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Market Basis for Salt-Cooled Reactors: Dispatchable Heat, Hydrogen, and Electricity with Assured Peak Power Capacity

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Abstract — *Energy markets are changing because of (1) the addition of nondispatchable wind and solar electric generating capacity and (2) the goal of a low-carbon energy system. The large-scale addition of wind and solar photovoltaics results in low wholesale electricity prices at times of high wind and solar output and high prices at times of low wind and solar input. The goal of a low-carbon energy system requires a replacement energy production system with assured peak energy production capacity.*

To minimize costs, capital-intensive nuclear reactors should operate at base load. To maximize revenue (minimize sales at times of low prices and maximize sales at times of high prices), the power cycle should provide variable heat and electricity. This requires the power cycle to (1) include heat storage that enables peak heat and electricity output that may be several times base-load reactor output and (2) provide assured peak power production. Assured peak power production requires the capability to efficiently burn low-carbon fuels such as hydrogen and biofuels. Alternatively, nuclear systems with base-load reactors can be built to produce peak electricity and storable hydrogen for industry, biofuels, and other markets. All power reactors with appropriate system designs can meet these requirements.

The lowest-cost technologies for heat storage, assured peak power production, and hydrogen production require high-temperature heat. This economically favors salt-cooled reactors with the average temperature of delivered heat of about 650°C versus heat delivered at lower average temperatures from other reactors such as light water reactors: 280°C, sodium-cooled reactors: 500°C, and high-temperature helium-cooled reactors: 550°C. Salt-cooled reactors include (1) Fluoride-salt-cooled High-temperature Reactors (FHRs) with solid fuel and clean salt, (2) Molten Salt Reactors (MSRs) with fuel dissolved in the salt, and (3) fusion reactors with salt blankets. Future energy markets, nuclear systems (heat storage, assured peak energy production capacity, and hydrogen production) designed for such markets and the power cycle technologies that economically favor salt reactors are described.

Keywords — *Heat storage, hydrogen, fluoride-salt-cooled high-temperature reactor, molten salt reactor, power cycles.*

Note — *Some figures may be in color only in the electronic version.*

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I. INTRODUCTION

Fossil fuels are a remarkable source of energy because they are relatively inexpensive, easy to store and transport, and capable of providing low-cost dispatchable energy. The capital cost of fossil power plants, furnaces, and other power conversion systems is low relative to the cost of fossil fuels. It is therefore economic to operate these systems at part load to provide economic

variable electricity, mechanical work, and heat to the customer. In this fossil fuel-dominated world, nuclear power plants (NPPs) that have high capital cost and low operating cost have been developed primarily for centralized electricity production and operated to provide base-load electricity to minimize production costs. Fossil fuels provide the variable electricity to the grid to match production with demand.

The world is undergoing two one-time changes in energy markets: (1) the introduction of large-scale non-dispatchable wind and solar photovoltaics (PV) that have low leveled cost of electricity (LCOE) production in good locations and (2) the goal of a low-carbon economy with no emissions of carbon dioxide to the atmosphere. Section II discusses the impacts of these changes on energy markets (electricity, residential, commercial, transportation, and industrial) and the resultant requirements for future nuclear power systems to be economically competitive in these markets.

The market changes create incentives for base-load reactors with large-scale heat storage and the ability to produce assured peak power above the base-load capacity to deliver variable electricity, heat, and hydrogen. These capabilities maximize plant revenue. The general power system designs to achieve these new capabilities are described in Sec. III.

The required systems can be coupled to any power reactor with the appropriate choices of heat storage and power cycle (steam or Brayton) technologies. Different reactor types deliver heat at different temperatures (Table I). Section IV discusses how the higher temperature of delivered heat from salt reactors reduces the costs of these power systems relative to other reactor systems and creates a competitive market-based economic advantage to develop and deploy salt-cooled reactor systems.

Liquid salt reactors include Fluoride-salt-cooled High-temperature Reactors¹ (FHRs), Molten Salt Reactors (MSRs), and fusion systems with fluoride salt blankets.² MSRs (Ref. 3) include thermal-spectrum MSRs that use fluoride salts and fast-spectrum MSRs with fluoride or

chloride salts. Only thermal-spectrum MSRs have been built. These salts have melting points typically between 450°C and 550°C; thus, the minimum temperature of delivered heat is 550°C or higher. Practical economic materials for heat exchangers typically limit peak temperatures between 700°C and 750°C. Salt boiling points are above 1200°C; thus, all of these machines operate at low pressures.

Section V provides the conclusions. The term “renewables” (implying wind and solar) is not used herein because nuclear energy⁴ is capable of providing energy for a world of 10 billion people with the current per capita energy consumption of the United States.

II. MARKETS

Markets define the requirements for energy production systems. The starting point for a long-term market assessment is the total heat and electricity markets of the United States (Sec. II.A). The question is then asked of how these markets will evolve with (1) the addition of large scale wind and solar and (2) the goal of a low-carbon economy. This assessment is then used to define what is required of a nuclear system to maximize revenue. This analysis is based on conditions in the United States, but the broad conclusions are applicable to most countries.

II.A. Energy Demand: Who Is the Customer?

Figure 1 shows the energy economy of the United States from sources of energy (nuclear, wind, solar, natural gas, etc.) to the ultimate customer (residential, commercial, industrial, and transportation). Electricity is an energy carrier and effectively acts as a fifth class of customer. Almost all energy today is provided by fossil fuels. Fossil fuels allow each fossil fuel to separately supply different end users. We have independent energy transport systems for electricity, natural gas, oil, and coal. Most energy is consumed as heat, not as electricity (orange lines in Fig. 1). This includes the transport sector where heat engines (internal combustion and jet) are used to move cars, trucks, and aircraft.

Figure 2 shows U.S. energy prices for major energy sources over the last 50 years. The cost of electricity (work) is about six times the cost of natural gas, which is a heat source. The price difference is a consequence of two factors. First, the laws of thermodynamics require several units of heat to produce a unit of electricity; thus, the cost of electricity is a multiple of any heat source. Second, electricity requires an electrical grid to move

TABLE I

Temperatures of Delivered Heat from Different Reactors

Coolant	Inlet Temperature (°C)	Exit Temperature (°C)	Average Temperature (°C)
Water	270	290	280
Sodium	450	550	500
Helium	350	750	550
Salt	600	700	650

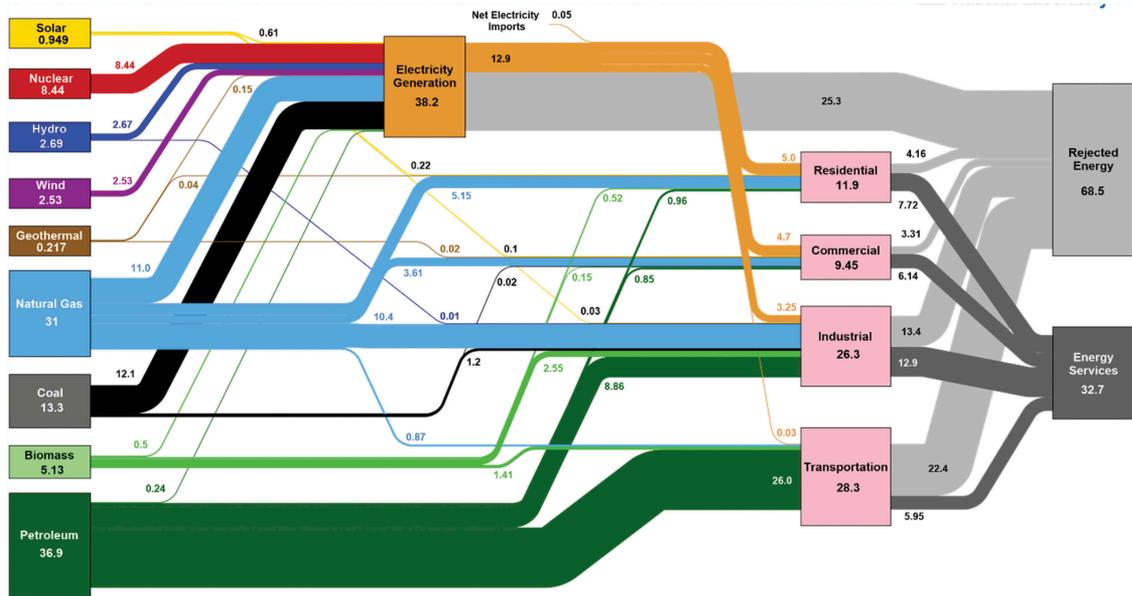


Fig. 1. Estimated energy consumption in 2018: 101.2 quadrillion BTU (quads) (Ref. 5).

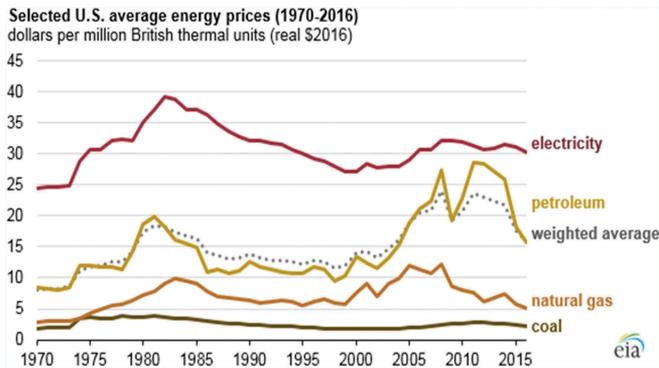


Fig. 2. U.S. energy prices over 50 years (Ref. 6).

from generator to user. Typically, half the cost of electricity is in production, and half is in delivery.

Table II shows the LCOE and levelized cost of heat (LCOH) from different energy sources. The LCOE is from Lazard⁷ while the LCOH is based on the heat-to-electricity efficiency of different types of power plants. Wind and solar costs are at sites with good wind and solar conditions. Technologies that directly produce electricity (wind and utility solar) at good locations have relatively low electricity production costs. However, they produce relatively expensive heat since one unit of electricity yields one unit of heat. Technologies that produce heat [natural gas, nuclear, concentrated solar power (CSP), etc.] produce lower-cost heat but make more expensive electricity because it takes several units of heat to produce

a unit of electricity. As discussed below, electricity grids require dispatchable electricity to provide electricity at all times including times of low wind or solar conditions; thus, low-cost electricity systems contain some mixtures of dispatchable and nondispatchable electricity.

These are not the full LCOEs because there are also system costs⁸ such as grid upgrades that are higher for wind and solar than for other generating technologies. In the United States those costs for wind are estimated to add \$16/MW·h (all \$ units are in United States dollars) if wind provides 10% of the electricity demand and \$20/MW·h if wind provides 30% of the electricity demand versus about \$2/MW·h for nuclear and \$0.5/MW·h for natural gas. The corresponding solar costs are estimated at \$15/MW·h and \$28/MW·h. As a consequence, natural gas is today in the United States the low-cost option. Various subsidies result in lower costs of wind and solar to the investor in parts of the United States. These same system costs apply to the LCOH when the heat is generated by electricity (wind and solar PV) but do not apply to natural gas or nuclear energy when providing heat. However, there is the requirement for users of nuclear heat to be collocated with the reactor. Natural gas and nuclear are the low-cost sources of heat.

Several conclusions follow from examination of energy markets. Nuclear reactors produce heat, which is what most customers require. Nuclear energy is more competitive in heat markets than electricity markets. If there are constraints on carbon dioxide emissions, large

TABLE II
Levelized Cost of Electricity and Heat in the United States

Technology	LCOE [\$/MW·h(electric)]	LCOH [\$/MW·h(thermal)]	Dispatch	Low Carbon
Solar PV: rooftop home	187 to 319	187 to 319	No	Yes
Solar PV: crystal, utility	46 to 53	46 to 53	No	Yes
Solar PV: thin film utility	43 to 48	43 to 48	No	Yes
Solar thermal with storage	98 to 181	33 to 60	Yes	Yes
Wind	30 to 60	30 to 60	No	Yes
Natural gas peaking	156 to 210	20 to 40	Yes	No
Natural gas combined cycle	42 to 78	20 to 40	Yes	No
Nuclear	112 to 183	37 to 61	Yes	Yes

customers such as the industrial sector will not convert to electricity because of the high cost of electricity relative to heat. We examine separately the future of the five energy markets (electricity, residential, commercial, transportation, and industrial) in the context of (1) adding large-scale wind and solar and (2) going to a low-carbon energy system.

II.B. Electricity Markets

II.B.1. Structure of Electricity Markets

The electricity sector has two primary requirements: (1) produce electricity measured in kilowatt hours and (2) provide assured electric generating capacity measured in kilowatts. In an all-fossil system, the required generating capacity (kilowatts) matches the peak electricity demand plus some additional generating capacity to allow for power plants that are shut down for maintenance. The major historical exceptions, such as in California, have been utility systems with nondispatchable run-of-the-river hydroelectric generating systems where the output depended upon rainfall and melting snow. In these systems the required generating capacity (fossil plus hydro) is larger than the peak electricity demand because at times of low river flow, little electricity was generated from the hydro facilities.

Historically, most electricity has been produced from fossil fuels (coal, oil, and natural gas). The cost of a power plant was low relative to the cost of fuel; thus, it was economic to produce variable electricity by varying the output of the power plant. When NPPs were developed, they had higher capital costs but lower operating costs. The most economic mode of operation was to operate NPPs at base load with fossil fuel power plants meeting the variable electricity demand.

In the United States there are regulated and deregulated utilities. Economic theory predicts that a perfectly regulated utility and perfectly deregulated market will obtain identical results, recognizing that there are no perfect regulators or perfect markets. In regulated markets, a single utility owns and operates electric generating systems, the transmission system, and the distribution system. The allowed profits by the regulator depend upon how well the utility performs. Historically, performance has been measured by how well the regulated utility minimized total electricity costs. In a deregulated market, electric generators compete for the sale of electricity where the transmission grid operator defines the market rules. There are two primary sources of revenue for electricity generators in these markets:

1. *Electricity markets (kW·h)*: Each electricity generator bids to produce a certain number of kilowatt hours for each hour, typically for the next 24 h. The grid operator predicts the amount of electricity needed each hour and accepts a sufficient number of bids to meet the total electricity demand for each hour. Every winning bid below the most expensive winning bid is paid the same for each kilowatt hour of electricity produced for that hour. A nuclear or run-of-the-river power plant will bid a low price to avoid shutting down. The price of electricity for each hour is determined by the electric generator with the highest operating costs.

2. *Capacity markets (kW)*: The grid operator must assure there are no electrical blackouts. The first option is to operate only with electricity markets where at times of peak demand the wholesale electricity prices may increase by a factor ≥ 100 to encourage power generators to build plants that produce electricity for < 100 h/year.

The alternative is a market for assured generating capacity (kilowatts) where generators bid to provide assured electricity capacity independent of payments for electricity (kilowatt hours).

There are other payments for specialized grid services, but these sources of revenue are small.

II.B.2. Addition of Nondispatchable Wind and Solar

The large-scale addition of wind and solar has massive electricity market impacts. Wind and solar in the right locations provide low-cost electricity (Table II) at times of high wind and solar output but no assured generating capacity. Figure 3 shows the impact of solar additions in California on a spring day in 2012 and 2017. In 2012 the price of electricity was controlled by natural gas with peak wholesale electricity prices in the early evening at times of peak electricity demand. The large-scale addition of solar resulted in collapse of wholesale electricity prices in the middle of the day with higher prices before sunrise and as the sun goes down. Wholesale prices in the middle of the day can become negative as conventional power plants bid negative prices to remain online at minimum output, so they are able to ramp up in the evening when electricity prices climb. The value of solar decreases as more solar is added⁹ as has been seen in multiple markets. This limits the large-scale economic deployment of solar.

Recent studies¹⁰ of the impacts of wind and solar on California electric wholesale markets provided insights to the long-term market effects of wind and solar. In the

United States wholesale electricity prices have been decreasing. The primary cause on a national basis has been the reduction of natural gas prices from fracking. However, California has aggressively pushed wind and solar relative to most of the United States. As a consequence, California provides a basis to understand the future impacts of wind and solar on wholesale electricity prices. Three conclusions follow from these studies:

1. Revenue to base-load power plants goes down with large-scale wind and solar additions.

2. There are large increases in the volatility of electricity prices. This creates large economic incentives for dispatchable electricity with fast response to produce electricity at times of higher prices (low wind/solar output) and avoid selling electricity at times of low or negative prices (high wind/solar output). Today, this favors gas turbines.

3. As more wind or solar is added, the revenue per installed kilowatt of capacity of wind and solar goes down. This effect is larger for solar than wind. Other studies¹¹ have come to the same conclusion. Revenue collapse limits the large-scale deployment of wind and solar unless large subsidies or markets are developed to absorb massive amounts of electricity to reduce times of very low electricity prices.

Historical studies¹² on electricity prices that cover multiple regions of the United States come to similar conclusions. We are going through a one-time transition of added nondispatchable wind and solar with low LCOEs in those parts of the country with high-quality wind and solar resources.



Fig. 3. Wholesale California electricity prices over 24 h on a spring day.

This change in the market creates incentives for electricity storage systems to buy electricity at times of low prices and sell at times of high prices to address hourly-to-daily price variations in electricity prices (Fig. 3). However, there are limits to such storage systems because of the seasonal variations in wind and solar. Figure 4 shows the smoothed electricity demand for California over a period of 1 year and the smoothed generating profile of wind and solar over the same time if sufficient wind and solar were built to meet the total electricity demand of California. That is, the total production of electricity from wind and solar matches total demand for electricity. There is a seasonal mismatch between production and demand with excess production in the spring and early summer.

If the goal is to produce all electricity from wind and solar, the system requires three components (Fig. 5). Electricity is generated by wind and solar with storage systems to better match production with demand over a period of days. To address the seasonal mismatch between production and demand, gas turbines, fueled with hydrogen or biofuels, could be used.

The cost of electricity (kilowatt hours) from wind and solar is low. However, for every unit of generating capacity (kilowatts), large amounts of energy storage and assured generating capacity are needed. The economics of large-scale wind and solar systems is determined by the economics of storage and assured generating capacity, not by the cost of producing electricity from wind and solar systems. This is why electricity costs have gone up in Germany, Denmark, California, and other locations that have attempted to create electricity systems based on wind and solar. Small amounts of wind and solar reduce electricity prices while large amounts increase prices.

The addition of wind and solar has two implications for nuclear energy. First, low-cost wind and solar reduce revenue for base-load NPPs. Second, if society is to economically benefit from the low cost of wind and solar electricity when available, one needs a second generating system with very low-cost storage and the capability to provide peak assured generating capacity, which an advanced nuclear power system can provide.

II.B.3. Implications of Restrictions on Carbon Dioxide Emissions

The requirement of low-carbon electricity has large impacts (Table III) on energy systems. Fossil fuels have reasonable costs, are easy to transport, and have low storage costs. As a consequence, the cost of a shipload of coal, oil, or liquefied natural gas (LNG) is about the same in New York Harbor as in Shanghai. The result is a relatively flat price of energy almost everywhere in the world. If carbon dioxide emissions must be eliminated, facilities that burn fossil fuels must capture carbon dioxide and sequester it, i.e., carbon capture and sequestration (CCS). Carbon dioxide sequestration requires the appropriate geology; it is geographically limited like hydroelectric facilities. Locations with inexpensive natural gas, such as Texas, will generally have viable sequestration sites in sedimentary rocks. In many geologies CCS is impossible. The permeability of granitic and many other common rocks is too low to store carbon dioxide.

Carbon dioxide can be shipped by pipeline to suitable sites for sequestration, but there are costs and significant constraints on the siting of long-distance carbon dioxide

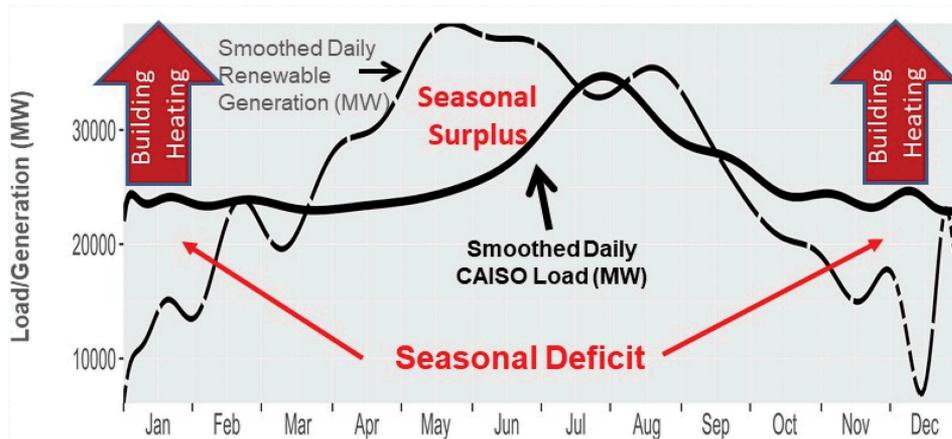


Fig. 4. Smoothed daily California electricity demand and smoothed daily renewable generation with total annual renewable generation equal to total annual electric demand (CAISO = California Independent System Operator) (courtesy of S. Brick, California Case Study, Clean Air Task Force).



Fig. 5. Nondispatchable wind and solar energy system design.

TABLE III

Characteristics of Low-Carbon Energy Sources

Energy Source	Dispatchable	Geographically Limited
Solar	No	Yes
Wind	No	Yes
Large reservoir hydro	Yes	Yes
Fossil with CCS	Yes	Yes
Nuclear	Yes	No

pipelines relative to natural gas pipelines. Natural gas is lighter than air whereas carbon dioxide is heavier than air. A break in a natural gas pipeline results in natural gas dispersing upward into the atmosphere. Whether it escapes to the atmosphere or burns, the hazards are very local. Carbon dioxide is heavier than air; it is a ground hugger that can asphyxiate people (as with the Lake Nyos disaster) at a distance away from a break. These transport constraints place geographical limitations on fossil fuel plants with CCS.

Recent studies^{13–16} have modeled the electricity systems in different parts of the world to determine the optimum electricity system in terms of minimizing average electricity costs with different constraints including (1) with and without nuclear power and (2) different limits on carbon dioxide emissions to the atmosphere. Figure 6 shows results from the Massachusetts Institute of Technology (MIT) study “The Future of Nuclear Energy in a Carbon Constrained World”¹³ for the two extreme cases: Texas in the United States and the Beijing region in China. Texas has low-cost natural gas, low-cost wind and solar, and relatively high construction costs for NPPs. China is the reverse with high-cost natural gas, higher-cost wind and solar, and low construction costs for NPPs.

Three future scenarios are shown in Fig. 6 for each carbon dioxide emission limit: no nuclear (blue), nominal cost nuclear (orange), and low-cost nuclear (gray). In Texas the low-cost option with no carbon constraints is natural gas; thus, the cost of electricity does not change until carbon dioxide constraints limit the use of natural gas. No nuclear is built. As carbon emissions become more constraining, added wind and solar are used to reduce the use of natural gas. If nuclear power is not allowed, at low carbon emissions one needs massive excess wind and solar generating capacity with storage to provide assured generating capacity. This rapidly drives up the cost of electricity. China is the reverse case with low-cost nuclear power and expensive alternatives; thus, if nuclear power is allowed, there is little change in the cost of electricity with changes in carbon constraints. Without nuclear power, electricity costs increase rapidly with increased carbon constraints.

Figure 7 shows the required capacity to meet electricity grid requirements in Texas for the case of no nuclear and nominal-cost nuclear. At very low carbon dioxide emissions, the no-nuclear case in Texas has almost 60 000 MW of capacity; most of that capacity is wind, solar, and batteries required to assure delivery of electricity. If nuclear is allowed, the total generating capacity is slightly less than 20 000 MW. The high cost of all-renewable scenarios is the cost of providing assured generating capacity.

The results of other studies reach the same conclusion. To avoid large increases in electricity costs with tight constraints on carbon dioxide emissions, one requires a dispatchable electricity source with assured peak electric generating capacity. Nuclear energy can fill that role, but there are other options in some locations, such as areas with massive hydroelectric capacity. There are caveats with these studies. In each case the existing demand profile for electricity was used. That demand profile will change if the entire economy is decarbonized, as discussed below. Second, the studies assumed electricity storage technologies and NPPs that did load-following. They did not evaluate the newer options of adding heat storage to NPPs for variable electricity output from base-load plants; that is, these studies did not consider redesigning nuclear systems as discussed below.

II.C. Residential/Commercial

The U.S. electricity and heat inputs into the residential and commercial markets are about equal (Fig. 1). The heat input is primary for building heating with a massive peak in the winter months that is supplied by natural gas.

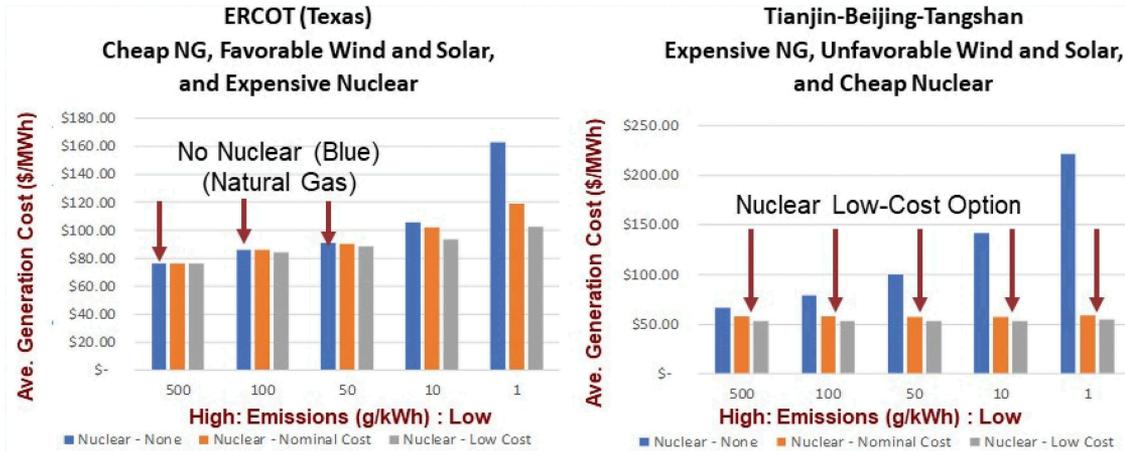


Fig. 6. Average price of electricity versus carbon constraint for Texas and Tianjin-Beijing-Tangshan.

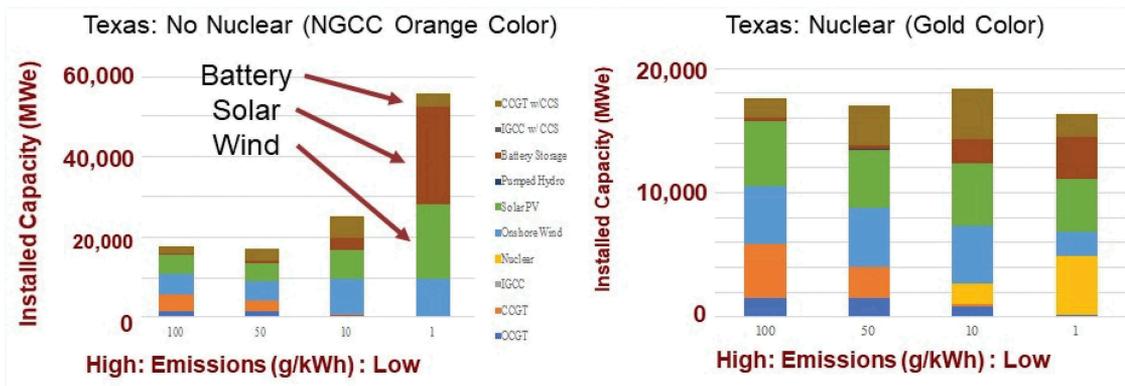


Fig. 7. Installed electricity capacity versus carbon dioxide constraints with and without nuclear power (NGCC = natural gas combined cycle; CCGT = combined cycle gas turbine; IGCC = integrated gasification combine cycle).

Peak natural gas demand is met by two mechanisms. The first mechanism is massive quantities of natural gas stored underground near consumers to meet winter demand. In the United States this storage capacity is about a fifth of a year of natural gas consumption.¹⁷ It would not be economically viable to build long-distance pipelines to meet peak demand. The second mechanism is fuel switching by industry and utilities to fuel oil at times of large home heating demand to free natural gas for home heating.

These options do not exist in a low-carbon world. In a low-carbon world much of this heating demand will be met by electricity that will move the seasonal peak electricity demand from summer to winter in northern climates. This peak demand will occur on cold days before sunrise at times of no solar input and minimum wind input. Wind output is lower at night. Multiday cold fronts will deplete electricity storage systems with less than multiday storage. The other low-carbon alternatives are hydrogen and biofuels that are discussed later.

Some parts of the world, such as Quebec, Canada, use electric heating. In most of these areas, peak electricity demand is met by massive hydroelectric capacity using the stored energy of water behind reservoirs. That option is not available for most of the United States, implying the need for large-scale added assured peak electric generating capacity for northern climates.

II.D. Transportation

The transport sector consumes about the same amount of energy as the industrial sector, primarily as fossil liquid hydrocarbon fuels, i.e., gasoline, diesel, and jet fuel. There are three competing low-carbon replacement technologies where choices will have large effects on the relative future demands for heat, electricity, and hydrogen—alternative products from nuclear energy systems. Those choices may strongly impact nuclear plant design (Sec. III). For some transport sectors¹⁸ such as aircraft, biofuels will be the preferred option, but there

are no clear winners for cars and light trucks. Different countries may adopt different light-vehicle fuels.

II.D.1. Electricity

Electric vehicles¹⁹ are proposed to replace gasoline and diesel in the light-vehicle market (cars and light trucks). There are two challenges: (1) battery cost and performance and (2) interface with the electricity grid. The cost of batteries is decreasing, but the cost of the raw materials in the battery (lithium, cobalt, etc.) may limit future cost reductions, so total vehicle costs remain above that of vehicles with internal combustion engines. Unlike heavy trucks or airplanes, the primary cost of automobiles is in the vehicle; thus, increases in vehicle costs present major problems for lower-income families.

Electric vehicles must be recharged from the electricity grid. A recent study²⁰ examined likely times when these vehicles will be recharged in California (Fig. 8) and found most recharging will be done in the early evening shortly after the sun sets, i.e., the time of peak daily electricity demand. This is caused by work schedules and single-car families that want assured car availability. That requires recharging vehicles in the early evening. From the perspective of the electricity grid, an all-electric vehicle implies massive grid and power plant expansion to meet a peak demand that lasts a few hours per day. There are proposals to require time-of-day electricity prices and other mechanisms to change recharging times; but all of these options require major changes in human behavior with most of the burden falling on single-vehicle families with lower incomes while reducing the advantages of cars—transportation on demand.

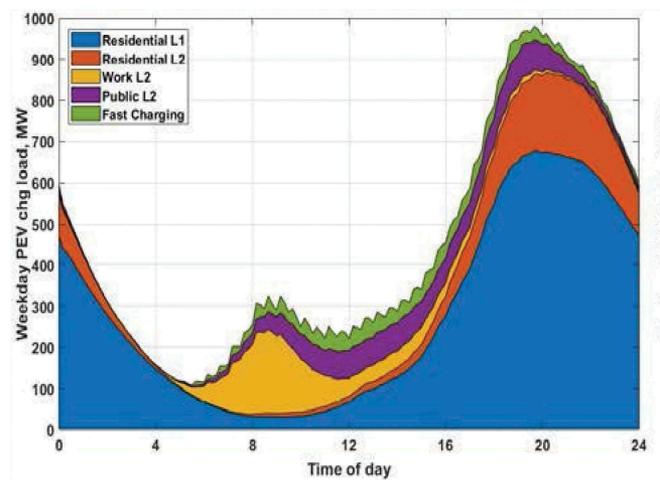


Fig. 8. Projected California plug-in electric vehicle (PEV) electricity demand 2017–2025 versus time of day.

In this context, there is a massive difference between all-electric vehicles and plug-in hybrid electric vehicles that have (1) batteries and (2) engines that could be fueled using biofuels, hydrogen, and other storable fuels. With a plug-in hybrid vehicle, there is assured transportation if the battery is not charged. The owner of such a vehicle would prefer to recharge when electricity prices are at a minimum and willing for the utility to partly control times of recharging. Plug-in hybrids have the potential to significantly reduce daily variations of electricity prices, reduce electricity prices, reduce investment in the electricity system, and result in a much more robust energy system.

There is a second effect of all-electric vehicles in northern climates. With internal combustion engines, heat for the passenger compartment is provided by the engine, which is waste heat at no cost. With all-electric vehicles heat is provided by batteries. This can substantially increase winter electricity demands.

II.D.2. Hydrogen

Significant work is underway to develop hydrogen-fueled vehicles¹⁹ and hydrogen-rich fuels such as ammonia. This is considered the main-line option in Japan and Korea. Hydrogen can be produced by multiple methods (Sec. IV), is storable, and is transportable. Beyond the vehicle, the primary challenge is the requirement to develop the refueling infrastructure. If hydrogen is adopted, it is likely to be first used in heavy trucks, delivery vehicles, trains, and ships that require less refueling infrastructure and have fewer weight constraints for on-board hydrogen storage systems.

II.D.3. Biofuels

Studies indicate that up to 25% of the global energy demand could be met by biofuels^{21,22} meeting most of the transportation fuel demand. This does require changing agriculture practices²³ to meet the multiple needs for food, fiber, and energy. The cost of biofuel (lignocellulosic) feedstock (\$20 to \$100/ton) is sufficiently low that biofuels are potentially competitive with fossil liquid fuels (Fig. 9).

In the area of biomass-to-liquid fuel conversion, there are three complementary strategies for liquid transport biofuels that can strongly affect the quantities of liquid fuels per ton of feedstock and net CO₂ releases to the air:

1. *Biomass as feedstock and energy source:* Biomass can be used as the feedstock for a biofuels refinery and the energy source to operate the biofuels refinery.

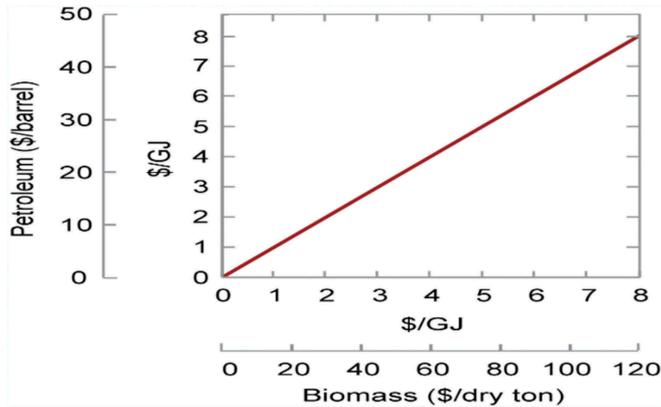


Fig. 9. Cost of biomass feedstock versus price of petroleum.

2. *Biomass as a feedstock*: The conversion of biomass into liquid fuels is energy intensive. If external sources of heat and hydrogen from nuclear, wind, and solar can be provided, the liquid fuel yield per ton of biomass feedstock can be doubled with dramatically lower feedstock requirements. Hydrogenation of biofuels²⁴ enables production of gasoline, diesel, and jet fuels, which are direct replacements for fossil fuels. The biggest component of biomass is plant cellulose $[(C_6H_{12}O_6)_n]$, comprising about a third of all biomass. The generic composition for hydrocarbon fuels is $[(CH_2)_n]$. Converting biofuels into high-quality hydrocarbon fuels requires at a minimum two hydrogen atoms to remove each oxygen atom. The hydrogen input requirements for biofuels could become 10% of the total energy demand and make hydrogen production, not electricity, the primary nonbiomass energy input into the transport sector (Fig. 1).

3. *Biomass for low-carbon biofuel and fossil liquid fuels*: Many of the biomass-to-liquid fuel processes produce nearly pure CO_2 as a by-product that could be sequestered underground. The sequestration of this CO_2 would allow burning an equivalent amount of fossil liquid fuel to be used with no net change in atmospheric CO_2 levels.

For aircraft and other vehicles that require the high energy density of hydrocarbon fuels, hydrocarbon biofuels will likely replace jet fuels. Detailed studies²⁵ of alternative fuels for aircraft show that liquid hydrogen and other such options result in significant reductions in aircraft efficiency. Lower-density fuels result in larger aircraft with larger resistance to airflow that increases fuel demand. Similarly, in long-distance trucks the volume and weight of lower-density fuels decrease truck cargo capacity.

II.D.4. Other Considerations

Today, the fossil fuel transport sector is almost independent of the electricity and industrial heat sectors. However, in a low-carbon world, transportation fuel choices will be tightly coupled to the electricity, hydrogen, and heat sectors. This implies that nuclear energy may become a major primary energy source for the transport sector. Grid challenges will likely limit all-electric vehicles with the widespread adoption of hybrid plug-in vehicles using (1) biofuels that use hydrogen in the production process or (2) hydrogen. Hydrogen is likely to become a major market for nuclear energy.

II.E. Industrial

The U.S. industrial heat demand is about twice the total electricity production. Direct electrification of industry would imply tripling the electricity system (Fig. 1) with the cost of electricity six times that of natural gas (Fig. 2). That would make much of U.S. industry noncompetitive. The industrial heat demand is relatively constant throughout the year and does not match production of energy from wind and solar (Fig. 4). In a low-carbon economy, the economic choices (Table II) are heat from nuclear reactors and fossil fuels with CCS. There are significant uncertainties in the cost of CCS systems, but estimates for large systems imply increasing heating costs by less than 30% (Ref. 17).

The cost of CCS is strongly dependent upon the specific industrial process. Restrictions on carbon emissions will likely result in major changes to some processes and replacement of other processes. For example, most hydrogen in the United States is produced by steam methane reforming²⁶ (SMR) where methane is reacted with steam to produce hydrogen and carbon dioxide. About two-thirds of the carbon dioxide from the process exits the process as a concentrated carbon dioxide stream. One-third of the carbon dioxide is from combustion processes to produce heat needed by the process including the production of steam. Most of the cost of CCS is producing a concentrated carbon dioxide stream for sequestration. The intrinsic process characteristics of SMR reduce CCS costs for that fraction of the natural gas that is a chemical feedstock. This is one of many examples where the requirement of a low-carbon system may result in CCS for concentrated carbon dioxide streams coming from the process and use nuclear heat to avoid burning fossil fuels and CCS with dilute off-gas steams. There has been almost no work to understand the relative use of nuclear and fossil fuels with CCS in the industrial sector for those parts of the world with sequestration sites.

The cost and technical constraints on fossil fuels with CCS are (1) continued low-cost fossil fuels and (2) appropriate sequestration sites. This leads to the conclusion that the industrial heat options for a low-carbon economy are (1) nuclear energy in any location and (2) fossil fuels with CCS where the appropriate geologies exist for carbon dioxide sequestration.

There is a long history²⁷ of using nuclear reactors to provide heat for district heating, water desalination, and various industrial uses. Most of these plants have been designed as cogeneration plants that produce heat and electricity. High-temperature steam is sent through a high-temperature turbine to produce electricity and steam at the temperatures required by the user of heat. The steam systems are similar to that used in fossil fuel cogeneration plants²⁸ that coproduce electricity and steam for industrial customers. Many cogeneration plants sell more electricity at times of high prices and reduce their heat demand by rescheduling production of other products. This can boost revenue and effectively is another way to vary electricity output to the grid. Cogeneration effectively couples the electric sector to the industrial heat sector. This enables optimizing the two sectors to minimize costs rather than separate optimization of the electric and industrial sectors.

A special challenge is providing low-carbon high-temperature heat to the steel, cement, glass, and other industries. Industrial heat in these sectors requires temperatures in excess of 1000°C, which is beyond the temperatures that can be provided by nuclear reactors. A recent study²⁹ examined the cost of heat to decarbonize heavy industry (Table IV) for different energy sources. Heat sources that were examined included (1) SMR to convert natural gas into hydrogen with different fractions of the carbon dioxide sequestered underground, (2) hydrogen from wind and solar, (3) biomass, (4) heat provided by high-temperature reactors (HTRs), and (5) electric heating. The hydrogen is burned to produce the very high-temperature heat. For many industrial processes, HTRs

can meet the temperature requirements. For other industrial processes, HTRs can preheat gases that are then further heated using hydrogen or electricity. There is, as discussed earlier, the option of adding CCS to existing industrial process; however, that option requires that the industrial facilities be located within a reasonable distance of appropriate geologies for carbon dioxide sequestration.

As in the transport sector, hydrogen is a major option to replace fossil fuels. In some industrial processes, such as steel production, hydrogen replaces carbon as a chemical reducing agent as well as a heat source. In other industrial processes, such as cement and glass production, it is a high-temperature heat source.

The capital costs of hydrogen production systems are large; thus, the hydrogen costs strongly depend upon high plant capacity factors. The high costs of hydrogen from wind and solar (Table IV) partly reflect the low capacity factors of wind and solar, which implies low capacity factors for hydrogen production facilities. In the United States, the average capacity factor³⁰ for utility solar PV systems is 22%, and for wind systems it is 33%. A secondary factor is that hydrogen pipelines are more expensive than natural gas pipelines with large economics of scale. Natural gas (CH₄) has a higher energy density per unit volume than hydrogen (H₂). Larger hydrogen pipelines are required to move the same amount of energy.

II.F. Implications for NPP Requirements

The goal of a low-carbon energy system in much of the United States will result in large changes in the electricity demand curve with peak demand likely occurring in the winter at night. If all-electric vehicles become a significant fraction of the transport fleet, added winter demand will occur as well as growth of peak daily demand shortly after sunset. Simultaneously addition of low LCOE from solar will depress wholesale daytime electricity prices in late spring and

TABLE IV
High-Temperature Heating Options for Heavy Industry

Heat Option	Heat Cost Minimum (\$/GJ)	Heat Cost Maximum (\$/GJ)
Hydrogen SMR, no CCS	8.8	12.5
Hydrogen SMR, 53% CCS	11.0	14.7
Hydrogen SMR, 89% CCS	14.2	17.9
Hydrogen renewables (wind and solar)	40.0	69.0
Biomass	15.0	29.0
Advanced nuclear (HTGR, salt reactors)	8.8	13.8
Electric heating (\$60 to \$120/MW·h)	16.7	33.3
Electric Heating (\$40 to \$90/MW·h)	11.1	25

early summer during the midday. Wind will depress prices at different times dependent upon location. Peak electricity demand will likely occur at times of no solar and little wind. The economic need is for nuclear plant systems (1) with assured peak electric generating capacity (kilowatts), (2) with variable electricity to the grid to meet the gap between electricity demand and supply from wind and solar and (3) that buy excess electricity (kilowatt hours) at times of very low prices (Sec. III).

There will be a large demand for nuclear industrial heat with relatively constant demand year-round. In most of these markets, wind and solar are not competitive. Much of the demand will be for high-temperature heat, but the relative quantities of heat at different temperatures is not well understood because of large changes in the industrial processes. Large heat users such as refining of crude oil will disappear. Biofuels and hydrogen production may become the largest markets for industrial heat. Unlike the electricity demand, this is likely to be regional with the primary competition being fossil fuels with CCS in areas with low-price fossil fuels and good carbon dioxide sequestration sites.

There will be a large demand for hydrogen. In some markets such as fertilizer production (ammonia) and metals production, there are no substitutes. The transport market may become the primary user, but this could be either as direct use as a fuel or indirect use in biofuel production. As discussed below, hydrogen production couples with electricity production and the industrial heat market.

III. NUCLEAR SYSTEM DESIGN WITH ENERGY STORAGE

The review of energy markets (Sec. II) defines the requirements for future nuclear systems. We describe herein the system designs required to meet those requirements. These system designs are independent of reactor type. The system designs are to deliver variable electricity, variable heat, and hydrogen to the customer.

III.A. System Architecture

Figure 10 shows the system design for variable electricity and heat with heat storage and assured peak generating capacity coupled to a nuclear reactor.^{31,32} The same system design is applicable to other heat generating technologies including fossil fuels with CCS, CSP, geothermal, and future fusion machines. To minimize the cost of energy, the nuclear reactor operates at base load. When electricity prices are high, all reactor steam is sent to industry and the turbine to produce electricity. When electricity prices are low, most steam is diverted

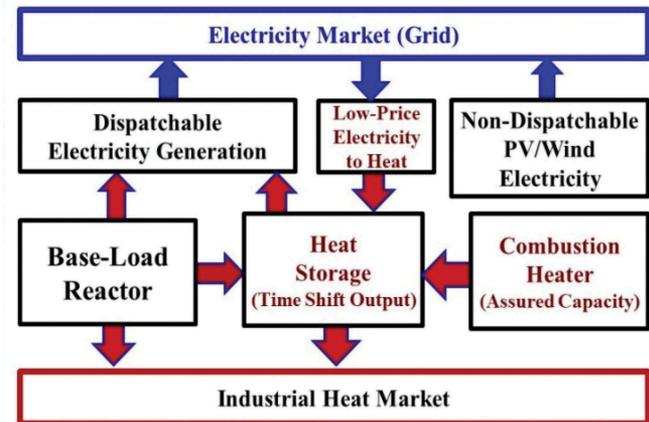


Fig. 10. System design for heat storage coupled to a base-load nuclear reactor for variable electricity and heat.

to heat storage. At times of peak electricity prices, heat from the reactor and heat storage is sent to the turbine for peak electricity production that is significantly above base-load reactor electricity output. Peak electricity production can be achieved by (1) oversizing the turbine generator or (2) building a separate peaking steam turbine for peak power output. At times of very low electricity prices, electricity from the grid and from the main turbine operating at minimum load is converted into stored heat with resistance heaters coupled to the heat storage system. The power plant sells and buys electricity. If heat storage is depleted, natural gas or low-carbon biofuels and hydrogen are used to enable assured peak electricity production by providing the extra heat that would have come from the heat storage system. The same system is used for cogeneration of electricity and heat for industry.

The choice of heat storage technology is dependent upon (1) the exit temperatures of the reactor coolant that must match the storage media and (2) the specific market. A market with large quantities of solar will have large daily variations in electricity prices whereas a market with large quantities of wind will tend to have multiday variations in electricity prices. In most parts of the United States and in many other countries, there is also a large difference in the electrical demand between weekdays and weekends.

Heat storage is inexpensive relative to storing electricity. The U.S. Department of Energy (DOE) goal for heat storage capital cost is \$15/kW·h(thermal) versus \$150/kW·h(electric) for batteries. The cost of the electronics associated with the batteries approximately doubles the cost. Table V shows current Electric Power Research Institute costs for bulk electricity storage systems.

TABLE V
Electric Battery Energy Storage Costs for Systems Installed in Fiscal Year 2018*

Technology	Rating (MW)	Duration (h)	Cost Range (\$/kW)	Cost Range (\$/kW·h)
Lithium ion	50 to 100	4	1400 to 2300	350 to 575
Flow battery	50 to 100	4	2300 to 3700	575 to 925
Lithium ion	30 to 50	6	2000 to 3300	335 to 550
Lead acid	30 to 50	6	2700 to 4100	450 to 685
Flow battery	30 to 50	6	2800 to 4800	465 to 800
Sodium sulfur	30 to 50	6	2500 to 4100	415 to 685
Lithium ion	20	0.5	500 to 1000	1000 to 2000

*Reference 33.

The cost difference between electricity and heat storage technologies reflects the cost of the raw materials to build the different storage systems. Table VI summarizes thermal-heat storage technologies and the upper temperature limits of these technologies. Recent workshops^{31,32} have explored the capabilities of these different heat storage systems when coupled to nuclear reactors. The technologies most likely to be used with salt-cooled reactors are described.

III.A.1. Liquid Salts

The primary heat storage materials used today in high-temperature CSP systems are nitrate salts with solar salt (60 wt% NaNO₃-40 wt% KNO₃) the most common salt. Sensible heat of storage is obtained by typically varying temperatures from 290°C to 565°C. With control of gas compositions over the salt storage tanks and salt chemistry, salt storage temperatures of 600°C or more may be viable. CSP salts need reasonable margins from decomposition temperatures to avoid hot spots in solar collectors degrading the salt. These salts are chemically stable in air. Heat storage system capital costs in CSP systems are ~\$20/kW·h of heat. The largest

storage system sizes are measured in gigawatt hours of capacity. Nitrate salts can be used to move heat to industrial customers.

The typical design of CSP systems with two-tank nitrate salt storage is shown in Fig. 11. Cold nitrate salt is pumped into the CSP system, heated by the sun to 565°C, and sent to the hot storage tank. Storage accomplishes two tasks: (1) enables the solar plant to produce electricity when the sun is down and (2) greatly simplifies operation. On partly cloudy days the power output of a CSP system varies depending on whether the clouds are blocking the sun. With storage, the power block does not see such transients. This greatly simplifies operations.

The same nitrate salt storage system designs are proposed for Sodium Fast Reactors (SFRs) (Terrapower), FHRs (Kairos Power), thermal-spectrum MSR, and fusion machines.² In addition to providing heat storage, in all of these systems, the low-pressure nitrate salt intermediate loop would provide isolation of the reactor from the high pressures in the power cycle. It replaces the intermediate heat transfer loop in these systems. In SFRs, it avoids the risk of generating hydrogen from a sodium-steam interaction. For FHRs, MSR, and fusion,² the salt serves two purposes: (1) heat storage and (2) tritium trapping. These

TABLE VI
Sensible Heat Storage Materials and Maximum Temperature Limits

Storage Technology	Temperature Limit (°C)	Storage Technology	Temperature Limit (°C)
Nitrate salt	<650	Hot sand	>1000
Chloride salt	<1000	Crushed rock	800
Cast iron	<900	Geothermal	<300
Pressurized water	<300	Liquid air	<1600
Concrete	>600	Sodium	<700
Hot oil	<400	Cold water	~0
Graphite	>1400		

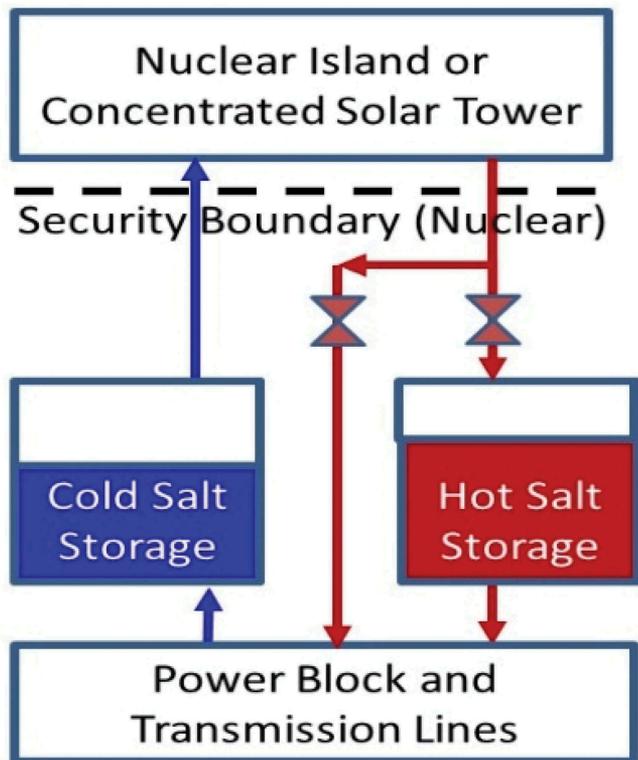


Fig. 11. System design for CSP and nuclear with heat storage.

reactor systems generate tritium in the coolant that may diffuse through heat exchangers. If tritium enters a nitrate salt, it is converted into steam that can be collected in the tank off-gas system. Hot nitrate storage acts as a backup tritium removal system.

Different designs of nuclear heat storage systems are evolving. Moltex Energy³⁴ is proposing that the peak electrical output be three times the base-load nuclear plant capacity based on its analysis of electricity markets in the United Kingdom. Terrapower and others are proposing that only the reactor be inside the security zone with the storage system and power block being outside the security zone. This would dramatically reduce the size of the security zone and enable the remainder of the plant to be built to normal commercial standards with the potential of large economic savings.

Work is underway³⁵ to develop second-generation salt systems that would allow CSP systems to operate at peak temperatures of $\sim 750^{\circ}\text{C}$ with higher-temperature stored heat. The goal is to have a pilot plant within 5 years. The proposed salt is a sodium, potassium, magnesium eutectic with a melting point of 383°C . This salt was chosen because of its extremely low cost combined with reasonable physical properties. Allowable peak operating temperatures could exceed 1000°C . The chloride storage salts

are proposed to be used with molten chloride fast reactors (Terrapower) with reactor peak temperatures near 750°C . The chloride storage salts would also couple to high-temperature gas-cooled reactors (HTGRs).

III.A.2. Crushed Rock

Crushed rock is the lowest-cost heat storage material; consequently, it is being developed as a heat storage material. Experimental work is underway on a second-generation nitrate heat storage system that would be a single tank filled with crushed rock.³⁶ Hot salt would be on top of cold salt. The addition of crushed rock would replace much of the nitrate salt with much less-expensive crushed rock. The crushed rock would also stabilize the thermocline between the hot salt/rock and cold salt/rock. The use of a single-tank system versus a double-tank system would further reduce costs. The goal is to reduce the capital cost of storage to about $\$10/\text{kW}\cdot\text{h}$ of heat storage in CSP systems.

Initial studies³⁷ are underway on a third-generation nitrate salt–crushed rock system for high-temperature nuclear reactors to further lower capital costs to a few dollars per kilowatt hour of heat storage. The tank structure would be replaced by an insulated trench up to 60 m wide and 20 m high and lengths that may exceed 1000 m with no internal structures. The trench would be filled with crushed rock with approximately 1 GW·h of heat storage for every 10 m in length. The design minimizes structural components and insulation by minimizing the surface-to-volume ratio. The bottom and sides have three layers. Facing the crushed rock is the salt pan that collects salt. It is backed up by insulation with cooling tubes between the insulation and soil to prevent increases in soil temperature, which is a structure similar to the foundation structure for CSP nitrate salt storage tanks. Above the crushed rock is a roof with insulation and salt spray equipment.

The crushed rock is heated by spraying hot salt on top of the rock (Fig. 12) to minimize (1) the inventory and thus the cost of nitrate salt and (2) requirements on the rock and the confinement structure. The salt inventory

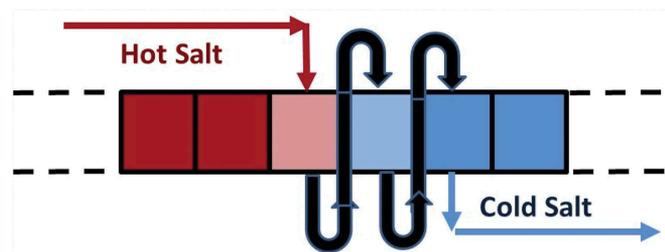


Fig. 12. Sequential heating crushed rock bed with hot salt.

is determined by the maximum rate of heat transfer to and from the crushed rock (megawatts) not by the heat storage capacity (megawatt hours). Hot salt sprayed on a section of rock heats the rock while flowing through the rock to a salt pan at the bottom of the structure. If the salt is not fully cooled, it is collected and sprayed onto the next segment of crushed rock. The rock is heated sequentially from left to right. To heat salt, a traveling wave of salt goes in the reverse direction.

There is a parallel effort^{37,38} to develop hot oil heat storage systems for CSP and nuclear systems. Heat transfer oils have peak temperature limits of $\sim 400^{\circ}\text{C}$; consequently, these storage systems are limited to lower-temperature CSP systems and water-cooled reactors. There are operating CSP systems with hot oil storage in tanks. Work is underway to develop systems with crushed rock in the tanks to replace some of the oil inventory and reduce costs. Last, work has begun on crushed rock in large trenches with heat transfer oil to move heat from the CSP/nuclear system to the crushed rock and from crushed rock to the peak power generating system.

III.A.3. Concrete

Low-cost specially formulated concrete is being developed for heat storage at different temperatures. The Westinghouse system consists of thin concrete slabs designed to couple with light water reactors (LWRs) and lead-cooled reactors. Heat is transferred from the reactor coolant to the heat storage system using high-temperature heat transfer oils at atmospheric pressure that can operate up to 400°C ; these are the same heat transfer fluids used in many chemical plants and lower-temperature CSP systems. The oil would be heated by steam from the reactor system and then used to heat the concrete at times of low electricity prices. For peak power production, the hot oil would be used for preheating of feedwater. Using stored heat for feed preheating enables peak electricity production 20% to 25% higher than base load. The heat transfer oils are not used for heat storage because of their high cost relative to the low cost of concrete.

Bright Energy is developing a concrete heat storage system that consists of helical tubes in special concretes capable of temperatures in excess of 600°C . The baseline design has steam in the tubes, but other fluids could be used. When steam is added, it heats long concrete modular units from one end to the other while the steam is converted to water. To recover the heat, water is sent in the reverse direction to produce high-temperature steam. This system will couple to any steam power

cycle. The initial market is for retrofit to existing coal plants with multiple boilers into peak electricity production systems. If the plant had three boilers, two can be shut down. Heat storage enables one boiler to operate at near full load to produce electricity and charge the heat storage system. At times of peak electricity demand, heat from storage is used to provide steam to operate the steam turbines of the other two units.

III.A.4. Cast Iron with Cladding

Sensible heat can be stored in solid tightly packed hexagonal assemblies 10 to 20 m high made of cast iron with a stainless steel cladding chosen for chemical compatibility to match the coolant, i.e., sodium, salt, lead, or helium. Coolant flows between the solid assemblies. This option places an upper limit on the cost of heat storage associated with any coolant, i.e., water, salt, sodium, and helium. It is compatible with any reactor coolant with the appropriate choice of clad.

III.A.5. Other Options

There are several classes of thermochemical systems where heat is stored in chemical bonds. In hydride systems heat is used to decompose a hydride-producing hydrogen. When the reaction is reversed, the formation of hydride releases heat. In carbonate systems the chemical reaction is conversion of a carbonate such as calcium carbonate into calcium oxide and carbon dioxide. Last, there is a set of chemical reactions that involves forming hydrates where steam is released when the hydrate is heated and heat is generated in the reverse direction. All of these systems are at much earlier stages of development.

III.B. Addressing Low-Carbon Requirements

Table VII compares the different systems: wind and solar, nuclear, and combined systems; Fig. 5 defines an all wind/solar system; and Fig. 10 defines a combined system. The combined system, with local variations in quantities of different energy sources, is the low-cost system because of four factors:

1. *Electricity (kW·h)*: In good locations, wind and solar provide lower-cost electricity but are available only when wind is blowing and the sun is shining.
2. *Storage*: Storage of heat is much less expensive than storing electricity. Heat storage costs will always be lower than electricity storage costs because of the lower cost of raw materials. Storage costs decrease as reactor

TABLE VII

Comparison of Nondispatchable and Dispatchable Low-Carbon Systems

System	Nondispatchable Electricity	Dispatchable Heat to Electricity	Combined
Technologies	Wind, solar, PV	Nuclear, fossil CCS, CSP, geothermal	All
LCOE (kW·h)	Low	Medium	
Storage technologies	Batteries, pumped storage	Salts, crushed rock, etc.	All
Cost of storage	High	Low	Low
Assured peaking capacity	Gas turbine	Combustion furnace	Combustion furnace
Cost assured peak generating capacity (kW)	High	Low	Low
Total cost of electricity	High	Medium	Low
Cogeneration	No	Yes	Yes

temperatures increase. For latent heat storage systems (salt, crushed rock, etc.), storage costs decrease as reactor temperatures go up because of the larger swing in hot to cold temperatures. If the temperature swing doubles (LWR to salt-cooled reactor), the quantity of storage material per kilowatt hour of heat is reduced by a factor of 2. Equally important is if heat is stored at high temperature, the heat-to-electricity efficiency is higher, which reduces the cost of heat storage and the cost of the heat-to-electricity conversion system.

3. *Assured peaking capacity (kW)*: Assured peaking capacity is less expensive for the nuclear systems. With wind and solar systems, one may buy 3 kW of capacity (wind/solar, battery storage, backup gas turbine) for every kilowatt of assured generating capacity (Fig. 5). In this system (Fig. 10), 1 kW of generator capacity (base load and peak) is 1 kW of total capacity. The cost of the backup boiler or furnace for assured peak power is much less than a gas turbine.³⁹

4. *Cogeneration*: Nuclear energy produces heat, which is required for industry. The same system including the heat storage systems allows efficient coupling of the energy demands of the electric sector and the industrial sector that allows trade-offs between the two sectors to reduce total energy costs.

III.C. Hydrogen Production

Hydrogen production could potentially be 10% to 30% of the total energy system. It has three roles. The first is as a chemical reagent in the production of fertilizer, metals, and biofuels. In these applications there are no substitutes. The second role is in fuel cells for electricity production for vehicle transport and other purposes. The third role is as a high-temperature heat

source for industry and possibly other markets. There are four hydrogen production options⁴⁰:

1. *Steam methane reforming*: High-temperature steam is reacted with natural gas to produce hydrogen and carbon dioxide. The carbon dioxide can be sequestered underground.^{26,41} The process produces a concentrated carbon dioxide stream and a second stream from the burning of natural gas to produce heat for the process; thus, partial CCS can be inexpensive. The United States currently produces 10 million tons of hydrogen primarily for fertilizer production and refining of crude oil. Almost all of this hydrogen is produced by SMR. In a low-carbon world, this becomes the low-cost hydrogen production option where there is inexpensive natural gas and sequestration sites, such as in Texas.

2. *Electrolysis*: Water is electrolyzed to produce hydrogen and oxygen. This is an old process used at remote sites to produce smaller quantities of hydrogen.

3. *High-temperature electrolysis (HTE)*: This is electrolysis of steam and is potentially a lower-cost process than electrolysis because (a) some of the energy is in the form of lower-temperature heat and (b) the process does not require expensive catalysts as used in traditional electrolysis. It is in the early stages of commercialization and would couple to NPPs (see below).⁴²

4. *Thermochemical hydrogen production*: In these processes water is converted to oxygen and hydrogen via a series of chemical reactions requiring the input of high-temperature heat. These processes are in the laboratory stage of development.

For hydrogen production SMR has a major advantage over all processes starting with water. Hydrogen is in

a chemically reduced form in methane (CH_4) whereas with all the other processes, hydrogen is in its oxidized form, i.e., water (H_2O). It takes less energy to get hydrogen from methane than water. It is the economic production option in locations with low natural gas prices and good carbon sequestration sites.

High-temperature electrolysis has major economic advantages over low-temperature electrolysis (LTE) but is at an earlier stage of development. Part of the energy input is in the form of steam that costs less than electricity. If there is very low-price electricity, there is the option of increasing hydrogen production but with lower efficiency. Second, HTE is more efficient than LTE (Ref. 43). Figure 13 (Refs. 44 and 45) shows the expected efficiencies of converting heat into electricity for LTE and HTE for different reactor systems at different temperatures. For any reactor, there is the choice of (1) converting all the heat to electricity and then producing hydrogen using LTE or (2) converting some of the heat to electricity and supplying the HTE with steam and electricity. This second option produces about a third more hydrogen for the same amount of heat from the reactor.

Hydrogen is a premium energy carrier like electricity, but unlike electricity, it can be inexpensively stored in the same underground storage facilities used for natural gas on an hourly to seasonal basis. Figure 14 shows the equivalent systems design for nuclear HTE hydrogen

production. Hydrogen storage partly replaces the role of heat storage in a system that can buy and sell electricity from the grid. At times of low electricity prices, electricity from the grid is used for electrolysis while heat from the NPP goes into heat storage and providing steam for the HTE system. At times of high electricity prices, heat from the reactor and heat storage produce peak electricity with no hydrogen production. This system configuration uses heat storage and hydrogen storage for a base-load NPP with variable heat, electricity, and hydrogen output.

A nuclear hydrogen electricity production facility allows the option of buying electricity from the grid with more steam and less electricity from the reactor. Dumping low-price electricity into hydrogen production produces a high-value product rather than dumping low-price electricity into heat storage. HTE systems have the capability to produce more hydrogen with higher voltages but at lower efficiency. This creates the option to vary hydrogen production depending upon the price of electricity, adsorbing more excess electricity. A similar system⁴⁶ is being developed in Japan for nuclear hydrogen systems coupled to thermochemical hydrogen production with variable electricity to the grid.

As discussed earlier (Table IV), hydrogen production facilities are capital intensive. It is uneconomic to operate

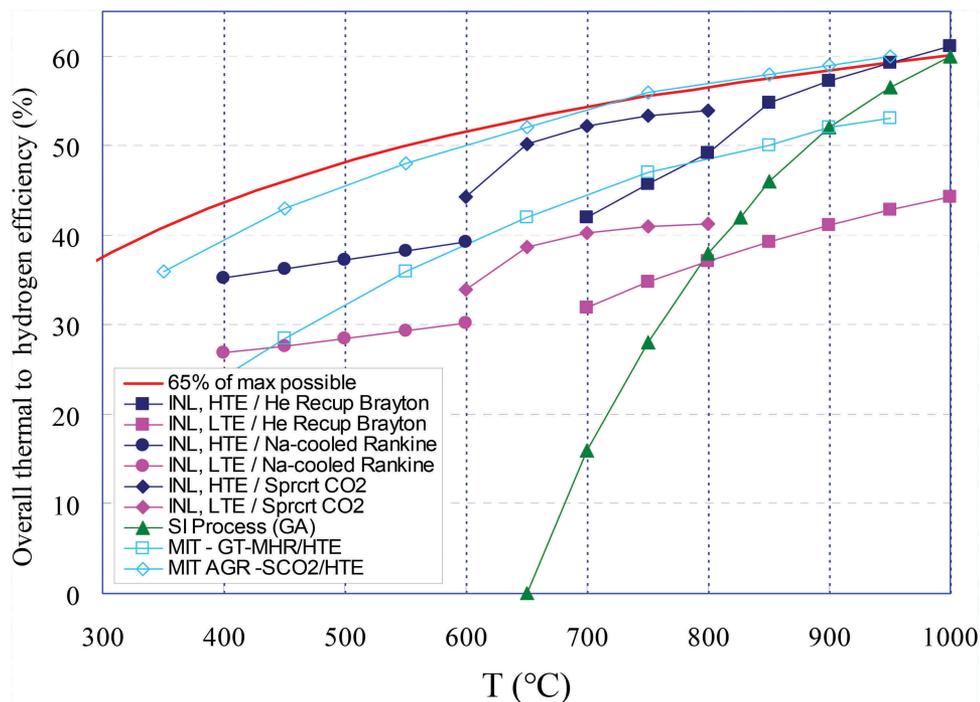


Fig. 13. Overall thermal-to-hydrogen efficiencies for LTE and HTE versus temperature for different reactor systems (INL = Idaho National Laboratory).

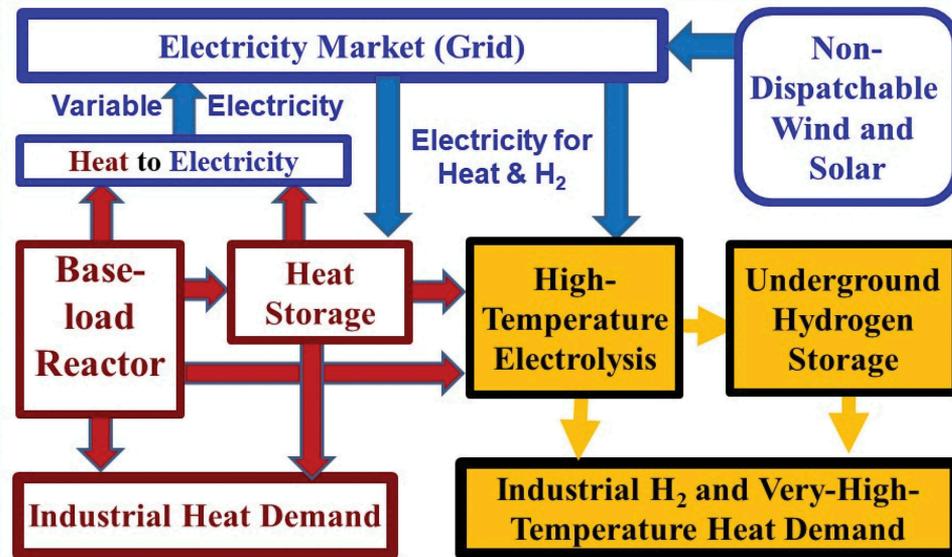


Fig. 14. Nuclear hydrogen production system using HTE and heat storage.

such facilities at low capacity factors. This may require that NPPs producing hydrogen operate the hydrogen production facilities more than 80% of the time,⁴⁷ i.e., the times at which electricity prices are low. Electricity is sold to the grid only at times of high prices. In effect, a nuclear electric hydrogen plant becomes, in terms of the electricity grid, a peaking plant as shown in Fig. 15 for peak assured electricity production. This system has the potential to efficiently address seasonal peak demands for electricity (Fig. 4). Large-scale seasonal hydrogen storage is inexpensive (the same technology used for natural gas); thus, at the same time, hydrogen supplies for customers can be assured.

IV. TECHNOLOGY CHOICES AND POWER CYCLE OPTIONS FOR SALT-COOLED REACTORS

The historical market for nuclear power has been base-load electricity. The new market for nuclear energy is variable heat and electricity with assured peak energy production capabilities. The systems to meet these requirements, as described in Sec. III, work with any type of power reactor. However, there are differences in costs depending upon the reactor type because different reactors deliver heat to these systems at different temperatures. The ideal system has several characteristics:

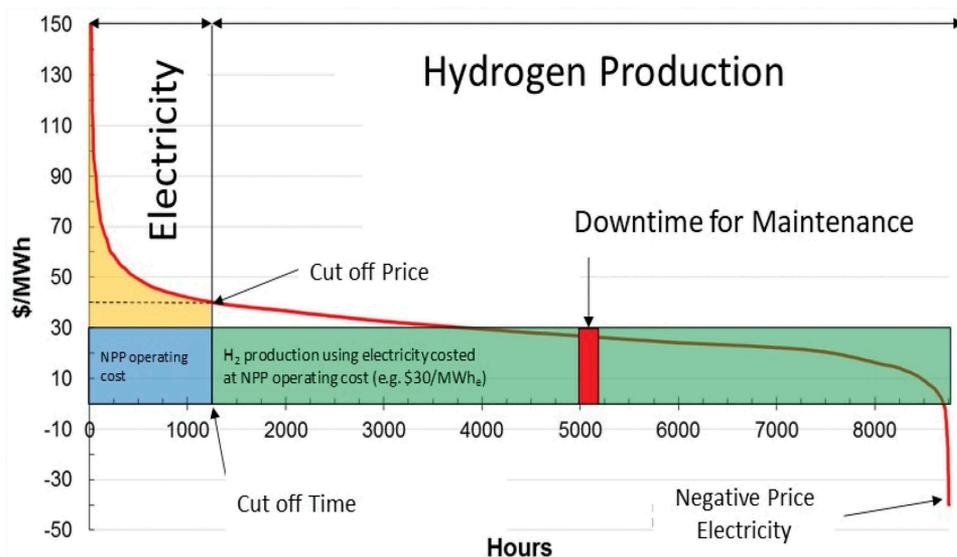


Fig. 15. Hydrogen electricity production strategy.

1. *Large peak-to-base-load capacity:* If one is to maximize use of low-cost wind and solar electricity where available, one needs nuclear systems that can provide low-cost assured peak capacity that may match the peak electricity demand of the grid if peak demand occurs at times of minimum wind and solar. In northern climates with heating loads, this becomes a real possibility.

2. *Low-cost heat storage:* The stored heat capacity per unit mass depends upon the hot-to-cold temperature swing. If one doubles the hot-to-cold swing, storage costs drop in half. Higher-temperature storage lowers heat storage costs.

3. *Efficient fuel-to-electricity conversion:* To provide assured backup in the event heat storage is depleted, a combustion heater or boiler is used. In a low-carbon system, the fuel would likely be hydrogen or biofuels. Economics favors power systems with high temperatures and thus high efficiency in converting combustible fuels to electricity. Similarly, if heat is stored at higher temperatures, less storage is required per unit of electricity that is produced.

4. *High-temperature heat for industry:* Industry requires high-temperature heat. Increased reactor coolant temperatures implies that a larger fraction of industrial heat demand (including hydrogen production) can be met with nuclear reactors.

Given the above goals, this section describes the technology and power cycle options for salt reactors that deliver all heat above 500°C. Two power cycles with heat storage are described: (1) steam (Rankine) cycles that are the near-term option and (2) nuclear air-Brayton combined cycles (NACCs). Either can be integrated into hydrogen peak electricity production options.

IV.A. Steam (Rankine) Cycles

Figure 16 shows a generic design of a high-temperature steam cycle coupled to a salt reactor with storage in multiple locations and capable of providing heat to industrial customers at various temperatures. Nitrate or chloride heat storage is located before the steam cycle with the option to provide heat to industry as hot nitrate or chloride salt. Hot salt can be sent to a steam generator to produce high-temperature high-pressure steam for the high-pressure turbine or industrial customers. After the steam goes through the high-pressure turbine, it can be sent to heat storage, a low-pressure turbine for electricity production, or industry.

IV.A.1. Salt Heat Storage

Most companies that are developing salt reactor systems have chosen to include an intermediate nitrate salt loop between the reactor and power cycle. The intermediate loop provides isolation between the low-pressure salt reactor and high-pressure power cycle as well as heat storage.

Today, the preferred salt is the sodium-potassium nitrate salts used for heat storage in concentrated solar power plants. This enables using the commercial nitrate heat storage and steam power cycles used in existing CSP plants, thus minimizing development risks associated with the power cycle. Some commercial CSP plants have backup steam boilers to provide assured generating capacity if heat storage is depleted, which is an option available for salt nuclear systems.

IV.A.2. Intermediate-Temperature Heat Storage

Many fossil fuel cogeneration plants produce high-temperature steam, send the steam through a high-pressure turbine producing electricity, and then use the lower-pressure steam as a heat source for lower-temperature industrial processes. The same option applies to salt reactors that produce high-temperature steam. Much of the industrial heat demand is for saturated steam where setting the steam pressure provides constant temperature heat via steam condensation. This includes many processes for production of organic chemicals and biofuels where higher temperatures cause organics to decompose.

Heat storage can be installed between the high-temperature and low-temperature turbines to provide assured steam to industry and variable electricity to the grid. At times of low electricity demand, heat is dumped to storage whereas the low-pressure steam is used for electricity production at times of high electricity demand. Because saturated steam is produced by some CSP systems, multiple heat storage technologies³¹ have been developed to operate at these temperatures. Work is underway to couple large-scale heat storage to LWRs at these same temperatures.

The leading heat storage options at the temperatures of saturated steam use high-temperature heat transfer oils and a secondary heat storage medium. The chemical industry has used heat transfer oils for over 50 years that are stable to about 400°C. These oils have low vapor pressures, thus minimizing the risk of fire. These same oils are used in lower-temperature CSP systems. These heat transfer oils have historically been used to transfer heat over long distances in large chemical plants via low-pressure pipelines; thus, such heat storage systems easily couple to industrial customers.

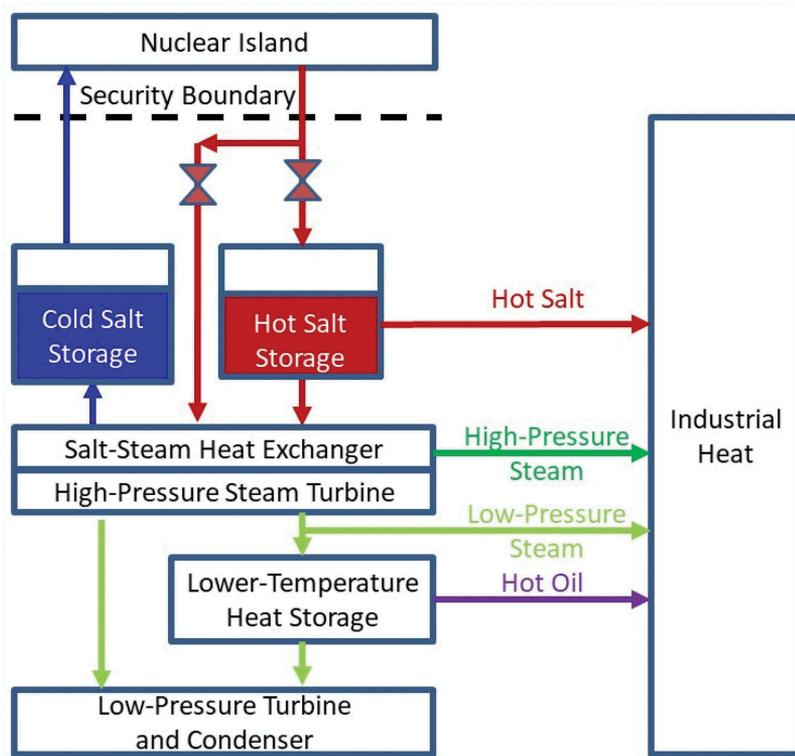


Fig. 16. Heat storage options for Rankine cycles with heat to industry.

The Koreans^{38,48–52} are examining a system using heat transfer oils where the heat storage material is crushed rock. There would be multiple tanks of crushed rock with heat transfer oil only in tanks where heat is being transferred from the steam cycle to the crushed rock or from the crushed rock back to the steam cycle. Round-trip efficiencies can approach 80%; that is, if a -megawatt hour is generated without storage, 0.8 MW·h of electricity is generated from the stored heat. The Korean design proposes that the storage system be built as a large barge (60 × 450 m) with multiple tanks with a heat storage capacity of 20 GW·h of electricity. This barge is the same size as a supertanker and would be delivered to coastal nuclear power sites where it would be floated into (effectively) a dry dock at the reactor site. When decommissioned, it would be sent back to the shipyard for decommissioning.

IV.B. Nuclear Air-Brayton Combined Cycles

Molten Salt Reactors were originally developed in the late 1950s as part of the U.S. Aircraft Nuclear Propulsion Program that had as its goal a jet-powered bomber of unlimited range to deliver nuclear weapons to the Soviet Union. The reactor was chosen based on its

ability to efficiently couple to a jet engine, i.e., a Brayton power cycle. In a jet engine, air is compressed, heated, and exhausted through a turbine that powers the compressor. That requires a reactor that delivers all of its heat at high temperatures significantly above the temperature of the compressed air. In modern gas turbines, that compressed air temperature is above 400°C. Salt reactors efficiently couple to Brayton power cycles with all heat delivered significantly above 400°C.

In the last 60 years, there have been revolutionary advances in gas turbines for electricity production. These advances enable gas turbine combined cycle (GTCC) plants with heat-to-electricity efficiencies above 60%. This enables NACC plants⁵³ with heat storage and thermodynamic topping cycles. Figure 17 shows NACC (Refs. 1, 32, 54, 55, and 56) with a thermodynamic topping cycle and integrated heat storage. The power cycle is similar to a GTCC plant. Research on NACC power cycles is just beginning. These cycles are not viable for lower-temperature LWRs. Like the steam cycle, there is the option of heat storage between the reactor and the power cycle as well as heat storage inside the power cycle.

The reactor operates at base load. Within NACC, air is filtered, compressed, heated in heat exchanger 1

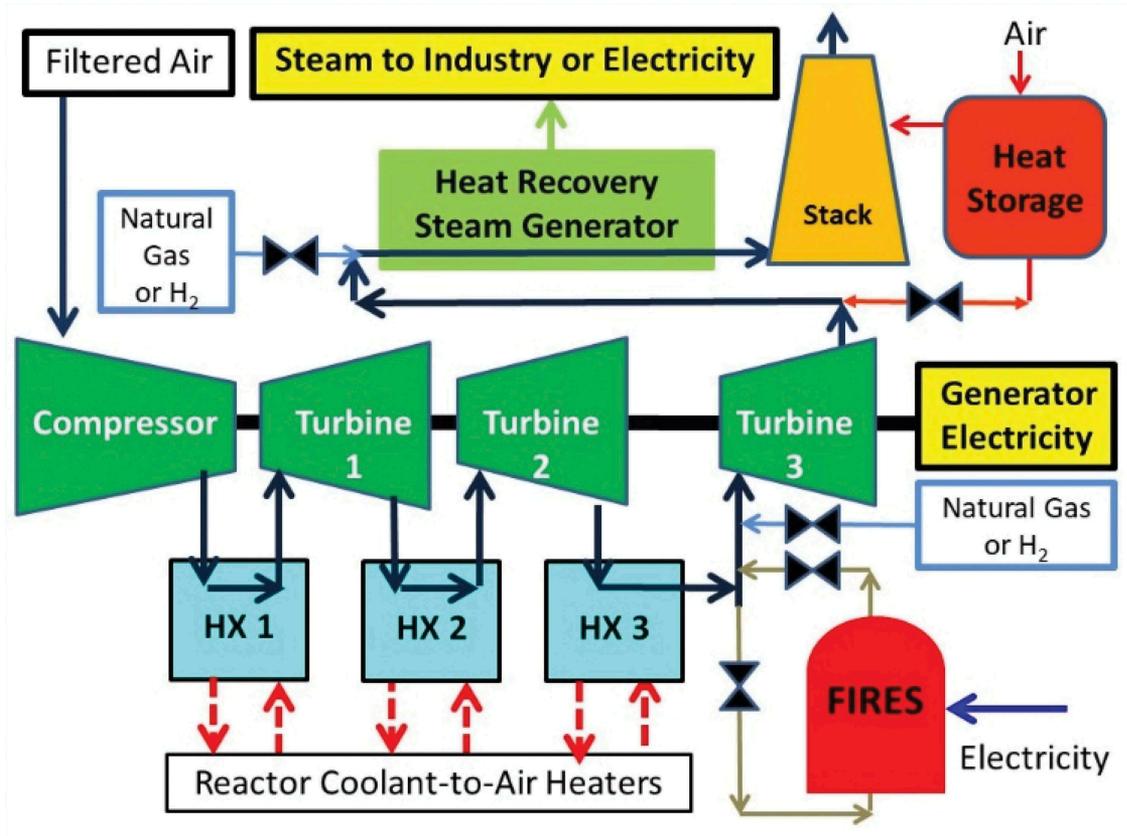


Fig. 17. Nuclear air Brayton cycle (NACC) with thermodynamic topping cycle and heat storage.

(HX1), goes through turbine 1, is reheated in heat exchanger 2 (HX2), goes through turbine 2, is reheated in heat exchanger 3 (HX3), goes through turbine 3, and exits to the steam cycle. The system can have two or three reheat cycles. The warm air from the Brayton cycle goes through the heat recovery steam generator (HRSG) and up the stack. Steam produced in the HRSG can be used to produce electricity or sent to industry. In base-load operation, this system is similar to a GTCC where air temperatures exiting the Brayton cycle are typically near 565°C, as would be if coupled to a salt reactor

For peak electricity production, the hot air exiting HX3 can be further heated by injecting natural gas, bio-fuels, hydrogen^{57,58} into the warm compressed gas or by adding high-temperature stored heat in a Firebrick Resistance Heated Energy Storage (FIRES) system before entering turbine 3. The peak temperature limits of modern turbines are far beyond the temperature limits of the heat exchangers between the reactor and the power cycle. Table VIII shows the nominal projected performance of this system for different reactor heat input temperatures and different peak gas turbine temperatures assuming existing gas turbine technology. Only the last

turbine can be used for peaking power because if one adds incremental heat before turbine 1 or turbine 2, the gas temperatures exiting these turbines into exchangers 2 and 3 will be above the reactor coolant temperatures.

In this specific example, it is assumed that hydrogen is used to provide peak electricity with incremental heat-to-electricity efficiencies between 71% and 75%, far above the natural gas-to-electricity efficiency of existing GTCC systems (~63%) and a higher incremental heat-to-electricity efficiency than any other heat engine. The four cases that are shown in Table VIII include two cases for sodium-cooled reactors and two cases for salt-cooled reactors. This range of temperatures includes salt reactors with and without a nitrate or chloride salt intermediate loop with heat storage. Two peak turbine temperatures are shown for each NACC design. The first is for uncooled turbine blades. The second is for cooled turbine blades used in high-performance GTCC systems.

The overall NACC plant efficiencies when producing peak power with internally cooled turbine blades are near 60% and similar to current GTCCs except low-cost uranium fuel provides the heat at lower temperatures and lower efficiency while a higher-cost fuel (natural gas,

hydrogen, biofuels, and stored heat) provides the higher-temperature heat for the thermodynamic topping cycle with higher efficiency.

Thermodynamic topping cycles are not a new concept. The Indian Point Unit I NPP in the United States was a pressurized water reactor that produced saturated steam that was then superheated with an oil-fired superheater before the steam went to the steam turbine. When that plant was built, it had the highest incremental heat-to-electricity efficiency of any oil-fired system. The lower-temperature heat was provided by nuclear heat, and the higher-temperature heat was provided by oil. This has large economic implications in systems that include existing natural gas-fired GTCCs. If a NACC system coupled to a nuclear reactor is added, it is the first “natural gas plant (NACC peaking mode)” to come on-line and the last to go off-line because it burns natural gas much more efficiently than conventional GTCC systems. In a low-carbon system where low-carbon biofuels or hydrogen are the combustible fuels, it becomes the preferred technology to burn these fuels for peak power.

The thermodynamic topping cycle increases the NACC output. For the first case in Table VIII, if the power output is 1 MW, operating the peaking cycle increases the Brayton cycle output by 46.4% (relative factor of 1.464), and the total plant output increases by 152.2%. Other designs allow much higher peak-to-base power outputs. The incremental capital cost for this peak power producing capability is very low, oversizing the last gas turbine and the HRSG and its steam turbine with associated electric generators.

Nuclear air-Brayton combined cycles can incorporate heat storage in several locations in addition to the option of heat storage between the reactor and NACC. Peak power can be produced using the FIRES system where low-price electricity is used to electrically heat firebrick to very high temperatures. For peak electricity production, compressed air is diverted after HX3 into FIRES, directly heated by the firebrick, and then sent to turbine 3. FIRES is inside a pressure vessel. Only firebrick is capable of withstanding the high temperatures required to match gas turbine combustion temperatures. FIRES (Fig. 18) is a new heat storage technology under development at the laboratory stage that converts excess low-price electricity into high-temperature stored heat for industrial use or power cycles.^{39,59,60} Gas temperatures from FIRES can be adjusted by adding either warm compressed air to reduce peak temperatures or supplemental combustion fuels to raise temperatures.

In electricity systems with large capacities of wind or solar photovoltaic generation, excess electricity is produced at times of high wind or solar output. Coupling

TABLE VIII
Performance of Different NACC Cycles

Turbine 1 and Turbine 2 Exit Temperature	Turbine 3 Nominal Exit Temperature	Turbine 3 Boosted Inlet Temperature	Base Efficiency	Fraction Base from Steam	Hydrogen Burn Efficiency	Combined Efficiency	Brayton Gain	Overall Gain
Sodium Near-Term System (Nominal Inlet Temperature 773 K (500°C))								
680.5 K	640.5 K	1100 K	32.8%	18%	71.1%	48.4%	1.464	2.522
680.5 K	640.5 K	1700 K	32.8%	18%	74.2%	60.4%	2.347	5.744
Molten Salt Advanced System (Nominal Inlet Temperature 973 K (700°C))								
792.5 K	722.5 K	1100 K	45.5%	24%	74.5%	51.1%	1.168	1.403
792.5 K	722.5 K	1700 K	45.5%	24%	75.0%	61.6%	1.834	3.070

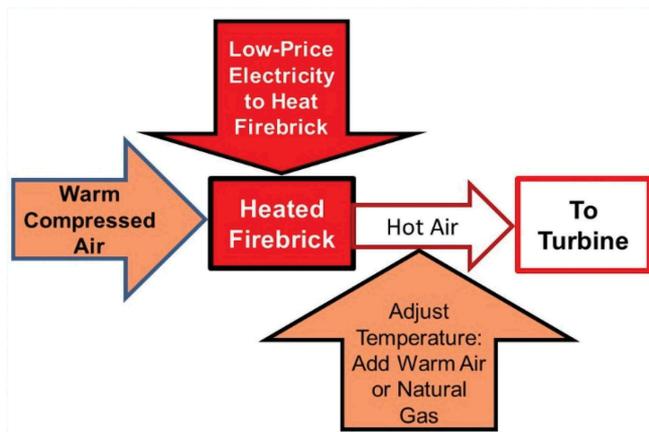


Fig. 18. FIRES for gas turbine system.

FIRES and NACC enables storing this electricity as high-temperature heat for peak power production, effectively operating as an electric battery. The round-trip efficiency is greater than 70% because the electricity-to-heat efficiency is near 100% and the incremental peaking heat-to-electricity efficiency can be as high as 75%. This system has two potential advantages over batteries and other electricity storage systems. First, the capital cost—heat storage plus the incremental added cost for peaking capability in the gas turbine—is expected to be less. Second, if heat storage is depleted, assured peak electricity production is still possible by burning natural gas, hydrogen, or biofuels. With batteries and other electricity storage technologies, a separate gas turbine must be added to the system to provide assured generating capacity if electricity storage is depleted.

Second, heat exhausted from gas turbine 3 at times of low electricity demand can be diverted from the HRSG to a heat storage recuperator (red) using firebrick, concrete, crushed rock, or other storage medium and then up the stack. At times of high electricity demand, cold air can be blown through the hot recuperator in the reverse direction to provide hot air to the HRSG in addition to the hot air from turbine 3 for peak electricity production. The cost of this heat storage system is low because these heat storage systems operate at low pressure and lower temperatures than the gas turbine. If the heat recuperator storage system is depleted, assured peak generating capacity can be provided with a combustible fuel to provide heat to the boiler.

There is ongoing work^{61–64} to develop heat storage for GTCC systems. Combined cycle plants have efficiencies over 60% versus simple gas turbines with efficiencies of ~40%. By including heat storage in CGCC systems between the gas turbine and HRSG, the combined cycle plant can vary electricity output over a much

larger range while maintaining the higher efficiency of the GTCC system.

IV.C. Hydrogen and Peak Electricity Production

In any low-carbon future, hydrogen will be a major chemical reagent and energy carrier. It will be a commodity like electricity except it is storable on an hourly to seasonal basis. This is why some hydrogen projections such as the Shell SKY scenario⁶⁵ show hydrogen as a major energy carrier, i.e., 800 million tons by 2040 versus 70 million tons today. Current hydrogen production uses 6% of global natural gas consumption and 2% of global coal production.⁶⁶

Such hydrogen futures create the option of NPPs with HTE operating more than 80% of the year producing hydrogen and producing peak assured electricity when most needed, at the scale to address the seasonal peak demand for electricity. Salt reactors have two advantages for this system:

1. *Efficient hydrogen production:* The high-temperature heat output enables more hydrogen production per unit of heat input.

2. *Efficient peak power production:* The NACC power cycle in peaking mode enables (a) a very large peak-to-base load output using a low-capital-cost gas turbine power cycle and (b) very efficient incremental heat-to-electricity production. In a low-carbon world hydrogen may be the storable combustible fuel, but it is a premium fuel because electricity is a major input in its production. NACC is the most efficient method to convert hydrogen to peak electricity, more efficient than a stand-alone GTCC or fuel cell.

IV.D. Economics

Historically, it has been assumed that there are significant differences in the costs of different reactor types. Recent reports¹³ have come to the conclusion that the costs of different reactor types are similar. The costs of design, licensing, and other indirect costs far exceeded the material cost differences among reactor types. In a low-carbon world with large changes in markets, the economics of different nuclear systems depends upon differences in revenue. That, in turn, depends upon the power system costs for storage and assured peak generating capability. Those power system costs favor the reactors with the highest average temperature of delivered heat, i.e., salt-cooled systems. The production of

hydrogen has similar incentives to use higher-temperature reactors.

V. CONCLUSIONS

Global energy systems are undergoing two changes: (1) the development of nondispatchable wind and solar with low LCOE in some locations and (2) the goal of a low-carbon energy system. It is in this context one must rethink the requirements for nuclear energy and what types of reactors will be economically most competitive:

1. *Markets*: The goal of a low-carbon world requires a replacement for fossil fuels in their role of providing variable electricity and heat. Separately, the large-scale addition of wind and solar creates highly volatile wholesale electricity prices with times of very low and high prices. The largest market is heat, not electricity.

2. *Requirements*: The top-level requirements for a nuclear system in a low-carbon world or a world with large-scale wind and solar are to provide variable heat and electricity with assured peak energy production capacity. This will require either low-cost nuclear reactors operating at variable load or base-load nuclear reactors with large-scale heat storage and the capability to provide assured peak energy production capacity.

3. *Industry energy options*: To be economically competitive, industry with massive heat demands will require either heat from nuclear reactors or locating industry near sites that allow continued use of fossil fuels with CCS. Higher-temperature reactors enable a larger fraction of total industrial heat demand to be met with nuclear heat versus electricity or hydrogen. The efficiency of nuclear hydrogen production increases with higher temperatures.

4. *System design*: To address the changing markets, new reactor system designs are required. For the electric sector this includes reactors with large-scale heat storage and assured peak electricity production. This system design can also provide industrial heat while coupling the electric and industrial sectors to minimize total cost of energy. The other set of alternatives is nuclear hydrogen peak-electricity systems with large-scale hydrogen storage. This option converts nuclear energy into a system to produce (a) hydrogen and (b) electricity to meet peak seasonal electricity demands. With all of these options, the reactor is designed to operate at base load.

5. *Reactor choices*: Other factors being equal, there are large economic advantages in coupling salt-cooled reactors with higher average temperatures of delivered heat

versus other types of reactors to power systems with heat storage and assured peak energy production capacity. HTGRs have many but not all of the advantages of salt-cooled reactors for meeting these goals. High-temperature heat is what industry requires. The higher average temperature of delivered heat to the power cycle significantly reduces the cost of (a) heat storage systems and (b) assured peak energy production capacity. Higher temperatures enable NACC cycles with high-efficiency peaking capabilities and more efficient hydrogen production in systems designed to produce hydrogen and peak electricity.

6. *Geographical energy markets*: Fossil fuels enabled a world of flat energy prices where the cost of coal, oil, or LNG is about the same in New York Harbor as Shanghai Harbor. The economics and viability of solar, wind, hydro, and fossil fuels with CCS are location dependent. Nuclear energy is the only low-carbon energy source where the costs and technical viability are not dependent upon local conditions. The ability to limit variations in energy costs with location (and thus the standard of living with location) depends upon success in minimizing the cost of nuclear energy systems that can provide variable electricity and heat.

Last, most of industry and most of the energy infrastructure were developed for use with fossil fuels. Going to a low-carbon system implies major changes in industrial processes to (1) use alternative energy sources (electricity, hydrogen, nuclear heat) or (2) produce concentrated carbon dioxide steams for CCS. Similar transformations must occur in the transport sector. While the broad outlines of future energy systems can be developed, the changes in the form of energy (electricity, heat, hydrogen) required by the customers (residential, commercial, industrial, and transportation) and quantities required are highly uncertain.

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