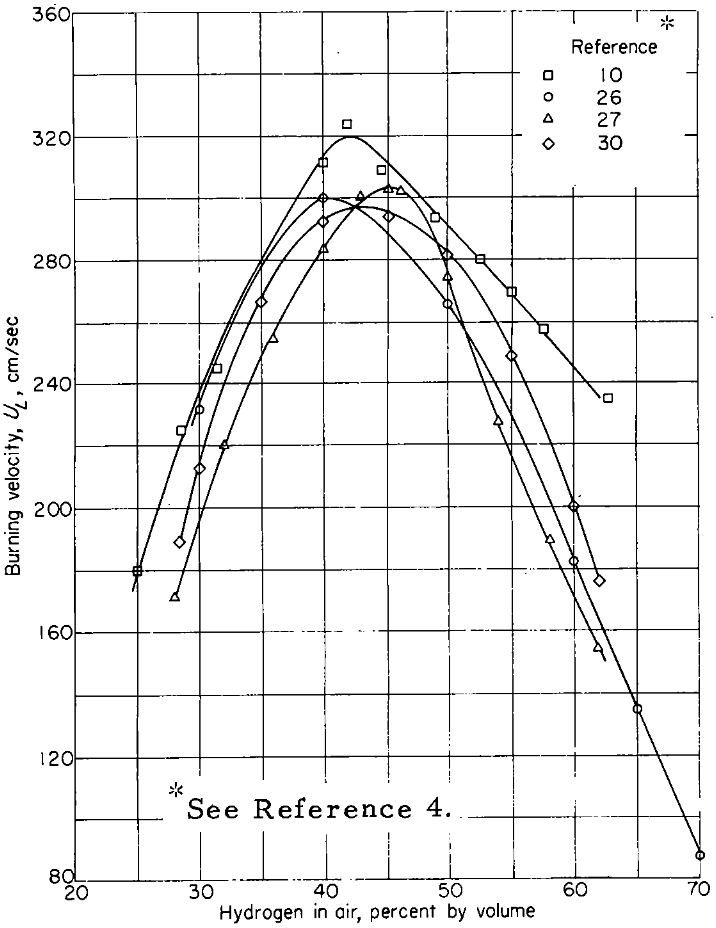


Figure VII-3. EFFECT OF HYDROGEN CONCENTRATION ON BURNING VELOCITIES OF HYDROGEN-AIR MIXTURES. PRESSURE, 1 ATMOSPHERE; INITIAL TEMPERATURE, 300°K[4]

In the practical design of flame arrestors, considerably smaller gaps than the 0.5-1.0 mm distances shown in Figure VII-4 must be used because pressure surges can occur which would lower the quenching distance. Egerton et al.[6] studied the use of sintered metals as flame traps and reported the limiting safe pressures below which a given trap will always stop a flame. While fine-mesh screens are conventionally used for hydrocarbon-air mixtures,[†] sintered metal will apparently have to be used for hydrogen. Although such traps give surprisingly low pressure drops, dust and lint from the air can clog them.

[†] Methane has a quenching distance of about 3.6 mm.

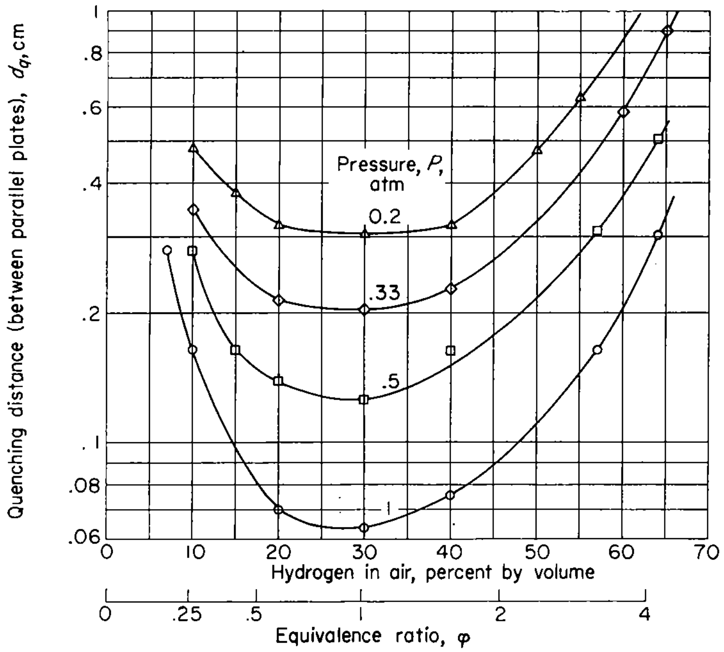


Figure VII-4. EFFECT OF HYDROGEN CONCENTRATION ON QUENCHING DISTANCE OF HYDROGEN-AIR MIXTURES[4]

Flammability limits for hydrogen-air and hydrogen-oxygen have been extensively studied. Data are given for experimental systems designed to avoid the quenching effect of walls and other geometry factors.

A distinct difference exists in the lower flammability limits behavior of hydrogen and methane. This is described by Drell and Belles[4] as follows:

> Effect of direction of propagation. The flammability limits for most fuels vary, depending on whether they are measured for upward- or downward-propagating flames, because convection assists flames traveling upward. For instance, the lean and rich limits of methane are: upward, 5.3 and 13.9% by volume in air; downward, 5.8 and 13.6% by volume in air. For hydrogen the behavior is different. The rich limit of hydrogen is the same for both directions of flame travel, 74% by volume in air. The lean limit is affected, but not in the usual way. It is 9.0% for downward propagation,[3] whereas for upward propagation there are two lean limits. One of them is called the limit of coherent flames; it is 9.0%[5] and is the leanest mixture that burns completely. Leaner mixtures down to the noncoherent limit of 4.0% hydrogen are still flammable, but the flame is made up of separated globules that slowly

ascend the tube. Although these globules do not consume all the fuel, they have to be reckoned with for safety. The noncoherent flames occur because of the high diffusivity of hydrogen; it appears that the flamelets actually consume a mixture richer in hydrogen than the original mixture.[3, 16]

Flammable range. The flammable range (i.e., the difference between the rich- and lean-limit concentrations) is exceptionally wide for hydrogen. Coherent flames can propagate in lean hydrogen-air mixtures down to 9.0 mole percent fuel, as already stated. This is an equivalence ratio of about 0.24, as compared with a lean flammability limit of about $\varphi = 0.5$ for most hydrocarbon fuels. The very high rich limit, 74% or $\varphi = 6.8$, is also outstandingly different from those for most ordinary fuels.... The lean- and rich-limit flame temperatures are about 1000° and 1200°K, respectively which are values much lower than those for hydrocarbons.[5] Egerton[5] suggests that these effects peculiar to hydrogen are due to the high concentration of active particles and their high mobility.

Recommended limits at atmospheric temperature and pressure. Various workers[3] who have used the accepted method agree with one another quite well. It is therefore unnecessary to make any further assessment of the data. The following table gives recommended flammability limits for hydrogen in air at atmospheric pressure and about 3000°K:

	Flammability Limits	
	Lean	Rich
	—vol % H_2 in air—	
Upward propagation		
Coherent flame	9.0	74
Noncoherent flame	4.0	
Downward propagation	9.0	74

For hydrogen burning in pure oxygen the lean limits are about the same and behave in the same way as those for hydrogen in air. The rich limit for upward propagation is 93.9%.[3]

The flammability limits are affected by temperature as shown in Figure III-5, so that a preheated mixture has considerably wider limits for stable, coherent flames.

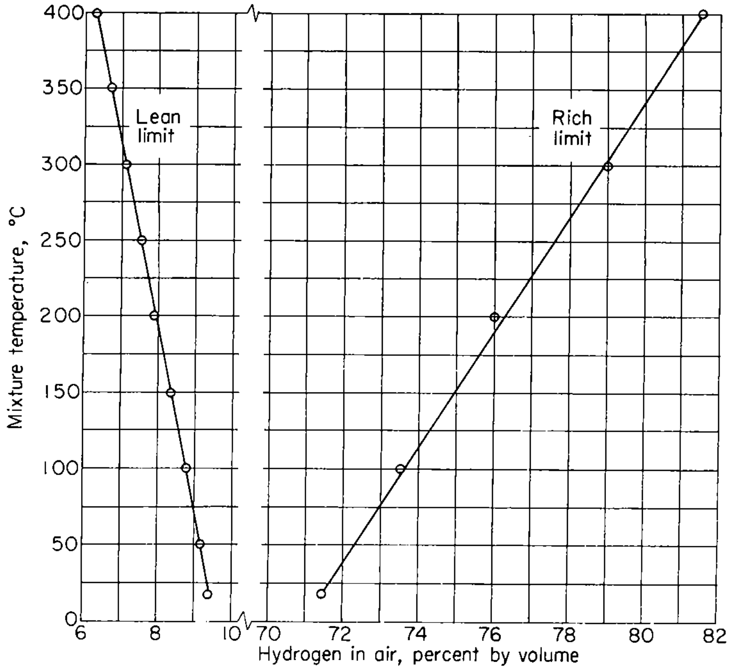


Figure VII-5. EFFECT OF TEMPERATURE ON FLAMMABILITY LIMITS OF HYDROGEN IN AIR FOR DOWNWARD PROPAGATION[4]

Flames will propagate in hydrogen-air mixtures down to very low pressures (i.e., down to 2 mm Hg) without significant effect on the flammable limits, although the quenching distance at such low pressures is increased considerably (10 cm). Increased pressures of up to 100 atmospheres have a small effect on flammability limits.

The spark ignition energy of hydrogen-air mixtures is small, about one-thirtieth that of methane-air. Again, to eliminate the effects of apparatus geometry, idealized conditions are used for measurement. Data for minimum spark energy capable of ignition are reported which are lower than the energy required to ignite mixtures in practical systems. Drell and Belles[4] stated that insufficient information was available on the effects of spark duration, flow velocity, and turbulence level, which would all be important in the design of a practical appliance ignition system. Later data may be available in the literature. The minimum observed spark ignition energies for hydrogen in air are shown in Figure VII-6. The required energy is markedly dependent on the fuel/air ratio and on pressure.

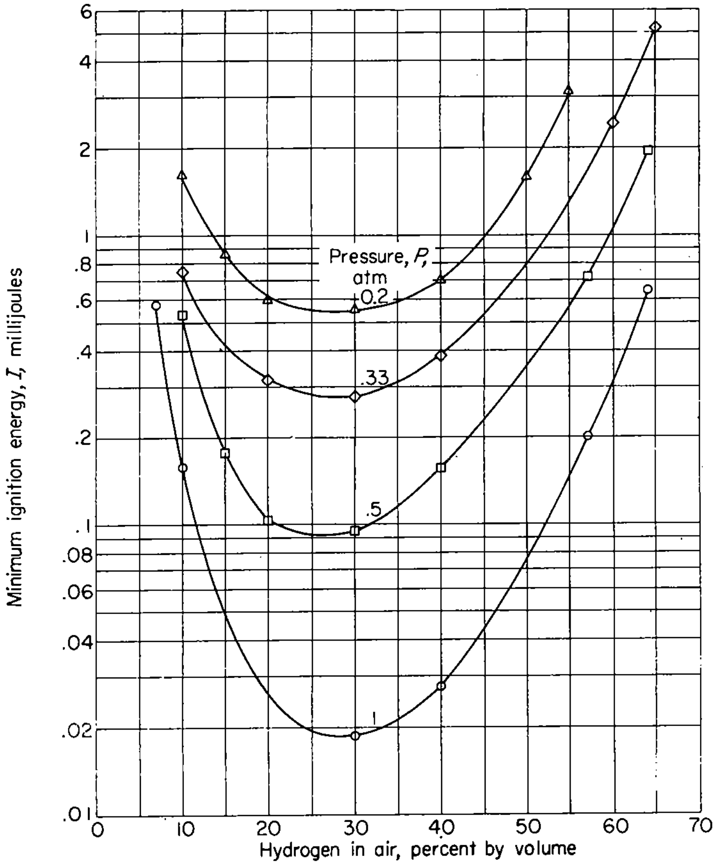


Figure VII-6. SPARK IGNITION ENERGIES FOR HYDROGEN-AIR MIXTURES AT VARIOUS PRESSURES[4]

The conditions under which a stable flame is obtained are determined not only by the fuel-air composition but also by the gradient of flow velocity near the burner wall. Grumer et al.[12] show the stability limits for hydrogen, which make an interesting comparison with those for methane (Figures VII-7 and VII-8). The hydrogen flame still has a wide stable region for hydrogen flames. In general the hydrogen flame can be leaner than a methane flame before encountering blowoff, but the velocity gradients must be maintained higher to prevent flashback.

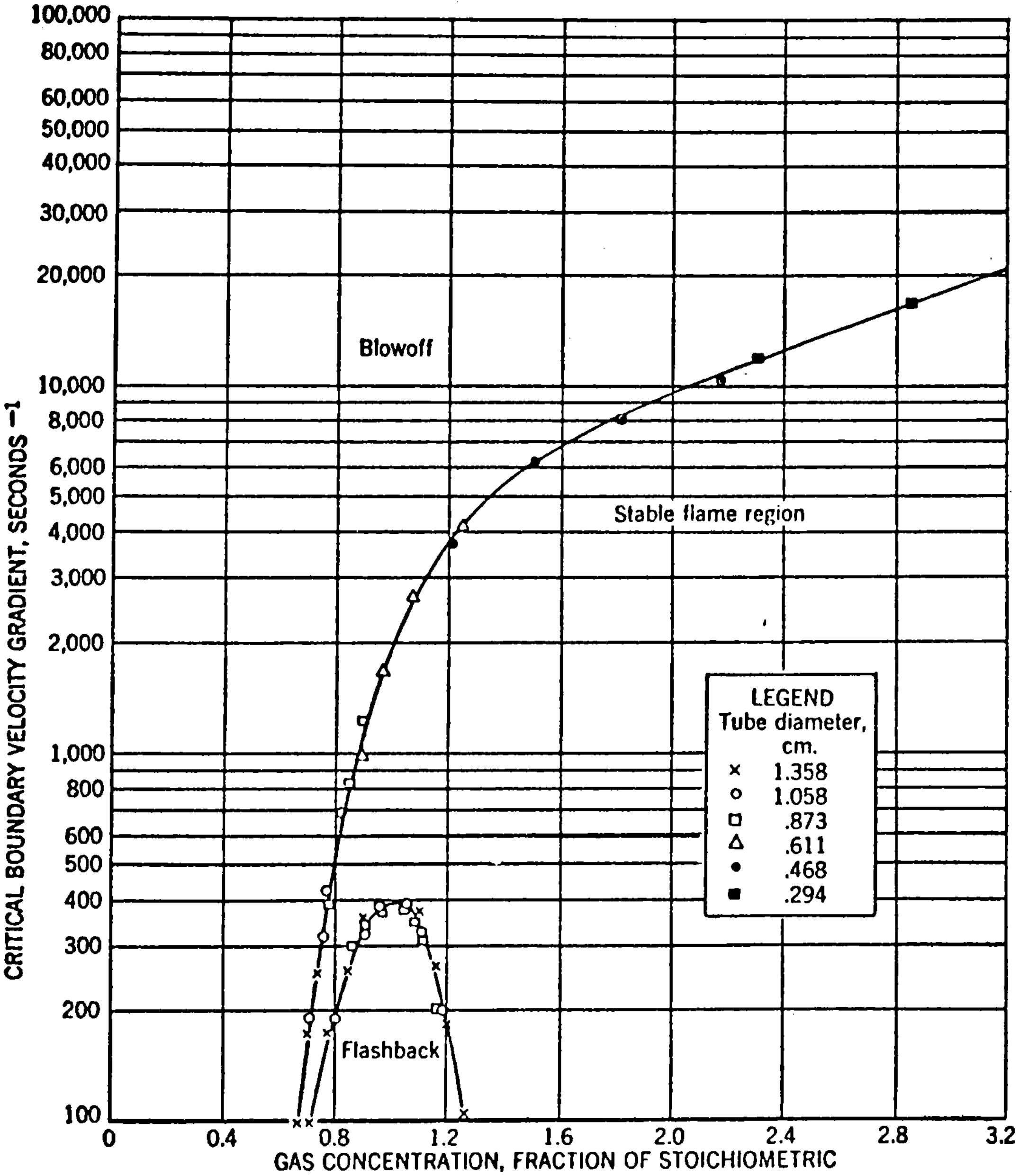


Figure VII-7. FLAME-STABILITY DIAGRAM FOR A FUEL CONTAINING 100% CH_4[12]

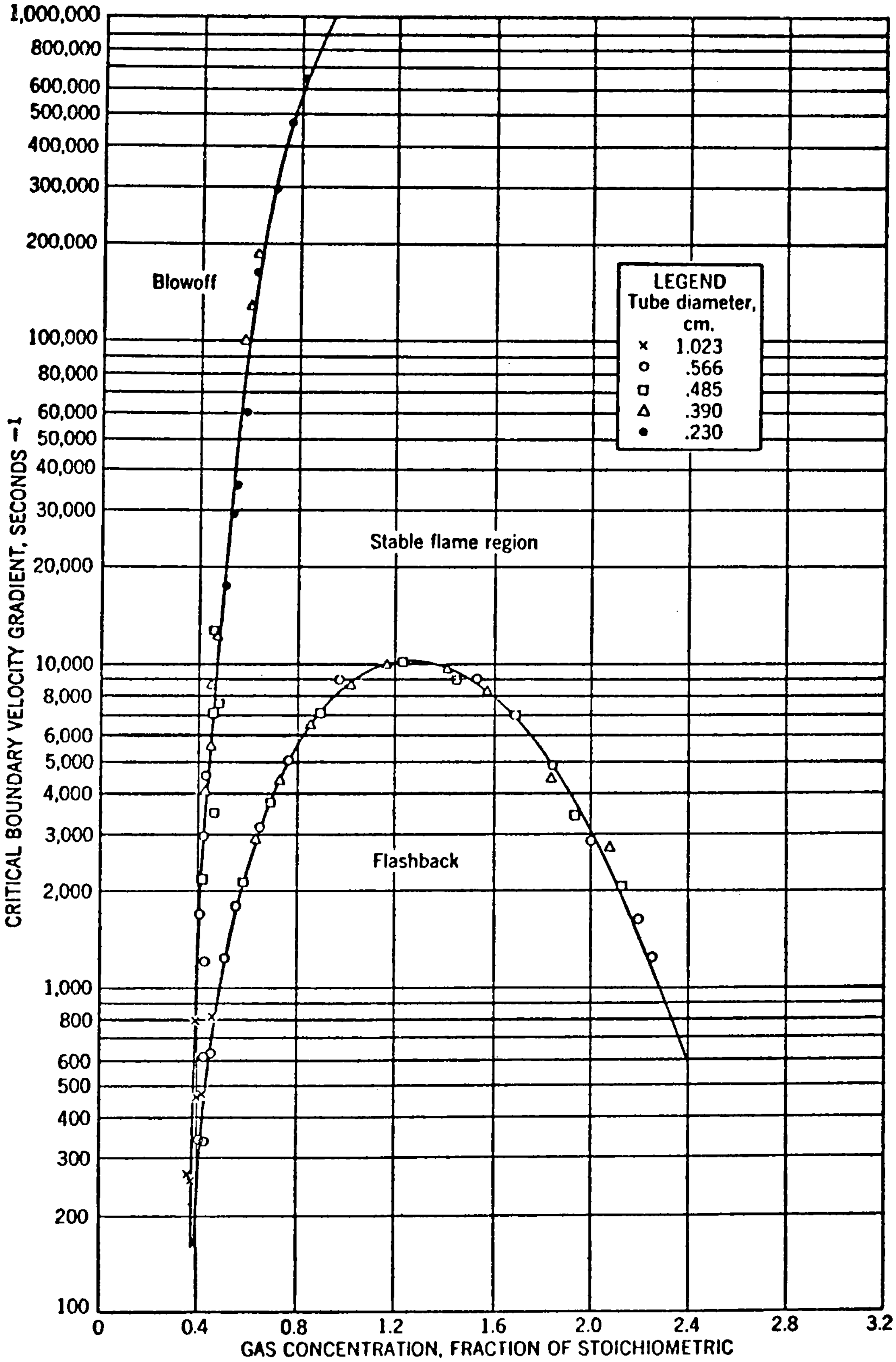


Figure VII-8. FLAME-STABILITY DIAGRAM FOR A FUEL CONTAINING 99.7% H_2 AND 0.3% O_2[12]

Flames held on bluff bodies in ducts owe their stability to the recirculation zone behind the flameholder. Blowoff occurs if the main stream flows so fast that sustained ignition cannot be achieved. Drell and Belles[4] remark that "since hydrogen diffuses more readily than oxygen, in contrast to almost all ordinary fuels, small flameholders actually stabilize hydrogen flames to higher flow velocities than do larger flameholders at a given lean equivalence ratio.... In turbulent conditions the stability behavior of lean hydrogen flames reverses, and larger flameholders become more effective." They go on to say that "much work remains to be done on the flameholder stability of hydrogen-air flames; the data are confined to lean mixtures and small flameholders. The difficulty is that the flames are <u>extremely stable</u>, and large air-handling facilities are needed to provide flows high enough to cause blowoff."[4] This research problem suggests that the design of stable flame burners of this type will not be a problem.

When heated to a high enough temperature, a mixture of hydrogen and air may spontaneously ignite after a lapse of time called the ignition lag. With certain combinations of pressure and vessel size, the mixture may fail to ignite at a temperature that would cause ignition under other conditions. The prevention of spontaneous ignition of premixed hydrogen and air mixtures prior to their reaching the proper burner location is important in satisfactory burner operation. Despite extensive work on spontaneous ignition, data are strongly dependent on apparatus. Therefore, data for a specific application are best chosen from work done in a manner that resembles the practical situation in question. Some data[1, 2] refer to heating for long enough periods (up to 10 seconds) to actually measure the ignition lag, while other data[9, 17] show the temperatures at which ignition lags are only in the millisecond range. Figure VII-9 shows the marked variation in ignition lag observed with variations in fuel-air mixture at two fairly close temperatures, while Figure VII-10 shows some widely varying data on ignition temperatures, indicating that spontaneous ignition will occur in the 1000°-1250°F region. A lowest figure of 968°F is reported, compared to values ranging from 1200° to 1310°F for methane-air.

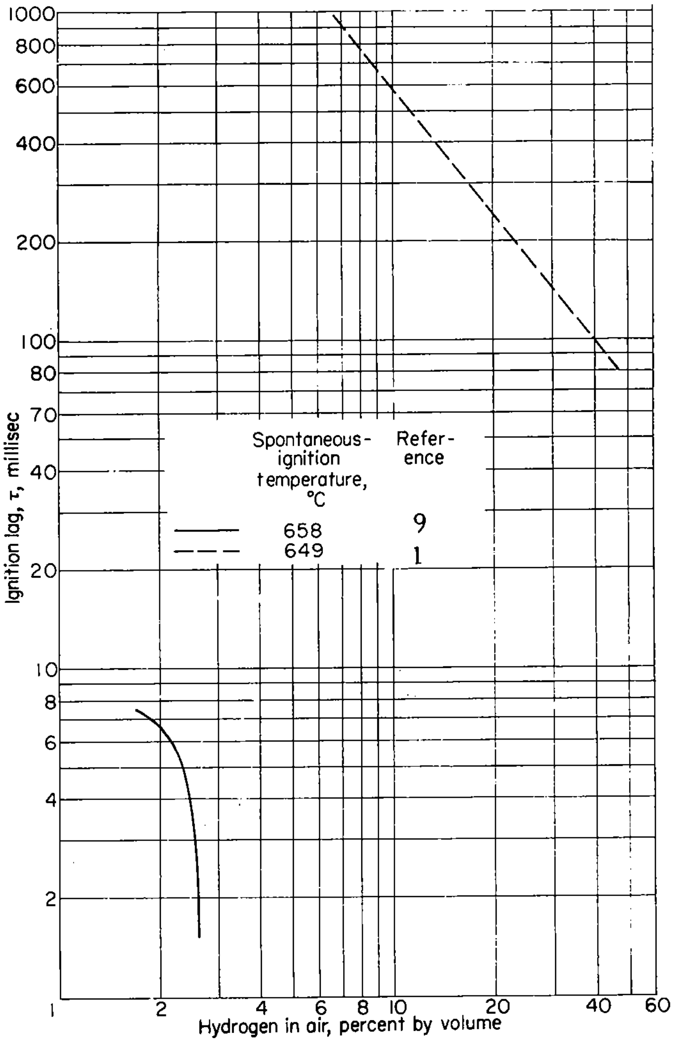


Figure VII-9. EFFECT OF HYDROGEN CONCENTRATION ON IGNITION LAG AT ATMOSPHERIC PRESSURE[4]

2. Burner Design

Since so many combustion data are available for hydrogen, the design of burners should be a straightforward task. Many of the important combustion properties of pure hydrogen are similar to those for gas mixtures of hydrogen with CO, CO_2, etc., which were present in high-hydrogen manufactured gas. The types of burners that worked well for manufactured gas will also work well for hydrogen. However, we should consider the changes and advances in appliance burner design that have occurred since the conversion to natural gas to see whether these changes are compatible with hydrogen operation. We will also discuss the suitability of existing natural gas burners for operation on hydrogen.

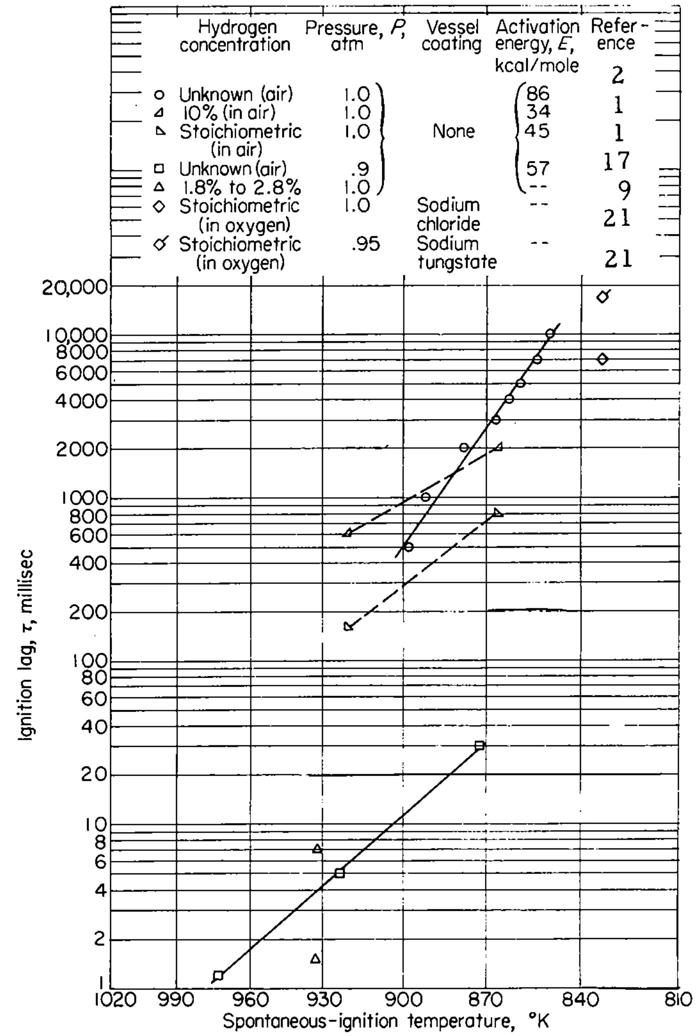


Figure VII-10. EFFECT OF SPONTANEOUS-IGNITION TEMPERATURE ON IGNITION LAG[4]

In Section IX, we discuss the problems of conversion of the existing natural gas system to hydrogen, including the need to convert all the burners on existing appliances.

An existing burner designed for natural gas will not operate on hydrogen for a variety of reasons. First, to produce the same amount of heat, 3 times the volumetric flow rate of hydrogen, compared to methane, is required. An existing orifice will be almost the right size to do this because the flow rate of hydrogen is about 3 times that of methane through the same orifice with the same pressure. Second, the fuel-air mixture required for hydrogen will be different than for methane. Third, a conventional air mixer will have to be readjusted since the rate at which air is drawn in will be changed because of the different density of the fuel gas coming through the orifice.

The requirement for a different fuel/air ratio may be clearly seen from the following reactions, which represent stoichiometric combustion:

$$\begin{array}{ccccc} CH_4 & + & 2O_2 & \rightarrow & CO_2 + 2H_2O \\ \text{1 volume} & & \text{2 volumes} & & \end{array}$$

$$\begin{array}{ccccc} 3H_2 & + & 1\text{-}1/2O_2 & \rightarrow & 3H_2O \\ \text{3 volumes} & & \text{1-1/2 volumes} & & \end{array}$$

Thus for the same heat output, requiring 3 times the volume flow of hydrogen, the oxygen requirement, or air requirement, will only be three-quarters of that required for methane.

Hydrogen burners have a strong tendency to flash back, as shown in Figure VII-8. The primary fuel-air mixture must flow so as to exceed the critical boundary velocity gradient required. In most burners this might be achieved by adjustment of port size. In any case the minimum fuel flow rate below which flashback occurs is likely to be higher for hydrogen than for methane. However, since hydrogen should have no flame blowoff problem, very small burner ports can be tolerated, which will help to alleviate this problem.

The theoretical flame temperature for hydrogen-air is considerably higher than for natural gas-air (3866^0F compared to 3484^0F) resulting from the higher specific flame intensity (6.37 Btu/sq in. of port area/s compared to 0.685 for natural gas). This may have the effect of increasing local temperatures at the port or the burner head. While older appliances used with manufactured gas were sturdy, cast iron structures, modern appliances tend to use diecast ports, or punched-sheet metal ports, which would be more prone to damage by local overheating. Also, the possibility of the burner head becoming hot enough to spontaneously ignite the premixed gas inside the burner should be considered.

The best way of determining if these potential problems are real would be to arrange a comprehensive experimental evaluation of many different types of burners on hydrogen. This is outside the scope of the present work, but is worthy of consideration in the future. Such an experimental evaluation will be especially important for many types of larger capacity burners used in industry.

Conventional ignition devices would operate well with hydrogen because the required ignition energy is lower than for natural gas. Adjusting a pilot if the flame is invisible presents a problem, but we are assuming that some form of illuminant will be added to the gas. Ideally, pilots will not be used for hydrogen because its ease of ignition should make electrical or catalytic ignition systems more practical and reliable than for natural gas.

We can summarize, therefore, by observing that no existing natural gas burners are expected to operate on hydrogen without modification. The extent of modification will vary according to the type of design of individual burners and can only be determined by experiment. Modification to the ports, by reducing their size, is almost certainly required. Modification of the air-mixing equipment may also be necessary. The materials that are close to the flame, including the burner head itself, may have to be changed. Since conversion requires a closing down of the port size, the operation will be somewhat more difficult than the previous conversion from manufactured gas to natural gas, where ports were drilled out. Comprehensive surveys of existing burner types will be required to determine what modifications and replacements are necessary.

Design of burners for use on hydrogen will be straightforward. Stable flames are easily achieved; reliable ignition devices can be devised.

D. Catalytic Combustion

The potential of catalytic combustion burners presents a great challenge and an exciting prospect for the design of radically novel gas appliances for use with hydrogen. Catalytic oxidation of a fuel gas differs markedly from flame combustion in that it is a chemical reaction that takes place on the surface of a catalyst and is therefore localized and confined to a fixed location. It normally occurs at a lower temperature than in an open flame, although this is not necessarily true. With hydrogen, the temperature for spontaneous ignition depends upon the ignition lag allowed; it may be that burners can be designed with fast-flowing gas mixtures such that quite high temperatures can be developed without the formation of conventional flames.

Considerable benefits are achieved from the operation of catalytic burners. The conventional use of such burners operating on propane in such applications as poultry-house heating and camp heaters is due to the safety factor of not having an open flame, which thus reduces the fire hazards. Gasoline can be poured over an operating propane-fired catalytic heater without igniting.

By far the most important potential advantage of low-temperature combustion is the complete elimination of nitrogen oxides formation. Nitrogen oxides are found in any flame using air as an oxidant when the air within and around the flame is heated to temperatures exceeding about 2800°F. A catalytic burner operating below this temperature will not cause nitrogen oxide formation.

The catalyst body itself — usually a small amount of actual catalyst material supported on a high-surface-area refractory support — can be made to operate at a high enough temperature to act as a radiant heater. On the other hand, if low-grade heat is required, for example, for space heating, a very lean mixture may be passed through a catalyst bed to produce an exit stream of warm air at the desired temperature for convective heating. For a radiant heater application, the range of emission temperatures available is wider than that for a conventional flame-type radiant heater and the radiant source temperature is more evenly distributed. The shapes of catalytic burners can be tailored to fit the needs of the application.

In the early to mid-1960's, research progressed on catalytic burners on the assumption that, to be economically practical for wide application, any catalytic burner should operate with the most commonly available gaseous fuel, namely, natural gas. This assumption imposed a serious limitation on the technology because of the difficulty in catalyzing natural gas combustion. Possibly because of the high ignition energy — and certainly because of the low reactivity of methane — catalytic combustion of methane and air cannot be initiated at room temperature, even on a highly active platinum catalyst. Thus a pilot or some other form of ignition device is required. Also, as catalytic combustion of methane-air mixtures cannot be sustained at low temperatures, preheating of the mixture is required before it will react. Under conditions where sustained combustion occurs, propagation of an open flame is possible, and sometimes occurs.

When hydrogen is considered as a fuel, an entirely different picture emerges. Even at room temperature, hydrogen is readily oxidized in air on an active platinum metal catalyst. This means that both initiation and sustaining of combustion can be carried out at low temperatures. For example, the conventional way of removing the last traces of oxygen from electrolytic hydrogen for certain laboratory work is to pass the gas over a palladized charcoal catalyst: Reaction of traces of oxygen occurs at room temperature, and the catalyst bed does not heat up significantly if the original O_2 level in the feed gas is low enough.

A catalytic burner for hydrogen can therefore be conceived in several ways. A low-temperature burner, capable of providing a hot-air stream for space heating, food warming, or other low-temperature applications, would consist of a porous ceramic or other inert bed impregnated with catalyst and fed with a leaner than stoichiometric mixture of hydrogen and air. The temperature of the bed, and thus of the effluent gas, would be determined by the relative rates of flow of hydrogen and air into the reactor and by the heat losses. The vent gases, the air convected around the exterior of the reactor, or both would be used as the heating medium.

Another concept is to pass a rich hydrogen-air mixture, or hydrogen alone, through the pores of a catalyst-impregnated ceramic or refractory bed and to allow secondary air to have access to the outer surface, which will thus become an effective radiant heater. The design of such a heater will be limited by the accessibility of secondary air to the surface. Adjustment of the ratio of primary air to secondary air will determine the local emission temperature.

Little experimental or development work has been carried out on hydrogen-fired catalytic burners for domestic or industrial use. The Institute of Gas Technology and A.G.A. demonstrated several catalytic burner appliances operating on "reformed natural" in the Home for Tomorrow exhibited in 1969. This "reformed natural" was a mixture of hydrogen, CO_2, and methane, obtained from conventional steam-reforming of natural gas. The presence of hydrogen in the mixture allowed the operation of catalytic appliances such as radiant wall heaters and food-warming trays. Because of the relatively low temperatures at which they operated, these appliances could be constructed of plastics and wood. High-temperature radiant cooking units were also displayed. These appliances, intended to demonstrate the potential of radically new concepts in operation, were relatively crude in design and offer ample opportunity for refinement.

The catalysts used in the Home for Tomorrow appliances and in most commercial catalytic heaters are based on precious metals, but only small quantities are used in the "supported catalyst" technique. We carried out a brief literature survey of work on the catalytic oxidation of hydrogen and found 75 references to relevant research. Although most of this work is of academic nature and involves platinum-metal catalysts, considerable work has been done on cheaper catalyst materials such as copper, copper oxide, silver, and manganese dioxide. All of these materials provide smooth oxidation of hydrogen in air at relatively low temperatures, though not at room temperature. Therefore, we have good reason to believe that catalytic burners for intermediate-temperature operation could be built without the use of precious metals, except in some form of ignition device. Experimental work would be required both to develop the catalysts themselves into rugged, stable forms and to determine the long-term effects of air impurities, etc., on their activities.

As far as ignition catalysts are concerned, the aerospace industry has had a requirement for some time for autoignition of the hydrogen-oxygen thrusters used for attitude control on spacecraft such as the "space shuttle." Catalysts capable of reliable autoignition of these mixtures down to temperatures as low as -250^0F have become available through the space program. These, of course, are based on platinum metals, but it appears that reliable autoignition catalysts for room-temperature appliances will not present a difficult technical problem and may not require the use of more than traces of platinum.

E. Appliance Concepts

The most important difference to observe when considering hydrogen rather than conventional fuels is the completely nontoxic nature of the exhaust or "flue gas." The combustion products consist only of water vapor and excess air, together with traces of nitrogen oxides, only if the flame temperature is high. For catalytic combustors, the combustion products are only water vapor and excess air. This mixture can safely be discharged into an interior working or living space, provided the humidity levels do not become excessive. Thus, it should be possible to dispense with the need for flues and chimneys connected directly to the appliance, provided we ensure adequate ventilation of the overall space to allow combustion air to enter and water vapor to leave.

Apart from the obvious advantage in avoiding the cost and inflexibility associated with a flue, one may observe that today's domestic "central heating" systems are only concentrated in one location so that only one chimney is required. How much less space and cost would be involved in distributing the fuel around the house rather than a flow and return system for heat?

We may conceive, therefore, domestic gas appliances on a "decentralized" system which would closely resemble electric appliances in their flexibility. Space heaters in each room can be individually controlled and would operate economically. Such heaters could either be the radiant type or could be convective units similar to hydronic baseboard systems. These units would provide winter humidity as well as heat.

Cooking appliances fed with hydrogen are unlikely to be cheaper or simpler than electric appliances, but they would combine many of the characteristics of electric cooking with the economy of gas. Catalytic food-warming devices, both open trays and hot cupboards, would be of simple construction because no "hot spot" is possible without flame combustion. Similar concepts would apply to clothes driers and warm-air furnaces, thus allowing plastics and other inexpensive and decorative materials to be used. A high-temperature radiant catalytic bed should be capable of incorporation into a smooth-top range cooking surface.

Elimination of the need for a flue will make the "portable" gas appliance an attractive possibility. This will require the development of an acceptable quick-release connector for hydrogen service.

Another aspect of the elimination of a flue is the increased efficiency one should obtain from a home-heating plant: No longer would 15-30% of the heat be discharged through the chimney and large volumes of "conditioned" air through the draft diverter; thus higher heating efficiencies would be possible.

Therefore, although conversion to hydrogen will create a considerable problem in conversion of existing appliances, a whole new range of "modern-image" appliances can be predicted, which would be attractive both in convenience and in efficiency, and which could add considerable stimulus to the appliance manufacturing industry.

F. Suitability of Customer's Equipment Other Than Burners

Some other equipment on the consumers' premises may have to be modified or replaced to cope with hydrogen. This equipment is discussed below in the order in which the gas flows through it.

1. Service Piping and House Piping

If a system currently delivering a quantity of natural gas with a specific gravity of 0.65 at a pressure drop of 1 inch H_2O is used to deliver the same number of Btu's of hydrogen (3.2 times the volume), the pressure drop will be slightly greater. We calculate this pressure drop to be 1.066 inch H_2O, or only 6.6% greater. In normal domestic service, this difference is considered to be insignificant. Notice that this relationship applies only to nonturbulent flow at nominally atmospheric pressure and is a different factor than that used for high-pressure transmission pipelines in turbulent flow.

2. Service Regulators

The rate of flow in Btu's through an orifice at a given pressure drop with natural gas will theoretically be reduced to 93.34% of that Btu flow when operated under the same conditions on hydrogen. Since, fundamentally, the capacity of both the regulator and the relief device are controlled by the equivalent of an orifice, one could expect that the capacity of both would be reduced to a like amount.

Regulators are very seldom sized so that they must operate near their maximum capacity. Most regulators now running on natural gas will probably continue to operate properly on hydrogen. The few that would be found operating near capacity could readily be replaced.

3. Meters

Because the heating value of hydrogen is 3 times less than that of natural gas, on a volume basis, 3 times the volume will have to be supplied to do the same heating job with hydrogen as with natural gas. Thus, the customer's meter will have to measure 3 times the flow rate. Many meters installed now are already operating close to their capacity limit; these would have to be replaced. In addition, a meter operating on the same principle as at present will be 3 times bulkier and may thus cause a problem in accommodating it in a confined space. The alternative is to operate the meter at a faster speed, the feasibility of which will have to be tested experimentally.

4. Appliance Regulators

Appliance regulators, just as service regulators, will probably operate with satisfactory capacity in the majority of cases. One item that may cause concern is the venting of the chamber above the diaphragm. Many appliance regulators are supplied with restricted vents that are intended to limit the escape of gas into the room in the event a diaphragm should rupture while at the same time allowing the regulator to "breathe" properly. An orifice restricting the flow of escaping gas to 2000 Btu/hr (2 CF) of natural gas is commonly accepted as a maximum on the basis that this amount can escape indefinitely into a room having normal ventilation without danger of creating an explosive mixture. To ensure the same degree of safety using hydrogen, the vent would have to be restricted to pass not more than 1.6 CF of hydrogen per hour. Because of the lower viscosity of hydrogen, this opening is very small (less than No. 80) and may not allow proper breathing of the regulator.

One possible solution to this problem might be the use of vents containing check valves now used on some larger regulators. These vents restrict the outward flow with a small orifice that bypasses the closed check valve. On the other hand, inward flow causes the check valve to open, thus permitting the regulator diaphragm to rapidly assume a control position when the appliance is first turned on.

5. Pilots

Since the hydrogen flame is a nonradiant flame, it is almost invisible in normal daylight. This characteristic will make it almost impossible to observe whether a pilot is lit or to adjust the pilot setting by conventional methods. Moreover, a conventional range-top burner is likely to require a "relearning" process on the part of the cook because it will not be possible to judge the input by observing the flame height.

One possible way to eliminate this problem is to introduce into the hydrogen a trace of a suitable compound that would color the flame. The amount would have to be restricted so as not to interfere with the nonpolluting characteristics of hydrogen.

G. Local Electricity Generation

Although we are considering the manufacture of hydrogen at central stations that may themselves include electrical power stations, we must concern ourselves with how electrical energy can be made available at the city load centers, which will be far from the power stations. Small, direct-conversion stations, operating on nuclear or fossil fuels can, of course, still be considered within a city, but the availability of pipeline hydrogen at a reasonable cost makes possible the generation of electricity directly from hydrogen. About 15-25% of our energy needs are most conveniently met by electric power, so it may be appropriate to reconvert up to this amount of our hydrogen into electric power at the load center. Whether or not this is done will depend largely on the relative economics of the transmission cost of electricity and the transmission and reconversion cost of hydrogen. In each case, the efficiency will play a major role.

Hydrogen can be converted to electricity in two different ways: by fuel cells and by direct thermal-mechanical systems. In each case, the efficiency will be higher and capital cost of the generator station will be lower if oxygen is also used (transmitted from the water-splitting hydrogen generation station). Moreover, the use of oxygen completely eliminates the possibility of nitrogen oxides pollution. Two unique characteristics of hydrogen-air fuel cells are that they cannot produce nitrogen oxide pollutants and that their efficiency is potentially higher than heat engines operating on the same fuel.

Hydrogen as a fuel can generally be viewed as a replacement of the various hydrocarbon fuels such as natural gas, turbine fuel, diesel oil, and residual oil, all of which are used at present to generate electricity. Gas- and oil-fired central steam plants remain of primary importance to a large number of electrical utilities, particularly those that have economic supply systems available to them. Utilities near the nation's natural gas production areas of the south-central part of the country (Texas, Oklahoma, and Louisiana) use a large amount of natural gas to raise steam for turbogenerators. Similarly, port areas where fuel oil importation is conducted use oil for the same purpose.

The use of hydrocarbon-fueled gas turbine-generators has grown significantly in the past decade for peaking and standby generation. Both natural gas and normal turbine fuel (JP-type fuel) are used for these machines, which offer the advantages of low capital costs and short order times to the utility companies compared with steam plants. On the other hand, gas turbines have significantly higher "heat rates" (Btu/kWhr) or operate at significantly lower efficiencies. This mix of cost factors has relegated them to peaking as opposed to base-load service. Hydrogen can be used to fuel gas turbines. The considerable background on aircraft gas turbines operated on hydrogen is reviewed later in this section. This reveals that not only is there no significant problem in using turbines in this way, but that certain benefits are achieved, not the least of which is the ability to increase turbine inlet temperatures because hydrogen, unlike a hydrocarbon fuel, can be used for blade cooling. The improvement of gas turbine efficiency that would result from such a temperature increase could allow turbines to find base-load as well as peaking use and thus allow full advantage to be taken of their small size, their low capital cost, and their short lead time compared to those of conventional power stations. On the debit side, increased temperatures could lead to increased nitrogen oxides emissions, and operation of gas turbines on hydrogen will do nothing to alleviate the noise problem associated with their installation in populated areas.

Diesel generators also remain in service for peak purposes. Burning No. 2 fuel oil, these large reciprocating units are amenable to conversion to hydrogen, but the technical and economic feasibility of this remains undeveloped. However, after extensive experimentation, Schoeppel[19] has concluded that the best way to convert a reciprocating engine to hydrogen fuel is to incorporate fuel injection timed to occur at the required ignition time. In this case, a diesel engine should convert readily.

Finally, for conventional generation equipment, hydrogen can be used to replace natural gas in large boilers associated with base-load generating plants. This type of conversion seems to be rather straightforward, being primarily associated with burner and other boiler modifications. However, technical feasibility remains to be demonstrated; any such effort will have to include the question of long-term effects of the conversion. Nevertheless, any urban power stations constructed or overhauled in the near future might be redesigned with a view to their ultimate conversion to operate on hydrogen. Such stations would have nitrogen oxides as their sole pollutant, reduction of this emission probably being reasonably amenable to research.

If a high-pressure oxygen supply is available at the power station, perhaps from a pipeline coming from the hydrogen-generating plant or from a cryogenic delivery system, a vastly improved thermo-mechanical generator can be conceived. By combusting the hydrogen and oxygen together in a high-pressure combustion chamber, hot steam is produced. The combustion can be quenched with water to protect the chamber itself, and a supply of high-pressure steam at any desired temperature up to 5000°F can be developed, according to the amount of extra water added. This steam can be used to drive conventional steam turbine generators. This steam generation equipment can be extraordinarily compact. A technical analogy is the hydrogen-oxygen rocket system used for Apollo's second and third stages. Each engine weighs only 2700 pounds and is 11 feet long, yet generates a power equivalent of 2000 MW. In comparison with the boilers required for a conventional 2000-MW power station, this is impressive and should offer substantial cost savings. In addition, the maximum efficiency of present stations is limited by boiler temperature not by turbine temperatures, so that a higher efficiency may be possible from a plant without a conventional boiler. Finally, since the system is a completely closed cycle, no emissions whatsoever (except distilled water) are produced and the 10-15% heat losses from conventional stack gases are eliminated. This concept is being promoted in the electric industry by Rocketdyne Division of North American Rockwell, which has reported[20] that it is hopeful of achieving 55% efficiencies. These interesting advantages must be weighed against the cost of supplying pressurized oxygen, and the cost of the pressure of hydrogen, since both reactants must be fed to the steam generator at high pressures. It appears quite possible to "retrofit" new steam generators into existing urban power stations. In fact, we understand that a major electric utility is considering one program to do this at this time. On the other hand, such a system is amenable to small-scale design and since no compressor or exhaust is involved, the noise problem associated with gas turbines will be absent.

Magnetohydrodynamic generation systems (MHD) are in limited development at present and are being considered as topping cycles for addition to conventional steam stations. Some of the problems associated with developing the very high temperatures needed are reduced if hydrogen fuel is considered. With fossil fuels, oxygen combustion is preferred for MHD; with hydrogen it may be possible to generate sufficiently high temperatures using preheated air.

Hydrogen's excellent cooling capability might be of significant aid in attacking a number of the other technical problems of MHD — that is, providing endurance to the duct walls by keeping wall temperatures down. Also, if cryogenic hydrogen is available, it may provide a useful heat sink for the use of cryo-cooled and even superconducting magnets in the drive to establish field strengths higher than 10 Tesla, which is considered about what the state of the art can provide at this time.

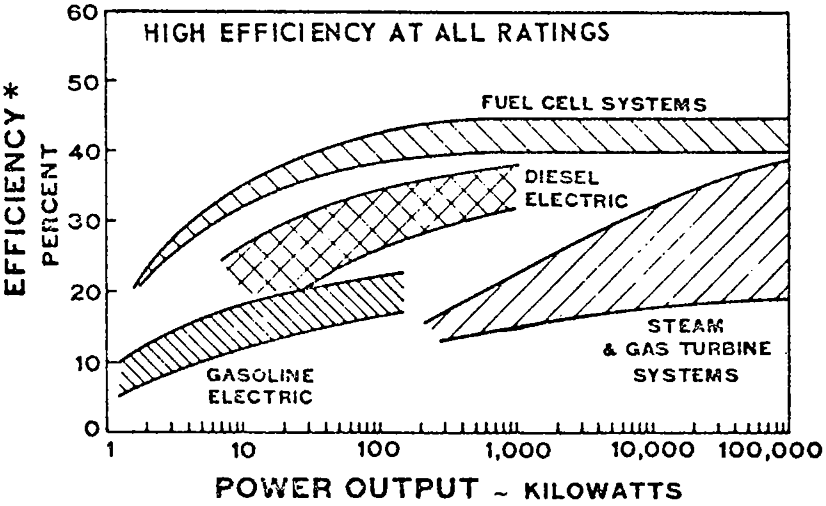
Fuel cell generation of electricity has been the subject of much basic and applied research for the last 15 years. At present, programs directed toward commercial electricity generation are limited in the U.S. to two, both carried out by Pratt & Whitney Aircraft Division of United Aircraft Corporation. One, the TARGET Program, aims to develop a natural-gas-fueled power supply for consumer application, either in the single-family home or in larger size dwellings. The other, sponsored by a number of electric utilities, aims to develop a larger unit of the 2-20 MW size for substation application. Other programs for commercial fuel cell development have been closed down over the past few years because of lack of financial support.

The fuel cell has been adequately described in detail elsewhere.[11] In summary, a fuel cell is an electrochemical device in which the electrochemical reactants, a fuel and an oxidant, are continuously fed in and the reaction products are continuously removed. Low-voltage d-c power is produced. Many cells are stacked together to provide useful voltages. The simplest fuel cell to construct operates on hydrogen and oxygen, which react to form water and electricity. Nowhere in the system do the hydrogen and oxygen actually meet. They are converted by the electrodes to soluble ions that meet in the electrolyte and react smoothly to produce water. No combustion is possible; no high temperatures are created. Since the fuel cell is an isothermal device, it is not subject to the "Carnot cycle" efficiency limitation, which applies to all heat engines operating between two temperatures. Although it is still subject to second-law limitations, it is potentially capable of operating at high efficiencies.

Hydrogen-oxygen fuel cells were developed for both the Gemini and Apollo space programs. The only source of electric power on board the Apollo, responsible for sustaining the astronauts' lives — communications and support systems — for the entire mission, was a battery of hydrogen-oxygen cells. These cells are extremely reliable and were optimized for maximum efficiency to conserve fuel. They are also capable of operating fully automatically in space vacuum and in zero gravity. Only relatively few were produced; accordingly, they were expensive, as are all "space-hardware" items. Besides the commercially oriented programs previously described, work is still going on at Pratt & Whitney and elsewhere to develop improved hydrogen-oxygen systems for space and undersea use, but the improvements are in weights, volumes, and efficiencies rather than in low cost.

Low cost has been the main thrust of the TARGET program, but the type of system has been constrained by limiting the fuel to natural gas. In addition to having a potentially lower efficiency and a higher cost, a hydrocarbon-air cell is a far more difficult technological problem than a hydrogen-oxygen cell.

With present-day technology, characteristic fuel cell power plant efficiency when operating on hydrocarbon fuels is in the range of 40% even at power levels as low as 100-200 kW (Figure VII-11).



***BASED ON LOWER HEATING VALUE**

Figure VII-11. FUEL CELL EFFICIENCY OPERATING ON HYDROCARBONS

Source: Pratt & Whitney Aircraft
Division of United Aircraft Corporation

On hydrogen and air, the efficiency (based on a-c power out) would be about 55%, and on hydrogen-oxygen, nearly 60%. Efficiency remains high over an extremely broad operating range from approximately 25% to 125% of the nominal power rating of the power plant. With pipeline hydrogen available, the fuel processing (steam-reformer) plant would be eliminated, thus saving some of the cost.

There seems a very good reason to suppose that hydrogen-air fuel cell systems and hydrogen-oxygen fuel cell systems can be developed commercially by combining the approaches of both TARGET and the space program. Up until now the incentive to do this had been practically non-existent because hydrogen had not been considered as a commercial fuel.

H. Vehicles and Aircraft

Natural gas has been proposed and is in limited use for vehicle propulsion, and has been considered for an aircraft fuel. If hydrogen is equally or more suitable for these applications, a large new market is opened up for the hydrogen-gas industry. On the other hand, we may ask ourselves what other propulsion systems will be available for vehicles and aircraft at a time when the fossil fuels become scarce and high priced. The alternatives are to develop suitable batteries for electric propulsion — a difficult task already being attempted with only limited success — or to produce synthetic gasoline-like fuels using a nonfossil source of CO_2 and hydrogen. The latter fuels would do nothing to alleviate the pollution problem now facing the automobile industry and threatening to restrict the aviation industry.

Hydrogen can be used as a vehicle fuel in three different ways. One is to operate conventional engines — reciprocating or gas turbine — on hydrogen with as little modification as possible. Another is to operate hydrogen fuel cells in conjunction with an electric drive. A third is to develop a completely new kind of mechanical engine based on a steam cycle, using a hydrogen-fueled steam generator. The first approach, if practicable, would allow for the past development investment in current engine technology to be used profitably, and so is to be preferred.

The operation of internal combustion engines on hydrogen has a long history, dating back to the late 1920's when the Germans realized that they could stabilize the weight of their airships if they used hydrogen from the lift bags as an engine fuel during descent. Erren worked on the conversion of airship diesels to hydrogen in the late 1920's. Then he and his colleague K. H. Weil went to England to continue their work for submarine applications. In 1937, Erren and Hastings-Campbell[7] saw the possibilities of using hydrogen generated off-peak as a vehicle fuel and stated that this would do much to help the pollution problems and the oil import problems then facing the British. Needless to say, this profound observation went unheeded at the time.

Among other workers who carried out early work on the operation of engines on hydrogen, we should note the work of King et al.[15], who operated a laboratory test engine at a compression ratio of 10:1 without combustion knock, provided no carbon deposits were present. This observation could be of great significance because carbon deposits will not form in an engine operated exclusively on hydrogen. The only possible source of carbon is the oil when the engine is warm, which may account for the failure of several other attempts to operate existing, previously run, engines on hydrogen. In the past few years, increasing concern over automobile pollution has kindled renewed interest in hydrogen automobiles; indeed, several investigations now are in progress. Among those with whom we have corresponded are —

- Prof. R. J. Schoeppel at Oklahoma State University. Operating several small 1 to 5-hp single-cylinder engines on H_2, using a fuel injection technique through a third valve or spark plug. He shows that the nitrogen oxides emissions from these engines are considerably lower than from gasoline engines, but his data are only approximate at this time (Figure VII-12).

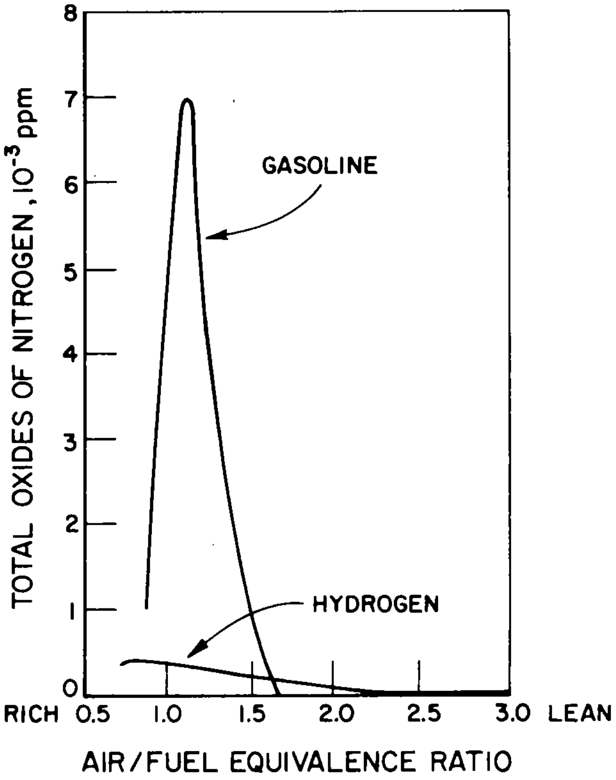


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Figure VII-12. WIDE-OPEN THROTTLE EMISSION CHARACTERISTICS OF SINGLE-CYLINDER ENGINES

- International Materials, Inc., Boston, Mass. Operating a Ford V-8 engine in a 1972 Torino and fueled by hydrogen and CO_2 from a trunk-mounted gasoline reformer. The only engine modifications are in the provision of a specially made carburetor and in the adjustment of ignition timing.

- Brookhaven National Laboratory. Operating a small (5-hp) Wankel rotary engine fed with hydrogen-air premixed from laboratory supplies with no conventional carburetor. Brookhaven reports satisfactory operation.

- A student group at the Illinois Institute of Technology, supported in part by IGT. Operating a 1972 Chevrolet Vega engine on pure hydrogen, using a commercial propane carburetor. Results are very encouraging, indicating that no major engine modifications will be needed.

- A student group at UCLA. Operating two Chevrolet engines, three different Ford 8-cylinder engines, and a Briggs and Stratton single-cylinder engine. They have been concerned with modifying piston rings and compression ratios to obtain optimized performance and are investigating exhaust gas recirculation to slow down the combustion speed of the hydrogen.

In addition to these activities, six or seven additional groups are known to be working on hydrogen engines. As far as we can ascertain, neither GM, Ford, or Chrysler has any activity in this area.

Because of the high flame speed of hydrogen, once ignition occurs, complete combustion takes place rapidly. Thus, if the inlet valve is still open when the plug fires, backfiring takes place. This clearly affects the performance of the engine, but an inlet manifold explosion does not cause mechanical damage. The ignition and valve timing of gasoline engines is therefore incorrect for optimum performance on hydrogen; the ignition timing should be retarded. Indeed, unlike gasoline engines, hydrogen engines have no need of advanced timing with increased engine speed.

Due to the low ignition energy of hydrogen, ignition can occur readily on any engine hot spot. This phenomenon also occurs with gasoline engines under severe carbon deposition conditions and under incorrect engine operating conditions. In fact, the phenomenon of "run on" after the ignition is turned off has become so prevalent in pollution-controlled cars in the last 2 years that an electric solenoid switch is now needed to completely cut off the fuel supply when the ignition switch is off. Spontaneous ignition of hydrogen can become a problem in a worn engine, subject to carbon deposition from oil combustion, and must thus be investigated. Schoeppel prefers to eliminate the chance of preignition causing manifold backfires by using a direct hydrogen fuel injection into the cylinder, as with the diesel engine. The possibility of crankcase explosions is very real because if only enough hydrogen leaks past the pistons to give a 5%

fuel-air mixture in the crankcase, such an explosion could occur, set off by hot spots that could develop on bearing surfaces. So far we have heard of no occurrences of such explosions. In our own (IIT) experiments we ensure continuous ventilation of the crankcase by using an air pump.

Thus, the conversion of conventional internal-combustion piston engines to hydrogen operation appears to present no major problem. Experience to date indicates that immediate starting, cool operation, smooth idling, and the absence of all emissions except nitrogen oxides, which is much reduced, will result.

An entirely new type of hydrogen vehicle propulsion scheme has been proposed by Escher[8] and is under consideration by Michigan State University. It requires both hydrogen and oxygen on board the vehicle, and operates by means of the closed steam cycle already described in connection with power stations. A hydrogen-oxygen combustor, into which water is injected, generates steam at the required temperature for a turbine or reciprocating engine. The exhaust is condensed by a conventional radiator and about 90% of the water is recycled for quenching the burner and to act as a working fluid. This concept has not progressed beyond the conceptual stage and suffers from problems of safety – where both hydrogen and oxygen tankage is considered – and of freezing problems in winter weather. Nevertheless, development of this type of engine should be promoted for its entirely nonpolluting character and because of the availability of hydrogen and oxygen for such a system.

Experiments were carried out on aircraft gas turbines operating on hydrogen during the 1950's. Pratt & Whitney Aircraft[18] converted a standard J-57 aircraft engine to hydrogen in 1956. It states: "The conversion of the J-57 engine to operate on liquid hydrogen turned out to be far easier than one might imagine, and the engine was first operated on hydrogen 5 months after the start of the program.... A very simple axial tube injection system provided excellent performance."

As an example of the excellent combustion characteristics of hydrogen, P&WA noted that the engine could be operated on a very low fuel rate, so that the combustion chamber temperature rise was less than 200°F and the engine turned so slowly "that the first-stage blades could be counted."

We met with the project officer at the Air Force Propulsion Laboratory who had been monitoring this project. He confirmed that operating a gas turbine on hydrogen presents no problems. After developing an engine (the 304 engine) designed specifically to operate on hydrogen at high altitudes, Pratt & Whitney's hydrogen engine program closed down in 1958 after only 25 hours of satisfactory wind-tunnel testing. Meanwhile, the National Advisory Committee for Aeronautics (predecessor of NASA) continued the development of the hydrogen-fueled aircraft and actually flew a B-57 aircraft (Figures VII-13 and VII-14) with one engine operating on hydrogen from a liquid-hydrogen wing tank. Subsequently, hydrogen-fueled aircraft research has been restricted to systems studies, referred to later.

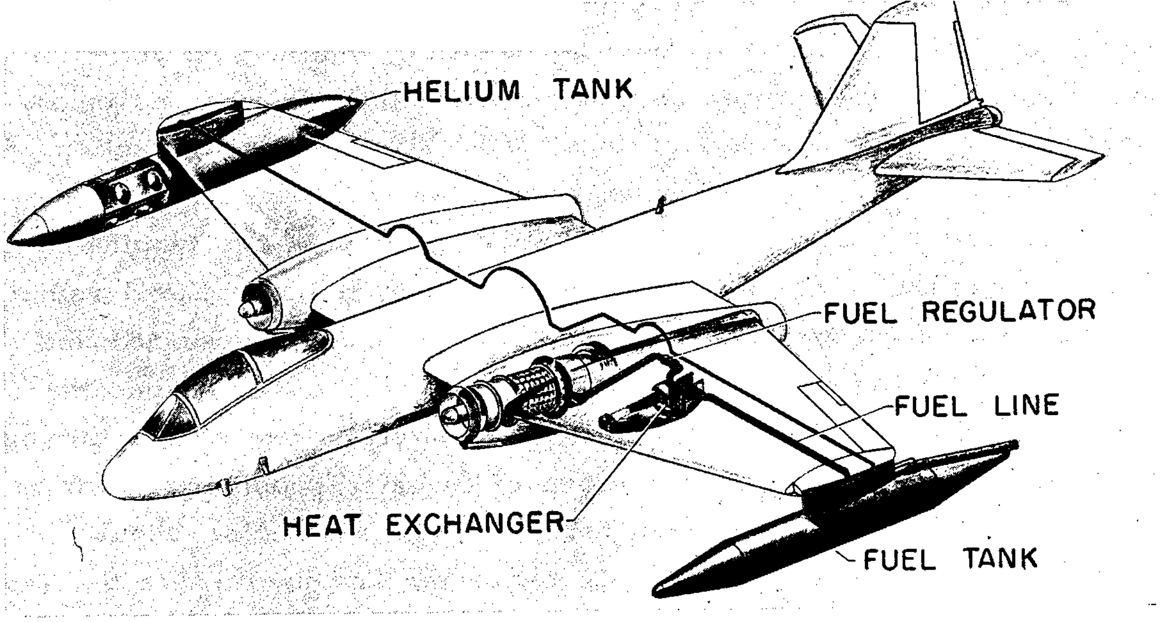

Figure VII-13. HYDROGEN SYSTEM FOR B-57 AIRPLANE

Thus, again operating gas turbine engines on hydrogen seems to present no difficult problem. The only pollutant would be nitrogen oxides, and the levels of these have not been investigated.

Although the engine conversions appear to be minimal, handling of the fuel presents more serious problems. The weight of cylinders required for pressure storage of hydrogen gas precludes its consideration as a mobile fuel. Two alternative approaches are possible: One is the use of liquid-hydrogen tankage, and the other is the use of chemically bound hydrogen as a hydride. Both of these approaches are discussed in some detail in Section V.

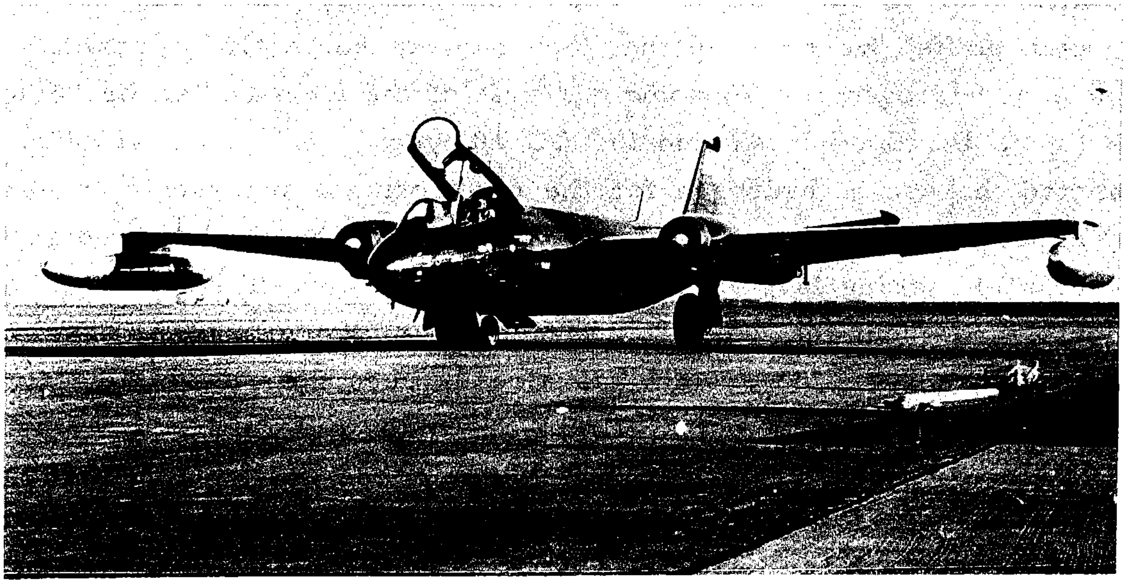

Figure VII-14. B-57 BOMBER IN WHICH HYDROGEN SYSTEM WAS INSTALLED

The specific energy/weight ratio of hydrogen itself is far higher than gasoline or any other hydrocarbon fuels (lower heating value of 51,600 Btu/lb and higher heating value of 61,000 Btu/lb, compared to gasoline's lower heating value of 19,500 Btu/lb). Hydrogen itself, then, will weigh only 0.38 times as much as the same energy equivalent of gasoline. A liquid-hydrogen tank, incorporating vacuum insulation, will admittedly be heavier than a gasoline tank, but the overall weights should be comparable in small sizes and should be considerably less for hydrogen in large sizes. For this reason liquid hydrogen has been seriously considered as an aircraft fuel for long-range, high-performance applications such as the supersonic and hypersonic air transport. The low density of liquid hydrogen, however, makes its use look less attractive: only 4.42 lb/CF compared to 44.9 lb/CF for gasoline. A similar energy content of hydrogen occupies 3.9 times the volume of gasoline. This, of course, affects the weight of the more complex hydrogen tanks.

In aircraft use, this disadvantage has prevented the serious consideration of hydrogen as a fuel for subsonic aircraft, but for hypersonic aircraft (Mach 4 to 6) the refrigeration qualities of liquid hydrogen are an additional benefit; it is used for skin cooling. NASA-Langley Research Center's staff told us that hydrogen is the only fuel possible for such aircraft. During our discussions with the Langley and NASA-Lewis Research staffs, we realized that they had not seriously reconsidered the use of hydrogen for subsonic aircraft of the wide-bodied or "Jumbo" size (i.e., the Boeing 747 and the DC 10 type). In the mid-1960's, NASA promoted the use of hydrogen for the now dormant supersonic transport project (SST). Under contract, Air Products & Chemicals[13] studied the problems of making large quantities of liquid hydrogen available at major airports throughout the world. Thus, much of the groundwork for a hydrogen-based aviation system has already been done. Detailed refinement will be carried out by NASA or by the aircraft industry as soon as it becomes clear that hydrogen could be made available in bulk at a "competitive" price. Again, we ask the question, competitive with what — in the nonfossil future?

The use of liquid hydrogen as an automobile fuel presents more of a question of acceptance and safety than of technical possibility. One of the smallest existing commercial vacuum-insulated tanks, designed for LNG, will fit into the trunk of a standard automobile and has a volume of 18.7 gallons, including ullage space. The manufacturers, AMETEK/Straza, indicate that this tank is adaptable to hydrogen service and has a lockup time of 18 hours; that is, the boil-off would be contained within the pressure limits of the tank, 60 psia, for that time without venting. Specially designed tanks for hydrogen service, with superior insulation, would give longer times without venting. The 18.7-gallon tank, which would contain 17 gallons, or 10.1 pounds of hydrogen, weighs 63 pounds and corresponds to 26.6 pounds or about 5 gallons of gasoline contained, for example, in a 10-pound tank. Thus, the hydrogen and tank will weigh about twice as much as the gasoline and tank. This ratio will decrease as tank size is increased. However, the size referred to above would be too small to serve a conventional automobile.

Nevertheless, present technology is apparently available to permit the construction of a properly designed liquid-hydrogen automobile tank that would be both heavier and bulkier than the existing gasoline tank, but would not be unacceptable. In partial compensation, most of the antipollution devices could be removed from the engine and at least an assist for the air-conditioning load could be obtained from the liquid-hydrogen evaporator. The problems of periodically requiring venting, of fueling availability, and of safety in fueling and in the inevitable road accidents remain to be evaluated, but may not be as severe as it appears.

The alternative is the use of metal hydrides. Workers at Brookhaven National Laboratory[14] have been and are still, on a very small scale, investigating metal hydrides for hydrogen storage. Their comparison of a magnesium hydride fuel system with pressure and liquid gas storage is given in Table VII-1.

Table VII-1. COMPARISON OF VARIOUS HYDROGEN STORAGE SYSTEMS

(Energy equivalent to 120 lb of gasoline; 45 lb of hydrogen)

Storage System	Weight of Carrier and Fuel, lb	Contained Volume, CF
Gas at 2000 psi	2250	66
Liquid H_2	353	10.2
Magnesium Hydride (40% voids)	692	10.8

Clearly, improvements must be made, and a search is still in progress for metal hydrides having a lower density. One problem with the use of a hydride in an automobile application is the usually exothermic nature of the charging process. When the metal is converted to the hydride, considerable heat is evolved and must be dissipated or possibly used. The family automobile, being charged with hydrogen overnight, could supply the heating plant for the home during the winter. Very considerable engineering studies, together with an increase in the chemical studies already in progress, seem to be warranted.

For larger vehicles such as trucks, buses, trains, and even ships, the penalties of weight and volume of fuel tankage are less critical than in automobiles. Both liquid hydrogen and ultimately hydrides can more reasonably be considered for such vehicles. The fuel-handling and safety problem becomes far less difficult if a controlled utilization system, such as in a rapid transit system or a trucking system, is considered. Such systems could provide a logical entry point for hydrogen into transportation service.

Under contract to the Department of Transportation, NASA-Lewis Research Laboratory has begun a study of high-speed rail transport and city buses that is beginning to investigate the possible use of liquid hydrogen as a fuel.

I. Industrial Hydrogen as a Raw Material

Hydrogen is a very important intermediate in use today in the chemical and petrochemical industry. Its use as a fuel is almost nil (except for space rockets), but its chemical uses are large and growing. The latest statistical figures are for 1968, when 2.06 trillion CF (5.8 million tons) were consumed commercially, of which 48% was for ammonia synthesis, basically for fertilizer manufacture; 38% for petroleum refining; and 20% for other uses including synthesis of methanol, hydrochloric acid, and other heavy chemicals, and for hydrogenation of unsaturated fats and oils for foodstuffs. Small amounts were used as a metallurgical reductant.

Most of these uses are growing rapidly: Industrial hydrogen requirements for the year 2000 have been estimated as between 6 and 60 trillion CF (3 to 30 times 1968 levels) depending on the extent to which it becomes used in coal and oil gasification and as a metallurgical reductant. The unit quantities of hydrogen used to make various products are shown in Table VII-2. Most of today's commercial hydrogen is made from natural gas, but as natural gas prices increase, reforming of naphtha or heavy oil is expected to take over. Hydrogen from coal is another attractive and likely source of commercial hydrogen in the near future. The fastest growing sector of utilization is in the petroleum refining industry, where it is used principally for desulfurization of heavy feedstocks and for upgrading distillate fuels to gasoline-type materials.

These trends will continue for the next 20-50 years, without doubt. The petroleum refining industry can become an important customer for bulk hydrogen, possibly produced by coal or heavy oil gasification in central plants. As a long-range prospect, both the sources and uses of hydrogen will change. As petroleum feedstocks become more expensive, treating them with nonfossil hydrogen to upgrade them to useful products will probably become desirable in order to conserve petroleum supplies.

Table VII-2. TYPICAL INDUSTRIAL HYDROGEN REQUIREMENTS

Use	Standard Cubic Feet/Unit of Product
Ammonia Synthesis	70,000-80,000/short ton of NH_3
Methanol Synthesis	36/lb of CH_3OH
Petroleum Refining	$\leq$610/bbl crude oil
Hydrotreating	
Naphtha	50/bbl
Coking Distillates	750/bbl
Hydrocracking	2000-2500/bbl
Coal Conversion to —	
Liquid Fuel	6000-7000/bbl "synthetic" oil
Gaseous Fuel	~1560/1000 SCF "synthetic" gas
Oil Shale Conversion to —	
Liquid Fuel	1300/bbl "synthetic" oil
Gaseous Fuel	1200/1000 SCF "synthetic" gas
Iron Ore Reduction	20,000/short ton of iron
Process Heat	$3070/10^6$ Btu or 2700/1000 lb process steam

Use of hydrogen as a metallurgical reductant in lieu of carbon (coke) has long been known to be feasible; however, only very limited use has been made of this technology so far. Since the production of iron (89 million tons in 1968) far outshadows the production of all other metals combined, hydrogen reduction of iron ore is of greatest significance in this area. Several processes have been developed; although none are yet economically competitive with the conventional blast furnace, many plants are already in operation in favorable conditions. The U.S. Bureau of Mines estimates that by the year 2000 production of about 30 million tons of iron using 600 billion CF of hydrogen may be feasible. Use for nonferrous metallurgy (copper, zinc, and lead) is equally feasible, but would be less hydrogen-consuming, both per unit of output and in total.

One of the primary incentives for using hydrogen as a reductant is that it results in much better environmental protection in an industry renowned for its contribution to pollution. Reduction of oxide ores in fluidized beds would result in the production of only water and slag. Reduction of sulfide ores (copper, lead, zinc, nickel, etc.) would produce hydrogen sulfide, which could be oxidized to sulfur for storage in its innocuous elemental form.

J. Oxygen By-Product

Any process for the production of hydrogen from water will produce oxygen as a by-product. If we consider the production of, for example, a 1000-MW power station electrolyzer, it will produce not only 185 million SCF/day of hydrogen but also 92 million SCF/day of oxygen. In other words, hydrogen production at 100 billion Btu/day will produce about 3800 tons/day of oxygen. This will be typical for only one individual plant (1800 MW electrical equivalent).

We have taken no credit for the sale of this oxygen in our economic calculations because the quantities will ultimately be so huge as to depress the current market. However, by way of comparison, the cost of oxygen now lies between \$8 and \$20/ton, according to quantity and means of delivery. At the lower figure of \$8/ton, this represents a credit of \$0.3/million Btu of hydrogen, which is between 10 and 15% of the expected hydrogen manufacturing cost.

Oxygen is used in large quantities by the steel industry; the "basic oxygen furnace" process now becoming widely used in the steelmaking business uses 1900 SCF of oxygen per ton of steel. Steel production in 1971 was 131 million tons, representing a potential use of 10 million tons of oxygen. Oxygen has also been proposed as a feedstock in sewage treatment and water purification systems, where similarly large quantities would be used. It is also receiving attention as an additive to commercial furnace air supplies, both to clean up the effluent and to increase efficiency.

Oxygen is not normally transported by pipeline further than about 30 miles because at greater distances it is cheaper to separate it from air onsite. Many large-diameter oxygen pipelines are in service in the U.S. and in Europe, primarily supplying steel mills. This future use of oxygen and the distance over which it can be economically transported will require further study because tonnage amounts of oxygen would become an important new product of the hydrogen-gas industry. The close interrelation between hydrogen and oxygen production from water and their potential use in the steel industry is of vital importance because industry will probably use these materials in a proportion other than their stoichiometric ratio in water, so that a surplus of hydrogen will be available for sale. The logistics of oxygen transportation could have a profound influence on the optimum siting of the hydrogen-production plant.

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VIII. HYDROGEN SAFETY

A. Introduction

Undoubtedly, hydrogen is a hazardous material; it is readily flammable in air and creates explosive mixtures with air. Because its flammability limits, when mixed with air, are very wide and its ignition energy is very small, a hydrogen fire is easier to create than a methane or a gasoline fire. The required safety precautions for handling hydrogen are therefore more stringent than those required for conventional fuels. But the emphasized public awareness of the danger of hydrogen is not justified on technical grounds.

Our purpose here is to examine the facts about hydrogen safety and to determine whether or not a hydrogen energy system could be operated safely. Since we consider liquid hydrogen to be a storage medium, both for peakshaving and as a possible vehicle or aircraft fuel, we also discuss the special safety precautions of liquid hydrogen.

B. Gaseous Hydrogen

1. Hazardous Properties of Hydrogen Compared With Natural Gas

To discuss the safety aspects of hydrogen, we must choose some reference standard. Thus we use natural gas here as a comparison standard. We must understand, however, that natural gas itself is also a potentially hazardous material, although we have learned to handle it safely. Nevertheless, we must watch for differences between it and hydrogen that will require extra safety precautions, changed codes of practice, or the potential inacceptability of the use of hydrogen.

Table VIII-1 lists some data for hydrogen and natural gas (methane), which relate specifically to safety considerations. A wealth of data are available on the physical and combustion properties of hydrogen because of its scientific importance as a simple combustion gas, and more recently, to its very considerable use both in the chemical industry and as an aerospace propellant. A good condensation of the combustion properties of hydrogen is available from NASA.[7]

Table VIII-1. HAZARDOUS PROPERTIES OF HYDROGEN AND NATURAL GAS

	H_2	CH_4 (Natural Gas)
Specific Gravity, Air = 1.00	0.0696	0.641
Heating Capacity, Btu/SCF	325	1056
Air Required, SCF/1000 Btu	7.325	9.404
Total Combustion Products, CF/1000 Btu	8.862	10.411
Ignition Energy, millijoules	0.02 (at 30% H_2 in air) 0.6 (at lower flammable limit)	0.3
Ignition Temperature, °F	968-1250	1200-1310
Ignition Velocity, 20% Primary Air, ft/s	2.8	<0.1
Ignition Velocity, 50% Primary Air, ft/s	9.2	0.1
Ignition Velocity, 100% Primary Air, ft/s	6.4	1.0
Ignition Velocity, Maximum, ft/s	9.4	1.0
Lower Flammable Limit in Air, vol %	4	5
Upper Flammable Limit in Air, vol %	75	15
Lower Detonation Limit in Air, vol %	18.3	
Upper Detonation Limit in Air, vol %	59.0	
Relative Orifice Capacity CF	3.03	1.0
Relative Orifice Capacity, Btu	0.93	1.0
Viscosity at 0°C, 1 atm, 10^{-6} poise	84.2	100
Molecular Speed at 0°C, m/s	1692	600
Quenching Distance, cm	0.06	0.25
Color of Flame	Invisible	Blue-Yellow

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Let us consider a gas-filled system potentially subject to leakage and compare the hazards of hydrogen and natural gas. First, the "orifice capacity," or the rate at which gas will escape through a hole of given size, is 3 times greater for hydrogen on a volume basis, but because of the lower heating capacity, the escape of energy is only 0.93 times as fast (that is, essentially the same).

If this hydrogen is escaping into a confined space, it will reach the lower flammable limit of 4% by volume in 0.26 of the time, or 3.78 times faster than natural gas will reach its 5% threshold. At this point, however, the energy contained within the confined space that would be released in a fire or explosion is only one-quarter of the energy of a 5% methane-air mixture occupying the same volume. Thus relatively small hydrogen explosions can be contained within the walls of laboratory glassware while methane explosions cannot.

If no ignition occurs and escape continues into the confined space, the hydrogen will reach its upper flammability limit of 75% in air and become "safe" again in 1.6 times longer than it would take for natural gas to reach its "safe" condition of 15% or above. However, in practical cases, some degree of ventilation is likely, and it is very possible that hydrogen would never reach its upper flammable level while methane can do so readily.

If the limited release of hydrogen is made in an unconfined space, we observe that the hydrogen moves away from the release point at a far greater rate than does natural gas for two reasons: The density of hydrogen is only one-fourteenth that of air, compared with about two-thirds for methane, so its tendency to rise is far greater and its smaller molecular size makes for a diffusion rate in air 2.82 times faster than that of methane.

We might stop here to compare the hazards of gasoline and propane in this context. Both gasoline vapor and propane gas are heavier than air and tend to collect around a spill or a leak and are thus extremely hazardous. The lower flammable limits of propane and gasoline in air are 2.1% and 1.5%, respectively, which adds to the danger. This point will be important when we come to discuss the public reaction to prospects of handling liquid hydrogen in the light of spectacular LPG and gasoline tanker accidents.

If a flammable mixture is created, the lower ignition energy of hydrogen will allow it to ignite far more readily than methane. The ignition energy for hydrogen is only 0.02 millijoules, and an invisible static spark can contain this energy. Thus, it is far more difficult to eliminate ignition sources for hydrogen than for natural gas. A lighted cigarette is reportedly[3] not hot enough to ignite a hydrogen-air mixture.

Once a flame occurs, the rate of propagation of the flame is between 6 and 100 times faster for hydrogen than for methane, depending on the air ratio. Although extremely rapid combustion of hydrogen can therefore occur, detonation of hydrogen-air mixtures is unlikely in an unconfined space. For this reason, large hydrogen installations are usually out of doors. Rapid deflagration (not detonation) can still cause a loud noise, structural damage, and all the unpleasant properties of an explosion. The quenching distance for hydrogen is only one-quarter of that for methane so that a flame will propagate through a smaller space. This property also makes the design of flame arresters for hydrogen slightly more complex since woven wire screens are unsuitable; sintered metal pads must be used.

A leaky piece of equipment producing a hydrogen flame can have an additional hazard because the flame is almost invisible. Therefore, a small hydrogen fire can go unnoticed, and personnel who are not aware until too late that a flame exists, may suffer serious burns. On the other hand, the very low level of radiation that a hydrogen flame produces results in less damage to personnel and property in the event of a major fire.

2. Extra Safety Precautions Necessary With Hydrogen

Having compared the hazardous properties of hydrogen and natural gas, we are now in a position to suggest what extra precautions are necessary for handling hydrogen. In reviewing the extensive literature on hydrogen handling and safety generated from NASA's and the Air Force's experiences, one is impressed with the extremely cautious and conservative approach to hydrogen, emphasizing leak detection as a major consideration. Nowhere does this literature mention the possibility of adding an odorant to hydrogen to assist in leak detection as is routinely done with natural gas. Discussions with commercial hydrogen producers indicate that such a step has not been considered because the industrial hydrogen user would probably not welcome the introduction of a potential catalyst poison such as a sulfur compound.

If one reads the hydrogen handling and safety literature, however, with the understanding that hydrogen has a synthetic "smell," then many of the difficulties of handling are reduced.

Fire detection is also a problem because the flame cannot be seen in daylight. The addition of a suitable flame colorant would eliminate this danger, too.

The higher rate of escape of hydrogen through a given size leak implies that the physical size of a "tolerable" leak in a hydrogen line will be smaller than for natural gas. However, conventional leak detection techniques such as smell, combustible-gas detectors, and pressure decay rate will respond in proportion to the gas volume (or Btu's) leaked physically so that these smaller sized leaks will be detected just as easily. Once the leak is located, however, the problem of closing up a "hole" of only one-third of the size will be greater, and therefore both installation and repair techniques for gas systems will have to be modified to achieve a "tighter" system than is now needed for natural gas.

Because hydrogen diffuses away, and rises, at a far greater rate than natural gas, a report states[15] that "leak detection will be difficult since a concentration of gas will not build up at the leak exit.... The properties of diffusivity and buoyancy make it very difficult to locate the exact site of a leak." This is true for combustible gas detectors, for example, but other simple techniques for precise leak location, such as soap bubble testing, should be equally applicable to hydrogen. However, we will expect outdoor main leak surveys to be rendered more difficult because of this phenomenon.

Current safety precautions for hydrogen are markedly different for installations out of doors and indoors. For example, the NASA Hydrogen Safety Manual[9] states that "threaded joints are acceptable for use on gaseous hydrogen systems with a suitable thread seal. Threaded joints inside a building are to be back-welded to prevent leaks." Little justification exists for such a radically different approach if the gas is odorized. However, it is clear that in the event of a catastrophic hydrogen leak into a confined space, such as indoors, the likelihood of a detonation, rather than a deflagration, is increased, if ignition occurs. Approved practices for installations for indoor and outdoor conditions should be different for hydrogen just as they already are for natural gas.

The very low ignition energy for hydrogen presents potential problems for one to ensure the absence of ignition sources in situations where a hydrogen leak is likely. For example, since an invisible static spark will ignite a hydrogen-air mixture, it is hard to see how a man can work on a leaking hydrogen main, for example, in an excavation pit without wearing special "non-static" clothing. This area needs further consideration and testing to define what precautions are really necessary.

Due to the "reverse Joule-Thompson effect," hydrogen heats up on expansion at normal ambient temperatures, so that an escaping stream of gas from a high-pressure pipe may reach the ignition temperature and ignite spontaneously.

At this time, therefore, the only extra precautions to be taken with hydrogen as opposed to natural gas relate to the extra accuracy or care in obtaining leak-tight joints, in installing equipment to the precautions required to protect personnel when carrying out repairs on leaking systems, and to the extra sensitivity required in leak surveying, especially out of doors. All of these areas should be studied further.

3. Established Safety Codes for Gaseous Hydrogen

Both the U.S.A. Standard Code for pressure piping[2] (USAS B31.8-1968) and the minimum safety standards for transportation of natural and other gas by pipeline of the Department of Transportation[6] may be directly applicable to hydrogen distribution systems. In both standards, although the inclusion of gaseous hydrogen is not explicitly spelled out, we believe it to be included on the basis of their definition of "gas." In USAS B-31.8, the term "gas" is defined as any gas or mixture of gases suitable for domestic or industrial fuel and transmitted or distributed to the user through a piping system. In DOT's standard, "gas" means natural gas, flammable gas, or gas that is toxic or corrosive. Since these two standards are the primary codes for natural gas distribution, hydrogen systems seem well covered by the existing specifications and regulations.

The National Fire Code,[11] however, has a special section covering the standard for gaseous hydrogen systems at consumer sites. Because the standard does not cover the distribution piping systems and is only specified for hydrogen systems where the hydrogen is delivered by mobile equipment, it is not clear if the standard applies to systems where the hydrogen is delivered to the consumer premises by pipeline. One major concern is that in piping, tubing, and fitting design, the standard specifically indicates that cast iron pipe and fittings are not to be used. (The other two national standards contain no such specification.)

In addition, an American Petroleum Institute subcommittee, which surveyed industrial use of materials subject to hydrogen service, has published its data in the form of an industrial recommendation on materials selection.[12,13]

4. Experience of Handling Manufactured Gas

Perhaps the most significant area from which we can obtain confidence in handling hydrogen as a fuel is by looking back at what were accepted practices in the days of manufactured gas, town gas, or coal gas. A typical analysis of coal gas and town gas is given below:[5]

Constituent	Town Gas	Coal Gas
	vol %	
Benzene, etc.	0.8	1.2
Carbon Dioxide	2.6	0.1
Oxygen	0.5	0.1
Ethylene	2.8	2.9
Carbon Monoxide	14.1	7.3
Hydrogen	46.6	50.6
Methane	19.4	29.7
Ethane	4.0	3.2
Nitrogen	9.2	4.9

These were hydrogen-rich gases. Their flammability limits ranged from about 5.3 to 30.0% in air, considerably wider than those of natural gas (4.3-13.4% under the same conditions of measurement), although not so wide as for hydrogen alone. In addition, the relatively high carbon monoxide content of these gases added the additional hazard of toxicity.

In 1961, the British Gas Council recommended that carbon monoxide levels in manufactured gas should be reduced to below 10%, preferably 5%;[14] all new manufacturing plants in Britain were designed to meet this standard. This indicates the very considerable concern over the toxic hazard of manufactured gas, which, of course, would be absent in a pure hydrogen gas.

In the U.S., manufactured gas was transmitted and distributed in pipelines in very considerable quantities up until the late 1940's. In 1945, 72,000 miles of gas main were in service for manufactured gas,[1] of which 3410 miles were designated as transmission main. (This manufactured gas included "water gas, retort coal gas, coke oven gas, oil gas, blue gas, producer gas, reformed gas, and any mixtures thereof;" most of these contained appreciable quantities of hydrogen.)

Town gas has been safely stored underground in a number of installations in Europe.[10] The largest is the aquifer storage facility at Beynes, near Paris, operated by Gaz de France. This storage facility operated for more than 10 years on coke-oven gas, or town gas, before being converted to natural gas. The storage capacity is 7000 million SCF with a 6000 million SCF cushion, at a working pressure of 570 psia. Two storage systems in Germany having a total operating capacity of 6000 million SCF operate on town gas, and another stores 2850 million SCF of "refinery gas," presumably hydrogen-rich. In England, a salt cavern storage facility has stored 10 million SCF of town gas at a pressure of 450 psia for several years (1959-1969).

C. Liquid Hydrogen

1. Special Hazards of Liquid Hydrogen (LH_2) Compared With LNG

Liquid hydrogen is proposed as an energy storage means for two purposes. One is for seasonal or diurnal peakshaving purposes, and the other is for a transportable fuel for vehicle use. Natural gas is already used for both of these purposes as LNG, although its use for vehicles is limited at present and is developing only slowly. We therefore compare the relative hazards of LH_2 and LNG. Because of its significant use as a rocket propellant, a great deal of experience has been obtained with LH_2 and one finds abundant information on its hazards and handling procedures.

Table VIII-2 cites some properties of LH_2 and LNG about their relatively hazardous natures.

Table VIII-2. COMPARATIVE PROPERTIES OF LIQUID HYDROGEN AND LIQUID NATURAL GAS

	LH_2	LNG
Melting Point, ^0F	–434.6	–296.4
Boiling Point, ^0F	–422.9	–258.5
Critical Temp, ^0F	–400	–117
Critical Pressure, atm	12.98	45.8
Specific Gravity of Liquid, water = 1.0	0.07	0.47
Specific Gravity of Liquid, lb/cu ft	4.43	26.5
Viscosity, poise	182×10^{-6}	1400×10^{-6}

In the liquid state, hydrogen has a very low viscosity and will leak through a ruptured tank at a high rate. However, the chance of a tank failure is remote, since hydrogen must be stored in double-walled vacuum-insulated dewars, with the evacuated space normally filled with "Perlite" insulation. This construction is inherently strong, and the inner container is protected from corrosion.

The normal storage temperature of liquid hydrogen is far lower than for LNG, below –423^{0}F, and this factor creates a significant and unique hazard. This temperature is low enough to liquefy all other gases except helium. Thus, any part of a hydrogen tank or transfer line that becomes cooled to this temperature and is exposed to air will liquefy the air. Because of the slight difference in boiling points between oxygen and nitrogen, the resulting liquid will become enriched in oxygen. Thus an improperly insulated LH_2 line can cause oxygen buildup with a consequent dangerous fire hazard. For this reason, all flammable materials, including asphalt pavement, must be excluded from the vicinity of an LH_2 installation. In addition, foam insulation cannot be used for liquid hydrogen pipes or tanks unless the voids within the foam are purged with either hydrogen or helium, the only gases that will not condense. Any air that leaks into the insulating space can cause a fire hazard due to oxygen concentration by liquefaction.

Any line or container to be filled with hydrogen as a gas or liquid must first be purged with an inert gas. Because of the capability of LH_2 to liquefy nitrogen, a nitrogen purge is often considered unsatisfactory, especially where 100% purity of hydrogen in the system must be maintained. Helium is therefore considered as a purge gas. The NASA report,[8] "Handling Hazardous Materials," states with emphasis, "Because of its scarcity, helium should be used only where absolutely necessary." In all three large-scale LH_2 storage tanks that we have inspected in this study, helium is used as a purge gas. Nevertheless, nitrogen purging will quite likely prove adequate for commercial handling of LH_2 used as a fuel. Linde uses nitrogen in its own liquid hydrogen commercial operations.

During transfer operations, and particularly during chilldown operations, hydrogen gas evolves and must be vented safely. A flare stack is normally provided for this purpose. In two LH_2 facilities at Cape Kennedy and at Brookhaven National Laboratory, the "flare stack" was a mere 100 feet from the storage tank. Although hydrogen was not ignited in these instances, this procedure is contrary to NASA-recommended (1965) practice. An earlier (1961) Bureau of Mines' study indicated that stacks used to dispose of excess hydrogen should be allowed to vent freely, but the gas should not be ignited.[16]

LH_2 is routinely delivered in rail tankers (11 tons) and road tankers to central storage tanks. Transfer operations are carried out by trained personnel who are present during the transfer. Remote control of LH_2 transfer is only used when filling rocket fuel tanks, for these are fragile, uninsulated, and filled while liquid oxygen is present. These handling and transfer practices have been well established and proved. Seemingly, all problems can be overcome by following established practice.

2. Established Safety Codes for Liquid Hydrogen

NASA and the Air Force have established safety practices and procedures for the handling of liquid hydrogen. Because much of the liquid hydrogen used in the space program was manufactured far from the sites where it was to be used, procedures to ensure its safe transportation over public roads and railways had to be developed. More recently, the manufacturers, especially Linde and Air Products, have developed a commercial business of supplying bulk hydrogen to industrial customers as a liquid. From this basis, regulations, specifications, and standards have been formulated. ASME, TCG, and NFPA have codes concerning the specifications for equipment, shipping regulations, and installation standards for liquid hydrogen containers, road trailers, tank cars and storage stations; they are summarized in Appendix VIII-B.

D. The "Public Image" of Hydrogen

1. The "Hindenburg Syndrome"

Whenever the prospects of using hydrogen as a domestic fuel are raised for the first time in open discussion, people who fear the danger of hydrogen fires or explosions immediately respond negatively. Hydrogen has obtained a bad reputation; much of this can be traced to the spectacular fire that destroyed the airship Hindenburg in 1937 at Lakehurst, New Jersey. This almost universal fear of hydrogen has been called the "Hindenburg Syndrome." (The team of enthusiasts who built a hydrogen-oxygen-fueled automobile at Perris, California, in 1970, coined the term in a confrontation with the public and local authorities.) Another, equally unjustified association many make is that hydrogen is the "stuff used in hydrogen bombs."

Although we, who have given serious and detailed consideration to hydrogen safety, may view this with some amusement, the public relations' task to sell the general public and local authorities on the acceptability of gaseous hydrogen as a fuel is important and essential. We must ensure that the "environmentalists," who are having such a dramatic effect on the siting of nuclear plants and on the erection of electric transmission lines, do not take an equally hostile attitude toward hydrogen pipelines and equipment on the basis of unjustified fear.

Let us look into the factors surrounding the Hindenburg disaster of 1937 and put them into proper perspective. The publicity and newsreels of the time documented the fire that completely destroyed the 837-foot-long aircraft in just over 1 minute. The emotional effect of this on the many spectators present was great and is reflected in the famous eyewitness description that is often repeated over the radio and TV channels.

The Hindenburg was designed to operate on helium. Unable to get helium from the U.S., the Germans had to make do with hydrogen, and the hand-operated valves for venting gas to bring the ship down were left in place inside the hull, exhausting into 70-foot-high air shafts reaching to the top of the ship.

The Hindenburg had flown through a thunderstorm immediately before approaching Lakehurst, N.J. It had vented hydrogen about 10 minutes before the fire to bring it down to the mooring. Immediately before the fire occurred, a steel mooring line was lowered to the ground, thus creating a 200-foot-high lightning arrester.

Today's safety regulations for hydrogen consider such a situation extremely hazardous and would prohibit it. A publication entitled Balloon and Airship Gases,[4] published in 1920, 17 years before the Hindenburg disaster, warned specifically about descending rapidly in thunderstorm conditions, venting hydrogen under such conditions, and the danger of trailing wires and antennas.

Fire destroyed the Hindenburg with its more than 7 million cubic feet of hydrogen in just over 1 minute; 36 people were killed. What does not get reported, however, is that 65 people on board survived. Their fortunate escape was partly caused by the unique properties of hydrogen: The fire did not produce a great deal of radiant energy, and the fireball of burning hydrogen once released, rose rapidly upward. In comparison with today's major aircraft disasters, the Hindenburg fire rates low in severity. That the Hindenburg made 10 round trips to Lakehurst and 8 to Rio from its home port in Germany prior to the accident is also not usually recognized.

In retrospect, that the Hindenburg would not have been destroyed if it had not carried hydrogen is certainly true; but the magnitude of the disaster and the hazards of hydrogen have been exaggerated, especially in the light of modern techniques of handling hydrogen.

The constant association of violent and spectacular fires with the use of hydrogen in any form remains, however. The widespread use of hydrogen-rich manufactured gas as a domestic fuel up to about 1955 in the U.S. and until quite recently, in Europe, should be enough to convince people of the reasonable safety in hydrogen. Unfortunately, while "everybody" knows that the Hindenburg contained hydrogen, remarkably few people associate manufactured gas with hydrogen.

2. Education Necessary

An intelligent and aggressive education campaign will have to begin to "sell" the public on allowing hydrogen to be piped under its streets and into its homes. It is not clear how this should be carried out, but it will be needed if a positive approach is going to be made toward the conversion of the present gas system to hydrogen.

While the electric utilities are actively interested in the use of hydrogen as a means of bulk energy transmission, they are not enthusiastic about delivering hydrogen to the consumer because they would rather reconvert it to electricity at the substation and sell that instead. They may therefore be among the opponents of domestic hydrogen on safety grounds. We should therefore give much thought and attention to the public relations' work required to make hydrogen acceptable.

Some safe and simple demonstrations should be devised to indicate both the hazards and the relative safety of hydrogen. For example, one can easily demonstrate that a hydrogen-air mixture, ignited in a glass bottle, will explode harmlessly, while a propane-air or acetylene-air mixture, when ignited, will violently shatter the glass.

The production of a hydrogen safety manual for the use of gas industry personnel would be a worthwhile task for the future. The production of educational and public relations oriented movies and other material would be useful. Some readily assembled demonstrations of the use of hydrogen in customer-oriented applications could also provide a source of confidence on the part of the potential user of hydrogen.

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Appendix VIII-A. Hydrogen Safety

Source: Rosen, B., Dayan, V. H. and Proffit, R. L., "Hydrogen Leak and Fire Detection: A Survey," Rep. SP-5092. Washington, D. C.: National Aeronautics and Space Administration, 1970.

CHAPTER 1

Introduction

Hydrogen, in both liquid and gaseous forms, has many industrial uses. Its extreme flammability, however, makes handling and storing hydrogen hazardous to personnel and equipment. A hydrogen flame is nearly invisible in normal lighting, and, the development of sound safety procedures is of continuing importance. During recent years much progress has been made, however, in reducing the hazards encountered in using hydrogen and in accelerating progress in hydrogen fire and hydrogen leak detection. Improved devices and methods have been developed and reported by numerous Government agencies, industrial users, detector manufacturers, and research organizations.

Because hydrogen is both plentiful and useful, its expenditure and diversified use has increased rapidly in recent years. Only a few decades ago gaseous hydrogen was used mainly in laboratory experiments, to fill balloons, to "harden" fats and oils, and to produce intensely bright theatrical spotlights. Liquid hydrogen was little more than a laboratory curiosity. Today, however, hydrogen is used in petroleum processing, hydrogenation processes, welding and brazing, cooling such equipment as electric generators and nuclear reactors, and production of ammonia and other chemicals. Hydrogen is also used in the laboratory now for cryogenic research, and in bubble chambers and targets for nuclear physics investigations. The growth of space technology has led to extensive production and use of liquid hydrogen as a rocket propellant. In addition to these uses hydrogen may be employed in such processes as the rapid charging of storage batteries and electrochemical machining.

In all these applications the hazards attendant to handling and storage are an ever-present problem. Hydrogen accidents continue, with damage ranging from no injuries and slight losses to several deaths and totally destroyed facilities. Hydrogen is highly prone to leakage and, when mixed with air, it readily forms a potentially explosive and easily ignited mixture. The near-invisibility of hydrogen fires burning at leak sites sometimes results in injury to personnel through unexpected contact with the flames or nearby heated objects. The Hindenberg dirigible disaster in 1937 was a dramatic example of the violence and destructiveness of a hydrogen mishap.

Means of detecting hydrogen gas before flammable or detonable mixtures accumulate, and promptly locating hydrogen fires, are needed so that appropriate action may be taken before damage is done. Since detection, in general, is based on sensing one or more of a number of physical properties of both hydrogen gas and hydrogen fires, it is necessary to have a variety of sensors and detection methods. A fairly broad selection of detectors is now commercially available, and more are being developed.

For this survey, several sources of information were used. Pertinent literature was reviewed, and users and producers of hydrogen were interviewed in person or by telephone about hydrogen fire and hydrogen leak detection practices. Visits were made to a diversified group of facilities in which hydrogen was used or handled. Finally, fire and leak detector manufacturers were asked for information regarding their products.

The following industrial plants, NASA installations, and research laboratories were visited: Bureau of Mines, Explosive Research Center, Pittsburgh, Pa.; Langley Research Center, Hampton, Va.; Lewis Research Center, Cleveland, Ohio; North American Rockwell Corporation, Rocketdyne Division, Canoga Park, Calif.; North American Rockwell Corporation, Space Division, S–11 Santa Susana Operations, Santa Susana, Calif.; Standard Oil Company of California, Richmond Refinery, Richmond, Calif.; Proctor and Gamble Company, Port Ivory Plant, Staten Island, N.Y.; Union Carbide Corporation, Linde Division, Liquid Hydrogen Plant, Sacramento, Calif.; Dow Chemical Company, Midland, Mich.; John F. Kennedy Space Center; Princeton—Pennsylvania Accelerator, Princeton, N.J.; and Charles Pfizer Company, Groton, Conn.

Other hydrogen users who were contacted by telephone included: Westinghouse Astronuclear Laboratories, Pittsburgh, Pa.; Shell Oil Company, Martinez Refinery, Martinez, Calif.; Allied Chemical Company, Morristown, N.J.; Humble Oil and Refining Company, Esso Bayway Refinery, Linden, N.J.; Bell Aerosystems, Buffalo, N.Y., and Hercules Powder Company, Salt Lake City, Utah.

The properties of hydrogen and hydrogen flame will be reviewed as background information for the discussion of detection techniques. Some of the hydrogen properties given also indicate both the usefulness and hazards associated with hydrogen. This review of properties will be followed by an examination of methods and devices for detecting hydrogen and findings of recent research. A similar examination of hydrogen fire detection will then be made. In addition to references from the text, a bibliography of related documents useful in the study of hydrogen safety and detection, is included.

CHAPTER 2

Properties of Hydrogen

Knowledge of the essential properties of hydrogen is required to understand the principles involved in the devices discussed later in this survey. The most important properties fall into three categories: (1) the physical and chemical properties of liquid and gaseous hydrogen, (2) hydrogen combustion properties, and (3) the physical properties of hydrogen fires.

LIQUID AND GASEOUS HYDROGEN

Liquid hydrogen is a transparent colorless liquid. Since it is usually in contact with, or near, materials that are at temperatures above its boiling point, gaseous hydrogen is present whenever a liquid leak occurs. Hydrogen gas is colorless, odorless, nontoxic, and noncorrosive.

The physical and chemical properties of hydrogen have been described in numerous textbooks, handbooks on hydrogen (refs. 1, 2), an earlier NASA Technology Utilization Survey (ref. 3), and several hydrogen safety manuals (refs. 4, 5). An excellent summary of the physical and chemical properties of hydrogen that are pertinent to the nature of the hazards of hydrogen leaks and fires is given in the appendix of the Bureau of Mines technical report on hydrogen safety (ref. 4).

Nature of the Leak Problem

Liquid hydrogen is an extremely low-temperature fluid. (Only liquid helium has a lower boiling point.) Its low temperature causes thermal contraction of confining materials, thereby creating incipient leaks and, at times, catastrophic failure of confining equipment. The parts most liable to develop leaks are the flanges, connections, or joints of transfer lines through which liquid hydrogen flows intermittently, resulting in numerous temperature cycles from ambient down to 20° K (normal boiling point of hydrogen). Even when lines are precooled with liquid nitrogen (boiling point, 77° K), the thermal shock is relatively large.

The small size of the hydrogen molecule permits it to leak through air-tight seals and escape from systems that appear leak-free when tested with more conventional fluids. The viscosity of liquid hydrogen also contributes significantly to the leak problem. At its boiling point, the viscosity of hydrogen is lower than that of most cryogenic liquids. Because leakage is inversely proportional to viscosity, leakage of liquid hydrogen will be roughly 12 times that of liquid nitrogen and 14 times that of liquid oxygen. Gaseous hydrogen also is particularly subject to leakage, being about twice that of nitrogen or oxygen.

Because of the low molecular weight of hydrogen gas, it has a very high diffusion coefficient (ref. 6). As a result, hydrogen in an open area diffuses to nonexplosive mixtures very rapidly; a spill of 500 gallons of liquid hydrogen in an unconfined area will diffuse to a nonexplosive mixture in about one minute. This rapid diffusion, however, makes leak detection difficult, since a concentration of gas will not build up at the leak exit. The problem is compounded further by the buoyancy of hydrogen gas. When its temperature is that of the ambient air, its density is only $1/14$ that of the air density. Thus, the properties of diffusivity and buoyancy make it very difficult to locate the exact site of a leak.

Properties Used in Hydrogen Leak Detection

Although hydrogen will react violently with strong oxidizers, such as oxygen, it is not hypergolic with oxygen (i.e., usually an ignition source is required). As a result, flammable mixtures of hydrogen and air can exist in the absence of an ignition source.

Hydrogen gas can be combusted catalytically on a heated filament at temperatures below the ignition temperature of hydrogen and air. At present, this is the most common property of hydrogen used in commercial hydrogen leak detectors. The thermal conductivity of hydrogen gas is the highest of all known gases. Very small amounts of hydrogen in air will cause a significant increase in the thermal conductivity of the gas mixture.

Palladium has long been known to be an absorber of large volumes of hydrogen. At 80° C and 1 atmosphere of pressure, palladium absorbs up to 900 times its own volume with the evolution of considerable heat. When the palladium is in the form of a thin film, the electrical conductance of this film is a function of the partial pressure of the hydrogen concentration. These two properties of hydrogen with palladium have been studied recently under separate NASA-supported programs in the development of specific sensors for hydrogen.

The difference in the refractive index of hydrogen from that of air has been the basis for another hydrogen leak detector. At 0° C and 760 mm of pressure, the refractive index of air is 1.0002926, while that of hydrogen is 1.000132. An optical interferometer has been used to detect small changes in refractive index. Other investigations based upon the electrochemical consumption of hydrogen and the fuel cell principle have been made recently.

Because of the continuing growth of hydrogen usage in both aerospace and nonaerospace industries, it seems likely that efforts to find accurate, specific, sensitive, and more reliable hydrogen leak detection devices will continue.

HYDROGEN COMBUSTION PROPERTIES

The principal reason for considering hydrogen a hazardous material is its flammability and detonability in air over a wide range of conditions. Hydrogen combustion has been the subject of much study. Lewis and Von Elbe's basic text (ref. 7) presents a thorough summary of combustion phenomena, including some data on hydrogen combustion. References 7 and 8 are valuable compilations which concentrate on hydrogen combustion properties. References 4, 9, and 10 contain summaries of properties relating to the combustion hazards of hydrogen in air.

A mixture of hydrogen and air may be ignited in several ways, and the resulting flame may propagate in various ways. The conditions affecting the ignition characteristics include: contents of the gas mixture, temperature, pressure, geometry of the surrounding walls, ignition energy and, in some cases, gas velocity. Such conditions determine whether there will be no ignition, a stationary flame at a source of hydrogen gas, a deflagration through a volume of gas, or a detonation. Ignition sources may be a hot solid body, a flame or other hot gas, an explosive charge, or an electric spark.

Combustion can propagate through a hydrogen air mixture either as a deflagration, a deflagration which grows to a detonation, or as a detonation from the start of ignition. (A deflagration is a flame propagating at subsonic velocity, whereas a detonation produces a shock wave propagating at supersonic velocities.) In a confined space, a deflagration can raise the pressure by about a factor of 7—enough to cause some structural damage. A detonation can cause a very rapid rise in pressure by as much as 20 times the initial pressure (ref. 4). Either of these processes may be accompanied by a sound (sometimes very loud), and the term "explosion" is applied to both processes. "Flammable" applies to a mixture in which any type of combustion can propagate.

Flammability Limits

Hydrogen has a wide range of flammable mixtures with air, being exceeded only by acetylene and hydrazine (ref. 11). The usually recognized upper and lower flammability limits for hydrogen in air saturated with water vapor at ambient temperature and pressure are 74 and 4 percent hydrogen by volume. The 4-percent hydrogen concentration point is called the lower explosion limit (LEL).

Flammability limits are affected by pressure, temperature, and the presence of inert diluents. As the pressure is raised above atmospheric, the range of flammable mixtures narrows up to about 5 atmospheres, then gradually widens as the pressure is raised (ref. 8). As the pressure is lowered, the limits of flammability narrow (refs. 12, 13). Raising the temperature of the gas widens the flammability limits (ref. 12).

The addition of inert gases to hydrogen-air mixtures narrows the flammable range in a manner dependent upon the inert gas. Compared to the effects with hydrocarbons, nitrogen and carbon dioxide are less effective in reducing the flammability of hydrogen in air. For instance, the fuel-lean limit is hardly affected by addition of up to 60 percent CO_2 by volume (ref. 8). Enrichment by oxygen raises the fuel-rich limit. The rich limit of hydrogen in pure oxygen is about 96 volume percent (ref. 12).

Flame Speed

Flame velocities in hydrogen-air mixtures are given in reference 8. The maximum velocity is about 300 cm/sec, compared to about 40 cm/sec for methane and propane.

Ignition Energy

The energy required to ignite a mixture near the stoichiometric ratio is quite low, but increases as the flammability limits are approached. The minimum ignition energy required increases as the pressure is lowered (ref. 8). This energy is about one tenth that required to enflame most hydrocarbons. An electrostatic discharge which can hardly be seen or felt can ignite a hydrogen-air mixture (ref. 9). The ease with which hydrogen ignites with air contributes to the burning of accidental leaks of hydrogen. Although no ignition source may be apparent, hydrogen leaks and unflared hydrogen vent stacks often ignite. It is assumed that a small discharge of static electricity is usually responsible, but this has not been conclusively proved (ref. 14). The autoignition temperature is quite high, about 1075°F, compared to 400° to 666° F for most hydrocarbons.

Detonation Limits

The range of detonable mixtures of hydrogen in air is 18 to 59 percent hydrogen by volume. Therefore, not all flammable mixtures are detonable. The occurrence of a detonation wave is dependent upon conditions of confinement, and is especially likely when the mixture is near-stoichiometric, the ignition source is strong, there are confining walls, and the flame path is long. Even partial confinement of hydrogen, for example, by four walls, can allow initiation of detonation (ref. 4). These reactions can be quite violent and destructive, and numerous examples of the damage that can be done are given in the literature (refs. 10, 15, 16). Detonation velocities are shown in reference 8.

Quenching Distance

When the dimensions of a passage or enclosure containing the gas mixture become small, the heat transfer and/or active particle loss can become great enough to prevent propagation of a flame. When a gas mixture has a certain temperature, pressure, and composition, a resulting flame cannot pass through openings smaller than some minimum size, which is called the quenching distance. This distance depends on the geometry of the passage, but apparently not on the nature of the surface. Most laboratory measurements of quenching distance are for flames propagating between parallel plates. The dependence of quenching distance on hydrogen concentration and pressure is illustrated in reference 8. By comparison, at atmospheric pressure, the minimum quenching distance for hydrogen in air is 0.06 cm, and for propane in air it is 0.2 cm. The quenching distance also decreases with increasing temperature.

These results are applicable to flame arrestors or flame traps to stop a flame from passing from one place to another. It is of great importance to have adequate flame arrestors in electrical equipment operated around a flammable hydrogen-air mixture. This has been a problem with some leak detectors having flame traps that were acceptable for hydrocarbons but not for hydrogen; they can serve as ignition sources, an obviously dangerous situation. In practice, workable flame arrestors must have openings even smaller than the minimum quenching distance, because there may be a large pressure gradient driving the flame and hot gas toward the arrestor. Fine mesh screens often are used to arrest hydrocarbon-air flames, but the problem is more difficult with hydrogen. Sintered metal, particularly bronze, has been found fairly effective as a flame stopper without greatly impeding the flow of gas (ref. 4). Whether any screen or porous metal practical for leak detectors can fully stop a detonation is in doubt. The considerations of quenching also apply to explosion-proof electrical equipment (including fire detectors), which must be mechanically strong and have close-fitting covers so as not to allow combustion to propagate from inside the equipment to the outside (ref. 9).

PROPERTIES OF HYDROGEN FIRES

Hydrogen fires and explosions have certain physical properties by which they may be detected. They have fewer observable characteristics than fires involving hydrocarbons, however, and this limits the choice of sensors for hydrogen fire detection.

Flame Temperature

Hydrogen burns in air with a flame that is comparable in temperature to that of most hydrocarbons. For a premixed flame of 43 percent hydrogen in air, the temperature is 3680° F, compared with 3400° F for methane, 3500° F for propane, and 4215° F for acetylene. A diffusion flame, such as that occurring at the site of a hydrogen leak, burns at about 3000° F (ref. 4). These comparative figures indicate that overheat fire detectors should work as well for hydrogen fires as for ordinary fires.

Smoke and Ionization

Pure hydrogen flames burn without smoke. The ionization of hydrogen-air flames is several orders of magnitude lower than that of organic flames, which typically have 10^7 to 10^9 ions cm^3 (ref. 17). Hydrogen flame ionization is so low, in fact, that it is extremely difficult to measure, and can be ruled out, at present, as a detectable flame property.

Noise

Stationary flames on open burners produce some acoustic noise. Except for large-scale combustion, such as in jet engines, there has been little study of this phenomenon. The sound from both premixed and diffusion flames increases rapidly as the gas flow increases enough to cause turbulence, and the noise of a burning mixture is greater than from a jet of an unignited gas (ref. 17).

Optical Radiation

The total electromagnetic radiation emitted from hydrogen-air flames is lower than from many organic flames by a factor of about 10. Values of emissivity (ratio of emitted radiation to that of a perfect radiator, or blackbody, at the same temperature) have been given variously as 0.01 to 0.1. These variations probably result from different measurement conditions, variations in the atmospheric absorption of the radiation, and different estimates of flame size and temperature (ref. 9). In any case, the total heat radiated by hydrogen fires to personnel and structures is significantly less than is radiated from other, more familiar fires.

For purposes of fire detection, a more important consideration than total radiation is the spectral distribution of the radiation; that is, the amount of radiation emitted in the various wavelength regions of the electromagnetic spectrum. The optical radiation from pure hydrogen-air flames comes almost entirely from two kinds of molecules, OH and H_2O. These molecules emit ultraviolet and infrared radiation, but neither emits appreciable visible light. The visible light from hydrogen flames comes most from impurities, particularly sodium. Pure hydrogen flames usually can be seen if the surroundings are quite dark; but even with moderate illumination they can be seen only by variations in the transmitted light or "heat wave." Even when the flame location is known, or when it contains some impurities, hydrogen fires often cannot be seen.

OH Radical Radiation.—The hydroxyl radical, OH, is a short-lived intermediate product in the combustion process. Its principal emission is in the ultraviolet. OH emission is in the form of bands, that is, collections of spectral lines. There are seven principal OH bands with heads at wavelengths of 3428, 3124, 3064, 2875, 2811, 2677, and 2608 Å ($1 \text{ Å}=10^{-10}$ m). The most intense bands are at 3064 and 2811 Å, and are shaded toward the red. In hydrogen flames, this radiation appears to arise mainly from thermal excitation, and is much weaker than OH radiation from the reaction zones of hydrocarbon flames. This radiation comes principally from the reaction zone, and disappears almost immediately when the flame is extinguished, although the hot gases still remain. The appearance of these OH bands on the film of a spectrograph is discussed in reference 18. A low-resolution spectral scan of relative intensity vs wavelength is discussed in reference 19. Very little data are available on the weak radiation from hydrogen-air flames between 2000 and 2600 Å (ref. 20). Information on spectral distribution is useful for fire detection because it shows the distribution of radiated energy. If the ultraviolet emission is to be detected, this spectrum can serve as a guide to the necessary spectral response of the sensor or sensor-filter combination.

A quantitative measurement of the power radiated from hydrogen flames in the ultraviolet is necessary to specify the size of the flame that can be detected and the requisite sensitivity of the detector. For fire detection, the radiant intensity (that is, the power radiated into a unit solid angle) is a convenient quantity. The power incident upon a detector or its collecting optics can be calculated for a given size of fire at a given distance, if the radiant intensity is known. Measurements of ultraviolet radiant intensity from hydrogen-air diffusion over the spectral range of 2200 to 4000 Å have been reported in reference 19. Results for three burner sizes and a range of hydrogen flowrates have been determined. There is no accepted standard size of fire or detection distances used to specify the response of fire detectors.

The ultraviolet emission from hydrogen-air diffusion flames also has been studied as a function of ambient pressure (ref. 19). It has been determined that the ultraviolet radiant intensity increases as the pressure is lowered. At about 60 mm Hg, it is over three times its value at atmospheric pressure. The radiant intensity then drops rapidly from 60 to about 15 mm Hg.

H_2O radiation.—Water is the final combustion product of hydrogen and air. Almost all its radiation is emitted in the infrared region of the spectrum, with some very faint bands in the deep red part of the visible region. The H_2O bands of interest in fire detection occur at about 1.4, 1.9, and 2.7 microns (1 micron $= 10^{-6}$ m). Other H_2O radiation bands are located at about 0.65, 0.72, 0.8, 0.9, 1.1, and 6.3 microns. The bands are fairly wide and generally do not have well defined heads as do the OH bands, so these wavelengths are only approximate. The intensity increases with wavelength up to 2.7-micron band, which is by far the strongest band in the water spectrum. The bands extending into the far infrared are weaker and, at present, are inconvenient to detect (detector considerations). Some of these bands are shown in ref. 21. (It should be remarked here that cooler water vapor in the atmosphere also absorbs part of the radiation in these bands. This will be discussed in the chapter on hydrogen fire detection.)

The radiant intensity of a hydrogen-air flame in the 2.2- to 2.7-micron range is shown as a function of ambient pressure in reference 19. The level of infrared emission is fairly constant from atmospheric pressure down to about 100 mm Hg, then decreases steadily as the pressure is lowered further.

Time-varying radiation. Another important characteristic of optical emission from flames is the time-varying component. The light output from flames at atmospheric pressure is not steady, but is modulated at a set of frequencies determined by various flame parameters. This time-varying component, analyzed for frequency, is discussed in reference 13. These plots of signal amplitude vs frequency are variously called ac spectra, modulation spectra, or flicker spectra. The data were obtained by analyzing the tape-recorded output from an ultraviolet-sensitive radiometer viewing the various flames. No significant difference in the frequency content of infrared and ultraviolet modulation spectra has been observed. This time-varying component of flame emission can be used as a basis of discriminating flame light from the light emitted by nonvarying sources. However, expected output levels of this ac component are not well known for various conditions that might be encountered. There is both a lack of experimental data and little understanding of flicker phenomena and the functional dependence of frequency and amplitude upon various factors such as rate of flow, burner size, gas composition, and ambient pressure. Another way in which radiation depends upon time is displayed by hydrogen-air explosions. As a flame is ignited in a gas mixture, its emitted radiation increases rapidly with time.

TABLE 3.—*Survey of Hydrogen Fire and Leak Detection Practices*

Type of facility	LH$_2$ or GH$_2$	Inside or outside	Pressure and/or temperature	Capacity and/or usage	Leak check methods	Portable hydrogen detectors (principle)	Fixed hydrogen detectors			Hydrogen fire detectors	Remarks
							Principle	Sampling heads	Number of heads		
Storage	GH$_2$	Out	2000 and 600 psi	120,000 cu ft (2 trailers)	Soap bubbles when connecting trailers; tape around flanges, look for ruptures or bulges	None	None	--------------------		None	Considering hydrogen detection tapes.
Test cell, mixing characteristics	GH$_2$	In	600 psi	About 0.1 lb/sec	Unperforated tape around flanges, semi-permanent leak-detecting system	None	None	--------------------		None	
Production and use of hydrogen for catalytic hydrocracking	GH$_2$	Out	---------------	Several million cu ft/day	Tape and bubble liquid	Catalytic combustion (2 manufacturers)	None (except tape)	--------------------		None	Hydrogen produced is not pure; therefore, flames are somewhat easier to see than pure hydrogen flames.
Liquid hydrogen facility	Both	Both	From 1900° F at 250 psi to 40.5 R at 10 psi	200,000 gal/day 680,000 gallons storage	Bubble compound and tape with punched holes	Catalytic combustion (2 manufacturers	Catalytic combustion	Aspirated	12	None	Detectors also used for other combustible gases. Fixed head locations: liquifier, chemistry laboratory, control room, propane compressor, and electrical power room. Alarm at 25 and 40 percent LEL.
Hydrogen production for hydrogenation processes	GH$_2$	Both	1600° to 2000° F at about 200 psi, to ambient temperature, 0.4 psi	10 to 15 × 10^3 cu ft/mo 150,000 cu ft storage	----------------------	Catalytic combustion	None	--------------------		None (ultraviolet sensor used as furnace flame monitor)	
Research laboratory	LH$_2$	In	1 to 5 atmospheres	Few thousand gallons	Portable detectors	Catalytic combustion	Catalytic combustion	Diffusion	≃50	Overheat detectors in building	Warning and alarm concentrations at 4 and 10 percent LEL. Automatic shutdown of experimental electronics near hydrogen and activation of high-speed fans.
Hydrogenation and other processes	GH$_2$	Both	1 atmosphere to 100 psi; one operation at 2000 psi	30 × 10^6 cu ft/year. Storage about 50,000 cu ft	Pressure decay and soap bubbles	Ultransonic	None	--------------------		None (sprinkler system in buildings)	
Propulsion laboratory	GH$_2$ (from LH$_2$)	Both	GH$_2$ at 3500 psi	2 × 10^6 gal/year LH$_2$ (vaporized)[2] 100,000 gallons storage	----------------------	------------	Catayltic combustion	Aspirated	4 or 5 in each room	None	Alarm at 50 percent LEL, if detected by at least two sampling points in a given indoor area. Sampling points in upper part of room.
Heat transfer laboratory	Both	Out (Partially enclosed)	GH$_2$—up to 2000 psi at 500° F. LH$_2$—up to 4000 psi	200 gallons, LH$_2$	Portable detector	Catalytic combustion	None	--------------------		None	Flares used in test areas to ignite accidentally escaping hydrogen.
Storage (at least ½ mile from other facilities)	LH$_2$	Out	---------------	26,000 gallons permanent; 150 to 5000 gallons portable dewars	Visual observation of frosting during transfer	None	None	--------------------		None	
Storage facility (50 to 500 feet from test facility)	LH$_2$	Out	---------------	20,000 gallons	----------------------	------------	Catalytic combustion	Diffusion	2	Thermal type triggers deluge system	One sensor over storage tank, one over vent stack.

TABLE 3.—*Survey of Hydrogen Fire and Leak Detection Practices*—Continued

Type of facility	LH_2 or GH_2	Inside or outside	Pressure and/or temperature	Capacity and/or usage	Leak check methods	Portable hydrogen detectors (principle)	Fixed hydrogen detectors			Hydrogen fire detectors	Remarks
							Principle	Sampling heads	Number of heads		
Shock tube research	GH_2	In	5000 psi (intermittent)	—	—	—	Catalytic combustion	Diffusion	5	None	Sensor location: (1) one at highest point in room, 12 to 15 feet above equipment; (2) three along tube about 4 inches above it; and (3) one in exhaust vent.
Brazing furnace	GH_2	In	≈.1 psi at 1200° to 2000° F.	3000 cu ft/hr maximum	Bubble compound and portable detector	Thermal conductivity	None	—	—	None	Leaks at high temperature occur in container inside furnance above auto-ignition temperature.
Storage	GH_2	Out	2000 psi	—	—	None	None	—	—	None	
Propulsion research	Both	Out (Partially enclosed)	—	~250 gallons LH_2	Portable detector	Catalytic combustion	Catalytic combustion	Diffusion	4	None	Sensors under roofs at, or near, hydrogen areas.
Production and use of hydrogen for hydro-cracking	GH_2	Out	—	Millions of cu ft/day	Breaks in plastic tape; portable detectors	Catalytic combustion (2 models)	None	—	—	None	Visual detection of accidental fires; small fires seen at night. Leaks sometimes diluted with steam.
Flame studies laboratory	GH_2	In	—	Small	—	—	Catalytic combustion	Diffusion	4	None	Placement: three sensors in laboratory—two in corners (14 feet above floor), one above burner; one sensor in control room.
Storage	LH_2	Out	—	200,000 and 20,000 gallons	—	None	None	—	—	None	
Rocket engine test	Both	Out	1500 psi	50,000 gallons	Helium-pressurized bubble compound; portable detector	Catalytic combustion	Catalytic combustion	Diffusion	2	Infrared television	Sensor heads attached to cable; can be moved and repositioned around test facility.
Pump and high-pressure storage	GH_2	Out	5000 psi	8-inch by 30-foot bottle	—	None	None	—	—	None	
Shock tube (under construction)	GH_2	In	12,000 psi up to 600° K	—	—	—	Catalytic combustion	Diffusion	—	None	
Compressor for pipeline system	GH_2	Partially enclosed	5000 psi	—	—	—	Catalytic combustion	Diffusion	4	None	Sensors above compressors and in roof. Replace aspiration-head system.
Rocket engine testing	LH_2	Both	—	15,000 gal/mo	—	Catalytic combustion	Catalytic combustion	Aspiration	8	Flame monitor in exhaust scrubber	Sampling points 0 to 100 feet from analyzer: (1) one 10 feet over LH_2 run tank; (2) one 12 feet over engine; (3) four in exhaust scrubber; (4) one in fuel pit, and (5) one in GH_2 storage pit.
Storage and LH_2 vaporizer	Both	Out	—	5000 gallons, plus 20 GH_2 bottles (2 by 20 feet)	—	—	Catalytic combustion	Diffusion	3	Thermal detectors trigger extinguisher	Diffusion heads over storage tank, vent stack, and vaporizer.
Production and use of hydrogen for reaction processes	GH_2	Both	From 3 to 8 psi at ambient temperature; to 5000 psi at 900° F.	7 × 10^6 cu ft/day 100,000 cu ft storage	—	Catalytic combustion; ultrasonic	Catalytic combustion	Aspiration	4	None	Alarm at 20 percent LEL, automatic shutdown of certain apparatus for a local concentration of 40 percent LEL.

TABLE 3.—*Survey of Hydrogen Fire and Leak Detection Practices*—Continued

Type of facility	LH_2 or GH_2	Inside or outside	Pressure and/or temperature	Capacity and/or usage	Leak check methods	Portable hydrogen detectors (principle)	Fixed hydrogen detectors			Hydrogen fire detectors	Remarks
							Principle	Sampling heads	Number of heads		
Launch complex for space vehicles	Both	Out	----------	Hundreds of thousands of gallons	----------	----------	Catalytic combustion	Diffusion	$\simeq$154	Ultraviolet fire detectors; G–M tube (about 60); thermal wire at flanges; etc. (42)	Output of each sensor to panels in control center and to event recorder. Hydrogen detectors alarm at 25 percent LEL. Infrared television being considered.
Cryogenic testing of materials, (six, open test cells)	LH_2	Both	Ambient pressure	2000 gal/mo	----------	Catalytic combustion	Catalytic combustion	Aspiration	6	Ultraviolet sensor (furnace-monitor type) at one enclosed test cell for fire detection	Fixed leak detectors, one above each cell, indicate when area is safe to enter (less than 20 percent LEL).
Rocket engine and structural testing	Both	Out	----------	Hundreds of thousands of gallons	----------	Catalytic combustion	Catalytic combustion	Diffusion	----------	Ultraviolet fire detectors (G–M tube); thermal wire	Only false fire alarm due to welding torch.
Testing of rocket engine at simulated altitude	LH_2	In	----------	----------	----------	----------	Catalytic combustion	Aspiration	----------	Considering infrared television	
Hydrogenation processes	GH_2	Both	9 to 15 psig and 150 psig	$\simeq$30,000 cu ft/hr	Soap bubbles	Ultrasonic; catalytic combustion	None	----------	----------	None	Some difficulty with ultrasonic detector due to background noise level.
Production and use of hydrogen in hydrocracking and other processes	GH_2	Out	Up to 3000 psi at several hundred °F.	Up to 14 × 10^6 cu ft/day	Tape, tape with holes, and bubble compound	Catalytic combustion	None	----------	----------	None	Visual detection of fires, usually at night.
Propulsion test all (combustion studies)	GH_2	In	600 psi	Up to 1 lb/sec for 15 or 20 seconds	----------	----------	Catalytic combustion	Diffusion	1	Ultraviolet flame detector used to ensure ignition	Rapid air flow causes false alarms from fixed H_2 sensor; helped by wrapping head with asbestos cloth. Head is 10 to 20 feet above and to side of flame area.

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Appendix VIII-B. Regulatory Codes for the Distribution of Hydrogen

Table VII-B1 summarizes the basic documents necessary to design and build hydrogen equipment and to transport and store gaseous and liquid hydrogen. The equipment specifications outline requirements for the type, size, service pressure, and temperature of the respective vessel. The functional requirements, design details, and manufacturing methods are then established around these equipment specifications. Shipping regulations cover the required operating procedures as they relate to the movement of equipment over the rails and highway. Installation standards provide basic guidelines about functional requirements, performance, and operating characteristics for equipment located on a customer's property. Applicable use of these guidelines provides equipment that will safely contain and distribute hydrogen.

Table VII-B1. REGULATORY GUIDELINES FOR DISTRIBUTION OF HYDROGEN

Distribution Method	Equipment Specifications	Shipping Regulations	Installation Standards
Liquid Cylinder	TCG 173.57	TCG 173.316	NFPA 50B
Liquid Trailer	ASME/(Ref. CGA 341)	Special Permit	--
Liquid Tank Car	TCG 173.316	TCG 173.316	--
Liquid Customer Station	ASME	--	NFPA 50B
Gas Cylinder	ASME/TCG 178.36-.37	TCG 173.301	NFPA 567
Gas Cylinder Trailer	ASME/TCG 178.37-.37	TCG 173.301	NFPA 567
Gas Pipe Line	ANSI B31.8	--	DOT Title 9 Part 192

Source: Martin, F. A., "The Safe Distribution and Handling of Hydrogen for Commercial Application." Paper prepared for the Intersociety Energy Conversion Engineering Conference, San Diego, Septemper 1972.

IX. CONVERSION AND IMPLEMENTATION

A. Introduction

At the outset of this study, we boldly assumed that the whole U.S. gas industry would be converted to pure hydrogen. This assumption was useful for the "scenario" and to identify some of the advantages and the problems of such a system. However, we know that it is quite impossible to carry out such a changeover without a severe disruption of the industry. How then can we implement a hydrogen system? This section discusses some of the problems that we anticipate and outlines some approaches to bring about widespread use of hydrogen as a fuel.

B. Problems of Nationwide Conversion to Hydrogen

Some of the problems of conversion of the U.S. gas system which immediately come to mind are as follows:

- Almost every existing appliance or burner is unsuitable for hydrogen operation and will have to be changed.
- Many metering devices will be inadequate for the increased flows required.
- Hazardous conditions may exist for hydrogen that do not exist for natural gas.
- Sufficient hydrogen generating capacity cannot be instantaneously brought on-line.
- Enormous amounts of natural gas still exist and will continue to be produced.

And so on....

All these problems lead us to think of some stepwise approach to a changeover. This could be carried out by several different techniques.

C. Mixed-Gas Approach

Rather than change from methane to pure hydrogen in one step, suggestions have been made that the change can take place in a series of smaller, acceptable steps by using mixtures of hydrogen and methane during interim periods. Two major problems exist.

One problem is that because of the radically different combustion properties of hydrogen and methane, burner design would have to be modified, even for a mixture. Experimental determination alone would show how much hydrogen could be added to methane before burners have to be changed and how many burner changes would be required during a complete transition. Different burners will likely have a different "tolerance" to hydrogen, so that complete inventories of every burner in each company's area will have to be made and programmed for conversion.

The other problem is that because of the large difference in heating value of hydrogen and methane, the problems of metering energy would be immense. To retain the existing practice of metering gas supply by volume, it will be necessary to state and maintain a given Btu value, thus a given H_2/CH_4 ratio, for a stated period of time, and carry out a 100% meter reading operation each time this ratio is altered.

These are not insuperable problems, but require detailed study. Clearly, from the operations point of view, a small number of large gas-quality changes, preferably only one, should be made. But from the production point of view, a gradual transition from today's almost adequate natural gas supply to a completely adequate hydrogen supply would be preferred.

More practical conversion procedures are described in the following sections.

D. Local Area Approach

To achieve the operating system's ideal of one once-and-for-all change from methane to hydrogen, we can consider taking one local area at a time and carrying out such a changeover. This would require that, at the actual time of change, a full supply capacity of both natural gas and hydrogen is available. To avoid enormous duplication of supply, these local areas would thus have to be quite small, also easing the conversion problem.

Such a changeover in the reverse direction took place in the U.S., more recently in Europe, and is still going on in Britain. Prior to the availability of natural gas, hydrogen-rich town gas was used. Conversion to natural gas was done on a nationwide basis progressively so that each local area was converted separately. Many lessons learned in these conversion programs, which were accompanied by many problems, would be applicable to the change to hydrogen.

There are two very important differences, however, between the situation in the U.S. at the time of the earlier change and today. First, hydrogen will be universally available to any company who chooses to install a generation plant and will not be limited to the rate or location at which new wells or transmission lines can be developed. Thus there will be a greater "geographic" freedom in selecting sites for conversion, but this in turn will require some kind of national conversion policy. Secondly, mobility of families has increased significantly in the last 20 years, leading to vastly increased problems in the adaptation of appliances to different locations. Again, these are not insuperable problems, but require advanced planning. From previous experience in converting from artificial or mixed gas to natural gas, many appliances more than 25 years old were commonly found and created the worst problems.

In converting an area directly from natural gas to hydrogen, preparation of the system is of great importance. Where necessary, additional feeds and sectionalizing valves must be installed to divide the area into workable sections of such size that the anticipated work force can complete the conversion of that section in a single day. With this type of preparation, inconvenience and hazard to customers are minimized. As part of the preparation, all mains and services of doubtful integrity should be replaced or repaired.

Ideally, implementation of the local area approach could be brought about by equipping new premises or new developments with a hydrogen system. If a new city, such as the "Minnesota Experimental City" is built, great efforts by the gas industry to have a hydrogen system incorporated into it would provide valuable experience. Alternatively, any large "new city" planned as part of urban renewal, urban overspill, or rehabilitation projects would also make admirable targets for "nucleating" the hydrogen economy. A number of these "nuclei" will tend to fuse together.

One can probably imagine the northern part of the U.S. converting to hydrogen first, while the southern and western parts would remain on their "local" fossil fuels. Ultimately, the hydrogen "front" would move southward as converting even the fossil fuel production to hydrogen at the wellhead or the mine mouth becomes worthwhile.

E. "Power Transmission" Approach

As an alternative to this local conversion of all customers, with its resultant impact on the "man in the street," we may consider the conversion of some large single users of natural gas, whose consumption is sufficient to justify the installation of new pipelines. A nucleus of established pipelines and large customers could spread out to smaller customers and ultimately to private users.

The most attractive objective for this kind of implementation is the electric power industry. That industry is already faced with tremendous problems of power plant siting, transmission line costs, and pressures to go "underground." It seems a natural step to consider the generation of hydrogen at remote power station sites. Then this gas, together with oxygen if it makes economic sense, can be brought to the load center in underground pipes. Electricity can be regenerated in small dispersed power stations, using either fuel cells or advanced steam turbines. Once such a system would be established, hydrogen-generating capacity could be increased so that customers for hydrogen along the way of the pipeline could be supplied. Ultimately, branch pipes would take care of many more customers, and the local gas distribution system could be hooked up to it. Clearly, such an integration would require planning and cooperation between the gas and electric utilities in an unprecedented fashion.

This mode of implementation, however, seems to be the most likely to occur at present. During the course of this study, we have discussed the hydrogen energy transmission concept with many people and have learned of the enthusiasm and active studies going on at several electric utility companies. In particular, Southern California Edison Co. has had a study carried out by General Electric Co. (Tempo Center for Advanced Studies, Santa Barbara) on this subject. Details are not available to us. Public Service Electric & Gas Co. (New Jersey) is known to be actively interested in the subject, using Professor Tanner of Princeton as an adviser. Reportedly, it is planning an experiment with a Teledyne electrolyzer and a Pratt & Whitney fuel cell in the 10-15 kW range. Northeast Utilities has shown equal interest in the concept and is believed to be working with a consultant firm.

Therefore, the first step in hydrogen energy transmission may likely be taken by the electric utility industry. The gas industry should become part of such an initial entry into the area so that it would gain a foothold in the construction, ownership, and operation of the pipelines and possibly of the generation plant as well.

F. Appliance Conversion

To burn hydrogen in existing appliances with natural gas burners requires modification of almost every burner. While modifications of burners in the field have in the past frequently been made in converting systems from manufactured gases to higher Btu natural gas, the problems when converting in the opposite direction are much more complex.

When converting from a high-hydrogen manufactured gas to natural gas, most of the problems encountered originated in the slow-burning characteristics of natural gas. To accomplish this, measures had to be taken to reduce port velocity so that flames would not lift from the ports. Usually the orifice was adjusted or replaced with a smaller orifice to provide proper Btu input. Burner ports were enlarged, or additional ports were drilled to increase port area. Each special jet-type burner was replaced by its natural-gas-designed counterpart.

In converting from natural gas to hydrogen, the port sizes or numbers must be reduced to speed up the flow and prevent flashback. Modern burners are almost all designed for natural gas using modern construction methods such as punched or die-cast ports. These would be extremely difficult to modify to reduce port areas.

Many modern house-heating and water-heating burners employ single-port burners equipped with flame spreaders or targets to distribute the flame. Such burners, because of their large port area, could be particularly troublesome because of flashback. There could also be a problem because of the high flame intensity destroying the target or flame spreader.

A general conversion of a system currently operating on natural gas to one capable of satisfactory operation on hydrogen would undoubtedly require a great amount of experimental and development effort. From the results of this work done on actual typical appliances, an approximate estimate could be made of a) the number of appliances that could be utilized with only minor field changes and adjustments, b) the number for which new parts would be necessary and available, c) the number that would justify major rebuilding, and d) the number that could not be converted or that would not justify the cost.

One suggested conversion method would be to design a series of "universal" replacement burners that could be substituted for present equipment. The burners themselves would not be difficult to design, but the method of support, connection to existing valves and manifolds, and ignition would be a most difficult task because of the many variations in existing appliance design.

Another plan would be to have the manufacturer of the appliance supply the required parts. This would only be practical if many areas were preparing to convert so that the manufacturer could justify making special runs of hydrogen parts for equipment not currently being produced. Complications of getting the right parts for each particular appliance and cost of installation as well as cost of replacement parts might well exceed the value of the appliance or of a new replacement.

If the changeover to hydrogen could be anticipated to provide a long enough "lead" time — such as 10 years — perhaps all new equipment could be specified to be capable of simple conversion to the use of hydrogen. For example, range burners could be provided with a ring-shaped spacer between the burner head and base casting that would contain additional ports to enable the burner to burn natural gas. When converting to hydrogen, this ring would be removed and discarded, leaving only the ports designed for hydrogen. The long "lead" time would be necessary to ensure that most of the appliances in the field were of the convertible type when it became necessary to change over. Again, previous experience has shown that many appliances more than 25 years old are still in use.

A relatively minor problem, yet one that may cause some concern, lies in the proper venting of appliance regulators. Most appliances are now equipped with appliance regulators to provide a constant input to the burner. For these regulators to function, atmospheric pressure must have access to the chamber above the regulator diaphragm. These vents are commonly restricted so that a gas leak caused by the rupture of the diaphragm would be limited to about 1.5-2 CF/hr. This same vent, however, would allow 4.5-6 CF/hr of hydrogen to escape. Leakage of this amount of hydrogen through the vent could be hazardous, yet an appropriately smaller sized vent would be easily blocked with dirt. One solution might be to use vent restrictors containing check valves that allow free movement of air into the upper diaphragm chamber while the regulator is opening, but which would restrict the outward flow of hydrogen to 1 CF/hr or less in the event of leakage. Such vents are available.

Industrial burners have many applications for each of which we assume that the burner and type of flame produced are closely related to the associated heating application. Some applications require long, soft flames that release their heat of combustion over wide areas. Other applications require intense, concentrated heat. Some burners transfer their heat by flame radiation while others rely on radiation produced by hot refractories. Fortunately, most industrial burners are capable of a wide range of adjustment; however, precautions must be observed to prevent damage to burner nozzles and refractories by the intensity of hydrogen flames.

Special attention must be given to premix burners about the effectiveness of flame arrestors in the mixed gas lines. The problem of arresting the propagation of hydrogen flames is much more severe than for methane. Sintered pads of stainless steel or bronze are conventionally used as flame arrestors for hydrogen service.

Special studies must also be made on burners where not only the heat but the pressure of the burner flame is used, as in the manufacture of electric lamp bulbs. We strongly recommend that a portable supply of hydrogen be taken to these locations prior to complete conversion to determine the performance on actual machines. These operations require the most delicate combinations of adjustments.

In changing a system from natural gas to hydrogen, modifying a well-designed and installed house-piping system will probably not be necessary. Calculations show that for a system in which a certain natural gas load produces a pressure drop of 1 in. wc, the pressure drop when supplying an equal heat load with hydrogen will only increase 6%. Most house-piping systems would probably be adequate.

The existing gas meter, being a volumetric-type device, would not be adequate since over 3 times the volume of hydrogen must be measured to supply the heat energy of one volume of natural gas. Either the meter must be replaced by a much larger meter or meters must be capable of operating at much higher speeds without excessive wear or pressure drop.

Service regulators as now installed would probably be adequate so far as capacity and pressure control are concerned. One factor that may need investigation could be the over-pressure relief function. Quite frequently, under circumstances that cause the relief mechanism to function, dirt and pipeline scale are discharged through the vent pipe. Normally this discharge is expelled harmlessly to the atmosphere. Because of the low energy required to ignite hydrogen, a possibility exists that static or abrasion sparks from debris in the blowing vent may cause ignition and fire.

Ignition devices of all types should operate readily on hydrogen. One precaution that should be observed in converting a system is to be sure that the high flame intensity of hydrogen does not destroy thermocouples or pressure-actuated elements.

If the conversion to hydrogen is to extend throughout a large area that may involve several cities and possibly several distribution companies, thought should be given to contracting the conversion or setting up a group under the hydrogen supplier to perform the conversion operation. The many benefits to such a plan include stocking of supplies and special tools, more expertise, and less disruption of local manpower. Regardless of the quality of conversion, the local gas company employees are certain to experience more than normal demands for their services.

G. Pipeline Conversion

Existing pipeline materials are compatible with hydrogen so that the lines may be operated with hydrogen within the same working pressure range as designed for natural gas. Unless the compressor stations are modified, however, a very considerable reduction in energy throughput will occur because of inadequate compressor capacity.

If we want to achieve the same energy-carrying capacity of the pipeline, both the compressor capacity and the engine horsepower must be raised. Doubling the compressor capacity alone, using the same engine, would allow 56% of the original energy throughput to be achieved.

We must realize, however, that the location of existing trunk pipelines may be quite inappropriate for a hydrogen system. We anticipate that the bulk hydrogen production stations will have to be located where thermal rejection can be accomplished, and this may well limit them to coastal or offshore sites. Many of the existing trunk lines, however, because they are linked to existing gas fields, would be appropriate for the bulk storage of hydrogen in depleted fields if such a course became economically justified.

Because of the capital investment already made in trunk pipelines, it may be advantageous to consider locating the hydrogen production stations on or close to the lines if appropriate sites can be found.

Conversion of pipelines to hydrogen, therefore, will require an individual, custom-design for each case. We foresee no insuperable technical obstacles. The cost and details of conversion procedures are given in Section IV.

Conversion of underground storage from natural gas to hydrogen presents a novel and unique problem. In the case of aquifer storage, the cushion gas must be replaced, and while this is being done, mixtures of hydrogen and natural gas are expected to be produced. A precedent for such conversion is at the Beynes storage area near Paris, operated by Gaz de France.[1] This will be converted from manufactured gas to natural gas by a sweeping technique; their experience will be useful. In the case of depleted gas-field storage, again a sweeping technique will be required, but some form of reprocessing the mixed gas that is produced may likely be required for several cycles of operation.

H. Reference Cited

1. Bresson, H., "Underground Storage at Beynes and Saint Illiers." Paper No. IGU/A24-20 presented at the 11th International Gas Conference, Moscow, June 1970.

X. ALTERNATIVES TO THE HYDROGEN ENERGY SYSTEM

A. Introduction

We have discussed the merits and attractiveness of a hydrogen energy system in other sections. Let us now look at the alternative technology being developed, or that would have to be developed, to provide our energy needs into the 21st century. We will then be in a position to compare the merits of hydrogen with these other alternatives.

The generation and use of electric energy will undoubtedly continue to grow rapidly. First, we will assess the ensuing problems and opportunities in transmission and storage of electric power.

We also should consider the synthesis and use of fuels other than hydrogen, which might be more convenient to handle. These fall into two classes: ammonia, which does not require a carbon source, and alcohols or hydrocarbons, which do.

Lastly, we will look into the alternative of relying on imported fossil fuels and the political and economic implications of doing this.

The scope of this section is very broad indeed, and details are beyond the subject matter of the study of hydrogen. The topics are therefore dealt with on a basis sufficient only to make the necessary comparisons of alternative energy systems.

B. All-Electric System

1. Generating Capacity and Location

The latest figures released for the U.S. electric utility industry[4] show that the total electric generating capacity in 1970 was 340,353 MW and operated at an average load factor of about 0.51. That is to say that the average plant operates for only 51% of the time, giving a total generation over the year 1970 of 1,529,581 million kWhr. The generating capacity and electric power consumption are growing at a rate of about 7%/yr and are projected by Edison Electric Institute to continue to do so, although trends in the past 2 years indicate some slowing down of the rate of demand.

Power stations are only about 30-40% efficient. The "heat rates," or efficiencies at which they convert fuel energy to electric energy, of the newest fossil stations[12] are lower in recent years than they were 5 years ago because of a backing off in boiler and turbine design temperatures. An average figure of 34.4% efficiency is reported for 24 modern fossil fuel stations. At present, the maximum temperature of a nuclear reactor is lower than a fossil fuel steam boiler; thus the heat rate or efficiency of new nuclear stations is typically lower than that of fossil fuel stations — about 31% for modern nuclear stations reported in 1969.[13] Moreover, since a nuclear plant produces no stack gases, all the waste heat must be discharged as cooling water. This results in the water-cooling load of a nuclear plant being about double that of a fossil station.

In round numbers, then, a 1000-MW electrical nuclear power station will produce about 2000 MW of low-grade heat as a waste product. No technical development is in sight that would substantially alter this situation. Even the high-temperature breeder reactor and the first generation of fusion reactors are limited by materials to temperatures in the region of those of conventional steam boilers.

This heat-release problem creates the major problems in siting new nuclear (and fossil) power stations. The disastrous sequence of refusals for licenses at the Quad Cities, Illinois, plant of Commonwealth Edison and Iowa-Illinois Power Co. is illustrative of the problems encountered in obtaining operating licenses for a thermal discharge system, even in a remotely located plant. The residents of Chicago are reportedly faced with possible power cuts in the summer of 1972 because of concern over the unpredictable effects on the fish life of the Mississippi River, over 130 miles away. More and more regulations make it impossible to discharge heat into inland waters including the Great Lakes. The alternative is to build cooling towers, which are expensive, consume large amounts of high-quality water, and are unsightly. For these reasons, we feel that the future trend in power station location must be to remote locations, away from population centers, and possibly in offshore ocean sites.

2. Transmission Requirements

a. General Comments

A direct result of this remote location of generating stations, together with the increase in generation capacity, is to vastly increase the requirement for bulk power transmission. At present, electric power is transmitted over average distances of about 200 miles by overhead a-c electric lines similar to those shown in Figure I-5 in Section I.

New developments in transmission include d-c overhead lines, which promise to be cheaper; a-c underground lines, which promise to be less unsightly, yet far more expensive than overhead lines; cryogenic and superconducting underground lines, which promise to be less expensive than conventional underground lines, but still more costly than today's overhead lines. These alternatives are discussed in more detail below, much of this material being extracted from a Federal Power Commission (FPC) report, The Transmission of Electric Power.[15]

b. Future of Transmission Systems

The FPC's discussion[15] on the future of transmission systems assumes that "there will be no unforeseen breakthroughs in small energy conversion plants, such as fuel cells, which would allow an individual home to economically generate its own electrical energy requirements."

The FPC report[15] goes on to say, "This assumption is based on the best knowledge and scientific judgment at the present time. It implies a basic premise that the present trend to larger, central generating stations supplying ever-increasing loads will continue. It implies also that further development of the interconnected transmission network in the United States will be dictated in the years ahead by the economic and reliability considerations inherent in the central generating station concept. As a result, the need for effective and economical transmission of increasingly larger amounts of electric power and energy will remain a major challenge to the electric utility industry.

"In view of the continually increasing competition for land and interest in scenic values, the need for underground transmission facilities will be more pronounced with each passing year. The cost of underground transmission today is so high compared to the cost of overhead systems that undergrounding is undertaken only in downtown areas, under conditions of very high right-of-way costs for overhead transmission, or for unusual environmental conditions and esthetic demands. In order to meet these certain demands of the future, the electric utility industry must continue and accelerate its efforts to find ways of reducing the cost of underground systems. In spite of some expected cost reduction for the transmission of electric power underground, however, there will continue to be many areas where the placing of existing or of new transmission systems underground will be neither economical nor practical for many years.

"The present trend toward larger generating units and plants can be expected to continue into the future for most, if not all, of the next twenty years. To begin with, the economies of scale are inherently more pronounced with nuclear generating units than with conventional, fossil-fired units. This means that as an increasingly greater percent of total generating capacity is made up of nuclear units, the average size of generating units being installed by the individual utility systems across the country is bound to increase also. This trend will be facilitated by 1) continued growth in demand, resulting in each of the growing systems, or groups of systems, being able to accommodate increasingly larger sizes of generating units, and 2) by the increasing scarcity of land, encouraging fuller utilization of available plant sites through the installation of larger blocks of generating capacity at each site.

"Given the continued trend toward larger generating units and plants, the trend toward stronger interconnections among power systems will likewise continue in an effort to provide day-to-day operating reliability and to minimize required installed generating capacity reserves. As a result, the interdependence among interconnected power systems will continue to increase during the years ahead."

c. Alternating-Current Overhead Transmission

The actual costs of transmission lines constructed in the U.S. in 1969 are shown in Table X-1. Variations in costs are caused by the higher costs of right-of-way, different clearance requirements, foundation problems, and other costs unique to urban areas.

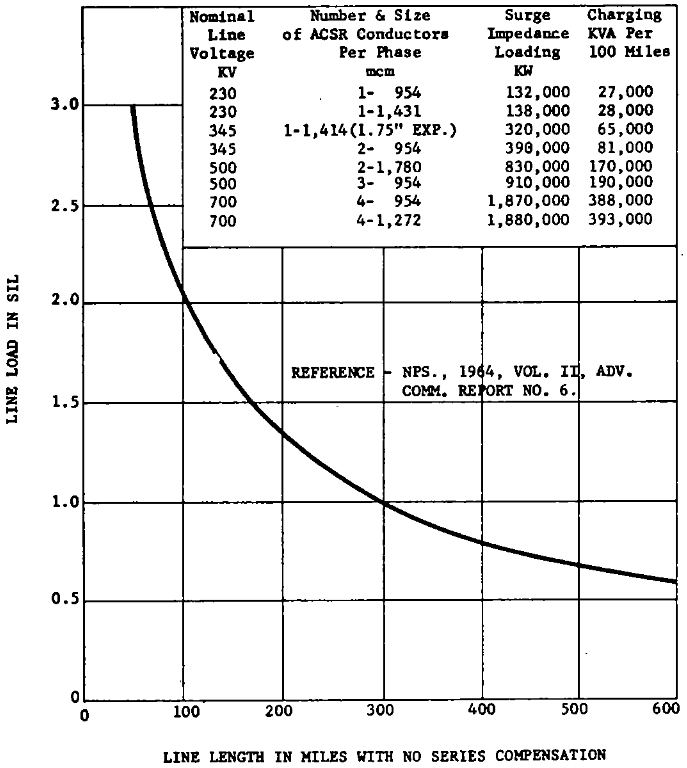
Table X-1. ACTUAL a-c LINE COSTS[15]

NOMINAL 500 KV AND 700 KV

	COST PER MILE		
Conductors	R/W and Clear.	Line Constr.	Total
EASTERN AREA - 500 kV			
2 - 2037 ACSR	$30,700	$ 80,800	$111,500
2 - 2493 ACAR	13,500	128,500	142,000
2 - 2049 5005	16,700	85,800	102,500
3 - 971 ACSR	12,400	65,300	77,400
4 - 583 ACSR	10,000	95,500	105,500
2 - 2032 ACSR	17,000	98,000	115,000 (1)
2 - 2490 ACAR	20,000	142,000	162,000 (1)
2 - 2490 ACAR	59,000	272,000	331,000 (1)(2)
2 - 2500 ACAR	22,000	118,000	140,000 (1)
3 - 954 ACSR	12,000	95,000	107,000 (1)
CENTRAL AREA - 500 kV			
3 - 954 ACSR	-	84,200	-
3 - 1024 ACAR	24,000	95,600	119,600
WESTERN AREA - 500 kV			
2 - 1780 ACSR	7,100	72,200	79,300
2 - 1852 ACSR	-	82,000	-
2 - 2156 ACSR	25,000	93,900	118,900
2 - 2156 ACSR	2,000	124,000	126,000 (1)(3)
700 kV			
AVERAGE OF 735 kV AND 765 kV LINES	18,700	146,300	165,000 (4)

(1) Latest data - other data prior to 1969.
(2) Line near urban center.
(3) Desert construction.
(4) Includes line sections built over 4-year span.

To derive a cost on an energy capacity basis, the energy-carrying capacity of a given line must be determined. This is difficult because the capacity of a line of given voltage decreases according to its length. Nevertheless, the FPC report shows data for this, reproduced in Figure X-1, from which we can establish that a 500-kV line can carry about 900-1200 MW over 200-300 miles, which we might consider as typical distances today.



Nominal Line Voltage KV	Number & Size of ACSR Conductors Per Phase mcm	Surge Impedance Loading KW	Charging KVA Per 100 Miles
230	1- 954	132,000	27,000
230	1-1,431	138,000	28,000
345	1-1,414(1.75" EXP.)	320,000	65,000
345	2- 954	390,000	81,000
500	2-1,780	830,000	170,000
500	3- 954	910,000	190,000
700	4- 954	1,870,000	388,000
700	4-1,272	1,880,000	393,000

REFERENCE - NPS., 1964, VOL. II, ADV. COMM. REPORT NO. 6.

Figure X-1. TRANSMISSION LINE CAPABILITY IN TERMS OF SURGE IMPEDANCE LOADING[15]

If we consider 1000-mile distances, then the power capacity is about half of this value.

Because of the relative unreliability of overhead lines, we must consider an additional cost factor. The electric industry generally seems to require a redundancy factor of about 5/3 in transmission line capacity, though this varies greatly from case to case.

Without the redundancy factor, we can establish that the average line costs for 500-kV lines are about $128,000/mile, or $0.14/kW-mile, corresponding to 41¢/million Btu-mile. Power losses in overhead a-c lines approximate up to 20% over average transmission distances of 200 miles. Much of the loss is resistive in the lower voltage lines and caused by corona discharge in the higher voltages. Corona losses are subject to weather conditions. While fair-weather corona losses of about 5 kW/3-phase mile in the 500-700 kV line class present no serious problems, foul-weather corona losses are about 500 kW or higher/3-phase mile at the same voltage level. Losses such as these can result in appreciable energy capacity cost penalties. Another effect of corona is that it produces audible noise in foul weather. This factor may control line design in some areas.

The FPC report[15] goes on to say, "Since the publication of the National Power Survey in 1964, the appearance of overhead electric lines, both distribution and transmission, has been a subject of criticism by the public in many parts of our nation. One solution would be to construct underground lines, and, for this reason, much development work has been done on underground cables.

"While the industry has been able to materially reduce the cost of lower voltage underground systems, there has been no major breakthrough on the cost of underground transmission systems. At the present time, research projects underway are aimed at reducing the cost of underground transmission facilities, but it will probably be several years before any major results are obtained.

"Realizing that it would take much time to develop underground facilities to economically handle the transmission esthetics problem, the Edison Electric Institute (EEI), in conjunction with the Electric Research Council, sponsored a research program to improve the appearance of overhead transmission facilities. This program was headed by a group of utility engineers who employed an architectural design organization to design transmission structures from an esthetic viewpoint. They also employed an engineering firm to check the practicability of the structure designs. This work was completed early in 1968 and a book was published entitled "Electric Transmission Structures" which is available through the EEI.

"[Any] discussion of esthetics [should also concern] transmission substations, which function as system switching and voltage transformation centers, generally at voltages above 69 kV. Functionally, substations satisfy electrical system operational and capacity requirements with designs which provide service reliability, ease and safety of operation and maintenance, and reasonable security. Esthetically, however, a substation is a collection of varied shapes, multicolored equipment, and structures highly identifiable with the utility industry and often unrelated to or clashing with its immediate surroundings. [See Figure X-2.]

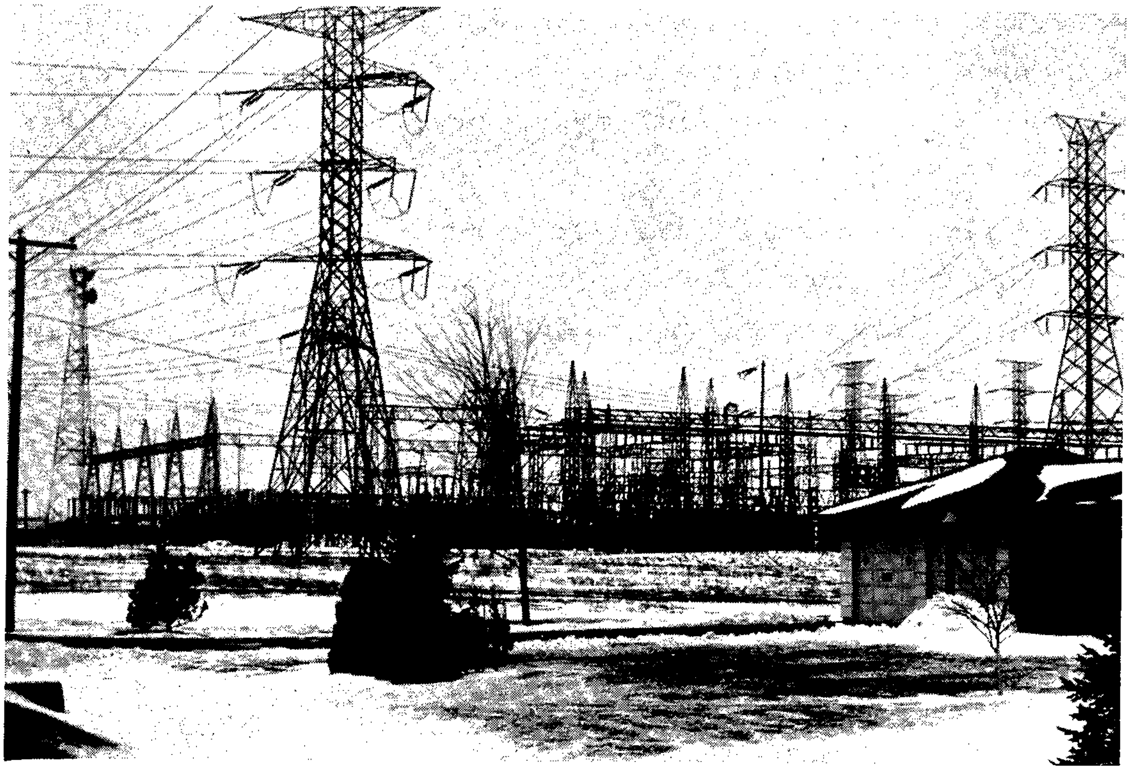


Figure X-2. ELECTRICITY TRANSMISSION SUBSTATION

"With transmission voltages today as high as 765 kV, and perhaps increasing to 1000-1500 kV in the future, substations have physical parameters which have become most difficult, if not impossible to hide or camouflage. It is not only the substations but also the converging overhead transmission lines which defy attempts for visual subduance and presents the most difficult esthetic problem.

"The practical avenues to improve appearances of most transmission substations are through judicious site selection, improved structural designs, materials and shapes, the appropriate use of colors, landscaping, and possibly some fenceline screening. An orderly arrangement of the connecting lines is highly important in making the total appearance more acceptable."

d. Direct-Current Overhead Transmission

The FPC report[15] states, "Modern HV dc transmission is generally still considered to be in its infancy; the first commercial link, installed between the Swedish mainland and the island of Gotland in 1954, carried only 20 MW. However, between 1960 and 1970, eight additional lines have gone into service with power [transport] capabilities ranging from 78 MW to 1440 MW. EHV dc projects with even larger transmission capabilities are now under construction. Table [X-2] lists pertinent data on the lines now in service or on order. As Table [X-2] reveals, a long overhead dc transmission line (Celilo-Sylmar) has been constructed in the United States. This line is nominally ±400 kV and is 846 miles long. Parameters of this order of magnitude are required for overhead dc transmission lines, if they are to be economically justified on the basis of the initial cost of their installation. However, other factors may override the 'break even distance' concept and result in installation of overhead dc transmission lines at considerably shorter distances.

"Economic considerations will continue to favor dc transmission wherever very long distance is involved. In these types of applications, economic considerations will also dictate large power ratings for such lines. In such instances, the voltage ratings may lie in the range from ±500 kV to ±1000 kV as future line capacities grow.

Table X-2. HIGH-VOLTAGE DIRECT-CURRENT POWER TRANSMISSION PROJECTS IN COMMISSION OR UNDER CONSTRUCTION[15]

Date of Commission	Line	Voltage to Ground	Length of Route (Miles)			Power Transmission MW
			Cable	O.H.	Total	
PROJECTS IN COMMISSION:						
1954	Gotland-Swedish Mainland	100	61		61	20
1961	English Channel	±100	34		34	160
1963	U.S.S.R. (Volgograd-Donbass)	±400		295	295	250
1965	Konti-Skan (Sweden-Denmark)	250	46	56	102	250
1965	New Zealand	±250	25	360	385	600
1965	Japan (Frequency Changer)	±125			0	300
1967	Vancouver Island	130	17.5	25.5	43	78
1967	Sardinia-Italy	200	73.5	185	258.5	200
1970	NW-SW Pacific Intertie	±400		846	846	1440
PROJECTS UNDER CONSTRUCTION:						
1971	Nelson River-Winnipeg	±450		600	600	1620
1971	Kingsnorth-London	±266	51		51	640
1972	New Brunswick Asynchronous Tie	80			0	320

"Dc overhead lines which must operate in series with dc cables are likely to be limited to much more moderate voltage levels. In such instances, maximum design levels for the cable may determine the system voltage. Extrapolation of limited data available on the dc cables indicates that operating voltages of ±500 kV should be readily attainable.

"Costs of overhead lines, ac or dc, vary widely due to terrain, labor rates, and other factors. Due to limited experience with dc line construction, comparative costs of ac and dc lines are limited to those cases in which the lines have similar capacity. Under average conditions, dc overhead lines will cost roughly between 0.65 to 0.75 times the cost of a comparable ac line. Such a dc line would have a voltage-to-ground of approximately 0.87 times the phase-to-phase voltage of a comparable ac line and an equivalent current rating.

"The power transfer capability of a dc line depends basically on the thermal capability of the conductors. When line lengths become very long, the resistive voltage drops, and the accompanying power losses may also become limiting factors. For dc lines, the conductor size will normally be limited by the corona and radio interference (RI) considerations, and the rating of the line will be limited by the power capability of the converter station at the line terminals. In special instances, the capacity of the link may be determined by the short-circuit capability of the ac buses at the line terminations.

"The same system considerations that limit the amount of power that can be safely allocated to one line are equally applicable to dc or ac lines. However, the dc line, when equipped with suitable ground electrodes or an insulated 'neutral' conductor, can operate at half-capacity with one pole conductor faulted. Thus, for most outages caused by lightning, switching surge over-voltages, or conductor faulting, only half of the line capability would be lost during a fault.

"In the 500-kV potential range, the fair-weather corona loss for a dc line is of the same order of magnitude to slightly less than that for a 3-phase line. The foul-weather corona loss of a dc line is on the order of five times its fair-weather loss in marked contrast to ac lines, where foul-weather corona loss can be up to 100 times the fair-weather value.

"Fundamentally, the transmission of power by direct current has several characteristics which distinguish it from its ac counterpart. Some of these characteristics are obviously instrumental in reducing the cost of transmission.

"The economic effects of other characteristics are less obvious and, indeed, may have opposite effects in different applications. Some of these characteristics may be listed as follows:

1. The construction of the transmission line, overhead or underground, is less expensive.
2. At present, for comparable rated lines, the transmission losses are reduced.
3. Dc transmission cable lines do not become limited [in length] by reactive charging.
4. The transfer of power on a dc line is readily controllable.
5. Modern dc lines do not add appreciably to the short-circuit capacity of their receiving buses.

6. The asynchronous nature of dc lines may be an asset in some situations.

7. Dc transmission terminal stations are appreciably more complex and expensive than their ac counterparts.

"With regard to item 7, firm data is difficult to establish. However, the cost of a dc transmission terminal will generally be in the range of $25 to $30 per kW per terminal and, in some cases, may go to $35. This cost does vary as an inverse function of terminal size. A comparable ac transmission switching station might cost $6 to $8 per kVA per terminal. When this difference in terminal costs is considered in conjunction with the possible savings indicated in items 1, 2, and 3 above, a concept of break-even distance is evolved and is the justification of most of the lines of Table [X-2]. This economic break-even distance will vary depending on the terrain, labor rates, and other factors, but is generally agreed to be between 20 and 50 miles for underground transmission and between 400 and 1000 miles for overhead lines. Of the nine lines shown to be in service in Table [X-2], six include considerable lengths of underwater cable as part or all of the justification for the use of dc. The Japanese Frequency Changer (listed in Table [X-2]) has essentially no length, and dc was chosen to permit the interchange of power between two systems of different frequencies. The Volgograd-Donbass overhead line is only 295 miles long and is considered as a prototype for future, larger and longer, transmission schemes.

e. Underground Transmission

The FPC report[15] continues, "Historically, the development of electric power systems has been based on the concept of using high-voltage overhead lines for bulk power transmission. The use of underground cable for this purpose has generally been limited to the short lengths required in extremely congested areas. Two principal reasons are (1) as transmission voltages have risen over the years, the technology for overhead lines has been available, while the technology for underground cables of equivalent capability has generally lagged, and (2) the cost of underground transmission has been, and remains, much higher than for equivalent aerial circuits.

"In the United States, the cost ratio of underground to overhead bulk power transmission lines can range from 10:1 to 40:1 for equal capacity.

Many factors influence this cost differential, and future technological developments may be effective in reducing it, and, in urban and suburban areas, the rising cost of rights-of-way alone for EHV overhead lines will provide significant reductions. However, the differential is large, and since as much as 60% of underground transmission costs can be attributed to installation labor, the prospects for major reductions in the ratio are not encouraging. It therefore appears that overhead transmission will continue to be dominant, with underground being used in those instances where technological and social conditions leave no alternative.

"In April 1966, the Federal Power Commission issued a report on underground power transmission which studied in depth the current state-of-the-art and included detailed analyses of the components of costs and prospects for their reduction. The coverage of underground transmission in this report will accordingly present subsequent progress and indicate trends based on the results of more recent research.

"There are two principal types of high-voltage underground power transmission cables in use at the present time — the self-contained and the pipe-type.

"Each phase of a self-contained cable consists of a conductor formed over a [tube] insulated by oil-impregnated paper and protected by a lead or aluminum sheath. The [tube] is filled with oil at one atmosphere-of-pressure to prevent voids from forming within the insulation structure.

"In the case of pipe-type cable, the phase conductors are usually segmental, have an impregnated paper insulation, and are covered with a combination of metal and synthetic tapes for shielding purposes. Three of these [conductors] are pulled into a pipe which is then filled with oil or gas under a relatively high pressure of 13-15 atmospheres.

"The pipe-type cable is inherently more rugged and can be installed in longer pulling lengths, resulting in fewer splices and few manholes. These characteristics give important economic-advantages over self-contained cables. As a result, pipe-type cable predominates in the United States, as shown in Figure [X-3]. It is of interest to note that the first energization of pipe-type cable to be operated at 345 kV occurred on May 1, 1964 in New York City and was 24 km (14.9 miles) in length.

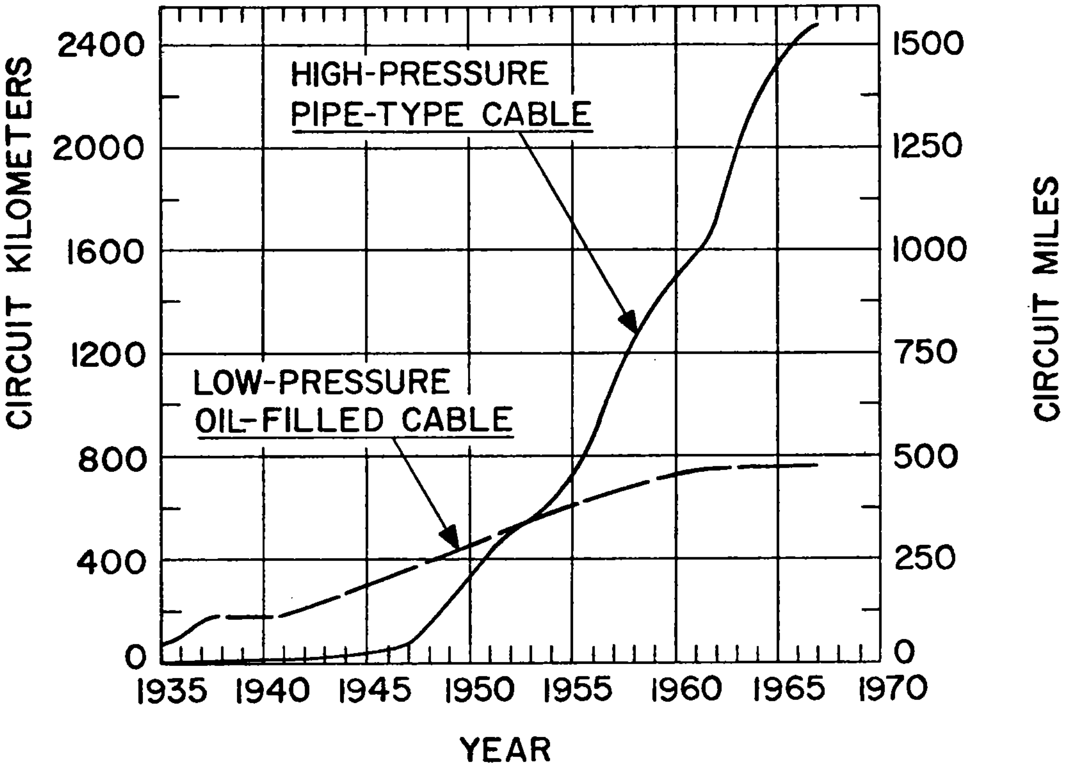


Figure X-3. UNDERGROUND TRANSMISSION CABLE IN THE UNITED STATES (69 kV to 345 kV)[15]

"The technological and economic problems associated with the use of high-voltage pipe-type cable are well summarized in the following quotation from Reference [2]:

> With currently available insulation systems, the dielectric losses increase rapidly with increases in voltage levels. For a 345 kV cable on a typical duty cycle, dielectric loss can run as high as 26 watts per circuit meter! Because the total permissible loss on such a line is about 72 watts per meter, not much room is left (46 W/m) for I^2R losses in the conductor. The result is that the power-transmission capability of the 345-kV system is only 4.2 times that of the 69-kV system. In overhead transmission, a quintupling of voltage operation would increase capability about 25 times.

> At 345 kV, the average line cost for a 48-kV underground circuit in a suburban area alone would be around $430, 000 a km as against $74, 000 a km for an overall circuit — but the overhead line would have a capability more than twice that of the underground line (1050 MW vs. 484 MW). In addition to the line cost, the underground circuit would require $3, 760, 000 for compensation and terminal facilities not needed for overhead, so that the cost per megawatt-kilometer would be $1, 050 for underground against $70 for overhead [$1, 680 and $112 per MW-mile].

"A third type of cable, now entering the high voltage field, is extruded synthetic insulated cable. Materials such as polyethylene, cross-linked polyethylene, and ethylene-propylene rubber are now being used up to 138 kV and are being tried experimentally at 230 kV.

"One of the most important factors limiting the capability of underground power cables is the generation and dissipation of heat. A large percentage of the research presently under way is aimed at this problem. Some of this research is on the forced-cooling of existing types of high-pressure oil-filled cables. [This] project investigated forced-cooling techniques applicable to presently used pipe-type cables, actual cooling systems, and the economic advantage of forced-cooling. The results of this investigation are encouraging.

"A five-year research project investigating synthetic insulation for extra-high-voltage cables was recently completed for the Edison Electric Institute by the Illinois Institute of Technology Research Institute. Such insulating materials can be utilized in cable in various ways. Extruded insulation has been mentioned already, of course. However, a suitable material could be prepared as a film and slit into tape for application in the same manner as an oil-impregnated paper insulation and then pressurized with a liquid or gas. Physical problems of impregnating such a build-up of synthetic tape has led to efforts to develop a synthetic 'paper' which would be made up of synthetic fibers and have sufficient porosity to permit impregnation with a compatible fluid.

"Two of the urgent needs of the power industry are the development of 500-kV cables and extending the voltage rating of extruded dielectric cables. These are the immediate objectives of a multi-million dollar research project funded by the Edison Electric Institute. This research is being conducted at a special test facility constructed at a cost of approximately $5 million at Waltz Mill, Pennsylvania. The entire Waltz Mill research program is expected to last 10 years or more and will test underground transmission systems in the range of 115 kV to 750 kV. Tests will be conducted on solid synthetic insulations, as well as synthetic-oil and paper-oil insulations. One-thousand foot cable samples will be energized and loaded at rated voltage in pipes that can be heated to simulate various ambient temperature conditions.

"Through the Edison Electric Institute, the Electric Research Council is sponsoring a research project at the Massachusetts Institute of Technology to determine the feasibility of using gas-insulated concentric lines (also known as compressed gas insulated cable) at voltages in excess of 500 kV.

"For the current and voltage levels needed to transmit large amounts of power underground, concentric metal tubes insulated by compressed gas, such as sulfur-hexafluoride (SF_6), appear to hold considerable promise. The compressed gas insulation has a dielectric constant of one, negligible dielectric losses, good heat transfer characteristics, and high thermal stability. All of these characteristics are highly desirable in high voltage, high power cables.

"The first installation of CGI cable [was] scheduled for completion in 1970 on the system of Consolidated Edison Company of New York. This underground link is 600 feet in length and will carry up to 3,350 amperes at 345 kV (2000 MVA). This particular installation is the solution to a problem in which one 345-kV circuit has to cross four others in a substation. This should be considered a trial installation and will produce useful data to further the development of this type of cable. However, it should be noted that this is only a 600-foot length of cable, entirely on the property of the user. Considerable further testing will be necessary before it would be practical to consider installation of long lengths of this cable on public rights-of-way."

f. Cryogenic Resistance Cable Transmission

The FPC report[15] further states, "Another method of high voltage, high power, underground transmission that is receiving increased attention utilizes resistive cryogenic cables. Resistive cryogenic cables operate at extremely low temperatures but above the superconducting range. In theory, advantage is taken of large reductions in the resistance of the conductor to increase line rating while avoiding the higher capital expenditure required for superconductivity. There are several competing designs that are under development and it is still too early to predict which may be reduced to practice first or which will prove to be the most economical in the long run. Present indications are that prototypes of two designs will have been built and tested by about 1974 or 1975. Assuming successful completion of these test programs, with no prohibitive problems being uncovered, resistive cryogenic cable systems might be available commercially about 1980.

"Conceptual designs for resistive cryogenic cables include one in which the cryogenic fluid (liquid hydrogen or liquid nitrogen) is used as an impregnant for a cable of conventional design using paper or synthetic tapes, another design in which the cryogenic fluid is the only insulation, and a design in which a vacuum is used as the insulating medium. In the first instance the cable is similar to conventional pipe-type cable and would be pulled into the pipe in long lengths and then both cable and pipe are filled with liquid hydrogen or nitrogen. These are classified as flexible cryogenic cables. When the cryogenic fluid or a vacuum is used as the insulating medium, spacers are required to support the conductors within the containment pipe. These are classified as rigid cryogenic cables.

"Preliminary research carried out for the Electric Research Council Underground Transmission Committee indicates that the most probable candidate for successful deployment is the liquid nitrogen cooled, flexible cable.

"Another separate research effort has pursued a rigid cryogenic cable with a high voltage vacuum insulation. Even if these tests should prove fully successful, it is doubtful if any significant commercial installations would be in service before the end of this decade."

g. Cryogenic Superconductive Cable Transmission

The FPC report[15] continues, "Superconductivity refers to the phenomenon where the electrical resistivity suddenly disappears at low temperatures. In its application to power cables, it refers to operation at the temperature of liquid helium, in the range of 4^0K. The appeal of superconducting cables is that losses in the cable can be reduced to practically zero (in the case of direct currents), or to a very low level (in the ac case), and thus virtually eliminate the heat dissipation problem. Also, superconductors can operate at unusually high current densities and consequently have very large power transfer capability of, say, up to 10,000 MVA at 345 kV.

"There are a number of problems that arise with superconducting cables beyond those of resistive cryogenic cables. Some of these are the ac losses in the superconductor and its dependence on temperature, current, and magnetic field strength. Heat transfer and thermal instability are also serious problems. Superconducting power cable research to date indicates that a continued research and development program is warranted. Such a program is estimated to cost about $8 million, exclusive of test facilities (the Waltz Mill site may be used for this purpose), and would extend over a period of 12 to 15 years. It appears, therefore, that superconducting power cables will not be commercially applied before the late 1980's.

"There are several configurations that have been proposed for superconducting cable. The general considerations in selecting the geometry of a superconducting cable are (1) it should be as compact as possible to minimize heat leak, material requirements, and induced electrical losses and (2) it must be large enough to satisfy the operating voltage and current requirements and to provide for adequate circulation of the liquid helium coolant.

"The magnetically-induced electrical losses can be made zero by surrounding the active superconductors with a superconducting shield to confine the magnetic field. The dielectric losses are minimized by using a minimum number of solid supporting spacers and using the liquid helium as the only insulation.

"The nature of superconductors is such that the current is confined to a thin surface layer, and thus only a small volume of material is required for the active conductor and the shield. This factor, material economy, and the desirability of low electrical stress dictate tubular configurations.

"Niobium is the preferred material for ac power transmission because it has low losses and has the highest critical magnetic field of all the low loss superconductors. It has a critical field of approximately 1500 gauss (a level which, if exceeded, will cause the material to revert to an ohmic conductor with a high resistivity of 0.6×10^{-6} ohm-cm). However, the use of pure niobium as the only active conductor in a superconducting cable would be hazardous; in the event of an emergency causing it to switch to its normal state for even a few cycles, sufficient heat would be generated to damage the cable. To provide for such contingencies, some sort of stabilization is required. Two-layer stabilization requires electrodepositing the layer of niobium on a copper substrate. If the niobium reverts from the superconducting state, the copper becomes the preferred current path, and power transmission can be continued as long as the added heat can be removed by refrigeration. A more flexible scheme is three-layer stabilization. Here a layer of niobium-titanium alloy would be placed between the layer of pure niobium and copper substrate. Then, if a high magnetic field switches the pure niobium to the normal state, the niobium-titanium layer which remains a superconductor will carry the current. If the stabilization is done adequately, the niobium will recover its superconducting qualities and the cable will return to its normal operational state.

"The terminals of a superconducting cable pose both electrical and thermal problems. The electrical problems arise because the high current superconductor must be operated at standard transmission voltages. The thermal problems stem from the large temperature differential, from near absolute zero to ambient, over a relatively short length of electrical conductor.

"The probable cost of superconducting cable systems per MVA-mile varies considerably with power rating and voltage level. Some estimated costs, based on the best available information, are shown in Figure [X-4].

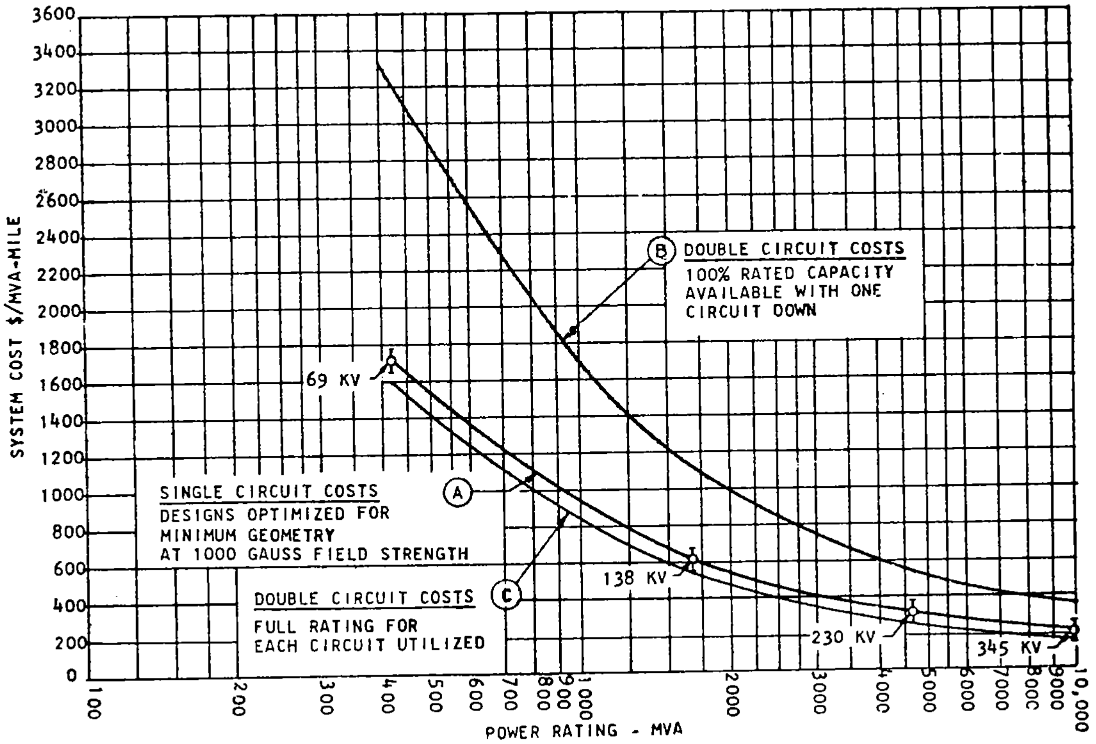


Figure X-4. SINGLE AND DOUBLE CIRCUIT SUPERCONDUCTING CABLE SYSTEM COSTS[15]

These curves indicate a lower transmission cost than present underground systems and point up the potential of superconducting cables for transmitting sufficiently large amounts of power. The cost of double-circuit systems depends strongly on the magnetic field level and the reliability demanded of the circuit. Thus, curve B in Figure [X-4], which demands 100% rated capacity with one circuit down, is considerably more costly than curve C, which assumes that power could be routed through other parts of the transmission network if one circuit were out of service. The double circuit costs in Figure [X-4] assume independent refrigeration systems for each circuit; these costs might be reduced if refrigeration were used jointly."

Figure X-4 indicates that system costs for 1000-10,000 MW ratings will be about $1000 down to $200/MW-mile, and these numbers are confirmed by Linde in a more recent publication[11] from which Table X-3 is taken.

Table X-3. SUPERCONDUCTING CABLE SYSTEM BREAKDOWN[11]

Line voltage, kV	69		138		230		345	
Total expense, $ per mVA mile^{-1}	1 720		601		307		201	
	$ per mile	*%*	*$ per mile*	*%*	*$ per mile*	*%*	*$ per mile*	*%*
Conductors and shields	70 100	9·6	147 000	14·6	290 000	20·1	558 000	26·3
Cryogenic enclosure	177 000	24·3	260 000	25·6	369 000	25·6	503 300	23·7
Helium	13 300	1·9	42 500	4·2	106 900	7·4	227 000	10·7
Terminals (5-mile spacing)	30 000	4·1	40 000	3·9	50 000	3·5	60 000	2·8
Refrigeration (5-mile spacing)	121 000	16·6	149 000	14·7	168 000	11·6	177 000	8·3
Installation	234 000	32·2	265 000	26·1	317 000	21·9	420 000	19·8
Annual capitalized expenses	82 300	11·3	111 200	10·9	143 000	9·9	178 000	8·4

The FPC report[15] summarizes that "expectations of greatly reduced costs per MVA-mile for the superconducting cables, and to a lesser extent for the resistive cryogenic and compressed gas insulated cables, are based on very large line ratings. Even if these systems were available today, there would be few systems that could utilize cable lines with ratings in the 3,500 MVA to 10,000 MVA range. The projected economy of these systems is, of course, not available on today's requirements for lines with capacities of 1,000 to 1,500 MVA.

3. Relative Costs of Electric Transmission Compared With Hydrogen

From the previously collected information, we have assembled a summary of installation costs shown in Table X-4.

The data of Table X-4 are used to construct some of the lines in Figure X-5, which compares capital costs for hydrogen, natural gas, and hydrogen transmission systems. As can be seen from the table, there is a wide range of cost projections for the cost of underground cable, depending on the source of opinion, but they are always considerably above the cost of overhead transmission.

Table X-4. ELECTRICITY TRANSMISSION COSTS

Data	Value Assumed	Source
Average cost of five 500-kV lines built since 1969 — Includes right-of-way, excludes the cost of one urban line	\$130,000/mile	p. 23*
Cost of d-c line at 0.65 times the cost of comparable a-c line	\$84,500/mile	
Typical power capability of 500-kV line	900,000 kW	p. 25*
Typical a-c terminal cost	\$8/kW	p. 115*
Typical d-c terminal cost	\$30/kW	p. 115*
Average 500-kV overhead line cost	\$0.144/kW-mile	
Average 500-kV overhead line cost	\$42.32/10^6 Btu-hr-mile	
Average d-c overhead line cost	\$0.093/kW-mile	
Average d-c overhead line cost	\$27.50/10^6 Btu-hr-mile	
Cost of two terminals for ac	\$16/kW	
Cost of two terminals for ac	\$4687/10^6 Btu-hr	
Cost of two terminals for dc	\$60/kW	
Cost of two terminals for dc	\$17,580/10^6 Btu-hr	
Cost ratio of underground to overhead power transmission	10:1 to 40:1	p. 123*
Cost of underground line	\$1.44/kW-mile	
Cost of underground line	\$423.2/10^6 Btu-hr-mile	
Total overhead line plus terminal costs for 200 miles	\$0.112/kW-mile	p. 127*
Total underground line plus terminal costs for 200 miles	\$1.68/kW-mile	p. 127*
Projected cost for 138,000–V superconducting line for 10 miles	\$0.88/kW-mile \$0.60/kW-mile	Reference 14 Reference 11
Projected cost of 345,000–V superconducting line for 10 miles	\$0.20/kW-mile	Reference 11

* The page numbers refer to specific pages of Reference 15.

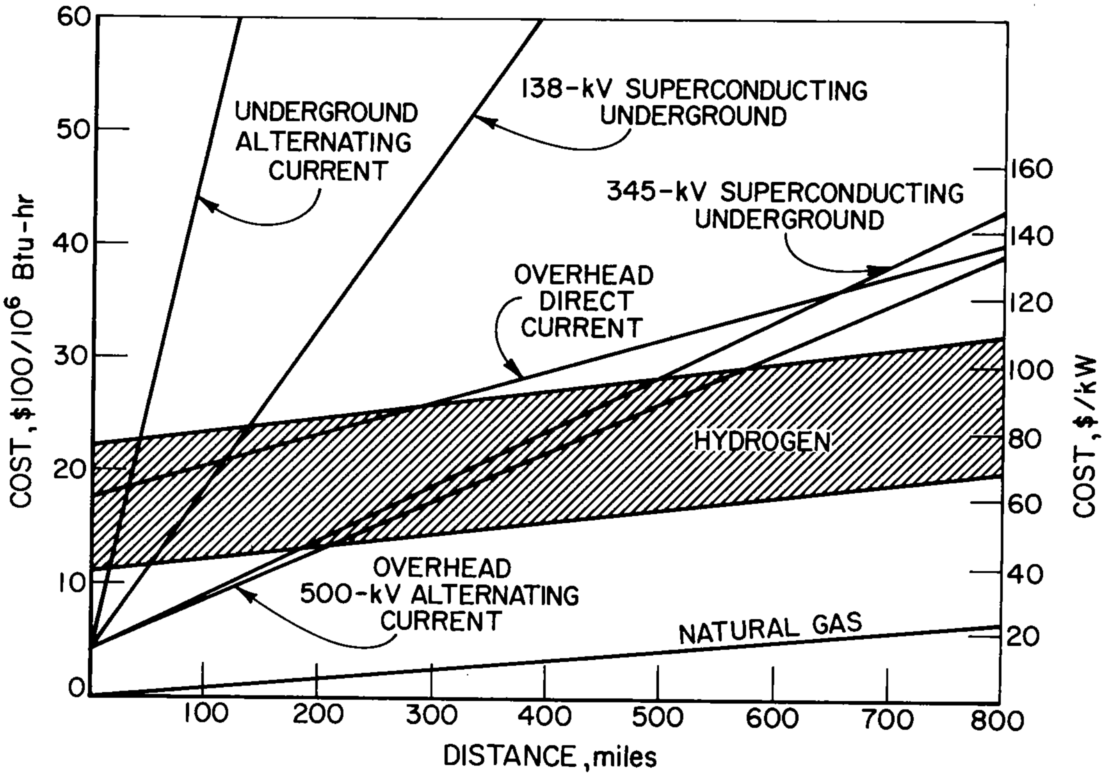


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Figure X-5. COST OF ENERGY TRANSMISSION FACILITIES

Figure X-5 also shows an estimate for the projected cost of a superconducting line. The a-c and d-c line costs are drawn so that their intercept on the zero-distance axis corresponds to the cost of two transformer stations, one at each end. In the case of superconducting line, the estimate made by Linde[11] has been used, and the costs of two typical 345-kV transformers have been added as an intercept.

4. Distribution Requirements

"Electric distribution" is normally defined by the operating voltage; levels below 138,000 V are considered to be distribution systems. Within many cities these lines are already being installed underground for aesthetic and reliability reasons. The technology for undergrounding these lower voltage lines is far less complex and less costly than for the EHV transmission lines.

The problem of the unsightly substation, or transformer station, has already been discussed. At a closer location to the user, further stepdown transformers are required, and they, too, present a problem in aesthetics.

5. Storage Requirements

a. General Comments

Perhaps the greatest problem facing the all-electric economy is the need for storage of electricity once it has been generated. At present, without significant storage capacity, our generators have to be sized for maximum demand. They have therefore redundant capacity and must be kept running at exactly the right generation rate to match demand. Provision of adequate storage would relax the reliability requirements of the generators, would provide a more even utilization of the plant, and would enable costs to be reduced.

b. Large-Scale Batteries

No large-scale battery installations are now in use for peakshaving purposes in the electric utility industry because the cost of suitable batteries is far too high. The need for bulk electric storage batteries is identified in the "Electric Utilities Industry R&D Goals,"[5] which states that significant research needs to be undertaken on materials, corrosion, incomplete discharge, large voltage drops, and lifetime. The present state-of-the-art is still at the single-cell experimental stage. Projected cost figures are not readily available, but the ERC report anticipates a demonstration plant by the early 1980's. The Edison Electric Institute announced[8] a contract to Electric Storage Battery Company, in November 1971, for the construction of a test model battery to confirm the feasibility of the concept.

c. Pumped Hydroelectric Power Storage

1) General

Pumped hydroelectric storage, or pumped storage as it is usually referred to, has the distinction of being the only significant energy storage system now in use in the electrical utility industry of the United States. At 3600 MW installed capacity in 1970, pumped-storage plants comprised about 1.5% of installed generating capacity. This fraction is expected to increase to approximately 3.6% in 1980 and 5.2% in 1990.[6]

Pumped-storage systems are technologically dependent on developments of the hydroelectric generation equipment industry and on the siting construction procedures used in the construction of large-scale dams. The largest turbine-generator units are now associated with pumped storage, as opposed to regular hydroelectric (nonreversible) service.

This points up the special technical requirement associated with pumped-storage turbine-generators: These electromechanical units must be operable in reverse, that is as motor pumps, and the operating efficiencies must be high for each component in each of its two modes. For the overall storage efficiency, the output/input ratio electrically is the product of motor, pump, turbine, and generator efficiencies plus other system losses such as hydraulic losses and evaporation of pumped water in the upper reservoir.

Comparatively, the efficiency levels demonstrated in operating plants are rather high, achieving levels of output/input ratios of about 0.65-0.70. Thus the expression often heard is "Two (kWhr) back for every 3 put in."

The general operating principle of pumped storage is straightforward. Two reservoirs, a lower and an upper one, are connected via conduits or "penstocks" at the bottom of which are located the reversible turbine-generator units. The penstocks are equipped with shutoff valves and the usual ancillary equipment required to keep foreign material out of the operating equipment.

In the pumping mode, when energy is being stored, electrical power transmitted from the system power network operates the generators as motors turning the turbines, which act as pumps to force water from the lower reservoir to the upper one. Subsequently, during peak electrical power usage periods, this potential energy can be reconverted to electrical form and injected into the power system network. This is accomplished with the turbine-generators operating in their conventional "hydroelectric mode," that is, as true turbine-generators.

Pumped-storage facilities are rated in terms of the maximum power level generated during the "discharge" mode. The largest plant size we noted was the 1800-MW plant at Ludington, Michigan. This facility will be described in detail later. Based on the cost of installation of the facility, a representative $/kW capital investment association can be developed for a given installation. Further, a total storage capacity (in kWhr) will normally characterize a pumped-storage facility. In the case of a fixed-capacity upper reservoir, the turbine-generators can be run "full out" for a period governed by the high and low reservoir operating level limits. A typical period might be about 8 hours. In cases where there is a much larger upper reservoir, or one that is continuously fed by a river, the maximum duration of generation is less well-defined.

The siting of pumped-storage plants is constrained in a very basic way by topological and geological considerations. An obvious need exists for two reservoirs with sufficient head difference to begin with. If both reservoirs are naturally occurring bodies of water, installation costs will be minimized. The alternative is to construct an artificial reservoir for one or the other, or both requirements. Geologically, the terrain must be capable of retaining water or so modified to be reasonably watertight.

These siting constraints limit the number of applicable sites potentially available for pumped-storage facilities. It is difficult, for example, to see how a pumped-storage plant could be sited in peninsular Florida or in the flat terrain of the Midwestern States. On the other hand, where there are high bluffs or flat-topped mountains adjacent to a large body of water to serve as the lower reservoir, we have a likely location for pumped storage. A measure of worth of a site is the distance from the plant to the system load centers served. This is because the cost of transmission from storage must enter strongly into the economics of site selection.

Another facet of the siting problem is the usual environmental-conservational criteria which must be faced by any electrical utility plant. Outside of the need for large-scale excavation, and the subsequent displacement of people and their properties, environmentalists should view pumped-storage plants favorably.

The usual atmospheric and thermal rejection problems associated with fossil fuel generating plants are gone.

Nevertheless, pumped-storage plants sometimes are held back by environmental action groups. Witness the proposed Storm King Mountain facility of the Consolidated Edison Company, near Cornwall, New York. Years of delays for this needed storage facility for metropolitan New York City have taken place because various spokesmen object and claim that an area of scenic beauty will be substantially compromised by this installation.

Actually, the most serious charge lodged against the Storm King facility is that fossil-fueled plants in and near New York will be used to pump the reservoir up. This issue is discussed in Reference 7. It points out that the energy conversion process requires 1.4 kW input for every kilowatt output taken during the peaking period. It also points out that these fossil-fuel plants will be putting out "... additional pollutants into the City's heavily polluted atmosphere at a very bad time from an air pollution standpoint, i.e., late night and early morning when the general stillness of the night air and frequency of early morning stagnations decrease considerably the likelihood of dispersion of the pollutants."

The above indicates the need to consider pumped-storage facilities as energy storage components, incomplete in themselves, in the overall utility system servicing a given area's load centers via transmission and generation stations. Specifically, one must relate the transmission system for carrying power to and from pumped storage, and the generation stations to be used to provide pumping power, in any net assessment of a pumped-storage facility.

2) Ludington Pumped Storage — An Impressive Case-in-Point

An aerial view of the world's largest pumped-storage facility, nearing completion on the shore of Lake Michigan near Ludington, Michigan, is shown in Figure X-6. The facility, a joint project of the Consumers Power Company and the Detroit Edison Company, is rated at 1872 MW and will provide a major storage capability for the Michigan Power Pool. Additionally, the Commonwealth Edison Company of Chicago has arranged to purchase approximately one-third the storage capability of Ludington for a period of 10 years and one-sixth for the following 5 years.

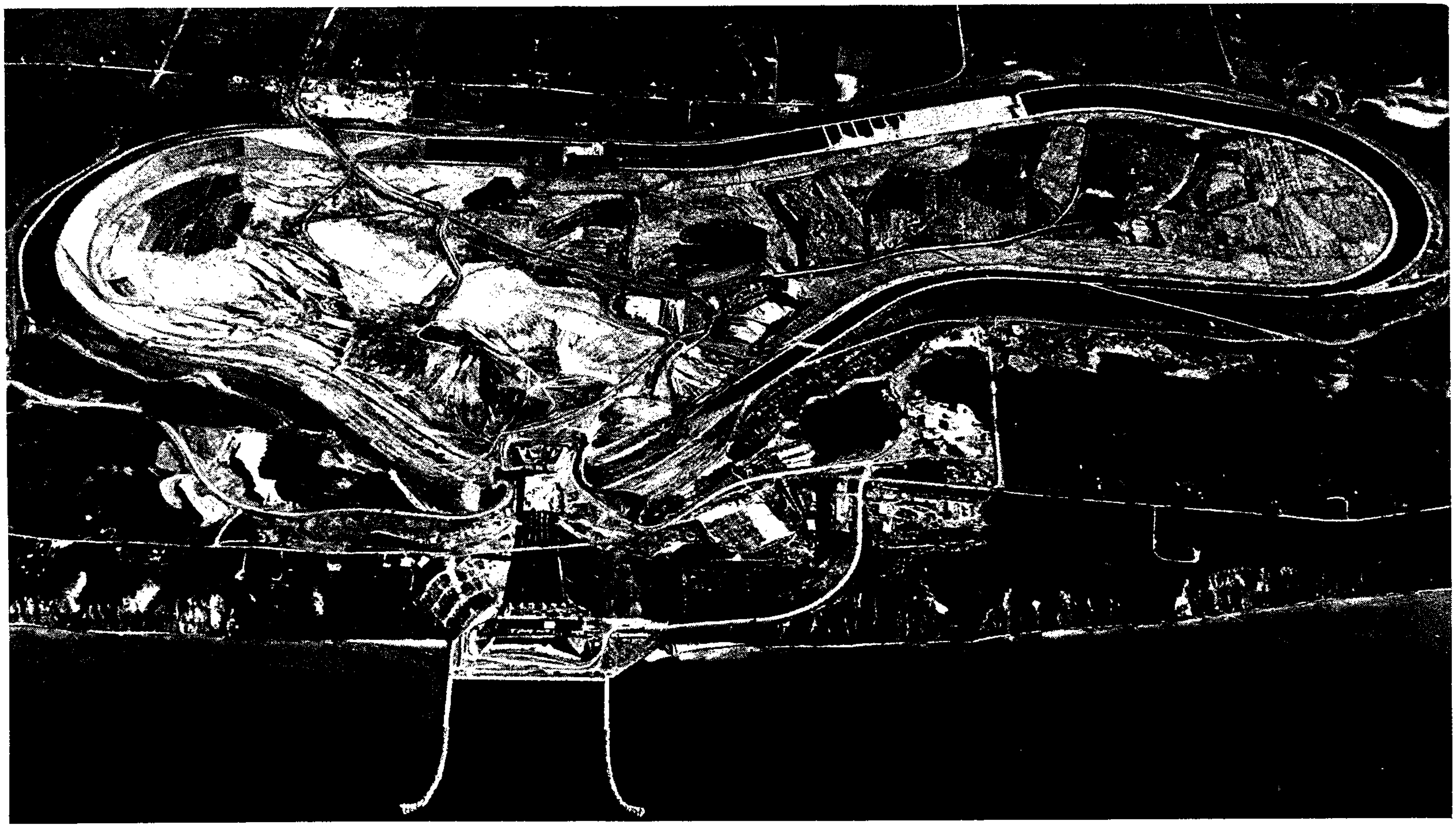


Figure X-6. LUDINGTON PUMPED-STORAGE HYDROELECTRIC PLANT

We visited the Ludington site in January 1972 to gather first-hand impressions of the size and makeup of the facility. What follows is a summary of information gathered during this visit under the auspices of the Consumers Power Company and from References 3 and 9.

The Ludington facility is located on a 1900-acre section of lakeside property about 3 miles south of Ludington, Michigan, and was in the planning stage for about 12 years. The utility companies selected the pumped-storage approach, and the timing for plant construction, through a detailed economic analysis which included other alternatives with similar capital investment and operating cost characteristics. For the purpose of the selection studies, a fossil-fuel steam generation plant, but one not of maximum sophistication (that is, a low capital cost, low efficiency, high fuel cost plant), was the principal alternative examined. From an overall systems standpoint, pumped storage was chosen, and work then proceeded at the Ludington site in the late 1960's.

As Figure X-6 shows, the facility physically utilizes Lake Michigan for its lower reservoir. The upper reservoir is man-made, consisting of a 2-1/4-mile-long "pond" comprised of a 22 degree slope dike averaging 108 ft in height above the original land surface. The dike is about 6-1/2 miles in length and follows the natural contour line of the plateau upon which the reservoir will be located. At the time the photograph (Figure X-6) was taken, the dike was partly covered with a multilayer liner of asphalt, clay, and waterproof filler material.

The powerhouse near the shore of Lake Michigan is evident in the photograph, being connected to the upper reservoir by six conduits or penstocks. These connect to the six turbine-generators within, each rated at 312 MW output. These are understood to be the largest units in the world. Hitachi of Japan is the manufacturer.

Although carrying a very high individual unit rating, the turbine-pumps operate at a somewhat low head (the difference in levels of the two reservoirs — a maximum of 362 feet) as pumped-storage facilities go. For example, in an advertisement in the September 1971 issue of Scientific American, Hitachi cites its 343,000-hp (256-MW) single stage reversible pump turbine "with the world's highest pumping up head of 1797 feet!"

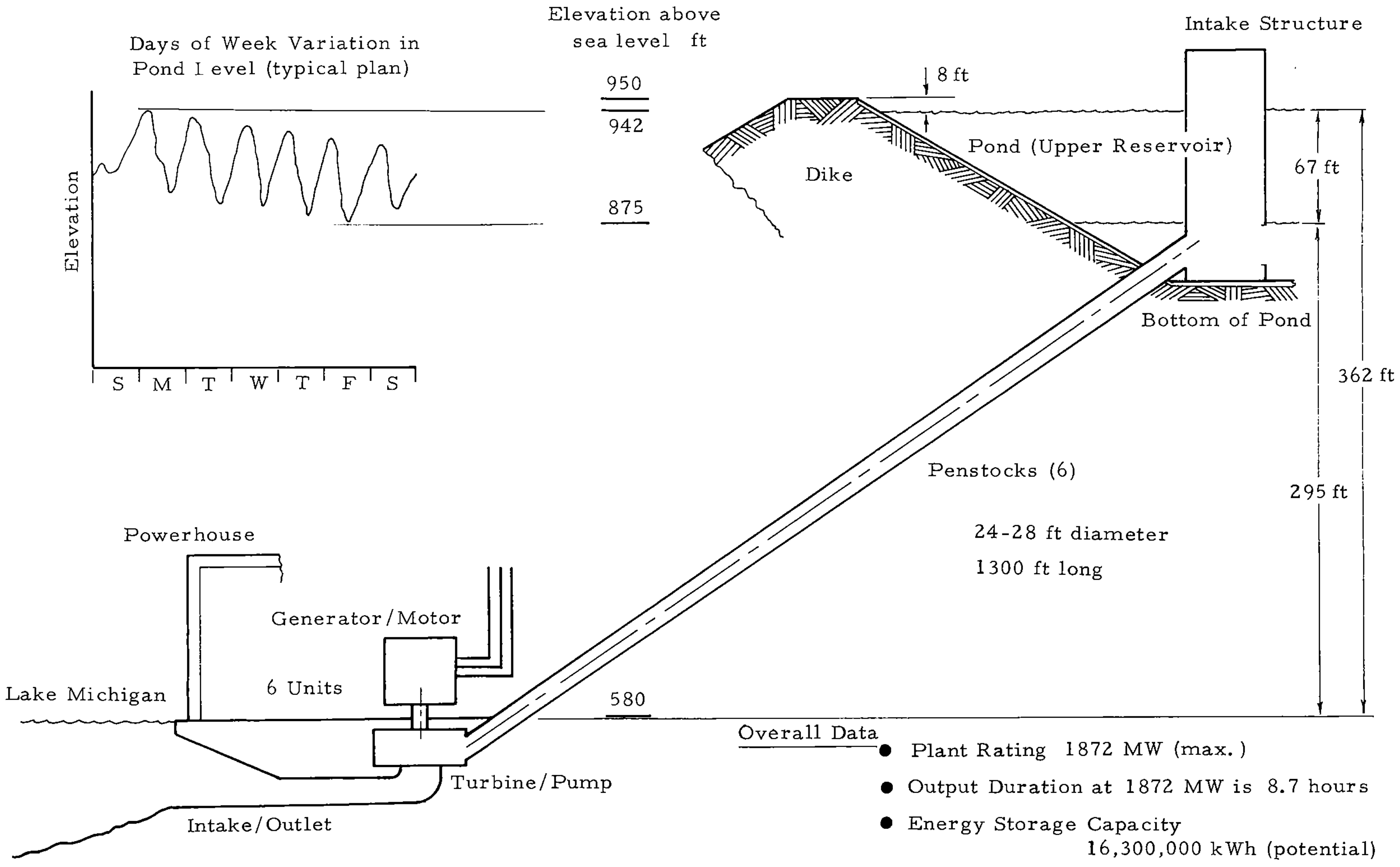
Figure X-7 is a pictorial schematic diagram showing the salient features of the Ludington pumped-storage facilities. The diked upper reservoir, with its maximum and minimum operating levels indicated, is shown in the upper right. The six turbine-generators at the lower left are connected by the 24-28 ft diameter penstocks, which run approximately 1300 ft down the slope in between the upper reservoir and Lake Michigan.

Note on the right-hand side of Figure X-7 that the operating head ranges from 362 ft to 295 ft as the upper reservoir empties during the electrical power output mode of operation for a differential head of 67 ft. This takes 8.7 hours at full output, that is, with all six generators carrying full loads. The resulting energy storage capacity is 16,300,000 kWhr for the Ludington plant.

The small figure at the upper left of Figure X-7 represents the fluctuations in the upper reservoir level over a week, assuming that full use is being made of the storage capacity. A rise in the curve signifies, of course, the motor-pump or "charging" mode of operation, which would normally take place during the late evening hours and early morning periods of "off-peak" power availability. At peak power need periods, the reservoir level drops to some low point. Note that this low point decreases over the operating week, reaching the lower operating level of the reservoir on Friday evening. Then with relatively lower system demand for power from the storage facility on the weekend (particularly on Sunday), the original reservoir upper level is reached by the time the weekly cycle is to be resumed on the following Monday.

Altogether, the Ludington facility is a very impressive engineering accomplishment. In sheer magnitude of the earth moved (about 52 million cubic yards) and water flow rates (34 million gpm — more than the Ohio River at Cincinnati), the project is notable. Another striking statistic we observed is that the very large turbine-pumps are supported in reinforced concrete 85 ft thick.

What about costs for pumped storage? The Ludington facility is estimated to cost approximately $340 million when complete. This is $182/kW in terms of installed $/kW of generation. As observed earlier this is in the range of fossil-fuel steam generation plants (an alternative to pumped-storage in the economics of selection), but the plant can only



Overall Data

- Plant Rating 1872 MW (max.)
- Output Duration at 1872 MW is 8.7 hours
- Energy Storage Capacity 16,300,000 kWh (potential)
- Plant Cost $ 340 million (approximately) or $ 182/kw
- Associated Transmission Cost $ 20/kw

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Figure X-7. SCHEMATIC DIAGRAM OF LUDINGTON PUMPED-STORAGE PLANT generate power for about 35% of the normal day. To this should be added some allocation of the Michigan Power Pool's transmission system to feed Ludington generation to the system load centers and to provide a link for "charging" the storage system back up again. This is covered later.

The capital cost of this plant, on an energy-capacity basis, is $21/kWhr or $6.1/1000 Btu. This figure can be compared with the estimated capital costs of energy storage for natural gas and hydrogen as cryogenic liquids ($0.022 and $0.042/1000 Btu) and in underground formations ($0.008 and $0.003/1000 Btu). (See Section V.)

In a way, this is an unfair comparison because pumped storage delivers the stored energy in an electrical form. Nevertheless, if peak demands for energy are required, for example, as for heating and other purposes where fuels can be used directly, clearly the cost of fuel storage, even as liquid hydrogen, is very significantly lower than that of pumped hydroelectric storage.

Another notable comparison we can make is in the relative sizes of this, the largest pumped-storage system in the world, and a typical LNG peakshaving tank of 1 billion SCF capacity, about 20 times as big. Pumped-storage units are unlikely to ever be constructed in the sizes associated with gas storage projects. Gas storage systems are normally capable of serving on a seasonal basis, whereas pumped hydroelectric systems normally serve to even out the daily peak.

Following our inspection of the Ludington plant, we visited Consumers Power's system planning group to discuss transmission associated with pumped storage. This transmission requirement represents in one sense the cost of not having pumped storage at the load center of the system. (We recognize that there is not one but many such load centers plus a generally distributed load represented by smaller towns, villages, and farms.) Here again, we should note the topological and geological constraints associated with this form of energy storage.

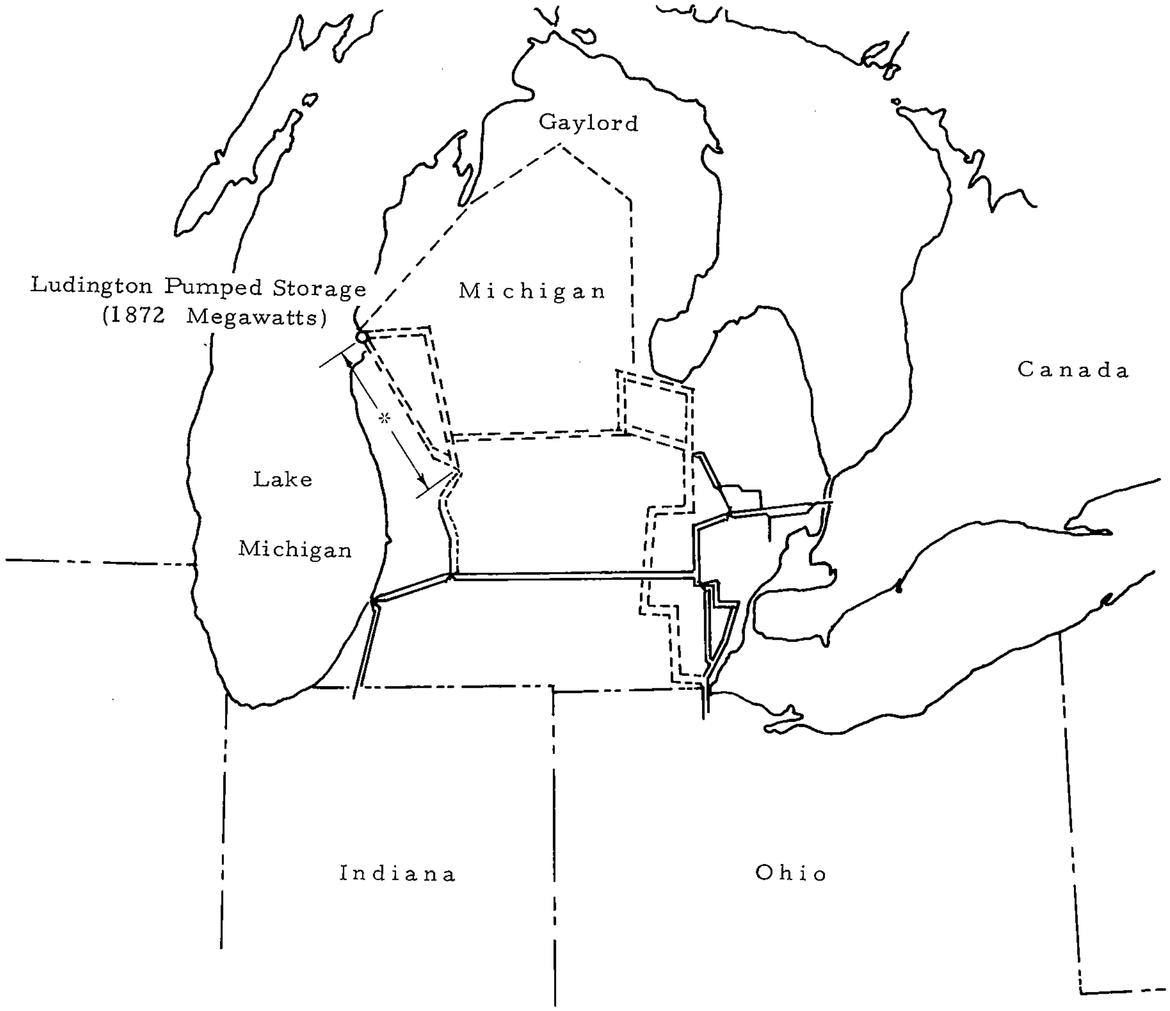
Figure X-8 shows the Michigan Power Pool's transmission system as existing and under construction. Ludington pumped storage is shown on the central western coast of Michigan. The 345-kV circuits radiating from Ludington, two double three-wire circuits and one single circuit, are under construction primarily to link pumped storage with the state's electrical power net.

In discussing the question of "Ludington-associated" transmission with Consumers Power's representatives we found that this is not the way the utility company thinks of transmission. Rather, when planning additional transmission circuits, it considers overall system growth and downstream trends as derived from computer-produced "scenarios" of projected requirements. Thus, for example, the single 345-kV circuit leading from Ludington to the northeast and ringing the upper perimeter of the state is required eventually to serve the anticipated growth requirements of upper Michigan. Technically, it should probably not be counted as additional cost of transmission for pumped-storage operation.

When consulting the company's system planners, we noted the double circuits leading from Ludington to the vicinity of Grand Rapids (marked with an asterisk in Figure X-8) as being those which could essentially be directly associated with linking the pumped-storage facility to the system. This represents about 250 miles of equivalent single-circuit 345-kV transmission which, at an estimated $150,000/mile total costs, amounts to an additional investment of $36.5 million. Based on Ludington's 1872-MW output, this is about $20/kW on an installed basis.

Thus the total installation cost for the Ludington pumped-storage plant and its associated transmission is slightly over $200/kW.

What has been emphasized here is a distinct case-in-point example of what is involved in a large modern pumped hydroelectric storage facility. The Ludington plant, the largest in the world, is a result of an overall utility system assessment in which other alternatives, such as fossil-fuel generation plants, were closely examined as competing approaches. Economics control such decision-making. But, particularly for pumped storage, strict constraints must be observed in locating the facility. In this case, the Ludington location represents one of the few potential sites for pumped storage in the state. Another potential area,


Michigan Power Pool Transmission System
(Showing existing ═══ and planned ═ ═ ═ 345-KV circuits)

* Transmission associated directly with placement of Ludington plant totaling 250 miles of single-circuit 345-KV transmission. At $ 150,000/mi and 1872 MW, this is $ 20/kw (installed).

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Figure X-8. TRANSMISSION SYSTEM ASSOCIATED WITH PUMPED STORAGE farther north, has already been acquired by Consumers Power for a second projected pumped-storage plant, one rated at as much as 6000 MW – over 3 times Ludington's capacity.

We emphasize that the attractiveness, and even the feasibility of pumped storage, is a function of the system and region under consideration. For each case examined, the cost associated with pumped storage will be variable and dependent on many factors. Not only is location a primary consideration, but the time period under consideration is important also. As apparently demonstrated in the Ludington project's lifetime, the escalation in labor costs have a very significant impact on such a labor-intensive undertaking as pumped storage.

In summary, the technology of pumped storage is a mature one, based as it is on long-standing hydroelectric equipment developments. The storage efficiency (output/input ratio) is quite high, particularly so since heat-engine cycles, which have definite Carnot efficiency limits, are avoided in the energy conversion equipment. But large-scale civil and mechanical engineering efforts are necessary in plant construction, and these are normally very labor-cost sensitive. On top of all this, the very feasibility of pumped storage is highly dependent on the nature of the countryside within which the electrical system to be serviced by the storage capability being sought is located.

d. Peakshaving Generators

One way of relieving the peak loads on the transmission system is to construct peakshaving generators close to the load center. This is not truly a storage system, but it enables the electric utility to consider the fuel for the peakshaving generator as a means of energy storage. Most peakshavers, because they are only used for relatively short times, are built to optimize a low capital cost and rapid start-up rather than high efficiency and reliability. Gas turbines and diesel generators are used for this purpose. Most are situated on the sites of the centrally located power stations, not on unique sites very close to the customers, because they are too noisy.

e. Dispersed Generation

If it is possible to generate electricity very close to the customers' premises, the importance of the load factor on the electrical transmission and distribution system is minimized. This approach would therefore eliminate some of the need for energy storage and throw the burden of coping with peak loads onto the fuel supply system, which is better able to cope with it.

Small local electric generators have traditionally been too noisy, unreliable, and inefficient to consider for this purpose. Fuel cells have long been considered for such use; interest is increasing in this area. The TARGET program, supported by the gas industry, has the objective of bringing a gas-fueled local generator into commercial use. The Edison Electric Institute recently announced a new program aiming to achieve substantially the same objective by "ultimately developing fuel cells capable of providing large amounts of peaking power at substation sites." This program is a 12-month effort being carried out by Pratt & Whitney Aircraft.[1]

A recent paper from Pratt & Whitney[10] indicates that fuel cells of about 20-MW capacity would be ideally suited for substation application, presumably to carry some base-load capability also. Present plans outlined by the Electric Research Council[5] call for "continued research on the concept for use at the substation [10-20 MW] level. Continued research is needed on various electrolytes, cell life, adaptation of this concept to present systems, and operational modes (whether base load with continual fuel supply or similar to pumped-storage-hydro with hydrogen produced from water electrolysis)."

The last mentioned mode of operation is, of course, specifically interesting in conjunction with a hydrogen energy system. The British Central Electricity Generating Board investigated fuel cell-storage systems some years ago and ruled out their economic use because of the high cost of the gas storage facilities. It is now reviewing that decision because of the increased need for energy storage close to the customer. If a hydrogen line network already existed that could act as a surge capacity for "reversible" fuel cell stations, the economics of such an energy storage system might change radically.

6. Electric Vehicles

About 16.3% of the U.S. energy consumption is currently used in transportation. Almost all of this is used directly as fossil fuel. There seems little chance of electric airplanes ever becoming feasible because of the great weight of batteries. There is a considerable interest, however, in electric vehicles, both road and rail, and in electric ships and boats. The electric industry's R&D plans[5] call for the development of electric transportation systems which the public will accept. Its report states, "A primary objective will be the development of higher energy-density transportable power sources. Specifically, this program envisions the doubling of energy-density capability of existing battery systems by 1975, 80-100 Whr/lb systems by 1980, and 150-200 Whr/lb systems by 1990."

Reaching these goals will require very considerable research success, since present lead-acid traction batteries do not exceed about 12 Whr/lb.

Another, usually ignored, problem facing the development of battery-propelled electric vehicles for personal transportation is the provision of adequate charging facilities. The power levels required to charge a vehicle battery very rapidly — even if technically feasible — are enormous and require very heavy-duty circuits, transformer-rectifiers, etc. When a gasoline automobile is refueled at say 10 gpm, energy is being transferred at a rate equivalent to 18 MW. A six-pump gasoline station thus has a power equivalent of over 100 MW. The provision of charging stations on this scale is virtually impossible because they would require a generating station at each location or very heavy distribution cables from a central power station, both of which would be very expensive indeed. Radical changes in "driving style" are mandatory for an electric vehicle concept. Similar reservations apply to the requirements for "refueling" trucks and trains if they are to be battery operated. On the other hand, electric vehicles for mass transportation, which ran over tracks or fed from overhead lines, were found to be so inflexible that gasoline and diesel buses replaced them. Clearly, a synthetic "chemical" fuel has a great advantage over an electric "fuel."

C. Synthetic Chemical Fuels

Rather than hydrogen as a fuel, we can consider the use of other chemical fuels, which may be easier to handle. If we restrict ourselves to the use of air and water as raw materials, we can confine our consideration to ammonia and hydrazine. If carbon is to be used, either from carbonate rocks or from atmospheric carbon dioxide, then methanol might be considered. Ethanol could be produced from vegetation by fermentation.

All of these fuels could form unacceptable pollutants or combustion products; thus their handling advantages over hydrogen must be weighed against these disadvantages. In addition, since they all, with the exception of fermented ethanol, require hydrogen as an intermediate in production, they will all then cost more and be made less efficiently than hydrogen itself.

Although ammonia is handled in industry in large quantities, it is a highly dangerous material because of its extreme toxicity. We feel, therefore, that the use of an alternative fuel is to be preferred, if possible. Ammonia burns in air with difficulty, and existing appliances will have to be considerably modified to handle it. It is also highly corrosive to copper and brass, which would mean extensive modification of present gas equipment.

Ammonia has been used directly to power gas turbines and piston engines, but better results are obtained when partial decomposition to hydrogen and nitrogen is carried out prior to the gas entering the engine. Ammonia can be dissociated to hydrogen and to nitrogen by heating over a catalyst. The technology to do this is well-developed. Further investigation is necessary to determine how much ammonia is left behind and what the effects of this ammonia would be on combustion.

Methanol is a liquid fuel which has handling properties more similar to today's hydrocarbon fuels. To synthesize methanol, a supply of carbon is required. Assuming that a suitable manufacturing process can be devised, methanol would make an admirable fuel for domestic and industrial cooking and heating, although appliances with new burners would have to be developed.

Methanol has been used apparently without complication as a piston-engine and a gas-turbine fuel. Because methanol is miscible with water, quality control problems and metering can create problems. Methanol has been used as a fuel cell fuel, either directly or by conversion to hydrogen. Further research and development of fuel cells utilizing methanol would be justified if methanol would be considered seriously as a synthetic fuel. Ethanol has very similar characteristics to methanol; the above remarks apply to it also.

Hydrazine is a highly explosive and highly toxic fuel used for rockets. In water solutions, it is safe to handle, but becomes less useful as a fuel for combustion. Hydrazine has been used successfully as a fuel cell fuel, and it is in this area where it is most attractive. The highly toxic properties of hydrazine, however, make its widespread use by the general public somewhat doubtful.

Metals can be reduced thermally or electrochemically at central stations and delivered to the user as an energy form. When the energy is released by oxidizing the metal, it will be imperative to collect the oxide and return it to the generating station. This two-way transportation problem would be prohibitively expensive.

D. Imported Fuels

An "easy" alternative to developing our domestic nuclear and other energy sources is to allow our fuel imports to grow to fill the "energy gap." When discussing the fossil fuel reserves in Section I, we included global fuel reserves, assuming unrestricted imports, and even then we observed an overall fuel shortage in 50-100 years time.

However, serious concern is already being felt about the political and economic implications of increasing our fossil fuel imports. Already, 90% of the residual oil used on the East Coast is imported, and both crude oil and light petroleum for East Coast use are fast reaching this point. As overall U.S. oil imports grow, we are concerned with both our own balance of payments and the increasing wealth of the Middle East countries, with the implied political dangers. For example, between now and 1980, the U.S. is estimated to pay more than $86 billion in taxes and royalties to OPEC (Middle East) countries, an amount equal to the combined monetary reserves (gold and foreign exchange holdings) of the U.S., Canada, the United Kingdom, and the European Common Market.

This type of concern may drive the U.S. to develop its own domestic energy resources at any cost; hydrogen energy can play a part in making coal, shale, and other resources more available to the user. In the long run, we in the U.S. must depend upon the "renewable" resources, such as nuclear fusion and solar energy.

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XI. RECOMMENDATIONS

A. Introduction

Our study has not indicated any areas where a seemingly insuperable obstacle appears to putting a hydrogen-energy system into practice. On the contrary, using today's technology, it would be possible to construct and operate all the components of a nonfossil hydrogen production, transmission, distribution, and utilization system, albeit with high cost, low efficiency, and some concern for safety and maintenance requirements, especially in the distribution area. Even so, delivery of hydrogen energy underground to the average user should be possible at a cost comparable with today's costs of delivered electricity.

Some technical, economic, and safety questions exist, however, which cannot be answered today. Research is needed to provide answers or to improve the present technology available. The research that we are recommending is directed toward decreasing the cost, improving the safety, or demonstrating the feasibility of the "Hydrogen Economy" Recognizing that the transition to hydrogen is a long-range prospect, we have given priority to those areas where immediate information will assist long-range planning and where long-range fundamental results are required.

A shorter term possibility has been identified: Hydrogen made from fossil fuels could become of increasing interest as a commodity in the petrochemical, metallurgical, and the electric utility industries, and pipelining it over greater distances than is done at present may become justified. Thus certain problem areas relating to this possibility are identified. This aspect of the utilization of hydrogen, although important, was beyond the scope of this program and is not covered in detail.

B. Decreasing the Cost of Hydrogen

The items discussed under this heading relate to improvements in already feasible technology with the objective of reducing its cost.

1. Production Costs

a. From Nuclear Electricity

Electrolysis is currently used today to produce hydrogen. The cost of electrolytic hydrogen is very sensitive to power costs, so that there is great incentive to increase the present efficiency of electrolysis. To a smaller extent, the cost of the electrolyzer cells themselves is amenable to reduction.

Current electrolyzer technology indicates that a) the voltage efficiency should be improved and b) the cost should be reduced if we are to make hydrogen at an attractive fuel price. The technical background available from fuel cell research and from direct-current electrical machinery research indicates that both of these are reasonable objectives for research. Electrode development should yield lower operating voltages (raising the efficiency) and higher currents (effectively lowering the cost per unit of hydrogen produced). Direct d-c power generation should be able to reduce the cost of the overall electrolyzer system, if acyclic generators become fully developed. The area of electrolyzer development is one that we identify as a general need for industry support and one that requires a long-term research program, starting immediately. As part of this work, a systems engineering and optimization study of an integrated power station and electrolyzer plant should be carried out. The development of d-c generation equipment will best be done by the electric industry.

b. From Nuclear Heat Directly

Thermochemical water-splitting, using the heat of a nuclear reactor directly to induce the step-by-step decomposition of water, is a fertile area for research. A program is already under way under A. G. A. sponsorship (Project IU-4-14) and should be continued as a long-range project because it offers the lowest cost prospect for hydrogen which can be visualized at present. Such a program should be considered at this stage as "prospecting" research — searching for a reaction sequence that is attractive enough for development. If and when one is found, a major pilot-scale development program, on the scale of today's coal gasification program, can be envisioned. Continued liaison with the Euratom work and any new projects that may be started is advisable.

c. From Solar Energy

Solar energy is a vast energy source; means may be found in the future to develop it as an important primary energy supply. Used as heat, it will require techniques similar to those considered for nuclear heat, except for possible differences in the available temperature levels. Other concepts may be developed in the future that could usefully employ hydrogen as a secondary energy source that would allow the storage of energy in an intermittent generation system. An awareness of technology in this important area should be maintained.

d. From Fossil Fuels

Broad cost studies for the production of pure hydrogen from coal and shale on a large scale would be worthwhile to provide data for consideration of an early entry into the hydrogen-energy scene by other than nuclear sources. Technology for this commodity usage of hydrogen is available today.

2. Transmission Costs

a. Long Distance

Even though present pipeline systems and techniques are broadly suited to hydrogen service, rather different design requirements are needed for the compressors. A detailed, optimized calculation for a hydrogen pipeline would yield information about the required pressure ratios and would thus more clearly define the types of compressors needed. Once design criteria have been established, new designs, for example, for large axial flow and screw compressors as well as multistage radial turbocompressors, can be examined.

b. Local

The prospects for using hydrogen, possibly together with oxygen in a twin pipeline, as a way to carry bulk energy from a power station to the electricity load center must be studied in detail. This concept requires the efficient reconversion of hydrogen energy back to electricity. Since the economics of doing this will vary markedly with local conditions and the relative costs of the alternatives, and since electrical transmission systems are also dominated by local conditions, these studies will best be carried out by the electric utility companies themselves.

The possibility of liquid-hydrogen transmission should be studied, especially in the context of integrating it with superconducting or "cryoresistive" cables for electric power transmission. The advantage of combining it with electric transmission may make liquid transmission more attractive for hydrogen than it has appeared for natural gas in the past. These studies may be undertaken by the electric power industry independently, if they believe that hydrogen will be available. There seems to be little urgency for this work to begin because of the early stage to which cryoresistive transmission technology has developed so far.

3. Storage Costs

a. Metal Hydrides

Metal hydrides offer a challenging prospect for small-scale portable energy storage. Basic and applied research are appropriate on a laboratory scale in order to find metal alloy systems that are able to accommodate hydrogen storage better than currently known systems, reducing the heat load required to regenerate the gas. A small effort under AEC sponsorship is likely to be increased. Since success in this area would not be vital to the "hydrogen-gas industry," it is not a priority item for gas industry support, but it appears to be a necessary development facing the evolution of a hydrogen-propelled vehicle and so should receive support from the automotive area.

b. Large-Scale Liquid-Hydrogen Storage

Large-scale liquid-hydrogen facilities, both processing and storage, are more expensive than LNG facilities, but perhaps they need not be as expensive as they are. Engineering studies directed toward the design of cheaper, very large scale liquid-hydrogen tankage are a task that should be undertaken. Integrated storage schemes that allow useful utilization of boil-off gases would be worthwhile.

4. Distribution Costs

A compact, inexpensive meter to measure gas flow rates at 3 times today's levels is needed. Modifying existing meters may be possible, but in any case a realistic objective would be to design a higher capacity meter of the same exterior size as existing meters so that conversion is easy.

5. Utilization Costs

a. Electricity Generation

Analysis of a fuel cell system specifically designed to operate on pure hydrogen and air would be worthwhile to see whether existing technology directed toward hydrocarbon (natural gas) fuel cells is 100% appropriate or not. If not, then special R&D programs toward this objective will be required. This should be undertaken by potential equipment manufacturers.

b. Aircraft Fuels

The aircraft industry should begin a design analysis for a large (wide-bodied) subsonic passenger transport fueled by liquid hydrogen. If this occurs, gas industry interests should be active in contributing to the inevitable fuel logistics study that would ensue.

c. By-product Credits

A potential-market study should be initiated immediately on the use and value of the oxygen produced as a by-product in hydrogen manufacture. As part of this, economic analysis of long-distance oxygen pipeline transmission is needed.

C. Increasing the Safety of Hydrogen

1. Production Safety

We make no recommendations in this area.

2. Transmission Safety

A close liaison, together with some experimental work, should be carried out in conjunction with the NASA-funded effort on "hydrogen-environment embrittlement." It is particularly important to ensure that the NASA work is extended into those conditions likely to be met in hydrogen transmission service. The behavior of welded pipe sections subject to possible yielding stress is of unique importance for study. This work is of prime importance to hydrogen pipeline design, and requires close integration with NASA programs.

3. Storage Safety

A study to determine the feasibility of underground storage of hydrogen in aquifers or depleted gas fields is discussed later; the recommendations made then also relate to safety. Otherwise, we make no recommendations in this area.

4. Distribution Safety

Because of the wide variety of materials and equipment in a distribution service and the proximity of gas mains to populated areas, the behavior of equipment and associated safety hazards with hydrogen service are still areas of concern. Experimental observations should be made of, for example, a) the behavior of pipe sealing materials in hydrogen pipes, since smaller leaks than are now tolerated with natural gas will be hazardous, and b) the actual behavior of lines under purging conditions. We feel that the best way of determining the nature of many of the problems will be to construct a small model distribution system and subject it to hydrogen service under carefully monitored conditions. Thus, leakage characteristics of deliberately introduced failures, such as pipe seals, corrosion pits, and fractures, can be monitored and existing leak detection equipment can be assessed. In addition, a strong need exists for operating experience with plastic pipes in hydrogen service to determine actual permeability and leakage rates in the field, and to provide confidence that such systems are truly practicable. The sooner such a model system is initiated, the larger will this experience be; thus this is a high-priority item

5. Utilization Safety

The development and testing of suitable odorants and illuminants for hydrogen are required. In particular, additives that are compatible with catalytic burners and with pollution requirements must be used.

D. Demonstrating the Feasibility of the "Hydrogen Economy"

1. Production, Transmission, and Distribution

The work already carried out has indicated that a hydrogen-energy system should be considered as a feasible objective. However, there is an urgent need to dispel the impression that already exists that hydrogen is an impossibly dangerous material to handle. We believe that the best way to do this is to set up a comprehensive demonstration system, or series of systems, incorporating production, transmission, and, in particular, utilization equipment for use by and for demonstration to such people as —

- Government and regulatory officials
- Potential users of hydrogen, including utility company representatives, commercial and industrial users, and domestic users
- Potential manufacturers of equipment and appliances

In addition, use of such a system by gas company maintenance crews would expose problems and develop confidence in the ability to ensure trouble-free service in the field. Lastly, such a system would be invaluable to the testing of new equipment and appliances.

We feel that such a demonstration system should be considered as a natural follow-up from the model distribution system outlined previously. A future need will be the publication of a hydrogen safety manual, similar to those documents already used by NASA and the Air Force, but tailored for gas industry personnel requirements. (A comprehensive data book of basic information on hydrogen would also be a valuable adjunct to such a manual.) Also, at a later date, public relations and promotional materials such as movies and booklets about the use of hydrogen will be needed. At present there is a need for the inclusion of the "hydrogen-energy story" in the gas industry's promotional materials on ways to increase gas supply. A comprehensive survey of national and, in particular, local codes should be undertaken as soon as possible to determine if they are restrictive enough to ensure safe operation with hydrogen. This cannot reasonably be done until more experience has been gained with the model distribution system.

There is an ultimate need for a demonstration, on a fairly large scale, of a complete hydrogen-energy system, including actual use of hydrogen by the public. A study of such a pilot system could be begun at a later date to lay out plans and determine costs of such a project. As part of this system, bulk electricity movement demonstrations using hydrogen as an intermediate will be best undertaken by the electricity companies, while transmission line demonstrations, perhaps using a closed loop with a compressor stage in the first instance, will be best carried out by gas transmission companies. In each case, large-scale electrolytic production equipment will be need and can be purchased from existing manufacturers.

2. Storage

Underground storage in depleted gas fields and aquifers appears possible. A field study, to outline a program and determine its cost, for the conversion of an existing field or the opening of a new one for hydrogen service should be carried out immediately. This would provide better confidence in the safety and feasibility of such a system. The second phase would be to actually convert a field in practice to hydrogen operation in order to develop complete confidence and operating experience and to expose problems.

3. Utilization

A brief experimental survey of existing domestic and industrial burners to determine practical conversion techniques for hydrogen service will be required, but is not urgent. The development of inexpensive and reliable catalysts for combustion of hydrogen and air is a long-term research objective that should be started soon and that would be of industry-wide importance. The development of completely novel types of appliances, possibly unflued, for both catalytic and flame-type burners should be started as soon as possible, so that experience with unflued appliances and their nonpollution characteristics is available for promotional and regulatory purposes.

E. Conclusions

In conclusion, let it be again stressed that this comprehensive action program need not be initiated in its entirety at this time. Rather, it should be used as an outline for a gradual development of the hydrogen-energy concept over the next several years.

Figure XI-1 is an outline of the research steps and objectives that we feel should be pursued in future. Some of these steps should be initiated immediately.

Figure XI-1 should not be regarded as an inflexible research program, for it is impossible to carry out detailed planning at this time. Its overall objective is to provide the capability of converting a "model city" or a local area to a hydrogen fuel service in a period 10-15 years from now and, in the interim, to provide the capability of constructing hydrogen-energy storage and transmission links for integration with both the existing gas and electrical systems. The overall plan will also allow the development of wider markets for "commodity" hydrogen," i.e., for the chemical and metallurgical industries, with pipeline delivery; will allow development of markets for the gas industry's new product, oxygen; and will lay the groundwork for expanding the new (hydrogen) gas industry's sales markets into vehicle and aircraft fuels.

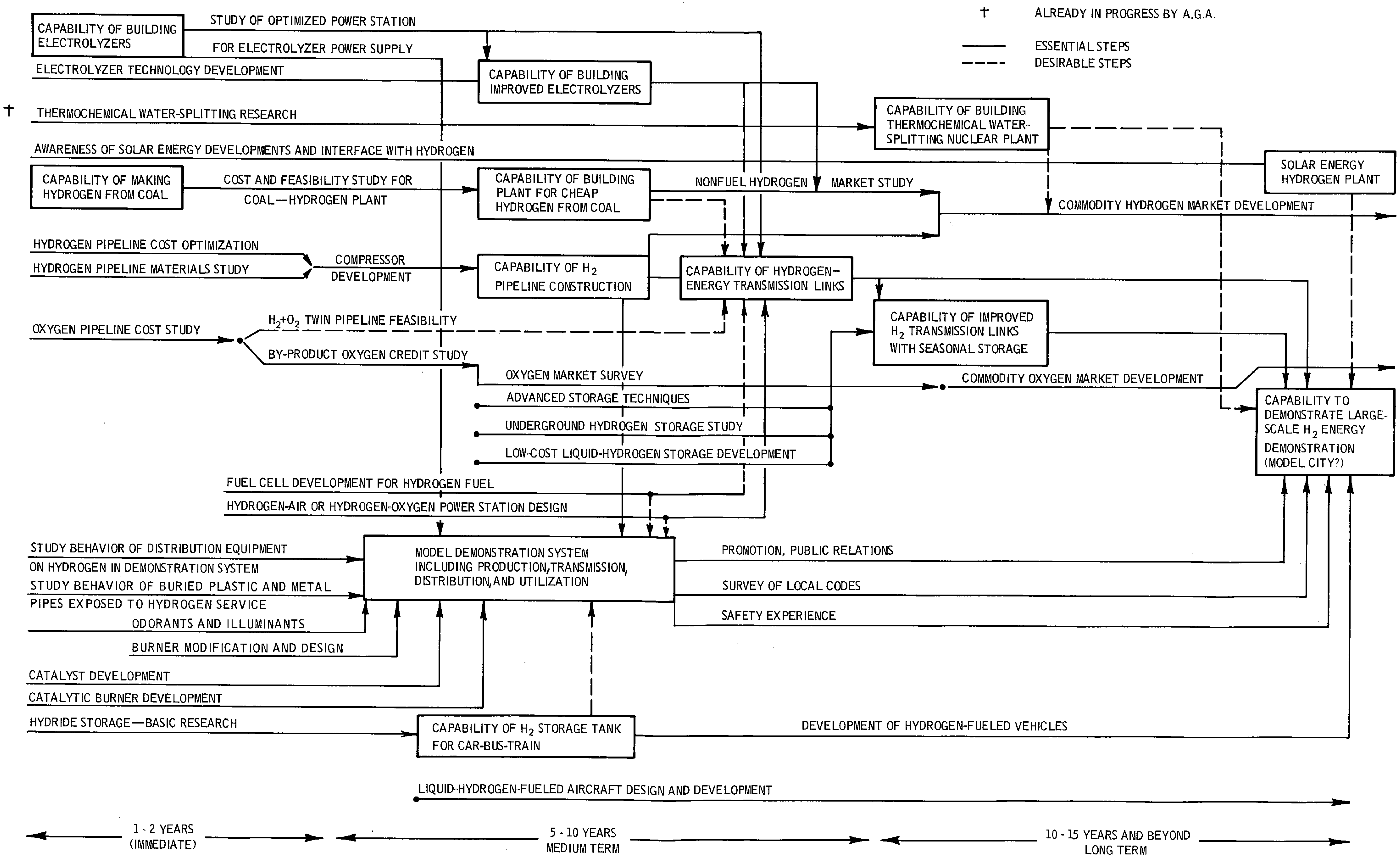

Figure X-1. OUTLINE OF FUTURE RESEARCH OBJECTIVES