Economic Implications of Peak vs Base-Load Electric Costs on Nuclear Hydrogen Systems

Charles W. Forsberg
Oak Ridge National Laboratory; P.O. Box 2008; Oak Ridge, TN 37831-6165
Tel: (865) 574-6783; Fax: (865) 574-0382; E-mail: **forsbergcw@ornl.gov**

Abstract

Electricity demand varies daily, weekly, and seasonally. The cost and price of electricity to meet the peak demands can be an order of magnitude greater or more than the cost and price of electricity at times of minimum demand. Nuclear systems are capital intensive, with low operating costs relative to those for most other methods used to produce electricity; thus, nuclear energy is most competitive in the production of base-load electricity (i.e., that part of the electricity demand that is constant throughout the year). Nuclear energy is generally not competitive for the production of intermediate and peak electricity, where the power plant operates for only a fraction of the year. Two nuclear hydrogen technologies (hydrogen produced using the energy from a nuclear reactor) have the potential to "convert" peak electricity demand into "base-load" demand and thus expand the markets in which nuclear energy is competitive.

The production of hydrogen by electrolysis for industrial markets at times of low electricity demand can significantly increase the base-load demand for electricity. Alternatively, the Hydrogen Intermediate and Peak Electrical System (HIPES) may enable nuclear hydrogen to be used to economically meet peak electrical demands and further expand the market for nuclear energy. HIPES would use off-peak electricity or dedicated nuclear hydrogen plants to produce hydrogen and oxygen that is stored and then used in hydrogen–oxygen steam cycles or fuel cells to produce peak electricity. If electrolysis is used, the off-peak electricity to hydrogen to peak electricity efficiency is ~50%.

The critical technology for both of these markets is low-cost bulk hydrogen storage for periods of days, weeks, and months because hydrogen demand does not occur at the same time that hydrogen is produced. Low-cost bulk hydrogen storage in underground salt deposits is a commercial technology; however, this technology has not been commercialized for other geologies. HIPES requires the development of several other technologies. These existing markets are not dependent upon future uses of hydrogen such as a transport fuel.

1. Introduction

Electricity can be converted to hydrogen, and hydrogen can be converted to electricity. Whereas electricity is difficult to store, hydrogen is stored (like natural gas) in salt caverns and could be stored in other types of geology. This raises a series of questions about the relationships between hydrogen and electricity. Can low-cost electricity during periods of low electrical demand be used to generate hydrogen for general applications? If so, can this increase the effective base-load electric demand and increase the fraction of electricity that can be economically produced by nuclear power plants? Can hydrogen be used to produce peak electricity? What are the implications of hydrogen storage on the size of nuclear hydrogen plants; that is, what is the trade-off between economics of scale of nuclear hydrogen production plants and storage of hydrogen to match variable production with variable demand? Sect. 2 provides an overview of these interrelationships and the implications for nuclear hydrogen and electricity production while the subsequent sections address specific technical challenges and issues.

2. Systems Characteristics of Electrical Grids, Nuclear Energy, and Hydrogen Production

Electricity demand varies daily, weekly, and seasonally. Fossil fuels are used to generate electricity and match electricity production with electricity demand. Fossil fuels excel in providing variable quantities of electricity to match demand because (1) fossil-fuel storage costs are low (piles of coal, oil tanks, etc.) and (2) the capital costs of equipment to convert fossil fuels to electricity are low relative to the costs of the fossil fuels. Relative to other options, it is economically viable to operate fossil electrical plants at low electrical outputs when there is a low electrical demand. Hydrogen production has similar characteristics in that the demand for hydrogen varies. When fossil fuels are used to produce hydrogen, hydrogen production is varied to match demand because (1) the fossil fuel storage costs are low (piles of coal, oil tanks, etc.) and (2) the capital costs of equipment to convert fossil fuels to hydrogen are low relative to the cost of the fossil fuels.

Nuclear energy is capital intensive; that is, the primary costs are associated with building the facility, not its operation. These systems can produce economic electricity only if they operate at near their full capacity to spread the capital cost over the maximum production of electricity. The same is true if hydrogen is produced. Such systems are uneconomic energy sources if the plants operate at low load factors. Unfortunately, their output does not match energy demand. This has several implications.

- *Electricity production*. The economic use of nuclear energy is limited primarily to base-load electricity production, when the plant can continuously operate near its peak output.
- *Hydrogen production*. Hydrogen is a chemical commodity and a method to transport energy—and represents an alternative to electricity. Like electricity, the demand for hydrogen varies with time. As with electricity, nuclear hydrogen is best suited for base-load production of hydrogen because of its high capital and low operating costs.
- *Economics of scale*. For both electricity and hydrogen production, large economics of scale are Associated with capital-intensive nuclear plants. The maximum-size economic plant is limited by the system requirement to provide electricity or hydrogen if that plant shuts down for any reason (including refueling). For most of the United States, this is not a major constraint on the size of electric-generating plants because of the existence of a large electrical transmission grid built over a period of almost a century. If a large plant is shut down, the electricity can be produced by other plants on the electrical grid. The absence of an equivalent transmission system for hydrogen represents a major constraint for the introduction of nuclear hydrogen in the early development of a hydrogen economy. Small nuclear hydrogen production systems are likely to be expensive. Nuclear hydrogen could be limited to industrial facilities where, if the nuclear hydrogen plant is shut down, the plants using the hydrogen could be shut down as well.

This mismatch between energy production and consumption can be potentially addressed by using bulk storage of hydrogen in underground facilities (the same technology used for seasonal storage of natural gas). Hydrogen storage avoids the need to match daily, weekly, or seasonal production with demand. Underground hydrogen storage in salt is a commercial technology that has been used on a limited scale to match hydrogen production with demand. Underground hydrogen storage is 1 to 2 orders of magnitude less expensive than other hydrogen storage systems. Current estimates indicate capital costs for large-scale hydrogen storage to be between \$0.80 and \$1.60/kg of hydrogen (Forsberg, January 2005; Leighty et al., 2006). Seasonal hydrogen storage costs would be a fraction of a dollar per kilogram vs production costs of \$2 and \$3. <u>The low storage cost allows daily, weekly and seasonal hydrogen storage to match production with consumption.</u> This has several implications.

- *Base-load electric demand*. If low-cost bulk storage of hydrogen is developed and there is a nearby market for large quantities of hydrogen, then low-cost electricity generated during periods of low electrical demand can be used for hydrogen production. The hydrogen can then be put into storage for use during periods of high hydrogen demand. Strong economic incentives exist for low-cost, long-term hydrogen storage because peak electric demand and peak hydrogen demand are likely to occur simultaneously. Low-cost electricity for electrolysis is available only when the demand for electricity is low. With this option, a significantly larger fraction of the electrical market can be dedicated to base-load electricity production because there is a secondary market for electricity at times of low electricity demand—the production of hydrogen by electrolysis. Recent studies of electrolysis options (Miller and Duffey; 2006; Texas Institute for Advancement of Chemical Technology, Inc., 2005) indicate that the technology is becoming competitive with the alternative of high-priced natural gas.

- *Economics of scale*. Nuclear plants (electricity and hydrogen) have large economics of scale (Forsberg, July 2006, August 2006). If low-cost underground hydrogen storage is available, the nuclear hydrogen facilities can be sized to minimize hydrogen production costs—not match the instant demand for hydrogen. The need to build multiple nuclear hydrogen plants to meet a minimum requirement for hydrogen production when one or more plants are shut down is eliminated. There is no requirement for a massive "hydrogen grid" such as exists for electricity.

- *Peak electricity demand*. Low-cost underground storage of hydrogen and oxygen (a by-product of hydrogen production from water) may enable nuclear hydrogen to be used for economic peak electricity production. Hydrogen and oxygen are produced by dedicated facilities or at times of low electrical demand using electrolysis. A Hydrogen Intermediate and Peak Electrical System (HIPES) then uses the stored hydrogen and oxygen to produce peak electricity. The combination of hydrogen and oxygen may enable low-cost, highly efficient methods for peak electricity production (Sect. 6) relative to traditional power conversion technologies that can use hydrogen and air.

Whereas the economics of hydrogen production using fossil fuels (high fuel costs and low capital costs) favor variable production of hydrogen to meet variable demand, <u>the economics of hydrogen production using nuclear energy (low operating costs and high capital costs) favor hydrogen storage to maximize utilization of the high-capital-cost nuclear plants.</u> Bulk hydrogen storage is a critical technology for the large-scale use of nuclear energy for hydrogen production. The following sections describe the technology and market factors for use of nuclear hydrogen in the context of the electrical grid as described above.

3. Characteristics of Electrical Markets

Energy systems have three components: energy sources, energy storage systems, and energy distribution systems. Energy sources include nuclear, renewables, and fossil. Energy storage systems, designed to match production of energy with demand, include water stored behind dams, as well as fossil fuels in the form of coal piles, oil tanks, and natural gas storage facilities. Energy distribution systems include electricity, natural gas pipelines, and liquid fuels. The cost of energy for the user is the sum of production, storage, and distribution costs; thus, the determination of the most economic system depends upon all three costs.

The electrical system matches electrical generation with electrical demand primarily by the use of fossil fuels. Fossil fuels can match electrical production and demand economically because they are inexpensive to transport (pipeline, railroads, etc) and to store until needed (piles of coal, oil tanks, etc.) and because the capital cost of equipment to convert these fuels to electricity is relatively low relative to the cost of the fuel.

In spite of these characteristics, matching electrical production to demand is still difficult. The demand for electricity varies with time of day, week, and year. A quantitative example of the challenge can be seen by assessing current electrical markets. In unregulated electrical markets, this fluctuation results in high costs for electricity during peak periods of electricity demand. An example [Miller and Duffy, 2003] of such variations is the price of electricity [$/MW(e)-h] in Alberta, Canada, during 2002 (Fig. 1). In regulated markets, the price of power may be constant. However, the utility must still build facilities to meet peak electrical demand. The cost to produce that electricity is significantly higher than the cost of electricity during periods of low demand.

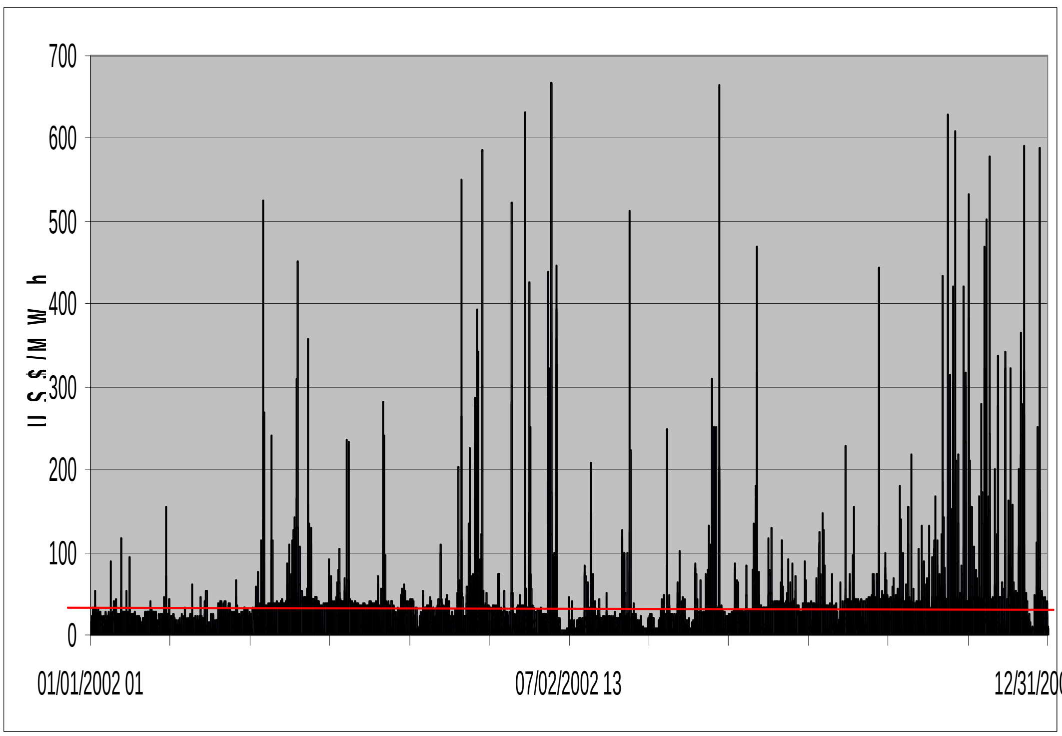

Fig. 1. Price of Electricity [$/MW(e)-h] as a Function of Time in Alberta, Canada.

For capital-intensive, low-operating-cost technologies such as nuclear energy, variable electricity demand presents an economic challenge. The cost of electricity is low only if the plant operates continuously at near its maximum capacity. However, the cost of electricity is high if the plant operates at partial load. Consequently, nuclear electricity is used primarily to provide base-load electricity at a constant rate. It is difficult to economically use nuclear electricity to meet a large fraction of the total electricity demand unless methods are found to levelize the demand. For electricity, historically, three approaches have been used to levelize electrical demand.

- *Time-of-day pricing*. Electric rates can be adjusted with time to provide lower costs to the consumer at times of lower electrical demand. The consumer can choose to buy a larger fraction of his electricity at these times. Multiple technologies are available to take advantage of time-of-day pricing. Many large industrial customers operate their most power-intensive equipment during times of low power demand. In Europe on a daily basis, fire brick is heated with lower-cost nighttime electricity to provide heat throughout the day. Hot water from night-time electricity is stored in tanks to provide hot water and heat for up to several days. France is the primary example of this strategy, in which time-of-day pricing reduces swings in electrical demand and thus increases the electrical base load that can be economically provided by nuclear. This strategy has been a major factor in allowing France to obtain over 70% of its electricity from nuclear energy. However, time-of-day pricing does not generally address weekly and seasonal variations in electricity demand.
- *Stored electricity*. Electricity produced at times of low demand and cost can be stored and delivered to the electric grid at times of high demand and cost. The traditional technology has been hydro-pumped storage. In a pumped storage facility, water is pumped uphill at night when the cost of electricity is low. At times of high power demand, the water flows downhill through turbines to produce electricity. For example, the Tennessee Valley Authority Raccoon Mountain pumped storage facility has a capability to produce 1530 MW(e) at times of peak demand. Similar systems have been built based on compressed air energy storage, with the compressed air stored in deep underground caverns. These technologies can store electricity on a daily basis; however, they are uneconomic for longer-term storage because the low energy density of the storage media (water stored at higher elevations and compressed air) makes it impractical and prohibitively expensive to store weeks or months of energy.
- *Hydroelectricity*. For countries in which a large fraction of the electricity is provided by hydroelectric plants, the hydroelectric plant outputs are varied to enable the nuclear plants to operate at base load. This situation exits in Sweden, where about half the electricity is generated by nuclear energy and the other half provided by hydro plants. For base-load nuclear electricity with hydro to provide the variable load, the hydro plants must provide almost half the total electricity—an option available only to countries in which hydro facilities can provide a major fraction of the total electricity demand.

The development of nuclear hydrogen systems creates two new options for levelizing the electrical demand and thus creating an electrical system where a very large fraction of the electricity can be economically provided by base-load nuclear facilities producing either electricity or hydrogen.

- *Increasing the minimum electric demand*. Hydrogen can be produced from electricity during off-peak hours, thus raising the fraction of the electricity that is base load. In this nuclear hydrogen future, the hydrogen production technologies must be electric intensive. For nuclear hydrogen, this implies electrolysis or hybrid cycles that use heat, electricity, and water to produce hydrogen.
- *Hydrogen to meet peak electric demand*. Hydrogen can be produced, stored, and then converted to electricity to meet peak power demand (Sect. 6). The hydrogen can be generated by electricity produced at times of minimum electrical demand or by dedicated nuclear hydrogen production systems that produce hydrogen at a constant rate.

The critical requirement for both of these applications is coupling nuclear hydrogen, the electrical grid, and low-cost, long-term bulk hydrogen storage.

4. Hydrogen Storage

Only one nonfossil method currently exists for weekly or seasonal storage of large quantities of energy (Quads) at low cost—storage of hydrogen as compressed gas in large underground facilities. No other low-cost technologies have been developed. Underground storage is the same technology used for seasonal storage of natural gas (U.S. Department of Energy, U.S. Energy Information Agency March 1995). In the natural gas industry, the most rapid consumption of natural gas occurs in winter. However, it is uneconomical to design transcontinental pipelines and natural gas treatment plants to meet peak natural gas demands. Instead, the natural gas is produced and transported at a relatively constant rate throughout the year. A variety of different types of large underground storage systems in different geologies at locations near the customer are used to store the excess natural gas produced during the summer for subsequent use in the winter (Fig. 2).

- *Man-made caverns*. Underground caverns are mined, with access to the surface provided via wells. The most common type of cavern is located in salt domes, where the cavern is made by pumping down fresh water and dissolving out the salt.
- *Pressure-compensated man-made caverns*. Underground caverns are mined, with access to the surface provided via wells. In addition, a surface lake connected to the bottom of the man-made cavern is created. The water pressure from the surface lake results in a constant pressure in the cavern that is equal to the hydraulic head of the water.
- *Porous rock with cap rock*. Porous rock exists with an impermeable cap rock above it that forms a natural trap for gases (inverted "U" shape). Wells are drilled into the porous rock, and injected gas pushes out whatever other fluids exist in the rock. Much of the world's natural gas is found in this type of geological trap. Similar structures are found worldwide without natural gas, many of which have been used for natural gas storage. In most cases, these are parts of aquifers and the injection of the gas pushes out the water.

The total existing natural gas storage capacity in the United States is 8.4×10^{12} ft^3, which is equivalent to about one-third of the natural gas consumed in the United States in 1 year. These facilities are large, with average storage capacities between 10 and 20 billion cubic feet. The usable capacity depends upon the required pressure at which the natural gas must be delivered to the pipeline and the rate of delivery. For high-pressure gas delivery, the capacity is about one-half, with one-half of the gas used as buffer gas to maintain storage facility pressure and minimize compression back to pipeline pressures.

The same technology is used commercially for storage of gaseous high-pressure hydrogen in salt to match variable industrial hydrogen demand with production, including assurance of hydrogen supply while hydrogen production facilities are shut down for maintenance. Hydrogen storage should be viable in other geologies. There has been limited assessments and experience in hydrogen storage in some other geologies but the technology is not fully commercial.

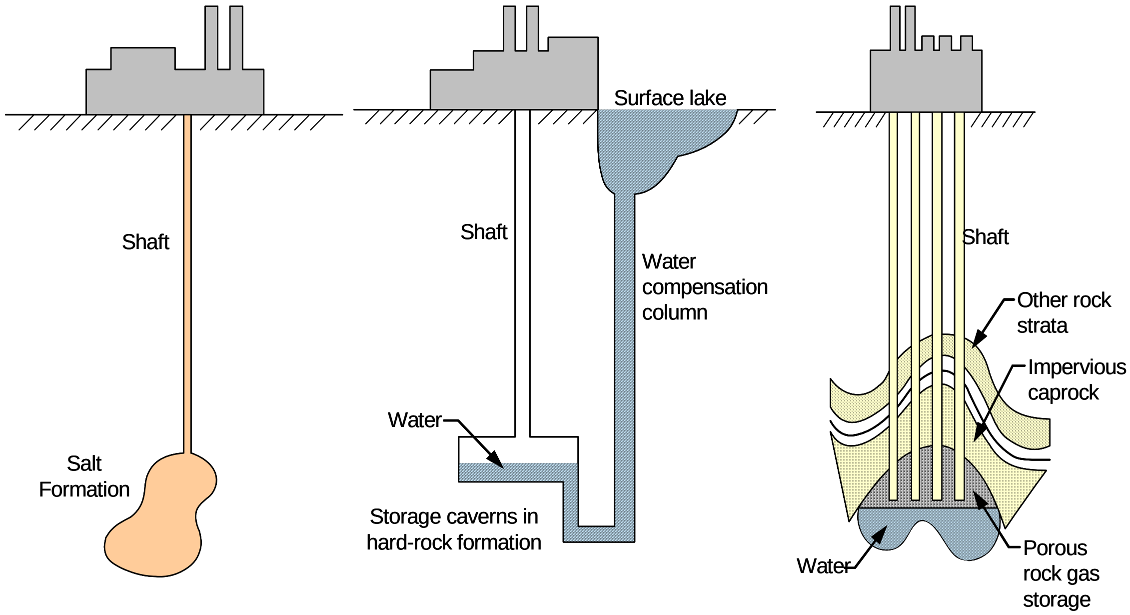

Fig. 2. Technologies for Underground Storage of Compressed Gases.

The capital cost (Forsberg, January 2005; Leighty et al., 2006) of an underground facility to store 1-GW-year of hydrogen (lower heating value) is estimated to be about \$200–\$400 million (\$0.80–1.60/kg storage capacity). The value of the hydrogen stored in such a facility will exceed the capital cost of the facility. The capital cost is sufficiently low as to make viable the seasonal storage of hydrogen. The capital cost estimate (1) assumes that the cost per unit volume stored is the same for hydrogen and natural gas and (2) is based on reported capital costs for existing hydrogen storage facilities and planned natural gas storage facilities (Thompson 1997).

5. Hydrogen Production

Hydrogen demand is rapidly growing because of the need to upgrade heavy crude oil to liquid fuels (gasoline, diesel, and jet fuel) and to improve the quality of liquid fuels by removal of sulfur compounds. Almost all hydrogen today is made by steam reforming of fossil fuels. In the United States, natural gas is the preferred fuel for hydrogen production. The combination of higher natural gas prices, concerns about greenhouse gas emissions (including those from hydrogen production using fossil fuels), and the growing hydrogen demand has resulted in major increases in research in hydrogen production methods.

The size of the hydrogen production unit is controlled by the market need, with multiple hydrogen production units typically located at a single facility (Ondrey, 2006) to ensure a continuous supply of hydrogen. Ten years ago, a typical single-train hydrogen plant produced $1.4 \cdot 10^6$ m^3/d ($50 \cdot 10^6$ ft^3/d).

Today, there are almost three dozen units with production capacities exceeding $2.8 \cdot 10^6$ m^3/d, with new units coming online with capacities of $3.7 \cdot 10^6$ m^3/d and plans for single-train units twice that size. The largest hydrogen production plants that use natural gas to produce hydrogen have production rates that would equal the hydrogen from a 1000-MW(e) nuclear power plant that used electrolysis. Today's hydrogen economy, primarily at oil refineries and chemical plants, is at a scale similar to nuclear power plants. If hydrogen can be produced at the right price and delivered to the refinery, a large rapidly growing market exists.

The energy from nuclear reactors can convert water to hydrogen and oxygen. The existing technology is electrolysis, the room-temperature process that converts electricity and water to hydrogen and oxygen. Three other classes of technologies, which use less electricity and more heat to convert water to hydrogen and oxygen, are being developed (Nuclear Energy Agency, 2003). Because heat is less expensive than electricity, these technologies have the long-term potential to produce hydrogen at lower costs. The energy inputs to high-temperature electrolysis are electricity and heat to convert water to steam. For hybrid cycles, the energy inputs are electricity and high-temperature heat to drive chemical reactions, while thermochemical cycles require primarily high-temperature heat to drive a series of chemical reactions.

In its 2004 report, the National Research Council recommended a significant effort to increase the electricity-to-hydrogen efficiency of electrolysis to 70% of the lower heating value of hydrogen, with a target capital cost of $125/kW(e) (U.S. National Research Council, 2004). In recent years there have been major reductions in the capital costs of these systems and the development of high-pressure electrolyzers that deliver hydrogen and oxygen at pressures suitable for hydrogen storage (Leighty et al., 2006; Miller and Duffey, 2006, Texas Institute for Advancement of Chemical Technology, Inc., 2005). In virtually all the studies, the primary cost of producing hydrogen by electrolysis is the electricity costs.

Hydrogen production studies show large economics of scale with scaling factors from 0.54 to 0.85 depending upon the technology (Forsberg, August 2006). The variation in the scaling factors depends upon the specific technology.

6. Peak Electricity Production

Hydrogen that is generated by a dedicated nuclear hydrogen facility or by off-peak electricity and the use of electrolysis can be used to produce electricity at times of peak electrical demand. There are two classes of hydrogen-fuel options to meet this highly variable electrical generating need.

- *Replacement fuel*. Hydrogen can be used as a replacement for natural gas using traditional heat-to-electricity technologies such as turbines. The current state-of-the-art commercial technology [U.S. Department of Energy, U.S. Energy Information Agency, April 2005] to meet intermediate and peak electric loads is the integrated combined-cycle plant. The natural gas is fed to a Brayton power cycle (jet engine) that produces part of the electrical power. The hot exhaust from the Brayton cycle is then fed to a conventional steam boiler to produce steam, which is sent to a conventional steam turbine. The plant efficiencies are ~55%, with overnight capital costs of ~$570/kW(e).

- *Hydrogen Intermediate and Peak Electricity System (HIPES).* Unlike fossil hydrogen production methods, nuclear hydrogen production methods convert water to hydrogen and oxygen. The hydrogen and oxygen may be used to produce intermediate and peak electricity at potentially much lower capital costs and significantly higher efficiencies than burning hydrogen in combined cycle plants (Forsberg, January 2005, August 2006). This is a new technology option that has not yet been demonstrated.

HIPES consists of three major components (Fig. 3).

- *Hydrogen production*. Hydrogen is produced from water, with the by-product production of oxygen. The hydrogen and oxygen can be produced by dedicated plants or use electricity at times of low electrical demand.
- *Hydrogen and oxygen storage*. Underground storage facilities are used for the low-cost storage of hydrogen and oxygen on a daily, weekly, or seasonal basis.
- *Hydrogen-to-electricity conversion*. Fuel cells, steam turbines, or other technologies are used to convert the hydrogen and oxygen to electricity. It is the use of the oxygen with the hydrogen that distinguishes this technology from other methods used to produce peak electric power.

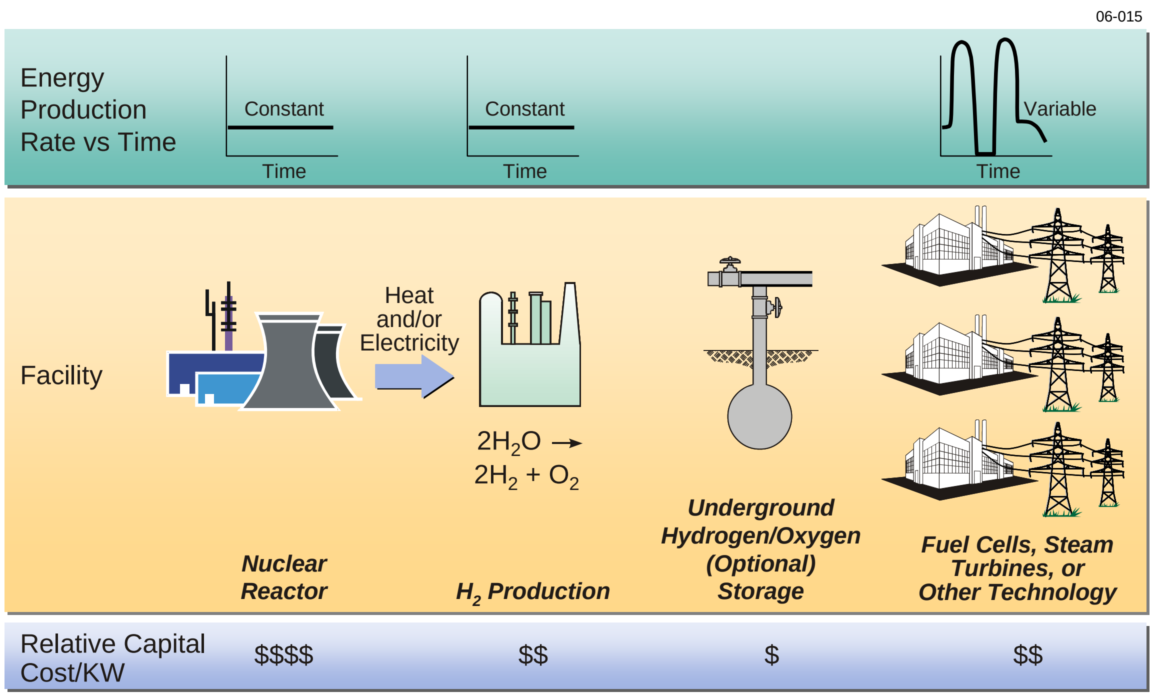

Fig. 3. Hydrogen Intermediate and Peak Electrical System.

The economics of HIPES are based on (1) minimizing the cost of hydrogen production by producing hydrogen at the maximum rate possible from capital-intensive facilities or using low-cost electricity at times of low electricity demand; (2) low-cost bulk hydrogen and oxygen storage; and (3) low-capital-cost, high-efficiency conversion of hydrogen and oxygen to electricity. Because of the wide variation in peak electricity demand, the hydrogen-to-electricity production capacity is many times that of the hydrogen production capacity.

6.1 Hydrogen-to-Electricity Production

Because the system design is driven by the peak electrical need, the hydrogen-to-electricity component is described first. Two technologies have been identified for conversion of hydrogen and oxygen to electricity at higher efficiencies and lower capital costs than those available with traditional combined-cycle plants.

6.1.1 Steam Turbines Without Boilers

The traditional technology to convert heat to electricity is the steam turbine. Heat from burning fossil fuels, nuclear reactors, or solar sources converts water to steam. To produce electricity, the steam is sent through a turbine that turns a generator. Historically, steam turbine peak temperatures have been limited to ~550°C because of corrosion in the boiler where the water is converted to steam. This restriction has limited the efficiency of converting heat to steam to ~40%. The most expensive component is the boiler, because it requires massive amounts of surface area to transfer heat from its source (burning fossil fuels, nuclear heat, or sunlight).

If hydrogen and oxygen are available, an alternative steam cycle (Fig. 4) exists (Forsberg, March 2006, August 2006]. Hydrogen, oxygen, and water are fed directly to a burner to produce high-pressure, very high temperature steam. Because the combustion temperature of a pure hydrogen-oxygen flame is far beyond that acceptable for current materials of construction, water is added to lower the peak temperatures. The technology is that of a low-performance rocket engine. The resultant steam is directly fed to a very high temperature turbine that drives an electric generator. With advancing gas turbine technology with actively cooled blades, it is expected that peak steam temperatures at the inlet of the first turbines will approach 1500°C. The projected heat-to-electricity efficiency for advanced turbines approaches ~70%.

HIPES has potentially lower capital costs than the hydrogen-fueled combined-cycle plants [$570/kW(e)] discussed earlier. The high-temperature turbine remains, but the need to compress air as an oxidizer is eliminated. The massive gas flow of nitrogen (80% of air) through the system is eliminated. Equally important, the boiler in the combined-cycle plant is eliminated and replaced by a small burner. These changes simultaneously increase efficiency (55 to 70%) and lower capital costs. This is a new option in a very early stage of development, and significant uncertainties remain.

The technology is based on ongoing development of an advanced natural-gas electric plant that uses oxygen rather than air (Anderson, 2004). Figure 5 shows the test burner that replaces a steam boiler. Combustors with outputs of ~20 MW(t) are being tested. With a natural gas oxygen feed, a steam–carbon-dioxide mixture is created. In the condenser, the steam is condensed and the carbon dioxide is available for (1) injection into oil fields to increase the recovery of oil and/or (2) for sequestration. There are strong incentives to develop the technology for burning of fossil fuels because of the higher heat-to-electricity efficiency and the production of a clean carbon dioxide gas stream for long-term sequestration of the carbon dioxide greenhouse gases.

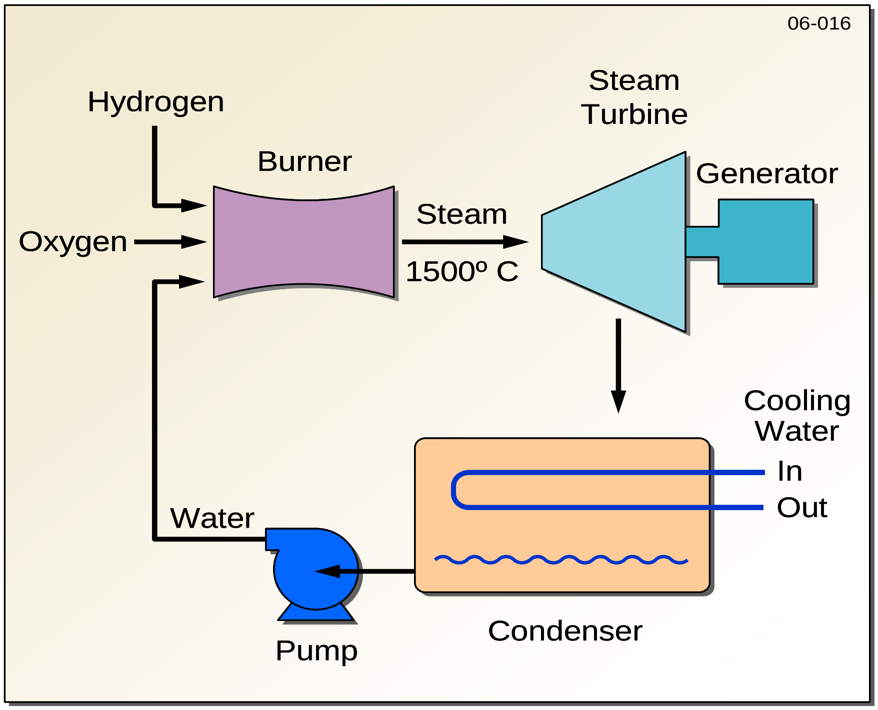

Fig. 4. Oxygen-Hydrogen-Water Steam Cycle.

Fig. 5. Fuel-Oxygen Combustor (Courtesy of Clean Energy Systems).

6.1.2 Fuel Cells

Hydrogen can be converted to electricity using fuel cells. A preliminary assessment (Forsberg, January 2005) based on near-term technologies indicates that the leading candidate for this application is the alkaline fuel cell. Alkaline fuel cells are one of the oldest fuel-cell technologies. A large experience base exists (EG&G Technical Services, Inc., and Science Applications International Corporation, 2002; McLean et al., 2002), and pure oxygen−hydrogen variants have been used for decades in the space program. The pure-oxygen alkaline fuel cells used in the Space Shuttle have an efficiency of ~60%. For large-scale industrial systems with no weight or size limitations, the efficiencies may approach 70%.

Several factors dramatically improve fuel-cell economics for this application relative to those for traditional fuel cell applications.

- *Oxygen feed*. Using oxygen feed increases fuel-cell output by several hundred percent (EG&G Technical Services, Inc., and Science Applications International Corporation, 2002) relative to air, with major reductions in capital costs with simultaneous improvements in efficiency. The size and efficiency of the fuel-cell system is controlled by the oxygen electrode. Pure oxygen increases the gas-phase oxygen concentration at this electrode by a factor of 5 over that achieved via the use of air with its 80% nitrogen content.
- *Utility application.* Fuel cells have primarily been used in aerospace and transport applications in which there are severe size and weight limits. These constraints do not exist for utility applications. Companies, such as Cenergie Corp. PLC, are now developing alkaline fuel cells for industrial and utility applications.
- *Economics of scale*. From an industrial perspective, a large-scale alkaline-fuel-cell facility has striking similarities to chlorine production facilities. Chlorine is used for water treatment, is produced on a massive scale, and is one of the largest sectors of the chemical industry. In a chlorine production facility, electricity is used in electrolytic cells to convert a sodium chloride brine solution to chlorine and sodium hydroxide. The facility includes large electrolytic cells, gas-handling systems for toxic gases, alkaline-solution (sodium hydroxide) processing systems with heat removal, and electrical power conversion systems. A large alkaline-fuel-cell facility has many similarities to the chlorine facility [electrolytic cells, hazardous gas (oxygen rather than chlorine), alkaline-solution processing systems with heat removal, etc.]. The scaling factor (Goossen et al., 2003) for chlorine plants has been estimated at 0.54; that is, increasing the size of the facility by a factor of 4 results in the capital cost of the larger facility being only 53% of that of the smaller facility per unit of capacity. Very large economics of scale that exist in such a process that are applicable for utility applications.

Work is also underway to develop multi-megawatt fuel cells that can operate in reverse as electrolyzers (Fletcher, 2006). For HIPES, the fuel-cell capacity would have to be sized significantly larger than the electrolysis capacity because of peak power demands that exist for relatively short periods of time.

6.2 Hydrogen and Oxygen Storage

HIPES requires the storage of hydrogen and oxygen. The oxygen would be stored underground like the hydrogen. However, there are additional technical issues associated with bulk oxygen storage. About 20% of air is oxygen; however, pure oxygen is hazardous. Pure oxygen can cause spontaneous combustion of clothing and many other objects. If high-pressure oxygen is stored and released, it cools as it is depressurized. Consequently, if a large-scale accidental release of oxygen occurs, the oxygen can form a cold high-density ground-level plume that floats off-site. Consequently, if oxygen is to be stored in large quantities, safety is a major design requirement.

One potential method to avoid this safety hazard has been identified. If the oxygen is heated 20 to 40°C above ambient temperatures before storage, should a release occur, the oxygen will have a lower density than that of air. This allows any oxygen plume to rise and be diluted by air. Nuclear reactors produce large quantities of low-cost heat, which would be suitable for heating the oxygen for safe storage. Other methods to ensure safety may exist as well, and significant work will be required in this area.

In contrast, hydrogen, which becomes warmer and lighter when depressurized, is a light gas that rises and rapidly disperses. There are significant operational safety challenges with hydrogen; however, a century of experience indicates that no significant off-site risk to the public exists for reasonable-sized sites.

HIPES places major constraints on the hydrogen and oxygen production technology. While hydrogen can be shipped by pipeline, pipeline shipment of oxygen is significantly more expensive and challenging because of associated safety concerns. Similarly, the storage of oxygen may require a significant heat input. These factors favor co-siting within several kilometers of hydrogen–oxygen production systems, storage systems, and electrical production systems and favor nuclear hydrogen production, centralized solar production technologies such as solar power towers, or advanced centrally located electrolyzer systems that use electricity from the electrical grid.

6.3 Economics

The economics of peak electricity production using HIPES depends upon (1) the efficiency, (2) the capital costs of the hydrogen-to-electricity conversion process, and (3) the difference in the price between low-demand and peak electricity. If electrolysis is the hydrogen production technique (Texas Institute for Advancement of Chemical Technology, Inc., 2005), the electricity to hydrogen to electricity efficiency is expected to be ~50%. Because this equipment operates for a limited number of hours per year compared with any other equipment in the system, the critical capital-cost component is the hydrogen-to-electricity conversion process. The peak rate of hydrogen consumption will be many times the peak rate of hydrogen production. In contrast, the hydrogen production equipment (even if electrolysis is used) may operate many thousands of hours per year. With weekly and seasonal hydrogen storage, there are large quantities of low-cost weekend, spring, and fall electricity that can be used for hydrogen production. The cost of hydrogen storage is a relatively small component in the total system cost (Forsberg, January 2005; Leighty et al., 2006). Peak electricity prices are often five to ten times the electric prices when the demand for electricity is low.

7. Status, Recommendations, and Conclusions

Because nuclear reactors have high capital costs and low operating costs, the historical market for nuclear energy has been the base-load production of electricity. Low energy costs occur only when plants are operated at full capacity. The use of nuclear energy for hydrogen production has the potential to dramatically increase the size of those markets in which nuclear energy is most competitive. This includes increasing the base-load electricity demand by production of hydrogen using off-peak electricity and enabling nuclear energy to be used economically to meet intermediate and peak electricity demand.

Today, the use of low-cost off-peak electricity for large-scale hydrogen production is a commercially ready technology. Preliminary studies have been conducted, and more detailed engineering studies are under way where high natural gas prices have resulted in high hydrogen costs and thus incentives to examine alternative methods of hydrogen production. There are strong economic incentives to develop lower-cost electrolyzers. The other technology limit is hydrogen storage. While low-cost hydrogen storage in salt is a commercial technology, salt deposits suitable for hydrogen storage exist in only some parts of the world. Thus, strong incentives exist to develop and demonstrate hydrogen storage in multiple types of geology so that the technology can be widely used.

HIPES is a new concept (<3 years old) for which the preliminary studies show great economic promise. However, the technology does not yet fully exist. Fortunately, most of the component technologies that are required, such as the oxygen–hydrogen steam turbine or fuel-cell systems, are under development for other purposes. However, these technologies will require modifications for this application. Major systems studies are required to understand the design trade-offs and economics relative to the markets for intermediate and peak electricity production. The one unique component technology that is not being developed for other applications is bulk oxygen storage. Only limited studies have been conducted in this area, and significant research and development is required.

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