NUCLEAR POWER - CONVENTIONAL

DESCRIPTION

Nuclear fission—the process in which a nucleus absorbs a neutron and splits into two lighter nuclei—releases tremendous amounts of energy. In a nuclear power plant, this fission process is controlled in a reactor to generate heat. The heat from the reactor creates steam, which runs through turbines to power electrical generators.

The most common nuclear power plant design uses a Pressurized Water Reactor (PWR). Water is used as both neutron moderator and reactor coolant. That water is kept separate from the water used to generate steam and drive the turbine. In essence there are three water systems: one for converting the nuclear heat to steam and cooling the reactor; one for the steam system to spin the turbine; and one to convert the turbine steam back into water.

The other common nuclear power plant design uses a Boiling Water Reactor (BWR). The BWR uses water as moderator and coolant, like the PWR, but has no separate secondary steam cycle. So the water from the reactor is converted into steam and used to directly drive the generator turbine.

COST

Conventional nuclear power plants are quite expensive to construct but have fairly low operating costs. Of the four new plants currently under construction, construction costs reportedly range from $4.7 million to $6.3 million per MW. Production costs for Palo Verde Nuclear Generating Station are reported to be less than $15/MWh.

CAPACITY FACTOR

Typical capacity factor for a nuclear power plant is over 90%.

TIME TO PERMIT AND CONSTRUCT

Design, permitting and construction of a new conventional nuclear power plant will likely require a minimum of 10 years and perhaps significantly longer. For example, proponents of the V.C. Summer Reactor in South Carolina submitted their application to the Nuclear Regulatory Commission in 2008, received a license in 2012, started construction shortly thereafter and anticipate completion of the first unit in 2018.

NOTES

The United States has 104 nuclear reactors in operation that produce more than 19% of the country's total electrical output. There are four new nuclear power plants currently under construction in the United States. The Tennessee Valley Authority is also completing a unit on which construction had been suspended in the 1980s. In 2013, four reactors were retired—one in Florida, one in Wisconsin and two in California.

WA
Columbia
OR
ID
MT
ND
SD
WY
NV
UT
CA
CO
NE
KS
AZ
NM
OK
TX
MN
Monticello
Prairie Island 1,2
IA
Duanne Arnold
Fort Calhoun
Cooper
Wolf Creek
MO
Callaway
WI
Kewaunee
Point Beach 1,2
MI
Palisades
Cook 1, 2
Fermi 2
Davis-Besse 1
Byron 1,2
Quad Cities 1,2
Dresden 2,3
LaSalle 1,2
Braidwood 1,2
Clinton 1
IL
IN
OH
Perry 1
Beaver Valley 1,2
KY
WV
VA
TN
Watts Bar 1
Sequoyah 1,2
AR
Arkansas Nuclear One 1,2
MS
Grand Gulf 1
LA
River Bend
Waterford3
AL
Browns Ferry 2 ,3
Farley 1,2
GA
Vogtle 1,2
Hatch 1,2
FL
Crystal River 3
St. Lucie 1,2
Turkey Point 3,4
NC
Harris 1
McGuire 1,2
Catawba 1,2
Oconee 1,2,3
Robinson 2
SC
Summer 1
Brunswick 1,2
North Anna 1,2
Surry 1,2
Calvert Cliffs 1,2
MD
DE
PA
Peach Bottom 2,3
Three Mile Island 1
Susquehanna 1,2
Limerick 1,2
NJ
Oyster Creek
Hope Creek 1
Salem 1,2
NY
FitzPatrick
Nine Mile Point 1,2
Ginna
Indian Point 2,3
CT
Millstone 2,3
MA
Pilgrim 1
VT
Vermont Yankee
NH
Seabrook
ME
Diablo Canyon 1,2
San Onofre 2,3
Palo Verde 1,2,3
Comanche Peak 1,2
South Texas Project 1,2

Nuclear Power in the USA

(Updated 31 July 2013)

- **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 104 nuclear reactors produced 821 billion kWh in 2011, over 19% of total electrical output. There are now 100 units operable and three under construction.**
- **Following a 30-year period in which few new reactors were built, it is expected that 4-6 new units may come on line by 2020, the first of those resulting from 16 license applications made since mid-2007 to build 24 new nuclear reactors.**
- **However, lower gas prices since 2009 have put the economic viability of some of these 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 2011, the US electricity generation was 4344 billion kWh gross, 1874 TWh (43%) of it from coal-fired plant, 1047 TWh (24%) from gas, 821 TWh (19%) nuclear, 351 TWh (8%) from hydro and 121 TWh (2.8%) from wind. 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 is currently around 12,300 kWh. Total capacity is 1041 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. 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 continued to grow. 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), the prospect of low natural gas prices continuing for several years has dampened these plans and probably no more than four new units will come on line by 2020.

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.

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 constrains 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.

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. Further industry consolidation is likely.

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 has dropped from 45 in 1995 to 25 today, 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 Ilinois, 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 2011 Exelon agreed a merger with Constellation Energy, including Constellation Energy Nuclear Group, adding 5 reactors at three plants and bringing its nuclear generating capacity to almost 21,000 MWe gross. This was finalized in March 2012. EdF owns 49.99% of CENG, but agreed to have the five CENG units (3.9 GWe) consolidated in Exelon’s fleet in mid 2013 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 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 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 ten 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, 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) 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 gives 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 conceals 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 is adding 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, from577 billion kilowatt hours to 809 billion kWh, a 40% improvement despite little increase in installed capacity, and equivalent to 29new 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 the 20-year extension to these dates means that major refurbishing, such as replacement of steam generators and upgrades of instrument and control systems*, can be justified.

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

At June 2013, the NRC had extended the licences of 73 reactors (72 still operating), well over two thirds of the US total. The NRC is considering licence renewal applications for 18 further units, with 7 more applications expected. Hence, almost all of the 100 reactors are likely to have 60-year lifetimes, with owners undertaking major capital works to upgrade them at around 30-40 years. The original 40-year period was more to do with amortisation of capital than implying that reactors were designed for that lifespan.

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 web site 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 – 1.87 ¢/kWh in 2008 – is 68% of electricity cost from coal and a quarter of that from gas.

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.

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 about 2012, with first concrete on two units in March 2013.

There are three regulatory initiatives which 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, planned and proposed[e]

Site	Technology	MWe gross	Proponent/utility	COL lodgement & issue dates	Loan guarantee; start operation
Watts Bar 2 , TN	Westinghouse PWR	1218 (1177 net)	Tennessee Valley Authority	No COL[f]	on line Dec 2015
Vogtle 3, GA	Westinghouse AP1000	1200 (1117 net)	Southern Nuclear Operating Company	24/7/08, COL Feb 2012	has loan g'tee, late 2017
V.C.Summer 2, SC	Westinghouse AP1000	1200 (1117 net)	South Carolina Electric & Gas	31/3/08, COL March 2012	short list loan g'tee, end 2017
Subtotal 'under construction': 3 unit (3618 MWe gross, 3411 MWe net)					
Vogtle , GA	AP1000	1200	Southern Nuclear Operating Company	24/7/08, COL Feb 2012	granted loan guarantee; late 2018
V. C. Summer 3, SC	AP1000	1200	South Carolina Electric & Gas	31/3/08, COL March 2012	short list loan guarantee; early 2019
Levy County, FL	AP1000 x 2	2400	Duke Energy (formerly Progress Energy)	30/7/08, COL target late 2015	2024-25
William States Lee, SC	AP1000 x 2	2400	Duke Energy	13/12/07, COL target late 2016	'2020s'
Turkey Point, FL	AP1000 x 2	2400	Florida Power & Light	30/6/09, COL target 12/14	2022, 23
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
Subtotal 'planned': 9 units(10,860 MWe gross), 6 COL applications					

Site	Technology	MWe gross	Proponent/utility	COL lodgement & issue dates	Loan guarantee; start operation
Shearon Harris, NC	AP1000 x 2	2400	Duke Energy (formerly Progress Energy)	19/2/08, suspended 5/13	2026
North Anna , VA	ESBWR[i]	1700	Dominion	20/11/07, delayed but expected end 2015	2022
Comanche Peak, TX	US-APWR x2	3400	Luminant (merchant plant)	19/9/08, COL target 12/14	2019, 2020
South Texas Project , TX	ABWR x 2	2712	Toshiba, NINA, STP Nuclear (merchant plant)	20/9/07, delayed	short list loan guarantee
Clinch River, TN	mPower x 2	360	TVA	construction permit application expected 2015	2022
Callaway , MO	Westinghouse SMR x 5	1125	Ameren Missouri	24/7/08 for EPR then cancelled, no decision re SMRs	
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	ESBWR[i]	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 mid-2015	
River Bend, LA	ESBWR[i]	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 review partially suspended	
Bell Bend (near Susquehanna), PA	US EPR	1710	PPL merchant plant	10/10/08, delayed	
Blue Castle, UT	unspecified	Perhaps 1200	Transition Power Development	ESP application expected 2013	
Salem/Hope Creek, NJ	To be decided in 2012	Perhaps 1200	PSEG	ESP only 25/5/10, target late 2014	On line 2021
Subtotal 'proposed': 15 large units, 7 small (ca. 24,000 MWe gross), 11 COL applications to Aug 2012, including 5 suspended					

Site	Technology	MWe gross	Proponent/utility	COL lodgement & issue dates	Loan guarantee; start operation
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	12/07 MHI
Piketon (DOE site leased to USEC), OH	US EPR	1710	Duke Energy	ESP application expected late 2013	
Hammett, ID	APR-1400	1455	Alternate Energy Holdings Inc. (merchant plant)	No credible plans	
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, site work is well under way at Vogtle, Georgia, with about $4 billion invested in the project to February 2012, before it was technically 'under construction' following first concrete on the reactor island, and work has also started at Summer, South Carolina, with $1.4 billion spent to February 2011, and original cost projections decreased. See also section below.

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 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 it is now Toshiba that is promoting the design most strongly in the USA.[k]
- 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 of many of them is being built in China. Westinghouse has submitted revisions to its design, and the NRC has requested another change, so the revised design will not be cleared until about August 2011.

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

- GE Hitachi's Economic Simplified BWR (ESBWR) of 1550 MWe, developed from the ABWR. The ESBWR has passive safety features and is included in the proposals of several companies planning to build new reactors. GE Hitachi submitted the application in August 2005,design approval was notified in March 2011 and design certification is now expected in 2013.
- 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 is expected to be complete in February 2016. Two US-APWR reactors have been proposed in the Luminant-Mitsubishi application for Comanche Peak, and one for Dominion's North Anna.
- 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 involve it. The application was submitted in December 2007 and the design certification rule is expected after mid-2015, with delays due to the complexity of digital instrumentation and control systems. Under a revised schedule, Areva is expected to submit to the NRC, by 30 August 2013, details of how the EPR design meets post-Fukushima requirements. 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. Following pre-application meetings, a design certification application is expected in mid 2013 and is likely to conclude in 2017.
- The Russian VVER-1200 reactor which is being built at LeningradII, 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:

- An application is expected in 2013 for the Westinghouse SMR, a 225 MWe integral PWR based on the AP1000. Ameren Missouri is proposing up to five units for its Callaway site, instead of using the EPR.
- The Babcock & Wilcox mPower reactor is an integral 125 MWe PWR which has attracted funding support from DOE. B&W and TVA plan to submit an application in 2015 for design certification and licensing to construct up to four units at Clinch River. B&W expects both design certification and construction permit in 2018, and commercial operation of the first two units in 2022.
- 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 45 MWe integral PWR is also proposed for Savannah River with Fluor and DOE support.

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 reactor at its Salem/Hope Creek site on the Delaware River in New Jersey in May 2010, and expects it to take three years to process.

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 1177 MWe 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 has slipped substantially, so that TVA now expects it on line in November 2015, with major budget overrun to almost $4.0 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 in April 2012 was 70% complete. 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.

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 August 2010, TVA had committed to spending $248 million to September 2011 towards that[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 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

Site works are largely complete in preparation for two 1200 MWe Westinghouse AP1000 reactors. Some of the reactor steelwork is on site, the steel reinforcing (rebar) for the base mat is largely complete, and assembly and welding of unit 3's containment vessel bottom head is complete. In April 2008, Georgia Power signed an EPC contract with Westinghouse and The Shaw Group consortium. JSW has shipped forged components to Doosan for fabrication. Southern Nuclear has been awarded government loan guarantees, and the COL was issued by NRC in February. 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 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 started in March 2013 and 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. Minority equity in the project is held by Oglethorpe Power (30%), MEAG Power (22.7%) and Dalton city (1.6%).

Summer 2 & 3

Site works are well advanced for two 1200 MWe Westinghouse AP1000 reactors. 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. In September 2011 SCEG was starting 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 has been reduced and the total estimated in April 2012 was $9.2 billion. 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. Reactor pressure vessels and steam generators will come 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 at the end of 2017 and in 2019. There have been delays in delivery of modules. SCEG's loan guarantee application was accepted by DOE and the project was short-listed in May 2009. It is a regulated plant, with guaranteed cost recovery.

Levy County, Florida

Site works have 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 expects 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. 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. Latest estimated operational dates are 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 project.

Turkey Point

NextEra Energy subsidiary Florida Power & Light 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 due for 109 MWe uprates in 2012-13. The NRC safety review is scheduled to be completed late in 2013, and the environmental review in 2014.

Lee

Duke Energy lodged a COL 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 due to be completed early in 2013, so that the first unit could be on line in 2021. 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 $320 million on licensing, planning and pre-construction activities for the plant to the end of 2012.

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 Nuclear Energy LLC to market the mPower small modular reactor design of125-180 MWe. The company intends to apply for design certification in 2013, and a COL in 2012 for TVA's Clinch River site, followed by construction start in 2015 and operation of the first unit in 2020.As well as TVA, First Energy and Oglethorpe Power are involved with the proposal.

Comanche Peak

Luminant plans 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. Design certification and COL are scheduled late in 2013. 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.

Calvert Cliffs 3

Unistar, now owned by EdF, plans 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 is due early in 2013, but the COL – originally scheduled in mid-2013 – will require 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, producing4700 m^3/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 12%of NINA with NRG Energy 88%, 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." It expected that the NRC decision would be reviewed by the NRC Atomic Safety Licensing Board (ASLB).

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 has 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 agreed to persevere with the project. 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".

North Anna 3

In December 2010, Dominion announced that it had agreed with Mitsubishi Heavy Industries to continue pre-construction efforts for this US-APWR unit, but Dominion also says it will not make a decision to build it until it gets the COL, and hence it remains "proposed" in WNA reckoning. 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. It is now expecting approval at the end of 2015. The US-APWR design certification and plant COL were scheduled in late 2013. Dominion suggests start-up in 2022 if it proceeds. It is a regulated plant, with guaranteed cost recovery.

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 are 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. In1953, 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 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 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 a2-3% 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 theAP1000 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 proposedAP1000 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 unit2 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 unit1.[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 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 ÉSBWR. 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 April2012 Ameren Missouri set out 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 November2010, 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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World Nuclear Association

Representing the people and organisations of the global nuclear profession

Economic Benefits of Palo Verde Nuclear Generation Station

An Economic Impact Study by the Nuclear Energy Institute

November 2004

NUCLEAR ENERGY INSTITUTE

Executive Summary

The Palo Verde Nuclear Generating Station in Arizona's western Maricopa County is an integral part of the county and state economy. The plant provides jobs and makes purchases that stimulate the local economy directly and indirectly. Additional benefits to the area include higher tax revenue, increased labor income and significant charitable contributions to the local community. In addition, there are important intangible benefits, such as clean air, environmental stewardship and stable, affordable electricity prices. According to this study by the Nuclear Energy Institute, Palo Verde's economic impact reaches beyond the local community to the state and nation.

The Palo Verde plant is operated by Arizona Public Service Co. and jointly owned by Arizona Public Service Co., El Paso Electric Co., Los Angeles Department of Water and Power, PNM Resources, Salt River Project, Southern California Edison, and Southern California Public Power Authority.

In 2002, operation of the Palo Verde Power Nuclear Generating Station increased Maricopa County's economic output by $149.3 million. Adding the direct value of the plant's electricity output brings the county's economic output attributable to Palo Verde to $868.5 million.

The plant's total economic impact includes direct effects, which comprise the value of electricity produced at the plants, as well as secondary—or indirect—effects resulting from plant operation.

The operation of Palo Verde, and its secondary effects, accounts for 3,943 jobs in Maricopa County. Earnings for these jobs total $245.2 million in the county. Additionally, the plant and its related economic activity provide $62 million to state and local tax coffers.

The plant is one of the largest employers in the far Southwest Valley area of Maricopa County. The plant directly employs 2,386 people, including long-term contractors and corporate staff. The vast majority of these workers live in Maricopa County. More than one of every 100 working people in the municipalities of Avondale, Buckeye, Goodyear, Litchfield Park and Wickenburg work at Palo Verde. In addition, these jobs pay 13 percent above the average Maricopa County salary.

The economic activity generated by the Palo Verde plant creates another 1,570 jobs in the county. Given the combination of employees at the plant and indirect jobs created by Palo Verde's economic activity, the plant is responsible for 3,943 jobs in Maricopa County.

The plant's principal expenditure in Maricopa County is employee compensation. During 2002, Palo Verde paid $193.2 million in compensation to employees living in the county. Additionally, the economic activity created by Palo Verde accounted for $51.9 million in non-Palo Verde employee compensation in Maricopa County. Together, the direct and indirect compensation from the plant accounted for $245.2 million in labor income in the county.

Palo Verde makes substantial purchases in Maricopa County. In 2002, these purchases totaled $223.4 million, including $17.8 million in Maricopa County. Economic activity generated by Palo Verde also led to $149.3 million in increased output in the county.

Palo Verde pays an estimated $54.1 million in state and local taxes annually. Additionally, the economic activity generated by Palo Verde contributes another $7.8 million in state and local taxes, through increased income, property and sales taxes. By combining direct and indirect taxes, Palo Verde accounts for $62 million in state and local tax payments.

Besides the economic benefits Palo Verde provides, the plant generated 30.9 billion kilowatt-hours of electricity in 2002, approximately 35 percent of Arizona's total electricity generation. This low-cost electricity helped keep energy prices in Arizona affordable. During 2002, Palo Verde had a production cost of 1.33 cents per kilowatt-hour, compared with an average production cost of 2.53 cents per kilowatt-hour for the rest of the Southwest energy market. Palo Verde did this without producing air pollution typical of some other large power generation sources.

Palo Verde also is an integral part of the local community, as seen in charitable giving by Arizona Public Service Co. and its employees. In 2002, Palo Verde employees donated $459,564 to charitable organizations. The largest contribution supported local educational programs. Additionally, Palo Verde employees contributed more than 50,000 man-hours of volunteer time to Arizona community events.

The plant also plays a vital role in maintaining regional air quality. Without the plant, nitrous oxide emissions in the local area would increase by 93,000 tons per year and sulfur dioxide emissions would rise by 158,000 tons annually because fossil-fueled power plants would be used to offset electricity generation from nuclear energy. Additionally, carbon dioxide emissions, one of the main greenhouse gases, would increase by 29.1 million tons.

Section 2: The Palo Verde Nuclear Generating Station

This section provides background information on Palo Verde and Maricopa County to frame the results of subsequent sections, including a brief history of the plant and information on its cost, employment, performance and taxes. This section also includes information on local area details of Maricopa County, its major cities and the state of Arizona, including total employment, earnings, local tax collections and regional electricity cost.

2.1 History and Information

The Palo Verde Nuclear Generating Station, near Wintersburg, Ariz., is about 45 miles west of Phoenix (see Figure 2-2). The facility is the largest nuclear power plant in the United States and has been the top power producer of any kind in the country for 12 consecutive years. The plant lies in Maricopa County, which has a population of about 3.3 million and covers 9,203 square miles. Palo Verde, operated by Arizona Public Service Co., is owned by Arizona Public Service Co., El Paso Electric Co., Los Angeles Department of Water and Power, PNM Resources, Salt River Project, Southern California Edison, and Southern California Public Power Authority.

Table 2-1. Palo Verde Nuclear Power Plant: At a Glance

Unit	Capacity	Commercial Operation Year	License Expiration Year	Reactor Type
Unit 1	1,243 MW	1986	2024	PWR
Unit 2*	1,243 MW	1986	2025	PWR
Unit 3	1,247 MW	1988	2027	PWR

MW = megawatts; PWR = pressurized water reactor

** Unit 2's capacity is larger because of an expansion of plant capacity in 2003.*

Throughout its operation, Palo Verde has been a leader in the nuclear energy industry. During most of the 1990s, the Palo Verde reactors maintained capacity factors above the industry average. Capacity factor, a measure of efficiency, is the ratio of actual electricity generated compared with the maximum possible generation if the plant were to operate at full capacity for one year.

Since 1998, all reactors have operated at or near a 90 percent capacity factor on a three-year rolling average basis.

Figure 2-1. Three-Year Average Capacity Factors

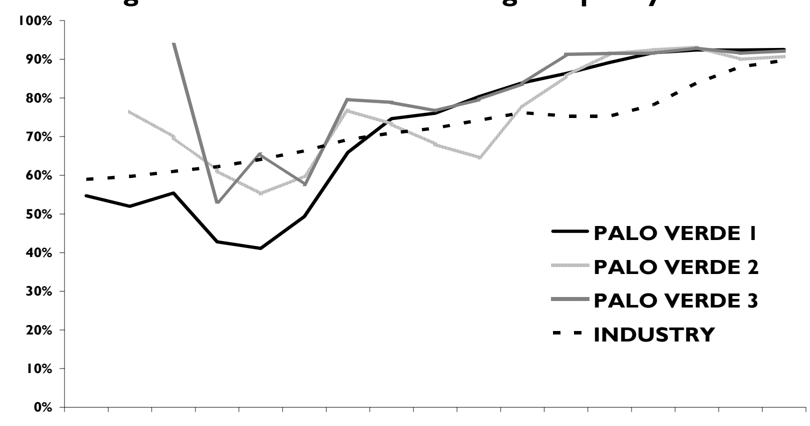


Figure 2-2. The Palo Verde Nuclear Generating Station and Surrounding Area

2.2 Generation

Palo Verde generated more than 30.9 billion kilowatt-hours of electricity in 2002—a U.S. generating record. The plant provides about 35 percent of the electricity generated in Arizona each year. Plant output was driven by a high capacity factor that reached 94.4 percent in 2002.

Palo Verde provides power primarily for the Arizona/New Mexico/Nevada Power Area, although it exports some of its power (13 percent) to utilities in California and Texas. Efficient performance has made Palo Verde very cost-competitive in the region. Palo Verde had a production cost of 1.33 cents per kilowatt-hour. By comparison, the three-year average production cost was 2.53 cents per kilowatt-hour for electricity generators in the region.

Production costs represent the operations, maintenance and fuel cost of the plant. They do not include depreciation, interest or ongoing capital cost. Contributions to the Nuclear Waste Fund, established to pay for the disposal of used nuclear fuel from commercial power plants, are contained within fuel cost. Customers of nuclear-generated electricity pay for the fund.

Table 2-2. Regional Power Production Cost and Generation

	Average Production Cost (in Cents per Kilowatt-Hour)	Generation (in Million Megawatt-Hours)
Palo Verde	1.33	30.9
Coal	2.26	68.8
Natural Gas	4.54	28.1
Hydro	0.63	10.5
Total (including Palo Verde)	**2.53**	**139.6**

Source: Resource Data International; Region includes Arizona, Nevada and New Mexico.

Palo Verde's low production costs help keep wholesale electricity prices affordable in the region. Although Palo Verde's exact contribution is difficult to measure, it can be estimated by determining how much average 2002 production costs in the region would increase if Palo Verde were replaced, for example, by a combined-cycle natural gas plant (the plant of choice for new generation). Substituting combined-cycle natural gas plants for Palo Verde in 2002 would have resulted in an increase in average generation costs for the region from 2.53 cents per kilowatt-hour to 3.13 cents per kilowatt-hour.

2.3 Employment, Spending and Taxes

Besides providing affordable electricity to the Southwest, Palo Verde is the largest employer in the far Southwest Valley. The plant employs 2,055 full-time on-site workers. Of these employees, 2,042 reside within the county. Full-time employees include 370 people from Glendale, 305 from Phoenix, 276 from Peoria, 211 from Buckeye, 197 from Goodyear, 168 from Avondale, and 153 from Litchfield Park. In a few cities almost one in 10 work at Palo Verde while in several other localities, one of every 100 employed people works at the Palo Verde Nuclear Generating Station.

Maricopa County, the fourth most populous county in the United States, has a vast employment base, and Palo Verde is responsible for one worker per 1,000 employed people. In addition to these workers, the plant also is responsible for the employment of 151 long-term contractors and 180 employees at Arizona Public Service's corporate offices in Phoenix.

Jobs provided by Palo Verde also are typically higher paying than most jobs in the area. Full-time Palo Verde employees who live in Maricopa County earned, on average, about $66,000 in 2002. This was about 13 percent higher than the average earnings of workers in the county, about $58,600 a year.

Palo Verde also spends a large amount of money in the local community. During the one-year period of this study, Palo Verde made $17.8 million in non-labor purchases in Maricopa County.

Palo Verde also made substantial tax payments to the county in 2002. The plant paid $46.1 million in county property taxes to Maricopa County, almost 12 percent of Maricopa County's $392.8 million property tax levy.

Table 2-3. Full-Time On-Site Employee and Salary Information by Top-10 Cities and Towns in Maricopa County

	Palo Verde			City/County Total*	
Location	**Permanent On-Site Employees**	**% of Employed Work Force**	**Average Earnings**	**Employed Work Force**	**Average Earnings**
Glendale	370	0.4%	$66,070	103,474	$54,391
Phoenix	305	0.0%	$64,448	611,019	$54,727
Peoria	276	0.6%	$68,257	49,793	$61,113
Buckeye	211	8.5%	$60,746	2,474	$50,639
Goodyear	197	2.6%	$68,319	7,651	$62,348
Avondale	168	1.1%	$68,057	15,670	$56,999
Litchfield Park	153	9.4%	$77,234	1,630	$88,323
Tonopah	74	NA	$59,816	NA	NA
Surprise	50	0.5%	$66,378	10,443	$46,902
Wickenburg	40	2.0%	$71,988	1,964	$40,530
Maricopa County Total	2,042	0.1%	$66,006	1,427,292	$58,635

** Source: Census 2000; NA = Not available*

2.4 Summary

Palo Verde provides reliable electricity generation and keeps power prices affordable in Arizona. The plant also offers well-paid employment and a large tax base to Maricopa County. However, these are only the direct economic benefits of the plant. As illustrated in the next section, the secondary effects on the local and regional economies are as substantial as the direct benefits.

Section 5: Nuclear Industry Trends

The U.S. nuclear energy industry has steadily improved performance and cost, while improving plant safety. The industry also serves as a model of industrial safety.

Total electricity production for U.S. nuclear power plants reached 764 billion kilowatt-hours in 2003. Power plant performance is measured by capacity factor, which expresses the amount of electricity actually produced by a plant, compared with the maximum achievable. U.S. nuclear power plants achieved a capacity factor of nearly 90 percent in 2003. At the same time, production costs for those plants have been among the lowest of any baseload fuel source.

5.1 Nuclear Industry Performance

U.S. nuclear plants have increased their output and improved their performance significantly over the past 10 years. Nuclear energy represents about 20 percent of all electricity generated in the United States. Since 1990, the industry has increased total output equivalent to 26 new, large nuclear plants. The increase in output occurred without building any new nuclear plants.

Meanwhile, overall capacity factors for the U.S. nuclear power plants increased dramatically over the past decade, reaching about 90 percent in 2003. By contrast, the average capacity factor for the industry was 60 percent in the late 1980s. One of the key reasons for these increased capacity factors has been the shortening of refueling outage times.

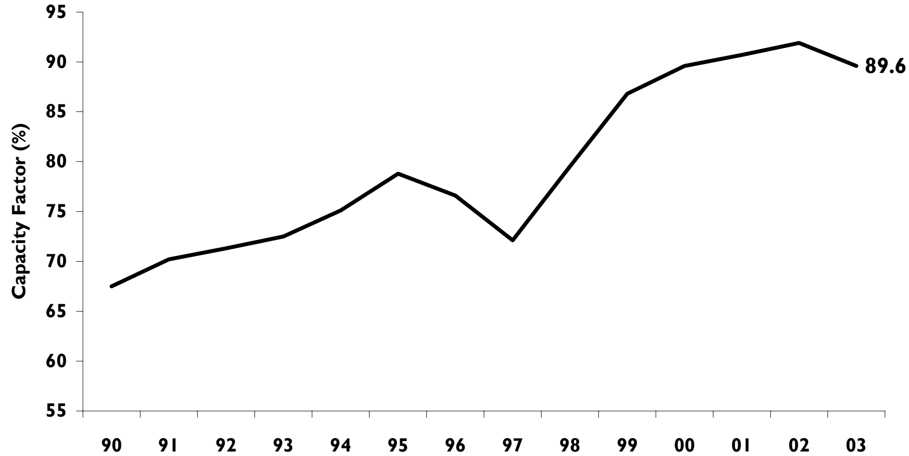
Figure 5-1. U.S. Nuclear Industry Net Electricity Generation

(32% increase from 1990 to 2003)

Source: Energy Information Administration

Figure 5-2. Nuclear Industry Average Capacity Factors

(1990-2003)



Source: Energy Information Administration

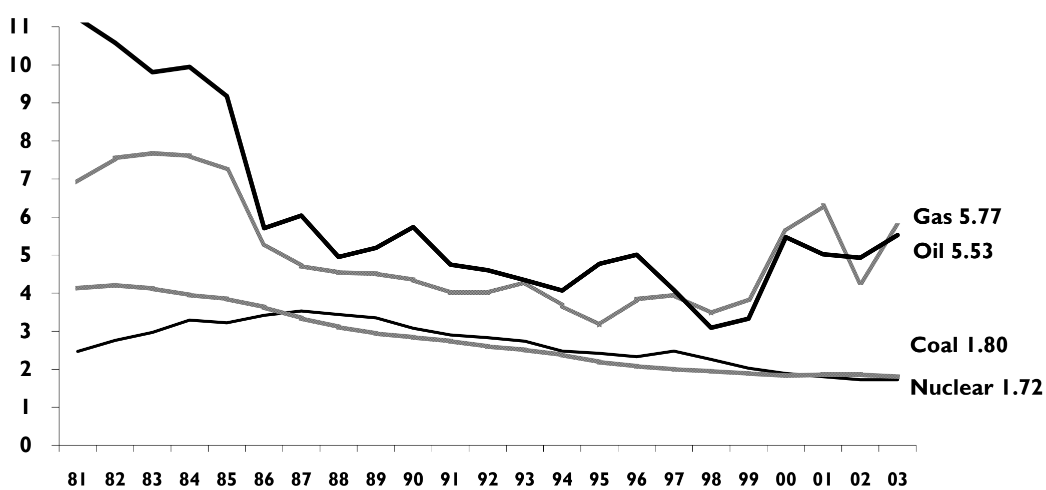
Nuclear plants need to shut down to refuel approximately every 18 to 24 months. Refueling represents one of the major determinants of nuclear plant availability. In the past 10 years, the durations of refueling outages have been declining. In 1990, the average refueling outage took 105 days to complete. By 2003, this number declined to an average of 40 days, and companies continue to apply best practices to further reduce this average. The record for the shortest refueling outage is 14.67 days for a boiling water reactor and 15.67 days for a pressurized water reactor.

5.2 Cost Competitiveness

Along with increasing output, the U.S. nuclear industry has continued to decrease its operations costs. In 2003, nuclear power had a production cost of 1.72 cents per kilowatt-hour. This was significantly lower than the production costs of electricity generated by oil and natural gas and slightly lower than coal. In the past decade, nuclear production costs have dropped by about one-third because of the increased capacity factor of the U.S. plants. Since most nuclear plant costs are fixed, greater electricity production creates lower cost. However, nuclear plants have also taken steps to reduce their total cost through improved work processes.

Figure 5-3. U.S. Electricity Production Costs

(1981-2003 in constant 2003 cents/kWh)



Source: Pre-1995: Utility Data Institute (UDI), Post-1995: Resource Data International (RDI) Modeled Production Cost

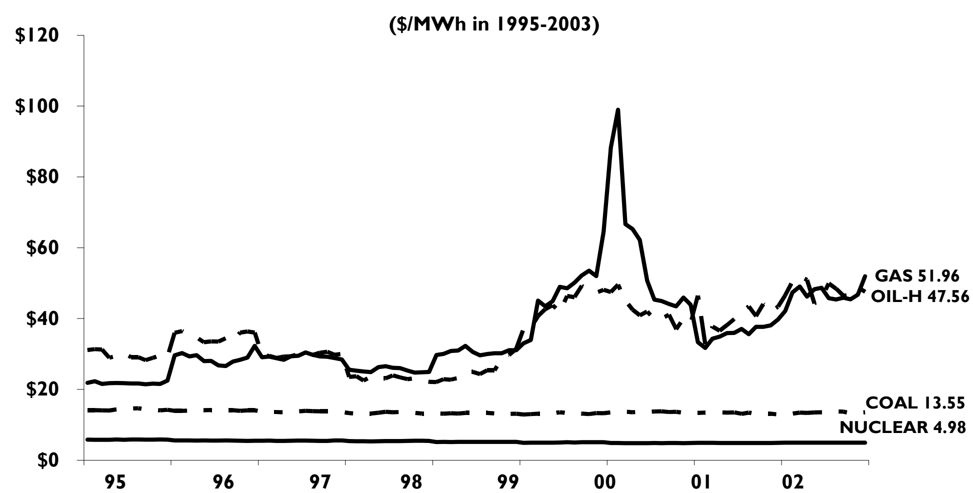
Table 5-1. Wholesale Electricity Prices by Region (cents/kilowatt-hour)

Region	2001 Average 24/7 Power Prices	2003 Average 24/7 Power Prices
New England	3.3	6.6
Mid-Atlantic	2.6	4.1
Tennessee Valley	2.0	2.9
Gulf States	2.2	3.0
Midwest	2.0	2.7
Texas	2.2	3.9
Northwest	2.2	3.8
Southwest	2.5	4.1

Because of low production costs and excellent safety performance, nuclear plants are very competitive in today's energy markets. Ultimately, the primary test of nuclear energy's competitiveness is how well it performs against market prices. In this respect, nuclear energy is highly competitive. Average production cost at the nation's 103 reactors was 1.72 cents per kilowatt-hour in 2003, lower than the average price in all regional markets. Nuclear energy is also competitive with futures market prices, one of the best ways to judge what prices will be in the year ahead.

Nuclear plants provide a unique degree of price stability for two reasons. First, production costs for nuclear plants are comprised of costs not associated with fuel. Fuel markets tend to be very volatile, so the production costs of generation sources tied to fuel expenses are highly volatile, as they swing with variations in the markets. Fuel represents only 20 percent of the production cost of nuclear energy, but it makes up 60 percent to 80 percent of the cost of natural gas, coal and petroleum-fired generation. Second, nuclear fuel prices are much more stable than those of fossil fuels, particularly natural gas and petroleum. Because of its stable, low production cost, nuclear energy can help mitigate large electricity price swings.

Figure 5-4. Monthly Fuel Cost to Electric Generators



Source: Resource Data International (RDI) and Utility Data Institute (UDI).
** Projected cost*

5.3 Current Industry Events

The excellent economic and safety performance of the U.S. nuclear power plants has increased interest in nuclear energy by the electric utility industry, the financial community and policymakers. This is evidenced by the increasing number of plants seeking license renewals from the Nuclear Regulatory Commission.

Nuclear plants were originally licensed to operate for 40 years, but can safely operate for longer periods of time. The NRC granted the first 20-year license renewal to the Calvert Cliffs plant in Maryland in 2000. As of December 2004, 30 plants have received license extensions, and 16 reactors have submitted an application to renew their licenses. License renewal is an attractive alternative to building new electric capacity because of nuclear energy's low production costs and the return on investment for license renewal.

Besides relicensing current plants, interest has recently increased in building new nuclear plants. Three companies—Entergy, Dominion and Exelon—have submitted early site permit applications with the NRC to test the agency's new permitting process for new reactor sites.

Three groups of energy companies are seeking to collaborate with the U.S. Department of Energy to test a new licensing process for building and operating an advanced nuclear reactor called a combined construction and operating license. The effort is part of DOE's Nuclear Power 2010 program, established to foster the development of next-generation nuclear power plants.