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Nuclear Power in the USA

(Updated January 2015)

- **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 822 billion kWh in 2013, over 19% of total electrical output. There are now 99 units operable (98,756 MWe) and five under construction.**
- **Following a 30-year period in which few new reactors were built, it is expected that six new units may come on line by 2020, four of those resulting from 16 licence applications made since mid-2007 to build 24 new nuclear reactors.**
- **However, lower gas prices since 2009 have put the economic viability of some existing reactors and proposed projects in doubt.**
- **Government policy changes since the late 1990s have helped pave the way for significant growth in nuclear capacity. Government and industry are working closely on expedited approval for construction and new plant designs.**

In 2013, the US electricity generation was 4294 TWh (billion kWh) gross, 1717 TWh (40%) of it from coal-fired plant, 1150 TWh (27%) from gas, 822 TWh (19%) nuclear, 291 TWh from hydro, 170 TWh from wind, 12 TWh from solar and 18 TWh from geothermal (IEA data). Import from Canada in 2012 was 46.6 TWh net and from Mexico 0.7 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 is not expected to recover to the 2007 level until about 2015. Annual per capita electricity consumption in 2012 was 11,900 kWh. Total capacity is 1068 GWe, less than one-tenth of which is nuclear.

The USA has 100 nuclear power reactors in 31 states, operated by 30 different power companies. 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 2013 it was 91%. The industry invests about \$7.5 billion per year in maintenance and upgrades of these.

There are 65 pressurized water reactors (PWRs) with combined capacity of about 64 GWe and 35 boiling water reactors (BWRs) with combined capacity of about 34 GWe – for a total capacity of 98,951 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 – is expected to start up in 2015 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.

While there are plans for a number of new reactors (see section on [Preparing for new build](#) below), no more than four new units will come on line by 2020. Since about 2010 the prospect of low natural gas prices continuing for several years has dampened plans for new nuclear capacity.

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.

Ten other nuclear plants (13 reactors) are 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.

US power plant shutdowns over 2010 to 2013 comprised 19,772 MWe of coal plant, 12,167 MWe natural gas, 6,793 MWe oil-fired, 3,554 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.

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.



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

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 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. Though it is a very small part of the supply, and is 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 that “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 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 per 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.

Following this, 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 was on capacity markets and whether they 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 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 a 30% reduction by 2030, with states to be responsible for achieving this. There has already been a 16% drop since 2005. Under this EPA Clean Power Plan, the rules are expected to be finalized in June 2015, and states will then have at least one year to submit their plans to comply with the emission reductions, using various means including increased energy efficiency, greater use of nuclear power and renewables, and carbon capture and storage. Nuclear plants are already the main carbon-free generation source for over half of US states, and avoid the emission of over 750 million tonnes of CO₂ per year relative to coal.

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.

In November 2014 the National Association of Regulatory Utility Commissioners urged the EPA, in its proposed rule to reduce carbon emissions from existing power plants, to adopt regulations which “encourage states to preserve, life-extend, and expand existing nuclear generation.” The EPA proposal in its original form would not achieve 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.

Ownership consolidation

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 mergers, some of which failed due to regulatory opposition.

The \$32 billion merger of Unicom and PECO in 2000 to form Exelon created the largest nuclear power producer in the USA, and the third largest in the world. In December 2003, Exelon purchased British Energy's 50% interest in AmerGen, which was originally a 50:50 partnership between PECO and British Energy. AmerGen owned the Clinton, Oyster Creek and Three Mile Island 1 nuclear reactors. Exelon has 10 operating nuclear plants with 17 reactors that generated 20% of US nuclear production in 2007. A proposed merger in 2004 between Exelon, with headquarters in Illinois, and PSEG in New Jersey was rejected by the State of New Jersey. In 2008, Exelon made a \$6.2 billion takeover bid for NRG Energy, which operates the two South Texas reactors, but this was rebuffed in mid-2009.

In 2000, Carolina Power & Light merged with Florida Progress Corporation to become Progress Energy, which now owns five reactors in North Carolina, South Carolina and Florida. Thirty-five percent of the electricity in those three states comes from nuclear power. In 2001, FirstEnergy Corporation, based in Ohio and itself the product of a merger three years earlier, merged with GPU Inc., based in New Jersey. The successor company, FirstEnergy, operates four reactors that provide 28% of the electricity for customers in Ohio, Pennsylvania and New Jersey.

In October 2007, TXU Corp. and Texas Energy Future Holdings Limited Partnership merged to form Energy Future Holdings Corp. The owner and operator of the two unit Comanche Peak nuclear plant is Energy Future Holdings' power generation subsidiary, Luminant.

In January 2011 Duke Energy agreed to purchase Progress Energy, and after shareholders in both companies overwhelmingly approved, this \$26 billion deal was approved by federal regulators in June 2012. The combined company was set to operate 12 power reactors, the largest regulated nuclear fleet in the USA, but Crystal River was decommissioned in February 2013, reducing this to 11.

Another means of consolidation has been via management contracts. The Nuclear Management Company, a joint venture formed in 1999 by four Midwest utilities, was approved by the Nuclear Regulatory Commission as a nuclear operating company. It took over operation, fuel procurement and maintenance of eight nuclear units (4,500 MWe) at six sites, which continued to be owned by the utilities, each with 20% of NMC. These

remained responsible for used fuel and decommissioning. As with mergers, the main drivers for NMC were cost reductions and streamlined operations. However, with sales of plants achieving consolidation in that way, only two plants (three reactors) – Monticello and Prairie Island – remained with NMC and these had the same owner. Accordingly the operating licence was transferred back to the owner and NMC was incorporated into Xcel Energy, the parent company, in 2008.

In 2012 Exelon took over management of Omaha Public Power District's Fort Calhoun for at least 20 years, to improve the performance of the single-unit plant. OPPD will remain the owner and licensee, but Exelon will provide management under contract, having already contributed consulting services.

In March 2012 Exelon merged with Constellation Energy (CENG) which operated five reactors at three plants (taking a 50.01% share, EDF retained 49.99%), and two years later the fleets were integrated operationally so that Exelon operated 23 reactors with over 22 GWe capacity and holds the licences.* These are all merchant plants.

* EDF agreed to have the five CENG units (3.9 GWe) consolidated in Exelon's fleet for a \$400 million exceptional dividend from CENG (funded by a loan from Exelon) and option to sell the CENG stake to Exelon at fair market value between 2016 and 2022.

In 2012, seven utilities with 13 Westinghouse PWR reactors totaling 16 GWe within the same NRC region set up the Stars Alliance LLC to rationalize their management. Stars members and their plants* are in Arizona, Texas, California, Missouri and Kansas. Stars – Strategic Teaming And Resource Share Alliance – was formerly part of a wider Utilities Service Alliance, which now comprises utilities with single-reactor nuclear power stations.

*Arizona Public Service Co., Palo Verde in Arizona; Luminant Generation Co., Comanche Peak in Texas; Pacific Gas & Electric, Diablo Canyon in California; Southern California Edison, San Onofre in California; STP Nuclear Operating Co., South Texas Project in Texas; Union Electric, Callaway in Missouri; and Wolf Creek Nuclear Operating Corp., Wolf Creek in Kansas.

Purchase of reactors

Acquisitions have been skewed toward plants in regions with high electricity rates due to the potential for higher profit margins if the plants' production costs can 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 (see Nuclear Power in the USA Appendix 2: [Power Plant Purchases](#)).

In the last 15 years, there have been 19 reactor purchases, usually in states where electricity pricing has 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. In many cases, large power companies have 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 has occurred over the last decade. Originally based in Arkansas, Louisiana, Mississippi and eastern Texas, Entergy has doubled its nuclear generation capacity since 1999 with the acquisition of reactors in New York, Massachusetts, 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).

Representing significant international rather than simply US consolidation, Constellation Energy in January 2009 accepted the Electricité de France (EDF) \$4.5 billion bid for half of its nuclear power business – more than 60% of its production. The deal gave EDF a major foothold in the USA, with the share of 3,994 MWe at Calvert Cliffs in Maryland, and Nine Mile Point and Ginna in New York. All the five reactors have been granted 20-year licence extensions, and the deal values them at about \$2,250/kWe net, but including fuel. (The NY plants were bought by Constellation for \$533/kWe without fuel earlier in the decade.)

EDF already owned 9.5% of Constellation itself, and had committed \$975 million to the UniStar Nuclear Energy joint venture which it set up with Constellation to build, own and operate a fleet of US-EPR units in North America with the "objective of leading the nuclear renaissance in the USA". In October 2010, Constellation pulled out of Unistar and sold its share to EDF for \$140 million. This meant that Unistar became wholly foreign-owned, which precluded any US nuclear development at all until that changed to majority US ownership.

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.

Lifetime extensions 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 October 2014, the NRC had extended the licences of 75 reactors (72 still operating), almost three-quarters of the US total, and about 30 were actually in their 40-60-year age bracket. The NRC is considering licence renewal applications for 19 further units, with six more applications expected. 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. The licence renewal process typically costs \$16-25 million, and takes 4-6 years for review by NRC.

The original 40-year period was more to do with amortisation of capital than implying that reactors were designed for only that lifespan. The NRC is now preparing to consider extending operating licences beyond 60 out to 80 years, with its Subsequent Licence Renewal (SLR) Program. The first applications are expected before 2020, and Dominion is already discussing prospects for North Anna with NRC.

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. Most PWRs have also replaced reactor pressure vessel heads. 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 programs 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.

Also 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.

Preparing for new build

Today the importance of nuclear power in USA is geopolitical as much as economic, reducing dependency on imported oil and gas. The operational cost of nuclear power in existing plants is very competitive with alternatives. In 2012 it was 2.4 c/kWh, compared with gas 3.4 c/kWh and coal 3.3 c/kWh.

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 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
Watts Bar 2, TN	Westinghouse PWR	1218 (1150 net)	Tennessee Valley Authority	2007 re-start	on line Oct 2015
Vogtle 3, GA	Westinghouse AP1000	1200 (1117 net)	Southern Nuclear Operating Company	March 2013	has loan g'tee, late 2017
	Westinghouse	1200	Southern Nuclear		has loan g'tee, late

Vogtle 4, GA	AP1000	(1117 net)	Operating Company	Nov 2013	2018
V.C.Summer 2, SC	Westinghouse AP1000	1200 (1117 net)	South Carolina Electric & Gas	March 2013	short list loan g'tee, end 2018
V. C. Summer 3, SC	AP1000	1200	South Carolina Electric & Gas	Nov 2013	short list loan g'tee; late 2019
Subtotal 'under construction': 5 units (6018 MWe gross, 5618 MWe net)					

US nuclear power reactors planned and proposed^e

Site	Technology	MWe gross	Proponent/utility	COL lodgement & issue dates	Loan guarantee; start operation
Bellefonte 1 , AL	B&W PWR	1263	Tennessee Valley Authority	30/10/07 for unit 3 (and unit 4) ^h but COL review suspended	2018-20
William States Lee, SC	AP1000 x 2	2400	Duke Energy	13/12/07, COL target late 2016	2024, 2026
Turkey Point, FL	AP1000 x 2	2400	Florida Power & Light	30/6/09, COL target late 2016	6/2022, 6/2023
Subtotal 'planned': 5 units (6063 MWe gross), 3 COL applications					
Levy County, FL	AP1000 x 2	2400	Duke Energy (formerly Progress Energy)	30/7/08, COL target late 2015	suspended indefinitely
Shearon Harris, NC	AP1000 x 2	2400	Duke Energy (formerly Progress Energy)	19/2/08, suspended 5/13	2026
North Anna , VA	ESBWR ⁱ	1600	Dominion	20/11/07, delayed but expected mid-2016	2022
Comanche Peak, TX	US-APWR x2	3400	Luminant (merchant plant)	19/9/08, COL target 12/14 but suspended 11/13	2020s
South Texas Project , TX	ABWR x 2	2712	Toshiba, NINA, STP Nuclear (merchant plant)	20/9/07, delayed	short list loan guarantee
UAMPS Carbon-free power project, ID	Nuscale x 12	600	Western Initiative for Nuclear, Utah AMPS, Energy NW	Design Cert Application planned 2016	2024
Clinch River, TN	mPower x 2	360	TVA	construction permit application expected 2015 but now deferred	2022
Callaway , MO	Westinghouse SMR x 5	1125	Ameren Missouri	24/7/08 for EPR then cancelled, SMR proposal suspended	
Calvert Cliffs , MD	US EPR	1710	UniStar Nuclear (merchant plant)	7/07 and 13/3/08, delayed, in 2012 barred	refused an offered loan guarantee, needs US equity

Grand Gulf, MS	ESBWRi	1600	Entergy	27/2/08 but COL application review suspended for some years
Fermi, MI	ESBWR	1600	Detroit Edison	18/9/08, no decision to proceed but COL target late 2015
River Bend, LA	ESBWRi	1600	Entergy	25/9/08 but COL application review suspended
Nine Mile Point, NY	US EPR	1710	UniStar Nuclear (merchant plant)	30/9/08 but COL application withdrawn 2013
Bell Bend (near Susquehanna), PA	US EPR	1710	PPL/Talen merchant plant	10/10/08, delayed
Green River, UT	AP1000 x 2	2400	Blue Castle/Transition Power Development	ESP application expected 2016
Salem 3/Hope Creek, NJ	unspecified	Perhaps 1200	PSEG Nuclear	ESP only 25/5/10, target late 2014
Subtotal 'proposed': 18 large units, 19 small (ca. 27,600 MWe gross), 12 COL applications to Aug 2012, including 5 suspended				
Other proposals, less definite or moribund:				
Victoria County, TX	2, unspecified	perhaps. 2400	Exelon (merchant plant)	03/9/08 but withdrawn, Now ESP only 25/3/10, but withdrawn 28/8/12
Piketon (DOE site leased to USEC), OH	US EPR	1710	Duke Energy	ESP application was expected late 2013
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)	

Of the above, for the first four AP1000 units, construction is well under way at Vogtle, Georgia, with about \$4 billion invested in the project to February 2012, before it was technically 'under construction'. Construction is also well under way at Summer, South Carolina, and original cost projections have been reduced. See also section below.

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

However the economic outlook in 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) of 1300-1500 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 it is now Toshiba that is promoting 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'.
- 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.

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

- The Mitsubishi US-APWR, a 1700 MWe design developed from the design for a reactor about to be built at Tsuruga in Japan. The application was submitted in December 2007 and certification was expected to be complete 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 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. The 1600 MWe EPR is being built in Finland, France, and Guangdong in China, and is planned for UK.
- The Korean APR-1400 reactor, which has been sold to the United Arab Emirates and is under construction there as well as in South Korea. Following 11 pre-application meetings, Korea Hydro & Nuclear Power submitted a design certification application to NRC in October 2013. However, further detail was requested, and it was resubmitted in January 2015.
- The Russian VVER-1200 reactor which is being built at Leningrad II, Novovoronezh II and the Baltic

plants may be submitted for US design certification through Rusatom Overseas, according to Rosatom.

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

- The Babcock & Wilcox mPower reactor is an integral 180 MWe PWR which has attracted funding support from DOE. B&W and TVA planned to submit an application in 2015 for design certification and licensing to construct up to four units at Clinch River. B&W expected both design certification and construction permit in 2018, and commercial operation of the first two units in 2022. In 2012 B&W secured up to \$226 million DOE support for the design, but in 2014 cut back development funding.
- 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 late in 2016. South Carolina and NuHub also back the proposal.
- A demonstration unit of the NuScale multi-application small reactor, a 50 MWe integral PWR is also proposed for Savannah River with Fluor and DOE support. There are also plans to build a 12-module power plant in Idaho, supported by six western states. This UAMPS Carbon-Free Power Project would be owned by Utah AMPS and operated by Energy Northwest. NuScale expects to lodge an application for US design certification in 2015. It had spent some \$130 million on licensing to November 2013, and expects the NRC review to take 39 months, so the first unit could be under construction late in 2019 and operating in 2024. In 2013 NuScale secured up to \$226 million DOE support for the design.

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 Nuclear Power 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.

In March 2010, Exelon applied for an ESP for its Victoria County, TX, site and withdrew the COL application for that project. 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 expects it to be approved about the end of 2014.

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 2.1 cents/kWh tax credit for the first 6,000 MWe of capacity in the first eight years of operation, 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 under construction and planned, or which have been planned

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 1150 MWe reactor (net summer capacity) was expected to start up in October 2012 and come online in 2013 at a cost of about \$2.5 billion, but this schedule has slipped substantially, so that TVA now expects it to start up in July and achieve commercial operation by November 2015, with major budget overrun to \$4.2 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, and by August 2014 was 90% complete. Fuel loading is expected mid-2015 and TVA reported it as on schedule and within budget. The construction permit has been extended to September 2016, and TVA says that the NRC expects to issue the operating licence in April 2015. 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.

Bellefonte

TVA also has 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 about 55% complete due to the transfer or sale of many components and the need to upgrade or replace others, such as instrument and control system, reactor pressure vessel, steam generators and main condenser tubing. In August 2011 TVA decided 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](#)). In late 2013 TVA revised the estimated cost to \$7.4 to \$8.7 billion.

In August 2010, TVA had committed to spending \$248 million to September 2011 towards that 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 decision to proceed, it includes construction and component replacement work on the plant's nuclear systems plus fuel design and fabrication. Areva will also supply a digital reactor instrumentation and control (I&C) system, a completely modernized control room and plant simulator for personnel training. Areva contracts amount to some \$1 billion. TVA has asked the NRC to defer consideration of its COL for units 3&4. Heavy construction will start when Watts Bar 2 is complete. No decision has been made on completing unit 2. It is a regulated plant, with guaranteed cost recovery.

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. JSW has shipped forged components to Doosan for fabrication. Southern Nuclear was awarded government loan guarantees, and 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) has 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. The units are expected on line in mid-2017 and mid-2018. 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. Minority equity in the project is held by Oglethorpe Power (30%), MEAG Power (22.7%) and Dalton city (1.6%).

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 includes 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. In October 2014 the cost was estimated at over \$11 billion, and the completion date of unit 2 has slipped to the end of 2018 or early 2019.

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 in 2019 and in 2020. There were delays in delivery of modules. SCEG's loan guarantee application was accepted by 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.

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 gas.) 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, but the NRC website in April 2014 gave no date. For the environmental review it showed February 2016 as the target date. FPL said in April 2014 that it expected to start operation of the first new unit in June 2022 and the second a year later.

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, and the safety evaluation review is due for completion late in 2015. 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 COL to late 2016. Duke spent \$403 million on licensing, planning and pre-construction activities for the

plant to mid-2014. The 1117 MWe (net) units are now expected on line in 2024 and 2026.

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 consortium (now CB&I). The contract is for \$7.65 billion (\$3462/kWe), of an overall project cost of about \$14 billion.

A final decision to build will be made when the NRC issues a licence for the project – following revisions to the COL application in April 2013, the COL safety evaluation is due to be complete in September 2014 and the COL likely in 2015. 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.

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 will continue to pursue the COLs (subject to Westinghouse cooperation), 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 Levy County NPP in the original time frame. Duke Energy Florida is planning to sell all the long-lead time equipment it had ordered by the end of 2014, but it is still 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 'canceled' 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 1520 MWe (net) ESBWR as preferred technology (as originally selected in 2005), and would amend its COL application accordingly. In May 2013 it agreed a construction contract with GE Hitachi and Fluor, conditional upon proceeding. It is now expecting COL approval in mid-2016. (The US-APWR design certification was scheduled in late 2013 but has now been extended indefinitely.) Dominion says it will not make a decision to build it until it gets the COL, and hence it remains "proposed" in WNA reckoning. Dominion suggests start-up in 2022 if it proceeds. It is a regulated plant, with guaranteed cost recovery.

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 granting 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.

Clinch River

Babcock & Wilcox (B&W) has set up B&W Modular NuclearEnergy 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 and construction permit application to be submitted to NRC in 2014 or 2015. Bechtel has joined the project as an equity partner to design, licence and deploy it. As well as TVA, First Energy and Oglethorpe Power are involved with the proposal.

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. WNA 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 are 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 WNA 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 m³/day.

South Texas Project 3&4

This is envisaged as a merchant plant with two 1356 MWe Advanced Boiling Water Reactors^m. NRG Energy already operates two reactors at the site, and works were under way preparing for the new units.

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 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.

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

NINA awarded the EPC contract to Shaw Group 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.

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 has persevered with the project, though it wrote off \$305 million (JPY 31 billion) on NINA in 2014. It is assumed that Tepco will not be in a position to maintain any involvement. In the light of developments WNA has moved the project from planned back to "proposed", but the ASLB ruling in April 2014 may lead to a change back if replacement US funding is secured.

Fermi 3

This is a reference unit for GE-H'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. The safety evaluation is not expected before full design certification for the ESBWR

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 and 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 being 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

Appendices

Appendix 1: [US Operating Nuclear Reactors](#)

Appendix 2: [Power Plant Purchases](#)

Appendix 3: [COL Applications](#)

Related information pages

[US Nuclear Power Policy](#)

[US Nuclear Fuel Cycle](#)

Notes

a. The first nuclear reactor in the world to produce electricity (albeit a trivial amount) was the small Experimental Breeder Reactor (EBR-1) in Idaho, which started up in December 1951. In 1953, President Eisenhower proposed his *Atoms for Peace* program, 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 1957 and 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 Regulatory Commission (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 to 31 March 2013. TVA still requires an operating licence for the reactor. [\[Back\]](#)

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 the TVA 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 is now expected to be complete in 2015.

The COL reviews of Entergy's applications for Grand Gulf and River Bend, 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. [\[Back\]](#)

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 the STP 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 with South 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 Nuclear Operating 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 Regulatory Commission 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 Toshiba ABWRs, 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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