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Implications of Carbon Constraints on (1) the Electricity Generation Mix For the United States, China, France and United Kingdom and (2) Future Nuclear System Requirements

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Abstract

Using the GexX model we determined the average price of electricity for an optimized electrical system as a function of allowable carbon dioxide emissions for Texas (good wind and solar resources), New England (poor wind and solar resources), France, the United Kingdom and two areas of China (low nuclear plant construction costs). Allowable emission rates varied from 500 to 1 g/kWh. Current U.S. carbon dioxide emissions are near 500 g/kWh. The inputs of the GenX model include hourly wind, solar and demand data as well as capital costs, operating costs and operating constraints of each technology. GenX optimizes the system over a period of one year. The capital cost of nuclear power plants was varied to understand the sensitivities in results to the relative cost of nuclear versus renewable energy sources.

In western countries, there were significant increases in the average cost of electricity as tighter carbon dioxide constraints were imposed on the system. In the U.S. with no carbon constraints, natural gas was the low-cost electricity generating option. As carbon dioxide constraints limited the use of natural gas, the optimum system used more wind, solar and then nuclear. There are major changes in the relative amounts of nuclear, wind and solar as a carbon dioxide constraints become more restrictive. The role of nuclear energy changes from traditional base-load nuclear power to variable electricity output—replacing fossil fuels in the role of providing dispatchable electricity at times of low wind and solar output. The relative quantities of wind, solar and nuclear depended upon (1) the quality of wind and solar resources and (2) the cost of nuclear power plants. The exception was China where nuclear energy is the low-cost option; thus, there was little change in electricity costs as carbon constraints became more restrictive. We also modeled the six areas in a scenario where nuclear energy was precluded as an option. This resulted in much higher electricity costs as carbon dioxide emissions became more constrained. Without a dispatchable energy source, one must overbuild wind, overbuild solar and install costly storage systems (batteries and pumped hydro) to replace fossil fuels in their role of providing dispatchable electricity.

Nuclear, wind and solar have high capital costs and low operating costs. In low-carbon scenarios, costs are driven by the need to provide assured electricity generating capacity (kW) more than by the need to provide energy (kWh). We then examined the implications for nuclear energy in this low-carbon world, including several emerging technologies that broaden the use of nuclear energy beyond its traditional role in electricity production.

> *Nuclear energy with heat storage*. The GenX model used current capabilities of nuclear power plants including load following with variable electricity to the grid but did not treat the emerging option of heat storage coupled to nuclear power plants. In a carbon constrained world, there are large economic incentives to develop nuclear power plants with heat storage to provide dispatchable electricity to the grid (Fig. A.1)—replacing fossil fuels in this role. Heat storage is an order-of magnitude less costly than electricity (batteries, pumped hydro, etc.) storage. One operates the nuclear reactor at base-load. At times of low-electricity prices, heat is sent to storage. At times of high electricity prices, reactor heat and heat from storage is used to produce peak electricity. Today heat storage at the gigawatt-hour scale is deployed at some solar thermal power systems for this reason. Nuclear energy and solar thermal produce heat and thus many of the same heat storage technologies and power conversion systems can be used. For assured peak power capacity in the event that heat storage is depleted, there is the option to add a combustion furnace burning natural gas, biofuels or ultimately hydrogen. Such a furnace provides assured peak capacity but would be seldom used because heat storage usually provides the peak capacity. Such furnaces have low capital costs. There is the option to send low-price electricity to heat storage systems where firebrick or crushed rock is heated to high temperatures and later air is blown through the firebrick or crushed rock to provide hot air to the combustion heater.

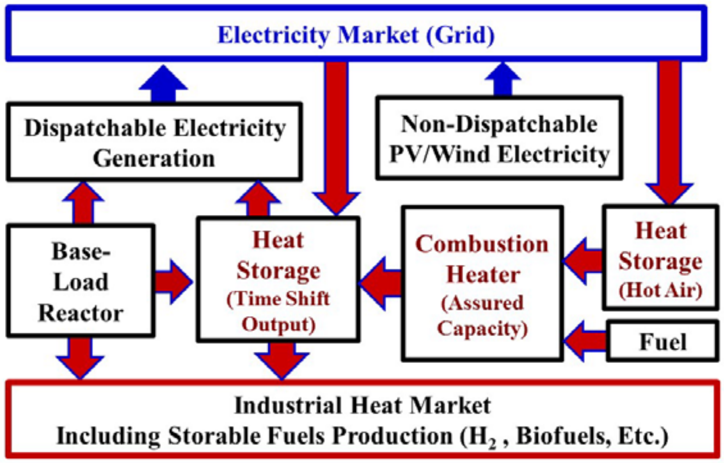

Fig. A.1. Nuclear Cogeneration System with Heat Storage

- *Nuclear co-generation*. The GenX model did not include the industrial sector. The industrial demand for heat is about twice the total electricity output of the United States. The industrial heat demand is larger relative to total electricity production in China than the U.S. Electrification of the industrial sector would triple the electricity sector at high costs. This creates economic incentives for nuclear co-generation with heat storage to provide dispatchable electricity to the grid and heat to industry. Co-generation enables the optimization of the combined electricity-industrial energy system rather than separate optimization of each sector with significant cost savings. Second, with the large-scale use of wind and solar, there are times of low or negative electricity prices. Excess electricity from the utility sector can be converted into high-temperature stored heat for industry or production of peak electricity from nuclear power plants.
- *High-temperature reactors*. There are large incentives to develop high-temperature reactors (HTRs) to lower the cost of heat storage and meet a larger fraction of the industrial heat demand. The larger temperature swing from hot-to-cold in heat storage reduces heat storage costs and higher-temperatures have higher heat-to-electricity efficiencies that reduces the amount of heat to be stored per kWh of peak electricity produced. Higher-temperature heat meets a larger fraction of total industrial heat demand.

The third energy sector is fuels production for transport and other uses. The decarbonization strategy has major implications for the electricity sector. Do we decarbonize the fuel supply (storable fuels such as hydrogen, ammonia, synthetic hydrocarbons [carbon dioxide and hydrogen] and biofuels) or decarbonize the vehicle (batteries, etc.)?

- *Electrification of Transportation*. If one electrifies much of the transport sector, it implies adding a large electricity demand with added hourly to seasonal variations in electricity demand. The limited studies in the U.S. indicate that the largest increase in electricity demand will occur in the early evening—times of peak electricity demand, highest prices and lowest wind/solar output in locations such as California. If such scenarios are correct, it implies (1) large additional needs for storage and dispatchable electricity and (2) major changes in the optimum mix of electricity generating technologies.
- *Decarbonization of the Fuel Supply*. Unlike most other industrial products, energy costs are a major fraction of low-carbon fuels production costs and thus could become the primary industrial demand for heat and electricity. There is the potential to vary the production rate of these fuels to better match the primary energy output of nuclear, wind and solar to energy production capacity. This strategy would reduce the challenges and has the potential to lower the costs of decarbonizing the electric sector.

Acknowledgements

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Executive Summary

Implications of Carbon Constraints on (1) the Electricity Generation Mix for the United States, China, France and United Kingdom and (2) Future Nuclear System Requirements

Concerns about climate change may require decarbonization of the electricity grid; that is, dramatically reduce greenhouse gas emissions. To inform policy and directions of research, we ask the question: *What would be the optimum mix of technologies to minimize total cost of electricity for different constraints on carbon dioxide emissions per unit of electricity produced? We then ask, do those constraints have implications for future nuclear system requirements?*

To answer this question we use GenX, a power system decision support tool, to explore the optimal electricity generation mix based on minimizing the total system cost of generation for a set of pre-specified scenarios. Each scenario is characterized by a carbon emission limit, a year-long hourly demand profile, year-long hourly availability profiles for solar and wind resources, and a set of investment and operational costs that model different systems under different carbon emission targets. The optimization is based on an economic criterion because energy is about 8% of the global gross national product. Large increases in energy costs imply large decreases in global standards of living.

We consider future scenarios with and without nuclear energy for six areas of the world[1]: (1) Texas, (2) New England, (3) Tianjin, Beijing, and Tangshan (T-B-T), China, (4) Zhejiang, China, (5) France and (6) and the United Kingdom. This includes electricity grids with excellent (Texas) and poor (New England) solar and wind resources. It includes countries with high (U.S. and U.K.) and low (China) capital costs for nuclear power plants. While some energy technologies such as batteries have similar costs everywhere, the capital costs of other energy technologies vary by a factor of two or more depending upon location. Nuclear energy is the extreme case where the large Chinese nuclear program has resulted in an efficient supply chain. Five different levels of carbon constraints were considered measured in carbon dioxide released per kilowatt-hour (gCO_2/kWh) of electricity produced: 500, 100, 50, 10 and 1 gCO_2/kWh. The average U.S. electric sector carbon emissions are near 500 gCO_2/kWh. We examined cost uncertainties primarily by varying the cost for nuclear power plants. When one examines scenarios with different nuclear plant costs, one observes the impacts of varying the capital costs of nuclear versus wind and solar.

The energy technologies included energy production technologies (natural gas, coal, fossil fuels with carbon sequestration, nuclear, wind, solar) and storage technologies (hydro and batteries). All of the technologies chosen are commercial or demonstrated technologies. The study did not evaluate advanced technologies that have not yet been deployed. However, a select set of emerging nuclear technologies are reviewed and discussed.

In western countries going from 500 gCO_2/kWh to 1 gCO_2/kWh in scenarios that included the option of building nuclear plants, electricity costs increased (Texas: $76.32 to 119.10/MWh, New England: $78.21 to 122.36/MWh, France: $102.85 to 148.64/MWh, and United Kingdom: $117.03 to 172.71/MWh). With no restrictions on carbon dioxide, natural gas is the preferred fuel with addition of nuclear electricity as carbon constraints become more limiting. If nuclear energy is not allowed, there are much larger increases in electricity costs as the carbon emissions limits go from 500 to 1 gCO_2/kWh (Texas: $76.52 to 162.99/MWh, New England: $78.23 to 214.09/MWh), France: $103.29 to 274.55/MWh, and United Kingdom: $116.38 to 355.05/MWh). In a carbon-constrained world, electricity costs for locations such as Texas with excellent wind and solar resources are lower than locations such as New England with poor wind and solar resources. There was little change in electricity costs or production technologies in China with tighter restrictions on carbon dioxide emissions because of the low capital cost of nuclear power plants

[1] The analysis uses results that are common to the MIT study on *Future of Nuclear Energy in a Carbon-Constrained World* (Petti et al, 2018).

makes this the preferred electric generating technology from high to low emissions of carbon dioxide (T-B-T: $57.83 to 59.30/MWh and Zhejiang: $56.97 to 59.62/MWh).

Figure S.1 shows average electricity costs for the six regions as carbon dioxide emissions are reduced and including all technologies for five different levels of carbon emission constraints. Fig. S.2 shows average electricity costs for the six locations if nuclear energy is excluded from the generating mix.

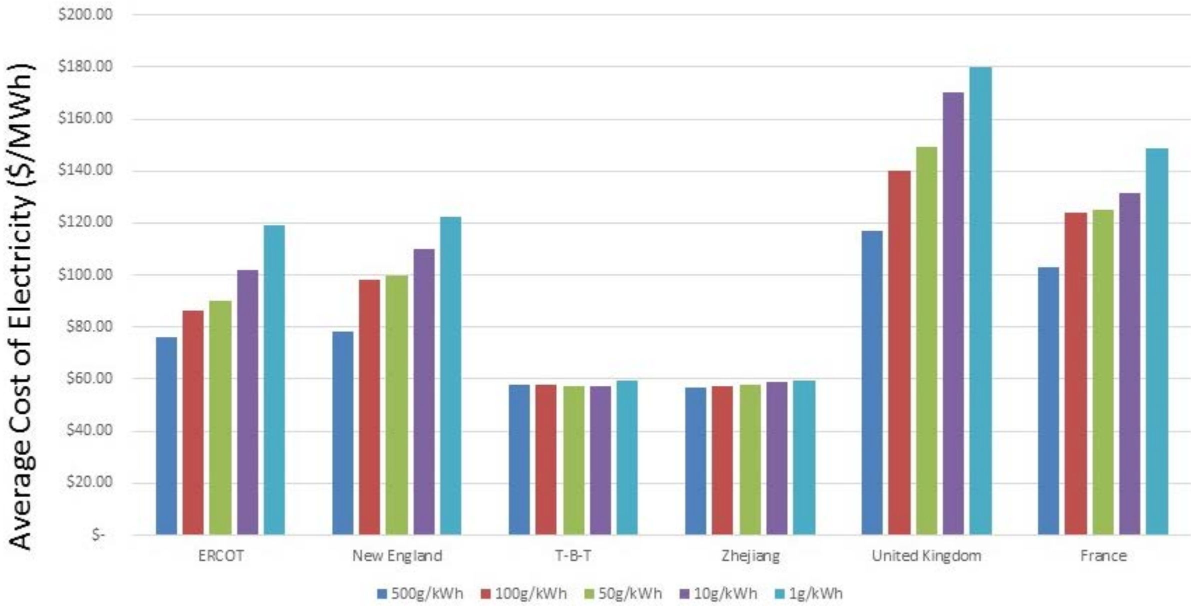

Fig. S.1. Average Cost of Electricity (All Technologies Allowed) Versus Carbon Constraint

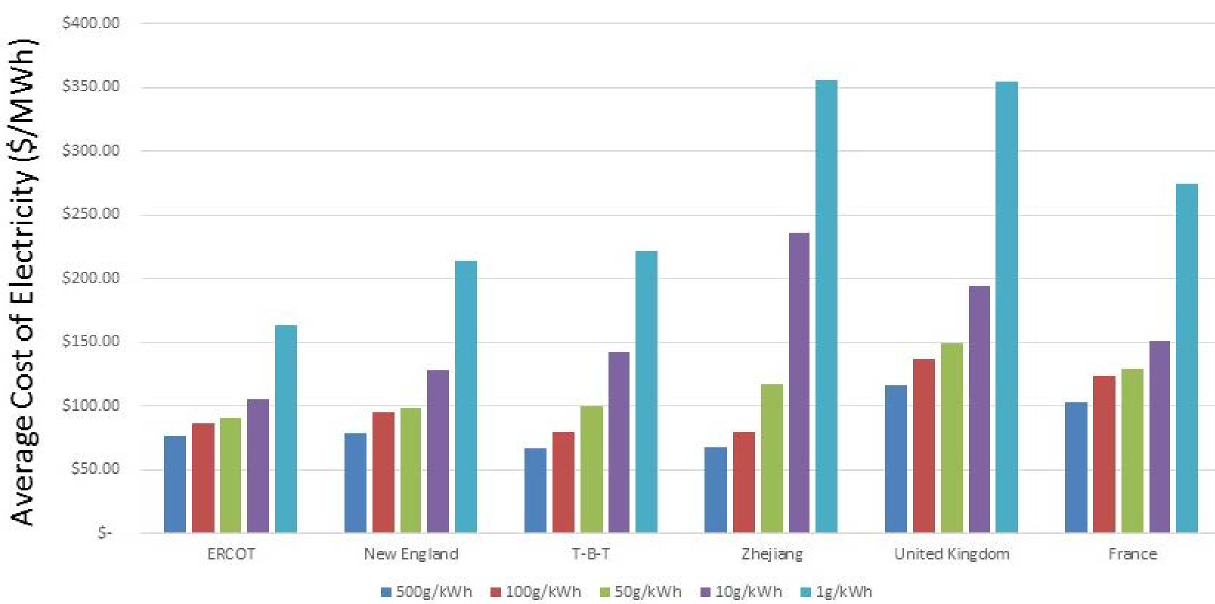

Fig. S.2. Average Cost of Electricity for Non-Nuclear Scenarios versus Carbon Constraint

There are several conclusions from these figures. First, there is a large increase in costs in low-carbon scenarios if nuclear is excluded. The vertical axis ($/MWh) is twice as high in Fig. S.2 compared to Fig.

S.1. Second, in a low-carbon world there will be large differences in regional energy costs because of the large variability of renewable resources and potentially because of the variability of the costs of nuclear power plants with location. The large differences in the cost of renewable resources reflects local wind and solar conditions. Third, Chinese have a large competitive advantage in a low carbon world that follows from a nuclear power program with an efficient supply chain that reduces nuclear plant costs. This same effect is seen in South Korea today and was seen in France in the 1970s because of a large nuclear construction programs.

Except for China, the optimum mix of generating technologies changes dramatically as carbon constraints become more restrictive. This presents a major policy and economic challenge. Power generating equipment generally have long lifetimes. If investments are optimized for one set of constraints and the carbon constraints change, there may be early retirement of capital-intensive generating assets.

The primary cause for higher electricity costs with lower carbon dioxide emission limits is the requirement for assured electric generating capacity (kW)—avoiding blackouts. Wind and solar provide energy (kWh) but have very limited capability to provide assured generating capacity (kW). To obtain assured capacity from these resources requires overbuilding wind and solar to produce some electricity at times of poor wind and solar conditions plus addition of energy storage—all with high capital costs. This implies many hours of excess electricity production capacity with very low or zero electricity prices and other times with very high electricity prices as storage systems provide large quantities of electricity. Scenarios with nuclear energy have smaller increases in electricity prices with lower carbon constraints; but, the role of nuclear energy changes. Historically most nuclear plants have operated at base-load. This changes in a world with carbon constraints. Nuclear plants provide dispatchable electricity to the grid—partly replacing the traditional role of fossil-fuel plants in providing assured generating capacity (kW). There is an economic tradeoff between operating nuclear plants in a load-following mode versus buying added electricity storage capacity on an hourly to seasonal basis.

Figure S.3 shows the operations of nuclear plants in the Texas grid versus carbon constraints while Fig. S.4 shows the operations of nuclear plants in the T-B-T, China grid versus carbon constraints. These are the extreme cases. Texas has excellent renewable resources, cheap natural gas and relatively expensive nuclear energy; thus, nuclear plants are not built until carbon constraints limit the use of natural gas. China is the opposite extreme with lower-quality renewable resources, expensive natural gas and low-cost nuclear energy; thus, the optimum system has nuclear plants in all scenarios. Nuclear operations are characterized in three ways.

- *Number of ramps per year*. GenX optimizes the system for each hour of the year—8760 hours. The number of ramps per year is the number of times the power level changes in a year. The maximum number of times the power level could change is 8760 times. The number of ramps per year increases as carbon constraints become more severe; that is, the nuclear plants do more load following and less time operating at baseload.
- *Average ramp up.* This is the average increase in power when the power level increases. This may occur over one hour (one ramping event) or many hours (multiple ramping events). It ends when the next change in power level decreases power levels.
- *Maximum ramp up*. This is the largest increase in power over a year in any ramping event that could occur in an hour or over many hours.

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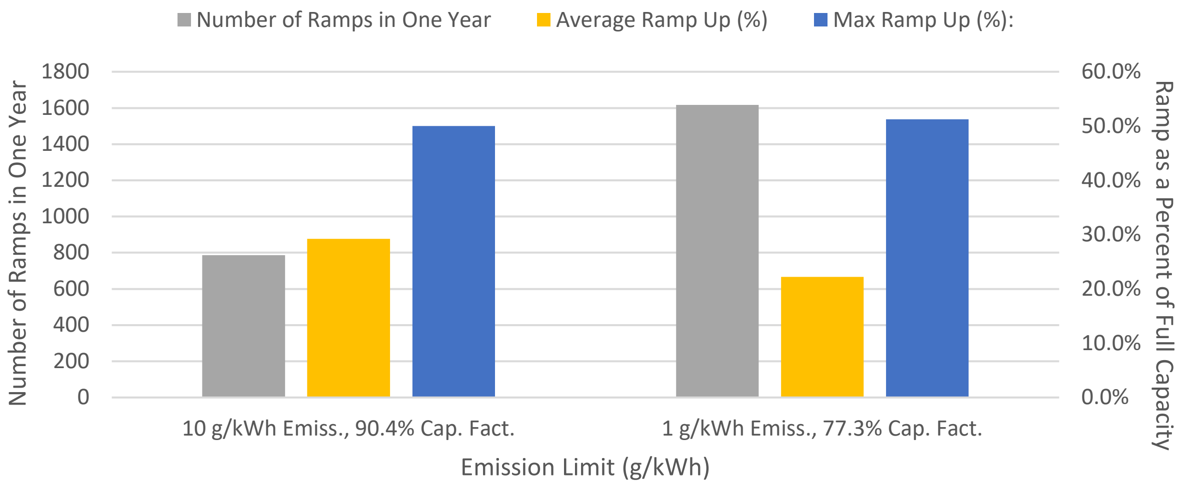

Fig. S.3. Texas ERCOT Nuclear Operations for Different Carbon Constraints

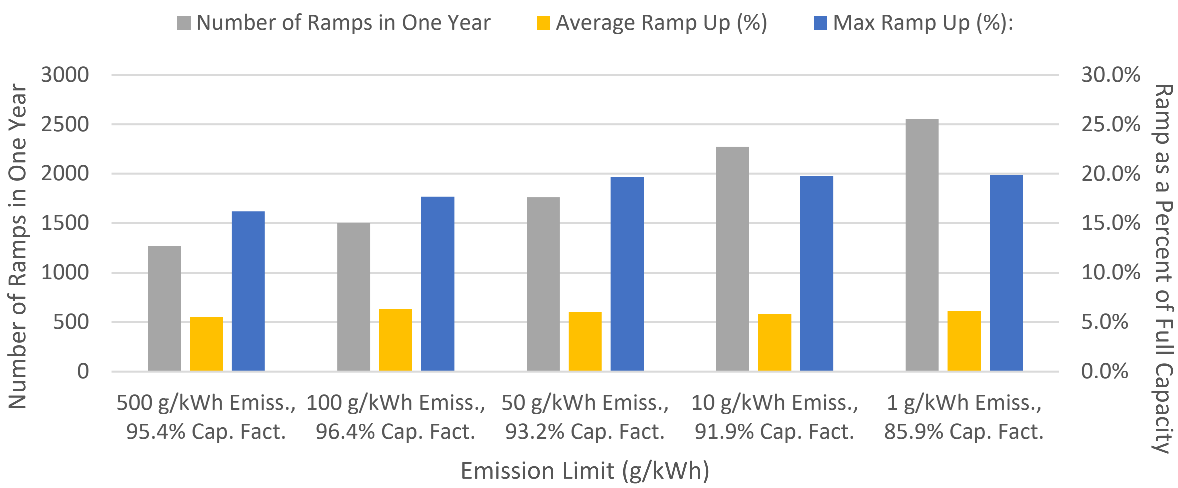

Fig. S.4. T-B-T China Nuclear Operations for Different Carbon Constraints

There are several conclusions.

- Number of ramps per year increases with tighter constraints on carbon emissions. Nuclear power plants become the dispatchable form of electricity that partly replaces this role of fossil fuels.
- Average ramp rates vary from near 5% to over 25% of full power. The largest ramp rates are in Texas that has low-cost wind and solar with a smaller fraction of nuclear power plants. The smallest ramp rates are in China where a large fraction of the electricity in an optimized system is from nuclear energy. If one has a large installed capacity of non-dispatchable wind and solar and relatively small amount of nuclear, the installed nuclear capacity must provide more dispatchable electricity with a smaller amount of installed capacity. Most of the time, the changes in power levels are small
- The maximum ramp as a percent of full capacity is large in western countries (near 50%) but smaller in China. In western countries with higher-cost nuclear, there is a larger fraction of wind and solar. The maximum ramping events are associated with times of low wind and solar. In China

most of the capacity is nuclear; thus, large changes in wind and solar output have a smaller impact on nuclear plant operations

The GENX model in this analysis assumes all reactors operate at the same load at any time. In a real system with multiple reactors, the utility may assign specific reactors to go up and down in power while operating other reactors at full power. This is the current strategy in France where a subset of the nuclear fleet is assigned to do load following with modifications to these plants to enable more efficient load following. The models herein assumed that the variable electricity from nuclear power plants was achieved by load following—the existing deployed technology. As discussed below, there are other options such as nuclear reactors with heat storage for dispatchable electricity.

From a broader perspective, going to a low-carbon economy is going from fossil-fuel electricity production that is characterized by low capital cost and high operating cost (fuel) to nuclear, wind and solar that are characterized by high capital costs and low operating costs. In a fossil-fuel electricity generating system, fossil plants can operate at part load with relatively small economic penalties because most of the cost is associated with the storable fossil fuels which are not used if the power plant is not producing power. This enables the production of low-cost dispatchable energy to meet human needs. The economic penalties become large if the electricity grid has high-capital-cost systems (nuclear, wind and solar) operating at low capacity factors because the capital costs are incurred regardless of the power output of the plant. The other change is going from a world with relatively uniform worldwide costs for energy to a world with large variations in energy costs depending upon location. The costs of oil or coal are similar at seaports around the world because of the low cost to transport these commodities. In contrast, the quality of wind and solar vary dramatically with location and thus the cost of wind or solar electricity vary dramatically with location. The cost of nuclear reactors also varies with location today but that is not an intrinsic characteristic of the technology. Nuclear technology cost is influenced, however, by the size and complexity of construction.

The different characteristics of a low-carbon grid imply the need for new technologies to address two economic challenges: (1) provide low-cost low-carbon dispatchable electricity and (2) find a beneficial use for excess low-price electricity generated at times of high wind or solar input and low demand. This is part of a broader challenge of reducing carbon emissions from the economy—including the industrial and transport sectors. Most low-carbon energy scenarios assume electrification of the industrial sector. However, in the United States the heat input into the industrial sector is about double the electricity output of the electricity sector (Fig. S.5). Brute force electrification of the industrial sector by providing electric resistance heating would require tripling of the electricity sector size. In China the relative size of the industrial sector compared to the electrical sector is significantly larger than in the United States. If a future low-carbon transportation sector uses hydrogen, biofuels or a variety of other low-carbon fuels, it implies massive additional growth of the industrial sector energy demands to produce these fuels. Any large-scale electrification of the industrial or transport sector has potentially major implications for the organization of the electricity, industrial and transport sectors.

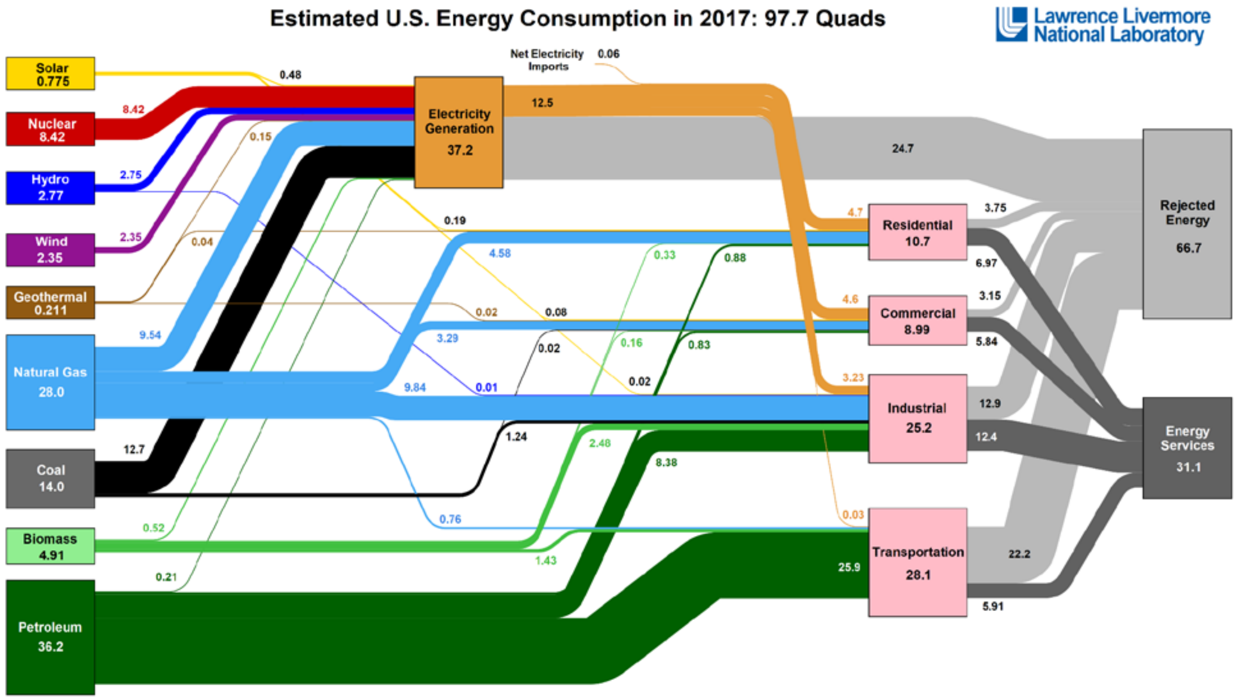

Fig. S.5. Energy Flows in the United States

- *Low-price electricity to the industrial sector.* If there is significant low-price electricity in the electricity sector at times of high wind or solar output, it can be converted into high-temperature stored heat for use in the industrial sector—the only sector of the economy capable of absorbing all low-price electricity at any time of year. The electricity at times of low prices is used to heat firebrick, crushed rock, liquid salts or other materials to high temperatures. This heat is then provided to industry as required and partly replaces the burning of fossil fuels.

- *Large-scale heat storage coupled to nuclear power plants.* If nuclear plants are required to provide dispatchable electricity to the grid there are two options: (1) operate the reactor with variable output [basis of above GenX analysis] or (2) operate the reactor at base-load with heat storage. Wind and solar photovoltaic produce electricity and thus couple to electricity storage systems (batteries, pumped hydro, etc.). Nuclear reactors produce heat that couples to heat storage technologies (hot rock, hot salt, hot oil, hot concrete, etc.). The cost of heat storage is an order of magnitude less than the cost of work (electricity) storage. The U.S. Department of Energy capital-cost goal for heat storage systems coupled to concentrated solar power systems is $15/kWt. Some advanced heat storage systems have projected costs significantly below this cost goal. Nuclear heat storage systems in many cases would use the same technologies that are used today in concentrated solar power systems and deployed commercially at the gigawatt-hour scale. The U.S. Department of Energy capital-cost goal for batteries is $150/kWe for the battery pack—double that if include the electronics and associated equipment. While one is for storing heat and the other electricity, this storage cost difference is far greater than the value of electricity compared to heat.

  A nuclear reactor with heat storage (Fig. S.6) at times of low-electricity demand would send some steam to the turbine to enable fast return to full power and the remainder of the steam to heat storage. At times of high electricity prices (demand), the reactor and the heat storage system would send steam to the power conversion system to produce peak power significantly above base-load capacity. Most of the time heat storage would provide assured peak-power generating capacity (kWe). There is the option to include a low-cost boiler using natural gas, biofuels, hydrogen or other combustible fuel to provide steam if heat storage is depleted. The fuel consumption would be very low because heat storage usually would provide the assured peaking capacity. The peak electricity output above base-load can be sized to meet electricity grid requirements. It is a low-cost way to provide assured peak generating capacity—creating a technology to replace the role of fossil fuels in providing dispatchable electricity to the grid under all circumstances. If there are large quantities of low priced electricity from wind and solar, there are two options to use this low-price electricity to enable the nuclear plant to buy and sell electricity.

- *Heat storage material.* Low-price electricity using electric resistance heating can be used to heat the storage material used to store heat from the nuclear reactor. This includes electricity from the grid and electricity from the turbine that is operating at minimum load to enable rapid return to full power.
- *Heat storage with hot air output.* Low price electricity can heat firebrick or rock to high temperatures. Air can be blown through the firebrick or hot rock to provide hot air to the boiler for peak power production.

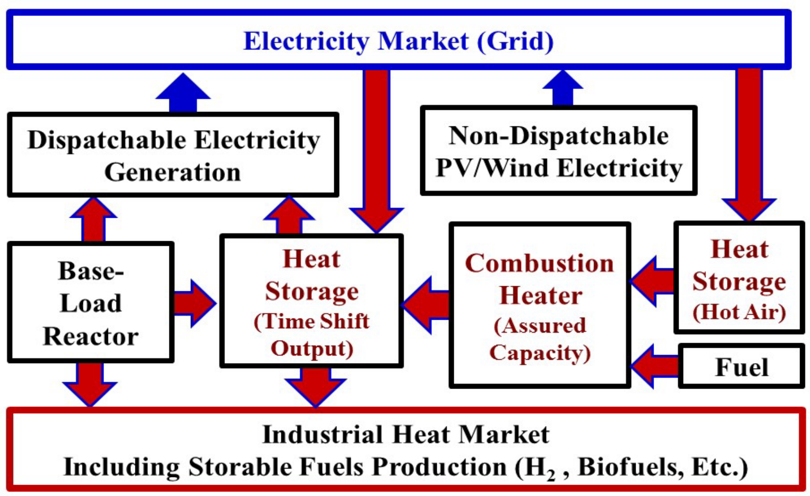

Fig. S. 6. Integration of Electricity, Industrial and Storable Fuels Energy Sectors with Heat Storage

This system design also has major implications for wind and solar. If a market exists that can adsorb excess very-low-price electricity and set a minimum price of electricity near that of fossil fuels, it substantially improves wind and solar revenue. There is a synergism between nuclear systems with heat storage, wind and solar.

- *Energy Integration of the Electric and Industrial Sectors with Nuclear Co-generation Coupled to Large-Scale Heat Storage.* Historically fossil fuels provide most of the energy inputs separately to these two sectors. What replaces fossil fuels in this role? Of the major low-carbon energy technologies only nuclear and concentrated solar power (CSP) provide heat, what the industrial sector requires (Fig. S.5). However, CSP is geographically limited to areas with direct sunlight with large seasonal variations in output. That implies that a major application of nuclear energy in a low-carbon world is heat for industry. In existing reactors the heat-to-electricity conversion efficiency is about 33% so the cost of heat is a third or less the cost of electricity. Wind and solar photovoltaic produce electricity that can be converted to heat with near 100% efficiency. This is an expensive way to produce heat when an assured heat supply is required. In some larger industrial plants today, heat is supplied by fossil-fuel co-generation plants that provide heat and electricity. If nuclear energy is used on a large-scale for industrial heat, nuclear cogeneration (electricity and heat production) may become a significant, or the primary, source of electricity for the grid. These changes suggest the following changes in systems and technologies to reduce energy costs.

- *Heat storage.* Large-scale wind and solar create low-price electricity at certain times and thus incentivize conversion of that electricity into high-temperature stored heat that can be used when needed by the industrial sector. If heat storage is coupled to nuclear co-generation reactors, heat storage can receive heat from the reactor at times of low electricity demand and low-price electricity from the electricity sector that is converted into high-temperature stored heat. That stored heat can be sent to industry or reactor heat and stored heat can be used for peak electricity production when needed. The economics of such storage is better than separate independent heat storage systems coupled to nuclear reactors and heat storage for low-price electricity for industry. First, there are economics of scale associated with large heat storage systems. Second, a major fraction of the cost in converting electricity into stored heat is the electrical system from the grid to the resistance heater. If a nuclear plant has heat storage for variable electricity output, it implies that the power lines, grid connections, transformers, switchgear used to send electricity to the grid are available at essentially no cost to import electricity to heat storage at times of low electricity cost. By definition, one will not be sending electricity to the grid or receiving electricity from the grid at the same time. Third, the heat storage system coupled to the reactor will be used many more times per year than an electricity-to-heat-storage system coupled to an industrial load. Stand-alone electricity-to-heat storage systems coupled to industry will only be used when electricity prices are less than the costs of fossil fuels to provide industrial heat loads. Heat storage systems coupled to a nuclear reactor will be used at such times but will also be used whenever there are large variations in electricity prices and there is an economic incentive to vary electricity outputs. The more times per year a heat storage system is used, the lower the cost of heat storage.
- *Coupled markets.* There are large incentives for nuclear co-generation to provide energy to two markets to (1) maximize revenue and (2) minimize financial risk. First, co-generation enables on to optimize the combined electricity and industrial sector energy demand. Some existing fossil-fuel cogeneration plants vary their industrial heat demand to enable production of added electricity at times of high prices to maximize revenue. That strategy increases revenue for the industrial company, provides electricity to the grid when most needed and helps reduce peak electricity prices. Second, co-generation in a low-carbon world reduces financial risk. The demand for industrial heat at a particular industrial site may change over a period of decades because of changes in demand for a particular product or changes in the industrial process that impact the need for heat. The reactor may have a lifetime of 60 years. A co-generation plant assures longer-term economic value for the nuclear plant if it can sell electricity. Co-generation minimizes total costs—the reason why fossil-fuel cogeneration exists today.

- *Storable Fuels Production*. The third major sector of the global energy system is fuels production. Fuels production for transport and other uses remains the largest uncertainty for a low-carbon world. Do we decarbonize the fuel supply (storable fuels such as hydrogen, ammonia, synthetic hydrocarbons [carbon dioxide and hydrogen] and biofuels) or decarbonize the vehicle (batteries, etc.)? There has been relatively little work to understand the impact of decarbonizing the transport sector on the electric sector

- *Electrification of Transportation*. If one electrifies much of the transport sector, it implies adding a large electricity demand with added hourly to seasonal variations in electricity demand. The limited studies to date indicate that the largest increase in electricity demand will occur in the early evening—times of peak electricity demand, highest prices and lowest wind/solar output in locations such as California. If such scenarios are correct, it implies (1) additional need for storage and dispatchable electricity in the electricity sector, (2) significant increases in electricity prices and (3) incentives for more dispatchable nuclear energy and nuclear energy with heat storage. Electrification of transportation forces the storage and dispatchability functions of fossil fuels into the electricity sector.
- *Decarbonization of the Fuel Supply*. Unlike most other industrial products, energy costs are a major fraction of low-carbon fuels production costs and thus could become the primary industrial demand for heat and electricity. Low-carbon storable fuels include hydrogen, ammonia, biofuels and a variety of other options. The production of biofuels requires massive amounts of heat and or hydrogen. If external source of energy, the quantity of liquid fuel per ton of biomass can be doubled. There is the potential to vary the production rate of these fuels with nuclear co-generation to better match the primary energy output of nuclear, wind and solar to energy demand. It is a strategy to address the hourly to seasonal mismatch between electricity generation and electricity production on an hourly to seasonal basis with full utilization of nuclear plants. Part of the low-carbon energy system requirements for storage and dispatchability are moved from the electricity sector to a storable fuels sector. This strategy could significantly reduce the challenges of decarbonizing the electric sector.
- *Hybrid Electric Vehicles*. There are large energy system differences between all-electric vehicles and plug-in hybrid vehicles that have a combustion engine and batteries. All-electric vehicles force the grid to meet the hourly to seasonal variations in energy consumption in the transport sector. With hybrid vehicles, the driver has assured transportation. If there are financial incentives, the vehicle owner can choose to charge the electric vehicle only when the price of electricity is low—times of less stress on the electric grid. The storable fuels sector meets the variable transport energy demand challenge.

These changes have major implications for future nuclear plants. Historically fossil fuels separately met the needs for dispatchable energy in the electricity, industrial, and transportation sectors. In a low-carbon world these energy sectors are coupled to each other. A major question is how and where to economically meet the energy storage and dispatchability requirements?

- *Heat storage*. If the electricity sector is decarbonized, the most economic nuclear power system is the reactor with heat storage that provides the lowest-cost dispatchable heat and electricity output to the electricity grid and heat to industry. The lowest cost system is not the system with the lowest levelized-cost-of electricity (LCOE) because that assumes the product is base-load electricity. If there are similar capital costs per unit of thermal power output for different types of reactors, this change strongly favors high-temperature reactors (HTRs) that can meet a larger fraction of industrial heat demand and have lower-cost heat storage systems.

    - *Temperature swing*. For sensible heat storage systems, if the hot-to-cold temperature swing by the storage system is doubled, the cost of energy storage is reduced by a factor of two.
    - *System temperature loses*. Most heat storage systems have heat exchangers—with a set temperature drop across the heat exchangers. Loses across heat exchangers are proportionally smaller in high-temperature systems.
    - *Heat-to-electricity efficiency*. Higher-temperature stored heat can more efficiently be converted to electricity. If the conversion efficiency is 50% at higher temperatures versus

33% in existing light-water reactors, much less heat must be stored per unit of peak electricity produced. The higher heat-to-electricity efficiencies also imply more heat storage cycles per year if low-price electricity is being converted into stored high-temperature heat and then converted back to electricity. If the number of storage cycles is doubled, the cost of storage drops in half. Higher efficiency power cycles imply higher round trip efficiency (electricity to heat to electricity) and more times per year where the difference between high and low prices make storage economically attractive.

- *Co-generation*. If nuclear cogeneration is a large fraction of the future market, the need is for reactors that are designed to efficiently supply heat to industry. That implies reactors that meet the temperature requirements for heat to industry and reactors whose safety characteristics enable co-siting with industrial facilities. These requirements favor HTRs. Such reactors have been developed but were not commercialized because of the drop in the price of natural gas makes natural gas the more attractive investment. Nuclear co-generation could become the primary source of nuclear electricity to the grid.

Last, the change in the market creates incentives for new power cycles for nuclear reactors with different capabilities to better match changing market requirements for dispatchable electricity and heat. One example is a nuclear air-Brayton combined cycle that couples to HTRs with large peak to base-load electricity output combined with high efficiency. There are other options. During normal operations, air is compressed, heated using high-temperature heat from the HTR, goes through a turbine producing electricity and send to a heat recovery steam generator where the steam can be used to meet industrial demands or to produce added electricity. For peak electricity production, after nuclear heating of the compressed air (600 to 700°C), the compressed air is further heated using a combustible fuel (natural gas, biofuels, hydrogen, etc.) or stored heat to as high as 1500°C (conventional gas turbine peak temperatures) before being sent to the turbine. This is a thermodynamic topping cycle with incremental heat-to-electricity efficiencies that can be above 70%--substantially above alternative power cycles. Because of the very high incremental heat-to-electricity efficiency, a reactor with such a power cycle would be the first "natural gas" plant dispatched and allow natural gas to be used for peaking power in a world with much tighter constraints on carbon emissions. The high efficiencies of thermodynamic topping cycles for peak electricity production would be favored in a low-carbon world using more expensive low-carbon hydrogen or biofuels.

This leads to several conclusions. The economically-optimum design of energy system changes with level of carbon constraints. The challenge in a low-carbon world is not generating electricity. The challenges are (1) providing heat to industry and (2) assured generating capacity that replaces the storage and dispatchability characteristics of fossil fuels. The role of nuclear energy changes with more restrictive carbon dioxide constraints. Historically nuclear energy has been used to produce base-load electricity with fossil fuels providing dispatchable electricity. As carbon constraints increase, nuclear energy is used to provide dispatchable electricity with highly variable electricity output to the electricity grid—partly replacing fossil fuels as the dispatchable electricity source. This creates incentives for nuclear co-generation plants with large-scale heat storage. The storage and dispatchability functions of fossil fuels are partly replaced by heat storage and partly replaced by optimization of the electricity-industrial energy demand rather that separately optimizing the electricity and industrial sectors to minimize energy costs. The change in requirements creates incentives for deploying high-temperature reactors that lower heat storage costs, can meet a larger fraction of the industrial heat demand and enable advanced power cycles designed to meet the changing market requirements.

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1. Introduction

Concerns about climate change have resulted in many countries adopting policies to reduce greenhouse gas emissions. The policies often change depending upon concerns about climate change, the cost to reduce carbon emissions, and political choices on energy technologies. These changes will continue. To inform policy and directions of research, we ask the question:

What would be the optimum mix of technologies to minimize total cost of electricity for different constraints on carbon dioxide emissions per unit of electricity produced?

Energy is about 8% of the global gross national product; thus, there are serious impacts on global standards of living if there are large increases in energy costs. Doubling or tripling of costs, as seen in many low-carbon scenarios, would have large political impacts as well as economic impacts. For that reason, our figure of merit is the average electricity generation cost. The analysis focuses on the United States, China, United Kingdom, and France and uses analysis results that are common to the MIT study on Future of Nuclear Energy in a Carbon-Constrained World (Petti et al, 2018). Two regions are analyzed for the United States: (1) Texas ERCOT region which has very good wind and solar resources and (2) New England ISO with less favorable wind and solar conditions. Two regions of China are analyzed because (1) China is the largest energy consumer on earth and (2) Chinese nuclear plant construction costs are low—a system that favors larger-scale use of nuclear energy. The analysis is done for different levels of allowed carbon dioxide emissions for the year 2050 and different mixes of technology. We assume a green-field system; that is, the technology mix is the optimum mix as if we were building the system from the ground up.

Deep decarbonization of the electrical energy sector is needed to mitigate the effects of climate change in this century. The term "deep decarbonization" means a substantial reduction (one order of magnitude or more) of greenhouse gas emissions domestically, as well as internationally, to mitigate or moderate climate change. For a country to accomplish deep decarbonization, a pathway to reduce the carbon emissions must be chosen. A number of studies have shown different mitigation pathways are possible with different likelihoods of achieving a goal that meets or exceeds the 2050 target of 2ºC (International Energy Agency, 2017; Chen et al, 2016) limit in increased global average temperature. Options include carbon taxes, cap and trade, and government mandates selecting specific technologies. Decarbonization studies primarily focus on the transformation of the electricity sector to reduce emissions by 2050, because the costs of carbon reductions in this sector are initially lower than for others. By contrast, the industrial and transportation energy sectors are expected to be more costly to decarbonize and affect significant changes by 2050.

In our analysis, we consider a broad range of decarbonization targets (i.e., grams of CO_2 per kilowatt-hour electric, gCO_2/kWh) for the electricity generation system. For example, in 2010, the average U.S. CO_2 emissions from electricity generation were about 500 gCO_2/kWh. To reach the 2050 goals set in the Paris accords for the U.S., the equivalent CO_2 gas emissions (so-called carbon intensity) from electricity generation would need to be reduced by over 97%; i.e., from 500 g /kWh to less than 15 gCO_2/kWh. This reduction target is based on the analysis of required reductions in the electric and non-electric sectors (e.g., Sachs et al, 2014), to limit the greenhouse gas concentration in the atmosphere to 450 ppm CO_2 equivalent.

To provide context for the CO_2 emission targets, the current 2017 levels of CO_2 emissions from electricity generation for selected countries are shown in Table 1.1. For comparison, we reference two analyses that set CO_2 targets to meet the requirements of the 2°C scenario by 2050, 'deep decarbonization'. The IEA analyses estimate that emission levels must be below 11 to 24 gCO_2/kWh, whereas the MIT analyses calculate that the emissions need to be reduced to about 1 gCO_2/kWh. Also, other studies have analyzed the path to decarbonization and have noted that to mitigate future economic risks in supply, a diverse set of carbon-free technologies need to be considered (Morris, et al, 2018). Thus, we consider a range of emission constraints from modest to deep decarbonization. This approach is consistent with past work (Sepulveda, 2016), where targets ranged from 400 gCO_2/kWh to 1 gCO_2/kWh in 2050.

Table 1.1 Comparison of Current CO2 Equivalent Emissions to 2050 Emissions Goals [2]

Country	2017 CO_2 Emissions from Electricity	2050 IEA ETP 2°C Scenario	MIT Joint Program Outlook [5]
United States	~470 g CO_2eq/kWh[1]	11 g CO_2eq/kWh[4]	~1 g CO_2eq/kWh
China	~680 g CO_2eq/kWh[2]	24 g CO_2eq /kWh[4]	~1 g CO_2eq/kWh
United Kingdom	~350 g CO_2eq/kWh[3]	11 g CO_2eq /kWh (for EU) [4]	~1 g CO_2eq/kWh
France	~90 g CO_2eq/kWh[3]	11 g CO_2eq /kWh (for EU) [4]	~1 g CO_2eq/kWh

[1] (US EIA, 2017) [2] (Liu et al, 2017) [3] (Gogan et al, 2017) [4] (International Energy Agency, 2017) [5] (Chen, et al., 2016)

We examine specifically the impact of nuclear energy on the optimum mix including scenarios with no nuclear, nominal nuclear and nuclear where capital costs have been significantly reduced. In a low-carbon world, nuclear is the primary dispatchable form of energy. Varying the capital cost of nuclear provides an understanding of the impact of varying the ratio of nuclear to wind/solar capital costs.

The second question we ask is **What are the implications in terms of changes in the system and new technologies with different capabilities?** Our analysis is of the existing system and existing technologies. We examine how nuclear plants would be operated as carbon constraints increase. Do the results point to the need for changing the system design or the need for new technologies?

[2] Excerpted from "The Future of Nuclear Energy in a Carbon-Constrained World," September 1, 2018

2. Baseline Assumptions and Models

Using energy technology costs or the Levelized Cost of Electricity (LCOE) does not adequately value the production of dispatchable, low carbon power at the system level and these approaches can have major shortcomings in evaluating system integration costs. The overall value of a given technology to the electricity system can only be understood when technologies are assessed together, not in isolation. Decision support tools, including power system optimization models, can help explore these important transitions, illuminate key mechanisms, uncertainties and risks, and help guide power system planners, policy makers and businesses. In particular, capacity expansion (or capacity planning) modeling tools have historically been used to help explore the least-cost mix of various available electricity generation resources under a given scenario.

To quantify the role of nuclear power, we use GenX (Jenkins, Sepulveda, 2017), a power system decision support tool, to explore the optimal electricity generation mix based on minimizing the total system cost of generation for a set of pre-specified scenarios. Each scenario is characterized by a carbon emission limit, a year-long hourly demand profile, year-long hourly availability profiles for solar and wind resources, and a set of investment and operational costs that model different systems under different carbon emission targets. This analysis considers two alternative pathways for each scenario. In the first one, nuclear power technology is allowed as an investment option in the least-cost system portfolio, i.e., deployed only if economically efficient for the system. Conversely, in the second pathway, nuclear power technology is not allowed as an investment option to be deployed in the system. We consider different carbon emission targets: 100, 50, 10, and 1 gCO_2/kWh in our system analysis as well as a 'business-as-usual' target of 500 gCO_2/kWh. We also did a case with no limits on carbon dioxide emissions. As noted in Table 1.1, China is currently above the business-as-usual target of 500 gCO_2/kWh.

We perform our analysis for a broad set of different cost and technological scenarios to investigate the breadth of conditions under which nuclear energy can play a significant role. These different technological scenarios can be viewed as sensitivities, wherein we individually vary the input parameters for technologies from an assumed "nominal case" scenario.

GenX optimizes the electricity generation capacity mix by minimizing the objective function of total annualized generation cost on a per megawatt-hour basis for a given scenario accounting for capital cost and financing charges, fixed operating cost, and variable operating costs, including fuel charges. In our scenarios, we impose the following constraints: (a) matching hourly electricity dispatch to electricity demand, (b) technology-specific operating constraints such the allowable ramp rates and unit commitment for dispatchable generators, and (c) the CO_2 emission limits (i.e., grams of CO_2 per kilowatt-hr, gCO_2/kWh).

The model is configured to consider a full year of operating decisions at an hourly interval to represent some future planning year. In this sense, the current formulation is static because its objective is not to determine when investments should take place over time, but rather to produce a snapshot of the minimum-cost generation capacity mix under some pre-specified future conditions.

We express our results in average cost of generation [$/MWh], i.e., the system total cost over the total demand served in the system throughout the year. For our analysis, we characterized different regional systems in the United States (Texas, New England), Europe (France, United Kingdom), and China (two eastern provinces) by the chronological hourly demand and renewables availability profiles.

To make our simulation computationally tractable in all of our scenarios, transmission networks were simplified to a single node representation (i.e., so-called copper plate assumption), assuming no transmissions constraints exist given future network reinforcements. Electricity flows are unimpeded within the region and the electricity generated only serves the electricity demand in that region. There is no imported or exported electricity considered in the scenarios. Table 2.1 summarizes the required inputs and the outputs of the simulations using GenX. Analysis details are provided in Appendix A.

Table 2.1: Inputs and Outputs of the GenX Model [3]

Inputs	Outputs
• Solar PV Hourly Capacity Factor • Wind Hourly Capacity Factor • Hourly Historical Demand and Demand Growth • Fixed (Capital and O&M) and Variable (O&M, cycling, etc.) Costs for Each Resource Technology • Operational Parameters for Each Resource Technology • Fuel Parameters such as Emissions Rate and Cost	• Optimal Installed Electricity Generation Capacity Mix • Total System Cost • Hourly Operation of Each Resource Technology • System Carbon Emissions • Energy Contribution and Capacity Factor for Each Resource Technology

Due to computational time constraints, we limited the number of technology options for each optimization scenario. A large light water reactor (LWR - 1000MWe) is used as the surrogate for advanced nuclear technologies. Table 2.2 shows technology options for both pathways (with and without nuclear energy as an option in the capacity mix).

Table 2.2: Technology Options for Each Pathway [4]

Nuclear Energy IS Allowed Option	Nuclear Energy is NOT Allowed Option
Carbon Free Options • Photovoltaic (PV) Solar • On-Shore Wind • Light-water Reactor (LWR) Nuclear • Coal w Carbon-capture-storage (CCS) • Natural Gas with CCS	Carbon Free Options • PV Solar • On-Shore Wind • ~~LWR Nuclear~~ • Coal with CCS • Natural Gas with CCS
Carbon Options • Open Cycle Gas Turbine (OCGT) • Combined Cycle Gas Turbine (CCGT) • Coal	Carbon Options • OCGT • CCGT • Coal
Storage Options • Battery Storage • Hydro-electric Storage (Fixed)	Storage Options • Battery Storage • Hydro-electric Storage (Fixed)

A global perspective is important since the cost of these electricity generation technologies varies regionally as well as renewable resources availability and electricity demand patterns. All of these elements shape the least-cost generation mix. The electricity systems modeled in China, Europe and the United States were:

[3] Excerpted from *The Future of Nuclear Energy in a Carbon-Constrained World*, September 1, 2018
[4] Excerpted from *The Future of Nuclear Energy in a Carbon-Constrained World*, September 1,2018

- Tianjin, Beijing, and Tangshan (T-B-T), China
- Zhejiang, China
- France, Europe
- United Kingdom, Europe
- Texas, United States
- New England, United States

The data sources used as inputs for each electricity system are summarized in Table 2.3.

Table 2.3: Data Sources for GenX Scenarios [5]

	Tianjin, China	Zhejiang, China	France	United Kingdom	Texas, United States	New England, United States
Solar Hourly Capacity Factor (2016)	Renewables Ninja[a]	Renewables Ninja[a]	Sepulveda 2016	Sheffield Solar[d]	Sepulveda 2016	Sepulveda 2016
Wind Hourly Capacity Factor (2016)	Renewables Ninja[a]	Renewables Ninja[a]	Sepulveda 2016	EnAppSys[e]	Sepulveda 2016	Sepulveda 2016
Historical Hourly Elec. Demand	CEIC[b] and SWITCH[c]	CEIC[b] and He et al.[c]	Sepulveda 2016	Gridwatch[f]	Sepulveda 2016	Sepulveda 2016

[a] (Pfenninger & Staffell, Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data, 2016) (Staffell & Pfenninger, 2016) (Pfenninger & Staffell, Renewables.ninja, n.d.)
[b] (CEIC, 2017) [c] (He, et al., 2016) [d] (The University of Sheffield, 2017) [e] (EnAppSys, 2017) [f] (Gridwatch, 2017)

Operating parameters (e.g., heat rates) were assumed constant across each electricity system. The estimated costs for the United States were taken from (National Renewable Energy Laboratory, 2016) and (Lazard, 2015 for battery storage) for 2050. The costs for all technologies except storage in the two regions in China, the United Kingdom and France were scaled from the U.S. costs based on scaling factors between the particular region and U.S. calculated from costs reported in (International Energy Agency, 2015). Overnight costs are shown in Table 2.4. All costs and assumptions are discussed in detail in Appendix A.

[5] Excerpted from *The Future of Nuclear Energy in a Carbon-Constrained World*, September 1, 2018

Table 2.4 Overnight Capital-Cost Inputs [6]

United States			
Resource	Low Cost ($/kW)	Nominal Cost($/kW)	High Cost($/kW)
OCGT		805	
CCGT		948	
Coal IGCC		3,515	
Nuclear	4,100	5,500	6,900
Wind	1,369	1,553	1,714
Solar	551	917	1,898
Battery Storage	429	715	1,430
Coal ICGT+CCS		5,876	
Gas CCGT+CCS		1,720	2,215
China			
Resource	Low Cost ($/kW)	Nominal Cost($/kW)	High Cost($/kW)
OCGT		421	
CCGT		496	
Coal IGCC		1,160	
Nuclear	2,094	2,796	3,500
Wind	1,117	1,267	1,398
Solar	404	671	1,389
Battery Storage	429	715	1,430
Coal ICGT+CCS		1,940	
Gas CCGT+CCS		900	1,159
United Kingdom			
Resource	Low Cost ($/kW)	Nominal Cost($/kW)	High Cost($/kW)
OCGT		865	
CCGT		953	
Coal IGCC		3,515	
Nuclear	6,070	8,142	
Wind	1,887	2,142	2,363
Solar	484	804	1,665
Battery Storage	429	715	1430
Coal ICGT+CCS		5,875	
Gas CCGT+CCS		1,434	1,847
France			
Resource	Low Cost ($/kW)	Nominal Cost($/kW)	High Cost($/kW)
OCGT		890	
CCGT		980	
Coal IGCC		3,515	
Nuclear	5,067	6,797	8,496
Wind	1,511	1,715	1,892
Solar	481	801	1,657
Battery Storage	429	715	1430
Coal ICGT+CCS		5,876	
Gas CCGT+CCS		1,475	1,899

All costs and assumptions are discussed in detail in Appendix A.

[6] Excerpted from *The Future of Nuclear Energy in a Carbon-Constrained World*, September 1,2018

3. Total Electricity System Costs

Figure 3.1 (a through f) shows average total system cost of electricity generation for the six regions chosen for comparison: Texas, New England, T-B-T (China), Zhejiang (China), the United Kingdom and France. For each region, the energy costs versus allowable carbon limit is shown from 500 to 1 grams of carbon per kWh of electricity generated.

We first present the results of our analyses from Texas in Fig. 3a, a state with good wind and solar resources. The total system cost of electricity generation for five technological scenarios are shown based on definitions developed in the MIT study (Petti et al, 2018):

1. ***No-Nuclear*** case where nuclear is not an allowed option.
2. ***Nuclear-Nominal*** case is the scenario in which nuclear technology can be selected at the currently projected Nth-of-a-kind (NOAK) overnight cost ($5500/kWe in 2050 for the United States), according to (National Renewable Energy Laboratory, 2016).
3. ***Nuclear – Low Cost*** case is the scenario in which nuclear technology can be selected at a cost that is 25% lower than currently projected costs for 2050. This estimate is based on our analysis where innovations in enabling technologies are employed to reduce the overnight cost of nuclear.
4. ***Nuclear – Extremely Low*** case is the scenario in which nuclear technology can be selected at a cost that is 50% that of the currently projected cost for 2050. This is a long-term cost goal of many advanced reactor technologies (US Department of Energy, 2016), and
5. ***Nuclear - High*** case where the nuclear cost is 25% higher than the currently projected cost for 2050 based on current First-of-a-kind (FOAK) costs

Texas (Fig. 3.1.a) represents a region with high renewable potential (windy and sunny climate) and low-cost natural gas. With the ‘Business as usual’ case of emissions at 500 gCO_2/kWh, which is the current U.S. emissions level, natural gas is the low-cost fuel option (See Section 4) and thus the costs of scenarios with and without nuclear are identical because there is no economic benefit in adding nuclear power to the generation mixture. However, as emissions targets are decreased and the use of natural gas is restricted due carbon emission constraints, nuclear is deployed as part of the least-cost generation mix for cases with a CO_2 emissions limit below 50 gCO_2/kWh at the nominal capital cost of nuclear. This is due to the value that nuclear energy presents to the system as a zero-emissions generation. The cost of the no-nuclear case begins to dramatically increase as emissions limits go down and the use of natural gas is restricted. This is because without a dispatchable electricity source, the only way to provide assured generating capacity to meet demand is to oversize wind and solar capacity with the addition of storage. Oversizing wind and solar capacity enables these technologies to meet electricity demand earlier and later in the day for solar and under lower-wind conditions. The economic optimum non-nuclear system also includes significant electricity storage. Reductions in the capital cost of nuclear reduce the cost electricity when there are major restrictions on carbon dioxide emissions.

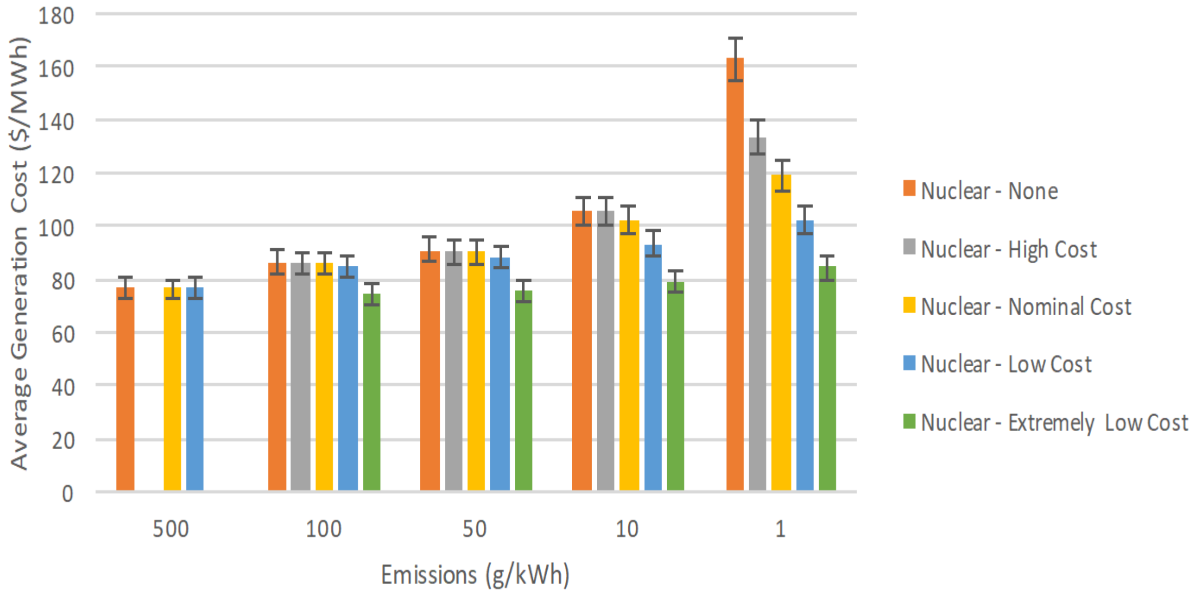

Figure 3.1.a: Texas Cost of Electricity Generation [7]

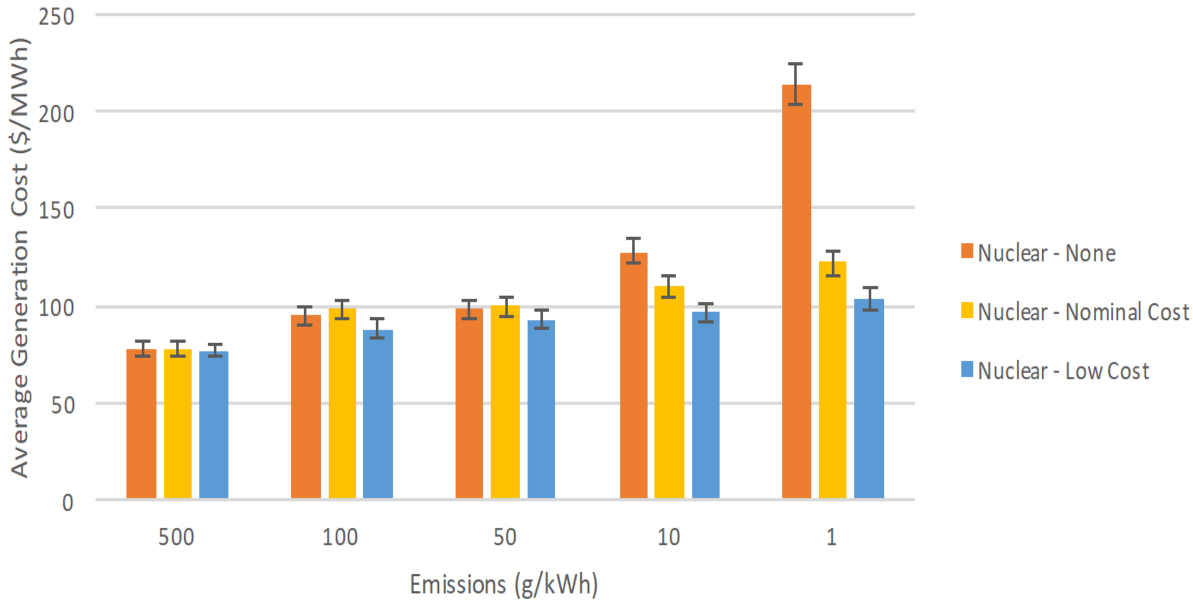

Figure 3.1.b: New England Cost of Electricity Generation [5]

[7]The GenX method optimizes the electricity generation system capacity mix based on minimizing the objective function of total generation cost in a year for a given market. There is an inherent error in this minimization procedure. The maximum expected error is depicted in the figure by the brackets. Results excerpted from *The Future of Nuclear Energy in a Carbon-Constrained World*, September 1, 2018

In comparison to Texas, New England sees a higher benefit from nuclear technology in the optimal capacity mix, because the quality of renewable resources is lower in New England when demand is high, than the quality of renewable resources when demand is high in Texas. Thus, for New England to generate enough electricity in periods of higher demand, it requires a larger amount of installed renewable capacity and storage. This build out of installed capacity requires a large amount of capital expenditure, which translates into a higher system cost. The combination of less favorable weather conditions and more stringent CO_2 constraint is the reason for the steep increase in the cost of generation in the non-nuclear scenario. As the emissions constraint decreases from the 'Business as usual' case of 500 gCO2/kWh, the cost of substituting one kWh of the carbon-emitting electricity generation with carbon-free electricity generation increases. At the less strict carbon emission levels, the carbon-emitting energy is displaced by renewable technologies during periods of high renewable potential (i.e., sunny and windy days). However, as the carbon constraint is decreased further, the electricity generation during these high renewable potential times is already carbon-free. The carbon-emitting electricity generation, which must be displaced, is at times with lower renewable potential. Therefore, either a large build out of renewable capacity with storage is needed to compensate for the lower generation potential or a carbon-free dispatchable generation technology is needed (such as nuclear). This means that there is a much higher cost to displace that unit of carbon-emitting energy generation at stricter carbon constraints without nuclear as an option.

The two Chinese cases (3.1.c and 3.1.d) are quite different than Texas and New England. In both Chinese regions nuclear is part of the low-cost option at 500 grams carbon dioxide per kWh and its proportional contribution grows at lower levels of carbon emissions. There is little impact on generating costs by reducing carbon emissions. This is because of several factors.

- *China does not have access to low-cost natural gas*. Most of its natural gas is imported. Imported liquefied natural gas (LNG) is more expensive than natural gas in the United States because of the cost to liquefy natural gas and ship that gas. China does have coal that is roughly similar in cost to nuclear power—but coal is not an option with any significant constraints on greenhouse gas emissions.
- *The estimated nominal capital cost of nuclear power is about half that in the United States*. Thus, it is an economically competitive option with coal plants and no constraints on carbon dioxide emissions. The most important reason is that China is building large numbers of reactors and has developed an economic supply chain. There is a massive learning curve in the production of any product including nuclear reactors. There are secondary factors such as labor costs (10 to 20% of the cost difference).

Because nuclear is the low-cost Chinese option, we added a high-cost nuclear option where the capital cost increases by 25% to $3500/kW to determine sensitivity of results to higher costs. These are also shown in 3.1.c and 3.1.d.

The costs herein can be converted into an equivalent cost of carbon. Appendix C does this conversion for several cases.

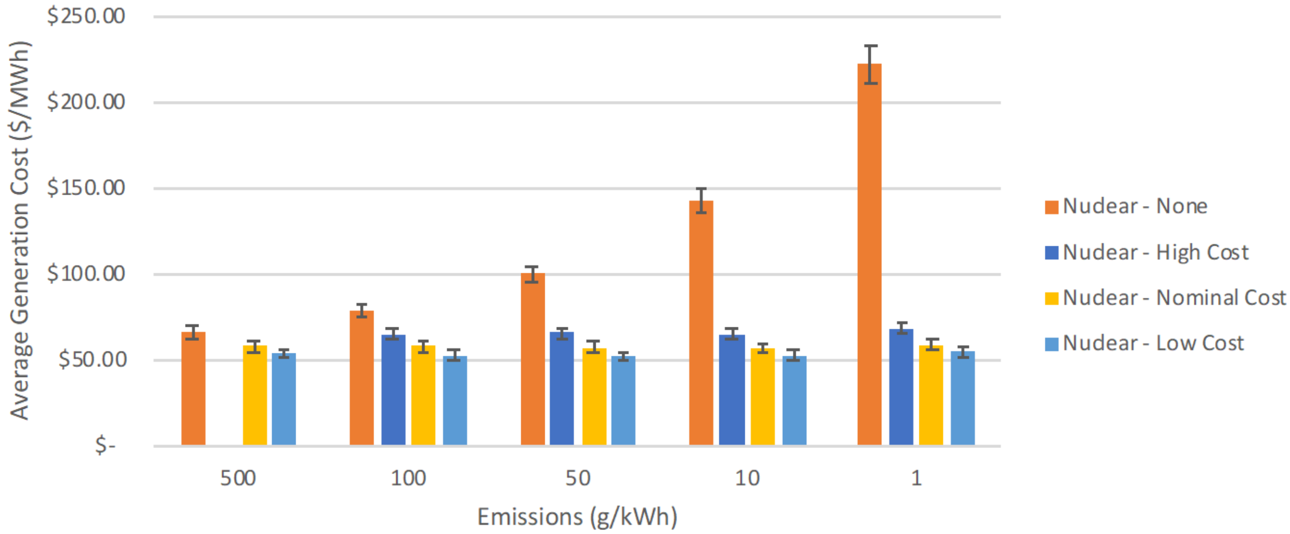

Figure 3.1.c: T-B-T Cost of Electricity Generation [5]

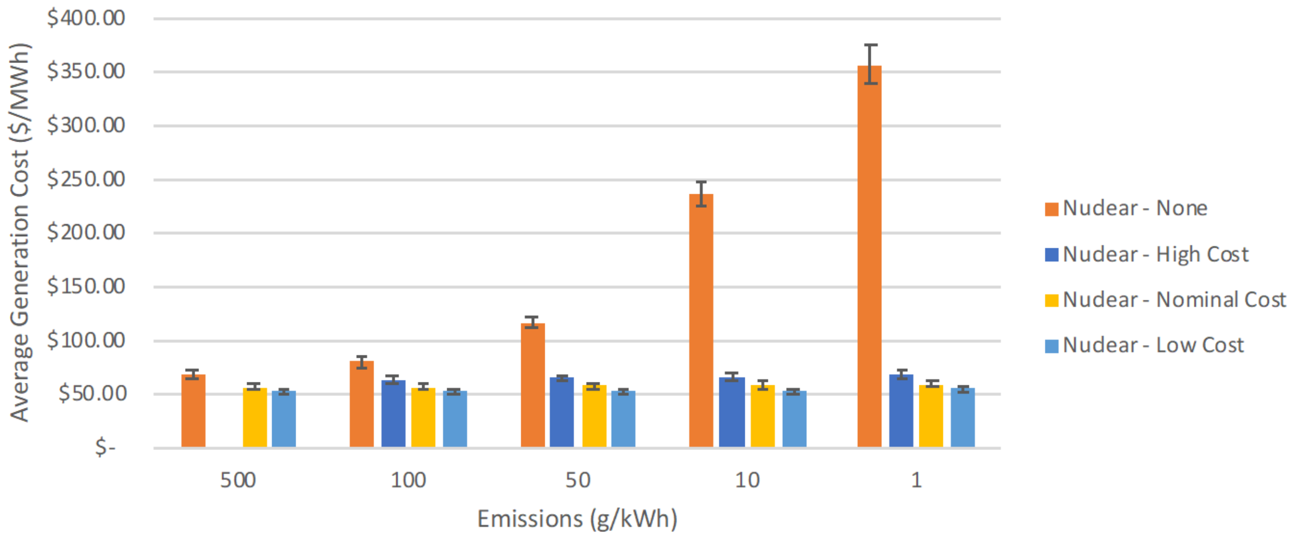

Figure 3.1.d: Zhejiang Cost of Electricity Generation [5]

The low-cost of nuclear power in China gives China a large competitive advantage if the world decides to substantially reduce carbon dioxide emissions and the Chinese expand nuclear power but western countries do not. There is the caveat that replacing coal may cause major disruptions in parts of the Chinese economy.

The United Kingdom and France are similar to the U.S. with some a few differences. The United Kingdom has major wind resources whereas France has wind and solar resources. Both countries currently have high estimated costs associate with new nuclear power plants.

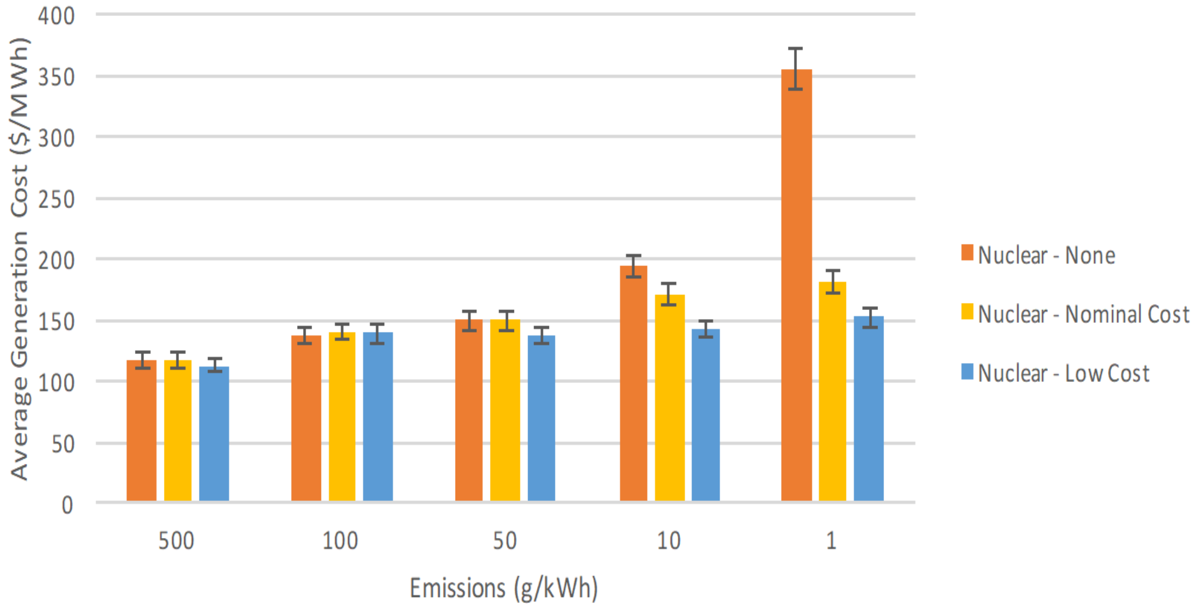

Figure 3.1.e: United Kingdom Cost of Electricity Generation [5]

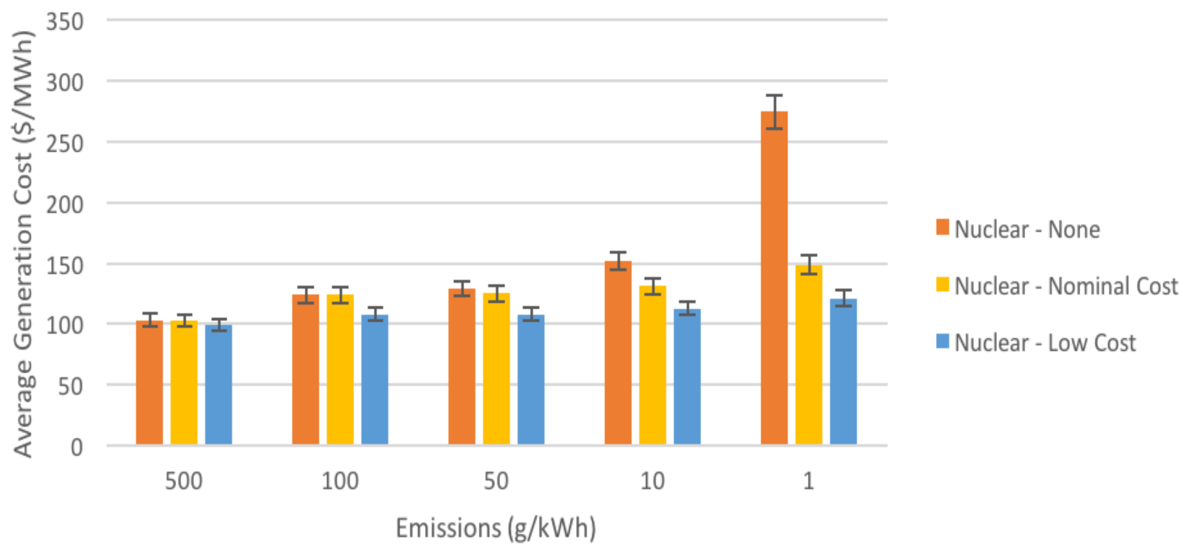

Figure 3.1.f: France Cost of Electricity Generation [5]

Figure 3.2 shows average electricity costs for the six regions as carbon dioxide emissions are reduced and including all technologies. Fig. 3.3 shows average electricity costs for the six locations if nuclear is excluded from the generating mix.

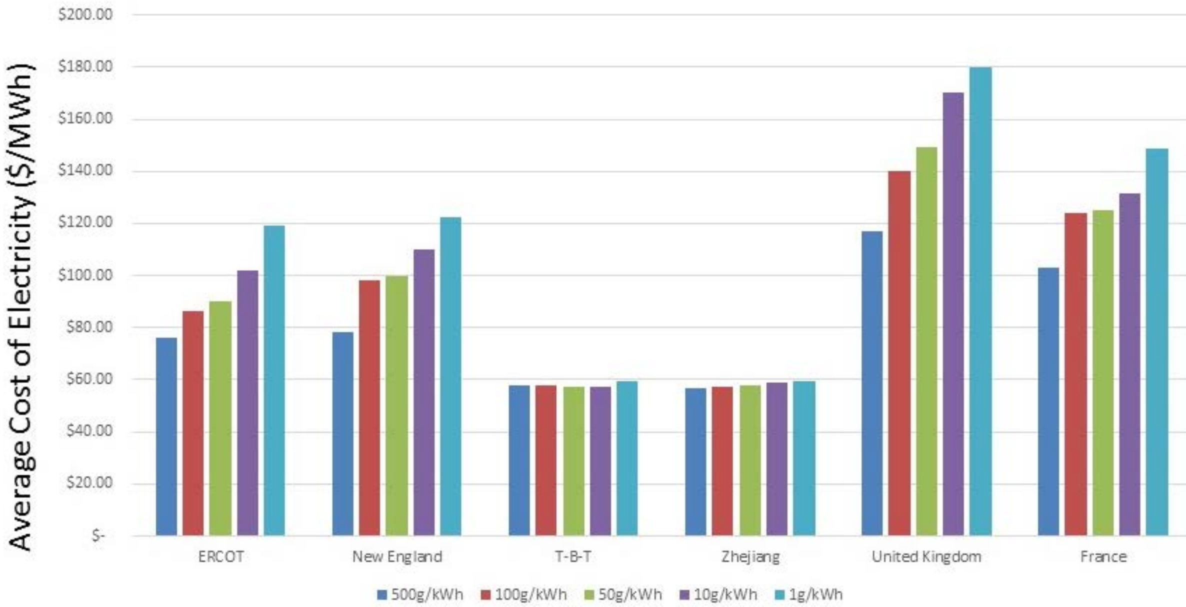

Figure 3.2. Average Cost of Electricity (All Technologies Allowed) Versus Carbon Constraint

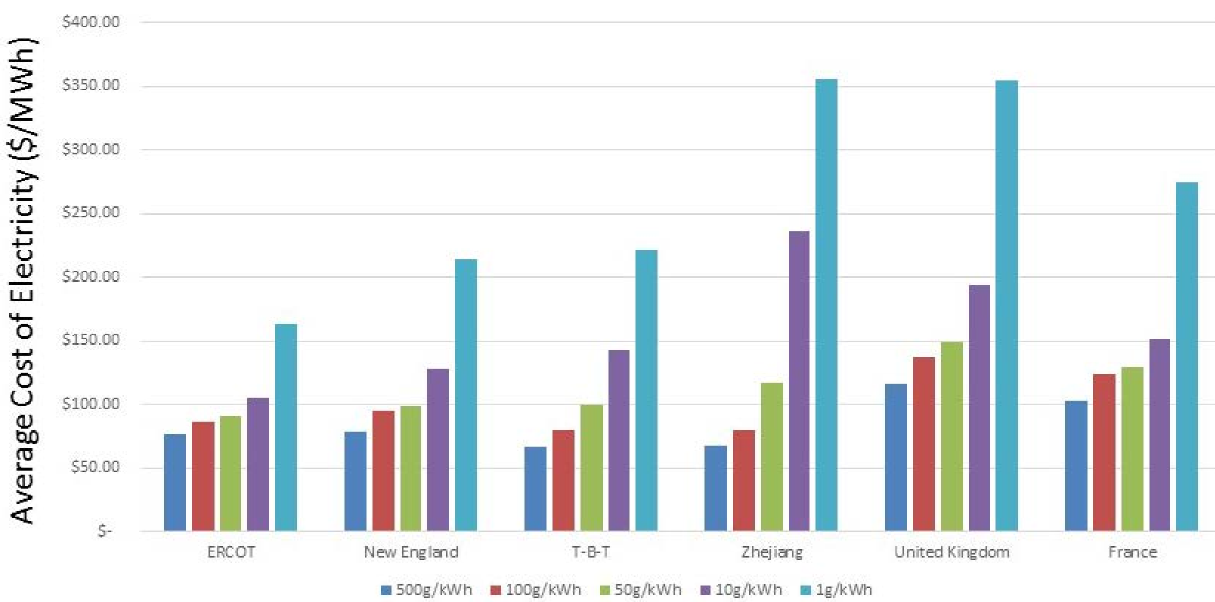

Fig. 3.3. Average Cost of Electricity for Non-Nuclear Scenarios versus Carbon Constraint

There are several conclusions from these figures. In a low-carbon world there will be large differences in regional energy costs because of the large variability of renewable resources and potentially because of the variability of the costs of nuclear power plants with location. The large differences in the cost of renewable resources reflects local wind and solar conditions. It is not a law-of-nature that there be large differences in nuclear cost with location. That is driven more by institutional factors. Second, low-cost nuclear implies low costs for transitioning the electricity grid to a low-carbon grid. There is some increase but it is much smaller than for other scenarios. Third, the Chinese have a very large competitive advantage in a low carbon world that follows from a nuclear power program with an efficient supply chain that reduces nuclear plant costs. This same effect is seen in South Korea today and was seen in France in the 1970s because of a large nuclear construction program.

4. Optimum Mixture of Installed Generating Capacity Vs Carbon Emission Limits

Installed capacity (kW) is what one buys to meet electricity demand. In a low-carbon world, most of the cost of electricity is associated with the capital cost of the power plants (nuclear, wind and solar) —the cost of capacity. The operating costs are low. In contrast fossil fuel plants have relatively low capital costs and high operating costs (fuel) in producing electricity (kWh). The transition to a low-carbon system is a transition to a system where most of the costs of electricity are associated with the capital costs of the power plants. The cost of fuel would not be not a significant part of the cost of electricity.

Figures 4.1 (a-f) show the optimum capacity mixes to minimize electricity system costs for three scenarios: (1) an electrical grid with no nuclear power plants, (2) an electrical grid with nominal capital-cost nuclear power plants and (3) an electrical grid with lower-capital-cost nuclear power plants. Each figure shows the generating mix for the three scenarios the 6 regions for a specific carbon constraint. The optimum technology mixture changes dramatically as carbon constraints are imposed that reduce the use of fossil fuels. The black diamonds show the total generating capacity (GWe)

Figure 4.1.a shows the optimum generating mix for a carbon capacity limit of 500 g carbon dioxide per kWh of electricity—about equal to emissions today from the power sector in the United States. In Texas the optimum installed capacity mix in 2050 would be a system where 70% of generating capacity is natural gas and most of the remainder is wind and solar. In New England the optimum capacity mix would be over 90% natural gas. Texas has more wind and solar capacity because of the good regional conditions for wind and solar generation but there is very little in New England because of the poor wind and solar conditions.

In China the low-cost system has nuclear providing most of the generating capacity—it is a competitive low-cost option. There is significant natural gas and coal capacity to meet variable demand but most of the time this capacity operates at part load. If nuclear was not allowed, the optimum system would burn primarily coal but such a system would have emission limits above 500 gCO_2/kWh. A non-nuclear system meeting the 500 gCO_2/kWh constraint includes coal with carbon capture.

In the United Kingdom, the optimum mix includes coal, coal with carbon capture, and natural gas. If low-cost nuclear is available, it becomes a significant contributor to electricity supplies in the United Kingdom. France has lower-cost renewables that partly replace coal with carbon capture.

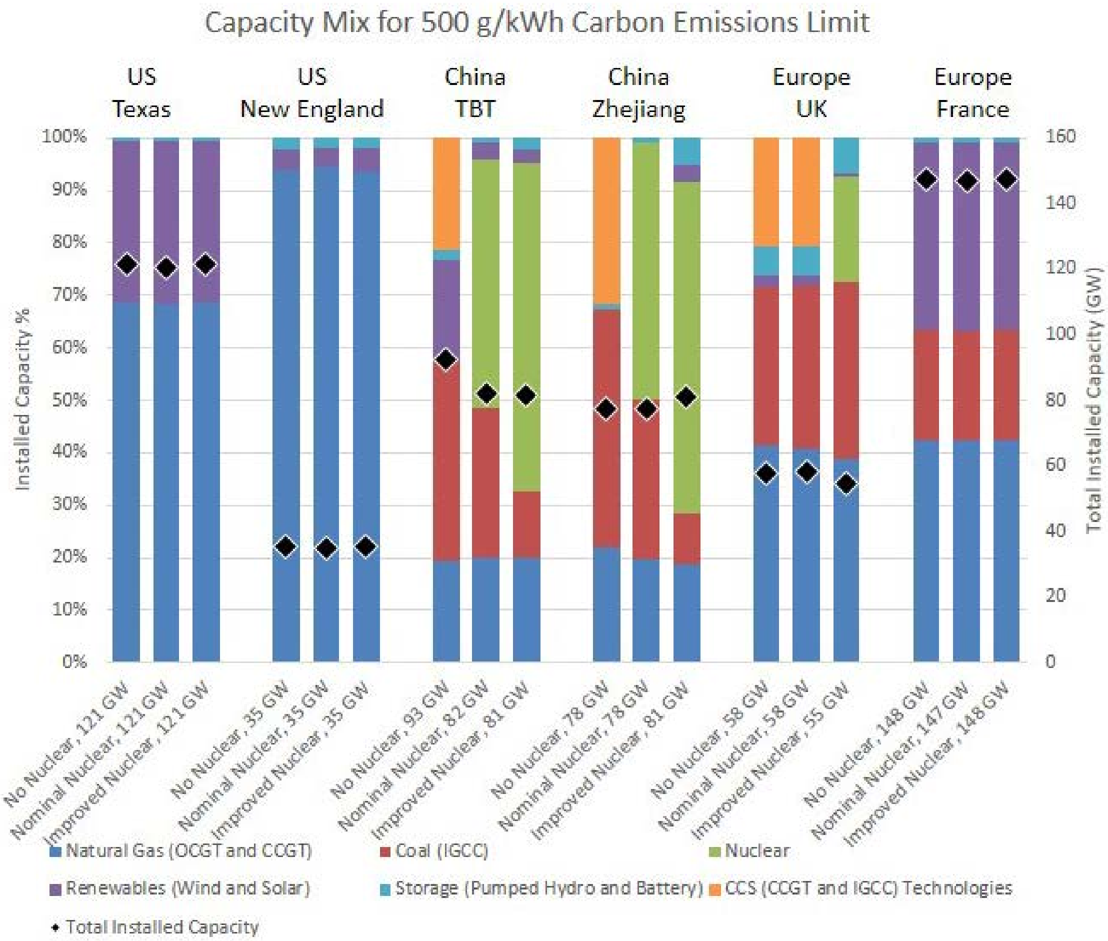

Figure 4.1.a: Generating Capacity for the Six Regions with a Carbon Constraint of 500 g/kWh

As carbon emission limits decrease from 500 g/kWe to 1 g/kWe, the optimum generating mix changes as coal and then natural gas are not chosen for the system mix and the nuclear generation share increases. The amounts of wind and solar depend upon the region with significant contributions in regions with good wind and solar conditions—such as Texas.

The generating mix provides a clear explanation of why electricity systems without nuclear energy become expensive as carbon constraints limit the use of fossil fuels. At the bottom of the three bars for each region (and denoted by the black diamond in the figure) is the total generating capacity in GWe. At 500 g/kWe, the total generation capacity for each set of generation options (listed in order: no-nuclear, nominal-nuclear, and low-cost nuclear) is about the same. For Texas those numbers are 121 GWe, 121 GWe, and 121 GWe—identical since nuclear is not part of the optimal system mix in any case. However, at 1 g/kWe the three total generating capacity numbers for Texas are 556, 163, and 148 GWe—a massive increase in generating capacity for the non-nuclear scenario although total electricity delivered to customers is nearly constant. For the no-nuclear case with tight limits on carbon constraints, there is (1) a massive build out of wind and solar to produce electricity at times of poor wind and solar output and (2) a massive build out of battery storage capacity. However, much of this capacity is not used most of the time—it is built to assure electricity for a relatively limited number of hours per year.

There is in this case a strong tradeoff between added renewables (wind and solar) versus battery storage to meet variable electricity demand. The challenge is not just meeting the daily variations in electricity demand but also the weekly and seasonal variations in electricity demand and generation from wind and solar resources.

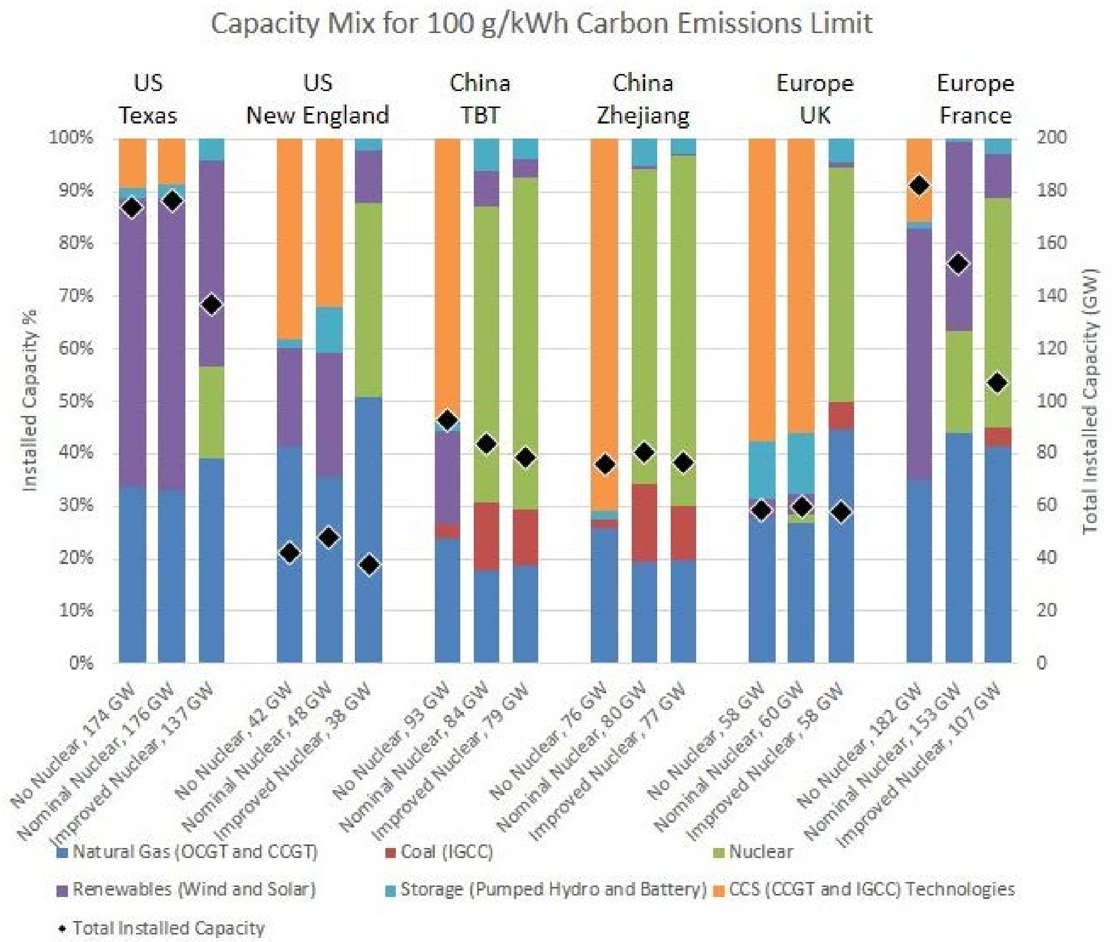

Figure 4.1.b: Generating Capacity for the Six Regions with a Carbon Constraint of 100 g/kWh

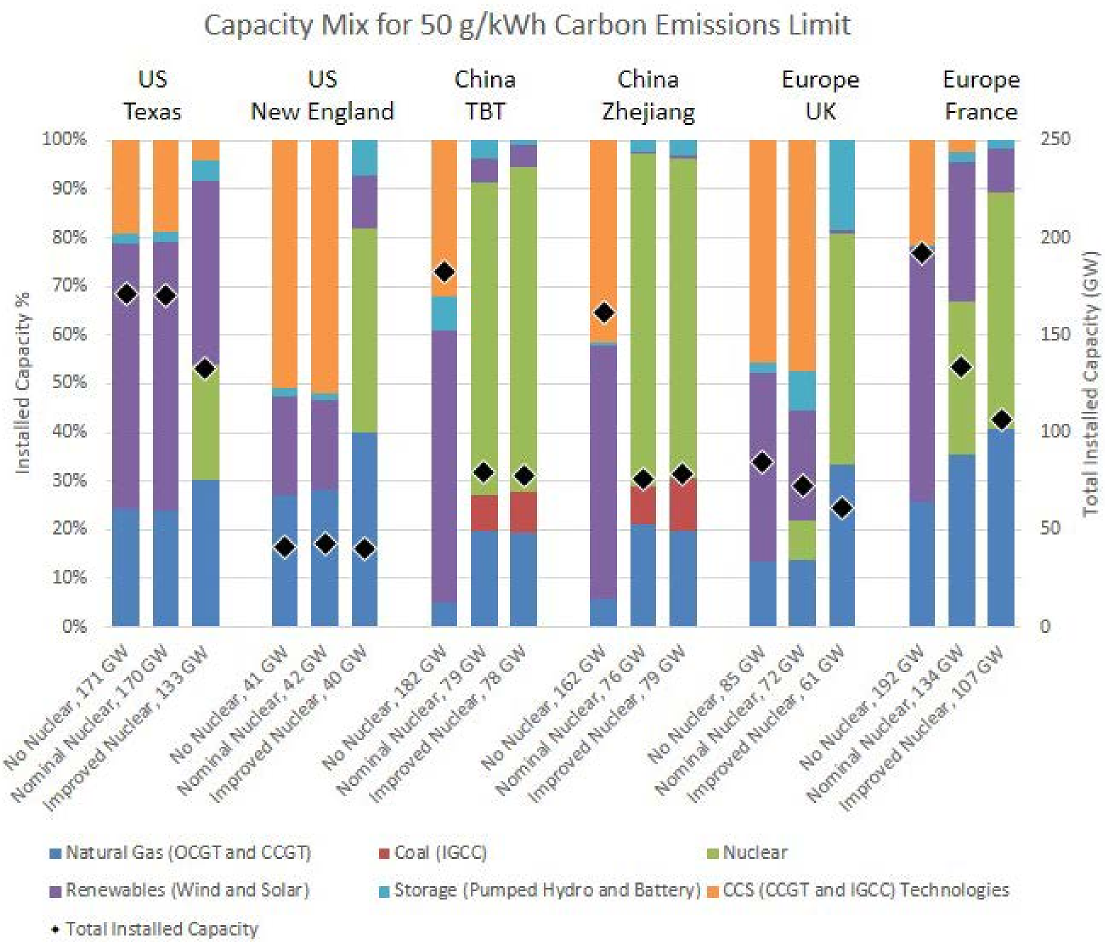

Figure 4.1.c: Generating Capacity for the Six Regions with a Carbon Constraint of 50 g/kWh

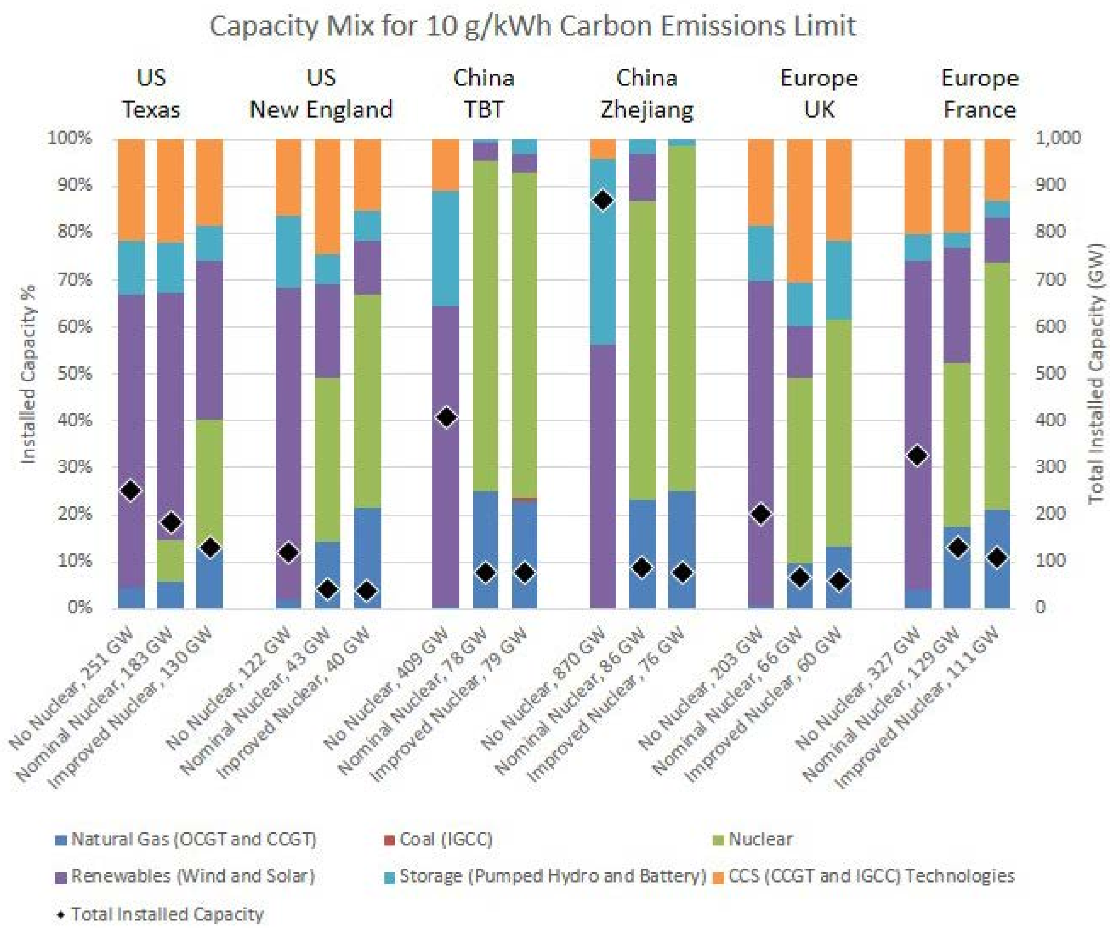

Figure 4.1.d: Generating Capacity for the Six Regions with a Carbon Constraint of 10 g/kWh

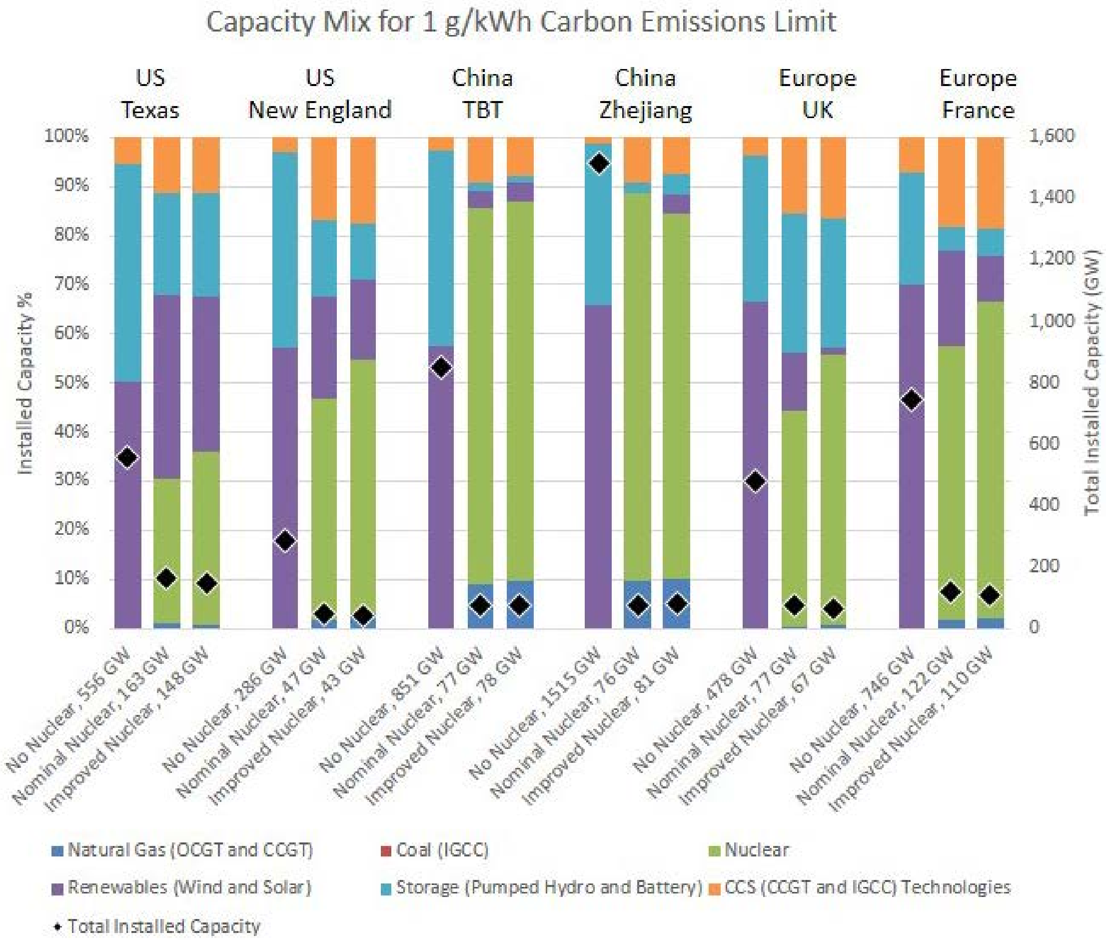

Figure 4.1.e: Generating Capacity for the Six Regions with a Carbon Constraint of 1 g/kWh

A more detailed explanation of the cost escalation without nuclear is shown in Figure 4.2 (a-f) for the six locations. Texas (Fig. 4.2.a) has highly favorable conditions for large-scale wind and solar relative to the other locations. If nuclear is not included in the pathway, large build outs of wind, solar, and battery storage are required to meet the constraint of a low CO_2 emission. This is evident in the 10 gCO_2/kWh emission scenario and more so in the 1 gCO_2/kWh emission scenario, where the installed capacity of the no nuclear technological scenario is over three times the installed capacity of the nuclear-nominal technological scenario. This installed capacity comes at a large investment cost, which dramatically increases the total system cost.

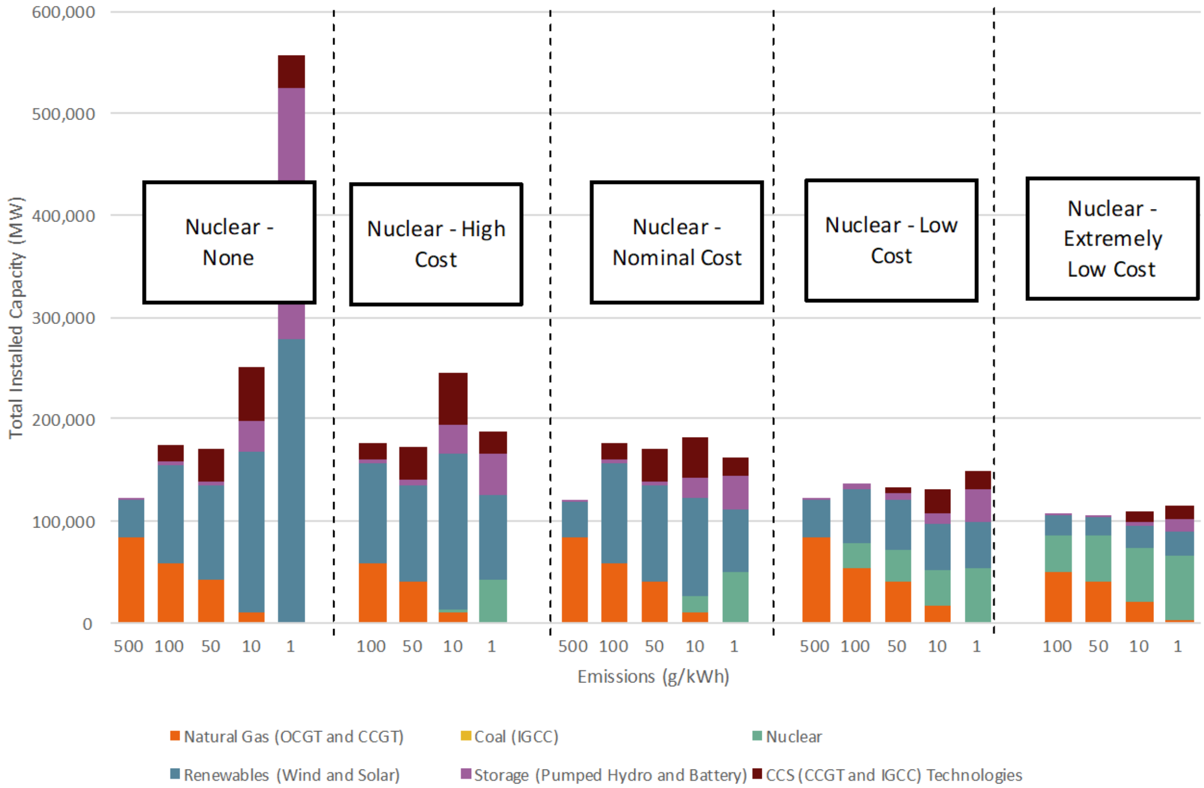

Figure 4.2.a: Optimal Capacity Mixes for Texas

In addition to the large investment cost of renewables build out, low carbon scenarios without nuclear come at a cost of sizable land usage. For the 1 gCO_2/kWh emission target in the "Nuclear – None" case, the land requirements for both solar and wind would be just under 4 million hectares (about 5.5% of the state of Texas). This is the largest build out of renewable energy in any of the Texas scenarios. This land usage is proportionately larger in the other regions analyzed as the renewable capacity factors are lower in the other regions investigated.

We would also note that we did not consider available land usage for CO_2 disposal as a constraint in the analysis. However, we did perform a limited set of selected scenarios for ERCOT in which natural gas (CCGT) with CCS is not available. These results indicate that the relative nuclear share increases for all the deep decarbonization emission targets. This result is not unexpected as the required demand will be met by additional nuclear as well as renewables to minimize the overall system cost.

Figure 4.2.b shows the optimal capacity mix for New England for each of the cases; Nuclear – None, Nuclear – Nominal Cost, and Nuclear – Low Cost. The required installed capacity of renewables and battery storage in New England is large due to the more limited wind and solar resource potentials in New England during periods of high demand. In addition, a large battery storage capacity must be supplied to compensate for weather variability.

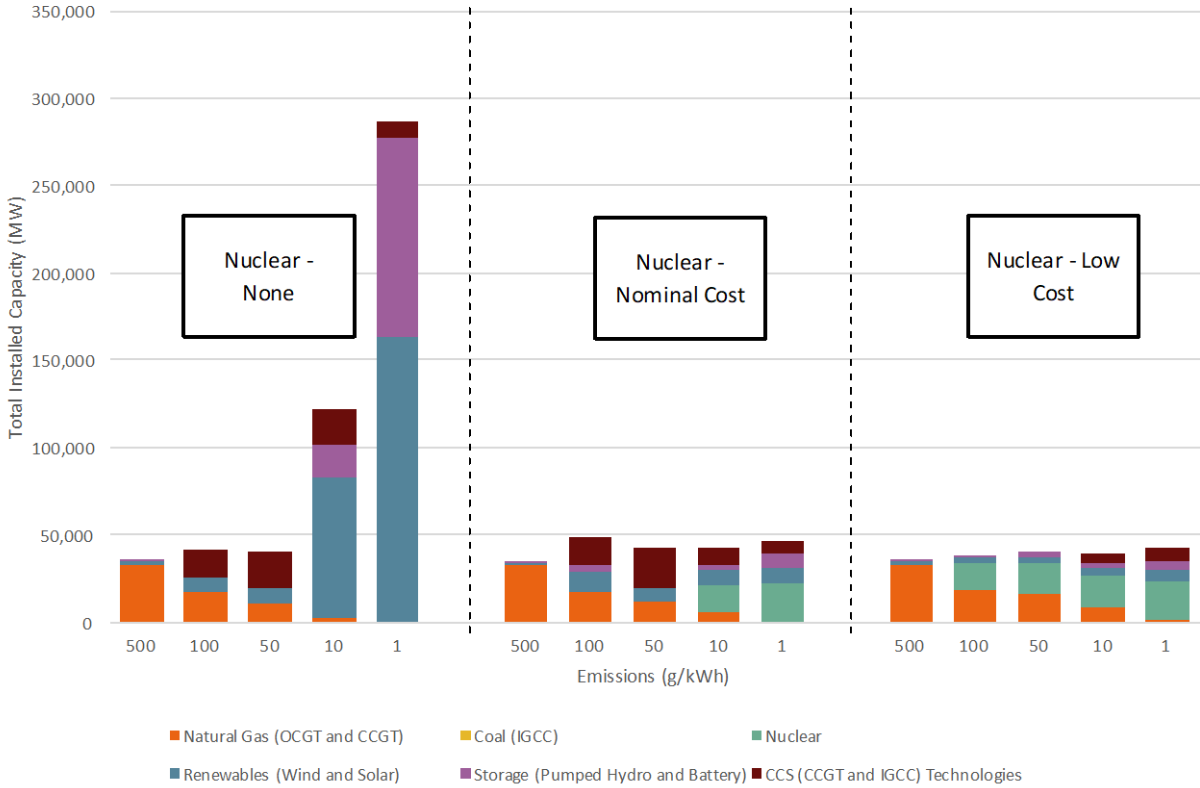

Figure 4.2.b: Optimal Capacity Mixes for New England

Figure 4.2,c shows the optimal capacity mix for T-B-T for each of the cases; Nuclear – None, Nuclear – Nominal Cost, and Nuclear – Low Cost. Figure 4.2.d shows the optimal capacity mix for Zhejiang for the same three cases. The same qualitative capacity trends are noted as in Texas and the New England regions, for renewables and battery storage, but even more pronounced. In China nuclear energy is the low-cost option and thus for all scenarios that allow nuclear, the optimal system has large quantities of nuclear.

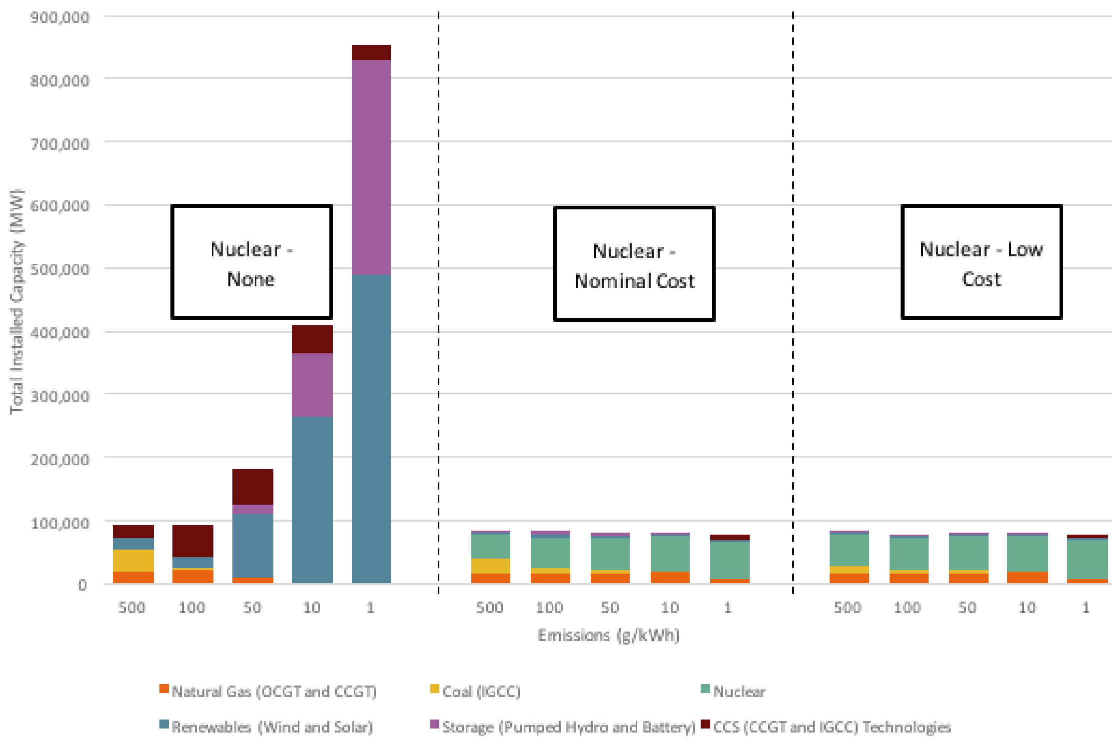

Figure 4.2.c: Optimal Capacity Mixes for T-B-T

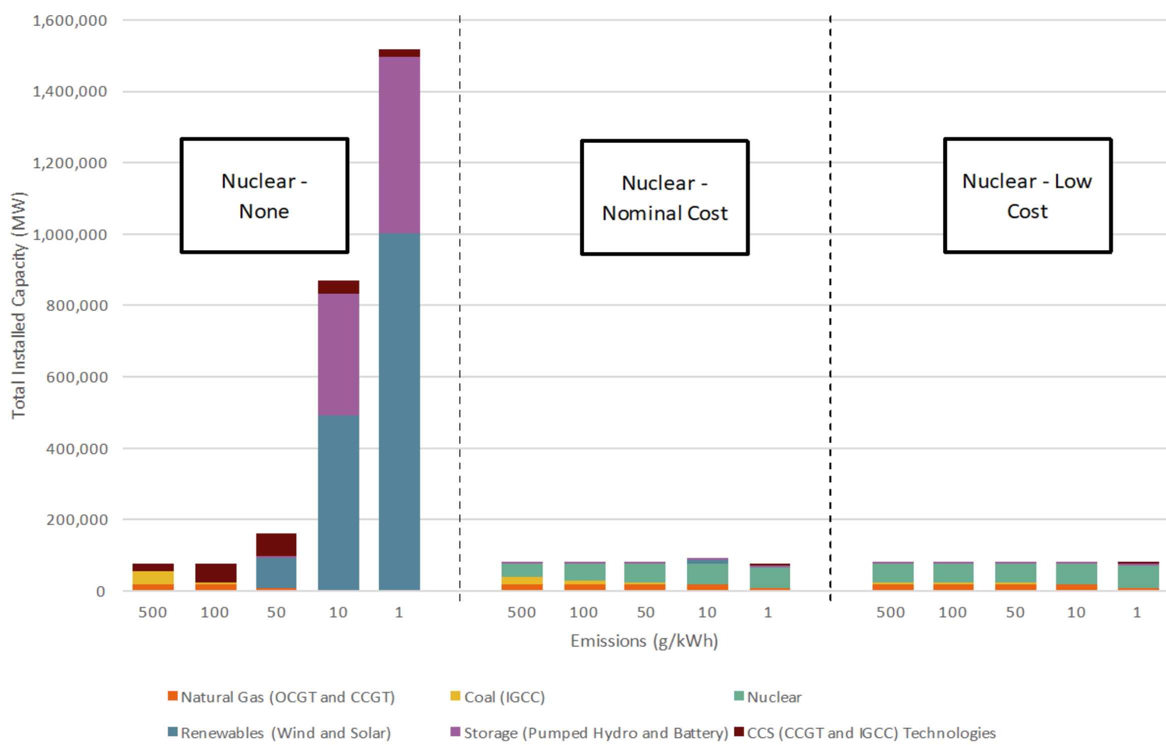

Figure 4.2.d. Optimal Capacity Mixes for Zhejiang

Figure 4.2.e shows the optimal capacity mix for the United Kingdom for each of the cases; Nuclear – None, Nuclear – Nominal Cost, and Nuclear – Low Cost.

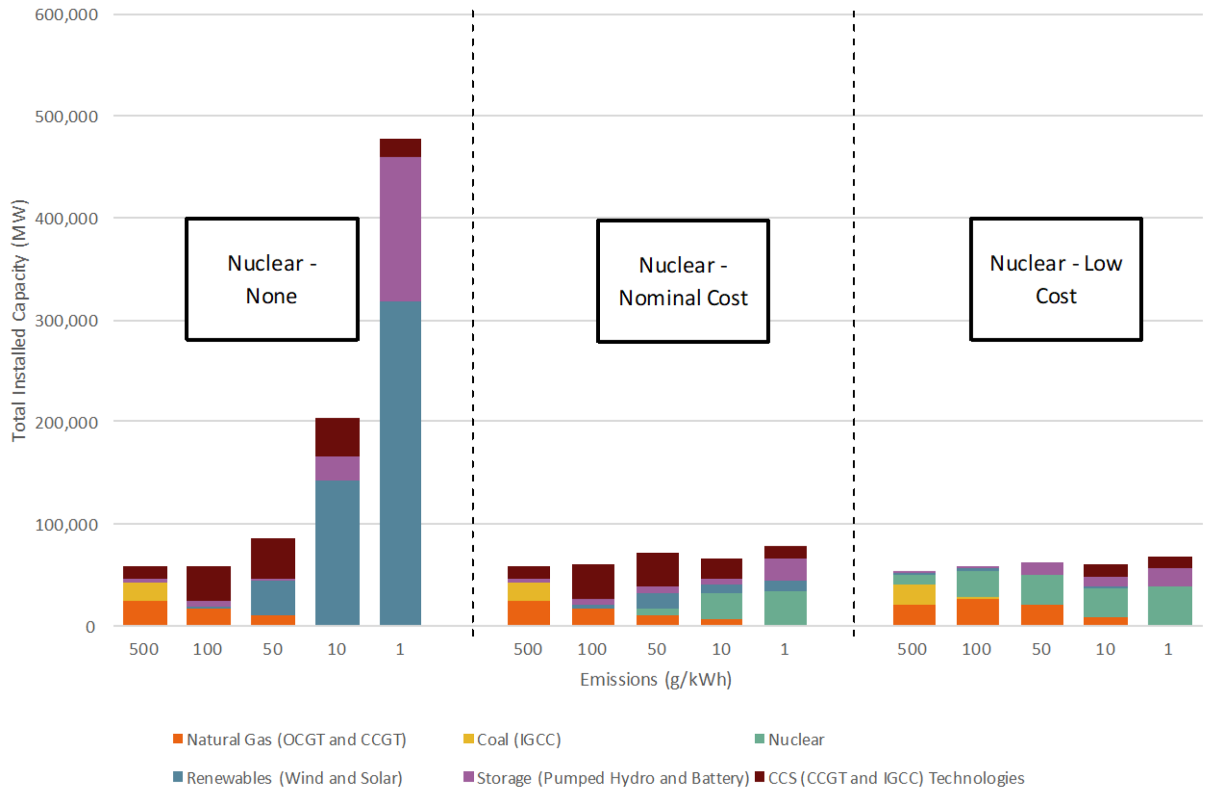

Figure 4.2.e: Optimal Capacity Mixes for United Kingdom

Figure 4.2.f shows the optimal capacity mix for the France for each of the cases; Nuclear – None, Nuclear – Nominal Cost, and Nuclear – Low Cost.

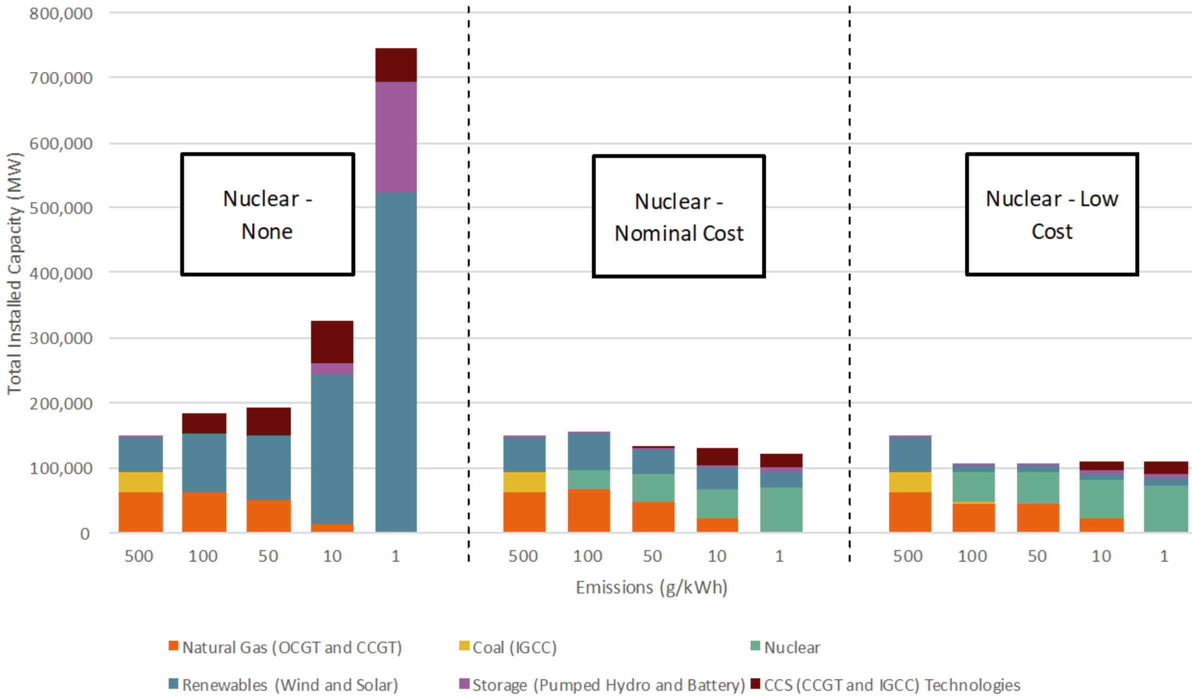

Figure 4.2.f. Optimal Capacity Mix for France

We examined the Chinese cases in further detail for a wider range of nuclear plant costs. The Chinese cases are characterized by lower-quality wind and solar resources and low cost nuclear. As shown in Fig. 4.3, almost the capacity is nuclear where nuclear is allowed. What is also shown is the very large amounts of wind and solar generating capacity that are required if nuclear is not allowed, there are strict limits on carbon dioxide emissions and relatively low-quality wind and solar resources.

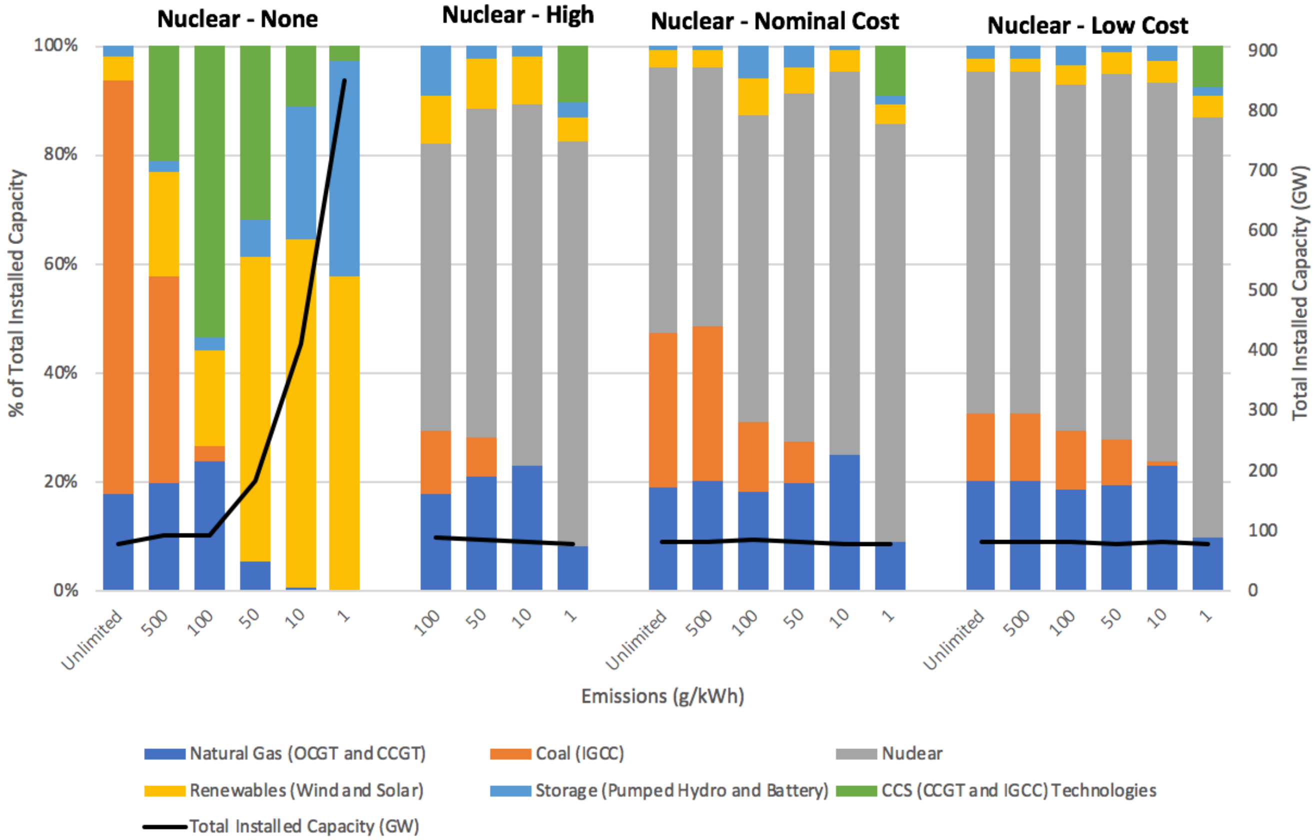

Fig. 4.3.a. Optimal Capacity Mix for T-B-T over a Wide Range of Nuclear Plant Costs

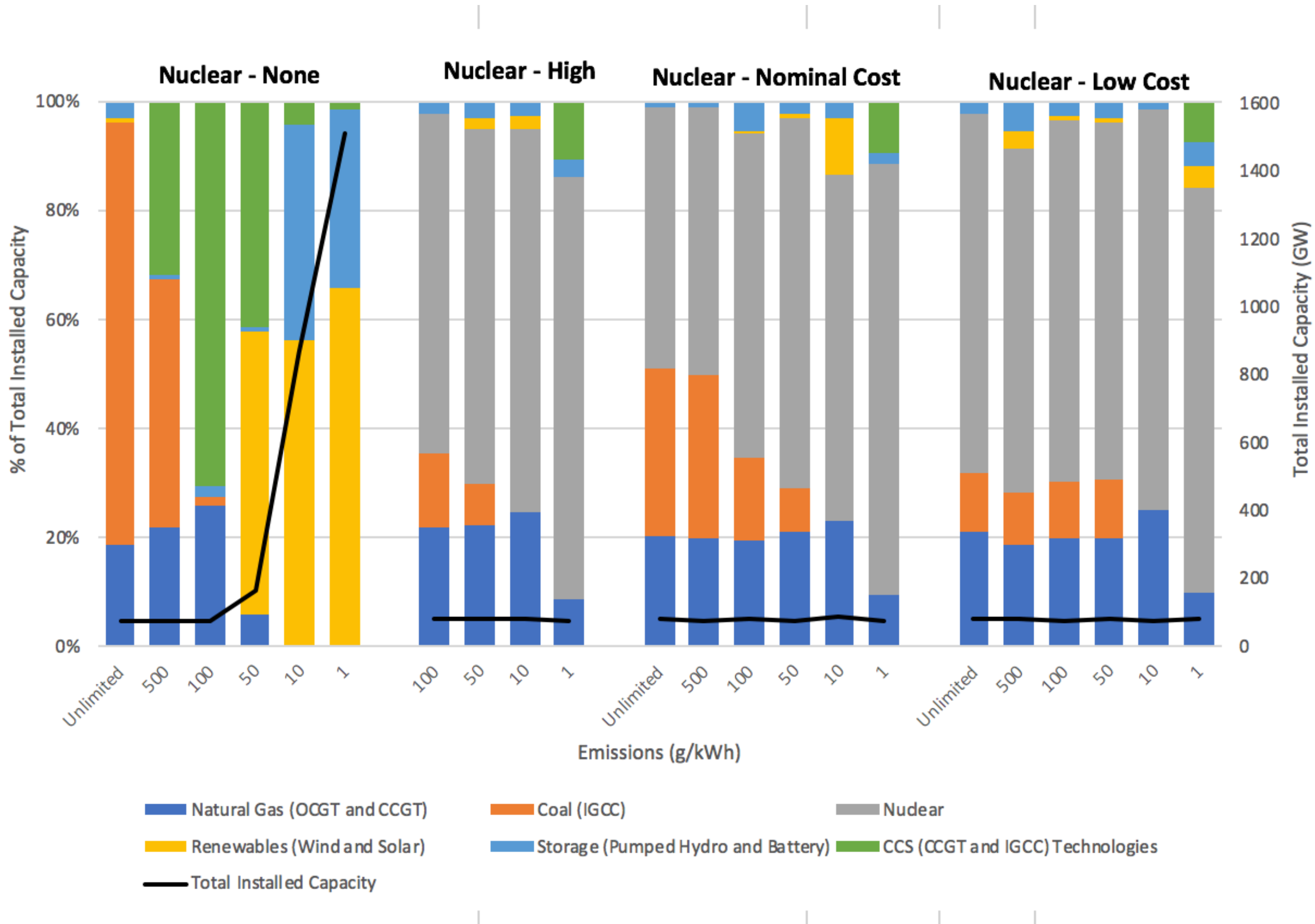

Fig. 4.3.b. Optimal Capacity Mix for Zhejiang over a Wide Range of Nuclear Plant Costs

Several general conclusions follow from the analysis.

- In western countries the optimum generating mixture changes noticeably with carbon constraints. There is very little change in the optimum generating mix in China because of the lower cost of nuclear energy.
- The economic use of renewables is strongly dependent upon the quality of local wind and solar resources due to their intermittent nature.
- Higher systems costs are always associated with greater amounts of installed capacity in low-carbon systems where capital cost, not operating cost, dominates electricity production costs. The high cost of all-renewable systems for very-low-carbon scenarios is because of renewable generation's intermittent nature. A very large amount of installed renewable and battery storage capacity is needed to ensure that the electricity generation always meets the demand if there is not a dispatchable energy source.

5. Electricity Generation by Source Vs Carbon Dioxide Emission Limits

Generation is the energy produced by different technologies (kWh). Capacity measures what is built (kW). Figure 5.1 (a-f) shows generation for the six regions as a function of allowed generating technologies and carbon dioxide emission limits.

Examination of the Texas case provides a useful perspective. If one looks at the Texas case with no nuclear, one sees the generation (black line) goes up significantly as carbon emissions are limited. That added electricity is needed to cover the inefficiencies in the storage system—losses in batteries and pumped storage facilities. A flat line implies little or no storage.

If one looks at the nominal cost nuclear case with a carbon limit of 10 g/kWe, it is observed that about 25% of the electricity is generated by nuclear plants. However, nuclear is less than 10% of the installed capacity (Fig. 4.1.d). Because of the capability of nuclear to operate continuously, it can be a relatively small fraction of the installed capacity but a large fraction of the total electricity generation and responsible for a large fraction of the reductions in carbon dioxide emissions. This is important in a low-carbon system, it is capital cost (i.e. cost of installed capacity) that dominates total system costs.

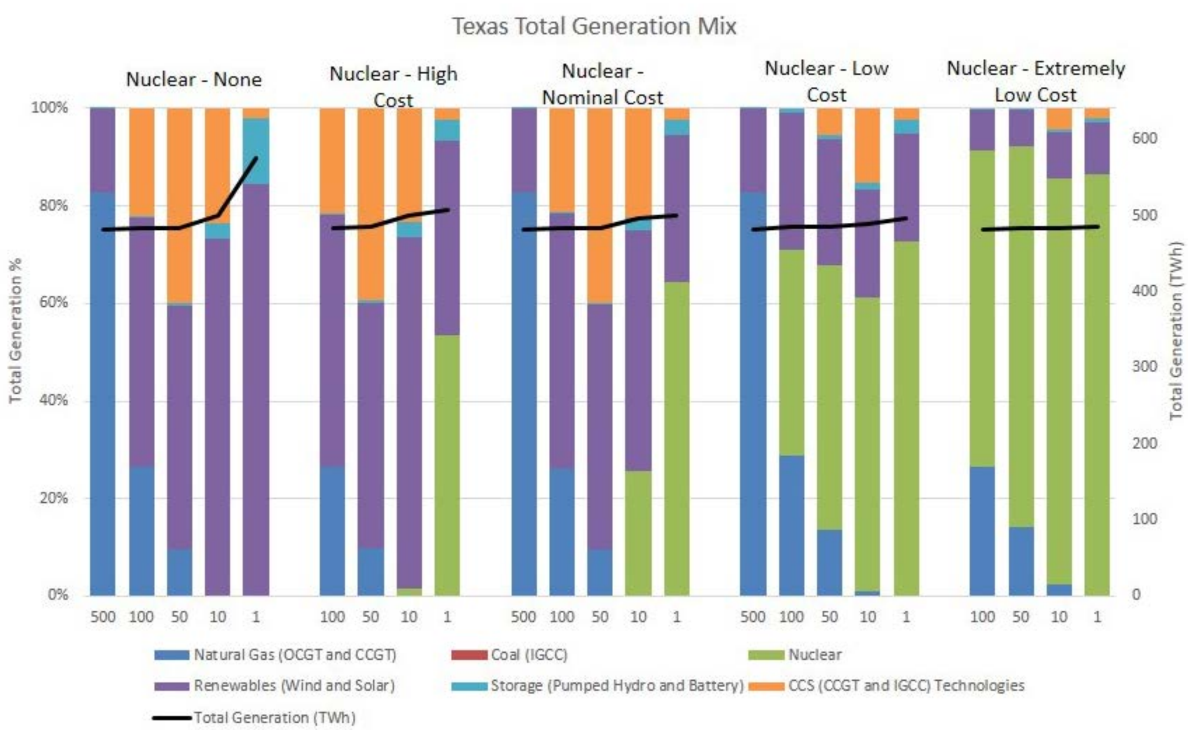

Fig. 5.1.a. Texas Total Generation Mix (left) and Total Generation (right; black line) versus Carbon Dioxide Constraint

When examining the role of nuclear as carbon constraints become more restrictive for different locations, one observes nuclear providing most the electricity generation except where low-cost renewables are available. That is what one would expect. Nuclear power generation is relatively independent upon location relative to wind and solar. There is an important caveat. This study examined a set of industrial countries that are at similar latitudes. Wind and solar are strongly dependent upon location. One might expect very different results if included a country such as Chile where northern Chile is near the equator with excellent year-round solar inputs.

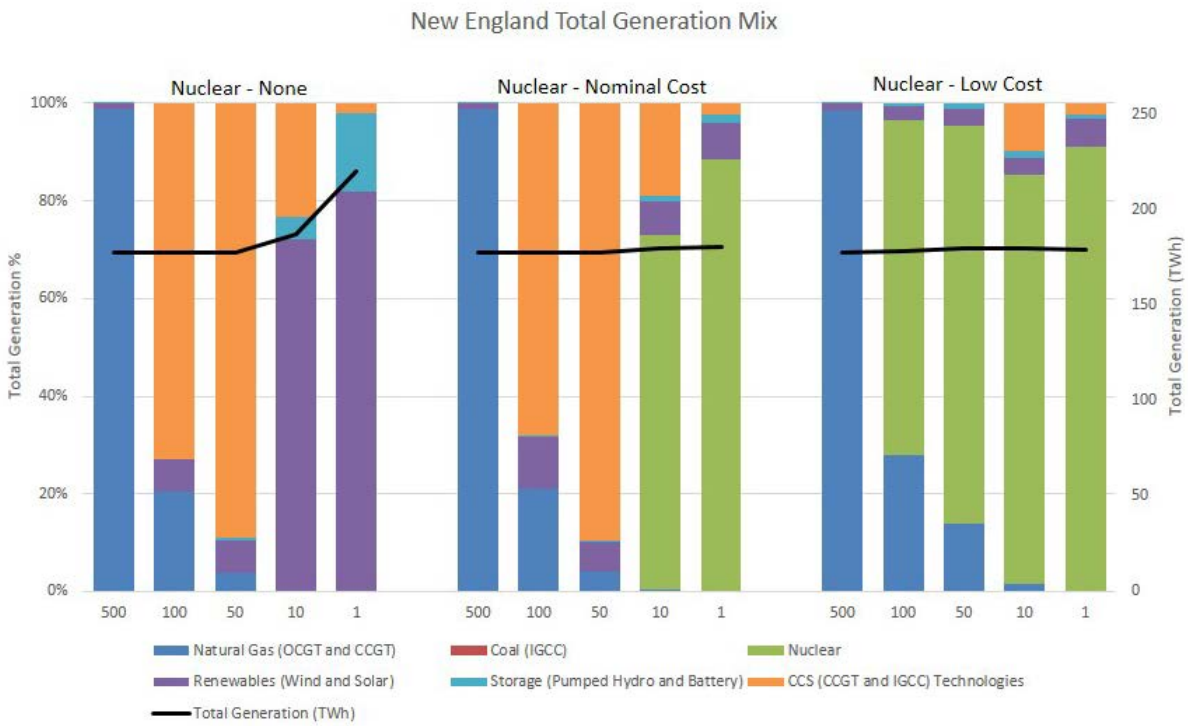

Fig. 5.1.b. New England Total Generation Mix (left) and Total Generation (right, black line) versus Carbon Dioxide Constraint

In China nuclear is the low-cost option. At higher allowable carbon emission limits, coal with its lower capital cost is used for variable electricity. If nuclear is not available, as carbon emissions are tightened, coal is pushed out in favor of carbon capture technologies. At the limits of carbon capture technologies, the carbon capture technologies are then pushed out due to non-100% efficiency at capturing the carbon dioxide in favor of renewables. If nuclear technology is available, as the carbon emissions are tightened, coal is pushed out in favor of nuclear. This happens over a large range of nuclear capital costs. It also reflects the relatively poor quality of wind and solar resources.

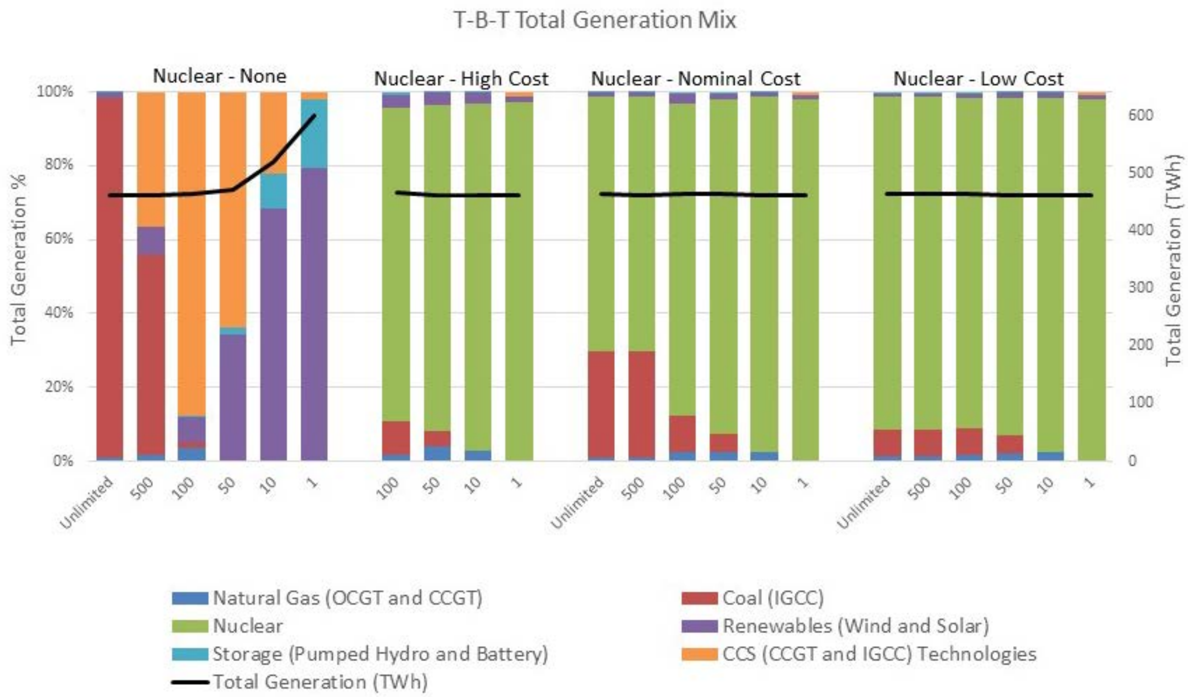

Fig. 5.1.c. TBT Total Generation Mix (left) and Total Generation (right; black line) versus Carbon Dioxide Constraint

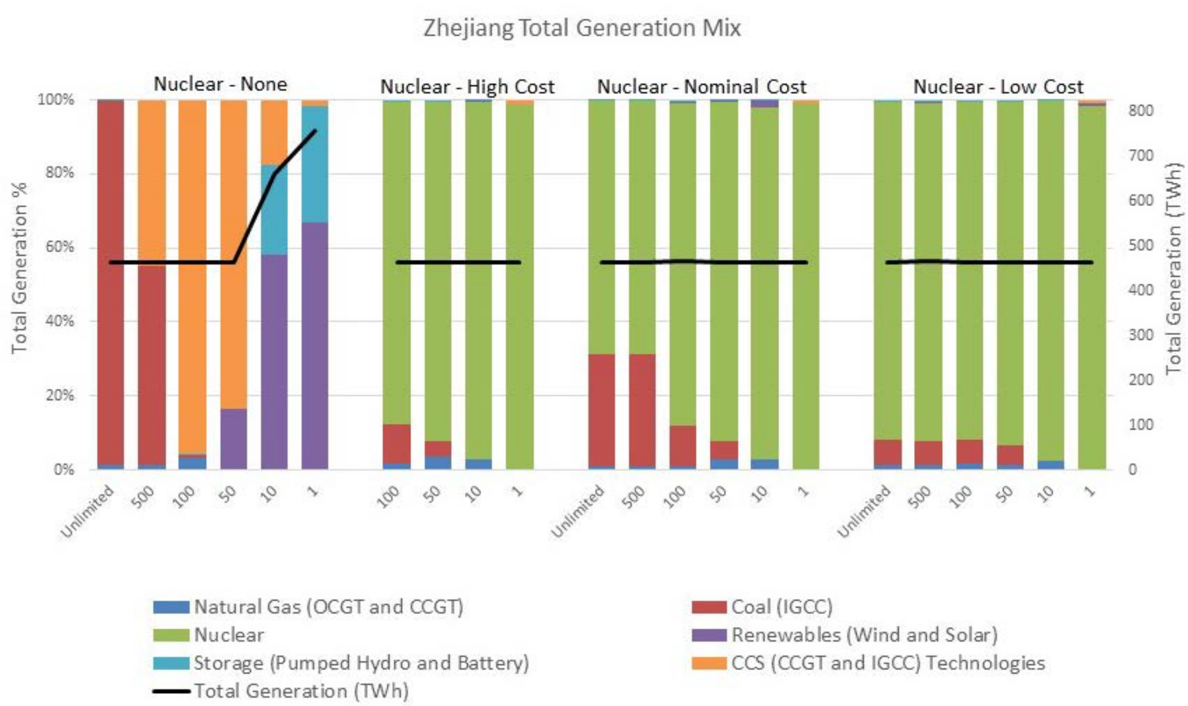

Fig. 5.1.d. Zhejiang Total Generation Mix (left) and Total Generation (right; black line) versus Carbon Dioxide Constraint

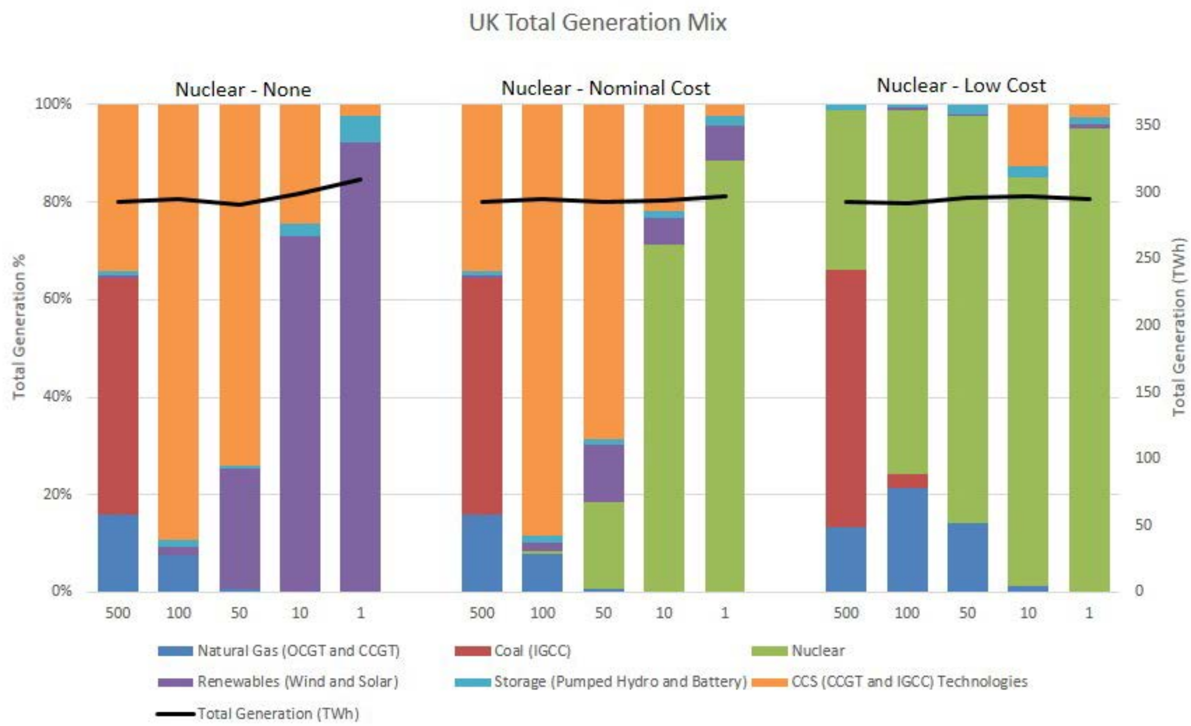

Fig. 5.1.e. United Kingdom Total Generation Mix (left) and Total Generation (right; black line) versus Carbon Dioxide Constraint

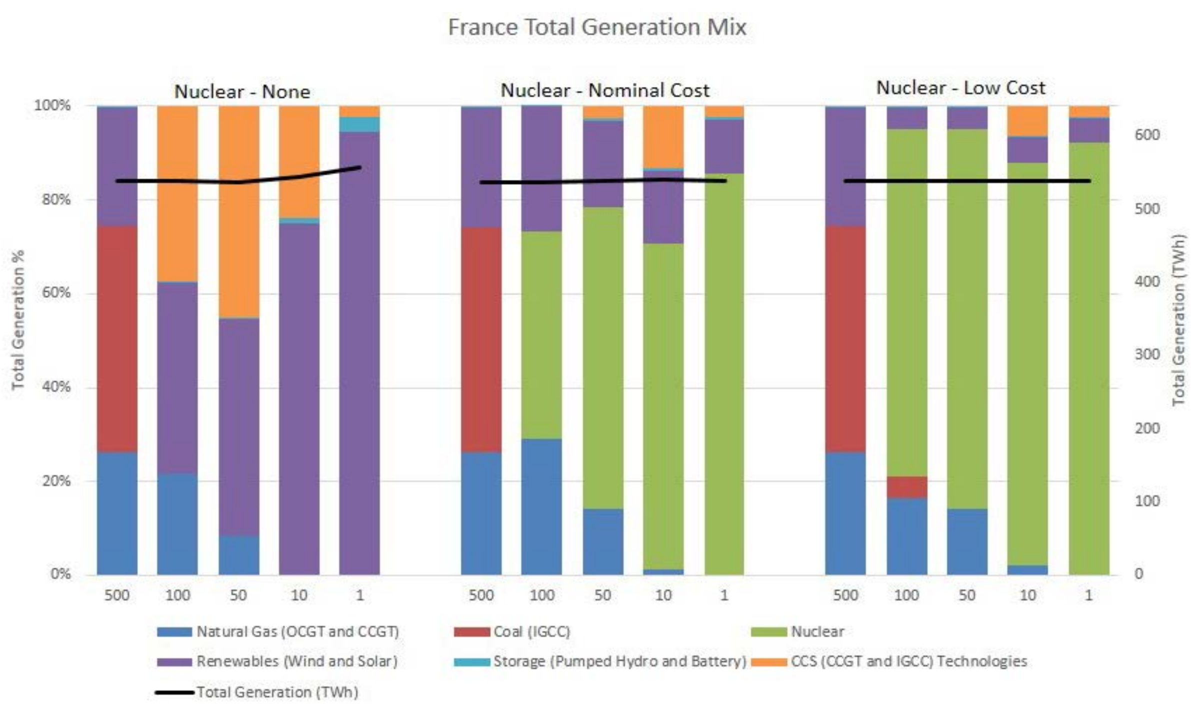

Fig. 5.1.f. France Total Generation Mix (left) and Total Generation (right: black line) versus Carbon Dioxide Constraint

6. Capacity Factors of Different Generating Systems Vs Carbon Dioxide Emission Constraints

Capacity factors define what fraction of the time a particular generating technology is producing electricity. In a traditional electricity grid without carbon constraints with nuclear and fossil generating capacity, the story is simple. The high-capital-cost low-operating-cost nuclear plants operate at full capacity to minimize electricity costs. The low-capital high-operating-cost fossil plants operate at variable load to match electricity production with demand. Both technologies are dispatchable; that is, can produce electricity on demand. Fossil fuel plants with carbon capture have higher capital costs.

The addition of renewables adds a major complication. Like nuclear, these are high-capital-cost low-operating-cost technologies. Thus, there is a large incentive to operate at full capacity. However, they are not dispatchable. Output only occurs when the sun shines and the wind blows. One can add storage devices but these storage systems can become depleted if there are extended times of high demand or low wind/solar production. Table 6.1 summarizes these differences.

Table 6.1. Characteristics of Major Energy Sources

Energy Source	Capital Cost	Operating Cost	Dispatchable
Fossil	Low	High	Yes
Fossil with Carbon Capture	High	High	Yes
Nuclear	High	Low	Yes
Wind and Solar	High	Low	No

In Figure 6.1 (a-f) we show the capacity factors for each region for each technology for different carbon constraints in the normal nuclear cost scenario. If a technology is not used under a particular set of conditions, no capacity factor is shown—by definition the capacity factor is zero. There are common trends. Nuclear when used has a relatively high capacity factor because it has a high capital cost and low operating costs.

Natural gas when allowed has a lower capacity factor because it has lower capital costs and high operating (fuel) costs. For many scenarios China has significant natural gas generating capacity but very low capacity factors for the gas turbines. Natural gas plants are cheap but natural gas is expensive so the natural gas plants in China are used for a limited number of hours to meet peak demand. When allowed, coal in China is the swing fuel to match production with demand.

Wind and solar have much lower capacity factors because there are long periods of no sun (night) and no wind. Their maximum capacity factors are limited by sunlight and wind. The other feature is the large difference in wind and solar capacity factors by region. The higher wind and solar capacity factors in Texas relative to New England reflect that fact that there are more hours of sunlight and more hours of good wind conditions in Texas than New England.

As carbon constraints are imposed, nuclear capacity factors generally decrease because they are the dispatchable energy source in the system. Decreasing capacity factors occur to other dispatchable energy sources in the system such as fossil fuels with carbon capture and sequestration—high-capital-cost systems use for a limited amount of time per year. There are exceptions such as the UK where once carbon emissions limit the use of coal, nuclear initially becomes the primary variable electricity source (but limited installed capacity). What the system needs is low-cost dispatchable power.

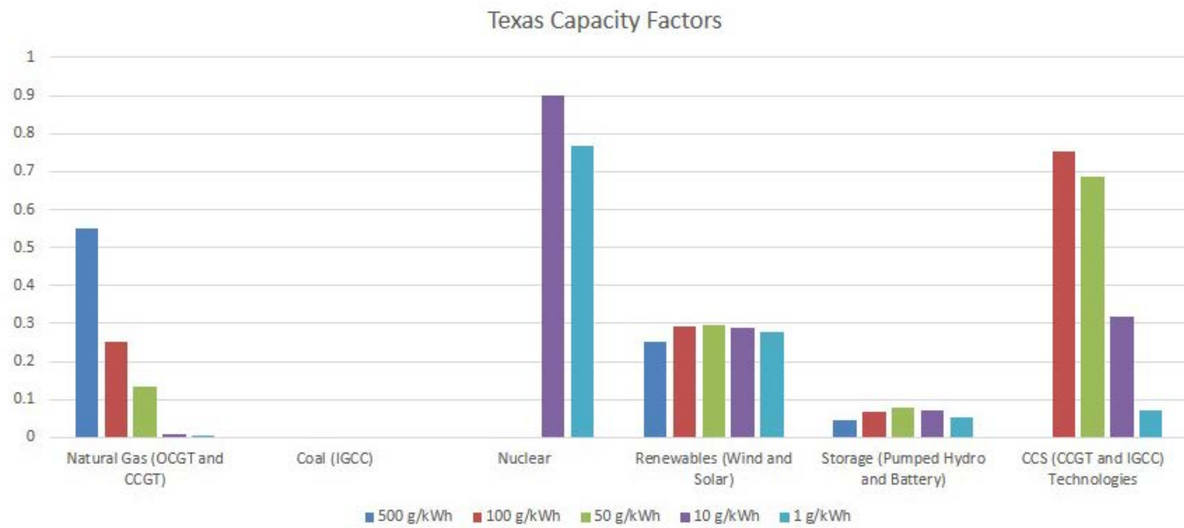

Fig. 6.1.a. Capacity Factors of Generating Technologies in Texas versus CO_2 Emission Limits

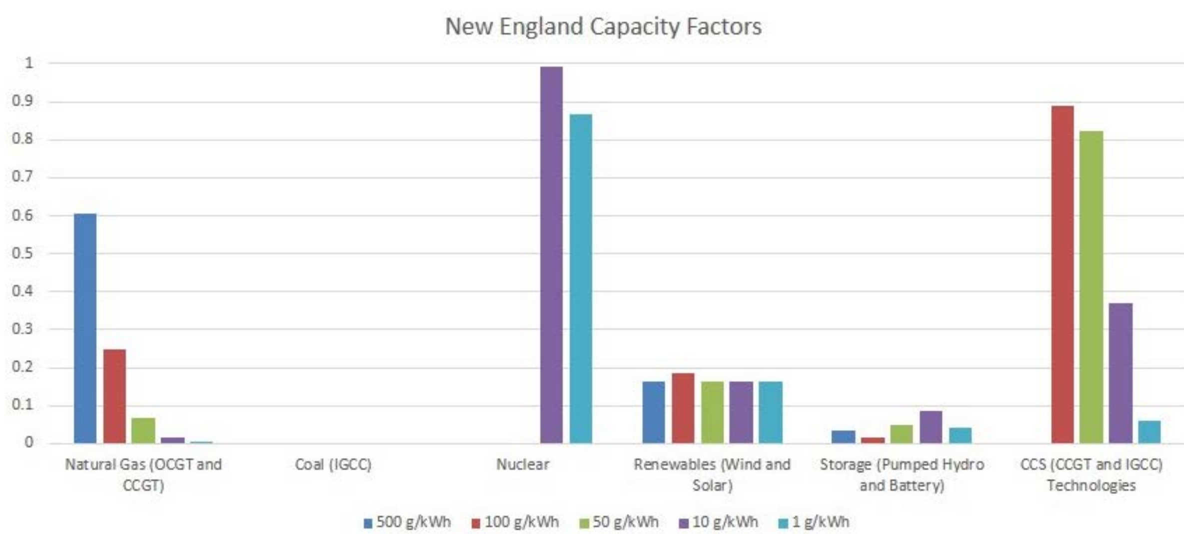

Fig. 6.1.b. Capacity Factors of Generating Technologies in New England versus CO_2 Emission Limits

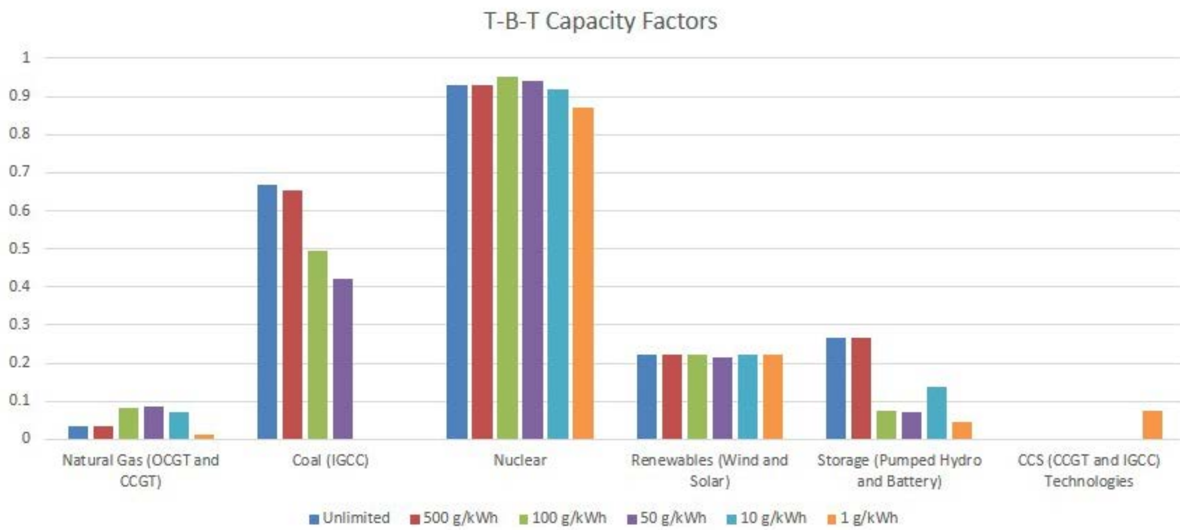

Fig. 6.1.c. Capacity Factors of Generating Technologies in TBT versus CO_2 Emission Limits

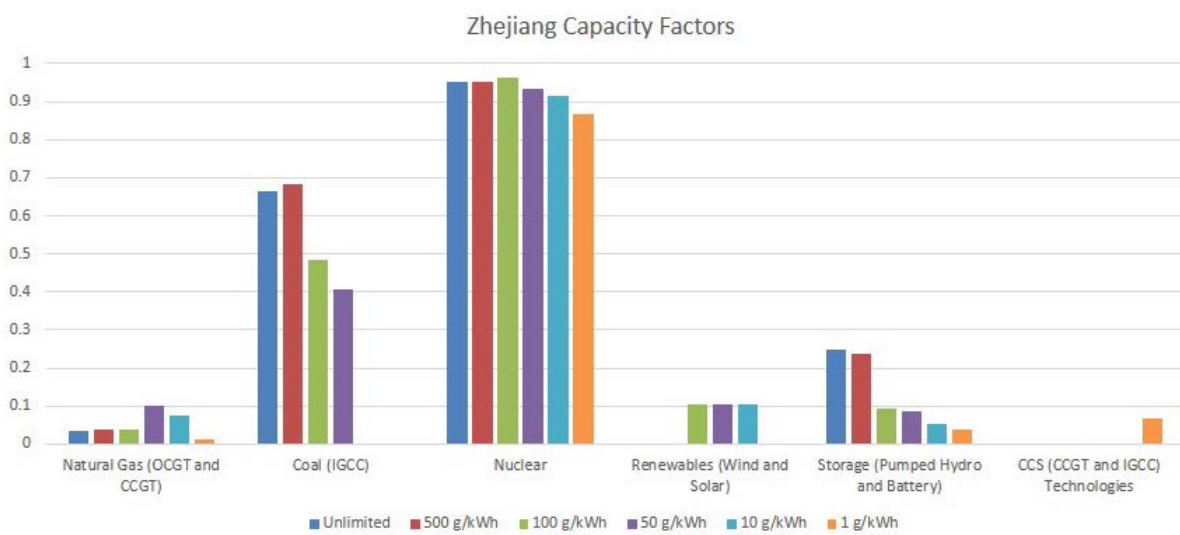

Fig. 6.1.d. Capacity Factors of Generating Technologies in Zhejiang versus CO_2 Emission Limits

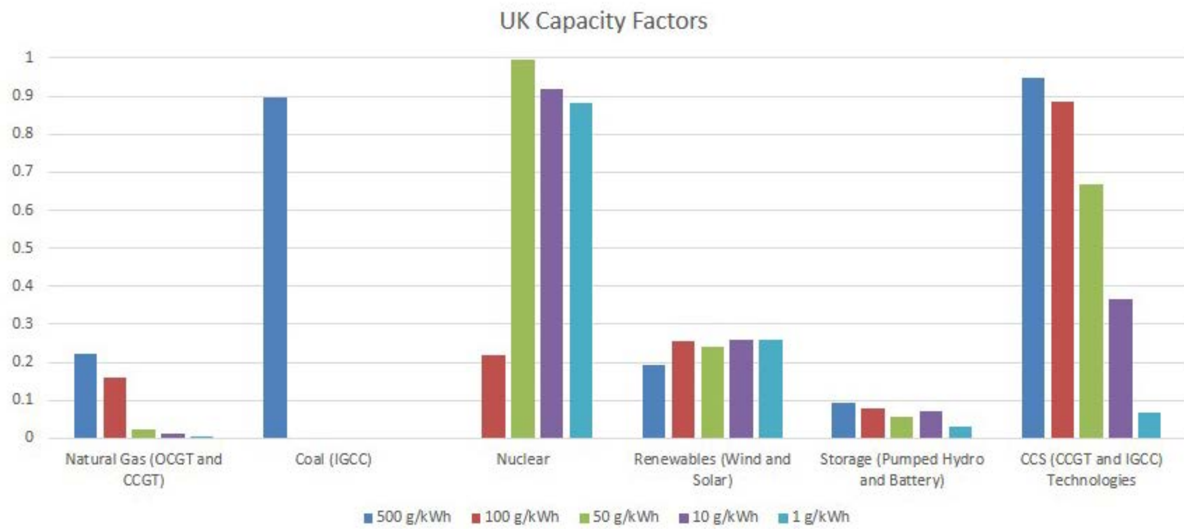

Fig. 6.1.e. Capacity Factors of Generating Technologies in the United Kingdom vs. CO_2 Emission Limits

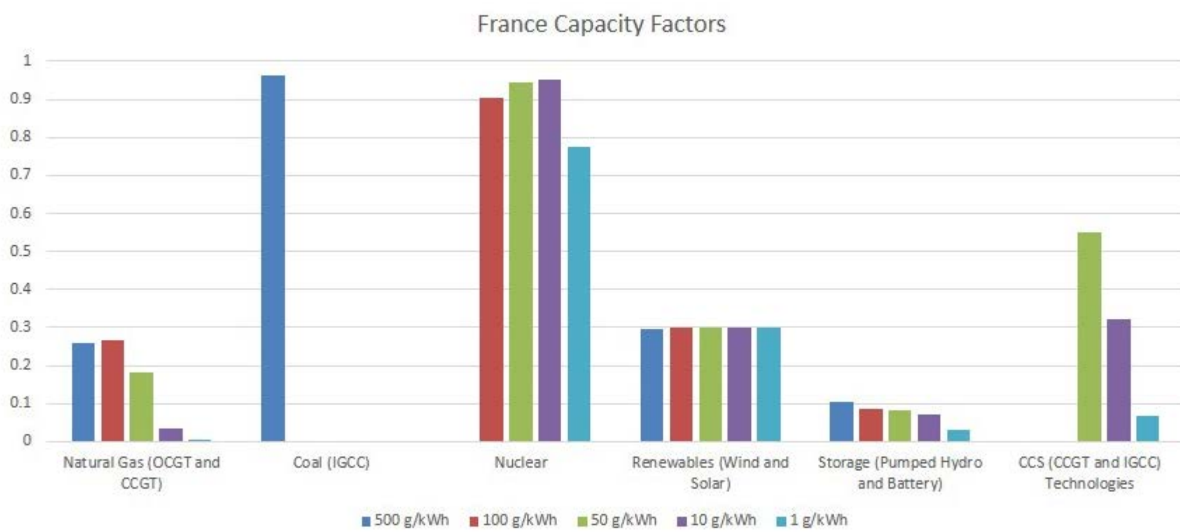

Fig. 6.1.f. Capacity Factors of Generating Technologies in France vs. CO_2 Emission Limits

There are two methods to assure sufficient generating capacity as one restricts carbon releases to the atmosphere: (1) dispatchable nuclear or fossil fuels with carbon sequestration and (2) wind and solar with storage. We examined the capacity factors of nuclear in additional detail because it is the primary low-carbon dispatchable form of electricity. Figure 6.2 shows nuclear capacity factors for the six regions for different carbon constraints in the nuclear nominal cost scenarios. Again nuclear capacity factors are only shown when nuclear is in the optimum generating mixture. There is the general trend that as carbon constraints become more restrictive, capacity factors go down-the plants operate in a load following modes.

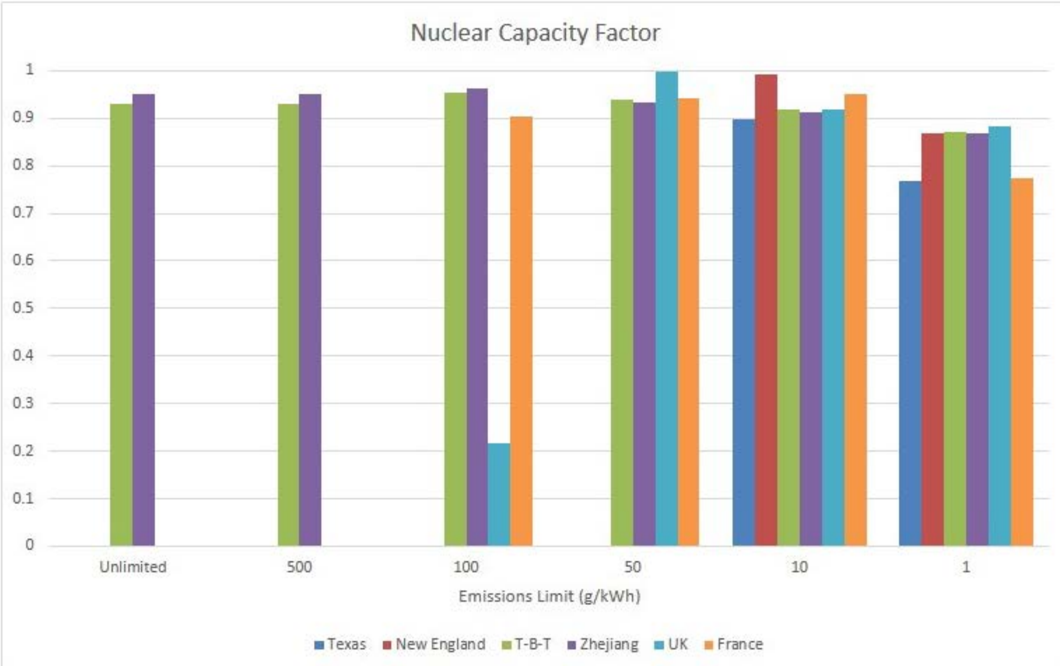

Fig. 6.2. Nuclear Capacity Factors of the Six Regions vs. Carbon Dioxide Emission Limits

Load following by nuclear reactors has been done for decades in countries such as France. This reflects the French (1) national policy and (2) generating capacity that is primarily nuclear with some hydro and limited amounts of fossil fuels. Because of energy security concerns (French Algerian war, oil embargo, trade balances), France chose not to depend upon imported fossil fuels for electricity. That resulted in a system where about a quarter of the French nuclear plants do load following. Load following has not generally been done in the United States until recently when there has been wholesale electricity price collapse at times of excess wind or solar production. The single exception has been the Columbia plant in Washington State where the system is primarily hydro where there are minimum flow requirements for the rivers for fish and barge traffic and thus required hydroelectric production.

Average capacity factors provide a single number to describe total utilization of nuclear plants but not how they are operated. Figures 6.3 (a-f) describe for different regions as a function of carbon constraint the variations in output from nuclear reactors. With capacity factor, 100% implies that the reactor is operating at full power when not refueling. There are several other trends shown in the figures. No data for a given carbon constraint indicates that there is no installed nuclear capacity for that optimized scenario.

- *Number of ramps per year*. The model optimizes the system for each hour of the year—8760 hours. The number of ramps per year is the number of times the power level changes in a year. The maximum number of times the power level could change is 8760 times. The number of ramps per year increases as carbon constraints become more severe; that is, the nuclear plants do more load following and less time operating at baseload.
- *Average ramp up*. This is the average increase in power when the power level increases. This may occur over one hour or many hours. It ends when the next change in power level decreases power levels.
- *Maximum ramp up*. This is the largest increase in power over a year in any ramping event that could occur in an hour or over many hours. In this case the maximum ramping event is near 25%.

There are several major conclusions.

- Number of ramps per year goes up with tighter constraints on carbon emissions. Nuclear power plants become the dispatchable form of electricity as other options disappear.
- Average ramp rates vary from near 5% to over 25% of full power. The largest ramp rates are in Texas that has low-cost wind and solar with a smaller fraction of nuclear power. The smallest ramp rates are in China where a large fraction of the electricity in an optimized system is from nuclear energy. If one has a large installed capacity of non-dispatchable wind and solar and relatively small amount of nuclear, the installed nuclear capacity must provide more dispatchable electricity with a smaller amount of installed capacity. Most of the time, the changes in power levels are small
- The maximum ramp as a percent of full capacity is large in western countries (near 50%) but smaller in China. In western countries with higher-cost nuclear, there is a larger fraction of wind and solar. The maximum ramping events are associated with times of low wind and solar. In China most of the capacity is nuclear; thus, large changes in wind and solar output have a smaller impact on nuclear plant operations.

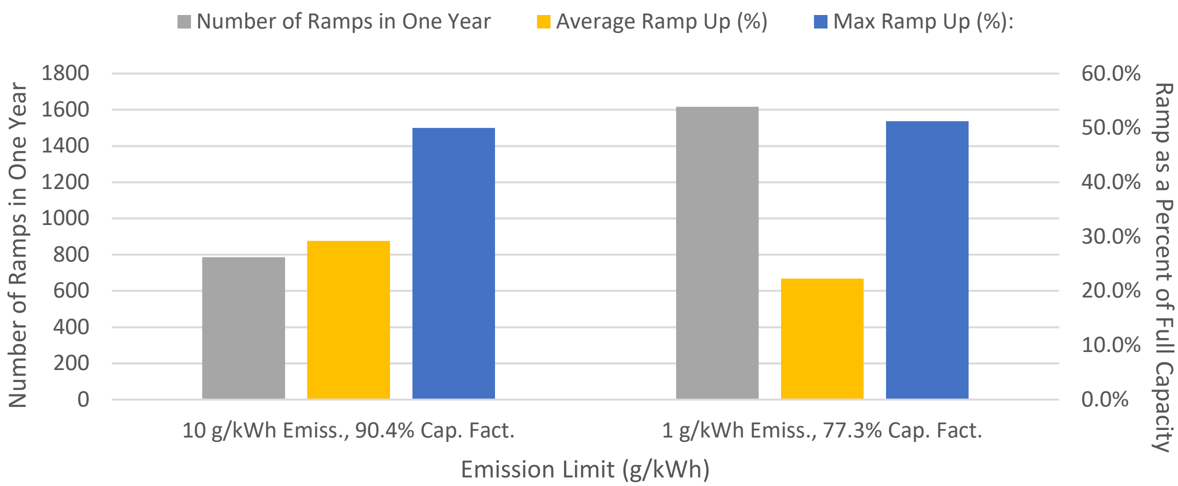

Figure 6.3.a: Texas ERCOT Nuclear Power Ramping

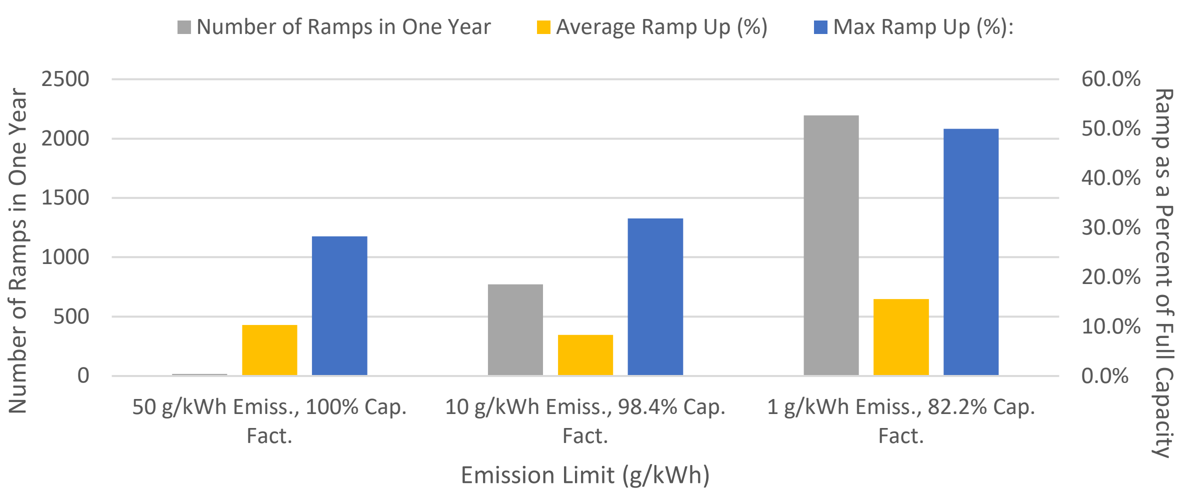

Figure 6.3.b. New England Nuclear Power Ramping

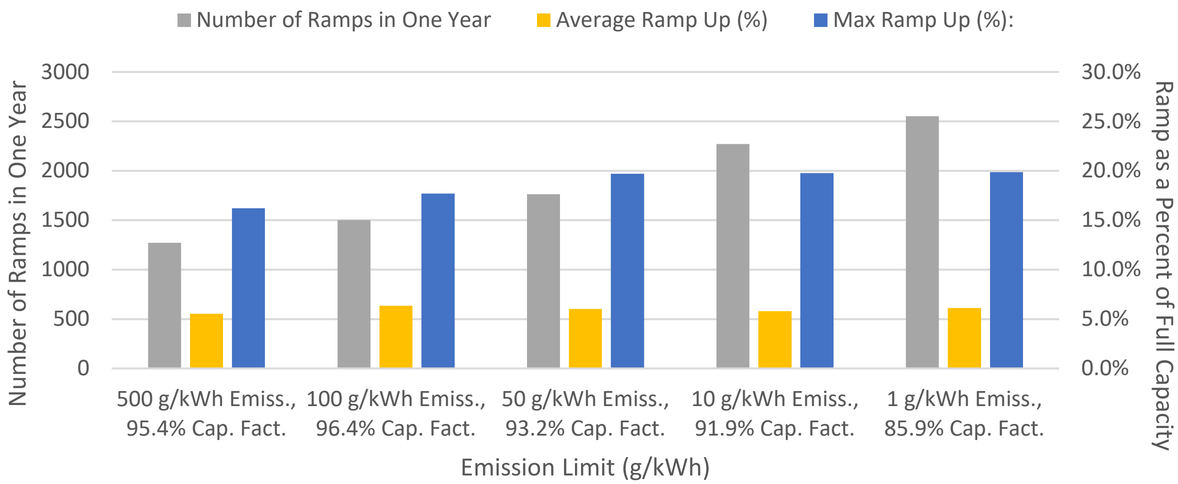

Fig. 6.3.c T-B-T Nuclear Power Ramping

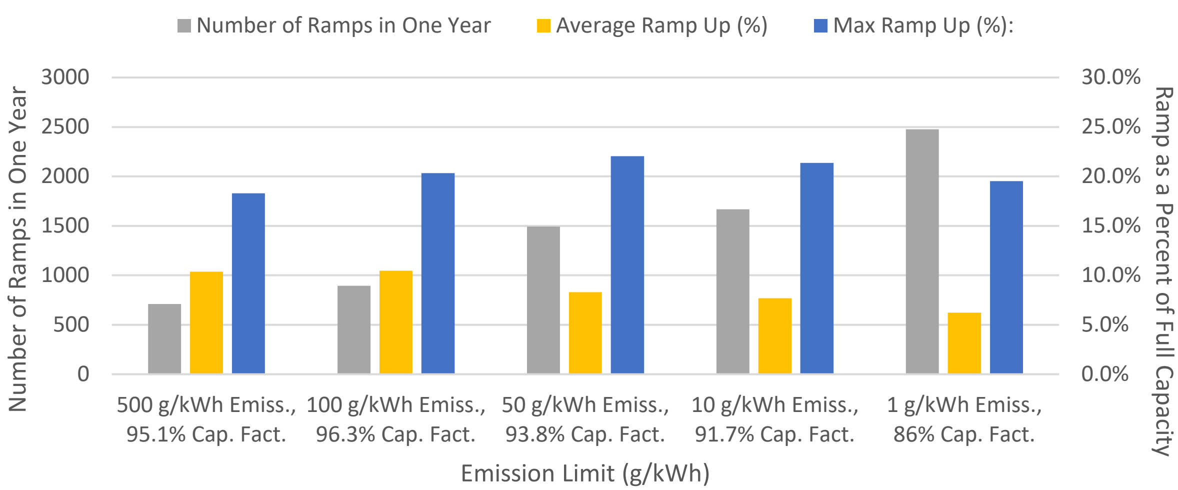

Figure 6.3.d. Zhejiang Nuclear Power Ramping

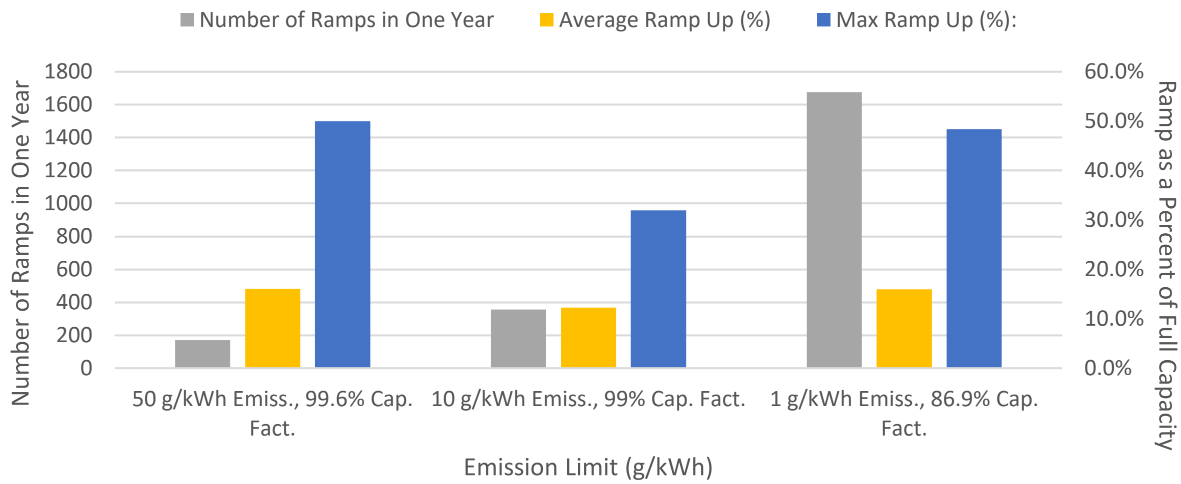

Fig. 6.3.e: United Kingdom Nuclear Power Ramping

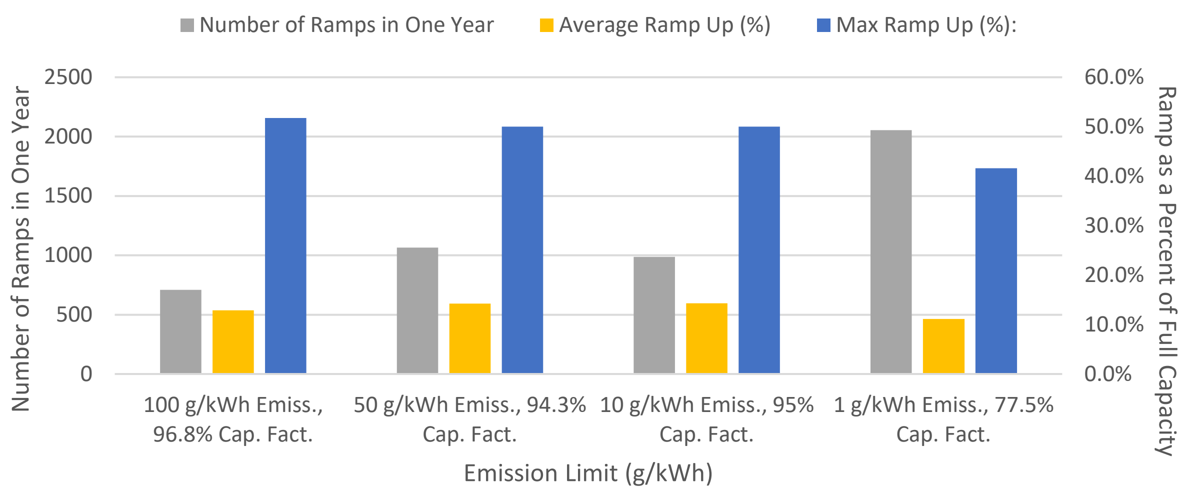

Fig. 6.3.f. France Nuclear Power Ramping

The GENX model in this analysis assumes all reactors operate at the same load. In a real system with multiple reactors, the utility may assign specific reactors to go up and down in power while operating other reactors at full power. This is the current strategy in France where a subset of the nuclear fleet is assigned to do load following with modifications to these plants to enable more efficient load following. With these simulations, we assume a copper grid—no transmission constraints. In real systems there are grid constraints that will result in some plants undertaking larger changes in output than other plants.

The models herein assumed that the variable electricity from nuclear power plants was achieved by load following—the existing deployed technology. As discussed below, there are other options as discussed in the next chapter—nuclear power plants with heat storage where the reactor operates at full load and uses heat storage to enable variable electricity to the grid. The goal is to reduce the capital cost by equipping some reactors with heat storage to reduce the total number of reactors required by the system to assure delivery of electricity.

7. Rethinking Energy Systems for a Low-Carbon World

7.1. Alternative System Design Overview

The primary cause for higher electricity costs with lower carbon dioxide emission limits is the requirement for assured electricity generating capacity (kW)—avoiding blackouts. In a fossil-fuel electricity generating system, fossil plants can operate at part load with relatively small economic penalties because most of the cost is associated with the storable fossil fuels—not the capital cost of the fossil fuel plant. Nuclear, wind and solar are high-capital-cost low-operating cost technologies. Non-dispatchable wind and solar photovoltaic provide energy (kWh) but very limited assured generating capacity (kW). To obtain assured capacity from these resources requires overbuilding wind and solar plus addition of energy storage—all with high capital costs. The minimum-cost electricity systems require dispatchable electricity sources such as nuclear energy. In such systems role of nuclear energy changes. Today nuclear power plants primarily provide base-load electricity to the grid with fossil fuels providing dispatchable electricity. In optimized low-carbon systems to minimize the cost of electricity, nuclear plants provide dispatchable electricity to the grid to reduce excess wind capacity, excess solar capacity and added storage capacity as methods to assure electricity when needed. Nuclear energy is partly replacing the traditional role of fossil-fuel plants in providing assured generating capacity (kW).

From a broader perspective, going to a low-carbon economy is going from fossil-fuel electricity production that is characterized by low capital cost and high operating cost (fuel) to nuclear, wind and solar that are characterized by high capital costs and low operating costs. The economic penalties become large if the electricity grid has high-capital-cost systems (nuclear, wind and solar) per unit of production operating at low capacity factors. *The radically different characteristics of a low-carbon grid imply the need to address two economic challenges to minimize costs: (1) provide lower-cost dispatchable electricity and (2) find a beneficial use for excess electricity generated at times of high wind or solar input and low demand.*

This is part of a broader challenge of reducing carbon emissions from the economy—particularly the industrial sector. Most low-carbon energy scenarios assume electrification of the industrial sector. However, in the United States the heat input into the industrial sector is about double the electricity output of the electricity sector. If one uses a brute-force strategy of electrifying the industrial sector, it implies tripling the electricity system and using the most expensive form of energy for the industrial sector. In China the industrial sector in terms of energy demand is much larger relative to the electric sector compared to the United States. If a future low-carbon transportation sector uses hydrogen, biofuels or a variety of other low-carbon fuels, it implies massive growth of the industrial sector energy demands. Beyond the energy input, there is a requirement to deliver that energy when needed—dispatchable energy. The decarbonization strategies for the industrial and transport sectors have potentially major implications for the electric sector.

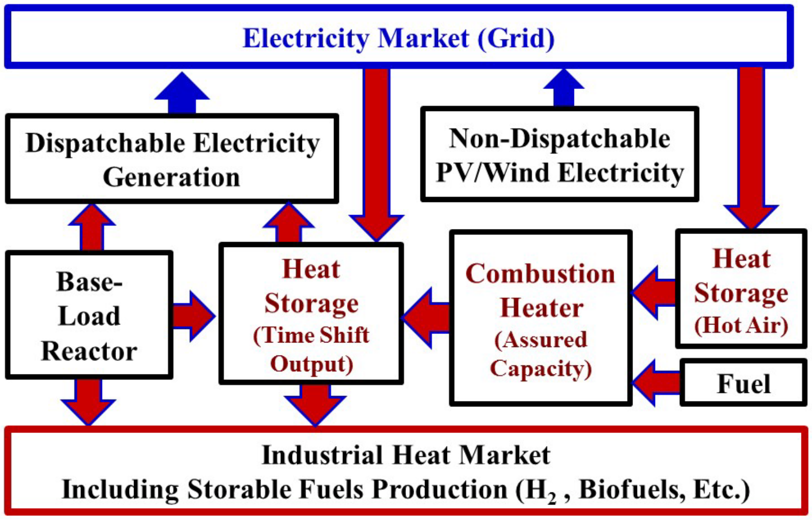

Fig. 7.1 Low-Carbon System Design

These factors indicate the need for an alternative energy system design (Fig. 7.1) to minimize costs while enabling reduction in carbon dioxide emissions. This would include several components.

- *Large-scale heat storage coupled to nuclear power plants.* Wind and solar photovoltaic produce electricity and thus couple to electricity storage systems (batteries, pumped hydro, etc.). Nuclear reactors produce heat and can thus couple to heat storage systems (hot salt, hot concrete, etc.; Appendix D). The cost of heat storage is about an order of magnitude less than the cost of work (electricity) storage. If nuclear plants are required to provide dispatchable electricity to the grid there are two options: (1) operate the reactor with variable output or (2) operate the reactor at base-load with heat storage. A nuclear reactor with heat storage at times of low-electricity demand would send some steam to the turbine to enable fast return to full power and the remainder of the steam to heat storage. At times of high electricity prices (demand), the reactor and the heat storage system would send steam to the power conversion system to produce peak power significantly above base-load capacity. Most of the time heat storage would provide assured peak-power generating capacity (kW). There is the option to include a low-cost boiler using natural gas, biofuels, hydrogen or other combustible fuel to provide steam if heat storage is depleted. The fuel consumption would be low because heat storage usually would provide the assured peaking capacity. It is a low-cost way to provide assured generating capacity. Coupling of heat storage to a heat producing technology for variable electricity output is not a new idea. Some existing concentrated solar power plants have gigawatt-hour heat storage to enable dispatchable electricity to the grid. Many of the same technologies can be used for heat storage coupled to nuclear plants. Other concentrated solar power plants use natural gas to provide assured generating capacity when the sun is not shining.
- *Energy integration of the electric and industrial sectors*. Historically, fossil fuels providing most of the energy inputs separately to these two sectors. In a low-carbon world, there are large incentives to couple these two energy sectors.

    - *Excess electricity from wind and solar*. Large-scale wind and solar create low-price electricity at certain times and thus incentives to send low-value electricity to the industrial sector that is converted into high-temperature stored heat that can be used when needed by the industrial sector. It is the only sector of the economy with continuous year-round energy demands large enough to adsorb all excess energy from a low-carbon electricity sector with a large installed capacity of wind and solar.

- *Nuclear co-generation with heat storage*. There are large incentives for nuclear energy to provide heat for the industrial sector. Nuclear energy produces low-carbon heat, what the industrial sector requires. The cost of heat is a third or less of the cost of producing electricity because of the conversion losses of converting heat to electricity. Electricity is a premium fuel and thus an expensive way to produce heat. Today in larger industrial plants that heat is sometimes supplied by fossil-fuel co-generation plants that provide heat and electricity. If nuclear energy is used on a large-scale for industrial heat, nuclear cogeneration may become a significant or potentially the primary source of nuclear electricity to the grid. Nuclear co-generation, rather than separate electricity and industrial sectors has several advantages.

    - *Minimize total costs*. Nuclear cogeneration enables optimizing the combined electricity and industrial sectors to minimize costs versus separate optimization of the electricity and industrial sectors.
    - *Heat storage*. Common heat storage for heat from the nuclear reactor and low-price electricity converted into heat minimizes storage costs and enables that stored heat to be used to maximize value—either peak electricity or heat to industry.
    - *Lower financial risks*. Co-generation minimizes financial risk. The demand for industrial heat at a particular industrial site may change over relatively short periods of time relative to the life of a nuclear power plant because of changes in demand for a particular product or changes in the industrial process that impact the need for heat. A co-generation plant assures longer-term economic value for the nuclear plant if it can sell electricity.

- *Storable fuels production*. The other challenge for a low-carbon world is storable fuels production for transportation and other parts of the economy. Storable fuels such as hydrogen, ammonia and biofuels require massive heat and electricity inputs. Unlike most other industrial products, energy costs are a major fraction of production costs—there is a significant financial incentive to maximize production when energy costs are lowest. There is the potential to vary the production rate of these fuels to better match output of nuclear, wind and solar to energy consumption on an hourly to seasonal basis.

We now examine these characteristics in further detail.

7.2. Energy Markets

If the goal is a low-carbon energy system, the entire system must be considered. Figure 7.2 shows the annual energy flows for the United States. The electricity sector has the largest inputs of primary energy but the output of energy services is about the same from the electric and industrial sectors. It is often proposed to electrify industry by electric resistance heating but in the United States the heat input to the industrial sector (21.9 quads: [25.2-3.23]) is almost twice the electricity output from the electricity grid (12.5 quads)—implying tripling the electric sector to meet industrial heat demand. Other studies (Mai 2918) propose industrial electrification using a wide variety of technologies to improve efficiency to lower electricity requirements but with substantial added capital costs.

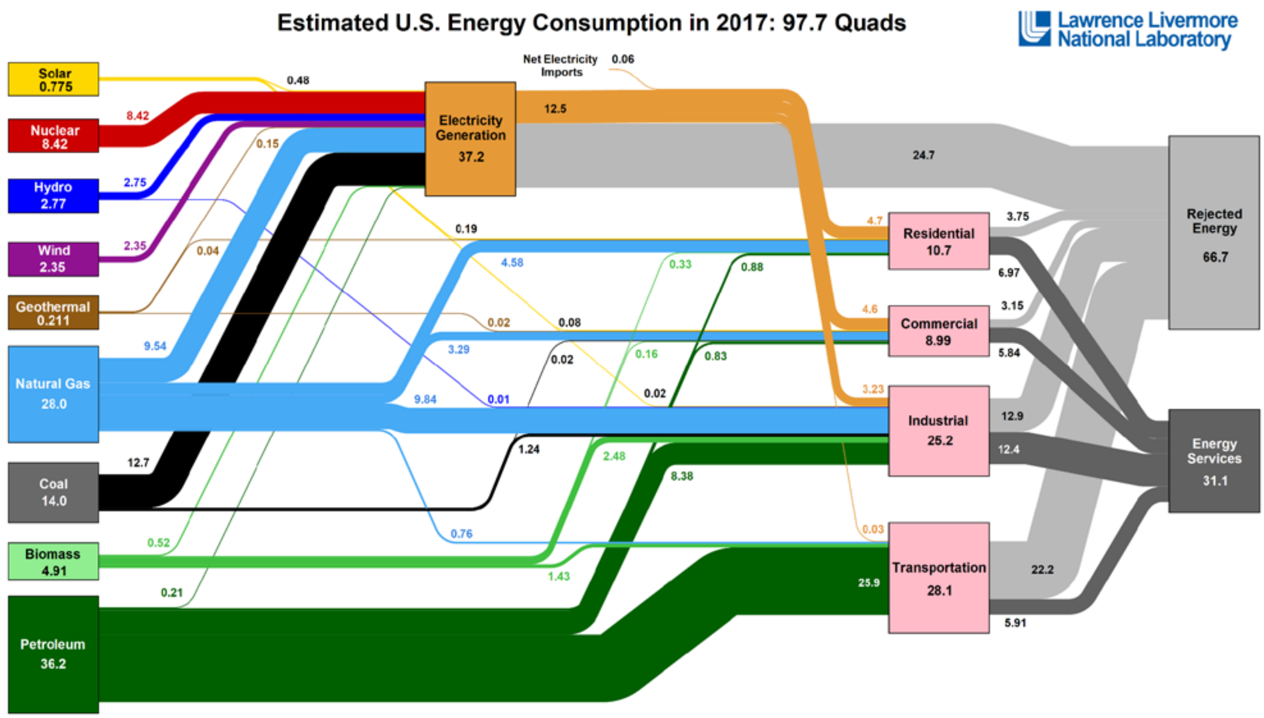

Fig. 7.2. Energy Flows in the United States [Lawrence Livermore National Laboratory, 2018]

Converting electricity into heat is an expensive way to produce heat. Table 7.1 shows the levelized cost of electricity from different generating technologies. Wind has the lowest cost: \$30 to 60/MWe. The efficiency of converting electricity into heat is near 100%; thus, the heat cost is about \$30 to 60/MWt. However, one must then add the cost of the electricity grid and storage to be able to provide heat at a near constant rate to the industrial customer that needs heat. Those costs can double the cost of delivered heat from a wind system. Nuclear electricity costs are estimated between \$112 and 183/MWe. The efficiency of converting heat to electricity in a light-water reactor is about 33% so the cost of heat from the reactor is \$37 to 61/MWt. However, one does not need the heat-to-electricity systems (turbine hall, etc.) so the cost of heat from a nuclear plant is substantially below this number. This reality is seen in prices for heat versus electricity. U.S. electricity prices are 4 to 6 times that of natural gas per unit of heat.

There are many proposals to produce low-carbon hydrogen that is made from electricity to supply heat to the industrial sector. That is an expensive route for heat production that also includes the added inefficiencies of converting electricity to hydrogen. The heat production technologies are nuclear and fossil fuels. The question is how to economically provide heat to the industrial sector in a low-carbon economy. The U.S. Next Generation Nuclear Program (NGNP), a joint government-private initiative, developed a high-temperature reactor to provide industrial heat; but, the demonstration plant was not built because of the large decrease in natural gas prices from fracking making natural gas the more attractive economic investment.

Table 7.1. Unsubsidized Levelized cost of electricity (LCOE) for new plants (1) in \$/MWe [Lazard, November 2017]. Non-dispatchable technologies (wind and solar) require dispatchable technologies for assured electricity

Technology	LCOE: \$/MWh(e)	Dispatchable
Solar PV: Rooftop Residential	187–319	No
Solar PV: Crystalline Utility Scale	46–53	No
Solar PV: Thin Film Utility	43–48	No
Solar Thermal Tower with Storage	98–181	No
Wind	30–60	No
Natural Gas Peaking	156–210	Yes
Natural Gas Combined Cycle	42–78	Yes
Nuclear	112–183	Yes

The U.S. is not unique in its need for heat for the industrial sector. The fraction of energy consumed by industry in China is larger [China Energy Group, 2016] than in the United States as shown in Fig. 7.3.

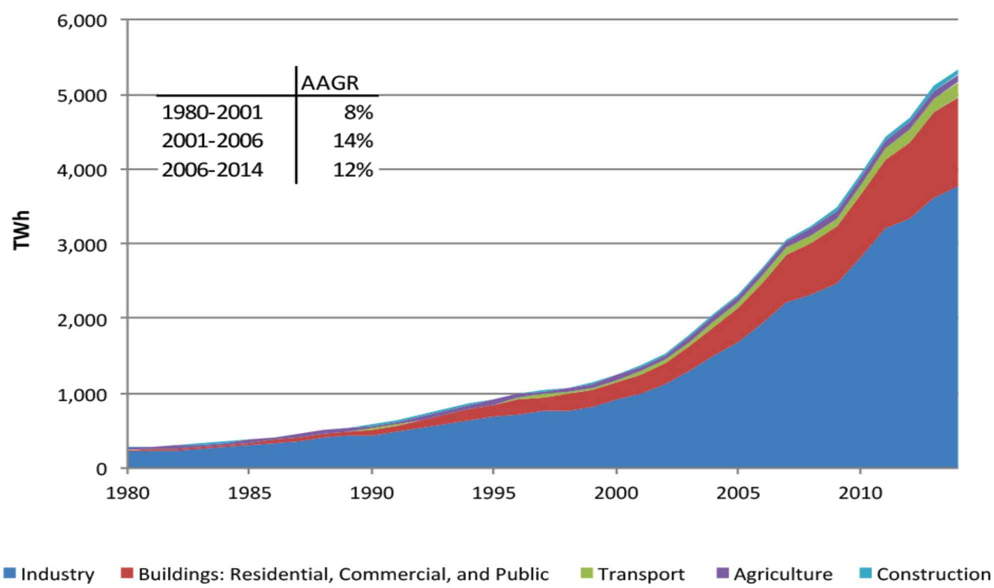

Fig. 7.3. Energy Consumption by Sector over Time in China [China Energy Group, 2016]

The implications are that any effort to decarbonize the entire economy could have massive impacts on the electric sector. Similarly, if nuclear co-generation is used to supply heat to the industrial sector, the scale of operations will have massive impacts on the electric sector. With fossil fuels it was simple and cheap to separately supply fossil fuels to each sector: electricity, industry and transportation. That separation of energy sectors may collapse in a low-carbon world.

The industrial heat challenge may be substantially underestimated. The transport sector is slightly larger than the industrial sector (Fig. 7.2). Today we use petroleum to make gasoline, diesel fuel and jet fuel. Most of the energy demands for refineries are met by burning low-value byproducts of the refinery. In the future we may use biofuels, hydrogen or synthetic fuels made from carbon dioxide and air. If these alternative transport fuels are used it implies massive added industrial demand for heat.

One example is hydrogen production. In any low-carbon future, there will be a large growth in hydrogen demand and hydrogen production may become the largest user of industrial heat [Forsberg, April 2009; Yan, 2011]. Hydrogen is primarily used today for fertilizer production and converting crude oil into gasoline, diesel and jet fuel. In a low-carbon future hydrogen would replace fossil fuels for chemically reducing metallic ores to metal—primarily the production of iron and steel. Adding hydrogen can almost double the yield of liquid fuels per ton of biomass. Hydrogen may be used directly as a transport fuel—either directly or in a hydrogen carrier such as ammonia. Last, hydrogen can be used for production of heat and peak electricity; however, it is a premium fuel and energy carrier. In some of these scenarios, hydrogen as a chemical feedstock and fuel could consume 20% or more of all primary energy production (nuclear, wind and solar). A recent review [Staffell, 2019] describes the current status.

The traditional process for hydrogen production is steam methane reforming of natural gas. There are three major non-carbon pathways to hydrogen [Yan, 2011]. The first option is traditional electrolysis of water. The second option is high temperature electrolysis (HTE)—steam electrolysis where the energy inputs are heat and electricity. The third set of options is the thermochemical processes that convert water to hydrogen and oxygen using high-temperature heat as the primary energy input. Because hydrogen production could become the largest single user of industrial heat, it has to be explicitly considered when examining future uses of heat for the industrial sector.

Hydrogen and hydrogen carriers such as ammonia are storable and transportable via pipeline; thus, there are incentives for large-scale centralized production to reduce costs. Today hydrogen is stored at very low costs in large underground salt caverns on the Gulf Coast of the United States with hydrogen pipelines connecting refineries, chemical plants, hydrogen production facilities and storage facilities in Texas and Louisiana. The storage technologies used for natural gas are used for storing hydrogen. In the U.S., up to a quarter of a year's worth of natural gas is stored in such facilities that could also be used in most cases for hydrogen storage allowing seasonal storage. In this context, it is one of three major zero-carbon energy carriers (Table 7.2) but unlike the others, it is also a chemical feedstock. Like electricity, it is a premium form of energy (thermodynamically work energy).

Table 7.2. Low-Carbon Energy Carriers

Energy Carrier	Transport Range (km)	Storability	Thermodynamic Energy Form
Electricity	>1000	No	Work
Heat	10s km	Yes	Heat
Hydrogen (Storable Fuels)	>1000	Yes	Work (Chemical)

The electric sector has its own challenges. The levelized cost of electricity (LCOE) for different generating technologies is shown in Table 7.1 for the United States. In areas of good wind and/or solar conditions, utility-generated wind and solar LCOE is significantly below that of nuclear energy. This is due to technology advances. The cost of nuclear is relatively uniform across the country whereas the cost of wind and solar vary with location. There is an important caveat associated with these estimates. There are large differences in grid integration costs associated with different technologies. These costs (NEA 2019) are significantly higher with wind and solar because of their dispersed siting and non-dispatchable characteristics.

Figure 7.4 (left) shows wholesale electricity prices in parts of California on a spring day in 2012 and 2017. In 2012, the California electricity market was dominated by fossil-fuel generating units. The minimum price of electricity was set by the price of fossil fuels resulting in relatively uniform wholesale prices for much of the day. This market structure favored base-load nuclear power plants. Over a period of five years, large numbers of photovoltaic (PV) systems were installed that collapsed wholesale prices on days with good solar conditions and low electricity demand. This also resulted in higher prices near sunrise and sunset when electricity demand goes up but PV can't provide electricity at those times. The large-scale addition of wind and PV change the characteristics of wholesale electricity markets.

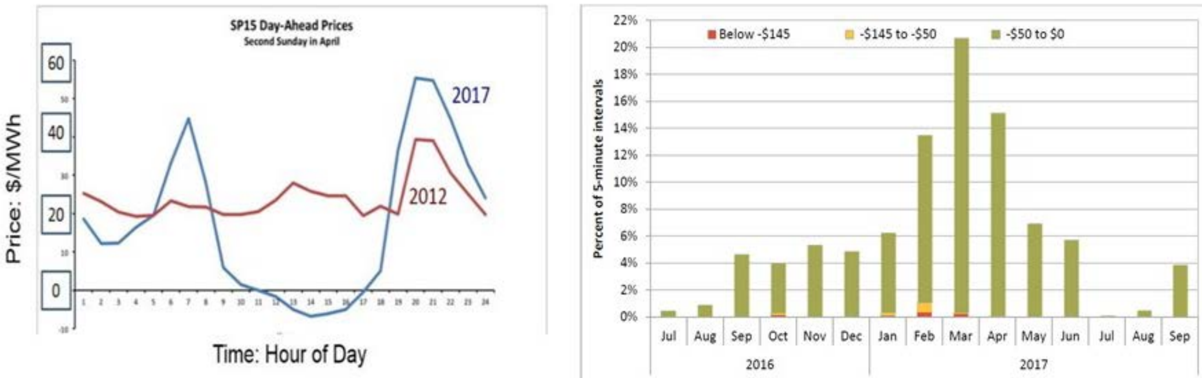

Fig. 7.4. Price impact of adding PV between 2012 and 2017 on a spring day in California [California ISO, April, 2017] and times of negative wholesale electricity prices [California ISO, November 2017].

Figure 9 (right side) shows the times of negative wholesale prices in the California Independent System Operator (ISO) electricity grid over a period of one year. Negative prices occur at times of low electricity demand and high inputs from non-dispatchable wind and solar. Most of the negative-price electricity is generated in the spring. Electricity demand is lower in the springtime with low heating and air-conditioning loads. Peak solar output occurs in June—the time of maximum solar input. The large air-conditioning load in summer implies high electricity demands in summer that minimizes times of low electricity prices. The negative prices show the seasonal challenge of managing electricity from wind and solar resources.

The number of hours of negative price electricity are expected to decrease significantly but with many more hours with electricity prices near zero. There are several reasons for times with negative electricity prices. Many wind and solar subsides are in the form of payments per kWh generated. If a wind farm receives a subsidy of $24/MWh, the wind farm is willing to sell electricity at -$23/MWh with a net income of $1MWh than shut down. As subsidies disappear, wind and solar producers will stop selling electricity at negative prices. The other factor is that many fossil, nuclear and hydro plants can't reduce their output to zero when prices are negative. Some hydro facilities have minimum water flows to maintain healthy river conditions for fish. Gas turbines remain on line at minimum output so that they can rapidly accelerate to full power when the price of electricity rapidly increases in the evening (Fig. 9, left). Nuclear plants can load follow but do not want to shut down because of the long restart time. Engineering changes in these systems will enable these electricity producers to reduce electricity generation when prices are low—but such changes take time. However, there will be more hours of very low-price electricity because of the addition of new wind and solar capacity.

One might assume that a low LCOE would result in low retail electricity prices. Limited additions of wind and solar lower electricity prices. However, large-scale deployment of solar and wind in Europe, the United States and elsewhere has caused increases in retail electricity prices. From 2011 to 2017, the California average retail electricity prices rose from $13.1/kWh to $16.2/kWh while wind and solar increased to meet 22% of the electricity demand. At the same time natural gas prices dropped—the primary fossil fuel. Without the drop in natural gas prices, there would have been larger increases in electricity rates. Retail prices are expected to accelerate upward because of with added wind and solar because of three factors: (1) natural gas prices have bottomed out, (2) California restrictions on future use of natural gas and (3) the best wind sites were developed first.

What happened? First, large-scale wind and solar collapses prices when good solar or wind conditions occur. A recent review of European experience [Sivaram, 2018] found no country produced more than 8% of its electricity from solar in spite of subsidies and other programs. The problem is that the solar output is only available in the day when there is reasonable sunlight. The potential for wind is greater, but likely less than 25% in the mid-latitudes of the United States, Europe, Japan and China before collapsing revenue limits their use. It's like the price of tomatoes in a local market in northern climates that crashes when all the tomatoes turn red at the same time. *Pushing larger-scale use of renewables requires subsidies (mandates, direct subsidies, etc.) to provide the revenue lost from price collapse as installed capacity increases or legal constraints such as on carbon emissions.*

Second, other power plants with higher operating costs reduce power at times of high wind or solar output but still require their full operating crews to produce electricity at times of low solar and wind conditions. The electricity grid has to start paying capacity payments ($/kWe) or see large wholesale electricity prices at certain times to keep these plants open to produce electricity when needed when the sun goes down or under low-wind conditions. Solar and wind does not significantly reduce the need for other power plants to provide assured capacity—it just lowers the number of hours per year other plants operate and thus raises their cost of electricity production while lowering revenue. In the near-term the system adjusts by operating existing fossil plants at part load. In the longer term these plants may be replaced with natural gas peaking plants—the most economic option for dispatchable electricity but that electricity is not cheap (Table 7.1: $156-210/MWH). These limits can be partly overcome with electricity storage—but with large increases in electricity prices because of the high cost of electricity storage systems (batteries, pumped storage, etc.).

While wind and solar subsidies have helped created low and negative prices (thus exacerbating the problem), even without subsidies there would be times of very low electricity prices and times of higher prices with non-dispatchable wind and solar. This is in contrast to electricity systems dominated by fossil fuels where the cost of the fossil fuel sets the minimum price. While major additional decreases in photovoltaic costs are not expected (siting, structural supports and power supply control costs, not PV cells), significant decreases in the cost of wind are possible. General Electric will soon deploy 12 MWe wind turbines [General Electric, 2019] offshore that can operate under lower wind conditions allowing more hours of operation per year. Recent advances in tower construction [Keystone Tower Systems, 2019] may enable these systems to be deployed on the Great Plains (best on-land wind sites) as well as offshore. Automated field construction of steel towers from plate steel bypasses the traditional transportation limits for large towers on the Great Plains. Most projections indicate offshore wind is likely to remain expensive because of the high cost of offshore construction and maintenance—but there are clear technical reasons to believe land-based wind will remain the low-cost non-dispatchable energy source.

The economic benefit of the low LCOE from wind and solar depends upon the development of lower-cost dispatchable electricity. Today that role in the U.S. is partly filled by low-cost natural gas. In a low-carbon world or a world of high fossil fuel prices that role may be played by nuclear cogeneration with heat storage as discussed below. In effect, the highly variable price of electricity in systems with large-scale deployment of wind and solar electricity creates an economic opportunity to greatly expand the economic use of nuclear provided nuclear can be made more economic as a dispatchable form of electricity—a win/win scenario.

In this context, it is observed that in the United States the cost of gas-turbine peak power ($156-210/MWh) with natural gas is more than the cost of new nuclear base-load electricity ($112-183/ MWh). Nuclear can be coupled to heat storage to enable the reactor to operate most of the time at base-load with variable electricity sent to the grid—dispatchable nuclear power that matches the changing wholesale market for electricity. There is the potential for nuclear reactors when coupled to low-capital-cost heat storage to become a competitive power source for dispatchable electricity even with relatively low natural gas prices.

Similar effects are seen in China with very different electricity markets. Fig. 7.5 shows the capacity factors for different energy sources. In the last several years there have been decreases in the capacity factors of nuclear and fossil fuels—partly because of the inputs of solar and wind at particular times of the year.

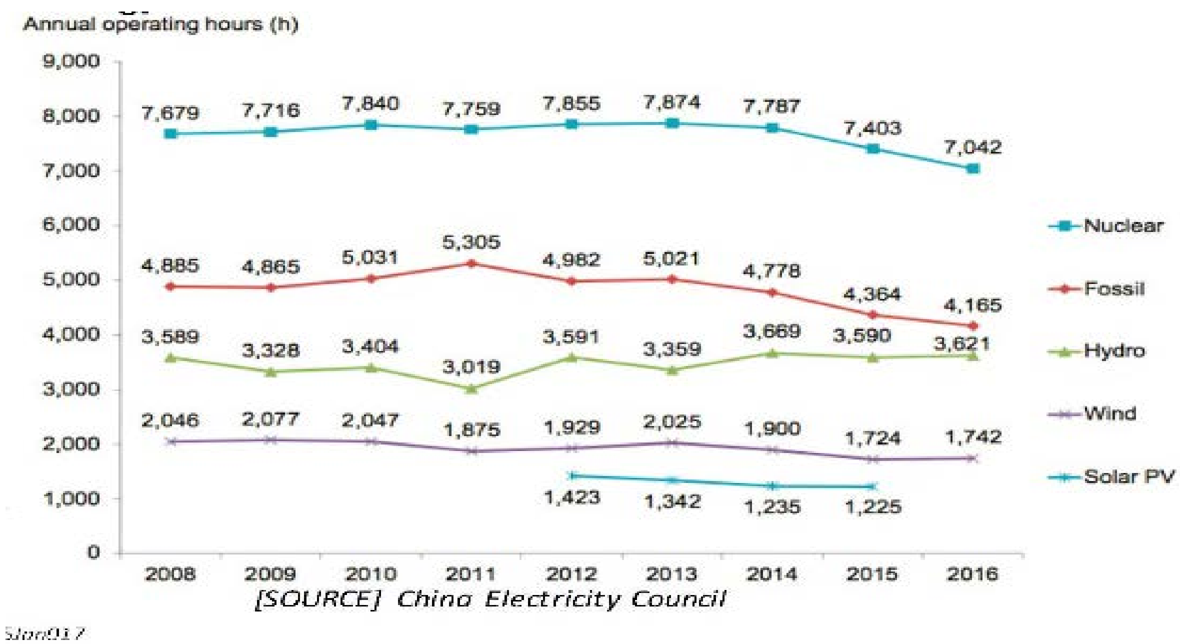

Fig. 7.5. Capacity Factors for Electricity Generation in China

7.3. Integration of Electricity and Industrial Markets

A low-carbon economy creates the incentive to integrate electricity and industrial energy markets—rather than the traditional model of separate industrial and electricity markets supplied by fossil fuels. The primary industrial demand is for process heat (Fig. 7.6) in the form of steam and fuel (hot air). Industrial heat demand does not have the large time variations in demand for several reasons. The capital cost for most processes is more important than energy costs; thus, incentives to operate plants at full capacity. Second, for high-temperature processes, there is significant thermal fatigue if temperatures change implying much higher maintenance costs. This creates large significant economic incentives to operate at steady state.

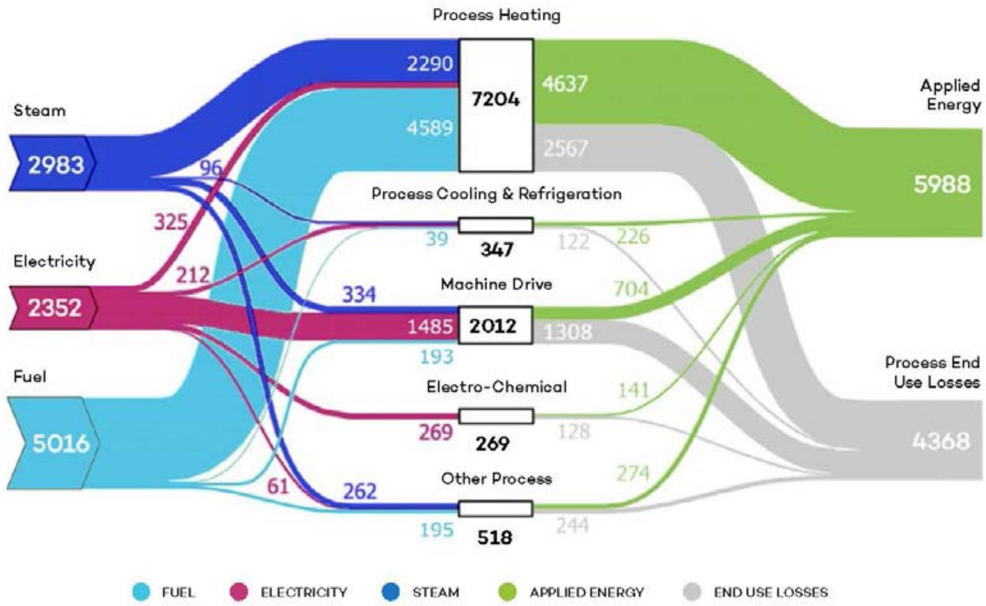

Fig. 7.6. U.S. Manufacturing Process Energy Flows in 2010: TBTU (U.S. DOE 2010, Breakthrough Institute 2019)

7.3.1. Non-Nuclear Integration of Utility and Industrial Sectors

Excess low-value electricity can be converted into high-temperature stored heat in the form of firebrick hot rock or similar storage media. Air is blown through the storage media to produce hot air for industrial furnaces, kilns, and power plants. In effect, the hot air from the firebrick is a substitute for hot air produced by burning natural gas and would be a partial substitute for natural gas. Figure 7.7 shows one such system: Firebrick Resistance-heated Energy Storage (FIRES). This family of concepts (Forsberg, July 2017) is based on several common features.

- *Industrial Heat Market*. The heat requirements for this market are larger than the electrical output of the U.S. The market is big enough to consume large quantities of low-price electricity. Equally important, it is a year-round heat market—unlike residential or commercial heat demand. It can adsorb electricity whenever available.
- *Electric Resistance Heat Input*. The lowest cost method to convert electricity to a useful product is resistance heating. Resistance heaters can work at any voltage, accept AC or DC and have no power phase requirements. The electronics are minimized.
- *Heat storage media*. Crushed rock and firebrick are among the cheapest materials available.

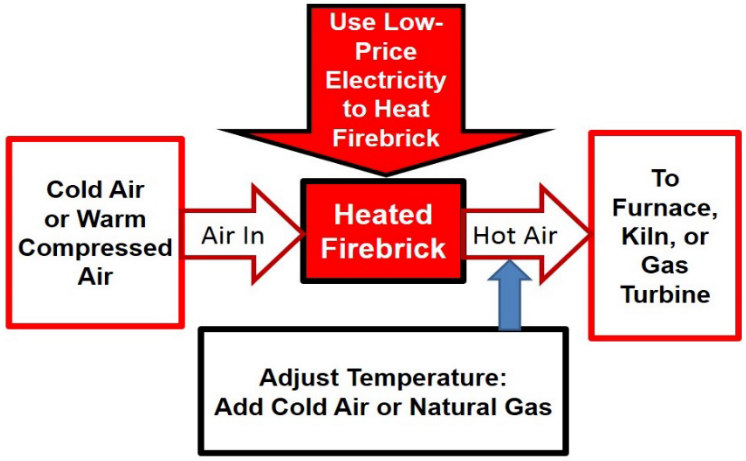

Fig. 7.7 Firebrick Resistance Heated Energy Storage (FIRES)

Low-temperature versions of these systems have been deployed for decades—but not in the form discussed herein. In the 1950s and 1960s home versions of this technology were deployed in Europe to convert from coal to electric residential and commercial heating to reduce local air pollution. Today such systems are being deployed in China on a large scale. In all of these cases a special electricity discount rate at certain hours of the day is made available—a subsidy to reduce local air pollution. What is described here is installation of such systems based on economics—not social policy to reduce local air pollution. *Until several years ago there was not enough low-price electricity to make such technologies economically attractive*. Coupling the electric sector with the industrial sector by such technologies may prevent zero-price electricity and set a minimum base price of electricity to that of fossil fuels on the bases of heating value.

7.3.2. Nuclear Co-Generation with Heat Storage

The utility and industrial sectors can be integrated by locating reactors with heat storage for co-generation of industrial heat and electricity with gigawatt-hour heat storage—a low-carbon energy system. Co-generation enables siting economically-sized reactors at much smaller industrial sites that require heat. Co-generation lowers the investment risk from the uncertainties in industrial heat demand over longer time frames. Heat not used for the industrial demand is converted to electricity or stored heat. Heat storage enables (1) variable electricity to the grid to maximize electricity sales at times of higher prices and (2) conversion of low and negative priced electricity from the grid into low-cost stored heat that can be used for either peak electricity production or for industry.

The proposed system is shown in Fig. 7.8. The reactor operates at base-load—it is the most economic mode. Heat goes to industry whenever needed [#11: Numbers (#) correspond to the process flows shown in Fig. 3]. At times of low electricity prices, the minimum amount of heat from the reactor [#1] goes to the power cycle to keep it on line to allow rapid return to power. The rest of the heat goes to heat storage [#3] and industry [#11]. There are multiple heat storage options including steam accumulators, molten salts, crushed rock and other systems as discussed below. Many of these technologies have been developed for solar thermal power stations and some have been deployed at the gigawatt-hour scale. At times of high electricity prices, heat from the reactor [#1] is used to generate electricity [#2] and added heat from storage [#4] goes to the power cycle to generate added peak electricity. In addition to the industrial heat demand, if the plant has a base-load electricity output of 200 MWe, its peak power output may exceed 400 MWe—depending upon design that depends upon local electricity markets.

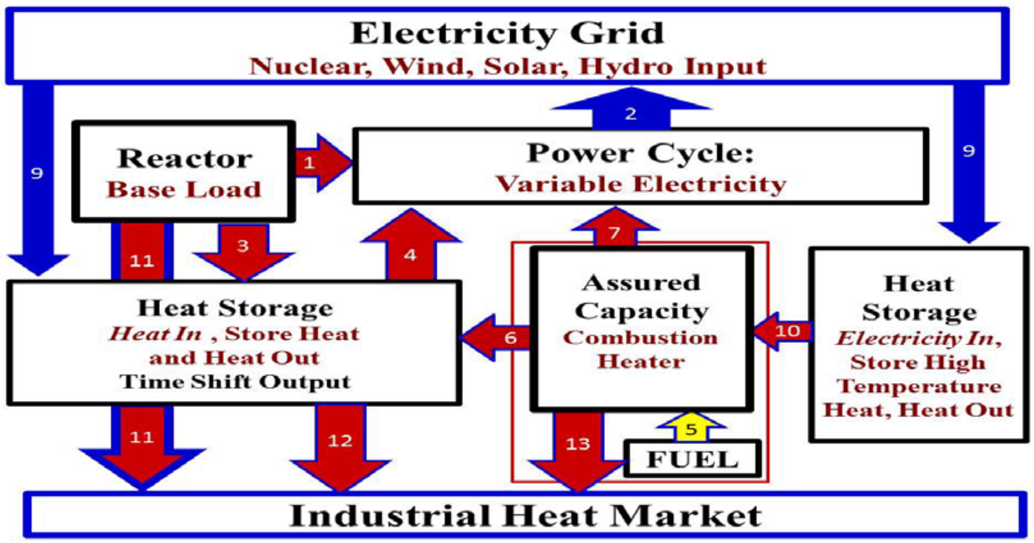

Fig. 7.8. Integrated Nuclear-Renewable Co-generation System

Heat storage systems coupled to nuclear reactors for peak electricity production were initially studied in the 1970s after the Arab oil embargo that made oil-fired power stations uneconomic because of the high price of oil. At that time oil-fired units provided variable electricity in many countries. The drop in oil prices ended research at that time for coupling heat storage to light water reactors (LWRs). The changes in electricity markets in the last several years with collapsing electricity prices in systems with large-scale wind and solar has resulted in new work by the research community, some utilities and some vendors on heat storage [Appendix D; Forsberg March 2019; Forsberg, Brick and Haratyk, 2018]. This work is for variable electricity to the grid for existing and new-build nuclear plants—not nuclear-cogeneration plants. The economics are based on several considerations:

- *Heat storage is less expensive than electricity (battery, pumped hydro, etc.).* The U.S. Department of Energy capital-cost goal for heat storage for concentrated solar power plants is $15/kWh of heat—where it is believed several projects are now below this number. The U.S. DOE long-term goal for batteries is $150/kWh electric and about double that after including the required electronics.
- *Heat to electricity conversion is less expensive than other power conversion systems.* There are two options for peak electricity production. The first option is an incrementally larger steam turbine and generator at an incremental cost far below peak power below any other technology. The second option is a stand-alone peaking turbine that can be sized to any desired capacity.
- *Thermal storage systems can have rapid heat input rates.* In many markets solar and wind induced price collapse may occur for a limited period of time in any one day creating large incentives to send massive amounts of heat to storage over a short period of time. Many of the thermal storage systems (steam accumulators, pebble beds, etc.) have the characteristic that one separately sizes heat input rates, storage capacity and peak power output with very low capital costs for very high heat input rates. This enables taking advantage of shorter periods of time with high rates of heat input when prices are low. This is in contrast to batteries and hydro pumped storage where maximum electricity input rates are coupled to discharge rates. For example, most pumped hydro

facilities use reversible pump/turbines. The same equipment is used to pump the water uphill as is used to produce power when the water flows downhill.

- *More cycles per year.* A nuclear reactor operates nearly all the time. This implies more storage cycles per year. If the number of cycles per year is doubled, the cost per cycle and unit of storage is cut in half.

If the price of electricity collapses, low-price electricity [#9] can be bought and used to heat the storage media using resistance heaters. This includes converting electricity from the turbine operating at minimum load into high-temperature stored heat. In electric resistance-heating systems, a major fraction of the cost is connection to the grid, the transformers, and switchgear. At a power station these systems are required to send electricity to the grid and thus available to import electricity to the heat storage system at times of low electricity prices. Consequently, the maximum rate of electricity purchases can match the maximum peak power sent to the grid using the same equipment. The power station buys and sells electricity depending upon price. While industry could buy electricity from the grid at low prices and convert it into stored heat, the cogeneration plant has three economic advantages: (1) the expensive grid connections, transformers and other equipment are available at essentially no cost to move cheap electricity into high-temperature heat storage, (2). the heat storage systems are large with economics of scale and (3) the reactor normally provides industrial heat.

The ability to buy massive amounts of low-price electricity has other implications. It sets a minimum price of electricity—no sales of nuclear electricity to the grid at times of very low prices. The nuclear generator may be operating at minimum load to enable rapid return to full power but its electricity can be sent to heat storage. This is not thermodynamically efficient but is the economic strategy—do not sell electricity to the grid at negative or very low prices. It also reduces curtailment of wind and solar—improving wind and solar economics.

The central problem with all storage systems is that they can become depleted and thus require backup electric generating capacity. To assure backup capacity, a combustion furnace can provide the heat equivalent that comes from storage to the power cycle for peak electricity production [#7] or the industrial heat load [#13]. Capital costs [Forsberg, March 2019] for such a boiler are estimated at \$100-300/kWe, substantially less than the cost of a simple gas turbine (\$600/kWe) to provide assured capacity—the next cheapest alternative to provide assured generating capacity. This cost would be covered by capacity payments in many markets. The combustion furnace will only be used a limited number of hours per year since most of the time heat storage is used for peak power generation and/or industrial heat. The fuel today would be natural gas. In the future it could be low-carbon biofuels or hydrogen. Actual consumption of combustible fuels is small because most of the time heat storage is available to meet the variable heat and electricity demands.

If there is a massive amount of excess low-price electricity, there is a second option to use excess electricity [#9] to heat firebrick [18] or hot rock [19]—rather than heating the main heat storage media. Air can be blown through the firebrick or hot rock to provide hot air to the combustion furnace [#10] rather than burning natural gas, oil, biofuels or ultimately hydrogen and thus provide heat to the power cycle for peak electricity production and assured heat for industry. In most cases the power system is a steam turbine and the furnace is a steam boiler—commercial technologies to provide steam to industry. With electric resistance heating, one can produce higher-temperature stored heat than storage systems with steam input. This has several implications.

- *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 feed-water systems. The heat-to-electricity conversion efficiency will be less.

- *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 operating at lower temperatures.

Heat for the industrial sector can be sent from the reactor [#11], heat storage [#12] or the combustion heater [#13]. This system has several characteristics.

- *Absorb all low-price electricity*. The only sector of the U.S. or Chinese economy large enough to absorb all low-price electricity for less than the price of fossil fuels and available at all times is the industrial sector. In this context, a nuclear power plant with heat storage or a nuclear co-generation plant with heat storage will be have a significant economic advantage over FIRES and similar technologies (previous section) at industrial sites without nuclear co-generation for converting low-price electricity to high-temperature heat and using that heat for several reasons.

    - *Power plant grid connections*. The power plant already has the transmission connections, switchgear, and transformers to economically receive low-price electricity and convert it to low-price stored heat for use when needed. The equipment is used to send electricity to the grid but is not needed when prices are low. This is a significant fraction of the total cost to bring in and convert low-price electricity into stored heat.
    - *Economics of Scale*.
    - *More cycles per year*. The nuclear plant with heat storage will be using the heat storage system whenever there is a significant variation in electricity prices—not just when electricity prices are less than the price of fossil fuel. Using storage more cycles per year lowers the cost of storage. In contrast a stand-alone FIRES-type heat storage system coupled to industry will only be used when the price of electricity is less than the price of fossil fuels.

- *Low system costs*. The system enables high-capital-cost low-operating-cost nuclear, wind and solar to operate at full capacity, their most economical mode. Industrial heat is provided by the reactor as well as heat from low-price electricity. Heat storage has economics of scale and the power station grid connections for economically dumping cheap electricity into heat storage. The capital cost of heat storage is an order of magnitude less than electricity storage [Forsberg, March 2019; Forsberg, Brick and Haratyk, April 2018; Schmidt et al., 2017].
- *Reliable heat supply*. Many industrial processes require high reliability for heat delivery systems. The storage systems with a combustion furnace (boiler) for *assured capacity* enable the base-load reactor to provide variable electricity to the grid and heat to industry with high reliability on an hourly to seasonal basis. Wind and solar have strong hourly to seasonal variations implying expensive hourly to seasonal energy storage systems if they are the primary source of industrial heat.
- *Enable nuclear heat for smaller industrial users.* The reactor has two sets of customers—the electricity grid and industry. Mega industrial parks to provide a large enough demand for nuclear heat are not required. Moving energy between electricity and industrial sectors minimizes heat costs to the industrial customer.
- *Lower the risk of stranded nuclear assets.* With two markets, the industrial company has higher assurance of long-term return on investment if the industrial market changes and the demand for industrial heat goes down. The reactor can send its energy to the grid.

- *Low carbon industrial system*. This system enables a zero-carbon industrial sector by combining what nuclear generates (heat) with heat storage for (1) assured reliability of supply and (2) use of any low-price zero-carbon electricity from the grid. It improves wind and solar economics by creating a minimum price of electricity slightly below that of competing fossil fuels.

There are also nuclear plant implications. Heat storage can improve plant resilience against unexpected rare events such as grid collapse and electromagnetic storms (Forsberg 2019, Green 2016a, Green 2016b, 2018, 2019). The stored heat enables rapid restart of the grid.

7.4. Storable Fuels Production

The third energy sector is fuels production—primarily for the transport sector. In a low-carbon economy, replacements for these fuels are required. There are many competing options including batteries, biofuels, hydrogen, synthetic hydrocarbon fuels (usually carbon dioxide and hydrogen to liquid fuels) and ammonia. For some applications such as aircraft and long-distance trucks, the transportation requirements may dictate use of high-density liquid hydrocarbon fuels. All of these options require massive energy inputs. All of these options except batteries have associated low-cost storage technologies that allow hourly to seasonal storage. The implication is that if the cost of converting heat and electricity to these products is low enough, they can be used as storage mechanisms—in addition to heat storage and electricity (batteries, pumped hydro, etc.) for using energy at times of excess production (low prices).

Central to these options is whether to decarbonize the fuel supply (hydrogen, biofuels, synthetic hydrocarbon fuels, etc.) or decarbonize the application (batteries and vehicles). That determines where there will be storage requirements and the need for disputable energy. The GenX analysis above assumed existing electricity demand profiles. If those profiles change significantly, the optimum system will change significantly

Decarbonization of transportation with just-in-time delivery of electricity imposes added requirements for the electricity grid because transport and other uses of storable fuels have hourly to seasonal variations in demand. There have been limited studies on electricity demand and the grid. The California Energy Commission (2018) recently projected electricity demand for plug-in and all electric vehicles for 2025 with relatively limited penetration of these vehicles as shown in Fig. 7.9 for weekdays and weekends. This was based on surveys and other sources of information on driver behavior. The extra electricity demand appears in the early morning and early evening with the evening peak at times of peak electricity demand, peak prices, and lowest solar/wind output. There are two primary drivers—the workday and one-car families. If a family has a single vehicle, there are large incentives to charge the vehicle when they get home to have the vehicle ready when they need it. If these projections are correct, electrification of the transport sector implies potentially added need for storage and dispatchable electricity—and a significantly different electricity grid than shown in the GenX models that assumed today's electricity demand profiles.

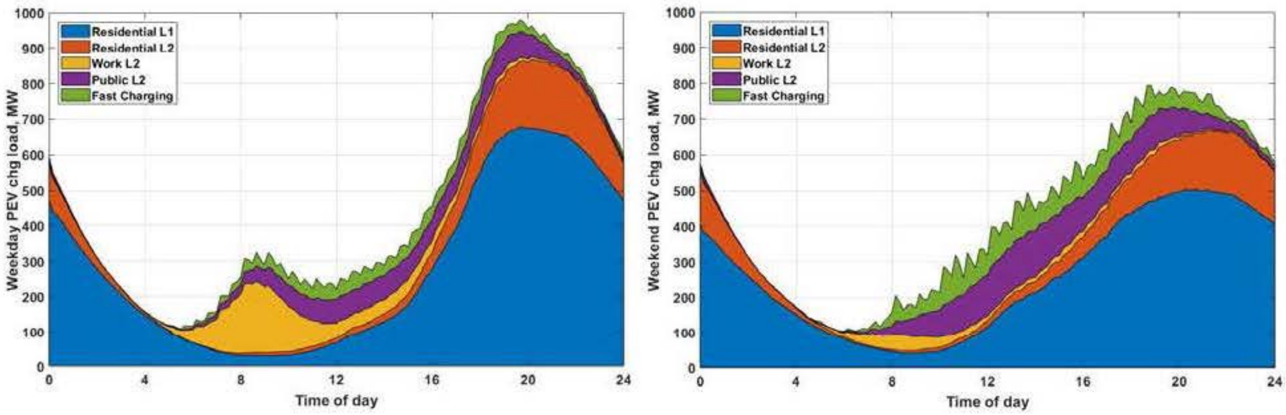

Fig. 7.9. Projected California Electric Vehicle Charging Load in 2025 for Weekdays (left) and Weekends)

An important distinction must be made between all-electric vehicles and hybrid plug-in vehicles that operate on combustible fuels and battery packs. If there is time-of-day pricing and a vehicle owner has a plug-in hybrid, he can chose to charge the vehicle when the price of electricity is low and be assured that he can use the vehicle when needed using its combustion engine. In such a scenario, the demands on the electricity grid are reduced because the load appears at times of sufficient generating capacity without the need for storage to assure electricity demands.

We are not aware of any studies that have examined the seasonal impacts of the large-scale use of electric vehicles on electricity demand. In the United States there are large changes in transport fuel demand associated with holidays and the summer vacation schedule. There are also weather effects. In northern climates where temperatures are significantly below 0°C, there will be major added loads to initially heat batteries and more importantly, heat for the passenger compartment. That could have major implications in a country such as the United States where a polar vortex can cover a third of the U.S. and some locations with temperatures as low as -30°C.

If we decarbonize the fuel supply, that has very different implications on the electricity grid. Such fuels are storable (hydrogen, biofuels, etc.). Their production would significantly increase the demand for heat and electricity. Because the fuels are storable and energy is a large fraction of their production costs, there is the option to vary fuels production with nuclear co-cogeneration plants with more electricity to the grid at times of high prices and electricity to the industrial facilities at times of low electricity prices. Such scenarios could reduce the demands on the electricity grid.

This is only a viable option for a product where the primary cost of the product is the energy input (Davis et al, 2018) of which hydrogen and ammonia are the two major candidates. However, all of the production technologies have higher capital costs than heat storage per unit of energy input. The capital cost of converting low-price electricity to heat using resistance heaters is small compared to any hydrogen or other storable fuel production system. These production plants must be operated a significant fraction of the year to cover capital costs—it is not economic to size the hydrogen or other fuels production plant to absorb a large fraction of all low-price electricity because much of that low-price electricity will be available for a limited number of hours per year. Limited work suggests that heat storage may significantly improve the economics of hydrogen and other fuels production. Heat storage can economically absorb massive and variable amounts of heat from the reactor and low-price electricity converted to heat. Heat storage then enables use of that energy in storable fuels production with higher capacity factors for the fuel production system. If heat storage exists, one expects it would enable high-temperature electrolysis (heat and electricity to hydrogen) to operate more hours per year (higher capacity factor)—partly dependent upon low-cost stored heat obtained at times of very low prices. The same logic may apply to other industrial processes that use large quantities of heat and electricity.

7.5. Where To Locate Energy Storage and Dispatchability

In a fossil fuel world, each energy sector (electricity, industry, transport) is separately supplied with fossil fuels that provide storable energy. In a low-carbon world where the primary energy sources are nuclear, wind and solar, these sectors may be tightly coupled. The question is where to provide the storage and dispatchability functions of fossil fuels? The GenX analysis indicates that locating those functions primarily within the electricity sector is expensive.

8. Implications on Requirements for Nuclear Energy

These changes have major implications for nuclear plant requirements beyond those used for base-load electricity production because goals have changed. .

- *Heat storage*. The changing market makes the most economic nuclear power system the reactor with heat storage that provides the lowest-cost variable heat and electricity output to the electricity grid and heat to industry. The economic criterion is no longer the lowest levelized-cost- of-electricity (LCOE). LCOE is the criterion if the goal is base-load electricity production.
- *Co-generation*. If cogeneration is a large fraction of the future market, one requires reactors that are designed to efficiently supply heat to industry. That implies reactors that meet the temperature requirements for heat to industry and reactors whose safety characteristics enable co-siting with industrial facilities.
- *Peak electricity capacity*. A low-carbon world implies large incentives for systems that can economically provide assured large-capacity peak generating capacity; that is, peak power ratings that are significantly above the base-load capacity of the reactor.

Existing reactors can meet these requirements with some restrictions but the requirements will favor futures reactors that can deliver heat at higher temperatures; that is, High-temperature Reactors (HTRs). Table 8.1 shows heat delivery temperatures for major classes of reactors. The helium and salt cooled reactors are considered HTRs.

Table 8.1: Typical Reactor Coolant Temperatures

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

High-temperature gas-cooled reactors (HTGRs) have been built. Today a test reactor is operating in Japan and two pre-commercial demonstration reactors are beginning operation in the China with the expectation that more HTGRs will be built. The United States planned to build a pre-commercial HTGR called the Next Generation Nuclear Plant to produce heat for industrial customers. It was a joint government-private industry effort. That program was cancelled with the development of fracking that dramatically reduced natural gas prices, making natural gas a more attractive economic investment. This occurred just before the addition of wind and solar resulted in wholesale electricity price collapse; thus the program did not examine large-scale heat storage coupled to HTGRs and its associated economic benefits.

The salt reactors deliver heat at the highest average temperatures. The liquid salts have melting points above 400°C that sets the minimum reactor temperature. The maximum temperature is set by the availability of cost-effective materials for heat exchangers. Salt reactors include the Fluoride-salt-cooled reactor (FHR) that uses solid fuel and a clean liquid coolant while molten salt reactors (MSRs) dissolve the fuel in the coolant. Two small MSRs were built—one in the 1950s and one in the 1960s. There has been a renewed interest in MSRs including several startup companies proposing different types of MSRs. The FHR is a newer reactor concept that uses HTGR fuel and liquid salt coolant—enabled by the development of high-quality HTGR fuel. The startup company Kairos Power is developing the reactor as well as a parallel effort in China. There are plans to demonstrate these reactors by 2030.

8.1. Coupling Heat Storage to Nuclear Reactors

There is expanding work to couple heat storage to existing and future LWRs and limited work on coupling heat storage to advanced reactors. Appendix D describes some of the technologies that couple to HTRs. There are multiple reasons why higher temperatures imply lower heat storage costs.

- *Heat capacity and temperature losses*. For sensible heat storage systems, if the hot-to-cold temperature swing by the storage system is doubled, the amount of heat storage media required drops in half and the cost of energy storage. For all systems, there are temperature losses through heat exchangers and other equipment. The same temperature drop is required if transferring 600°C heat or 300°C. However, at 300°C, a 20°C temperature drop is much more significant.
- *Heat-to-electricity conversion efficiency*.
  - Higher-temperature stored heat can more efficiently be converted to electricity. If the conversion efficiency is 50% higher, much less heat must be stored to per unit of peak electricity produced.
  - Cycles per year. If the number of heat storage cycles per year is doubled, the cost of heat storage per cycle drops in half. Consider a system where low-price electricity is converted to high-temperature stored heat and then converted back into peak electricity. The conversion of the electricity-to-heat efficiency is near 100%. The conversion of heat to electricity depends upon the power cycle and thus determines round-trip efficiency. If one compares a power cycle with 30% versus 45% round trip efficiency, the more efficient cycle requires a smaller price difference between the buy and sell price of electricity to be profitable. In practice, this implies a more efficient higher-temperature system will cycle more times per year with higher revenue.

8.2. Assured Peak Generating Capacity

The defining need for a low-carbon electricity grid is assured peak generating capacity [Sepulveda et al, 2018]—the ability to deliver variable electricity as needed. The base-line power cycle is steam because (1) that technology is available today and (2) most industrial heat is used in the form of steam. There are other power cycles that may be able to provide assured peak generating capacity at significantly lower costs—but have not been explored in detail because until recently there was no incentive for such power cycles. These cycles preferentially couple to HTRs and include thermodynamic topping cycles. A thermodynamic topping cycle can convert a combustible fuel (natural gas, hydrogen biofuels) or stored heat into peak electricity at much higher efficiency that traditional combined cycle gas turbines. There has been very little work on these cycles because there was little economic incentive for their development unless one wants an energy system with very low carbon dioxide releases. We describe two examples. There may be other options that have not been identified.

For the FHR, there is the option of a Nuclear Air-Bratyon Combined Cycle (NACC) that has peaking capability [Forsberg and Peterson, October 2016, Andreades et al. September 2016]. In this system [Fig. 8.1], air is compressed, heated using nuclear heat, goes through a turbine, reheated using nuclear heat, goes through a second turbine and goes to heat recovery steam generator. It is a nuclear variant of a natural gas combined cycle (NGCC). NGCC plants using natural gas and other fuels are used for cogeneration of electricity and heat with steam for industry provided by the heat recovery steam generator.

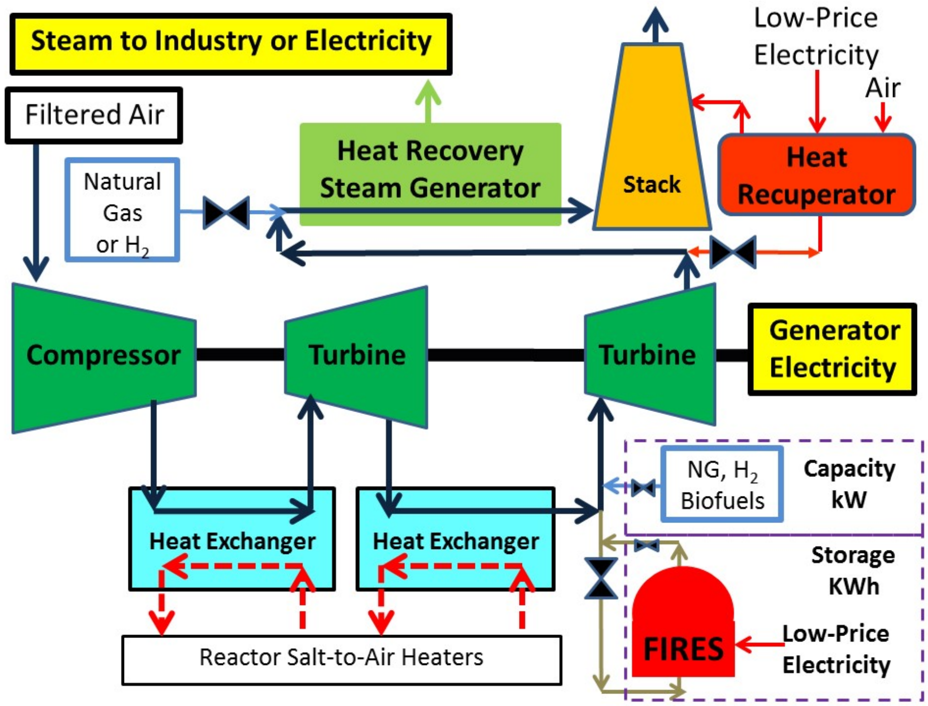

Fig. 8.1. Nuclear Air-Brayton Combined Cycle with Peaking Capability

Added peak power can be produced by adding high-temperature heat or a combustible fuel after the nuclear reheat step to increase the gas temperature going into the second turbine up to temperatures as high as 1500°C. The peak power capability is a thermodynamic topping cycle with incremental heat to electricity efficiency substantially above 70% and the cycles can be designed for different base-load to peak power outputs to match market requirements—including large peak power capabilities to provide large assured generating capacities.

The limitation of this cycle is that the front-end air compressor of a modern gas turbine is near 400°C. That implies efficient coupling with salt reactors that deliver heat above this temperature. Other reactors can be coupled to NACC but with the requirement to modify the reactor (raise the minimum temperature in an HTGR) or use intercoolers with the air compressor to lower air compressor exit temperatures.

Nuclear topping cycles are not new. NACC can be viewed as the high-temperature Brayton cycle equivalent of that used at the Indian Point I nuclear power plant in the 1970s. Indian Point I was a pressurized water reactor that produced saturated steam near 271°C. The saturated steam was sent to a high-temperature oil-fired superheater to produce high-temperature steam (~540°C)—a thermodynamic topping cycle. At the time, Indian Point I was the most efficient oil-fired plant in converting incremental additional oil heat into electricity.

For all HTRs there is the option of a Nuclear Steam-Injected Air-Brayton (NUSIB) cycle [3] that also has a base-load operating mode and a thermodynamic topping cycle using stored high-temperature heat, natural gas, biofuels or a premium fuel such as hydrogen with an incremental heat-to-electricity efficiency exceeding 70%. One NUSIB cycle is shown in Fig. 8.2. It has two major sub-systems. During base-load operations the HTR and any heat storage system produces high-temperature steam that is sent to industry and uses a conventional steam cycle to produce electricity. For peak electricity production, some fraction of that steam is sent to a steam-injection Air Brayton power cycle.

For peak electricity production, a steam-injection Brayton cycle is used (dotted lines). Stand-alone (non-nuclear) steam-injection Brayton power cycles are commercial products and there has been considerable work done on conventional steam-injected Brayton cycles for different applications [Bahrami; Betelman, 2017; Jesionek, 2012]. In current systems, it is a way to boost power levels in simple gas turbines without adding a heat recovery steam generator. In a NUSIB cycle, air is compressed. The compressed air and high-temperature steam are mixed with fuel (natural gas, biofuels, hydrogen, etc.) and burnt to produce a high-temperature high-pressure gas. The heated compressed gas goes through the gas turbine generating electricity and then to a heat recovery steam generator (HRSG) and up the stack. Effectively the "low-temperature" 550 to 650°C steam is heated with compressed air to the peak gas turbine temperature—which with existing turbines could be as high as 1500°C. Gas turbines can operate at much higher peak temperatures because heat is not transferred through heat exchangers—the temperature limiting component in conventional steam cycles. Again, the incremental heat to electricity efficiency will be above 70%

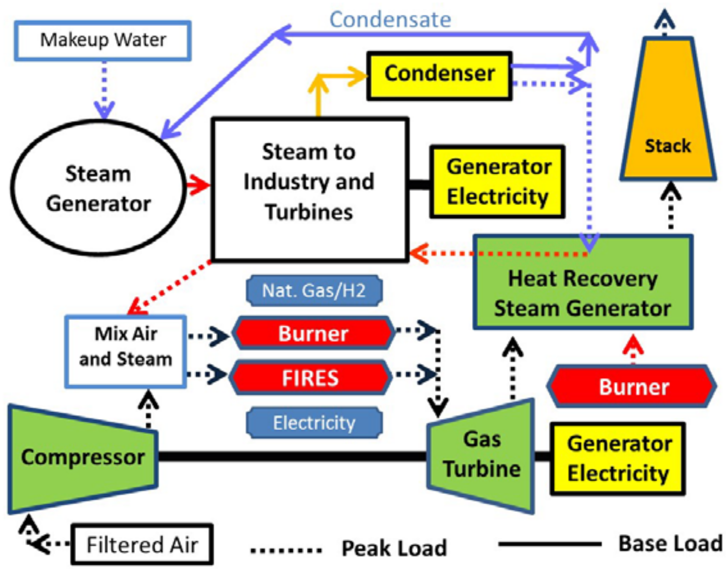

Fig. 8.2. Schematic of Base-load Steam Cycle with Steam-Injection Brayton Topping Cycle

Both of these cycles can be designed with high peak to base-load output. There is the option to add a Firebrick Resistance-heated Energy Storage (FIRES) system [Forsberg et al., July 2017] where low-price electricity is converted to high-temperature stored heat in the form of firebrick and can partly replace the use of natural gas or hydrogen. Firebrick is electrically heated to very high temperatures at times of low prices. The compressed gas goes through the firebrick to be heated. Firebrick is the only heat storage material capable of operating at the peak temperatures of a gas turbine (~1500°C).

This has major implications on the generating mix. Fig. 8.3 shows the total electricity generation in Texas for different carbon constraints. This figure was shown earlier (Fig. 5.1a). Consider the nominal nuclear cost case. Nuclear air-Brayton power cycles have significantly higher incremental natural gas-to-electricity efficiency; that is, lower carbon dioxide emissions that traditional OCGT and CCGT plants. If the costs are similar to traditional nuclear plants, one expects nuclear air-Brayton cycles would enable natural gas to be used at lower carbon constraints. There is one other effect. Such cycles are the most efficient natural gas-to-electricity systems and thus would be expected to be the first "natural gas" plants to start up and the last "natural gas" plants to shut down.

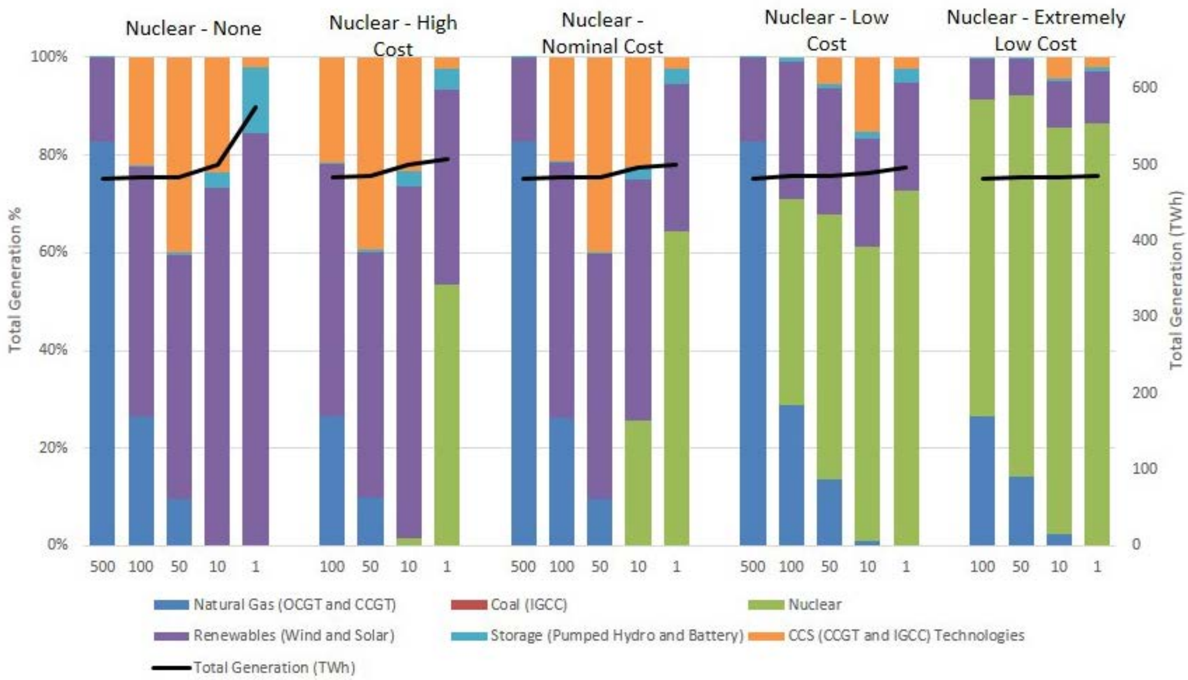

Fig. 8.3. Texas Total Generation Mix versus Carbon Dioxide Constraint

The other implication is that if a low-carbon economy uses more expensive combustible fuels such as hydrogen, such plants have the highest efficiency in converting the combustible fuel to electricity. This strongly favors the development of such technologies if expensive combustible fuels.

8.3. Advance Nuclear Reactor Goals

Historically the market for nuclear power was base-load electricity because low-capital-cost high-operating-cost fossil fuels could provide dispatchable electricity. That resulted in development programs emphasizing reductions in capital cost, fuel cycle sustainability (including safeguards) and safety. In a low-carbon world the market is for dispatchable electricity and energy storage. That can impact total plant revenue by a factor of two—implying that reactor development must start with the market and work backwards to requirements and design. It implies the need to rethink development strategies and may change preferred future reactor choices.

9. Conclusions

Using the GexX model we determined the average price of electricity for an optimized electrical system as a function of allowable carbon dioxide emissions. This was done for Texas (good wind and solar resources), New England (poor wind and solar resources), France, the United Kingdom and two areas of China. In all of the western countries, there were significant increases in the average cost of electricity as tighter carbon dioxide constraints were imposed on the system. In the United States with no carbon constraints, natural gas was the low-cost option and provided most of the electricity. As carbon dioxide constraints limited the use of natural gas, the optimum system used more wind and solar. There was increased use of nuclear energy as the carbon constraints became more limiting. The role of nuclear energy changed from traditional base-load nuclear power to variable electricity output. Nuclear partly replaced fossil fuels in the role of providing dispatchable electricity—providing electricity at times of low wind and solar output. The relative quantities of wind, solar and nuclear for any scenario changed depending upon (1) the quality of wind and solar resources and (2) the cost of nuclear power plants. The exception was China where nuclear energy is the low-cost source of electricity and there was very little change in the cost of electricity as carbon constraints became more restrictive.

We also modeled the six areas with no use of nuclear energy. This resulted in much higher electricity costs—particularly as the carbon dioxide emissions became more constrained. Without dispatchable nuclear energy or an equivalent dispatchable energy source, one must overbuild wind, overbuild solar and install costly storage systems to replace fossil fuels in their role of providing dispatchable electricity. The central observation (Sepulveda, 2018) is that low-carbon futures become very expensive if there is not a low-cost technology to provide dispatchable electricity to replace fossil fuels in this role.

In low-carbon futures, the role of nuclear energy changes. Today that role is base-load electricity. In a low-carbon electricity system, nuclear energy partly replaces fossil fuels in their role of providing dispatchable electricity. The same challenges exist in the industrial and transport sectors—finding a replacement for fossil fuels in their role of providing dispatchable electricity. In this context, we examined the future role of nuclear energy in a low-carbon world.

- *Nuclear energy with heat storage*. There are large economic incentives to develop nuclear power plants with heat storage to provide dispatchable electricity to the grid—replacing fossil fuels in this role. Heat storage is an order-of magnitude less costly than electricity (batteries, pumped hydro, etc.) storage. One operates the nuclear plant at base-load. At times of low-electricity prices heat is sent to storage. At times of high electricity prices, all reactor heat and heat from storage is used to produce peak electricity. Heat storage at the gigawatt-hour scale is currently deployed at some solar thermal power systems to sell electricity at times of high prices and avoid selling at times of low prices.
- *Nuclear co-generation*. The industrial demand for heat is about twice the total electricity output of the United States. In China, the industrial heat demand is larger relative to total electricity production than in the U.S. It will be expensive to reduce carbon dioxide emissions from the industrial sector by direct electrification because electricity is a premium fuel. This creates a large incentive for nuclear co-generation with heat storage to provide electricity to the grid and heat to industry. The coupling of the electricity and industrial sector with heat storage has the potential to significantly lower energy costs in a low-carbon world (Fig. 9.1). First, it enables optimization of the electricity and industrial sectors instead of separate optimization of each sector—with potentially large savings. Second, with the large-scale use of wind and solar, there are times of low or negative electricity prices. Excess electricity from the utility sector can be converted into high-temperature stored heat for industry or production of peak electricity from nuclear power plants.
- *High-temperature reactors*. There are large incentives to develop high-temperature reactors to couple to heat storage. HTRs lower the cost of heat storage and can meet a larger fraction of the industrial heat demand. The cost of heat storage is lowered because there is a larger temperature swing from hot-to-cold in heat storage reducing heat storage system size. In addition, higher

temperature systems have higher heat-to-electricity efficiencies that reduces the amount of heat to be stored.

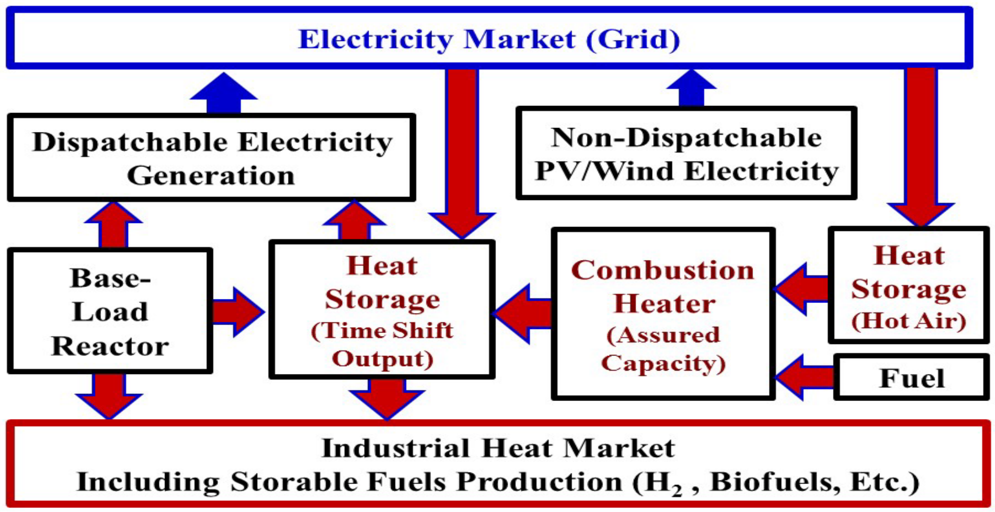

Fig. 9.1. Nuclear Cogeneration System with Heat Storage and Assured Peak Heat and Electricity Output

Last, the market changes create incentives to consider alternative power cycles—specifically nuclear air-Brayton power cycles that operate in two modes: base-load nuclear and a thermodynamic topping cycle where heat can be provided as stored heat or a combustible fuel such as natural gas, biofuels or ultimately hydrogen. The incremental heat-to-electricity efficiency can be over 70%. Such systems become attractive if (1) constraints on carbon dioxide emissions or (2) expensive fuels for peak electricity production.

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Appendix A:

GenX Input Values

This appendix provides all GenX input values used in the analysis. This appendix is from the MIT *Future of Nuclear Energy in a Carbon Constrained World* (September 2017)

Table A.1 Cost Assumptions for Electricity Generation Investments in the United States

Technology	Overnight Cost [$/MW]	Construction Period [years]	Life Time [yr]	Interest Rate	Future Cost [$/MW]	Investment Cost [$/MW-yr]
OCGT	$1,038,000.00	2	20	8%	$1,122,191.82	$114,333.51
CCGT	$1,143,000.00	2	20	8%	$1,235,708.33	$125,899.03
Coal	$3,514,839.91	4	40	8%	$4,116,254.00	$345,345.33
Nuclear (High)	$6,875,000.00	7	40	8%	$9,110,863.69	$764,382.92
Nuclear (Nominal)	$5,500,000.00	7	40	8%	$7,288,690.95	$611,506.33
Nuclear (Low)	$4,100,000.00	7	40	8%	$5,433,387.80	$455,850.18
Nuclear (Very Low)	$2,750,000.00	7	40	8%	$3,644,345.47	$305,753.17
Solar (High)	$1,897,747.42	1	20	8%	$1,972,722.65	$200,989.08
Solar (Nominal)	$916,570.16	1	20	8%	$952,781.54	$97,073.29
Solar (Low)	$551,282.53	1	20	8%	$573,062.32	$58,385.94
Wind (High)	$1,714,103.19	1	20	8%	$1,781,823.09	$181,539.45
Wind (Nominal)	$1,553,387.38	1	20	8%	$1,614,757.81	$164,518.15
Wind (Low)	$1,368,619.70	1	20	8%	$1,422,690.42	$144,949.54
Battery (Nominal)	$1,430,000.00	1	10	8%	$1,486,495.70	$221,573.74
Battery (Low)	$715,000.00	1	10	8%	$743,247.85	$110,786.87
Battery (Very Low)	$429,000.00	1	10	8%	$445,948.71	$66,472.12
Coal IGCC+CCS	$5,875,883	6	30	8%	$7,468,797.41	$663,697.50
Gas CCGT+CCS	$2,215,000	3	25	8%	$2,491,723.88	$233,505.55
Gas CCGT+CCS	$1,720,000	3	25	8%	$1,934,882.65	$181,322.60
Hydro-electric storage	Our scenario assumes that hydro-electric storage capacity is already built, so investment costs for this option are not considered.					

Table A.2 Cost Assumptions for Electricity Generation Investments in China

Technology	Overnight Cost [$/MW]	Construction Period [years]	Life Time [years]	Interest Rate	Future Cost [$/MW]	Investment Cost [$/MW-yr]
OCGT	$542,971.62	2	20	8%	$587,011.86	$59,807.18
CCGT	$597,896.49	2	20	8%	$646,391.67	$65,857.04
Coal	$1,160,273.19	4	40	8%	$1,358,804.17	$114,000.90
Nuclear (Nominal)	$2,796,046.84	7	40	8%	$3,705,367.50	$310,872.79
Nuclear (Low)	$2,084,325.82	7	40	8%	$2,762,183.05	$231,741.54
Solar (High)	$1,389,408.38	1	20	8%	$1,444,300.41	$147,151.25
Solar (Nominal)	$671,053.61	1	20	8%	$697,565.25	$71,070.81
Solar (Low)	$403,613.55	1	20	8%	$419,559.31	$42,746.42
Wind (High)	$1,398,452.48	1	20	8%	$1,453,701.82	$148,109.11
Wind (Nominal)	$1,267,332.36	1	20	8%	$1,317,401.47	$134,222.27
Wind (Low)	$1,116,589.50	1	20	8%	$1,160,703.14	$118,257.20
Battery (Nominal)	$1,430,000.00	1	10	8%	$1,486,495.70	$221,573.74
Battery (Low)	$715,000.00	1	10	8%	$743,247.85	$110,786.87
Battery (Very Low)	$429,000.00	1	10	8%	$445,948.71	$66,472.12
Coal IGCC+CCS	$1,939,670	6	30	8%	$2,465,502.15	$219,091.18
Gas CCGT+CCS	$1,158,653	3	25	8%	$1,303,405.92	$122,145.36
Gas CCGT+CCS	$899,722	3	25	8%	$1,012,125.59	$94,848.77
Hydro-Electric Storage	n/a[1]	n/a[1]	n/a[1]	n/a[1]	n/a[1]	n/a[1]

[1]Our scenarios assume that hydro-electric storage capacity is already built, so investment costs for this option are not considered.

Table A.3 Cost Assumptions for Electricity Generation Investments in the United Kingdom

Technology	Overnight Cost [$/MW]	Construction Period [years]	Life Time [years]	Interest Rate	Future Cost [$/MW]	Investment Cost [$/MW-yr]
OCGT	$865,454.07	2	20	8%	$935,650.75	$95,327.94
CCGT	$953,000.00	2	20	8%	$1,030,297.50	$104,970.94
Coal	$3,514,839.91	4	40	8%	$4,116,254.00	$345,345.33
Nuclear (Nominal)	$8,142,682.93	7	40	8%	$10,790,818.06	$905,327.67
Nuclear (Low)	$6,070,000.00	7	40	8%	$8,044,064.38	$674,880.63
Solar (High)	$1,664,524.56	1	20	8%	$1,730,285.74	$176,288.61
Solar (Nominal)	$803,928.66	1	20	8%	$835,689.86	$85,143.51
Solar (Low)	$483,532.90	1	20	8%	$502,636.07	$51,210.62
Wind (High)	$2,363,445.81	1	20	8%	$2,456,819.61	$250,310.86
Wind (Nominal)	$2,141,847.07	1	20	8%	$2,226,466.06	$226,841.50
Wind (Low)	$1,887,085.04	1	20	8%	$1,961,639.02	$199,859.83
Battery (Nominal)	$1,430,000.00	1	10	8%	$1,486,495.70	$221,573.74
Battery (Low)	$715,000.00	1	10	8%	$743,247.85	$110,786.87
Battery (Very Low)	$429,000.00	1	10	8%	$445,948.71	$66,472.12
Coal IGCC+CCS	$5,875,883	6	30	8%	$7,468,797.41	$663,697.50
Gas CCGT+CCS	$1,846,802	3	25	8%	$2,077,526.56	$194,690.11
Gas CCGT+CCS	$1,434,086	3	25	8%	$1,613,248.61	$151,181.48
Hydro-Electric Storage	n/a[1]	n/a[1]	n/a[1]	n/a[1]	n/a[1]	n/a[1]

[1]Our scenarios assume that hydro-electric storage capacity is already built, so investment costs for this option are not considered.

Table A.4 Cost Assumptions for Electricity Generation Investments in France

Technology	Overnight Cost [$/MW]	Construction Period [years]	Life Time [years]	Interest Rate	Future Cost [$/MW]	Investment Cost [$/MW-yr]
OCGT	$889,973.75	2	20	8%	$962,159.22	$98,028.73
CCGT	$980,000.00	2	20	8%	$1,059,487.46	$107,944.93
Coal	$3,514,839.91	4	40	8%	$4,116,254.00	$345,345.33
Nuclear (Nominal)	$6,797,195.12	7	40	8%	$9,007,755.38	$755,732.34
Nuclear (Low)	$5,067,000.00	7	40	8%	$6,714,872.19	$563,364.11
Solar (High)	$1,657,421.33	1	20	8%	$1,722,901.88	$175,536.31
Solar (Nominal)	$800,497.96	1	20	8%	$832,123.62	$84,780.17
Solar (Low)	$481,469.46	1	20	8%	$500,491.11	$50,992.09
Wind (High)	$1,891,906.43	1	20	8%	$1,966,650.90	$200,370.46
Wind (Nominal)	$1,714,519.63	1	20	8%	$1,782,255.99	$181,583.55
Wind (Low)	$1,510,586.07	1	20	8%	$1,570,265.53	$159,985.09
Battery (Nominal)	$1,430,000.00	1	10	8%	$1,486,495.70	$221,573.74
Battery (Low)	$715,000.00	1	10	8%	$743,247.85	$110,786.87
Battery (Very Low)	$429,000.00	1	10	8%	$445,948.71	$66,472.12
Coal IGCC+CCS	$5,875,882.51	6	30	8%	$7,468,797.41	$663,697.50
Gas CCGT+CCS	$1,899,125.11	3	25	8%	$2,136,386.18	$200,205.99
Gas CCGT+CCS	$1,474,715.66	3	25	8%	$1,658,954.50	$155,464.69
Hydro-Electric Storage	n/a[1]	n/a[1]	n/a[1]	n/a[1]	n/a[1]	n/a[1]

[1]Our scenarios assume that hydro-electric storage capacity is already built, so investment costs for this option are not considered.

Table A.5 Operating Cost Assumptions for the United States

Resource	Unit Size (MW_e)	Fixed O&M Cost ($/$MW_e$-yr)	Variable O&M Cost ($/$MWh_e$)	Heat Rate (MMBTU/MWh_e)	Fuel	Minimum Power (%)	Ramping Capability (%)	Fuel Cost ($/MMBTU)	CO_2 Emissions (tons/MMBTU)
OCGT	200	$7,300	$10.69	9.75	Natural Gas	24%	100%	$7.52	0.053
CCGT	500	$15,800	$3.37	6.43	Natural Gas	38%	70%	$7.52	0.053
IGCC	600	$52,000	$7.34	8.80	Coal	70%	30%	$3.14	0.097
Nuclear	1000	$95,000	$6.89	10.49	Uranium	50%	25%	$1.02	0.000
Wind	1	$51,000	$0.00	n/a	n/a	0%	100%	n/a	n/a
Solar	1	$17,000	$0.00	n/a	n/a	0%	100%	n/a	n/a
Battery	1	$5,000	$0.00	n/a	n/a	0%	100%	n/a	n/a
IGCC (CCS)	600	$73,965	$8.58	8.31	Coal (CCS)	70%	10%	$3.14	0.010
CCGT (CCS)	500	$32,278	$6.89	7.49	Natural Gas (CCS)	30%	70%	$7.52	0.005
Hydro-Electric Storage	(max total = 500)	$4,600	$4.00	n/a	n/a	0%	100%	n/a	n/a

Table A.6 Operating Cost Assumptions for China

Resource	Unit Size (MW_e)	Fixed O&M Cost ($\$/MW_e$-yr)	Variable O&M Cost ($\$/MWh_e$)	Heat Rate ($MMBTU/MWh_e$)	Fuel	Minimum Power (%)	Ramping Capability (%)	Fuel Cost ($/MMBTU)	CO_2 Emissions (tons/MMBTU)
OCGT	200	$5,102	$7.47	9.75	Natural Gas	24%	100%	$12.92	0.053
CCGT	500	$11,043	$2.36	6.43	Natural Gas	38%	70%	$12.92	0.053
IGCC	600	$19,032	$2.69	8.80	Coal	70%	30%	$3.78	0.097
Nuclear	1000	$59,677	$4.33	10.49	Uranium	50%	25%	$0.84	0.000
Wind	1	$40,884	$-	n/a	n/a	0%	100%	n/a	n/a
Solar	1	$60,091	$-	n/a	n/a	0%	100%	n/a	n/a
Battery	1	$5,000	$-	n/a	n/a	0%	100%	n/a	n/a
IGCC (CCS)	600	$73,965	$8.58	8.31	Coal (CCS)	70%	10%	$3.78	0.010
CCGT (CCS)	500	$32,278	$6.89	7.49	Natural Gas (CCS)	30%	70%	$12.92	0.006
Hydro-Electric Storage	(max total = 500)	$4,600	$4.00	n/a	n/a	0%	100%	n/a	n/a

Table A.7 Operating Cost Assumptions for the United Kingdom

Resource	Unit Size (MW_e)	Fixed O&M Cost ($/$MW_e$-yr)	Variable O&M Cost ($/$MWh_e$)	Heat Rate (MMBTU/MWh_e)	Fuel	Minimum Power (%)	Ramping Capability (%)	Fuel Cost ($/MMBTU)	CO_2 Emissions (tons/MMBTU)
OCGT	200	$10,408	$15.24	9.75	Natural Gas	24%	100%	$15.39	0.053
CCGT	500	$22,528	$4.80	6.43	Natural Gas	38%	70%	$15.39	0.053
IGCC	600	$52,000	$7.34	8.80	Coal	70%	30%	$3.14	0.097
Nuclear	1000	$180,759	$13.11	10.49	Uranium	50%	25%	$1.02	0.000
Wind	1	$54,194	$-	n/a	n/a	0%	100%	n/a	n/a
Solar	1	$91,952	$-	n/a	n/a	0%	100%	n/a	n/a
Battery	1	$5,000	$-	n/a	n/a	0%	100%	n/a	n/a
IGCC (CCS)	600	$73,965	$8.58	8.31	Coal (CCS)	70%	10%	$3.14	0.010
CCGT (CCS)	500	$32,278	$6.89	7.49	Natural Gas (CCS)	30%	70%	$70.41	0.040
Hydro-Electric Storage	(max total = 500)	$4,600	$4.00	n/a	n/a	0%	100%	n/a	n/a

Table A.8 Operating Cost Assumptions for France

Resource	Unit Size (MW_e)	Fixed O&M Cost ($/$MW_e$-yr)	Variable O&M Cost ($/$MWh_e$)	Heat Rate (MMBTU/MWh_e)	Fuel	Minimum Power (%)	Ramping Capability (%)	Fuel Cost ($/MMBTU)	CO_2 Emissions (tons/MMBTU)
OCGT	200	$9,811.83	$14.37	$9,811.83	Natural Gas	24%	100%	$15.39	0.053
CCGT	500	$21,236.56	$4.53	$21,236.56	Natural Gas	38%	70%	$15.39	0.053
IGCC	600	$52,000.00	$7.34	$52,000.00	Coal	70%	30%	$3.14	0.097
Nuclear	1000	$115,122.73	$8.35	$115,122.73	Uranium	50%	25%	$1.02	0.000
Wind	1	$93,176.84	$-	$93,176.84	n/a	0%	100%	n/a	n/a
Solar	1	$54,194.30	$-	$54,194.30	n/a	0%	100%	n/a	n/a
Battery	1	$5,000	$-	n/a	n/a	0%	100%	n/a	n/a
IGCC (CCS)	600	$73,964.80	$8.58	8.31	Coal (CCS)	70%	10%	$3.14	0.010
CCGT (CCS)	500	$43,384.84	$9.26	7.49	Natural Gas (CCS)	30%	70%	$70.41	0.040
Hydro-Electric Storage	(max total = 500)	$43,384.84	$9.26	n/a	n/a	0%	100%	n/a	n/a

Appendix B: GenX Sensitivity Studies[8]

A sensitivity study was performed on the costs and technology parameters that were used in GenX for each region. The following sensitivities were performed based on costs from the 2016 NREL analysis (National Renewable Energy Laboratory, 2016). This is from the MIT Future of Nuclear Energy in a Carbon Constrained World (2018) where nuclear reactors can do load following but do not include heat storage:

- Low Renewables/Storage Cost (60% of nominal costs)
- High Renewables/Storage Cost (200% of nominal costs)[9]
- High CCS Cost (130% of nominal cost)
- Low Natural Gas Cost (75% of nominal cost)
- High Natural Gas Cost (125% of nominal cost)
- 99% Efficient CCS Systems (nominal efficiency is 90%)
- Demand Side Resources Considered [10]
- Extreme Weather Year (10% wind and solar capacity for first week in July) [11]

The results of each region's sensitivity study are shown in Figure 1.B.1 to 1.B.6. We use the same definition of opportunity cost as in Table 1.5a.

$$Opportunity\ Cost = \begin{pmatrix} Average\ cost\ of\ electricity \\ generation\ without\ nuclear \\ technologies\ available \end{pmatrix} - \begin{pmatrix} Average\ cost\ of\ electricity \\ generation\ with\ nuclear \\ technologies\ available \end{pmatrix}$$

[8] Excerpted from "The Future of Nuclear Energy in a Carbon-Constrained World," September 1,2018

[9] This is the current (2017) cost of renewables and storage. This sensitivity represents the scenario where costs are not reduced in the next 30 years.

[10] Demand side resources are the ability of the grid operator to shift demand when generation is low as well as the ability of electricity consumers to curb demand when prices are too high. It is assumed that the grid operator can shift up to 5% of demand each hour, with a maximum shift of 6 hours. The amount that consumers will curb demand depends on how much they value the electricity. See Appendix 1.A from the MIT *Future of Nuclear Energy in a Carbon Constrained World* for the assumed inputs for value of electricity. See Sepulveda M.S. Thesis (2016) for electricity values (pp86 – Table 4.6)

[11] We have represented an extreme weather year for low renewable potential. We have done this by arbitrarily lowering the renewable potential for both wind and solar during the entire first week of July to 10% of its original value. This time of the year was chosen arbitrarily to illustrate the effect of prolonged cloudy and windless days.

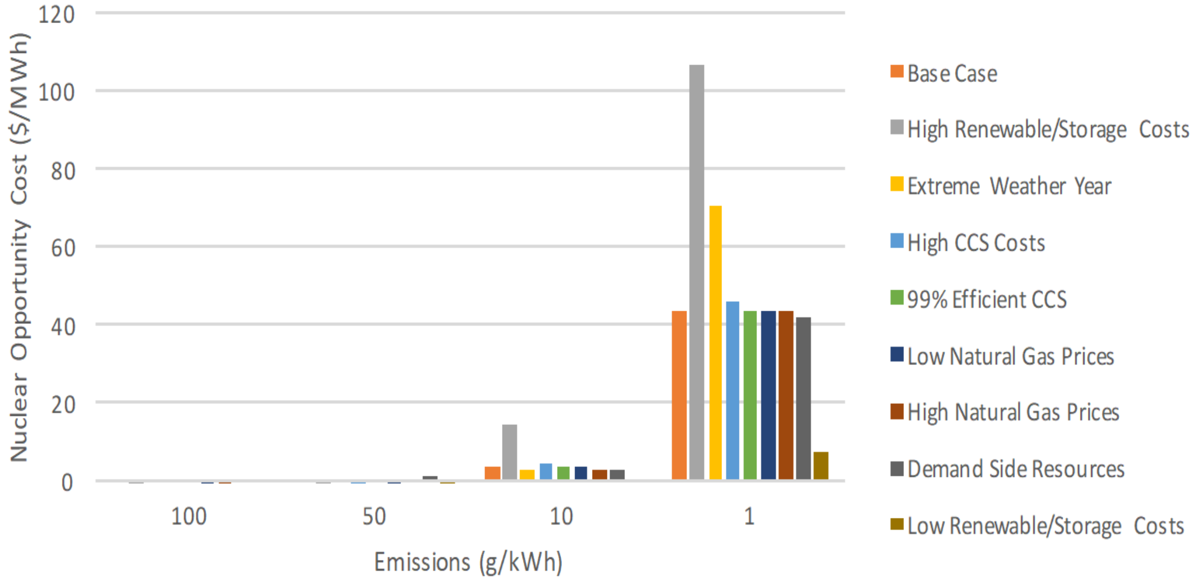


Fig. B.1: Texas Sensitivity Study

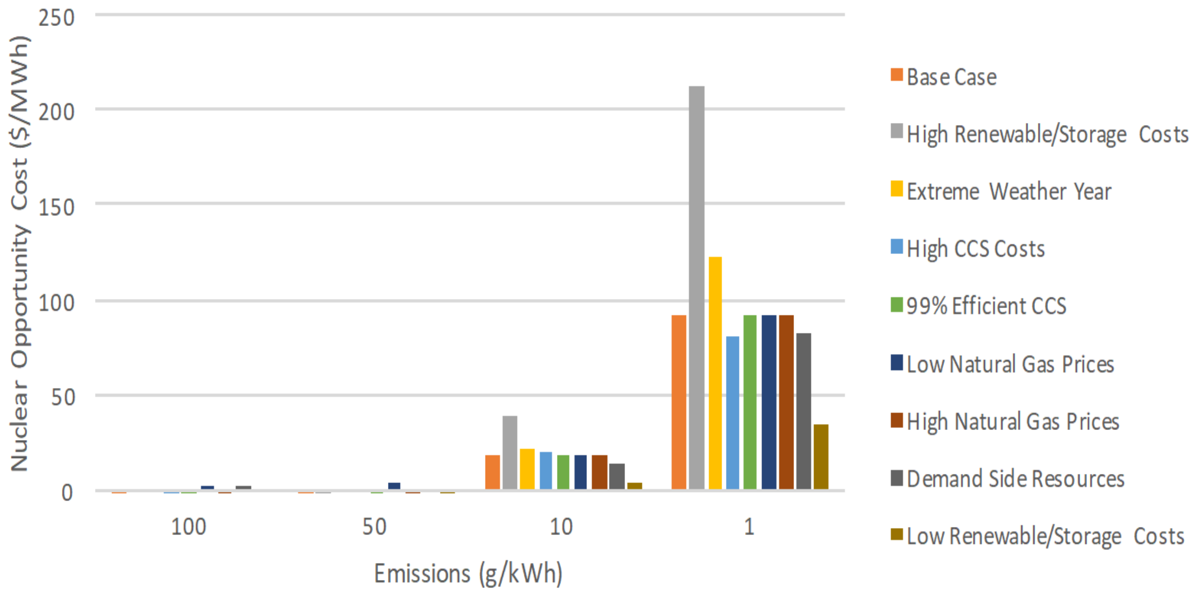


Fig. B.2: New England Sensitivity Study

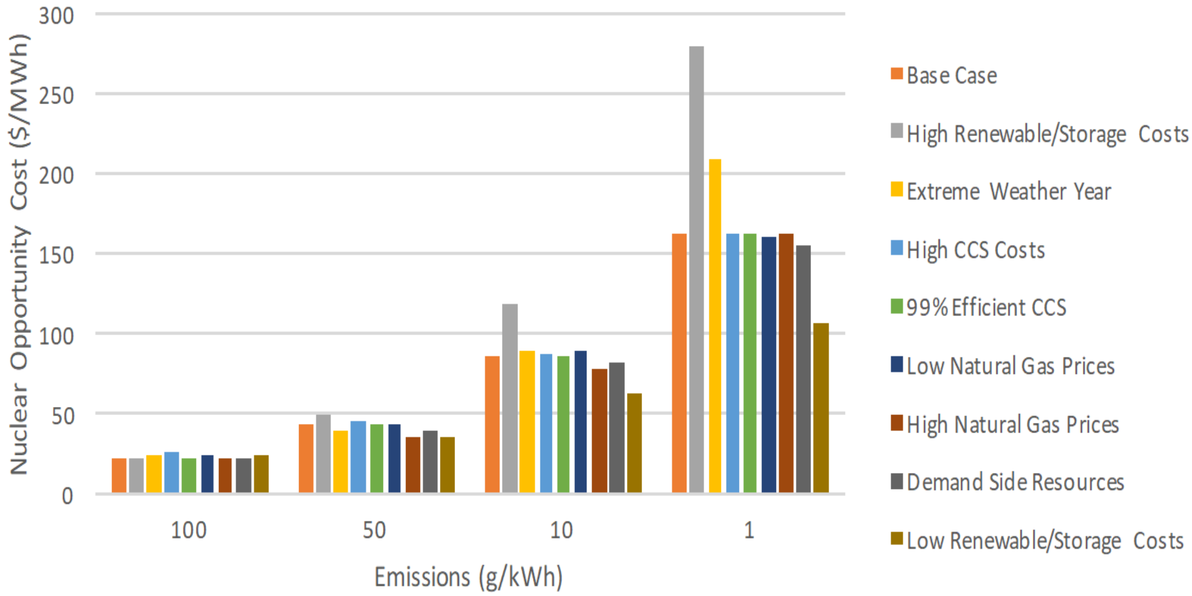


Fig. B.3: T-B-T Sensitivity Study

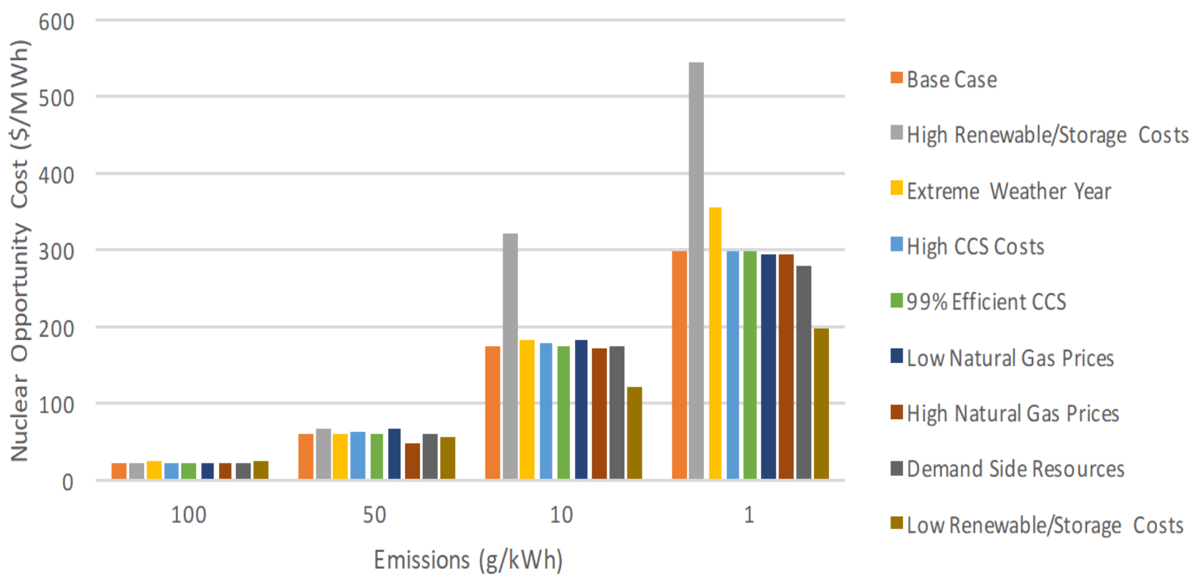


Fig. B.4: Zhejiang Sensitivity Study

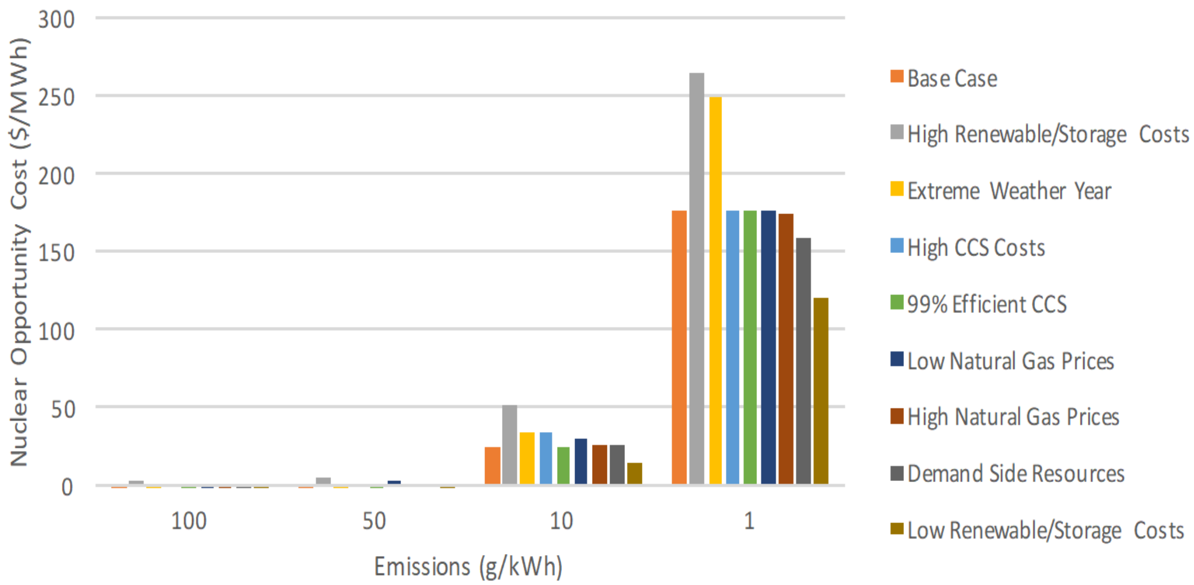


Fig. B.5: United Kingdom Sensitivity Study

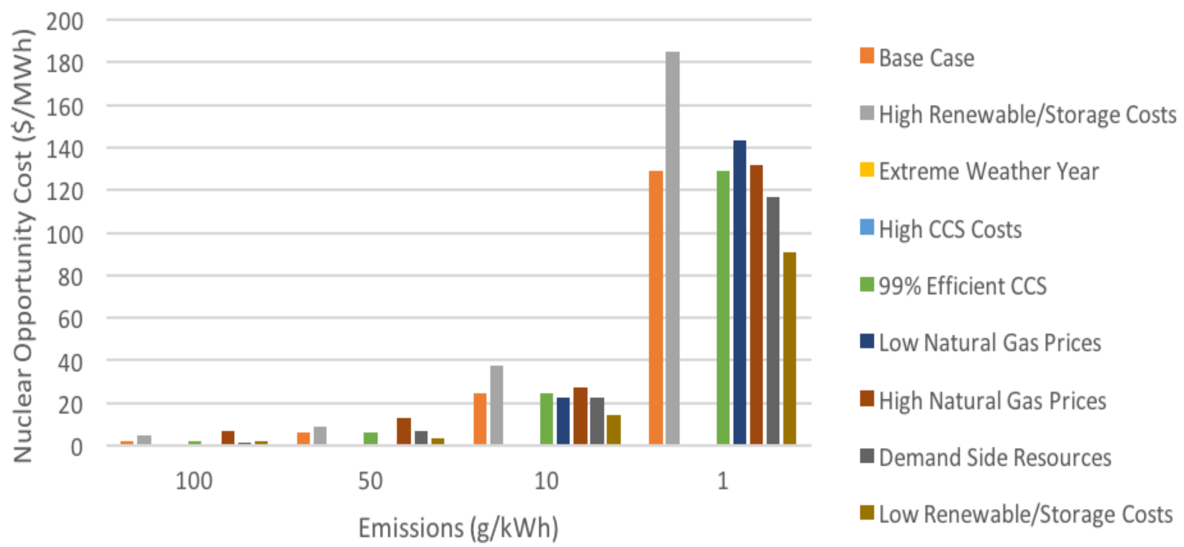


Fig. B.6: France Sensitivity Study

Appendix C: Equivalent Cost of Carbon

One can calculate the equivalent cost of carbon using the data created by GenX. The equation is:

Cost-of-Carbon = 1000*(delta $/MWh) / (delta gm-CO2/kWh)

Table C.1 shows the results of this calculation for the Texas ISO. There are several caveats. This method calculates the incremental cost of carbon going from one emission level to the next emission level. The total carbon tax equivalent to go from 500 to 1 g/kWh is the sum of the numbers in that column. The uncertainties associated with the calculated cost of electricity can be as high as 5%. When one sees small variations in the average cost of electricity with tighter carbon restrictions, such as the extremely low-cost nuclear option going from 100 to 10 g/kWh, the calculated carbon cost has large uncertainties because one is subtracting two large numbers that are about the same size with uncertainties[12] with each number.

TEXAS	**Average Generation Cost ($/MWh)**				
Emissions (g/kWh)	**Nuclear - None**	**Nuclear - High Cost**	**Nuclear - Nominal Cost**	**Nuclear - Low Cost**	**Nuclear - Extremely Low Cost**
500	$76.52		$76.32	$76.51	
100	$86.34	$86.29	$86.18	$84.54	$74.52
50	$90.96	$90.46	$90.23	$88.34	$75.93
10	$105.4	$105.42	$101.93	$93.46	$79.45
1	$162.9	$133.21	$119.10	$102.46	$84.47
Cost of Carbon ($/mton-CO2)	**Nuclear - None**	**Nuclear - High Cost**	**Nuclear - Nominal Cost**	**Nuclear - Low Cost**	**Nuclear - Extremely Low Cost**
500 - to - 100	$25	$24	$25	$20	
100 - to - 50	$92	$84	$81	$76	$28
50 - to - 10	$363	$374	$292	$128	$88
10 - to - 1	$6,391	$3,087	$1,907	$1,001	$557

Table C.1. Cost of Carbon for Texas as Reduce Carbon Emissions

As expected, the carbon equivalent taxes for New England are higher than for Texas. The results follow the analysis results as would be expected.

[12]The GenX method optimizes the electricity generation system capacity mix based on minimizing the objective function of total generation cost in a year for a given market. There is an inherent error in this minimization procedure. The maximum expected error is depicted in the figures in this report by the brackets. Those uncertainties are in these calculations. Results excerpted from *The Future of Nuclear Energy in a Carbon-Constrained World*, September 1, 2018

New England	Average Generation Cost ($/MWh)		
Emissions (g/kWh)	Nuclear – None	Nuclear - Nominal Cost	Nuclear - Low Cost
500	$78.23	$78.21	$77.01
100	$95.00	$97.08	$88.11
50	$98.20	$99.74	$92.53
10	$128.06	$110.13	$96.42
1	$214.09	$122.36	$103.72
Cost of Carbon ($/mton-CO2)	Nuclear – None	Nuclear - Nominal Cost	Nuclear - Low Cost
500 - to - 100	42	47	28
100 - to - 50	64	53	88
50 - to - 10	746	260	97
10 - to - 1	9559	1359	811

Table C.2. Cost of Carbon for New England as Reduce Carbon Emissions

T-B-T	Average Generation Cost ($/MWh)		
Emissions (g/kWh)	Nuclear - None	Nuclear - Nominal Cost	Nuclear - Low Cost
No limit	$57.27	$57.40	$53.47
500	$66.21	$57.83	$53.48
100	$79.43	$57.97	$52.89
50	$99.95	$57.46	$52.76
10	$141.93	$58.06	$52.90
1	$221.71	$59.30	$54.74
Cost of Carbon ($/mton-CO2)	Nuclear - None	Nuclear - Nominal Cost	Nuclear - Low Cost
No-Limit - to - 500	$17.88	$0.86	$0.02
500 - to - 100	$33.06	$0.35	$(1.49)
100 - to - 50	$410.29	$(10.11)	$(2.50)
50 - to - 10	$1,049.65	$14.86	$3.41
10 - to - 1	$8,864.40	$137.82	$205.14

Table C.3. Cost of Carbon for T-B-T China as Reduce Carbon Emissions

France	Average Generation Cost ($/MWh)		
Emissions (g/kWh)	Nuclear – None	Nuclear - Nominal Cost	Nuclear - Low Cost
500	$103.29	$102.85	$99.18
100	$123.79	$123.78	$107.82
50	$129.04	$125.14	$107.91
10	$151.67	$131.32	$112.98
1	$274.55	$148.64	$121.28
Cost of Carbon ($/mton-CO2)	**Nuclear – None**	**Nuclear - Nominal Cost**	**Nuclear - Low Cost**
500 - to - 100	51.3	52.3	21.6
100 - to - 50	105.1	27.2	1.8
50 - to - 10	565.5	154.5	126.6
10 - to - 1	13653.4	1924.9	922.2

Table C.4. Cost of Carbon for France as Reduce Carbon Emissions

Appendix D. Heat Storage for High-Temperature Reactors

Heat storage is cheap relative to other energy storage technologies. The U.S. DOE goal for battery storage is $150/kwh(e)—about double that if the power electronics and other equipment to couple batteries to the grid for storage are included. The DOE heat storage goal is $15/kwh(t) for concentrated solar thermal power systems with several advanced heat storage technologies that are expected to cost significantly below that number. This large cost difference is why some solar thermal power plants now have gigawatt-hour heat storage to avoid selling electricity at times of low prices but there are no equivalent-scale battery storage facilities. A recent report [Forsberg and Sabharwall, 2018] summarized many of the storage options for GenIV reactors including the HTGR and FHR. Many but not all HTR heat storage technologies are similar to or identical to those used for concentrated solar thermal power systems. There are three ways to couple heat storage to HTRs.

D.1. HTGR (350 to 750°C) with heat storage at pressure.

There are two strategies. The first option is to use the reactor core heat capacity to provide heat storage. The reactor core is allowed to go up and down in temperature. Japan [Sato and Yan, 2019] is investigating this option in the context of a high-temperature HTGR with a direct gas-turbine power cycle. This option has relatively limited heat storage capabilities but very fast response times for stabilizing the electricity grid. The proposed system is coupled to a hydrogen plant where heat is used to produce hydrogen from water. Longer-term and much larger variations of electricity to the grid with base-load reactor operations are achieved by varying heat to the power cycle versus heat for electricity generation.

The second option is to have a separate pressure vessel with the heat storage material. The heat storage media (firebrick, steel, etc.) is heated and cooled by primary-system helium. This option minimizes temperature drops in heat storage because heat does not go across heat exchangers (D.1). A major expense is the pressure vessel—thus this option may be good for storage for hours but not many days.

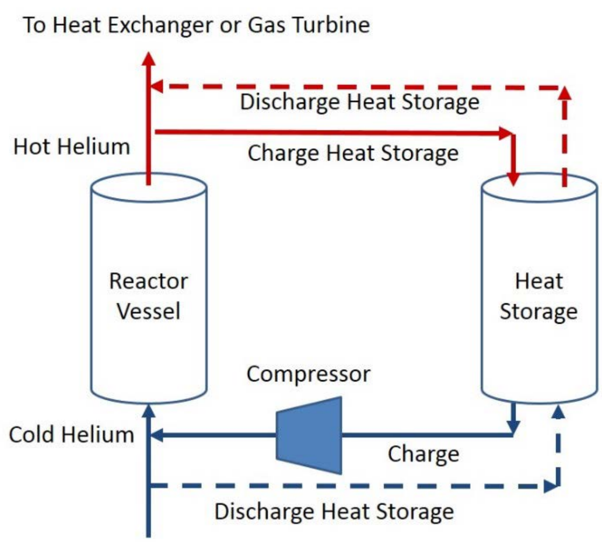


Fig. D.1. HTGR with At-Pressure Heat Storage

High-pressure heat storage is being developed for adiabatic compressed air storage (ACAS). In an ACAS system [Zunft, 2014], as shown in Fig. D.2, at times of low electricity prices, air is compressed to

90 bars and 600°C, goes through a regenerative heat storage system and is injected into an underground cavern at 40°C. At times of high electricity prices, compressed air is sent through the heat storage system and a turbine to produce peak electricity. The same heat storage system and prestressed concrete pressure vessel could be coupled to a modular HTGR. There are many variants of this system.

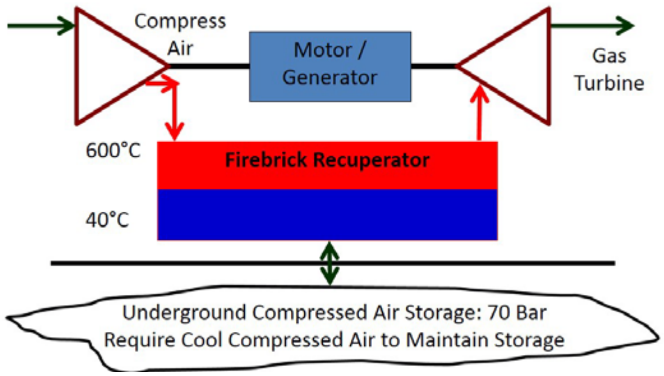


Fig. D.2. Adiabatic Compressed Air Storage

Fig. D.3 shows drawings of ACAS and some of the experimental work that has been done to develop the large pressure vessel with a brick recuperator.

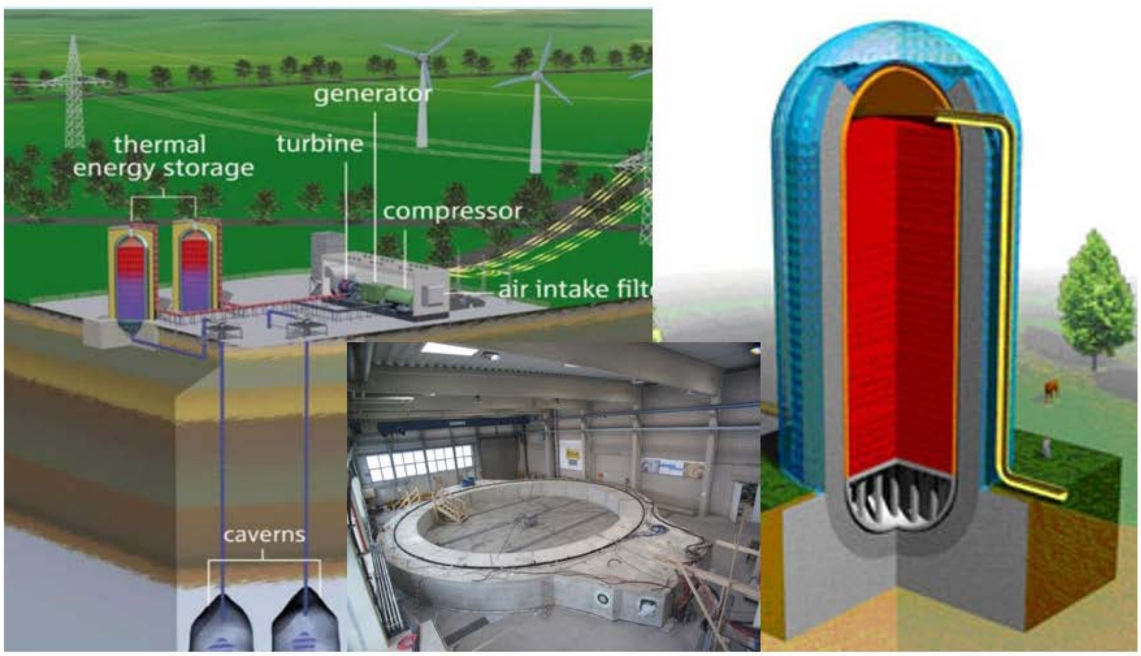


Fig. D.3. Project Adele system, laboratory section of prestressed pressure vessel and schematic of the pressure vessel. Courtesy of General Electric, RWE AG, and Zublin.

D.2. Modular HTGR (350 to 750°C) or salt reactor (600 to 700°C) with heat storage on the other side of a heat exchanger.

The large temperature difference drives down the cost of sensible heat storage with a large hot-to-cold temperature drop. In the near-term nitrate salts are the leading heat storage candidate (same as used in solar thermal power systems). Longer term options include chloride salts and hot rocks as the heat storage media. There are other longer-term options including phase change materials.

Today the leading near-term heat storage system for HTGRs and FHRs is nitrate-salt heat storage using a two-tank system—essentially the same system used at the gigawatt-hour scale for concentrated solar power systems. In a two tank system (Fig. D.4) at times of low demand, heat is sent to industry with just enough hot salt sent to the power system to operate it at minimum load to keep the turbine-generator on-line for fast return to full power. The remainder of the hot salt goes to the hot-salt storage tank. Cold return salt from industry, the power cycle and cold salt from the cold-salt storage tank goes back to the reactor. At times of high power and/or industrial heat demand, hot salt from the reactor and from the hot-salt storage tank goes to industry and the power cycle. Part of the cold salt from the power cycle goes to the reactor and part goes to the cold-salt storage tank.

The most recent work coupling HTRs with salt storage has been done for salt-cooled reactors. The U.S. Next Generation Nuclear Plant to deploy a modular HTGR did not look at heat storage because the major development effort was undertaken just before electricity price collapse became a common feature of markets with large-scale deployment of wind or solar.

In an FHR, the minimum reactor salt temperature is somewhere near 550°C. To minimize heat storage costs, the nitrate salt can provide heat to the power cycle down to its minimum temperature—typically near 280°C. This minimizes the cost of heat storage since a large temperature change in the nitrate salt reduces heat storage costs. However, if this is done, the return nitrate salt temperature will be significantly below the freezing point of the reactor salt (Flibe salt, T_{melt} = 459°C). To avoid freezing the reactor salt, hot nitrate salt is mixed with cold nitrate salt to meet whatever temperature requirements are needed for the nitrate salt/reactor salt heat exchanger.

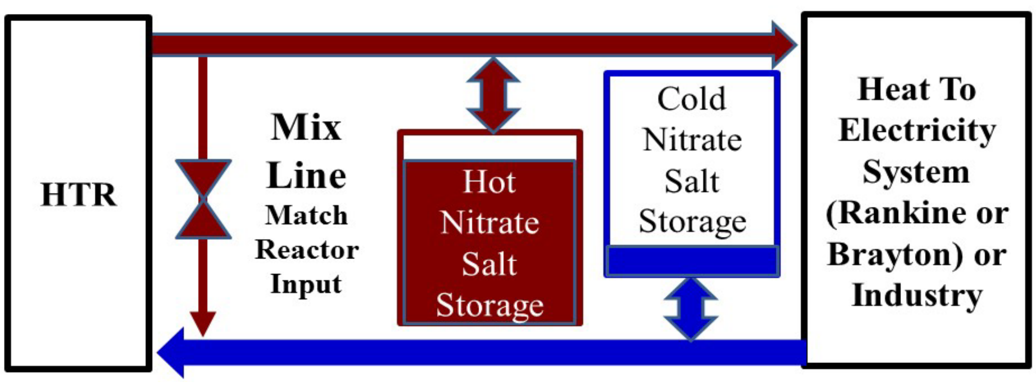


Fig. D.4. Two-Tank Liquid-Salt Heat Storage

With HTGRs, typical peak helium exit temperatures are 750°C—exceeding the temperature limits of current nitrate salts. Work is underway on chloride salts (mixtures of sodium, potassium and magnesium chlorides) with temperature limits over 1000°C for advanced solar power towers that will create higher-temperature salt storage options. Preliminary estimates are that such salts will cost about $7/kWh(t), a major reduction in storage costs.

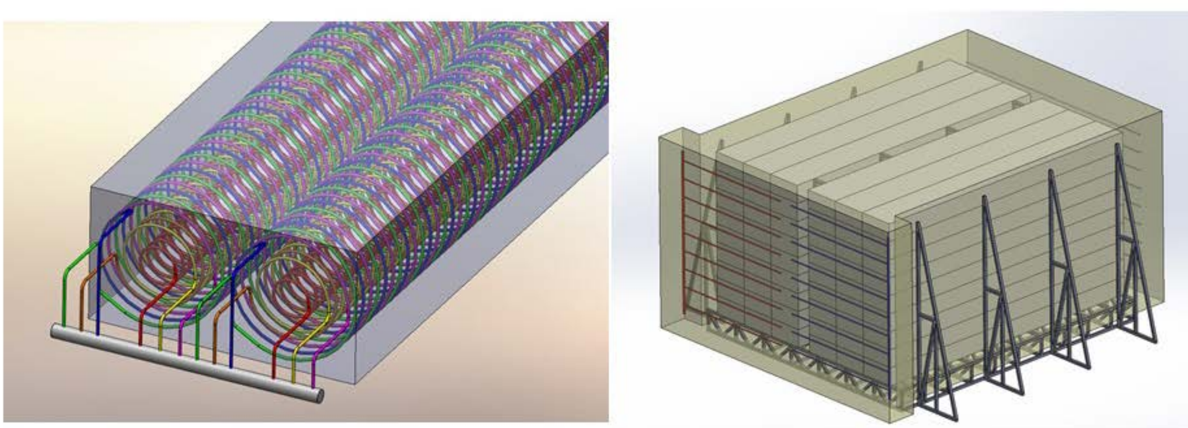
One of the near-term challenges of FHRs is that tritium is generated in the coolant and can escape through the heat exchangers. This is also a concern in HTGRs but the quantities of tritium are much smaller. By using a nitrate salt, any tritium that diffuses through the heat exchangers is oxidized to tritiated water, trapped in the nitrate loop (water does not diffuse through heat exchangers) and removed as steam from the off-gas system. The nitrate loop provides two functions: (1) heat storage and (2) backup tritium removal system. The use of a secondary nitrate loop to capture tritium was first investigated in the 1970s for the molten salt reactor program [Bohlmann, 1972]. It was concluded that the system would work but it was not adopted because of the added cost of the nitrate loop. At that time there was no economic rationale for heat storage. Today there is an economic rationale which is why nitrate storage is being considered for FHRs [Kairos Power, 2018] for the dual purposes of secondary tritium control and variable electricity from a base-load reactor.

There may or may not be differences in heat storage coupled to a nuclear system versus heat storage coupled to a concentrated solar power system. The same is true if one sends heat to an industrial customer. With traditional nuclear cogeneration plants, there is an isolation heat exchanger between the nuclear supplied heat and the district heating system or industrial customer. If one adds large-scale storage, the storage system in some cases may eliminate isolation heat exchangers or add other complications.

D.3. Heat storage using cement in high-temperature steam cycles.

There is ongoing work to incorporate heat storage into high-temperature high-pressure steam cycles. One example is using high-temperature cements with cement monoliths with high-pressure steam pipes running through the cement monolith. At times of low-prices, steam heats the cement and condenses. To recover heat, hot water flows in the reverse direction and is converted to high-temperature high-pressure steam. The goal is to enable heat storage coupled to steam cycles that operate at 600°C.

Figure D.5 shows one such system being developed by Bright Energy Storage Technologies. The initial market is for coal plants to improve dispatchability—reduce electricity sales when prices are low and added peak power when prices are high. On the left is a cutaway view of the concrete thermal energy storage module, the different colors on the tubes do not have significance other than a visual cue to track them, all of the tubes are attached to the same header/steam source. The assembly view is a pilot/demo-sized system, designed to deliver 10 MWh_e at a coal plant, with a hot inlet on the left and cold outlet on the right. The far side of the assembly is manifolded from left stack to right stack. The individual modules are 1 m wide x 0.5 m tall x 12 m long (14.6 metric tons). The system is designed to go to 600°C. It could likely go to higher temperatures but to date tests have only been conducted to 600°C. The exergetic efficiency is ~86% with expected heat losses to the environment of less than 1% per day. The same technology would be applicable to any high-temperature reactor with a high-temperature steam cycle.



D.5. High-Temperature Cement-Based Storage System [Bright Energy Storage Technologies, Arvada, CO].

Historically cement-based heat storage systems have been limited to lower temperatures [Laing 2015]. The viability of these systems depends upon non-Portland-based cements that are capable of peak temperatures to ~800°C [UHM, 2019]. These systems are in the early stages of development.

D.4. References

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