Beyond Loan Guarantees:
Fostering U.S. Nuclear Investment in a Post-Fukushima World

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Nuclear investment in the U.S. faces a variety of "headwinds" that present increased challenges to the prospects for financing new nuclear construction. These include the following:

- ***Zero carbon price*** – prospects for a national cap-and-trade or carbon tax regime are currently limited by political and economic considerations, and carbon prices are not expected to be significant for the foreseeable future.
- ***Low natural gas prices*** – large increases in U.S. shale gas production and the tripling of acknowledged reserves are depressing current and projected natural gas prices.
- ***Increased renewables supply*** – expanded generation from renewables is already putting pressure on baseload generation in parts of the U.S., and aggressive RPS standards in many states will continue to push increases in renewables supply.
- ***Risk of construction cost overruns*** – uncertainty regarding construction costs for new plant designs, and the unfortunate history of cost overruns in the prior generation of U.S. plants, undermines the ability to secure traditional project financing.
- ***Perceived risks as a result of events in Japan*** – the Fukushima Daiichi accident has led a number of countries (including the U.S.) to undertake safety reviews of existing nuclear plants, has resulted in the temporary shutdown of significant existing nuclear capacity in Germany, and has caused some national programs for new nuclear capacity (including those in Japan, China, and Italy) to be scaled back or delayed.

The existing U.S. Department of Energy (DOE) loan guarantee program for supporting new nuclear development faces a variety of challenges. Foremost among these challenges is the likely cancellation of two of the four nuclear projects being supported: Calvert Cliffs unit 3 and South Texas Project units 3 and 4. Beyond that, there is uncertainty regarding future funding for the loan guarantee program, which would be needed to support plants beyond the initial four, although President Obama's proposed 2011 budget included $36 billion in additional loan guarantee authority.

Even supporters of the loan guarantee program express doubts about its viability. For example, Marvin Fertel, president of the Nuclear Energy Institute, had this to say in recent congressional testimony:

> NEI continues to believe that *the clean energy loan guarantee program*, although essential, *is not yet a workable financing platform*, and urges the Subcommittee to exercise its oversight responsibilities on implementation by the Executive branch, particularly on the issues of the credit subsidy cost that project sponsors are expected to pay.[1]

Assuming a policy interest in promoting new zero-GHG baseload nuclear generation, it is prudent to consider initiatives, policies, and programs beyond the loan guarantee program that might usefully foster new nuclear investment and development.

The largest unmitigated risk for nuclear development is still that of construction cost overruns. Cost projections for proposed nuclear plants in the U.S. range from $3,000/kW to $5,000/kW—and in some cases beyond that range—and past experience of cost overruns double and triple expectations will continue to dampen enthusiasm for financing new nuclear without fresh approaches—including both new public policies and initiatives from within the industry itself—to mitigate construction cost risk. We discuss the challenges of new nuclear development and potential approaches for promoting and facilitating financing.

The economics of new nuclear development

In simple terms, nuclear power plants are expensive to build but generate cheap electricity. Estimated capital and variable cost assumptions for new gas, coal and nuclear generation plants are shown in Table 1.

Table 1: New Generating Plant Costs[2]

	Capital cost ($/kW)	Variable cost ($/MWh)
Natural Gas Combustion Turbine (CT)	$660	$55
Natural Gas Combined Cycle (CC)	$990	$40
Coal	$2,270	$24
Nuclear	$3,900	$12

One way to evaluate the overall relative costs of these technologies is to calculate the cost of generation inclusive of annual fixed costs (including the levelized carrying cost of the initial investment and ongoing fixed operating and maintenance ("O&M") costs). Such an "all-in" cost can

[1] See http://www.nei.org/publicpolicy/congressionaltestimony/april-7-2011/, viewed April 27, 2011. Emphasis added.

[2] Rounded values. Derived from EIA assumptions, inflation and current fuel price references. Capital cost, operating cost and plant characteristics are based on assumptions from the Annual Energy Outlook 2010. See http://www.eia.doe.gov/oiaf/aeo/excel/aeo2010%20tab8%202.xls.

be calculated by spreading annual fixed costs over the assumed hours of operation and adding this hourly value to the variable cost. Table 2 presents calculated all-in costs for the four technologies in Table 1, assuming, among other things, a natural gas price of $6.00/MMBtu.[3]

Table 2: All-in Costs by Generating Technology – $6/MMBtu gas ($/MWh)

Capacity Factor	CT	CC	Coal	Nuclear
10%	$165	$201	$419	$740
20%	$110	$120	$221	$376
50%	$77	$72	$103	$158
75%	$69	$61	$77	$109
90%	$67	$58	$68	$93

Capacity factor is the ratio of the electrical energy produced by a power plant over a period of time to the electrical energy that could have been produced at continuous full power operation during the same period of time.[4] For each of the technologies in Table 2, the all-in cost falls as capacity factor rises, since fixed costs are being spread over an increasing number of hours, while variable cost is taken to be constant. With the understanding that this is a simple analysis that excludes a number of other important factors, such as fuel price risk and the shape of load that needs to be served, Table 2 provides some insight into generation alternatives.[5] If generation is needed primarily to meet peak demand in a small number of hours each year, it is more cost effective to build a CT than any of the other technologies above. The CT is the lowest cost resource at lower capacity factors despite the fact that it is more costly to operate in a given hour, because it is significantly cheaper to build. However, if more energy is needed – i.e., if the plant is needed to operate at a higher capacity factor – it becomes more cost effective to build a CC unit. In the illustration above, neither coal nor nuclear is cost effective, even at very high capacity factors, in large part because natural gas is assumed to be so cheap.

The results of this sort of assessment of course depend on a number of more-or-less debatable assumptions. One significant uncertainty is the price of natural gas. If gas is $10/MMBtu rather than $6/MMBtu, the comparison looks quite different, as shown in Table 3. Coal is now the cheapest resource at high capacity factors.

[3] Various assumptions were made in deriving annualized fixed costs, such as financing costs, construction period, etc. The calculated all-in costs are intended to be rough approximations for illustration, so many of the underlying assumptions are not discussed, though they are consistent with accepted methodologies and are available from the authors by request.

[4] Of course power plants do not necessarily operate at full output. In general, capacity factor is the ratio of actual generation to maximum theoretical generation over a given period.

[5] We have excluded from this illustration renewable resources such as wind and solar, which are not dispatchable, i.e., their ability to generate depends on the presence of wind and sun, respectively. The simple analysis presented above is not well-suited to putting such intermittent resources on a comparable basis with dispatchable ones.

Table 3: All-in Costs by Generating Technology – $10/MMBtu gas ($/MWh)

Capacity Factor	CT	CC	Coal	Nuclear
10%	$199	$226	$419	$740
20%	$144	$146	$221	$376
50%	$111	$97	$103	$158
75%	$103	$87	$77	$109
90%	$101	$83	$68	$93

The great unknown at the moment is what price (or cost), if any, will be imposed on greenhouse gas ("GHG") emissions. Table 4 shows the effect of adding $30/ton of cost for CO_2 emissions. Now new nuclear capacity is the cheapest alternative, and it would enjoy an even greater advantage at capacity factors above 90%, which is now routine for nuclear plants in the U.S.

Table 4: All-in Costs by Generating Technology – $10/MMBtu gas, $30/ton CO2 ($/MWh)

Capacity Factor	CT	CC	Coal	Nuclear
10%	$214	$237	$446	$740
20%	$159	$157	$249	$376
50%	$126	$109	$130	$158
75%	$119	$98	$104	$109
90%	$116	$95	$95	$93

That coal is still comparable in cost to a combined cycle in this case indicates that $30/ton for CO_2-equivalent emissions would be on the low side. That is, the purpose of a carbon tax (or a cap-and-trade regime or control mandates) would be to reduce CO_2 emissions, and studies have shown that such emissions reductions would come predominantly from the power sector, i.e., from retirements and reduced output from conventional coal-fired generation.[6] From this simple analysis it appears that $30/ton would not be sufficient to reduce coal generation substantially, particularly west of the Mississippi, where cheap sub-bituminous is readily available (in fact, the illustrations above reflect a coal price assumption closer to western coal prices than to eastern coal prices). A GHG policy with a meaningful impact would thus need to impose a CO_2 price (or an equivalent cost in terms of control equipment) of more than $30/ton in 2011 dollars, which would further enhance the cost advantage of nuclear generation.

[6] See, for instance, EIA's analysis of the Waxman-Markey proposed legislation: "Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009," (August 2009), which concluded that at least 80% of total reductions under the proposed rules would come from the electric power sector, and most of that would result from reduced generation from conventional coal facilities.

Headwinds facing new nuclear development in the U.S.

Zero prices for greenhouse gas emissions

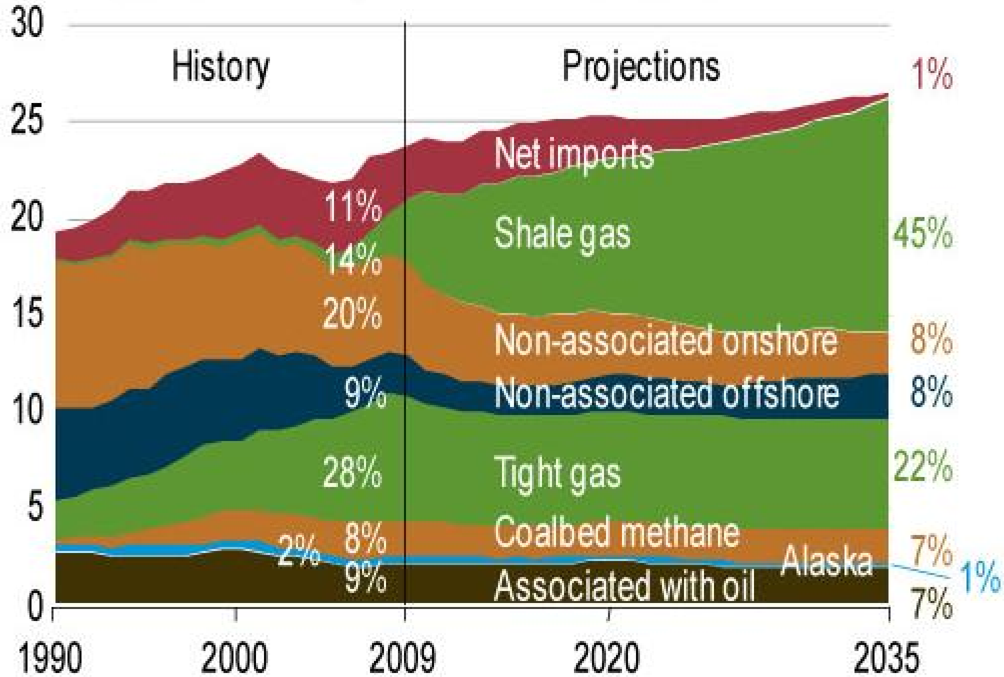
In the years immediately preceding the recent recession, expectations were high that federal legislation to control greenhouse gas emissions was imminent. The near-term prospect for federal action on GHG was among the casualties of the economic slowdown, and the timing of a renewal of federal legislative efforts is anyone's guess. As indicated in the simple cost analysis above, the economics of new nuclear development are highly sensitive to the existence of a price on GHG emissions (or, equivalently a cost for GHG emissions control). The financial viability of *merchant* nuclear development (i.e., plant investments for which costs must be recovered through the competitive wholesale market rather than through a utility's rate base) likely depends on a $C0_2$-equivalent price of more than $30/ton.

The fact that national GHG legislation is unlikely in the near term is undeniably a blow to the long-anticipated nuclear renaissance, but if the past several years prove anything, it is that the *status quo* can change rapidly. If the economy picks up steam, and further evidence of global warming accumulates, GHG legislation will likely be back on the table in relatively short order. At the same time, new nuclear development faces several other headwinds, which we summarize below.

Low Natural Gas Prices

As indicated in the tables above, the economics of coal and nuclear generation depend greatly on the relative cost of generation from natural gas. The astonishing boom in shale gas production over the past five years has radically changed forecasts of natural gas prices going out twenty years. Advances in extraction technologies like directional drilling and hydraulic fracturing have made recovery of natural gas from large underground shale basins economic, causing a rapid expansion in supply. Today's U.S. shale gas production rate is around 5 trillion cubic feet annually, over five times what it was in 2006. The United States has several large shale gas deposits that were untapped until recently, including the Marcellus, Fayetteville, and Haynesville Shale. These shale deposits represent massive additions to U.S. natural gas reserves. Proved recoverable gas reserves grew 42% from 2004 to 2009, largely due to shale gas. As historic sources of natural gas go offline, the EIA expects shale gas production to more than fill the void. EIA estimates that 45% of dry natural gas will come from shale in 2035 compared to 14% in 2009. The recent and projected impact of shale gas production on natural gas supply is shown in Figure 1, below.

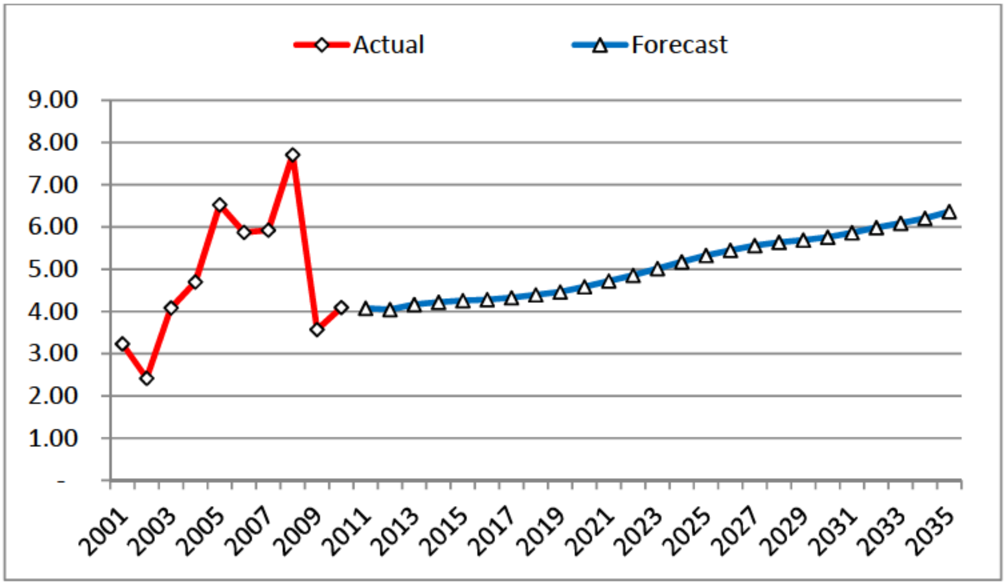
Figure 1: U.S. Dry Gas Production (trillion cubic feet per year)



Source: EIA 2011 Annual Energy Outlook Early Release Overview

This increase in supply, which is being paralleled in other parts of the world, has reduced projected natural gas prices decades into the future. EIA projects real wellhead prices rising from $4.08/mmBtu in 2011 to $6.37/mmBtu in 2035 (in 2009 dollars). Figure 2 graphs historical and projected natural gas wellhead prices.

Figure 2: U.S. Natural Gas Wellhead Price ($/mmBtu, 2009 dollars)



Source: EIA data, Annual Energy Outlook 2011

The availability of cheap natural gas significantly undermines the investment economics of new nuclear power plants. John Rowe, CEO of Exelon Corporation, the largest owner/operator of nuclear power plants in the U.S., has averred that cheap natural gas could postpone the construction of new U.S. nuclear power plants by a decade or more.[7]

Though the prospect of rapidly expanding shale gas production weakens the case for nuclear development, natural gas prices are notoriously volatile, and a number of factors may moderate expectations of a future supply glut. For instance, a feature of shale gas production that distinguishes it from more traditional extraction methods is that shale wells have a very steep decline curve, meaning that new wells must continually be drilled to maintain production volumes, and declines in new drilling activity translate quickly into supply reductions. Unresolved concerns regarding the environmental impacts of hydraulic fracturing may hinder the extent of new drilling activity necessary to support increasing production.

[7] John Rowe interview with Bloomberg News, March 16, 2011.

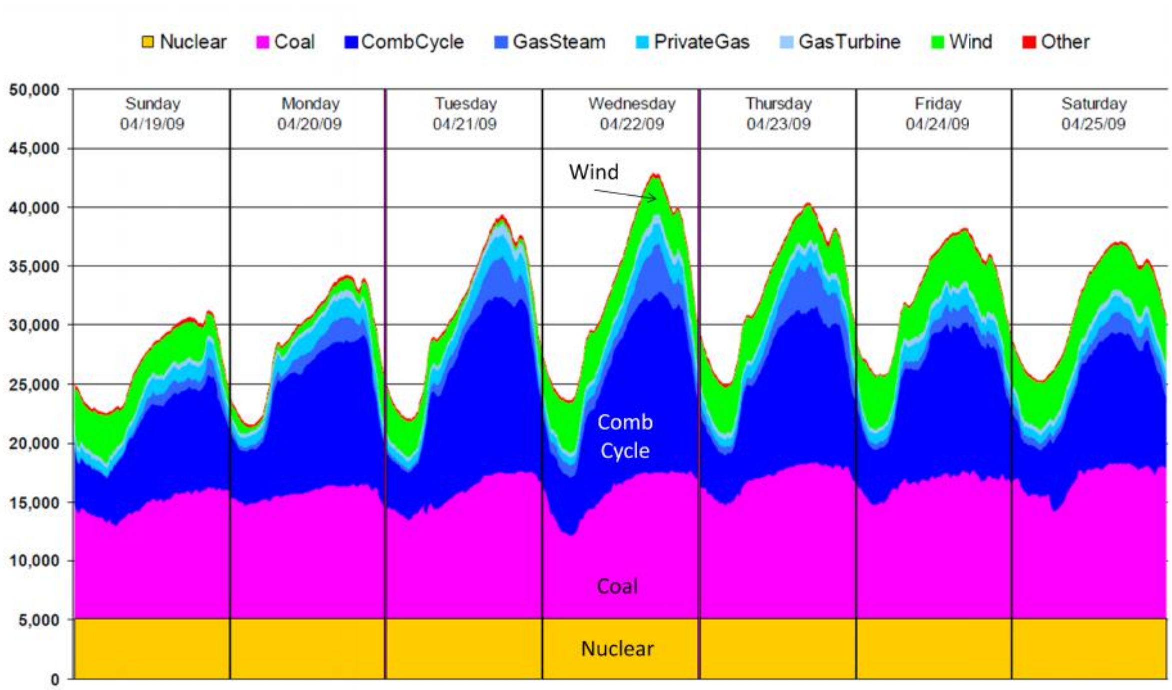
Increased renewables supply

As with federal GHG legislation, the economic downturn has dimmed near-term prospects for establishing national renewable portfolio standards ("RPS"). Yet, state RPS requirements continue to grow more ambitious: over the past two years, state RPS targets for 2020 have grown from 15% to 16.7% of aggregate U.S. electricity sales. Despite a recent lull in development activity, wind generation is expected to continue to grow rapidly to help meet aggressive RPS goals.

Wind generation is an intermittent resource, meaning that its availability is dependent on the wind and it cannot be called on to meet load whenever needed. This contrasts with dispatchable resources, such as natural gas-fired plants that can operate on demand at short notice, and particularly with so-called baseload resources, such as coal and nuclear plants, that can (and do) operate at high output around the clock. The unpredictable nature of wind generation presents a challenge to system operators as they attempt to balance supply with demand in real-time. When the wind drops suddenly, the system must rely on dispatchable resources to replace the lost supply quickly. When the wind surges, generating plants must be backed down to accommodate the low-cost wind generation.[8] Areas with high wind penetration in the U.S., such as Texas, already have sufficient wind capacity to displace coal-fired generation during high wind periods. This can be observed in Figure 3, which shows generation by fuel type during a typical spring week for 2009.

[8] Generation sources such as wind and solar, with zero "fuel" cost, will virtually always be the cheapest resources available, though the total variable cost will be positive when accounting for O&M costs.

Figure 3: ERCOT Typical Spring Week Generation by Fuel Type, Actual (MW)



Source: ERCOT

The wind-induced curtailment of baseload fossil resources, illustrated in Figure 3, will become increasingly common as wind generation grows in coming years. In addition to reducing fossil plant operation, increased wind output reduces revenues of operating plants, including nuclear, by lowering wholesale market prices. This occurs because high-cost, marginal units, which set the market clearing price in centralized electricity markets, are curtailed completely, and the market price is then set by lower-cost units. The effect on nuclear plant revenue may be mitigated to the extent that coal-fired generators are forced to retire, but it is worth noting that nuclear plants are not immune from being curtailed. In Ontario, in spring 2009, so-called "surplus baseload generation" events resulted in output reductions at nuclear units on 54 days, and complete nuclear unit shutdowns on five days.[9] These events were caused by a combination of high wind output, low demand and the inability to readily adjust import schedules. Various states in the U.S. are adapting system rules to better manage the effects of intermittent resources, yet the associated challenges for nuclear of reduced energy market prices and increased uncertainty will likely remain.

[9] Ontario IESO, *Ontario Reliability Outlook*, December 2009, p. 11.

Risk of construction cost overruns

The last nuclear plant to come on line in the U.S. was Watts Bar Unit 1, in 1996. A major contributing factor in the long development inactivity is that many U.S. nuclear plants constructed since 1970 experienced long construction delays (Watts Bar 1 took 24 years to complete), and sometimes staggering cost overruns. From 1974 to 1982 the construction of over 100 nuclear plants was canceled; from 1984 to 1993 over $17 billion in nuclear investments were written down; and of 75 first-generation nuclear plants built in the United States, the capital cost was 207% more than estimated.[10]

The exemplar for cost overruns (and regulatory risk) is the Shoreham Nuclear Power Plant, which was proposed in 1965 at an estimated construction cost of $70 million, but had an eventual total project cost of $6 billion and was decommissioned in 1994 without ever providing electricity to consumers. Seabrook Station in New Hampshire experienced similar cost overruns and delays, eventually forcing its owner Public Service New Hampshire into Chapter 11 bankruptcy in 1988. PSNH was the first privately held utility to go bankrupt since the Great Depression.

The delays and cost overruns at both Shoreham and Seabrook resulted partly from changing designs and regulatory challenges. Though the NRC has streamlined its nuclear licensing process, and enhanced its coordination with nuclear technology companies on new reactor designs, there remains a significant degree of uncertainty regarding expected construction costs for new nuclear plants. Even for proposed plants announced in recent years, construction cost estimates cover a wide range, as indicated in Table 5.

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[10] David Schlissel *et al*., *Don't Get Burned: The Risks of Investing in New Coal-Fired Generating Facilities,* Synapse Energy Economics, Inc., 2008.

Table 5: Estimated project costs for proposed nuclear plants

Project/Site Name	Estimated Output	Estimated Project Cost[11]	Estimated $/kW
Calvert Cliffs 3	1,600 MW	$7.2-9.6 billion	$4,500-6,000/kW
South Texas Project 3&4	2,700 MW	$5.4-17.5 billion	$2,000-6,500/kW
Plant Vogtle units 3&4	2,200 MW	$14 billion	$6,300/kW
Levy County	2,200 MW	$14-17 billion	$6,300-7,700/kW
Bell Bend	1,600 MW	$13-15 billion	$8,100-9,400/kW
Turkey Point 6 and 7	2,200 MW	$6.8-17.8 billion	$3,100-8,100/kW
Upgrades to existing reactors at St. Lucie and Turkey Point	400 MW additional	$1.5 billion	$3,750/kW

Some of the variation in the above cost estimates reflects varying definitions of total cost, which in some cases excludes financing costs, or includes required infrastructure upgrades. Nonetheless, a high degree of technical and cost uncertainty is fundamental to the construction of such complex machines. Add to these uncertainties the economic, regulatory and political risks associated with a long-term and publicly controversial project, and the challenges of new nuclear development seem almost insurmountable.

NRG's South Texas Project ("STP") provides a good example both of the uncertainty of construction costs and also the challenge of financing such a large capital outlay. In 2007, NRG estimated the total project cost of STP 3&4 to be $5.4-6.75 billion ($2,000-$2,500/kW).[12] By 2008, the Institute for Energy and Environmental Research (IEER) estimated that $12.1-17.5 billion ($4,480-$6,480/kW) was a more accurate total cost range for the project.[13] NRG was unable to secure a long-term contract for power from the plant, and at a market capitalization of around $5 billion, NRG lacked the ability to provide significant financial support for the project without a government loan guarantee. NRG announced on April 19, 2011 that it would not invest further capital in the project. (On April 20, NRG's stock rose close to 3%).

[11] Based in most cases on press releases made by the project developers themselves.

[12] NRG Energy.

[13] Arjun Makhijani, Assessing Nuclear Plant Capital Costs for the Two Proposed NRG Reactors at the South Texas Project Site, March 24, 2008. It should be noted that IEER is generally biased against the use of nuclear power.

Financiers have been understandably skeptical of nuclear investment opportunities, given the unhappy financial history of nuclear development in the U.S. Yet the economics of nuclear generation are reasonable across a range of plausible future scenarios, and nuclear generation offers solutions to pressing national concerns: providing large quantities of zero-GHG energy, facilitating a shift toward chargeable electric vehicles, and reducing dependence on imported fossil fuels. That the financial markets will not support investment in nuclear projects that can provide direct economic benefits plus important ancillary benefits is an indicator of market failure. It was precisely the recognition of this market failure, and the potential for government policy to correct it, that prompted the nuclear provisions of the 2005 Energy Policy Act, which established the DOE nuclear loan guarantee program.

The Fukushima Daiichi accident

Since March 11, 2011, there has been much discussion of the effects on the worldwide nuclear industry of the Fukushima-Daiichi accident in Japan. Though it is difficult to downplay the magnitude of the incident – each day during the first weeks following the earthquake and tsunami seemed to bring more alarming information to light regarding damage at the power plant—it is still too early to evaluate longer-term implications for nuclear energy.

Our expectation is that Fukushima will increase scrutiny of nuclear design, plant location, and disaster planning, but that the main effect may be to tip the balance of public and political support against nuclear power in countries where these were already tenuous, as in the case of Germany and possibly Italy and Switzerland. There have been protests against a proposed nuclear plant at Jaitapur, India; the Chinese government has scaled back near-term new nuclear build from 100 GW to 80 GW; and there are understandable delays in future nuclear development plans in Japan.

The threshold determinant of new nuclear development in the U.S. will be investment economics – expected return relative to cost (and quantity) of capital. Near-term momentum for nuclear investment in the U.S. has been slowed by the “headwinds” discussed above, leading to the withdrawal of Constellation from the Calvert Cliffs 3 project and the near-abandonment of NRG’s STP 3&4 project. Nonetheless, there are a number of long-term scenarios that support the business case for building and financing new nuclear plants. These are discussed below.

EPACT 2005 and the nuclear loan guarantee program

Title XVII of the Energy Policy Act of 2005 authorized the DOE to issue loan guarantees to projects which “avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases” and employ new or improved technologies.[14] New nuclear power facilities are officially qualified to receive loan guarantees based on these criteria, and of the program's total of $51 billion of guarantees, $18.5 billion has been specified for nuclear power facilities. The Obama administration has requested an additional $36 billion for new nuclear power facilities alone, which would bring total nuclear loan guarantees to $54.5 billion if approved by Congress.

The loan guarantees are intended to allow private corporations to borrow more funds at lower rates than would otherwise be possible. In exchange for credit backing, the borrower must pay a fee, or "subsidy cost," to the government. In the case of default the federal government, and ultimately taxpayers, must pay off the remaining debt.

In May 2009, DOE selected four nuclear projects for final due diligence and negotiations toward providing conditional loan guarantees: Vogtle 3&4, Calvert Cliffs 3, VC Summer 2&3, and STP 3&4. Thus far, there has been one conditional award of $8.3 billion to Southern Company to construct two nuclear reactors at the Plant Vogtle in Georgia. As noted above, Constellation Energy pulled out of its partnership with Electricité de France (EDF) to develop Calvert Cliffs 3, casting the future of the project in doubt, though EDF is searching for another project partner. More recently, NRG recently suspended most expenditures on the South Texas Project, throwing its future into considerable doubt.

Subsequent to the Fukushima disaster, DOE has indicated that it still intends to move forward with the existing slate of loan guarantees, at least until any of them is formally withdrawn, provided that the Obama administration's request for an additional $36 billion in loan guarantee authority is approved by Congress.

Limits of current policies

Historical cost overruns and political sensitivity to defaults make for a difficult environment for loan guarantees. While the point of the loan guarantee program is to facilitate project financing by having the federal government assume some project risk, the program was fashioned to ensure that taxpayers would not shoulder all risks of project development. The required subsidy payment by the borrower is the mechanism that limits the assumption of risk by the government. At the same time, charging a subsidy necessarily reduced the financial advantage of the loan guarantee for the borrower, and moderates the extent to which the program can encourage private investment. When Constellation pulled out of the Calvert Cliffs 3 project, it cited the high subsidy payment required to secure a loan guarantee as a major factor in its unwillingness to proceed. This type of roadblock indicates that nuclear loan guarantees may not be the most functional mechanism for financing nuclear power development.

[14] Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594, 1117–22 (Aug. 8, 2005) ("EPAct").

The difficult history of the nuclear sector makes it likely that some standard financial approaches, such as project finance, will simply be unavailable. The magnitude of the required capital commitment creates challenges to on-balance-sheet financing, when the capital investment may be a large fraction of the company's enterprise value. Off-balance-sheet financing is hindered by the sector's track record in both construction cost overruns and plant operating performance. In the U.S. over the years there have been 51 instances of outages that have lasted longer than one year. In these cases, defaults might have occurred had the plants been financed off balance sheet (assuming one-year cash reserves).

In addition to the DOE loan guarantee program, other public policy efforts to encourage new nuclear development in the U.S. include simplified licensing, congenial ratemaking provisions (in some states), production tax credits, and "standby support" for regulatory delays. Despite these efforts, construction cost overrun risk remains unmitigated. Even when assuming that there will be no major construction delays, some engineering, procurement, and construction contracts contain provisions that make the project sponsor bear price risk for labor and commodities—exposure that can potentially exceed $1 billion.

Unfortunately there are few other options to traditional project finance approaches, and though the nuclear loan guarantee programs may be more effective for regulated utilities that already enjoy the advantage of cost recovery through regulated service rates, the recent difficulties of merchant plant proposals, and the tenuous status of the loan guarantee program itself, highlights the importance of creating a new investment paradigm

Preparing for life beyond nuclear loan guarantees

Although the President's budget request for fiscal year 2012 contains $36 billion in new loan guarantee authority for new nuclear plants, this funding—assuming survives the budget review process—would be sufficient to finance perhaps four or five new plants (beyond those already in the loan guarantee pipeline). Given the long-term need to replace all 104 operating nuclear units, and add additional nuclear capacity in pace with load growth, just to maintain the current fraction of nuclear in the nation's generation mix, this funding is clearly insufficient, in itself, to fund the "nuclear Renaissance" in full. It is prudent therefore for players in the U.S. nuclear market (including, but not limited to generators considering new nuclear investment) to plan for life after the DOE loan guarantee program.

As part of this planning process, the nuclear sector should consider a variety of new and creative public policies in support of new nuclear development. For example, a more closely coordinated interagency approach in support of nuclear exports (involving the Departments of Energy, State, and

Commerce, the U.S. Trade Representative, and the Office of Management and Budget, among others) would help support U.S. exports to faster-growing nuclear markets, including and especially China. Other policy elements might include a more flexible export control regime, which would provide greater flexibility for U.S. nuclear exporters.

Consideration should also be given to a federal Nuclear Energy Investment Bank. Such an institution would be analogous to the Clean Energy Bank proposed in several pieces of legislation (though not passed into law as yet). The intent of such a bank would be to overcome the market failures associated with nuclear financing. Such barriers and impediments include lack of regulatory clarity around new nuclear development, difficulty in estimating financial risk, and the quantity of capital required relative to the size of the companies developing new nuclear capacity.

This effort will also involve the development of improved analytical approaches to replace standard economic and financial tools (e.g., NPV and IRR) that are ill-suited to evaluating new nuclear investments. The unsuitability of these tools derives in part from the considerable uncertainty associated with cash flows from new nuclear plants in early years (due to construction risk) and the unusual degree of certainty in later years (when nuclear plants are virtually guaranteed to be the lowest-cost dispatchable baseload power in the market)—reversing the typical profile associated with power plant investments. Creative and insightful financial and economic tools are needed to value the benefits of nuclear power, including such intangibles as energy security and fuel diversity. Economists should have much to say on these topics in the years to come, suggesting a research and publication agenda for the authors and many others.

Developers will also need to think creatively about ways to mitigate the remaining risks associated with new nuclear capacity until first-of-a-kind (FOAK) cost approaches n^{th}-of-a-kind (NOAK) cost, which may occur only after a significant number of units of a standardized design are completed and enter operation. (Indeed, cost overrun risk can be conceptualized as the probability the FOAK-NOAK cost learning curve in reality differs from expectations.) This analytical effort should focus especially on mechanisms to address construction cost overrun risk. One promising idea in this area is to develop a new form of insurance coverage focused on mitigating cost overrun risk, at least to the degree it is beyond the control of the developer itself. Such insurance coverage could perhaps be provided by insurers, reinsurers, or insurance markets which have experience in nuclear risk. Alternately, the insurance could be provided by the industry itself, perhaps in some kind of consortium or mutual structure, among either suppliers or plant owners (along the lines of Nuclear Electric Insurance Limited (NEIL)).

Finally, the industry should look to South Korea, Japan, France, and Russia for both useful models—and cautionary tales. The state capitalism model offered by China and Russia and to a lesser degree South Korea and France suggests some useful avenues for policy innovation. On the other hand, given the dissonance between the underlying political economy of such models and U.S. institutional arrangements and corporate culture, there may be limited scope for direct emulation of these models.

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