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Variable and Assured Peak Electricity Production from Base-Load Light-Water Reactors with Heat Storage and Auxiliary Combustible Fuels

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Abstract — *In a low-carbon world (nuclear, wind, solar, and hydro) there is the need for assured dispatchable electricity to replace the historical role of fossil fuels. Base-load reactors can provide variable electricity to the grid by (1) sending some of their output (steam) to storage at times of low electricity prices and (2) using stored heat to produce added peak electricity at times of high electricity prices. Heat storage (steam accumulators, sensible heat, etc.) is less expensive than electricity storage (batteries, hydro pumped storage, etc.). The added cost of incrementally larger or standalone turbine generators for peak electricity production is small. However, energy storage systems (heat or electricity) can't provide assured capacity for extreme events, be it supply side (extended low-wind or low-solar conditions in systems with high wind or solar capacity) or demand side (long periods of cold or hot weather). With heat storage systems there is the option to provide peak electricity output when heat storage is depleted by heat addition with a water-tube boiler using natural gas, biofuels, or ultimately hydrogen. Fuel consumption for assured peaking capacity is small because most of the time the heat storage system meets peak electricity demands. The same systems enable reliable low-cost heat production for industry. Such systems enable an all nuclear or nuclear/hydro/wind/solar/geothermal low-carbon electricity grid.*

Keywords — *Heat storage, light-water reactor, variable electricity, capacity.*

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

I. INTRODUCTION

The electricity market is changing because of advances in technology and policy goals to reduce greenhouse gas emissions. In much of the world the emphasis is on wind and solar; however, the large-scale addition of wind or solar collapses the price of electricity at times of high wind or solar output. The revenue collapse limits the economic use of wind and solar. In the United States this favors the use of natural gas because of (1) the low cost of natural gas and (2) the ability to rapidly ramp up and down the output of gas turbines so the gas turbines avoid selling electricity at times of low prices. The economics result in a system where most electricity is produced by natural gas with wind and solar used to reduce natural gas consumption as discussed in Sec. II. This environment does not favor high-capital, low-operating-cost nuclear plants because wind and solar drive down prices when available while natural gas limits electricity prices at other times. Such a solution does not meet the long-term goals of a low-carbon electricity grid.

An alternative option is to store energy at times of excess production (low prices) and sell electricity at times of high prices. However, unlike natural gas, most storage technologies (pumped hydro, batteries) have limited storage capacity and can't provide assured electricity generating capacity. Assured electrical generating capacity are generators that can produce electricity at all times such as fossil and nuclear plants. Wind and solar plants depend

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upon wind and solar conditions and thus can't provide assured generating capacity. With traditional storage technologies, gas turbines are required to back up storage systems and provide electricity when storage systems are depleted. This eliminates many of the incentives for large-scale storage. What is needed is low-cost storage with low-cost assured electricity generating capacity.

Energy can be stored as work (pumped hydro, batteries, etc.) or heat (steam accumulators, hot oil, hot salt, etc.). Wind and photovoltaic (PV) systems produce electricity and thus couple to electricity storage technologies—work storage. Nuclear and concentrated solar power produce heat (thermal energy) that is converted to electricity; thus, these technologies can couple to heat storage technologies. Heat can be stored at times of low electricity prices and used to generate electricity at times of high prices. A recent review[1] of electricity storage technologies and future costs concluded capital costs of \$340 ± \$60 per kilowatt hour of electricity when deployed at the terawatt-hour storage scale. The U.S. Department of Energy (DOE) long-term battery storage goal is \$150/kW(electric)·h for the battery and about double that when installed with power conversion and other required systems to couple to the grid. These storage costs would more than double electricity costs.[2] In contrast the DOE thermal energy storage goal for concentrated solar power systems is \$15/kW·h of heat. Because heat storage is much less expensive than work (electricity) storage, heat storage for variable electricity production with base-load nuclear plant operation can improve nuclear plant revenue. It is an option that may make nuclear power the enabling technology for (1) large-scale use of wind and solar by addressing the energy storage challenge and (2) an all-nuclear grid where the economics of wind and solar are unfavorable.

Heat storage coupled to electricity generating plants to match energy production with electricity demand has existed for almost a century. The first large-scale heat storage system for electricity production was the Charlottenberg Power Station steam accumulators[3] that were built in Berlin in 1929 and charged with steam from a coal boiler at times of low electricity demand with a peak output of 50 MW(electric). Heat storage systems coupled to concentrated solar power systems[3] today have heat storage capacities in excess of 1 GW(thermal) · h to enable electricity production after sunset at times of higher electricity prices.

The other consideration is assured generating capacity. If one buys a heat storage system coupled to a nuclear power plant, one increases the size of the turbine, generator, condenser, and other equipment to enable peak power production—electricity output greater than a base-load nuclear plant. For many existing nuclear plants, the existing equipment allows a 5% to 10% increase in electricity output if storage is added, with the capability to reduce output by dumping 50% or more of the steam to storage at times of low electricity prices. Alternatively, a separate steam turbine and generator can be built for peak electricity production—an option that may be particularly attractive for reactor stations with multiple nuclear reactors. If storage is depleted, assured capacity can be obtained by adding a low-cost water-tube boiler to provide steam at a rate equivalent to heat from storage for peak electricity production.

The economics of heat storage are based on two considerations:

1. *Electricity prices*. The differences in electricity prices with time are increasing because of (1) the large-scale addition of wind and solar that causes price collapse at times of high wind and/or solar input, and (2) the goal of a low-carbon market that implies a need to find a replacement for fossil plants in their role of providing variable electricity to the grid. The rapidly increasing variations in electricity prices make energy storage attractive, although there are significant inefficiencies in energy storage. Large increases in revenue are possible if more electricity is sold when the prices are high and less when electricity prices are low.

2. *Cost structure of nuclear power*.[4] In a nuclear power plant 80% to 90% of the costs are associated with the nuclear reactor and its safety systems. The cost of the power conversion system (steam turbine, generator, etc.) is small. In the United States the estimated capital cost for a new plant is \$5500/kW(electric) with good construction management. The reactor capital costs for producing steam are measured in thousands of dollars per kilowatt (electric) of capacity while the power conversion and heat storage system costs are measured in hundreds of dollars per kilowatt(electric) of capacity. If there are large variations in electricity prices, this creates economic incentives to operate the nuclear steam supply system at base load with variable electricity to the grid using heat storage.

Herein we examine electricity markets, system design, and the technologies available for heat storage with assured electricity generating capacity for light-water reactors (LWRs). Most but not all of these systems also couple to concentrated solar power systems—the other low-carbon heat generating technology.

II. ELECTRICITY MARKETS (HEAT STORAGE AND CAPACITY REQUIREMENTS)

There are three electricity markets that are sources of revenue for electricity generators and storage systems.[5] We describe herein the market mechanisms for deregulated, competitive markets that define the requirements for any energy storage system with assured capacity. In theory, an ideal free market and an ideal regulated market will have similar outcomes. In practice, there are no fully free markets or ideally regulated utilities.

II.A. Energy Markets

Energy markets pay per unit of electricity (megawatt hour) delivered to the grid. These are also known as competitive wholesale electricity markets that are run by either independent system operators (ISOs) or regional transmission organizations. In deregulated electricity markets, electricity generators bid a day ahead on the price that they are willing to sell electricity into the market, typically for each hour of the day. Generators bid their short-run operating cost[6] to produce electricity, including fuel costs and variable operations and maintenance (O&M) costs. The grid operator accepts electricity bids up to the expected electricity demand for each hour. The accepted bid (dollars per megawatt hour) with the highest electricity price sets the price for that hour, and everyone who bids below that price gets the same, marginal price. Energy markets have existed for decades and are reasonably well understood with relatively stable market rules. Energy markets are the primary source of revenue for storage technologies.

In a perfect market, wind and solar will bid near zero dollars per megawatt hour—their variable O&M costs. Figure 1 shows electricity prices in parts of California on a spring day in 2012 and 2017 (Ref. 7). Over a period of 5 years, large numbers of PV systems were installed that collapsed prices on days with good solar conditions and limited electricity demand. As more solar plants are built, electricity prices collapse more hours per year during times of high solar output. This includes times of negative electricity prices, partly caused by gas turbines operating at minimum load so as to be able to provide rapid response when needed. California has had its first month where more than 20% of the time (mid-day) the wholesale electricity price was zero or below. That will become increasingly common as more solar is added. In several European countries (Italy, Spain, Germany, etc.) with national commitments to solar this has limited solar output to less than 8% of total electricity to the grid.[8] Revenue collapse limits solar deployment[9] even if there are large decreases in solar capital costs.

Fig. 1. Price impact of adding solar PV between 2012 and 2017 on a spring day in California.[7]

The same effect occurs with wind. Studies have quantified this effect in the European market.[10,11] If wind grows from providing 0% to 30% of all electricity, the average yearly price for wind electricity in the market would drop from 73 €/MW(electric)·h (first wind farm) to 18 €/MW(electric)·h (30% of all electricity generated). There would be 1000 h per year when wind could provide the total electricity demand, the price of electricity would be near zero, and 28% of all wind energy would be sold in the market for prices near zero. With the growth of installed wind capacity, this is expected to be seen in multiple markets in the next several years.

In the traditional electricity grid the cost of fossil fuels sets the minimum wholesale electricity prices that historically have been above the operating costs of nuclear power plants. The major low-carbon electricity generation options (solar, wind, nuclear, hydro) all have low operating costs, which implies significant periods of time with the market price of electricity near zero. In that market a power technology producing base-load electricity is at a competitive economic disadvantage. The traditional role of nuclear energy for base-load electricity production is a consequence of its early development for a market dominated by fossil fuels. The market is changing and thus nuclear power must change.

II.B. Capacity Markets

There are two strategies to assure sufficient generating capacity to meet demand; that is, to avoid blackouts. The first strategy is to have no capacity market and allow energy prices to go to very high levels (thousands of dollars per megawatt hour or more) at times of scarcity. Plants will be built whose revenue depends upon incomes during the sale of electricity for tens or hundreds of hours per year when prices are very high.

The second strategy is for the grid to offer forward-capacity contracts for assured electricity supply (auctions for such contracts are known as a capacity market) even if there are multiday periods of low solar production, month-long periods of low wind (such as January 2017 in Europe), or extreme weather events (United States).[12] Most electricity markets have capacity markets where the grid operator pays so many dollars per megawatt of assured capacity. The grid operator pays to lower the risks of blackouts because of the high costs of such blackouts in terms of economics, public health risks (cold houses, summer heat exhaustion, etc.), and social disruption (crime waves, riots, etc.).

Capacity markets are a type of insurance. Without capacity markets (energy-only markets), a small number of hours with very high prices provide a large fraction of total revenue to certain types of generators. In a simple illustration produced by Joskow,[13] the 20 h per year (<1%) with a theoretically permitted wholesale price of \$4000/MW·h provides 33% of the net revenues earned by a base-load plant, 50% by an intermediate plant, and 100% by a peaking unit. With a capacity market, the same revenue is provided as a capacity payment and the wholesale price does not spike to \$4000/MW·h. Instead the same revenue is provided by a ~\$9/MW·h fee for all hours, yielding a capacity payment of ~\$80/kW·year for technologies that can provide assured capacity (fossil and nuclear).

Historically, capacity markets were not needed or the payments were low because the electricity was generated by nuclear and fossil units—dispatchable electricity sources. The addition of wind and solar have increased the use of capacity markets because these energy sources can't assure production of electricity when needed given their intermittency. Capacity markets and market rules are changing rapidly as regulators attempt to create workable solutions to systems with increasingly large quantities of wind and solar that can't provide much assured capacity as older fossil plants shut down. Quantifying capacity requirements with solar or wind is complicated because of the uncertainties in solar and wind output. If there is a large solar production capacity and peak demand occurs in the middle of the day, some fraction of the solar can be considered assured capacity—electricity is produced when needed. However, clouds and peak temperatures with air conditioning loads will limit the fraction of solar that can be considered assured capacity in meeting electricity demands.

The capacity system-wide clearing price in ISO-NE (New England) for delivery years from 2017–2018 through 2020–2021 varies from \$55.56 to 114.60/kW·year. The ISO-PJM (Pennsylvania, New Jersey, Maryland) capacity auctions over the last 5 years have not been higher than \$80/kW·year. The NYISO (New York) demand curve suggests a maximum clearing price for the Installed Capacity Market ranging from \$15 to \$26/kW·month, or \$190 to \$313/kW·year, depending on the region of the NYISO service area.

There are other complications that have not been addressed. If one has a yearly market for capacity payments and a local economic recession, the peak electricity demand will go down and capacity payments will be reduced. If the economy picks up, the electricity demand grows with the need for more capacity, but it takes more than a year to build more capacity even if that assured capacity is met with the addition of gas turbines.

There are also generating capacities that may appear to provide assured capacity but may not over a decade. For example, Brazil and parts of eastern Canada have large hydroelectric facilities that were thought to provide assured capacity; however, long periods of low rain resulted in capacity shortages. Large-scale wind was assumed to provide some assured capacity on the assumption that the wind will not disappear over distances of a 1000 km; however, Europe has had two such low-wind events. These "surprises" are partly a consequence of the lack of good historical rainfall and wind measurements over many decades and may also be a consequence of climate change. It may be a decade or more before stable capacity market rules are developed.

II.C. Ancillary/Auxiliary Service Markets

This refers to other electricity grid services[14,15] such as frequency control, black start (start after power outage), and spinning reserves for rapid response to grid emergencies such as another electrical generator failing. Currently this is not a large source of revenue in any electricity grid, typically several percent of total electricity revenue.

III. SYSTEM DESCRIPTION: HEAT STORAGE WITH ASSURED GENERATING CAPACITY

Figure 2 shows the proposed system for variable electricity to the grid and heat to industry from a base-load nuclear plant with assured delivery of electricity to the grid

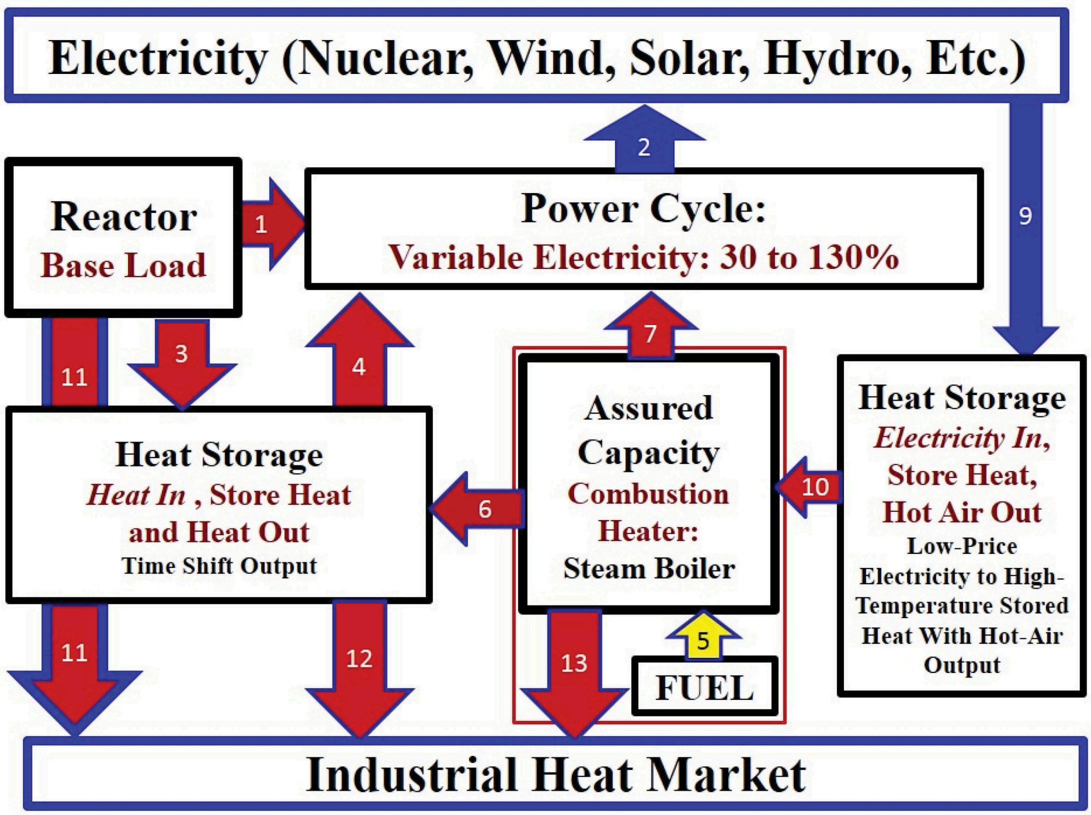

Fig. 2. Reactor system with dispatchable electricity to the grid.

and heat to industry. The top-level goal is variable electricity and optional heat to industry with nuclear, solar, and wind facilities operating at full capacity—their most economic mode of operation. For any particular market, only some components may be built.

The reactor operates at base load (its most economic mode of operation) with variable electricity (2) to the grid with the option of heat to industrial customers (11). (The numbers in the parentheses refer to energy flows in Fig. 2.) The electricity grid may include wind or solar production facilities. When there is excess electricity production (low prices), some of the steam from the reactor is diverted to heat storage (3). To maximize heat storage efficiency, this steam is high-pressure steam that normally is fed to the high-pressure turbine and would be extracted from the steam header before the main turbine. Sufficient steam is sent to the power cycle (1) to operate at minimum electricity output. By operating the power cycle at minimum load, the power cycle can quickly return to full base-load power by sending all steam from the reactor to the power cycle. When additional electricity is needed (high electricity prices), all steam from the reactor (1) is sent to the power cycle and additional heat from storage (4) is sent to the power cycle to produce added peak electricity.

The heat from storage may be in the form of steam to the main turbines or to the LWR feedwater system.[2,3] The temperature of heat from storage will be lower than the steam temperature sent to storage because of inefficiencies in any storage system. The returning steam may go to the intermediate pressure turbine or it may be sent to feedwater heaters. In LWRs about a third of all steam goes to a series of feedwater heaters where each feedwater heater requires heat input at different temperatures. There are up to seven feedwater heaters in an LWR steam cycle. This characteristic of LWR steam cycles allows steam at different temperatures from storage to be efficiently sent back to the turbine hall for peak electricity production. Alternatively, if a separate steam turbine is built for peak power from storage, it will be designed for the temperatures of steam coming from storage.

The addition of heat storage enables variable electricity from a base-load reactor but does not assure peak electricity production at all times. The heat storage system can become depleted and electricity production will be limited to base-load electricity production from the reactor operating at full power. To assure the capability of peak electricity production at all times, a combustion heater [natural gas, oil, biofuels, hydrogen, etc. (5)] can provide heat to the storage system (6) or directly to the power cycle (7). Where to add heat will depend upon the specific system design. The combustion heater in an LWR is a water-tube boiler that provides saturated steam that matches LWR steam conditions.

The addition of the combustion heater to provide assured peak generating capacity fundamentally changes this storage technology relative to other storage technologies (batteries, pumped storage, etc.). Other storage technologies can become depleted and can't provide assured capacity in the case of low-wind, low-solar, or extreme weather events. Other storage technologies require gas turbines or similar technologies to provide backup assured generating capacity.

The cost of assured peaking capacity is small. If one has a 1000 MW(electric) LWR and adds a storage system to produce an additional 200 MW(electric) of peak power capacity, one has the extra power cycle equipment (added turbine, generator, electrical switchgear, condenser, cooling tower capacity) required to produce the added 200 MW(electric) of peak power capacity. To provide 200 MW(electric) of added assured generating capacity even if storage is depleted, a water-tube boiler is only needed to provide the heat for that peak 200-MW(electric) capacity. For an LWR with 33% efficiency, that would be 600 MW(thermal) of saturated steam. Because heat storage usually provides peak capacity, the boiler will likely be operated less than 100 h per year with very low annual fuel consumption. In a low-carbon system, biofuels could be used rather than oil or natural gas. Capital costs[16] for such a boiler are estimated at $100 to $300/kW(electric), substantially less than the cost of a simple gas turbine [$600/kW(electric)] to provide assured capacity and a cost that would be covered by capacity payments (Sec. II) in many markets.

If there is excess electricity production from wind and solar (Fig. 1), there are options to convert excess electricity from the reactor power cycle and the electricity grid into stored high-temperature heat rather than curtailing wind or solar resources. The first option is to add electric resistance heaters to the heat storage systems with steam input—an option that works with some but not all types of heat storage (see Sec. IV.B). The second option is to add hot-rock or Firebrick Resistance-Heated Energy Storage[17] (FIRES) to convert excess electricity (9) into high-temperature stored heat in the form of hot rock or hot firebrick. When there is a demand for peak electricity, cold air is blown through voids in the crushed rock or channels in the hot firebrick to produce hot air (10) that goes to the combustion boiler to produce steam. These systems are being developed by Siemens and others to convert low-price electricity into high-temperature hot rock where air is blown through the hot rock to a steam boiler to produce peak electricity—a less efficient but a lower-capital-cost standalone electricity storage option. In locations such as Germany with large-scale wind, there are long periods of time with very-low-price electricity where the storage times exceed those of batteries. The incremental capital cost of hot-rock heat storage per unit of heat storage is very low making such systems potentially attractive in such electrical markets. With electric resistance heating one can produce higher temperature stored heat than storage systems with steam input. This has several implications:

1. *Steam plant efficiency.* Steam from the boiler will be at LWR conditions for maximum efficiency in converting heat to electricity. Steam from storage will be at lower temperatures than the input steam from the reactor because of various loss mechanisms associated with storage. The steam must be fed back into the intermediate- or low-pressure turbines or feedwater systems. The heat-to-electricity conversion efficiency will be less.

2. *Storage efficiency.* With high storage temperatures, there is a larger temperature difference between hot and cold heat storage temperatures implying larger heat storage capacity per unit volume or mass of crushed rock or firebrick. This may enable lower heat storage costs than is possible with storage systems with steam input.

The system above enables highly reliable variable heat to industry. Heat from the reactor (11), heat storage (12), and the combustion heater (13) can provide low-cost industrial heat generated at times of low electricity prices. There have been only limited studies of such systems to understand the strengths, weaknesses, and requirements for different components for an optimum system under different conditions.

IV. HEAT STORAGE AND ASSURED CAPACITY TECHNOLOGIES

There are three options for variable electricity to the grid from a nuclear power plant: (1) vary reactor output,[18,19] (2) hybrid systems where a base-load reactor coproduces electricity and one or more energy intensive products such as hydrogen,[20–22] and (3) base-load reactors with heat storage with variable electricity to the grid and heat to industry. There are a wide variety of proposed hybrid systems that may include heat storage as discussed in Sec. V. We summarize options for reactors where heat storage is integrated into the steam cycle. These options are applicable to LWRs, CANDU reactors, and British advanced gas-cooled reactors. There are a parallel set of options for advanced reactors[23] where heat is stored in an intermediate loop (sodium, lead, etc.)[24] in high-temperature gas-cooled reactor cores[25] and systems incorporated into Brayton power cycles.[2,26–28]

IV.A. Heat Storage with Steam Input

A recent workshop[3] examined heat storage coupled to LWRs where at times of low electricity prices some steam is diverted to heat storage but sufficient steam is sent to the turbine to keep it online to enable quick return to full electricity output when needed. When prices are high most of these storage technologies would send steam back to the turbine hall for injection into the main turbine or feedwater heaters or to a separate peaking turbine system, boosting the electricity output over the base-load output of the power plant.

There are significant incentives to use the main power conversion systems rather than a standalone steam cycle for peak electricity. One is then buying a somewhat larger power conversion system at about half the cost of a separate power conversion system to convert stored heat back to electricity. The use of the main turbine also allows faster response since the turbine is always operating. However, it is also noted that within the last decade there have been major advances in steam cycles with the capability for rapid start, stop, and changes in power levels that can be used for a standalone peak power system. Concentrated solar power systems have steam cycles that turn on and off each day. The change in electricity markets with the addition of wind and solar has resulted in combined cycle natural gas turbines turning off and on many times per year, as well ramping rapidly up and down. These plants include a gas turbine topping cycle that exhausts hot air to a heat recovery steam generator where the steam goes to a conventional steam cycle. The market changes that created the incentives for heat storage coupled to LWRs has resulted in a large market for steam turbines with requirements similar to those required for a reactor with heat storage and peak electricity production capability.

There is massive literature[29] associated with heat storage although much of it is associated with building heating and cooling. Initial studies on coupling heat storage with LWRs were conducted in the 1970s after the Arab oil embargo that drove up the price of oil, the primary fuel used at that time for variable electricity production. Today most of the work on heat storage applicable to LWR temperatures is being done in the concentrated solar power community that operates at similar temperatures using steam cycles.

IV.A.1. Liquid-to-Gas Latent Heat Storage

IV.A.1.a. Steam Accumulators

A steam accumulator is a pressure vessel nearly full of water that is heated to its saturation temperature by steam injection. The heat is stored as high-temperature high-pressure water. When steam is needed, valves open and some of the water is flashed to steam that is sent to a turbine or feedwater heaters generating electricity while the remainder of the water decreases in temperature. This system has a faster response than any other heat storage system but the steam from any one bank of accumulators decreases in pressure and temperature with time. Multiple accumulators can be arranged to provide a steady flow of steam at several different pressures.

Steam accumulators have been used for energy storage and pressure buffers in steam plants for over a century and are coupled to several solar thermal power plants[30,31] as a mechanism of heat storage to enable variable electricity production including electricity production after sunset. The technology is well understood.[32,33] The first steam accumulator for peak electricity production, built in Berlin in 1929, was charged with steam from a coal-fired power plant, had a peak power output of 50 MW(electric), and operated for decades. Steam accumulators coupled to nuclear reactors were studied[34,35] in the 1970s after the oil embargo that dramatically increased oil prices and the interest in variable electricity from nuclear power plants. In the last several years there have been studies on steam accumulators coupled to LWRs (Refs. 3, 36, 37, and 38). Steam accumulators are being built today with some concentrated solar power systems; thus, the technology can be considered commercial. There are many design options. The cost of the high-pressure storage tanks probably limits these systems to hourly to daily energy storage where there are many cycles of storage per year to cover capital costs.

IV.A.1.b. Cryogenic Air Systems

A cryogenic air energy storage system[39–41] stores energy by liquefying air. Air is liquefied at times of low electricity prices where the compressors could be powered with electric motors or steam turbines. The liquefied air is stored in facilities similar to those used to store liquefied natural gas (LNG). To produce electricity, the liquid air is compressed, heated using low-temperature heat (cooling water) from the power plant, further heated with steam from the LWR, and sent through an air turbine before being exhausted to the atmosphere. This technology can be coupled to any heat source or operate as a standalone storage system. The estimated round-trip efficiency for this technology coupled to a LWR is over 70%—approaching that of hydroelectric pumped storage but without siting constraints. The distinguishing feature of this system is that the peak to base-load electricity output is higher than for other heat storage systems. A pilot plant coupled to a biofuels power plant is now operating in the United Kingdom.

IV.A.2. Sensible Heat Systems

Sensible heat storage involves heating a second material where heat is stored by raising the temperature of the second material. New concentrated solar power systems now deploy sensible heat storage in the form of liquid nitrate salts at the gigawatt-hour scale[42] to minimize sales of electricity at times of low prices (Fig. 1). There are many technology options.

IV.A.2.a. Liquid Sensible Heat Storage

Sensible heat storage[43–46] involves heating a second fluid with steam, storing that second hot fluid at atmospheric pressure, and using that fluid later to provide the heat to produce steam to then produce electricity. This technology is used with some solar thermal power systems[47] at temperatures near those of LWRs to enable electricity production after the sun sets. Much work has been done on choices of heat storage materials.[48] Studies at North Carolina State University[45,46] (NCSU) and Westinghouse[3] are examining heat transfer oils as the heat transfer fluid when coupling sensible heat storage to an LWR steam cycle. NCSU uses the heat transfer oils as the storage media with hot and cold tanks for hot and cold oil storage.

Westinghouse has begun development of a sensible heat storage system for LWRs (Fig. 3) where each storage module stores sufficient heat to generate 1 MW·h of electricity. Steam heats low-pressure oil which then transfers its heat to a heat storage module in which vertical concrete plates serve as the primary heat storage medium rather than a heat transfer oil. Concrete is used because it is a less expensive heat storage medium than oil and can be produced locally. The hot oil flows through narrow channels between slabs of concrete. To recover

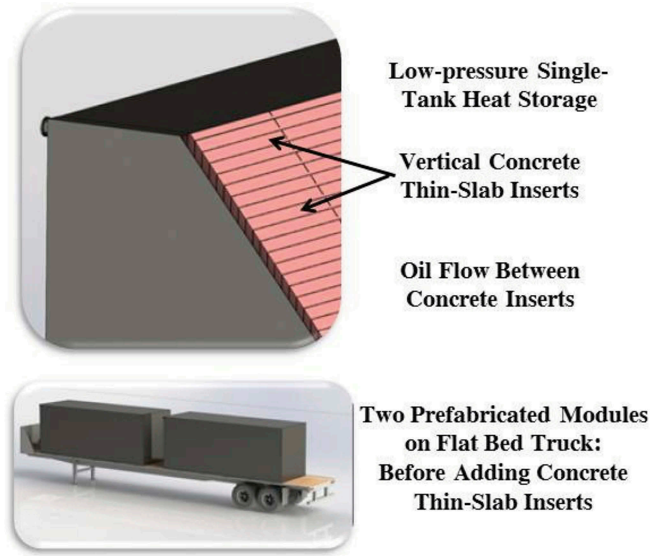

Fig. 3. Westinghouse thermal heat storage module for 1 MW·h of electricity storage.

the heat, the direction of oil flow is reversed. The hot oil would be used to generate steam that is sent to (1) the main reactor turbine, (2) a partial replacement for steam to feedwater heaters, or (3) a separate power system. The round-trip efficiency is about 60%; that is, if 1 kW·h of electricity is produced in base-load operations, 0.6 kW·h of electricity is produced if the heat is sent through the storage system. The efficiency depends upon engineering trade-offs between capital expenditures and efficiency. If the value of steam is very low, there are limited incentives to design high-efficiency systems if this substantially increases capital costs.

Much work has been done on using concrete as a heat storage media in many different types of systems using many different fluids (air, water, oil) to move heat to and from the concrete.[49] In some cases the fluid is in direct contact with the concrete while in other cases the fluid is in tubes that go through the concrete. The major advantages of concrete are its low cost and ability to be fabricated in different geometries. Long-term cycling of concrete samples up to 500°C has been done for over 14 000 cycles.[50] This requires special concrete. One of the challenges is that excess water in the concrete upon heating will convert to steam that breaks apart the concrete. There are two methods to address this challenge. The first is high-temperature steam curing in an autoclave at pressure that removes excess water—a procedure used for concrete bridge beams and other preformed concrete structures to provide protection against freeze-thaw cycles. The other strategy is to make the concrete permeable, where there are multiple options.

Such systems can also use latent heat storage where a phase-change material (liquid to solid) provides for heat storage. Thus far such systems have not been deployed in utility solar thermal systems. Historically the interest in solid-liquid phase-change heat storage systems has been for applications where minimizing volume or weight is important. For most utility applications this is not a requirement—minimizing cost is the priority.

IV.A.2.b. Steam Heating of Packed-Bed Thermal Energy Storage

A packed-bed thermal energy storage system (Fig. 4) consists of a pressure vessel filled with solid pebbles or other heat storage media with a steam valve at the top and water outlet at the bottom.[51,52] Heat is stored as sensible heat in the pebbles. To charge the system, steam injected into the pebble bed condenses as the cold pebbles are heated and water exits from the bottom of the vessel. At the end of the charging cycle all pebbles are hot and there is hot water filling the voids at the bottom of the vessel. To discharge the system, water is injected into the bottom of the vessel and steam is produced by the hot pebbles. In theory, this system should have the highest round-trip efficiency. The technology is in the early stages of laboratory development.

IV.A.2.c. Air-Heated Hot-Rock Storage

In a hot-rock energy storage system[53,54] a volume of crushed rock with air ducts at the top and bottom is created (Fig. 5). To charge the system, air is heated using a steam-to-air heat exchanger delivering heat from the reactor, then the air is circulated through the crushed rock,

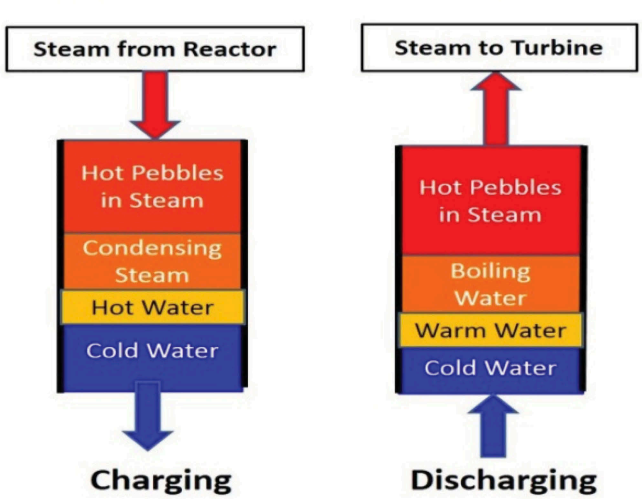

Fig. 4. Packed-bed heat storage system.

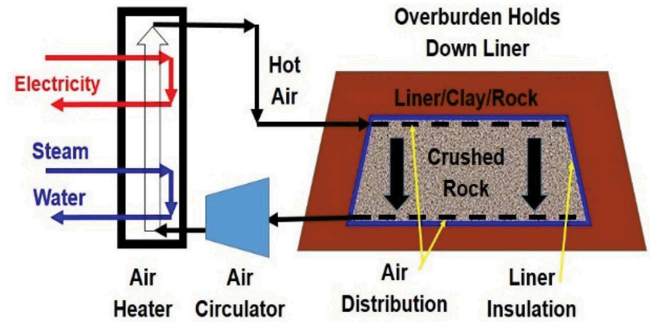

Fig. 5. Schematic of hot-rock heat storage in charging mode.

heating the rock. To discharge the system, the airflow is reversed and cold air is circulated into the crushed rock at the bottom. The discharged hot air produces steam that is sent back to the turbine hall. It has the lowest incremental heat storage costs per kilowatt hour.

If electricity prices are very low, there are the options of (1) heating the air with a steam-air heat exchanger and then further heating the air with electric resistance heating, or (2) heating the air only with low-price electricity. The very hot air can be sent back through the assured capacity boiler to produce steam at LWR conditions to maximize heat-to-electricity conversion efficiencies.

Several versions of this technology are under development for different purposes. Siemens in Germany is constructing[55] a hot-rock heat storage system where the air is to be heated by electric resistance heaters using low-price electricity generated by wind before being blown through the crushed rock. For power production cold air flows through the rock, is heated, and then fed to a steam boiler to produce steam for electricity production at times of high electricity prices. This is one variant of a family of concepts where the air is heated by various hot fluids (oil, salt, carbon dioxide, steam) from concentrated solar power systems or electricity. The hot air is then used to heat the rock—the storage media. A 100-kW test of the CellFlux concept[56] (one variant) has been tested.[57] There have also been tests to 800°C with another hot-rock variant with a variety of different rock types.[58]

Red Leaf [59] is developing an oil shale process where oil shale is crushed and placed in piles approximately 30 m high. Hot gas is blown through the crushed hot rock to heat it up, decomposing the kerogen and releasing shale oil. It is a one-time process but similar physics—heating crushed rock with hot gas. Large-scale experiments are underway.

Hot-rock heat storage is also being experimentally investigated[60–67] for direct use with concentrated solar thermal power towers. In these applications concentrated light would heat ceramic structures cooled by incoming air. The hot air would be sent directly to the hot-rock storage system. While the pumping power for air is higher than in solar power towers with liquid coolants, air cooling with ceramic absorbers would avoid the normal temperature limits associated with the receivers. As with other systems, heat is recovered by blowing cold air through the hot rock that is sent to a steam boiler to produce electricity.

There are several general observations from the various experimental programs. The capital costs of heat storage are very low. Many of the experimental challenges and inefficiencies disappear as the capacity increases. The system is well behaved with vertical gas flow with hot air in at the top and cold air out at the bottom. There has been significant work on horizontal gas flow options to avoid the need for the air inlet/outlet structure to support the full weight of rock; but major losses in efficiencies are caused by stratification of hot air toward the top of a system with horizontal flow.

IV.A.2.d. Geothermal Heat Storage Systems

Thermal energy is stored by injecting hot water heated by steam from the reactor into the underground reservoir; energy is discharged by pumping hot water back to the surface for electricity production in a conventional geothermal plant. Only limited studies have been completed.[68,69] This heat storage technology has different characteristics than the other heat storage options. It can provide seasonal energy storage but can only be deployed as a large system because there is no way to insulate rock deep underground. The underground surface area for heat losses goes up as the square of the energy storage capacity while the storage volume (heat capacity) increases as the cube resulting in low losses for systems with more than 0.1 GW·year of heat storage.

IV.A.3. Other Options

There are several other classes of heat storage that are potential candidates if the right materials are found, but are all in earlier stages of development. In chemical heat storage systems heat is stored in some type of chemical reaction. Relatively little work has been done on these systems relative to the options described above.

Solid-liquid latent heat can be used for heat storage. This includes systems where the temperature of the solid-liquid system is close to the condensation temperature of high-pressure steam.[70] These systems have higher heat storage capacity per unit volume but are more expensive. There are a wide variety of options because LWR steam temperatures are below the degradation temperatures of many organics. Most of the work has been for systems where compact size is important, such as in residential and commercial facilities, a constraint that does not apply to utility-scale systems. These systems can be coupled to steam accumulators and many sensible heat storage systems as a secondary heat storage media in these systems.

IV.B. Heat Storage with Electricity Input

If there are times of very low electricity prices (Fig. 1) that are below the price of fossil fuels, there are several options to divert low-price electricity from the nuclear power plant turbine that is running at minimum load and/or from the electricity grid to heat storage:

1. *Heat storage system*. The electricity can be converted to heat using resistance heaters in most of the heat storage systems described in Sec. IV.A. Where the heat is added depends upon the specific storage technology.

2. *Hot-rock heat storage*. As discussed in Sec. IV.A.2.c, this option uses electricity to heat air that then heats rock. Air is blown through the hot rock to produce hot air for steam production.

3. *FIRES* (Ref. 17). Low-price electricity can be sent to FIRES to heat firebrick to high temperatures using resistance or induction heating. To convert this heat back to electricity, air is blown through FIRES. The hot air can be used to generate steam or hot air for industrial applications. This is the high-temperature variant of hot-rock storage and has applications beyond the reactor that can impact electricity markets.

A schematic of FIRES is shown in Fig. 6. FIRES is a general purpose technology to convert low-price electricity less than the price of fossil fuels into high-temperature stored heat and then to convert that heat into hot air to substitute for hot air produced by burning fossil fuels. The firebrick is heated with electric resistance heaters. Cold air is blown through channels in the firebrick to produce hot air that replaces hot air generated by burning natural gas, oil, biofuels, and ultimately hydrogen in industrial furnaces, boilers, and other applications.

Historically, small FIRES units (<100 kW·h) have been used for home heating where utilities provide low-price electricity during off hours for FIRES to be charged and hot air produced for home heating for a day or more. More recently the Chinese have deployed units up to 8 MW·h with electricity input rates at 1 MW(electric) for heating

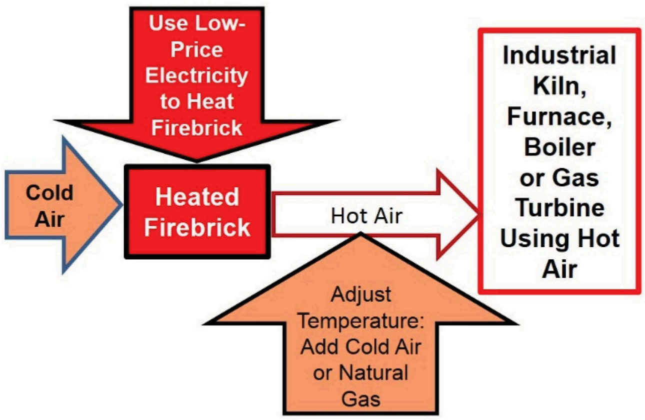

Fig. 6. Firebrick resistance-heated energy storage.

large apartment complexes. FIRES is charged at night and the hot air is used to provide steam or hot water for building heat. For temperatures to 850°C and atmospheric pressure, FIRES is an off-the-shelf technology. Advanced versions[17] are under development to raise peak temperatures to above 1400°C by use of conductive firebrick as the resistance heaters or induction heating of conductive firebrick.

The technology has major implications in terms of electricity prices by potentially placing a floor on the price of electricity near the heating value of the competing fossil fuel. The heat equivalent of total electricity produced in the United States is less than the heat input into the industrial sector. The industrial sector has the potential with FIRES to use low-price electricity less than the heating cost of natural gas to partly replace natural gas as a source of heat. Only in the last several years have significant quantities of electricity become available at prices less than natural gas. In this context, the United States has extremely low-cost natural gas compared to most of the world. The cost to convert natural gas to LNG and ship that gas to foreign countries significantly increases the cost of natural gas elsewhere relative to the United States.

The first large-scale users of FIRES in the United States will likely be industrial cogeneration plants that produce (1) electricity for the industrial plant and the electricity grid and (2) steam for process heating. These plants must operate to provide process steam, which implies sending electricity to the grid even when the prices are very low—part of the reason for negative electricity prices in California when solar conditions are good (Fig. 1). When there are negative prices the electricity generator pays the electricity grid to take the electricity. California has had its first month[71] where more than 20% of the time (mid-day) the wholesale electricity price was zero or below. This will become increasingly common as more solar is added. This also implies many additional hours per year where wholesale electricity prices will be below that of fossil fuels creating incentives for FIRES deployment. FIRES creates an option to store low-price and negative-price electricity as high-temperature heat for process heat production, reduce fuel consumption of these plants, and avoid selling electricity at a loss.

IV.C. Assured Peak Electricity Capacity

Assured generating capacity for peak power production (Fig. 2) can be enabled by adding steam boilers burning natural gas, oil, biofuels, or ultimately hydrogen to provide the heat that would have come from storage. FIRES or crushed rock heat storage would use the same steam boilers. If the difference between nominal base-load output and peak capacity with storage is 200 MW(electric), the steam boiler would be sized to generate steam needed to produce 200 MW(electric). Because the peak turbine capacity is already paid for (part of the storage system), the only capital cost for the assured extra production capacity is for the steam boilers.

The incremental cost[16] of such a steam generation system [\$100 to \$300/kW(electric)] is significantly less than a simple cycle gas turbine [~\$600/kW(electric)] or a larger reactor [>\$5000/kW(electric) (United States)]. Costs were estimated by several methods. The ASPEN process-design code[72] yielded a cost of \$148/kW(electric) while the HYSYS model library estimated costs at \$204/kW(electric). Not all of the assumptions were identical and there are significant differences depending upon location. What is important is that all of the estimates were substantially less than a gas turbine, normally the lowest cost technology to provide assured capacity. The fuel consumption would be low because most of the time heat storage provides the steam for added capacity. Such an investment would be justified where (1) market capacity payments justify such an expense and/or (2) where there are sufficient hours per year where the storage system would be expected to be depleted and electricity prices will be high. There is an economic trade-off between the capacity of the storage system and how many hours per year the auxiliary boiler would be used.

IV.D. Matching Storage Options to Markets

Each heat storage technology has different characteristics: round-trip efficiency, cost to input energy into the system [dollars/megawatt(thermal)], cost of storage (dollars/megawatt hour), and cost of converting heat to electricity [dollar/megawatt(electric)]. As a consequence, the preferred option will depend upon both the electricity market and the technology. The preferred heat storage system in a grid with large solar capacity and the need for daily energy storage may be different than a system with excess wind capacity and multiday cycles of low- and high-price electricity.

Energy storage cost structures are different for electricity (pumped hydro, batteries, etc.) and heat storage systems. The capital costs for a pumped hydro facility can be broken into two parts. In a pumped hydro facility there is a pump-motor system that pumps the water up the hill and operates in reverse as a turbine-generator system to produce electricity. The capital cost is measured in dollars/kilowatt. The rate of electricity input is coupled to the rate of electricity output. The second capital cost (dollars/kilowatt hour) is associated with building the two water reservoirs to provide energy storage capacity. The cost structure of most electricity storage systems,[73] where input rates are coupled to output rates, results in a business strategy to buy low-price electricity and sell only during the relatively few hours when electricity prices are very high (Fig. 7).

In heat storage systems the heat-to-storage input power (kilowatts), energy storage capacity (kilowatt hour), and heat-to-electricity output power (kilowatts) are separately sized. Much of the cost is associated with the cost of converting heat to electricity. In a market with large-scale solar, the profitable strategy may be to send steam to storage 6 h per day when prices are low and produce added electricity 18 h per day. The storage system would have high steam input rates into storage (low-cost part of system) and smaller peak electricity production rates (higher-cost part of system). This minimizes the cost of the heat storage system. It also better matches what is required to integrate large-scale solar into the electricity system—a storage system with massive input for the limited number of hours of high solar output with output spread out over time. The market is different where there are large wind resources with the multiday cycle of high and low winds; thus, the optimum engineering solution could be different.

The second heat storage feature is that the nuclear turbine-generator can be used for peak power. The cost of the heat-to-electricity subsystem is the incremental cost of a somewhat larger power cycle, not a standalone power cycle as is required in a hydro pumped storage or battery system. Cost scaling factors for industrial equipment follows well-known scaling laws:

$$C_1 = C_0 (S_1/S_0)^x \ ,$$

where

C_1, C_0 = total costs

S_1, S_0 = equipment capacities

x = scaling factor that is typically between 0.6 and 0.7 for industrial equipment.

As the system output increases, the costs do not increase linearly because the system has the same number of parts—just slightly larger parts. For $x = 0.7$, a 1000-MW(electric) turbine costs 5 times as much as a 100-MW(electric) turbine, but only half as much per unit of capacity. Scale dramatically reduces costs for the heat-to-electricity component of any heat storage system coupled to a large reactor with large turbine relative to heat storage coupled to smaller solar thermal or geothermal systems. There are large

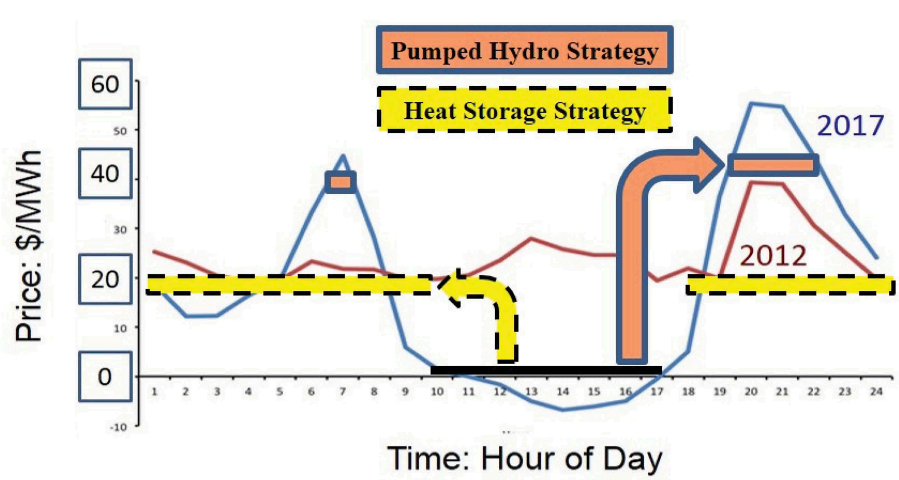

Fig. 7. Buy and sell strategies for pumped hydro and nuclear heat storage in California electricity market.

economics of scale associated with steam turbines and generators[74] up to about 500 MW(electric).

For existing LWRs, limited studies indicate that at many reactors a storage system may divert 20% to 40% of the steam at times of low electricity prices with peak power output 4% to 5% above base-load capacity without major changes in the plant. The numbers are plant specific. For new LWRs one could divert up to 70% of steam to storage at times of low prices with a peak output 25% higher than base load. There are efficiency penalties operating at part load but this is much less of a concern because the price of electricity is low at these times. Figure 8 shows the efficiency of the main steam plant goes down as the load goes down.

There is the alternative option of building a standalone steam plant for peak power production. Because it is designed with the storage system, its efficiency will be higher in converting stored heat to electricity than using the main reactor turbine. This minimizes design changes in the main nuclear turbine—the changes are limited to allowing massive dumping of steam to the heat storage system. The only connections between the peaking unit and the nuclear plant are the steam lines and the return steam condensate lines. There are capital costs versus efficiency trade-offs. With multireactor power stations, the expectation is that a standalone peaking turbine will be the preferred option because the peaking turbine system will be large with economics of scale and higher efficiencies. We are not aware of any studies that have examined what options are the preferred options in different markets with different technologies and different reactor sizes.

None of these storage technologies has yet been coupled to a nuclear reactor for heat storage. NCSU (Refs. 45 and 46) has simulated the operations of a modular LWR with oil heat storage with heat going to large-scale cooling systems or back to the turbine hall for peak electricity production. The simulations show nearly constant reactor output with highly variable electricity to the grid and heat to storage. Steam accumulators and sensible heat systems have been deployed with utility-scale solar thermal power systems. Cryogenic heat storage is in the pilot-plant stage. The other technologies require added research, development, and demonstration. In this context it is noted that the capital cost of a new nuclear plant[4] with good project management in the United States is ~$5500/kW(electric) and about half that in China and South Korea. The equipment costs for the power conversion system is ~$500/kW(electric). From an economic perspective, the costs of changes in the power cycle to improve revenue are small relative to reactor costs.

V. INDUSTRIAL HEAT MARKETS

The heat market in the United States (Fig. 9) in terms of energy services is about the same size as the electricity market.[75] There are proposals to meet industrial heat demand by converting industry to electricity to meet low-carbon goals. That would require more than doubling electricity production. This creates large incentives to use nuclear reactors to directly produce heat for the industrial market. It takes about three units of heat to generate one unit of electricity. There are large incentives to provide heat directly to industry rather than convert heat to electricity and back again to heat.

Light water reactors with heat storage and assured capacity have potentially major advantages in providing

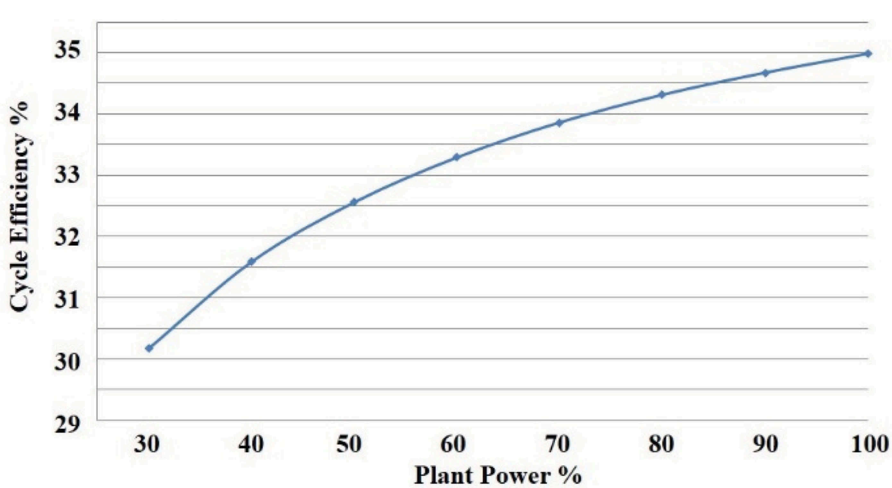

Fig. 8. Typical 1200-MW(electric) pressurized water reactor plant cycle efficiency versus power level. (Courtesy of Westinghouse Corporation.)

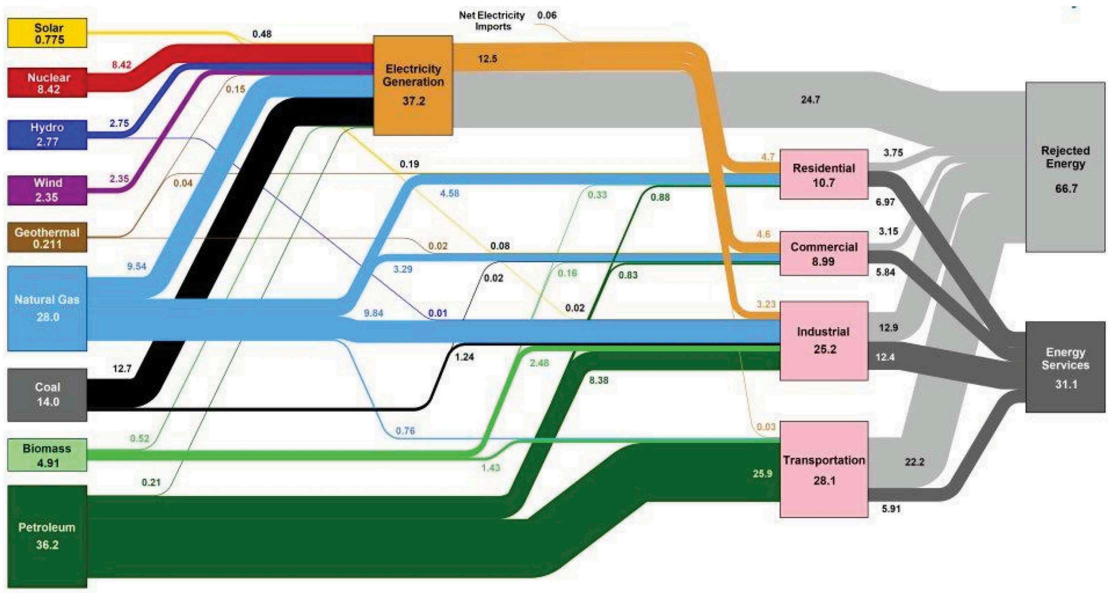

Fig. 9. Estimated U.S. energy consumption in 2017: 97.7 quads.

lower-temperature steam to industry relative to traditional nuclear cogeneration strategies:

1. *Reliability*. Industrial processes have very high requirements for reliability of steam supplies. Assessments of those requirements[76,77] with the goal of 99.9% reliability often lead to the requirement for "extra" reactors or other equipment to assure steam supplies. Heat storage combined with assured delivery capacity can help meet these requirements while minimizing the number of reactors required to achieve specific reliability goals.

2. *Lower costs*. Heat storage enables coupling the electricity market with the industrial heat market to store low-price energy when available from the electricity market for later use by the heat market.

3. *Tritium control*. There is the requirement to provide isolation between the reactors and the industrial markets to avoid transport of radionuclides off-site, particularly tritium. That requirement has been historically met by the addition of a reboiler where steam from the reactor is condensed while producing clean steam for industry. Some of the heat storage systems intrinsically provide that isolation. For example, the proposed Westinghouse system described earlier transfers heat from steam to a heat transfer oil for heat storage in cement. Later, stored heat is transferred to the oil that then is used to produce steam. If this system is used to provide industrial heat, it may provide complete isolation between the reactor and the industrial user. There are the heat exchangers but tritium (the radioactive form of hydrogen) under certain conditions can diffuse through heat exchangers and isotopically exchange with normal hydrogen in water on the other side of the heat exchanger tubes. Tritium does not normally exchange with heat transfer oils and thus the oil provides a separate barrier to tritium escape in addition to the heat exchangers.

Heat storage with assured capacity has another implication. For any reactor with such systems, the cost barriers for selling steam to industrial customers is lower because much of the infrastructure is in place from steam diversion valves in the nuclear plant to storage systems. One does not need a mega-customer to justify the off-site sale of steam. The barriers for steam sales are lowered enabling the use of nuclear energy for industrial heat. This has major implications for the United States and countries with smaller industrial infrastructures and few industries that could use most of the output of a nuclear reactor.

VI. MARKET IMPACTS

A recent report by Lawrence Berkeley National Laboratory[78] modeled the impacts to the electricity grid if 40% to 50% of electricity is generated by wind and solar but otherwise a business-as-usual scenario that includes low-price natural gas. The results are summarized in Fig. 10. The analysis imposed different mixtures of wind and solar. Four areas of the United States were analyzed: Southwest power pool (Great Plains), NYISO (New York), CAISO

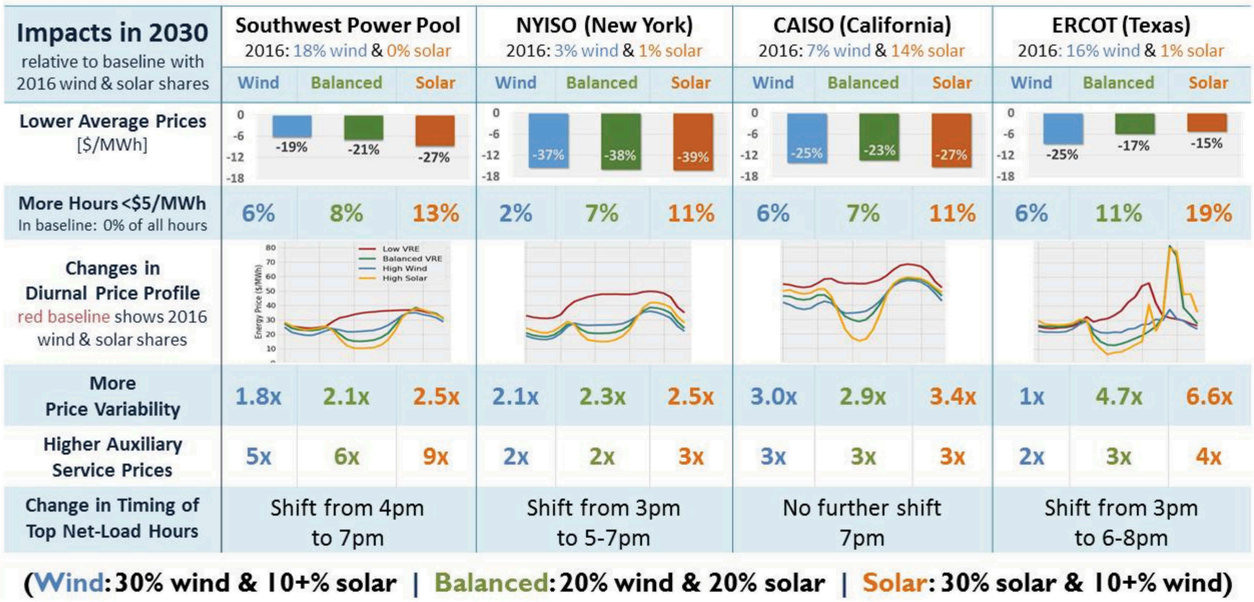

Fig. 10. Wholesale price effects of 40% to 50% wind and solar.

(California), and ERCOT (Texas). Such studies provide one view of the future of the electricity grid and can help characterize potential characteristics of future markets.

The impacts of added wind and solar strongly depended upon region, with reductions in electricity prices that varied from 15% to 39%. Up to 19% of all hours had electricity prices below \$5/MW·h with up to 6.6 times larger variation in electricity prices over time. At the same time, the costs of ancillary services increased by up to a factor of 9 with peak electricity loads shifting to ~7 pm across the country. For this level of wind and solar penetration to occur there must be (1) legal requirements to use wind and solar (renewable mandates), (2) large reductions in the cost of wind and solar, or (3) massive subsidies.

Electricity prices and thus revenue collapse at times of high wind or solar input are seen in the lower average prices and more hours (<\$5/MW·h) of very-low-price electricity when wind and/or solar provide most of the electricity. It is also evident in the large variability in electricity prices—low prices when high input from wind and solar. This is a business-as-usual case except for wind and solar where peak prices are limited by low-cost natural gas that varies from \$3.25 to \$4.69 per million BTUs depending upon location. If natural gas prices increase or if there are restrictions on carbon emissions, wholesale electricity prices at times of low wind or solar output would increase with much larger swings in electricity prices with time.

The costs of ancillary services increase dramatically, primarily because of the need for more spinning reserve to address the large variations in output from wind and solar. Reactors with heat storage can meet these requirements because the opening of valves can rapidly divert steam to the turbine or heat storage depending upon need, but does impose other requirements on the balance of plant.

In these types of markets, nuclear plants with storage and assured capacity have significantly higher revenue streams than base-load reactors. The large variability of prices implies large incentives to sell electricity when prices are high. The higher capacity market prices become a major revenue stream for such nuclear plants with peaking capabilities. The higher ancillary service market may become a major source of revenue but this is much less certain because of completion from competing technologies such as batteries. The large quantities of low-price electricity in some markets (far under the price of natural gas) create large financial incentives for using technologies such as hot-rock storage and FIRES to convert excess electricity into stored heat for later use in peak electricity production. In such markets the nuclear plant would buy and sell electricity. Buying electricity and converting it to stored heat becomes economically attractive when the peak electricity prices are greater than the cost of low-price electricity that is bought after accounting for electricity-to-heat-to-electricity inefficiencies.

Various studies[79] indicate storage coupled to nuclear power plants is economic today in some markets—a market development that has only occurred in the last 3 to 4 years. A decade ago, there would have been no incentive for heat storage. A decade from now heat storage may be a standard feature of many nuclear reactors. There is an important caveat with such markets. The first few nuclear plants with heat storage could see large increases in revenue but the revenue enhancement decreases with the addition of more storage capacity. In a free market the relative amounts of wind, solar, and nuclear will vary with location as well as the quantities of storage per megawatt(electric) of base-load capacity.

VII. RESILIENT NUCLEAR POWER PLANTS

In recent years there has been increased concern about "black sky" events that would cause grid collapse.[80–83] Examples of such events include geomagnetic disturbances induced by solar coronal mass injections, electromagnetic pulse attacks, and cyberattacks. In each case there have been historical events that suggest the risks may be significant given society's dependence upon electricity and that a low-carbon future would increase dependence on electricity. Related to these concerns is the increasing dependence of the U.S. electricity system on natural gas where a single natural gas line may provide fuel for a dozen natural gas plants. If a single pipeline is lost, a massive amount of electrical generating capacity may be lost. The Electric Power Research Institute[84] has documented the need for enhanced nuclear plant flexibility during normal grid operations. Nuclear reactors have the potential to be major assets under such circumstances because they have on average 9 to 12 months of fuel in their reactor core depending upon the refueling schedule. Natural gas plants are dependent upon pipelines, oil plants typically have a week or two of supply, and coal plants may have a few months of supply. The term resilient nuclear power plants (rNPPs) is sometimes used to describe plants with such enhanced capabilities.

Six functional requirements[81] for resiliency have been defined: (1) robust real/reactive load-following and flexible operation capacity, (2) immunity (extremely low vulnerability) to damage from external events including grid anomalies, (3) the ability to avoid plant shutdown (reactor scram) in response to grid anomalies, (4) the ability to operate in island mode without connection to off-site transmission load and electric power supply, (5) unlimited independent safe shutdown cooling capacity, that is, no requirement for off-site power or resupply of diesel fuel from offsite, and (6) independent self-cranking black-start capability.

The addition of heat storage with assured capacity to an LWR helps meet many of these requirements[81] because the plant output to the grid can go from peak power to a consumer of electricity and back very quickly. If there is a grid failure, the nuclear plant can make the rapid transition from full power to house load (island mode) and be ready to assist in grid restart. The transition to island mode is an easier task because of four methods to reduce power to the grid: (1) reduce reactor power, (2) bypass steam to the condenser, (3) send steam to the heat storage system, and (4) send generator electricity to resistance heaters in the storage systems. Similarly, grid restart is simplified because the reactor can be operating at full power with increased electricity to the grid by diverting less steam and electricity to storage. If the plant has resistance heaters that are sending electricity into heat storage, turning that electricity sink off or on can be done in a fraction of a second. The addition of energy storage capacity to the plant enhances its operational flexibility and its contribution to grid resilience in all cases.

VIII. CONCLUSIONS

Most nuclear plants have been operated to produce base-load electricity—the economically optimum solution in an electricity grid with nuclear and fossil plants where nuclear plants have high capital costs and low operating costs while the fossil plants have low capital costs and high operating costs. The market is changing. The large-scale addition of wind or solar creates times of very low electricity prices because these technologies are nondispatchable, driving prices down at times of high wind or solar inputs while raising prices at other times because the other power generators operate fewer hours per year. New nonwind or nonsolar plants that operate fewer hours per year will not be built unless the price of electricity increases at times of low wind and solar output. Separate from the addition of wind and solar, the goal of a low-carbon electricity grid creates the need for nuclear energy as a dispatchable form of electricity to replace fossil fuels in this role.

These recent changes create economic incentives for nuclear reactors to operate at base load to minimize production costs while using heat storage to enable varying electricity production to maximize revenue while meeting variable energy needs. The combination of heat storage with assured peak generating capacity using a combustion heat source can meet the requirements of a low-carbon world. The economics are based on multiple factors: (1) heat storage is less expensive than electricity storage (batteries, hydro pumped hydro, etc.) and other options, (2) the cost of the nuclear power plant is in the nuclear steam supply system (NSSS), not the power cycle and thus creates large incentives for the NSSS to operate at full capacity while making major changes to the power cycle by adding storage, and (3) a low-cost boiler can provide assured capacity at lower costs than competing technologies such as gas turbines with little fuel consumption because peak electricity demand is primarily met with heat storage. These technologies can be retrofitted to existing LWRs. The options and capabilities are much larger with new turbine halls designed for variable electricity production. The combination of technologies potentially is the enabling technology for a replacement for fossil fuels in a low-carbon world and the enabling technology for larger-scale use of wind and solar by providing economic dispatchable electricity with power plants that can buy and sell electricity.

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