WORLD NUCLEAR ASSOCIATION

Nuclear Power in the USA

(Updated 16 March 2017)

- **The USA is the world's largest producer of nuclear power, accounting for more than 30% of worldwide nuclear generation of electricity.**
- **The country's 100 nuclear reactors produced 798 billion kWh in 2015, over 19% of total electrical output. There are four reactors under construction.**
- **Following a 30-year period in which few new reactors were built, it is expected that four more new units will come online by 2021, these resulting from 16 licence applications made since mid-2007 to build 24 new nuclear reactors.**
- **Government policy changes since the late 1990s have helped pave the way for significant growth in nuclear capacity.**
- **Some states have liberalized wholesale electricity markets, which makes the financing of capital-intensive power projects difficult, and coupled with lower gas prices since 2009, have put the economic viability of some existing reactors and proposed projects in doubt.**

In 2014, the US electricity generation was 4094 TWh (billion kWh) net, 1582 TWh (39%) of it from coal-fired plant, 1138 TWh (28%) from gas, 797 TWh (19.5%) nuclear, 259 TWh from hydro, and 279 TWh from other renewables (EIA data). EIA figures show 727.5 TWh from nuclear in 2015, 19.3% of the total. Provisional IEA figures show 4331 TWh gross in 2014. Import from Canada in 2013 was 52 TWh net and from Mexico 7 TWh net. Annual electricity demand is projected to increase to 5,000 billion kWh in 2030, though in the short term it is depressed and has not exceeded the 2007 level. Annual per capita electricity consumption in 2013 was 11,955 kWh. Total net summer capacity is 1060 GWe, less than one-tenth of which is nuclear.

Nuclear power plays a major role. The USA has 99 nuclear power reactors in 30 states, operated by 30 different power companies, and in 2015 they produced 798 TWh. Since 2001 these plants have achieved an average capacity factor of over 90%, generating up to 807 billion kWh per year and accounting for 20% of total electricity generated. Capacity factor has risen from 50% in the early 1970s, to 70% in 1991, and it passed 90% in 2002, remaining at around this level since. In 2015 it was a record 91.9%. The industry invests about $7.5 billion per year in maintenance and upgrades of the plants.

There are 65 pressurized water reactors (PWRs) with combined capacity of about 64 GWe and 34 boiling water reactors (BWRs) with combined capacity of about 35 GWe – for a total capacity of 99,062 MWe (see Nuclear Power in the USA Appendix 1: US Operating Nuclear Reactors). Almost all the US nuclear generating capacity comes from reactors built between 1967 and 1990. Until 2013 there had been no new construction starts since 1977, largely because for a number of years gas generation was considered more economically attractive and because construction schedules during the 1970s and 1980s had frequently been extended by opposition, compounded by heightened safety fears following the Three Mile Island accident in 1979. A further PWR – Watts Bar 2 – started up in 2016 following Tennessee Valley Authority's (TVA's) decision in 2007 to complete the construction of the unit.

Despite a near halt in new construction of more than 30 years, US reliance on nuclear power has grown. In 1980, nuclear plants produced 251 billion kWh, accounting for 11% of the country's electricity generation. In 2008, that output had risen to 809 billion kWh and nearly 20% of electricity, providing more than 30% of the electricity generated from nuclear power worldwide. Much of the increase came from the 47 reactors, all approved for construction before 1977, that came on line in the late 1970s and 1980s, more than doubling US nuclear generation capacity. The US nuclear industry has also achieved remarkable gains in power plant utilisation through improved refuelling, maintenance and safety systems at existing plants. Average generating cost in 2014 was $36.27 per MWh ($44.14 at single-unit sites and $33.76 at multi-unit sites), including fuel and capital, and average operating cost was $21/MWh.

While there are plans for a number of new reactors (see section on Preparing for new build below), no more than four more new units will come online by 2021. Since about 2010 the prospect of low natural gas prices continuing for several years has dampened plans for new nuclear capacity. In May 2016 the Energy Information Administration (EIA) said that nearly 19 GWe of new gas-fired generation capacity was expected online by 2019, mostly using shale gas. It later reported that 9 GWe of gas capacity had come online in 2016, along with 8.7 GWe wind and 7.7 GWe solar. There was a net capacity gain in 2016 of 15 GWe after about 12 GWe retirements.

The four AP1000 reactors under construction at Vogtle and Summer will be eligible for subsidies similar but significantly less than those applied to wind power generation. Under the Energy Policy Act 2005, up to 6,000 MWe is eligible for production tax credits, divided pro-rata among those applicants which filed combined construction and operating licence (COL) applications by the end of 2008 and commenced construction of advanced plants by 2014, as these did, and which enter service by 2021. The level is $18 per MWh, for eight years.

In February 2013 Duke Energy's 860 MWe Crystal River PWR in Florida was decommissioned due to damage to the containment structure sustained when new steam generators were fitted in 2009-10, under previous owner Progress Energy. Its 40-year operating licence was due to expire in 2016. Some $835 million in insurance was claimed. Dominion Energy's 566 MWe Kewaunee PWR in Wisconsin was decommissioned in May 2013, after 39 years operation. Then in June 2013 the two 30-year old PWR reactors (1070 & 1080 MWe) at San Onofre nuclear plant in California were retired permanently due to regulatory delay and uncertainty following damage in the steam generators of one unit.* In August 2013 Entergy announced that its 635 MWe Vermont Yankee reactor would be closed down at the end of 2014 as it had become uneconomic, and this was done.

* An economic study claimed that Californian generating costs rose by $350 million in the following year and carbon emissions by 9 million tonnes per year as a result.[9]

Ten other nuclear plants (13 reactors) were considered (at the start of 2014) to be at risk of closure, all but one of these in the northeast of the country, in deregulated states. The factors giving rise to uncertainty are high costs with low power prices, regulatory issues, and local concerns with safety and reliability. The Nuclear Energy Institute (NEI) said in December 2015 that "total electric generating costs at US nuclear plants have increased 28% – to an industry average $36.27 per MWh – over the past 12 years," including fuel, capital and operation and maintenance costs. It announced an initiative coordinated with the Nuclear Regulatory Commission (NRC) to cut electricity production costs by 30% by 2018.

US power plant shutdowns over 2010 to 2013 comprised 19,772 MWe of coal plant, 12,167 MWe natural gas, 6793 MWe oil-fired, 3554 MWe nuclear and less than 1000 MWe other (NEI, quoting Ventyx).

Coal is projected to retain the largest share of the electricity generation mix to 2035, though by 2020 about 49 GWe of coal-fired capacity is expected to be retired, due to environmental constraints and low efficiency, coupled with a continued drop in the fuel price of gas relative to coal. Coal-fired capacity in 2011 was 318 GWe. In 2014 the USA added 15.45 GWe of new generation capacity, 7.9 GWe of which was gas-fired, almost entirely (92%) CCGT. The predominance of CCGT is driven by low gas prices, strict regulation of coal-fired plants, and the need to back-up intermittent renewables input.

Given that nuclear plants generate nearly 20% of the nation's electricity overall and 63% of its carbon-free electricity, even a modest increase in electricity demand would require 13.2 GWe of new nuclear capacity by 2025 in addition to the five nuclear plants currently under construction in order to maintain this share. If today's nuclear plants retire after 60 years of operation, 22 GWe of new nuclear capacity would be needed by 2030, and 55 GWe by 2035 to maintain a 20% nuclear share.

Capital expenditure on existing nuclear plants peaked in 2012 due to post-Fukushima upgrades, and it declined 26% to 2015 when capital investment in operating plants was $6.25 billion, according to the Nuclear Energy Institute.

Background to nuclear power

The USA was a pioneer of nuclear power development.[a] Westinghouse designed the first fully commercial pressurised water reactor (PWR) of 250 MWe capacity, Yankee Rowe, which started up in 1960 and operated to 1992. Meanwhile the boiling water reactor (BWR) was developed by the Argonne National Laboratory, and the first commercial plant, Dresden 1 (250 MWe) designed by General Electric, was started up in 1960. A prototype BWR, Vallecitos, ran from 1957 to 1963.

By the end of the 1960s, orders were being placed for PWR and BWR reactor units of more than 1000 MWe capacity, and a major construction program got under way. These remain practically the only types built commercially in the USA.[b]

Nuclear developments in USA suffered a major setback after the 1979 Three Mile Island accident, though that actually validated the very conservative design principles of Western reactors, and no-one was injured or exposed to harmful radiation. Many orders and projects were cancelled or suspended, and the nuclear construction industry went into the doldrums for two decades. Nevertheless, by 1990 over 100 commercial power reactors had been commissioned.

Most of these were built by regulated utilities, often state-based, which meant that they put the capital cost (whatever it turned out to be after, for example, delays) into their rate base and amortised it against power sales. Their consumers bore the risk and paid the capital cost. (With electricity deregulation in some states, the shareholders bear any risk of capital overruns and power is sold into competitive markets.)

Operationally, from the 1970s the US nuclear industry dramatically improved its safety and operational performance, and by the turn of the century it was among world leaders, with average net capacity factor over 90% and all safety indicators exceeding targets.

This performance was achieved as the US industry continued deregulation, begun with passage of the Energy Policy Act in 1992. Changes accelerated after 1998, including mergers and acquisitions affecting the ownership and management of nuclear power plants.

Electricity market challenges, EPA Clean Power Plan

About 54 GWe of US nuclear capacity is in regulated markets, and 45 GWe in deregulated merchant markets, with power sold competitively on a short-term basis. In these liberalized markets, regional transmission organisations (RTOs) and independent system operators (ISOs) operate the grid, using free-market auctions and longer-term power purchase agreements. See NEI listing.

In states with deregulated electricity markets, nuclear power plant operators have found increasing difficulty with competition on two fronts: low-cost gas, particularly from shale gas developments, and subsidized wind power with priority grid access. The imposition of a price on carbon dioxide emissions would help in competition with gas and coal, but this is not expected in the short term. Single-unit plants which tend to have higher operating costs per MWh are most vulnerable. The basic problem is low natural gas prices allowing gas-fired plants to undercut power prices. A second problem is the federal production tax credit of $22/MWh paid to wind generators, coupled with their priority access to the grid. When there is oversupply, wind output is taken preferentially. Capacity payments can offset losses to some extent, but where market prices are around $35-$40/MWh, nuclear plants are struggling. According to Exelon, the main operator of merchant plants and a strong supporter of competitive wholesale electricity markets, low prices due to gas competition are survivable, but the subsidized wind is not. In 2016 the subsidy (production tax credit) is $23/MWh. Though wind is a very small part of the supply, and is limited or unavailable most of the time, its effect on electricity prices and the viability of base-load generators "is huge".

Entergy's six merchant units benefited from unusually cold weather and tight power supplies during the two winters to 2014, but the company warned that the power supply situation in the Northeast remained uncertain.

In February 2014 the Nuclear Energy Institute (NEI) warned: "Absent necessary changes in policies and practices, this situation has implications for reliability, long-term stability of electricity prices, and our ability to meet environmental goals." In April 2014 the heads of the NEI, Edison Electric Institute and Electric Power Supply Association urged the Federal Energy Regulatory Commission (FERC) to continue its efforts to improve US electricity and capacity markets. While the nation's electricity supply and delivery system largely passed the 'stress test' imposed by extreme cold weather from the polar vortex earlier in the year, the weather events raised reliability and market design issues that should be addressed, they said. Grid operators found that problems in bringing coal and gas capacity online had brought the North Atlantic grid close to breakdown. The situation was saved by a very high level of nuclear availability. “FERC reforms of competitive wholesale power markets as to market design, tariff rules and grid operator practices” are needed to improve investment signals and provide the portfolio of resources necessary to maintain grid reliability.

In May 2014 five Exelon reactors at three plants – Oyster Creek, Quad Cities and Byron – for the first time failed to clear the PJM Interconnection capacity auction for three years ahead, 2017-2018, so will not receive capacity payments or an assured market for 12 months then, despite having been a reliable basis of supply in New Jersey and Illinois for decades, and zero-carbon sources. The clearing price was $120/MWe-day (except for part of New Jersey: $215/MWe/day). This was for 167 GWe, which included a 19.7% reserve margin. About 4.8 GWe of new combined cycle gas plant was successful in the auction, along with almost 11 GWe of demand-side response. PJM said that capacity prices account for about 10 to 15% of retail bills – the above price nominally being 0.5c/kWh.

In August 2015, three Exelon merchant plants (four reactors) failed to clear the capacity auction for 2018-19 – Oyster Creek, Quad Cities and Three Mile Island. Byron did clear it. The clearing price was $167/MWe-day (except for two small areas: $215 and $225/MWe-day) under new rules offering bonuses for reliability and penalties for failure to supply. Exelon noted: "This auction was the first held under FERC’s new 'capacity performance' reforms designed to spur investments in power plants that will improve their performance and strengthen electric grid reliability." This is a "step in the right direction to recognize nuclear energy's high reliability," and "while three of our plants in the PJM did not clear, we view the auction results as an encouraging sign that these reforms will begin to level the playing field." Total supply commitments rose to $10.9 billion.

In September 2015 all Exelon’s Illinois nuclear plants in the PJM region cleared the transition capacity auctions for the 2016-17 year and for the 2017-18 year. These are supplementary to the earlier base auctions for those years and designed to boost reliability. The May 2015 PJM auction cleared at $216/MWe-day. As a result, the company deferred any decisions about the future of its Quad Cities and Byron nuclear plants and will bid Quad Cities, Byron, Three Mile Island and all eligible nuclear plants into the 2019-2020 PJM capacity auction in 2016. Exelon said that deferring any decision on Quad Cities and Byron was “only a short-term reprieve. Policy reforms are still needed to level the playing field for all forms of clean energy and best position the state of Illinois to meet EPA's new carbon reduction rules." The Illinois EPA calculated the incremental societal cost of losing two plants at more than $10 billion – excluding the major cost of higher energy bills, reduced electric reliability and lost jobs.

In April 2016 Exelon announced that Clinton had cleared the Midcontinent Independent System Operator (MISO) capacity auction for 2016-17 (clearing price $72/MWe-d), which would take it to May 2017, albeit unprofitably. In May 2016 Exelon’s Quad Cities and Three Mile Island plants failed to clear the PJM capacity auction for 2019-20 (clearing price $202.77/MWe-day). Exelon’s other Illinois plants in the PJM region cleared the auction: Braidwood, Dresden and La Salle, with part of Byron’s capacity, along with over 5000 MWe of gas-fired combined cycle capacity which reduced the price.

Following the 2014 auction, FERC said it was actively considering ways it can ensure that base-load power sources, such as nuclear plants, are appropriately valued and their viability maintained in wholesale electricity markets. FERC’s focus is on capacity markets and how they should take into account the full value of a base-load power plant. Also whether there are appropriate incentives for plants that contribute to the country’s electric reliability to survive and continue providing those services.

The NEI presented figures from the Electric Utility Cost Group on generating costs comprising fuel, capital and operating costs for 61 nuclear sites in 2012. The average came to $44/MWh, being $50.54 for single-unit plants and $39.44 for multi-unit plants (all two-unit except Browns Ferry, Oconee and Palo Verde). The $44 represented a 58% increase in ten years, largely due to a three-fold increase in capital expenditure on plants which were mostly old enough to be fully depreciated. Over half of the capital expenditure (51%) in 2012 related to power uprates and licence renewals, while 26% was for equipment replacement.

The US Energy Information Administration forecast in April 2014 that the country will lose 10,800 MWe of nuclear generation by 2020 because of lower prices of natural gas and stagnant growth in electricity demand. This will have significant implications for CO2 emissions, and it projected that early retirement of nuclear capacity, instead of coal, could see annual CO2 emissions be 500 million tonnes higher by 2040.

In June 2014 PPL decided to spin off all its merchant plants including the two-unit Susquehanna nuclear plant (2520 MWe net) and combine them with those of a private equity company Riverstone Holdings, to form Talen Energy, which will operate over 15 GWe of capacity in the USA. This move underlines the very different market situations of merchant and regulated plants. About 8.1 GWe of regulated capacity in Kentucky will remain with PPL. Talen will have a major presence in the PJM Interconnection region.

Exelon's single-reactor Oyster Creek plant in New Jersey is already scheduled for early closure at the end of 2019, ten years before its current operating licence ends, to avoid the expense of state environmental regulations that would require the construction of $800 million cooling towers. Entergy's 677 MWe single-reactor Pilgrim plant in Massachusetts is to be shut down in May 2019, due to market conditions and increased costs, the same situation as caused Entergy to close its 635 MWe Vermont Yankee reactor at the end of 2014, and plan to close its 852 MWe Fitzpatrick reactor in January 2017. In November 2015 Exelon said that its Clinton, Ginna and Quad Cities plants were at greatest risk of early retirement for economic reasons, with a question mark also over Byron. In May 2016 Exelon said it would close Clinton in June 2017 and Quad Cities in June 2018 unless the state of Illinois made provision for them to be profitable, by means of zero emission credits, likely to be capped at 20 TWh/yr for the 2884 MWe. New York state is making similar provision for its upstate plants (see below). In June 2016 Omaha Public Power decided to close Fort Calhoun in Nebraska, the smallest US nuclear power plant, at the end of the year. PG&E in June 2016 announced that the Diablo Canyon units would close in 2024 and 2025.

In December 2016 Entergy announced that it intended to close the 789 MWe net Palisades plant in Michigan in October 2018 due to economic factors in the partly deregulated market.

In January 2017 Entergy announced that it intended to close the 2061 MWe (net) two-unit Indian Point plant in New York state in 2020-21 due to "sustained low current and projected wholesale energy prices that have reduced revenues, as well as increased operating costs" coupled with political pressure. The reactors have been operating since 1974 and 1976, and Entergy had invested over $1.3 billion in them over the 15 years it owned them. Its application for licence renewal of the two units was proceeding very slowly through the NRC review. Entergy will now request that the NRC shorten the term of renewed operating licences for units 2 and 3 to 2024 and 2025 respectively.

EPA Clean Power Plan

In June 2014 the US Environmental Protection Agency (EPA) announced that it would use its authority under the Clean Air Act to require a reduction in carbon emissions from US power plants of 25% below 2005 levels by 2020, and more by 2030, with states to be responsible for achieving this. There has already been a 16% drop since 2005. In August 2015 the EPA issued its Clean Power Plan to curb greenhouse gas emissions from existing fossil fuel-fired power plants under section 111(d) of the Clean Air Act and to reduce CO2 emissions by 32% from 2005 levels by 2030. The plan becomes effective in December 2015, and states will have until September 2018 to submit their plans to comply with the emission reductions, using various means including increased thermal efficiency by 2.1 to 4.3%, greater use of nuclear power and renewables, and greater use of gas.

The plan is heavily biased to wind and solar renewables, but allows credit for new nuclear power plants and uprates to existing units, but does not credit the role of existing nuclear capacity, some of which is marginal economically in present market conditions. Nor does it credit nuclear licence extensions on the same basis as new capacity. Nuclear power produces 63% of US carbon-free electricity, nuclear plants are already the main carbon-free generation source for over half of US states, and they avoid the emission of over 750 million tonnes of CO_2 per year relative to coal. It is accepted that the 32% CO_2 reduction by 2030 will be impossible without at least the present level of nuclear contribution. About one-third of the nation's 300 GWe of coal-fired base-load capacity is expected to be retired by 2030. States are preparing legal challenges to the plan.

In November 2014 the National Association of Regulatory Utility Commissioners urged the EPA, in its proposed Clean Power Plan, to adopt regulations which “encourage states to preserve, life-extend, and expand existing nuclear generation.” The EPA proposal in its original form would not have achieved what is intended in respect to nuclear power, and Exelon applauded the NARUC resolution. In January 2015 the NEI said that a top priority was for nuclear plant operators to be fully compensated in competitive wholesale US electricity markets for the value they provide as the main source of reliable, carbon-free, 24/7 base-load power.

State initiatives, zero-emission credits

In December 2015 the **New York state** governor directed its Department of Public Service (NYDPS) to develop a clean energy standard (CES) that calls for a 40% reduction in greenhouse gas emissions from 1990 levels by 2030 and a longer-term decrease of 80% by 2050, while not losing carbon reduction gains achieved to date. The state intends to comply with the EPA Clean Power Plan, and its six nuclear reactors provided nearly one-third of the state’s electricity in 2015. Entergy had announced the premature closure of its FitzPatrick nuclear plant in upstate New York by January 2017, and Exelon had warned its Ginna and Nine Mile Point plants are at risk of closure for similar economic reasons. The governor said that closing nuclear facilities “would eviscerate the emission reductions achieved through the state’s renewable energy programs, diminish fuel diversity, increase price volatility, and financially harm host communities.” The New York independent system operator later warned that to preserve the reliability of the grid, the state must keep all of its nuclear plants operating while slowing renewable energy growth.

The NYDPS issued a white paper in January 2016 proposing 'zero-emission credits' (ZECs) for nuclear generators that would work in parallel with the tax credits that renewable sources receive, and provide the market signals necessary to warrant continued operation of these non-emitting plants. The Nuclear Energy Institute noted that the proposal “establishes a mechanism that can ensure nuclear operators receive the market signals necessary to warrant continued operation of these non-emitting assets.” In addition, a cost study issued by the NYDPS in April 2016 as a supplement to the white paper shows the “outstanding value” that including nuclear in the clean energy standard would provide to New York citizens. The study pointed out that the zero-emission credits would generate $2.8 billion in benefits, or two-thirds of the entire clean energy standard program’s $4.4 billion – for $270 million, or less than 8% of the program’s costs.

In July 2016 the NYDPS put forward a proposal which would value the zero-emissions attributes of the upstate nuclear power plants, based on the social cost of carbon and requiring the distribution utilities “to pay for the intrinsic value of carbon-free emissions from nuclear power plants by purchasing zero-emission credits.” The department said that there is a "public necessity" for subsidies for the Fitzpatrick, Ginna and Nine Mile Point plants (four reactors, total 3371 MWe). The benefits of paying such subsidies would far outweigh the costs, the department said. During the first two years of the program, the state’s economic and environmental benefits associated with carbon reductions, supply cost savings and property tax benefits were estimated to be about $5 billion, against total payments of up to $965 million – a net benefit of $4 billion.

New York's Zero-Emission Credits (ZEC) program will be implemented in six tranches over a period of 12 years starting April 2017. For the first two-year period nuclear generators would receive ZECs of $17.54/MWh, paid by the distribution utilities (and hence eventually ratepayers) but otherwise similar to the federal production tax credits applying to renewables since 1993 on inflation-adjusted basis, though at a lower rate than its $23/MWh for wind. ZECs would escalate to $29.15/MWh over subsequent years. Later in July Entergy’s Indian Point plant was included in the proposal, adding 2061 MWe to it, albeit not for the first two years. The NY Public Service Commission on 1 August 2016 approved the CES plan, but excluded Indian Point. The majority vote was reported to be on three main criteria: grid reliability, reducing carbon emissions, and maintaining jobs. The governor’s announcement said: “A growing number of climate scientists have warned that if these nuclear plants were to abruptly close, carbon emissions in New York will increase by more than 31 million metric tons during the next two years, resulting in public health and other societal costs of at least $1.4 billion.” The Environmental Defense Fund and Natural Resources Defense Council have supported the legality of New York's ZEC scheme.

The broader CES requires that NY state's utilities source at least half their electricity from renewables by 2030, less than it gets now from all clean energy sources: nuclear 32%, hydro 19%, wind 3%, and solar (less than 1%). Gas supplies 40% of power. The CES also requires distribution utilities to obtain a targeted number of renewable energy credits each year for new wind developments on a similar basis, at about $22/MWh.

In August 2016 Exleon reached agreement to buy the 838 MWe Fitzpatrick plant from Entergy for $110 million in anticipation of the NYPDS CES proposal being implemented. Also it confirmed that it will now proceed with investing about $200 million in Nine Mile Point and Ginna plants early in 2017 and will "invest hundreds of millions of dollars in Fitzpatrick in January to refuel the plant and upgrade systems needed to reverse the shutdown decision." Fitzpatrick is licensed to 2034. Entergy said it plans "to move away from merchant power markets and toward a company operating exclusively as a utility in regulated markets."

In October 2016 a coalition of non-nuclear energy companies and groups filed a lawsuit against the New York Public Service Commission challenging the PSC's authority to raise electricity rates to pay for the zero emission credits which will subsidize the continued operation of several nuclear power plants. The plaintiffs, led by the Coalition for Competitive Electricity, included Dynegy Inc, Eastern Generation LLC, Electric Power Supply Association, NRD Energy Inc., Roseton Generating LLC and Selkirk Cogen Partners LP.

In February 2015 **Illinois**, another state with a deregulated market, took steps to enhance the competitiveness of nuclear power and renewables. The Illinois Low Carbon Portfolio Standard would require utilities to purchase low-carbon energy credits equivalent to 70% of their retail sales to customers within the state. This is congruent with the subsequent EPA Clean Power Plan. Eleven Exelon nuclear reactors at six sites supply almost half of the state's electricity, but five of these are at risk of closure if the legislation is not enacted. In mid-2016 the legislation had lapsed. Following the failure of Illinois legislature to pass its Next Generation Energy Plan, in June 2016 Exelon said that it would move forward with plans to close down Clinton in June 2017 and Quad Cities a year later. It would terminate capital investment projects required for the long-term operation of both plants, and would immediately take one-time charges of $150 million to $200 million for 2016, and accelerate some $2 billion in depreciation and amortization.

In October 2016 Exelon confirmed that it would close the Quad Cities and Clinton plants if legislation was not passed by year end since they had lost more than $800 million in the past seven years. In November the Future Energy Jobs Bill was introduced, reflecting "a diverse set of interests, as well as agreement in important areas among environmentalists, consumer advocates, community leaders and energy companies." A core feature of the legislation is the establishment of a zero emission standard that will preserve the state's at-risk nuclear plants, saving 4,200 jobs, retaining $1.2 billion economic activity annually and avoiding increases in energy costs. The bill provides zero emission credits (ZEC) similar to those in New York – "a tradable credit that represents the environmental attributes of one megawatt hour of energy produced from a zero emission facility" such as the nuclear power plants which supply about 90% of the state's zero-carbon electricity. The state legislature passed the bill in December 2016 and it was then signed into law. It will provide up to $235 million annually to support the two plants – 2884 MWe net – for ten years. The state utilities will purchase ZECs from the nuclear generators and collect payments from ratepayers.

In February 2017 FirstEnergy announced that it was in dialogue with the **Ohio** state government to secure the future of its two nuclear plants in the state: Davis-Besse and Perry, owned by its subsidiary FirstEnergy Solutions, a 894 MWe PWR and a 1256 MWe BWR respectively. They produce about 90% of the state's carbon-free electricity, and 11% of the total in Ohio. Proposed legislation would give state lawmakers greater control and flexibility to preserve nuclear generation. "We believe this legislation would preserve not only zero emission assets but jobs, economic growth, fuel diversity, price stability and reliability, and grid security for the region."

FirstEnergy has 13,000 MWe of generating capacity including these and another nuclear plant of 1825 MWe which are in operating in deregulated markets. It has decided to relinquish all these assets by mid-2018, and withdraw from competitive generation altogether, maintaining only its generation assets in regulated markets. This means that if Ohio does not proceed with legislation to provide ZECs so that the plants can be sold, they will be closed. The company recorded a $9.2 billion impairment charge for the fourth quarter of 2016, resulting from its intention to exit competitive operations significantly before the end of the useful lives of generation assets, including the nuclear and coal-fired plants. The drastic decision is indicative of the economic effect of competition from low-cost gas, particularly from shale gas developments with fracking, and subsidized wind power.

Transmission infrastructure

The USA has a patchwork of grids which are often barely interconnected. The Western Interconnection includes about 11 states plus British Columbia and Alberta. ERCOT includes most of Texas, and Eastern Interconnection takes in the rest of the USA and Canada. There is very little grid capacity in the middle of the country. Exelon has temporarily curtailed off-peak output at one or more of its nuclear plants in Illinois numerous times for more than a year to late 2016 because of grid constraints. The company has previously said intermittent grid congestion has been occurring in the region around those plants because of transmission line outages for scheduled maintenance, large influxes of wind-generated power into the grid during off-peak hours, or a combination of those factors.

There is an evident need for major investment. More information on the US grid situation is in the information paper on Electricity Transmission Grids.

Consolidation of ownership and management

The US nuclear power industry has undergone significant consolidation in recent years, driven largely by economies of scale, deregulation of electricity prices and the increasing attractiveness of nuclear power relative to fossil generation. As of the end of 1991, a total of 101 individual utilities had some (including minority) ownership interest in operable nuclear power plants. At the end of 1999, that number had dropped to 87, and the largest 12 of them owned 54% of the capacity. With deregulation of some states' electricity markets came a wave of mergers and acquisitions in 2000-1 and today the top 10 utilities account for more than 70% of total nuclear capacity. The consolidation has come about through mergers of utility companies as well as purchases of reactors by companies wishing to grow their nuclear capacity.

In respect to the number of operators of nuclear plants, this dropped from 45 in 1995 to 25 in about 2010, showing a substantial consolidation of expertise.

Mergers and consolidation of management

Most of the of nuclear generation capacity involved in consolidation announcements has been associated with corporate mergers, some of which failed due to regulatory opposition. Another means of consolidation has been via management contracts, and other means of management rationalisation for single-unit plants have also occurred. Details are in Appendix 2: Power Plant Purchases.

Purchase of reactors

In the 12 years from 1998, there were 20 reactor purchase deals involving 25 plants, usually in states where electricity pricing had been deregulated (see Nuclear Power in the USA Appendix 2: Power Plant Purchases). The plants acquired were often those with high production costs, offering the potential for increased margins if costs could be reduced. Of the 5,900 MWe involved to mid-2000, half was associated with plants having 1998 production costs above 2.0 cents per kWh. Sellers tended to consider the higher-cost plants as potential liabilities and were willing to get rid of them for a fraction of their book value, whereas the larger utility buyers considered the plants to be potential assets, depending only on their ability to lower the production costs. In many cases, large power companies acquired plants from local utility companies and at the same time entered contracts to sell electricity back to the former owners. Entergy Corporation, for example, bought two reactors from New York Power Authority in 2000 and agreed to make the first 500 MWe of combined output available at 2.9 cents/kWh and the remainder at 3.2 or 3.6 cents/kWh.

Along with Exelon, Entergy is a prominent example of the consolidation that occurred. Originally based in Arkansas, Louisiana, Mississippi and eastern Texas, Entergy doubled its nuclear generation capacity over 1999 to 2007 with the acquisition of reactors in New York, Massachussets, Vermont and Michigan, as well as a contract to operate a nuclear plant in Nebraska. Other companies that have increased their nuclear capacity through plant purchases are FPL Group based in Florida (four units), Constellation Energy based in Maryland (three units, since merged with Exelon) and Dominion Resources based in Virginia (two units).

However, some older plants acquired from their original owners for their value as 'cash cows' are now unprofitable in deregulated markets and threatened with closure due to the very low prices of natural gas. In addition, onerous safety requirements following the Fukushima accident compound the economic challenges with already tight NRC regulations. See comments above regarding some Exelon and Entergy plants in deregulated markets.

Improved performance

At the end of 1991 (prior to passage of the Energy Policy Act), there was 97,135 MWe of operable nuclear generating capacity in the USA. In March 2009, it was 101,119 MWe. The small increase concealed some significant changes:

- A decrease of 5,709 MWe, due to the premature shutdown of eight reactors, due to their having high operating costs.
- A net increase of 6,223 MWe, due to changes in power ratings.
- An increase of 3,470 MWe due to the start-up of two new reactors (Comanche Peak 2, Watts Bar 1) and the restart of one unit (Browns Ferry 1).

So far more than 140 uprates have been implemented, totalling over 6500 MWe, and another 3400 MWe is prospective, under NRC review[c]

The Shaw Group has undertaken about half of the uprates so far, and early in 2010 it said that companies are planning more uprate projects and aiming for bigger increases than in the past. It perceived a $25 billion market.Further uprate projects are in sight, many being $250 to $500 million each.

The largest US nuclear operator, Exelon, has plans to uprate much of its reactor fleet to provide the equivalent of one new power plant by 2017 – some 1,300-1,500 MWe, at a cost of about $3.5 billion. The company has already added 1,100 MWe in uprates over the decade to 2009. In addition to increasing power, many of the uprates involve component upgrades. These improve the reliability of the units and support operating licence extensions (see below),which require extensive review of plant equipment condition[d].

Florida Power & Light added 450 MWe in uprates to four reactors over 2011-13: 12% for St Lucie 1&2, and 15% for Turkey Point 3&4.

A significant achievement of the US nuclear power industry over the last 20 years has been the increase in operating efficiency with improved maintenance. This has resulted in greatly increased capacity factor (output proportion of their nominal full-power capacity), which has gone from 56.3% in 1980 and 66% in 1990 to 91.1% in 2008. A major component of this is the length of refuelling outage, which in 1990 averaged 107 days but dropped to 40 days by 2000. The record is now 15 days. In addition, average thermal efficiency rose from 32.49% in 1980 to 33.40% in 1990 and 33.85% in 1999.

All this is reflected in increased output even since 1990, from 577 billion kilowatt hours to 809 billion kWh, a 40% improvement despite little increase in installed capacity, and equivalent to 29 new 1,000 MWe reactors.

Licence renewals and regulation

The Nuclear Regulatory Commission (NRC) is the government agency established in 1974 to be responsible for regulation of the nuclear industry, notably reactors, fuel cycle facilities, materials and wastes (as well as other civil uses of nuclear materials).

In an historic move, the NRC in March 2000 renewed the operating licences of the two-unit Calvert Cliffs nuclear power plant for an additional 20 years. The applications to NRC and procedures for such renewals, with public meetings and thorough safety review, are exhaustive. The original 40-year licences for the 1970s plants were due to expire before 2020, and were always intended to be renewed in 20-year increments.

By the end of 2016, the NRC had extended the licences of 87 reactors (83 still operating) beyond 40 years, 88% of the US total, and about 30 are now in their 40-60-year age bracket. The NRC is considering licence renewal applications for eight further units. Hence, almost all of the US power reactors are likely to have 60-year lifetimes, with owners undertaking major capital works to upgrade them at around 30-40 years. For instance for Davis-Besse, renewed in 2015 to 2037, the owners had invested almost $1 billion. The licence renewal process typically costs $16-25 million, and takes 4-6 years for review by the NRC.

The original 40-year period was more to do with amortisation of capital than implying that reactors were designed for only that lifespan. It was also a conservative measure, and experience since has identified life-limiting factors and addressed them. The NRC is now preparing to consider extending operating licences beyond 60 out to 80 years, with its Subsequent Licence Renewal (SLR) programme. The first applications are expected before 2020, and Dominion has already advised the NRC of its intention to apply for a second 20-year renewal for the two Surry reactors in 2019. In June 2016 Exelon said it would apply in 2018 for the second licence renewal for its two Peach Bottom reactors, taking them to 80 years.

The licence extensions to 60 years mean that major mid-life refurbishing, such as replacement of steam generators and upgrades of instrument and control systems*, can be justified. By 2017, 56 out of 65 US PWRs will have replaced their original steam generators with more durable ones, involving a three-month outage. About 45 PWRs have also replaced reactor pressure vessel heads, mostly by 2010**, and BWRs may need to replace core shrouds. While active plant components such as pumps and valves are under continuous scrutiny for operability, passive components need to be assessed for ageing which may have weakened them. There are robust R&D programmes focusing on this run by DOE, EPRI and ASME.

* All US operating plants have analogue control systems. Duke Energy converted its three Oconee units to digital control systems over 2011-13.

** at about $150 million each in 2015 dollars, mostly due to corrosion cracking.

Beyond licence renewal to 60 years, some 55 GWe of new nuclear capacity will be needed by 2035 to maintain 20% nuclear share of generation if the current fleet is retired at 60 years. In total, 432 GWe of US generating capacity is 30-50 years old and 60 GWe of coal-fired capacity is expected to be retired by 2020 largely for environmental reasons.

The NRC has a new oversight and assessment process for nuclear plants. Having defined what is needed to ensure safety, it now has a better-structured process to achieve it, replacing complex and onerous procedures which had little bearing on safety. The new approach yields publicly-accessible information on the performance of plants in 19 key areas (14 indicators on plant safety, two on radiation safety and three on security). Performance against each indicator is reported quarterly on the NRC website according to whether it is normal, attracting regulatory oversight, provoking regulatory action, or unacceptable (in which case the plant would probably be shut down).

On the industry side, the Institute of Nuclear Power Operations(INPO) was formed after the Three Mile Island accident in 1979. A number of US industry leaders recognised that the industry must do a better job of policing itself to ensure that such an event should never happen again. INPO was formed to establish standards of performance against which individual plants could be regularly measured. An inspection of each member plant is typically performed every 18 to 24 months.

Following the Fukushima accident in 2011 which was exacerbated by inadequate outside assistance to the flooded reactors, the US nuclear industry has set up the FLEX accident response strategy. It has 61 centres across the country and two national centres which together provide the capacity to respond to nuclear power plant accidents anywhere in the country within 24 hours.

Preparing for new build

Today the importance of nuclear power in USA is geopolitical as much as economic, reducing dependency on oil and gas. The operational cost of nuclear power in existing plants is very competitive with alternatives. In 2012 it was 2.4 ¢/kWh, compared with gas 3.4 ¢/kWh and coal 3.3 ¢/kWh. But plans for new nuclear capacity are starting to take account of opportunities for small reactors as well as large ones.

From 1992 to 2005, some 270,000 MWe of new gas-fired plant was built, and only 14,000 MWe of new nuclear and coal-fired capacity came on line. But coal and nuclear supply almost 70% of US electricity and provide price stability. When investment in these two technologies almost disappeared, unsustainable demands were placed on gas supplies and prices quadrupled, forcing large industrial users of it offshore and pushing gas-fired electricity costs towards 10 ¢/kWh. Today, due to the advent of shale gas, costs are much lower.

The reason for investment being predominantly in gas-fired plant was that it offered the lowest investment risk. Several uncertainties inhibited investment in capital-intensive new coal and nuclear technologies. About half of US generating capacity is over 30 years old, and major investment is also required in transmission infrastructure. This creates an energy investment crisis which was recognised in Washington, along with an increasing bipartisan consensus on the strategic importance and clean air benefits of nuclear power in the energy mix.

The Energy Policy Act 2005 then provided a much-needed stimulus for investment in electricity infrastructure including nuclear power. New reactor construction got under way from 2012, with first concrete on two units in March 2013, and two more in December 2013.

Continued low gas prices depress the prospects for commitment to further construction, and it is generally considered that natural gas prices need to recover to $8/GJ or /MMBtu before there is renewed confidence in deregulated states. In regulated states, a longer-term outlook is possible. Small modular reactors provide possible relief from major upfront finance burdens, but these are some way off having design certification from the NRC.

There are three regulatory initiatives which in recent years have enhanced the prospects of building new plants. First is the design certification process, second is provision for early site permits (ESPs) and third is the combined construction and operating licence (COL) process. All have some costs shared by the DOE.

US nuclear power reactors under construction[e]

Site	Technology	MWe gross	Proponent/utility	Construction start	Loan guarantee; start operation
Vogtle 3, GA	Westinghouse AP1000	1250 (1117 net)	Southern Nuclear Operating Company	March 2013	has loan guarantee; late 2019
Vogtle 4, GA	Westinghouse AP1000	1250 (1117 net)	Southern Nuclear Operating Company	Nov 2013	has loan guarantee; mid-2020
V.C. Summer 2, SC	Westinghouse AP1000	1250 (1117 net)	South Carolina Electric & Gas	March 2013	shortlist loan guarantee; Apr 2020
V.C. Summer 3, SC	AP1000	1250 (1117 net)	South Carolina Electric & Gas	Nov 2013	shortlist loan guarantee; Dec 2020
Subtotal under construction: 4 units (5000 MWe gross, 4468 MWe net)					

US nuclear power reactors planned and proposed[e]

Site	Technology	MWe gross	Proponent/utility	COL lodgement & issue dates	Loan guarantee; start operation

William States Lee, SC	AP1000 x 2	2500	Duke Energy	13/12/07, COL issued Dec 2016	2024, 2026
Turkey Point 6&7, FL	AP1000 x 2	2500	Florida Power & Light	30/6/09, COL target early 2017	2027, 2028
UAMPS Carbon-free power project, ID	Nuscale x 12	600	Western Initiative for Nuclear, Utah AMPS, Energy NW	Design cert application Jan 2017, COL application early 2018	2023 on
Subtotal planned: 4 large & 12 small units (5600 MWe gross)					
Fermi 3, MI	ESBWR	1600	Detroit Edison	18/9/08, COL issued May 2015	no decision to proceed
North Anna 3*, VA	ESBWR[i]	~1500	Dominion	20/11/07, delayed but expected 2017, ESP issued	2028?
South Texas Project*, TX	ABWR x 2	2712	Toshiba, NINA, STP Nuclear (merchant plant)	COLs issued Feb 2016 but design certification application withdrawn	shortlist loan guarantee
Clinch River, TN	Uncertain, was mPower x 2	360? up to 800	TVA	ESP application May 2016, COL application mid-2018	
Bellefonte 1&2[g, h], AL	B&W PWR (partly built)	1263	Nuclear Development LLC (bought from Tennessee Valley Authority)	30/10/07 for units 3&4[h] but COL withdrawn 2016	
Levy County, FL	AP1000 x 2	2500	Duke Energy (formerly Progress Energy)	30/7/08, COLs approved Oct 2016	suspended indefinitely
Shearon Harris 2&3, NC	AP1000 x 2	2500	Duke Energy (formerly Progress Energy)	19/2/08, COL review suspended 5/13	
Comanche Peak, TX	US-APWR x2	3400	Luminant (merchant plant)	19/9/08, COL review suspended 11/13	
River Bend, LA	ESBWR[i]	1600	Entergy	25/9/08, COL application withdrawn	
Bell Bend (near Susquehanna), PA	US EPR	1710	PPL/Talen (merchant plant)	10/10/08, COL review suspended 2014 but EIS approved. COL application withdrawn Aug 2016	suspended indefinitely
Callaway[j], MO	Westinghouse SMR x 5	1125	Ameren Missouri	24/7/08 for EPR then cancelled, SMR proposal suspended, COL application for EPR withdrawn	
Grand Gulf, MS	ESBWR[i]	1600	Entergy	27/2/08, COL application withdrawn 9/15, ESP issued	
Calvert Cliffs*, MD	US EPR	1710	UniStar Nuclear (merchant plant)	7/07 and 3/08, terminated in 2012, COL application withdrawn 7/15	refused an offered loan guarantee, needs

					US equity
Nine Mile Point, NY	US EPR	1710	UniStar Nuclear (merchant plant)	30/9/08 but COL application withdrawn 2013	
Green River, UT	AP1000 x 2	2500	Blue Castle/Transition Power Development	ESP application expected 2016	2030
Salem 3/Hope Creek, NJ	unspecified	Perhaps 1200	PSEG Nuclear	ESP issued May 2016	
Subtotal proposed: 19 large units, 7 small (ca. 28,500 MWe gross), 15 projects, 2 COLs awarded, 2 awaited, 2 planned (SMRs), 4 suspended, 4 withdrawn and 2 ESP only.					
Other proposals, less definite or moribund					
Victoria County[i], TX	ESBWR	3200	Exelon (merchant plant)	03/9/08 but withdrawn, ESP application 25/3/10, but withdrawn Oct 2012	
Piketon (DOE site leased to USEC), OH	US EPR	1710	Duke Energy		
Payette county, ID	APWR	1700	Alternate Energy Holdings Inc. (merchant plant)	Plans stalled since 2012	
Fresno, Ca	US EPR	1710	Fresno Nuclear Energy Group		
Amarillo, TX	US EPR x 2	3420	Amarillo Power (merchant plant)		
Stewart County, GA	AP1000	1250	Georgia Power (Southern Co)	COL application deferred in 2017	build after 2030

Of the above, for the first four AP1000 units, construction is well underway at Vogtle, Georgia, with about $4 billion invested in the project before it was technically 'under construction'. Construction is also well underway at Summer, South Carolina. See also section below.

In addition to sites listed above, Southern Company is evaluating several possible sites, including existing plants and greenfield locations, for additional AP1000 reactors.

However the economic outlook since 2013-14 suggests that merchant plants are not prospectively viable, and that some kind of assured market is necessary to underwrite the high capital costs on nuclear plants. A February 2013 white paper published by NEI addresses The Cost of New Generating Capacity in Perspective.

Design certification

As part of the effort to increase US generating capacity,government and industry have worked closely on design certification for advanced Generation III reactors. Design certification by the Nuclear Regulatory Commission (NRC) means that, after a thorough examination of compliance with safety requirements, a generic type of reactor (say, a Westinghouse AP1000) can be built anywhere in the USA, only having to go through site-specific licensing procedures and obtaining a combined construction and operating licence (see below) before construction can begin. Design certification needs to be renewed after 15 years.

Designs now having US design certification and being actively marketed are:

- The GE Hitachi advanced boiling water reactor (ABWR) of1300-1500 MWe. Several ABWRs are now in operation in Japan, with more under construction there and in Taiwan. Some of these have had Toshiba involved in the construction, and more recently it has been Toshiba that promoted the design most strongly in the USA.[k] Both the Toshiba and the GE Hitachi versions need to have their design certification renewed from 2012, but NRC shows both as "applicant delayed, not scheduled". Toshiba withdrew its design certification renewal application in mid-2016.
- The Westinghouse AP1000 is the first Generation III+ reactor to receive certification[l]. It is a scaled-up version of the Westinghouse AP600 which was certified earlier. It has a modular design to reduce construction time to 36 months. The first four of many are being built in China, and four more in USA.
- GE Hitachi's Economic Simplified BWR (ESBWR) of 1600 MWe gross, developed from the ABWR. The ESBWR has passive safety features and is currently included in the COL applications of two companies in USA. GE Hitachi submitted the application in August 2005, design approval was notified in March 2011, and design certification was in September 2014. The first COL with it was approved in May 2015.

Reactor designs undergoing US design certification or soon expected to do so are:

- The Korean APR-1400 reactor, which is operating in South Korea since 2016 and under construction in the United Arab Emirates. Following 11 pre-application meetings, Korea Hydro & Nuclear Power submitted a design certification application to the NRC in October 2013. However, further detail was requested, and the revised submission was accepted by the NRC in March 2015. The final safety report is expected late in 2018.
- The Mitsubishi US-APWR, a 1700 MWe design developed from that for a 1538 MWe reactor planned for Tsuruga in Japan. The application was submitted in December 2007 and certification was expected to be completed in February 2016, but Mitsubishi delayed the NRC schedule for “several years”. European certification for the almost identical EU-APWR was granted in October 2014. Two US-APWR reactors were proposed in the Luminant-Mitsubishi application for Comanche Peak, but Mitsubishi has withdrawn from this project.
- The Russian VVER-1200 reactor which is operating at Novovoronezh II and being bult at Leningrad II may be submitted for US design certification through Rusatom Overseas, according to Rosatom.

A reactor design formerly undergoing US design certification:

- The US Evolutionary Power Reactor (US EPR), an adaptation of Areva's EPR to make the European design consistent with US electricity frequencies. The main development of the type was to be through UniStar Nuclear Energy, but other US proposals also involved it. The application was submitted in December 2007 and the design certification rule was expected after mid-2015, with delays due to the complexity of digital instrumentation and control systems. Areva then delayed the NRC schedule and in March 2015 indefinitely suspended the application. The 1600 MWe EPR is being built in Finland, France, and Guangdong in China, and is planned for UK.

In addition, several designs of small modular reactors (SMRs) are proceeding towards NRC design certification application:

- A demonstration unit of the 160 MWe Holtec SMR-160 PWR (with external steam generator) is proposed at Savannah River with DOE support, and a design certification application is likely. In September 2016 Mitsubishi Electric Power Products and its Japanese parent became a partner in the project, to undertake the I&C design and help with licensing. South Carolina and NuHub also back the proposal.
- A demonstration unit of the NuScale multi-application small reactor, a 50 MWe integral PWR planned for the Idaho National Laboratory. Subsequent deployment of 12-module power plants in western states is envisaged under the Western Initiative for Nuclear. NuScale applied for US design certification in January 2017 and a COL application is planned early in 2018. Nuscale had spent some $170 million on licensing to mid-2015, and expects the NRC review to take 40 months, with the first unit operating in the mid-2020s. In 2013 NuScale secured up to $226 million DOE support for the design. Further details under the section on UAMPS below.
- SCEG is evaluating the potential of X-energy’s Xe-100 pebble-bed SMR (50 MWe) to replace coal-fired plants, in 200 MWe ‘four-pack’ installations. The company plans to apply in 2017 for US design certification.
- In August 2015 Russia's AKME-Engineering received a US patent for its modular SVBR-100 lead-bismuth cooled

integral fast reactor. The company said that it wants to protect its intellectual property as it prepares for the construction of a prototype SVBR-100 unit at Dimitrovgrad. No plans for the USA have been announced.

In February 2014 the NRC said that its most optimistic scenario for awarding design certification for small reactors such as SMRs was 41 months, assuming they were light water types (PWR or BWR).

A fuller account of new reactor designs, including those certified but not marketed in the USA, is in the information page on Advanced Nuclear Power Reactors, or for the small modular reactors, in the page on Small NuclearPower Reactors.

Early site permit

The 2001 early site permit (ESP) program attracted four applicants: Exelon, Entergy, Dominion and Southern, for Clinton,Grand Gulf, North Anna and Vogtle sites respectively – all with operating nuclear plants already but room for more. In March 2007, Exelon was awarded the first ESP for its Clinton plant in Illinois, after 41 months' processing by the NRC and public review. The NRC then awarded ESPs to Entergy for its Grand Gulf site, Dominion for North Anna, and Southern for Vogtle. No plant type is normally specified with an ESP application, but the site is declared suitable on safety, environmental and related grounds for a new nuclear power plant. The last three of these 2001 ESPs were replaced by COL applications.

In March 2010, Exelon applied for an ESP for its Victoria County, TX, site and withdrew the COL application for that project. In 2012 it withdrew the ESP application. PSEG Nuclear lodged an application for an ESP for a new reactor at its Salem/Hope Creek site on the Delaware River in New Jersey in May 2010, and this was granted in May 2016.

The seventh ESP application was for small reactors. The Tennessee Valley Authority (TVA) submitted an ESP application to the NRC for its Clinch River small reactor project (two or more units) in May 2016. The application was based on a plant parameter envelope encompassing the light-water SMRs currently under development in the USA by BWX Technologies, Holtec, NuScale Power and Westinghouse. TVA then plans to submit a combined licence application with a view to building up to 800 MWe of capacity there. The DOE is supporting TVA's ESP application.

Combined construction and operating licence

In 2003, the Department of Energy (DOE) called for combined construction and operating licence (COL) proposals under its Nuclear Power 2010 program on the basis that it would fund up to half the cost of any accepted. The COL program has two objectives:to encourage utilities to take the initiative in licence application, and to encourage reactor vendors to undertake detailed engineering and arrive at reliable cost estimates. For the first,DOE matching funds of up to about $50 million are available, and for the second, up to some $200 million per vendor, to be recouped from royalties.

Several industry consortia have been created for the purpose of preparing COL applications for new reactors. By mid-2009, COL applications for 26 new units at 17 sites had been submitted to the Nuclear Regulatory Commission. A summary of submitted and expected applications is given in the Table above (New US nuclear power reactors), and further information is given in Nuclear Power in the USA Appendix 3: COL Applications.

However, the only construction of new plants in the short term is in regulated markets, where costs can reliably be recovered.

Advance orders for heavy forgings

Several companies have ordered heavy forgings and other long lead time equipment for building new plants, in advance of specific plans or approvals. Some have even proceeded to full engineering,procurement and construction (EPC) agreements while the relevant COL applications are being processed, thus indicating a strong probability of actually building the plants concerned. These are indicated in the above Table and further details are given in Nuclear Power in the USA Appendix 3: COL Applications.

Financial incentives

The Energy Policy Act of 2005 provided financial incentives for the construction of advanced nuclear plants. The incentives include a 2.3 cents/kWh production tax credit (PTC) for the first 6,000 MWe of capacity in the first eight years of operation (same as that for wind), and federal loan guarantees for the project cost. After putting this program in place in 2008, the DOE received 19 applications for 14 plants involving 21 reactors. The total amount of guarantees requested is $122 billion, but only$18.5 billion has been authorized for the program. In light of the interest shown, industry has asked that the limit on total guarantees be raised to $100 billion.

For further discussion see information page on US Nuclear Power Policy.

Reactors recently brought into operation

Watts Bar 2

While the focus is on new technology, TVA undertook a detailed feasibility study which led to its decision in 2007 to complete unit 2 of its Watts Bar nuclear power plant in Tennessee. The 1165 MWe (net) reactor was expected to start up in October 2012 and come online in 2013 at a cost of about $2.5 billion, but this schedule slipped substantially, with major budget overrun to $4.7 billion. Construction had been suspended in 1985 when 80% complete and (after parts were cannibalized to reduce that figure to 61%) resumed in October 2007 under a still-valid permit. The construction permit has been extended to September 2016, and in October 2015 TVA received a 40-year operating licence from NRC. Grid connection was early in June and commercial operation commenced in October 2016. Its twin, unit 1, started operation in 1996.

Completing Watts Bar 2 utilizes an existing asset, thus saving time and cost relative to alternatives for new base-load capacity. It was expected to provide power at 4.4 ¢/kWh, 20-25% less than coal-fired or new nuclear alternatives and 43% less than natural gas. It is a regulated plant, with guaranteed cost recovery.

In 2014, before start-up, TVA ordered new steam generators for the unit and plans to change them over after 7-10 years operation. The early 1980s ones are made of an alloy that is prone to stress-corrosion cracking. Those in unit 1 were replaced after nine years operation, and the vast majority of US PWRs have had replacements.

Reactors under construction and planned, or which have been planned

Vogtle 3&4

In April 2008, Georgia Power signed an EPC contract with Westinghouse and The Shaw Group (now CB&I) consortium for two 1200 MWe Westinghouse AP1000 reactors which will be licensed and operated by Southern Nuclear Operating Company. JSW in Japan sent forged components to Doosan in South Korea for fabrication. The COL was issued by NRC in February 2012. Construction start (first concrete) was delayed to late 2012, and then to March 2013, after NRC issued a licence amendment allowing use of a higher-strength concrete that permits the company to pour the foundation of the new reactors without making additional modifications to reinforcing steel bar. At that point ten million working hours had been invested on the site. Shaw (now CB&I) agreed with China's State Nuclear Power Technology Corporation (SNPTC) to deploy engineers with experience in building China's AP1000 units to provide technical support. Following early delays, construction of unit 3 started in March 2013 and unit 4 in November. Fluor joined the project as construction manager in January 2016, taking over part of the CB&I role, and in January 2017 Bechtel became involved with the nuclear islands. The units are expected online late in 2019 and September 2020. It is a regulated plant, with guaranteed cost recovery.

Georgia Power as 45.7% owner reduced its earlier cost estimate for building its share of the new plant from $6.4 billion to $6.1 billion as a result of being able to recover financing costs from customers during construction, but this increased to $6.2 billion in 2012 due to delays. Over the life of the plant, the utility's customers will save about $1 billion through federal loan guarantees, production tax credits and the early recovery of financing costs in the rate base. The Georgia Public Service Commission in February 2013 approved Georgia Power's costs for the project and said that the project "remains more economically viable than any other [energy] resource, including a natural gas-fired alternative."

The total cost of the project is expected to be $14 billion. Delays to mid-2014 resulted in a cost increase of $381 million but this was offset by lower interest rates than budgeted. When further delay was announced in January 2015, the company said that cost escalation was about $10 million per month plus financing cost of about $30 million per month. Minority equity in the project is held by Oglethorpe Power (30%), MEAG Power (22.7%) and Dalton city (1.6%).

Loan guarantees totaling $6.5 billion were issued to Georgia Power and Oglethorpe Power in 2014. The final $1.8 billion of loan guarantees were issued to three subsidiaries of the Municipal Electric Authority of Georgia (MEAG) in June 2015. (Dalton Utilities did not seek a loan guarantee.)

Summer 2&3

In May 2008, South Carolina Electricity & Gas (SCANA subsidiary) and Santee Cooper signed an EPC contract with Westinghouse and the Shaw Group (now CB&I) consortium for two 1200 MWe Westinghouse AP1000 reactors. In September 2011 SCEG started to assemble the containment vessel for the first unit (43 mm thick, from Chicago Bridge & Iron) and was starting construction on the four low-profile forced-draft cooling towers.The total forecast cost of $9.8 billion included inflation and owners' costs for site preparation, contingencies and project financing, though the last was reduced and the total estimated in April 2012 was $9.2 billion, and in November 2016 the state public service commission agreed for SCEG’s 55% share to be $7.66 billion, excluding financing, with the company’s return on equity reduced to 10.25%. In October 2014 the cost was estimated at over $11 billion. "These delays and related cost increases are principally due to design and fabrication issues associated with the production of submodules used in construction of the units," according to SCANA. Fluor joined the project as construction manager in January 2016, taking over the CB&I role. In November 2016 the anticipated completion dates for the two units were August 2019 and August 2020, but in February 2017 they slipped to April 2020 and December 2020.

The COL was issued by the NRC at the end of March 2012, and construction of unit 2 commenced in March 2013, with first main concrete. That for unit 3 was in November 2013. Reactor pressure vessels and steam generators are from Doosan in South Korea. A crane capable of lifting 6800 tonnes is installed on site, though the heaviest component 1550t. The units are expected to enter commercial operation late in 2019 and late in 2020. SCEG's loan guarantee application was accepted by the DOE and the project was short-listed in May 2009, though nothing has happened since then. It is a regulated plant, with guaranteed cost recovery.

In 2014 it was announced that SCEG’s stake in the project will be increased to 60% by acquisition of 5% from Santee Cooper after the plant starts up, for about $500 million, leaving it with 40%. Duke Energy Carolinas had been seeking up to 10% of the project from Santee Cooper, but this plan was dropped in January 2014.

Bellefonte

Tennessee Valley Authority had a pair of uncompleted 1213 MWe PWR reactors: Bellefonte 1&2. Construction on these units was abandoned in 1988 after $2.5 billion had been spent and unit 1 largely (88%) completed and unit 2 about 58% completed. In February 2009, the NRC reinstated the construction permits for these (and later the status of the reactors classified as 'deferred'). Today unit 1 is considered no more than 55% complete due to the transfer or sale of many components and the need to upgrade or replace others, such as the instrumentation and control systems, reactor pressure vessel, steam generators and main condenser tubing. In August 2011 TVA opted to complete unit 1 at a cost of about $4.9 billion rather than building a new AP1000 reactor as unit 3* (see Appendix 3: COL Applications). TVA then asked the NRC in 2011 to defer consideration of its COL for units 3&4 (AP1000 option), and in February 2016 it withdrew the COL application.

* In August 2010, TVA had committed to spending $248 million in the year to September 2011 towards work at Bellefonte[8] and an engineering contract was awarded to Areva SA in October 2010 for work on unit 1, including engineering, licensing and procurement of long-lead materials in support of a possible start-up date in the 2018-19 timeframe. Following TVA's 2011 decision to proceed, the Areva contract included construction and component replacement work on the plant's nuclear systems, a digital instrumentation and control (I&C) system, a modernized control room, a plant simulator for personnel training plus fuel design and fabrication. Areva contracts amounted to some $1 billion, with heavy construction to start when Watts Bar 2 was completed. In late 2013 TVA revised the estimated cost to $7.4 to $8.7 billion.

However, TVA's 20-year integrated resource plan in 2015 did not have Bellefonte 1&2 as a firm prospect, and it projected 2028 completion of unit 1 as having the effect of increasing system costs. Later in 2015 the company said it would defer consideration of completing unit 1 for a decade. In May 2016 the TVA board decided to offer the plant for sale at auction, and in November it was bought by Nuclear Development LLC for $111 million. The company said it intended to invest up to $13 billion from 2017 to complete the plant. Bellefonte is a regulated plant, with guaranteed cost recovery.

Lee

Duke Energy lodged a COL application in December 2007 for two Westinghouse AP1000 units for its William States Lee III plant at a new site near Charlotte in Cherokee County, South Carolina. The company is seeking a loan guarantee and is considering regional partnerships to build the plant, though it has not yet committed to proceed. The environmental review for NRC was completed in December 2013, showing no problems, the safety evaluation review was completed in August 2016 and the COLs issued in December 2016. Duke told NRC in 2012 that it was revising its COL application to move the nuclear island of both Lee units by some 20 metres to make excavation and construction easier. Partly as a result of this, the NRC delayed its target date for completing the COLs to late 2016. Duke had spent $471 million on licensing, planning and pre-construction activities for the plant to February 2016. If proceeding, the 1117 MWe (net) units are now expected online in 2024 and 2026.

Turkey Point 6&7

NextEra Energy subsidiary Florida Power & Light (FPL) applied in June 2009 for a COL for two Westinghouse AP1000 reactors at Turkey Point in Florida where two 693 MWe PWR units (3&4) are operating and were uprated in 2012-13. (Unit 5 is a 1190 MWe combined cycle gas plant; units 1&2 are 400 MWe oil/gas units.) In 2011 the Florida Public Service Commission approved a levy towards construction of the reactors, and in May 2014 the state government approved the project, with new transmission lines.

The NRC safety review was scheduled to be completed late in 2013, and the NRC website early in 2015 showed COL completion early in 2017. FPL will then make a decision about proceeding. The company said in April 2014 that it expected to start operation of the first new unit in June 2022 and the second a year later, but in January 2015 changed this to 2027 and 2028, due to "NRC licensing schedule adjustments and changes to the Florida nuclear cost recovery law," which delay the start of site works.

South Texas Project 3&4

This is envisaged as a merchant plant with two 1356 MWe Advanced Boiling Water Reactors (ABWR)[m]. NRG Energy already operates two reactors at the site, and some preparatory works have been done for the new units. The COL application was in September 2007.

The project is owned 92.375% by Nuclear Innovation North America (NINA), and 7.625% by CPS Energy of San Antonio. Toshiba America Nuclear Energy (TANE) holds 10% of NINA with NRG Energy 90%, but following NRG's withdrawal from STP 3&4, Toshiba has fully funded NINA to continue licensing. The COL review by the NRC was due to be completed late in 2011, and the units were expected on line in 2016 and 2017, but in late 2011 the NRC notified NINA that the corporation did not meet the foreign ownership requirements and would therefore be ineligible to receive a licence; however NINA subsequently filed revisions to its COL application and a "negation action plan" to address the issue. In April 2013 the NRC "determined that NINA and its wholly owned subsidiaries … continue to be under foreign ownership, control, or domination and do not meet the requirements … of the Atomic Energy Act or the requirements of (federal regulations)." NINA responded by saying it would continue "to move forward on the technical portion of the permit and other activities necessary to obtain the license. This action by NRC is a step in the process necessary to reach a final resolution of the foreign ownership issue." The NRC decision was then reviewed by the NRC Atomic Safety Licensing Board (ASLB), which ruled in April 2014 that the 10% Toshiba equity was no problem. NRC's Advisory Committee on Reactor Safeguards in April 2015 also supported issuing the COLs and the NRC issued a final safety evaluation report in September 2015. In February 2016 the NRC issued the COLs.

The new units would be operated by the South Texas Project Nuclear Operating Co. (STPNOC), a US company owned by NRG Energy (44%), CPS Energy and Austin Energy. STPNOC already operates STP units 1&2.

NINA awarded the EPC contract to Shaw Group (now CB&I) and Toshiba America Nuclear Energy in November 2010. One reactor pressure vessel was ordered from IHI in May 2010, and JSW had already shipped other components. In May 2016 Toshiba and CB&I dissolved their 2010 partnership in relation to all ABWR plans. Toshiba America Nuclear Energy is now the sole EPC contractor for South Texas.

However, based largely on low natural gas prices in Texas compounded by the Fukushima accident, in April 2011, NRG decided to pull out of the project and write off its $331 million investment in it. Toshiba had spent $150 million and persevered with the project, though it wrote off $305 million (JPY 31 billion) on NINA in 2014. It is assumed that Tepco and Toshiba will not be in a position to maintain any involvement.

In the light of developments the World Nuclear Association moved the project from 'planned' back to 'proposed', but the ASLB ruling in April 2014 would lead to a change back if replacement US equity were secured. Meanwhile in April 2015 NRG said it was proceeding with licensing, but Toshiba's withdrawal of its design certification renewal in mid-2016 puts the project on hold.

UAMPS

The UAMPS Carbon-Free Power Project, a 12-module Nuscale SMR plant, would be owned by Utah Associated Municipal Power Systems and operated by Energy Northwest in Idaho, supported by six western states. UAMPS plans to submit a COL application early in 2018. NuScale expects the first unit to be operating in the mid-2020s. In 2013 NuScale secured up to $226 million DOE support for the design. UAMPS expects to decide upon proceeding or not with the $3 billion project in fiscal 2017 and in January 2017 started soliciting power sales contracts for the 600 MWe plant. The DOE has granted permission to site the plant on the 2300 square km Idaho National Laboratory estate, and recent reports put this in the southern part of it. Under this agreement UAMPS has ten years to begin operating the first module, and this will trigger a 99-year lease for the plant. If Idaho state does not welcome the project, Wisconsin would now do so, though it is a long way from UAMPS.

Fermi 3

This is a reference unit for GE Hitachi's ESBWR design, proposed by Detroit Edison in Michigan, but the company has not yet committed to proceeding. A COL application was made in 2008 and environmental approval was received in January 2013. Full design certification of the ESBWR in 2014 allowed the safety evaluation to proceed, and the COL was approved in May 2015.

Levy County, Florida

Site works started for two 1200 MWe Westinghouse AP1000 reactors on a greenfield site in Florida, and to January 2012 some $860 million had been spent on this. The company expected to have spent about $1 billion on the design, acquisition of heavy equipment and site works by the time it secures NRC approval. In September 2008, Progress Energy Florida signed an EPC contract with Westinghouse and The Shaw Group (now CB&I) consortium. The contract is for $7.65 billion ($3462/kWe), of an overall project cost of about $14 billion.

In August 2013 Duke Energy resolved to terminate the 2008 EPC contract as "a result of delays by the NRC in issuing COLs for new nuclear plants, as well as increased uncertainty in cost recovery caused by recent legislative changes in Florida." It continued to pursue the COLs in order to keep the option open. In April 2014 Duke announced plans to build 2745 MWe of gas-fired capacity by 2021 instead of proceeding with the Levy County nuclear plant in the original timeframe. Duke Energy Florida was planning to sell all the long-lead time equipment it had ordered by the end of 2014, but it was in dispute with Westinghouse over EPC contract termination. In October the Florida Public Service Commission ordered Duke to repay to ratepayers $54 million it had collected in advance to fund the "cancelled" project. In October 2016 the NRC approved the COLs – the eighth and ninth it had issued.

A final decision to build is pending now that the NRC has issued licences for the project. The last estimated operational dates were 2024-25, the delay being due to "lower-than-projected customer demand, the lingering economic slowdown, uncertainty regarding potential carbon regulation and current low natural gas prices." The revised cost is $19-24 billion. It is a regulated plant, with guaranteed cost recovery. This is now a Duke Energy Florida project.

North Anna 3

In December 2010, Dominion announced that it had agreed with Mitsubishi Heavy Industries to build a US-APWR unit, but in April 2013 Dominion announced that it had reverted to the ESBWR as preferred technology (as originally selected in 2005), and would amend its COL application accordingly. Dominion quotes 1453 MWe net (summer capacity) for the plant there. In May 2013 it agreed a construction contract with GE Hitachi and Fluor, conditional upon proceeding. It is now expecting the COL to be issued in 2017. Dominion says it will not make a decision to build it until it gets the COL, and hence it remains as 'proposed' according to the World Nuclear Association. Dominion suggests start-up in 2028 if it proceeds. It had spent $345 million on the project to early 2016. It is a regulated plant, with guaranteed cost recovery. A consultant to the state has estimated the cost of the plant as $19.3 billion including financing, or $13,283/kW, and Dominion has said that such a figure would not be unreasonable.

Clinch River

Babcock & Wilcox (B&W) has set up B&W Modular Nuclear Energy LLC to market the mPower small modular reactor design of 180 MWe. In February 2013 B&W signed an agreement with TVA to build up to four units at Clinch River, with design certification application intended to be submitted to the NRC in 2015. Bechtel has joined the project as an equity partner to design, license and deploy it. As well as TVA, First Energy and Oglethorpe Power are involved with the proposal. TVA submitted an early site permit (ESP) application in May 2016, with no particular technology specified.

Harris 2&3

Progress Energy lodged a COL application for two AP1000 units at its Shearon Harris site at New Hill in North Carolina in February 2008. This was proceeding towards being granted at the end of 2014. Expansion of the plant would require raising the water level of Harris Lake by 6 metres, and relying on the Cape Fear River as backup cooling water. However, in May 2013 Duke Energy (which had taken over Progress) asked NRC to suspend the COL review due to projected electricity demand being low for next 15 years.

Comanche Peak

Luminant planned to use two US-APWR units for its merchant plant in Texas, and in May 2011 remained positive about the prospects for these by 2109-20. The World Nuclear Association lists the plant as "proposed" pending progress with design certification and COLs. However, design certification has been extended by several years and the COL suspended. In May 2011 the NRC concluded that there were no environmental considerations that would hinder the project. Luminant's loan guarantee application was accepted by DOE and it was understood that this was the first alternative to the four short-listed projects, two of which are now not proceeding for the time being. Meanwhile Mitsubishi has withdrawn as a joint venture partner.

Calvert Cliffs 3

Unistar, now owned by EdF, planned to build a 1710 MWe Areva US-EPR alongside Constellation's units 1&2, as a merchant plant. The NRC design certification for US-EPR was due early in 2013, but the COL – originally scheduled in mid-2013 – required a new US partner for the project. At the end of August 2012 the NRC said that it would terminate the COL application in 60 days if Unistar did not have majority US ownership by then, and it did so. In May 2011 the NRC concluded that there are no environmental considerations that would preclude issuing the COL for construction and operation of the proposed US-EPR at the site. The NRC was now completing the safety evaluation. Unistar's loan guarantee application was accepted by DOE and the project was short-listed in May 2009.

In the light of equity developments the World Nuclear Association has moved the project from "planned" back to "proposed". Exelon, merging with Constellation (owner of units 1&2 there, and in which EdF has 49.9% equity) said in November 2011 that with the advent of shale gas, a new nuclear plant at Calvert Cliffs was "utterly uneconomic" by a factor about two.

Calvert Cliffs 3 will have a closed-loop cooling system using a single hybrid mechanical draft cooling tower, giving it a much larger footprint than units 1&2 together. It will also have a reverse osmosis desalination plant for potable water, producing 4700 m^3/day.

Salem 3

PSEG has an application for an early site permit for up to two new Salem reactors at Hope Creek, NJ. This is scheduled for awarding early in 2016, and a positive environmental review was reported in November 2015. No reactor technology is specified.

Other new capacity

TVA upgraded and restarted Browns Ferry 1 in May 2007. The unit had originally commenced commercial operation in 1974 but all three Browns Ferry reactors were shut down in 1985 to address management and operational concerns. Units 2&3 were returned to service in 1991 and 1995, respectively. The five-year refurbishment program of unit 1 also increased its power to 1,155 MWe, similar to the newer units 2&3.

In April 2010, Areva signed an agreement with Fresno Nuclear Energy Group for a clean-energy park near Fresno in California,including a 1600 MWe EPR and concentrated solar power plant. Possible locations were investigated.

Other planned or proposed new US nuclear capacity is described more fully in Appendix 3 on COL Applications.

Future nuclear reactor designs

After 20 years of steady decline, government R&D funding for nuclear energy is being revived with the objective of rebuilding US leadership in nuclear technology.

In an effort that brings together government research laboratories, industry and academe, the Federal government has significantly stepped up R&D spending for future plants that improve or go well beyond current designs. There has been particular attention to the Next Generation Nuclear Plant (NGNP) project to develop a Generation IV high-temperature gas-cooled reactor, which would be part of a system that would produce both electricity and hydrogen on a large scale. The DOE has stated that its goal is to have a pilot plant ready at its Idaho National Laboratory (INL) by 2021.The total development cost has been estimated at $2 billion. See also information page on US Nuclear Power Policy.

Savannah River Nuclear Solutions (SRNS), which manages the Savannah River Site (SRS) in South Carolina on behalf of the DOE,has proposed a demonstration complex with prototype or demonstration models of up to 15 small reactors (up to 300 MWe, but mostly smaller). Hyperion has signed an agreement to build the first, and SRNS has approached several other small-reactor developers, including General Atomics (re GT-MHR or EM2), GE Hitachi (re PRISM) and Terrapower (see section on Hyperion Power Module in the information page on *Small Nuclear Power Reactors*). It is understood that the DOE has the authority to build and operate such small reactors if they are not supplying electricity to the grid.

Further Information

Notes

a. The first nuclear reactor in the world to produce electricity (albeit a trivial amount) was the small Experimental BreederReactor (EBR-1) in Idaho, which started up in December 1951. In1953, President Eisenhower proposed his *Atoms for Peace* programme, which reoriented significant research effort towards electricity generation and set the course for civil nuclear energy development in the USA. The Mark 1 naval reactor of 1953 led to the US Atomic Energy Commission building the 60 MWe Shippingport demonstration PWR reactor in Pennsylvania, which started up in 1957and operated until 1982. [Back]

b. Fort St. Vrain in Colorado was a 330 MWe high-temperature gas-cooled reactor (HTGR) operating 1976-89. The technology was developed from an earlier 40 MWe HTGR at Peach Bottom, Pennsylvania, which operated from 1967 to 1974. [Back]

c. To the end of September 2010, the Nuclear RegulatoryCommission (NRC) had approved 135 power uprates totalling 5810 MWe (not including capacity recapture uprates for provisional operating licence plants). A further 10 applications for power uprates totaling 1125 MWe were under review. In addition, the NRC said that it expected to receive 40 power uprate applications by 2014. If approved and implemented, these uprates would add 2400 MWe.Information on power uprates is available on the NRC website (www.nrc.gov/reactors/operating/licensing/power-uprates.html). [Back]

d. Contra to uprates, occasionally plants install equipment such as new cooling towers which increases internal power consumption, and therefore reduces net power slightly (without changing gross power). There is also sometimes a 2-3% difference between summer and winter power, due to cooler ambient temperatures in winter increasing thermal efficiency. [Back]

e. An asterisk (*) denotes reference COL for reactor type. EPC = Engineering, procurement and construction agreement. Merchant plants are without regulated cost recovery. 'Planned' status shows a higher level of commitment – such as an order for large forgings or an EPC contract – than 'Proposed' status. [Back]

f. Construction of Watts Bar 2 was suspended in 1985 and resumed in 2007. In July 2008, the Nuclear Regulatory Commission issued an order extending the Watts Bar Unit 2 construction permit completion date. [Back]

g. The site chosen by the NuStart Energy Development consortium for the reference COL application for the AP1000 was originally TVA's Bellefonte. However, NuStart later decided to transfer the AP1000 reference COL application to Vogtle on the grounds that the Vogtle application had "specific near-term construction plans." In May 2009, NuStart announced that it was "consulting with the Nuclear Regulatory Commission and Department of Energy to develop a process for transferring the reference combined construction and operating licence application from TVA's Bellefonte nuclear site to Southern Nuclear's Vogtle Electric Generating Plant."[1] [Back]

h. A COL application for two proposed AP1000 units as units 3 and 4 at TVA's Bellefonte site was submitted to the Nuclear Regulatory Commission in October 2007. This COL application was originally the reference COL application for the AP1000 design but the reference application is being transferred to Vogtle (see Note g above). The site also has two unfinished 1,213 MWe PWRs (unit 1 being about 88% complete and unit 2 about 58% complete) and TVA has been considering all options for the site, including the completion of units 1&2. In May 2010 theTVA staff identified completion of unit 1 as the best option for the site, and in August 2011 the TVA Board decided to complete unit 1.[2] [Back]

i. Dominion's North Anna COL application referenced the ESBWR, but in March 2009 it issued a new request for proposals from reactor vendors and in May 2010 it selected the Mitsubishi US-APWR. Then in April 2013 it reverted to the ESBWR, and agreed on an EPC contract for it with GEH and Fluor, though this will not be signed unless it decides to proceed. The COL review by NRC in now expected to be complete in 2015.

The COL reviews of Entergy's applications for Grand Gulf and RiverBend, along with the review of Exelon's application for the Victoria County site were suspended by the NRC, following the decisions by Entergy and Exelon to review their initial reactor design choice of the ESBWR. Exelon had initially proposed two ESBWR units for its Victoria County site but, early in 2009, switched to the ABWR design, to be built by GE-Hitachi. Shortly afterwards, citing adverse economic conditions, Exelon withdrew its COL application and instead said it would submit an early site permit application in late 2009/early 2010. [Back]

j. AmerenUE announced in April 2009 that it was suspending its efforts to build a new unit and in June 2009 the company requested the Nuclear Regulatory Commission to suspend all review activities relating to the Callaway 2 COL application. However, in April 2012 Ameren Missouri set out to seek DOE support for the first of five Westinghouse SMR units at Callaway. In July 2015 Ameren withdrew its COL application. [Back]

k. The ABWR design that has NRC certification is the GE-Hitachi design, some aspects of which are proprietary to GE-Hitachi. While the licence application for the first new ABWRs to be announced for the USA – at the South Texas Project (STP) – references the certified GE-Hitachi design, Toshiba was selected as the main contractor to build the units. In November 2010, Toshiba submitted an application to renew the design, which includes revisions to bring the certified design in line with theSTP units (see Note m below). [Back]

l. The NRC had approved full design certification for the Westinghouse AP1000 in 2005 and issued a final rule certifying the design in January 2006. However, in May 2007, Westinghouse submitted an application to amend the AP1000 final design certification rule. The NRC expects a final safety evaluation report for the amendment to be issued late in 2010. [Back]

m. Since the decision to go ahead withSouth Texas Project (STP) units 3& 4 was first announced, there have been a number of developments. The combined construction and operating licence (COL) application was prepared by STP NuclearOperating Company (STPNOC) together with GE-Hitachi Nuclear Energy and Bechtel and submitted in September 2007.[3]Just before submittal of the COL application, NRG Energy and STPNOC signed a project services agreement with Toshiba to support the design, engineering, construction and procurement of the units. Fluor was then enrolled to support Toshiba[4]. In November 2010, Nuclear Innovation North America LLC (NINA, the nuclear development company jointly owned by NRG Energy and Toshiba) announced that it had awarded the engineering, procurement and construction (EPC) contract to a "restructured EPC consortium" of Toshiba's US subsidiary Toshiba America Nuclear Energy Corporation (TANE) and The Shaw Group[5].

In the meantime, the reactor technology has moved from being based on the GE design certified by the US Nuclear RegulatoryCommission in 1997. The design had to be renewed by 2012 and a renewal application by Toshiba was submitted in November 2010.[6] The renewal application includes revisions in accordance with the STP design. Hence, the STP reactors are now considered to be ToshibaABWRs, whereas the original intention was to use the 1997 certified design "with only a limited number of changes to enhance safety and construction schedules," with these changes incorporated into the COL application[7].[Back]

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