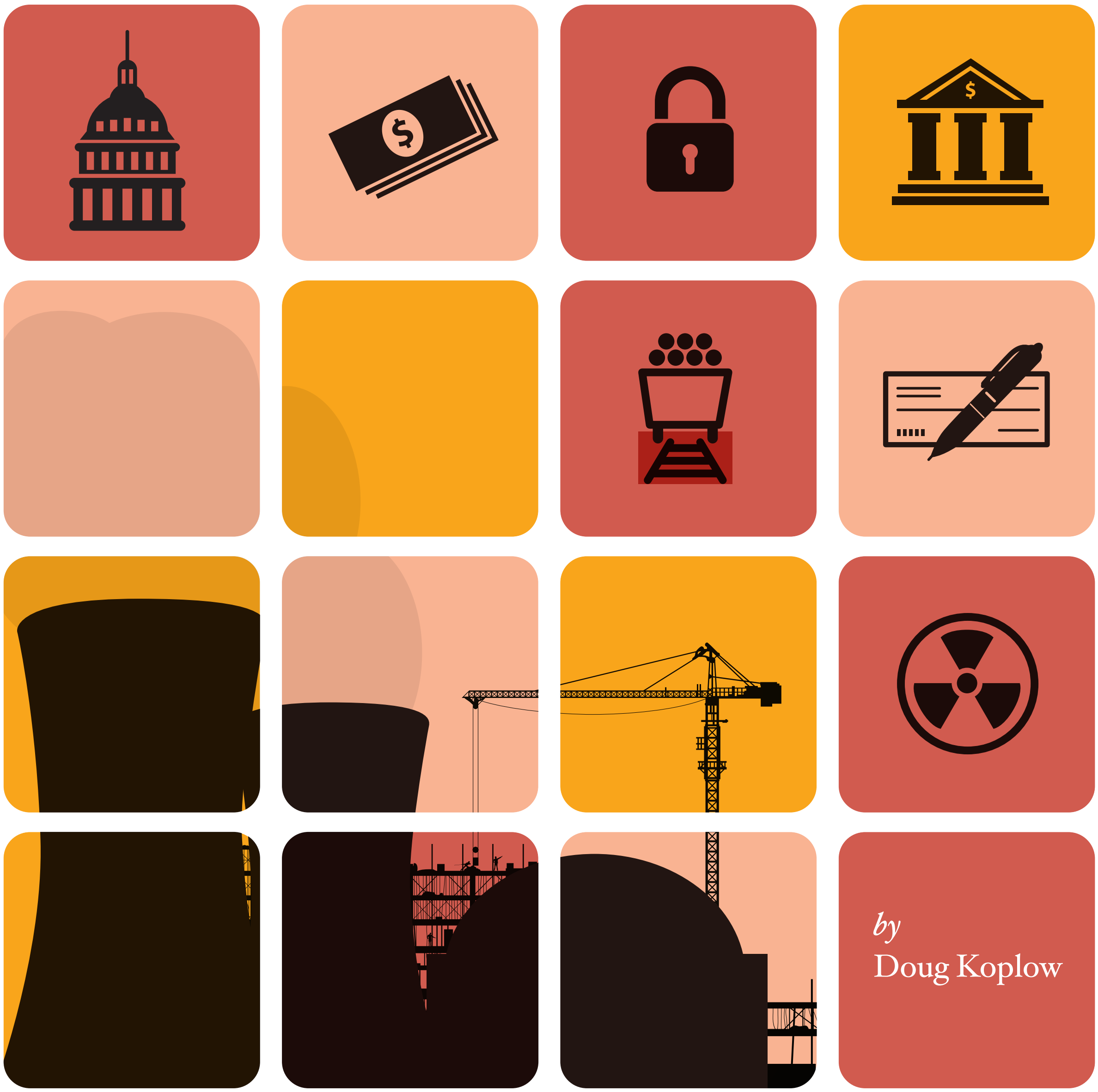
NUCLEAR POWER:

Still Not Viable without Subsidies



by
Doug Koplow

Union of Concerned Scientists
Citizens and Scientists for Environmental Solutions

NUCLEAR POWER:

Still Not Viable without Subsidies

Doug Koplow

Earth Track, Inc.

Union of Concerned Scientists

February 2011

Doug Koplow is the founder of Earth Track, Inc., and has worked on natural-resource subsidy issues for more than 20 years, mainly in the energy sector. He holds a B.A. in economics from Wesleyan University and an M.B.A. from the Harvard Graduate School of Business Administration.

The Union of Concerned Scientists (UCS) is the leading science-based nonprofit working for a healthy environment and a safer world. UCS combines independent scientific research and citizen action to develop innovative, practical solutions and to secure responsible changes in government policy, corporate practices, and consumer choices.

More information about UCS is available on our website at *www.ucsusa.org*.

The full text of this report is available on the UCS website (in PDF format) at *www.ucsusa.org/publications* or may be obtained from:

UCS Publications
2 Brattle Square
Cambridge, MA 02138-3780

Or, email *pubs@ucsusa.org* or call (617) 547-5552.

Contents

Figures & Tables

Figures

Tables

Acknowledgments

This study was written by Doug Koplow of Earth Track, Inc., on behalf of the Union of Concerned Scientists (UCS). Ellen Vancko, nuclear energy and climate change project manager for UCS, was the primary reviewer and project manager.

We are grateful to the following people for reviewing versions of this paper: Michele Boyd (Physicians for Social Responsibility), Peter Bradford (University of Vermont Law School), Simon Carroll (Swedish Biodiversity Centre and Member, Nuclear Liabilities Financing Assurance Board, UK), Mark Cooper (University of Vermont Law School), Robert Cowin (UCS), Antony Frogatt (Chatham House), Ken Green (American Enterprise Institute), Autumn Hanna (Taxpayers for Common Sense), Dusty Horwitt (Environmental Working Group), Stan Kaplan (U.S. Congressional Research Service), Amory Lovins (Rocky Mountain Institute), Ed Lyman (UCS), Arjun Makhijani (Institute for Energy and Environmental Research), Alan Nogee (UCS), Doug Norlen (Pacific Environment and ECA Watch), Marcus Peacock (Pew Charitable Trusts/Subsidyscope), Mycle Schneider (Mycle Schneider Consulting), Henry Sokolski (Nonproliferation Policy Education Project), Sharon Squassoni (Center for Strategic and International Studies), and Steve Thomas (University of Greenwich Business School).

The final document has benefited from their insights, as well as from the scores of other people who provided information to the project in other ways. However, any remaining errors or omissions are the responsibility of the author.

We are also indebted to Steve Marcus, Bryan Wadsworth, Matt Freeman, and Rob Catalano for their work on the report's editing and layout.

Executive Summary

Conspicuously absent from industry press releases and briefing memos touting nuclear power's potential as a solution to global warming is any mention of the industry's long and expensive history of taxpayer subsidies and excessive charges to utility ratepayers. These subsidies not only enabled the nation's existing reactors to be built in the first place, but have also supported their operation for decades.

The industry and its allies are now pressuring all levels of government for large new subsidies to support the construction and operation of a new generation of reactors and fuel-cycle facilities. The substantial political support the industry has attracted thus far rests largely on an uncritical acceptance of the industry's economic claims and an incomplete understanding of the subsidies that made—and continue to make—the existing nuclear fleet possible.

Such blind acceptance is an unwarranted, expensive leap of faith that could set back more cost-effective efforts to combat climate change. A fair comparison of the available options for reducing heat-trapping carbon emissions while generating electricity requires consideration not only of the private costs of building plants and their associated infrastructure but also of the public subsidies given to the industry. Moreover, nuclear power brings with it important economic, waste disposal, safety, and security risks unique among low-carbon energy sources. Shifting these risks and their associated costs onto the public is the major goal of the new subsidies sought by the industry (just as it was in the past), and by not incorporating these costs into its estimates, the industry presents a skewed economic picture of nuclear power's value compared with other low-carbon power sources.

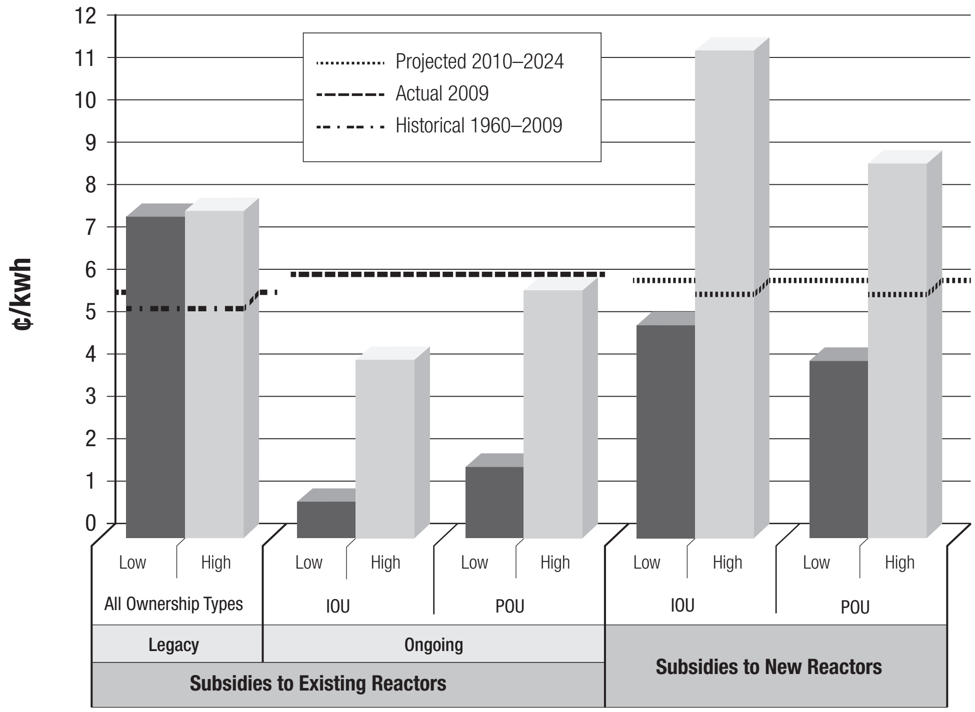
SUBSIDIES OFTEN EXCEED THE VALUE OF THE ENERGY PRODUCED

This report catalogues in one place and for the first time the full range of subsidies that benefit the nuclear power sector. The findings are striking: since its inception more than 50 years ago, the nuclear power industry has benefited—and continues to benefit—from a vast array of preferential government subsidies. Indeed, as Figure ES-1 (p. 2) shows, subsidies to the nuclear fuel cycle have often exceeded the value of the power produced. This means that buying power on the open market and giving it away for free would have been less costly than subsidizing the construction and operation of nuclear power plants. Subsidies to new reactors are on a similar path.

Throughout its history, the industry has argued that subsidies were only temporary, a short-term stimulus so the industry could work through early technical hurdles that prevented economical reactor operation. A 1954 advertisement from General Electric stated that, "In five years—certainly within ten," civilian reactors would be "privately financed, built without government subsidy." That day never arrived and, despite industry claims to the contrary, remains as elusive as ever.

The most important subsidies to the industry do not involve cash payments. Rather, they shift construction-cost and operating risks from investors to taxpayers and ratepayers, burdening taxpayers with an array of risks ranging from cost overruns and defaults to accidents and nuclear waste management. This approach, which has remained remarkably consistent throughout the industry's history, distorts market choices that would otherwise favor less risky investments. Although it may not involve direct cash payments, such favored

Figure ES-1. Nuclear Subsidies Compared to EIA Power Prices



Note: Legacy subsidies are compared to the Energy Information Administration (EIA) average 1960–2009 industrial power price (5.4 ¢/kWh). Ongoing subsidies are compared to EIA 2009 actual power prices for comparable busbar plant generation costs (5.9 ¢/kWh). Subsidies to new reactors are compared to EIA 2009 reference-case power prices for comparable busbar plant generation costs (5.7 ¢/kWh).

treatment is nevertheless a subsidy, with a profound effect on the bottom line for the industry and taxpayers alike.

Reactor owners, therefore, have never been economically responsible for the full costs and risks of their operations. Instead, the public faces the prospect of severe losses in the event of any number of potential adverse scenarios, while private investors reap the rewards if nuclear plants are economically successful. For all practical purposes, nuclear power's economic gains are privatized, while its risks are socialized.

Recent experiences in the housing and financial markets amply demonstrate the folly of arrangements that separate investor risk from reward. Indeed, massive new subsidies to nuclear power could encourage utilities to make similarly speculative, expensive investments in nuclear plants—investments that would never be tolerated if the actual risks were properly accounted for and allocated.

While the purpose of this report is to quantify the extent of past and existing subsidies, we are not blind to the context: the industry is calling for even more support from Congress. Though the value of these new subsidies is not quantified in this report, it is clear that they would only further increase the taxpayers' tab for nuclear power while shifting even more of the risks onto the public.

LOW-COST CLAIMS FOR EXISTING REACTORS IGNORE HISTORICAL SUBSIDIES

The nuclear industry is only able to portray itself as a low-cost power supplier today because of past government subsidies and write-offs. First, the industry received massive subsidies at its inception, reducing both the capital costs it needed to recover from ratepayers (the "legacy" subsidies that underwrote reactor construction through the 1980s) and its operating costs (through ongoing subsidies to inputs, waste management, and accident risks). Second, the industry wrote down tens of billions of dollars in capital costs after its first generation of reactors experienced large cost overruns, cancellations, and plant abandonments, further reducing the industry's capital-recovery requirements. Finally, when industry restructuring revealed that nuclear power costs were still too high to be competitive, so-called stranded costs were shifted to utility ratepayers, allowing the reactors to continue operating.

These legacy subsidies are estimated to exceed seven cents per kilowatt-hour (¢/kWh)—an amount equal to about 140 percent of the average wholesale price of power from 1960 to 2008, making the subsidies more valuable than the power produced by nuclear plants over that period. Without these subsidies, the industry would have faced a very different market reality—one in which many reactors would never have been built, and utilities that did build reactors would have been forced to charge consumers even higher rates.

ONGOING SUBSIDIES CONTRIBUTE TO NUCLEAR POWER'S PERCEIVED COST ADVANTAGE

In addition to legacy subsidies, the industry continues to benefit from subsidies that offset the costs of uranium, insurance and liability, plant security, cooling water, waste disposal, and plant decommissioning. The value of these subsidies is harder to pin down with specificity, with estimates ranging from a low of 13 percent of the value of the power produced to a high of 98 percent. The breadth of this range largely reflects three main factors: uncertainty over the dollar value of accident liability caps; the value to publicly owned utilities (POUs) of ongoing subsidies such as tax breaks and low return-on-investment requirements; and generous capital subsidies to investor-owned utilities (IOUs) that have declined as the aging, installed capacity base is fully written off.

Our low-end estimate for subsidies to existing reactors (in this case, investor-owned facilities) is 0.7 ¢/kWh, a figure that may seem relatively small at only 13 percent of the value of the power produced. However, it represents more than 35 percent of the nuclear production costs (operation and maintenance costs plus fuel costs, without capital recovery) often cited by the industry's main trade association as a core indicator of nuclear power's competitiveness; it also represents nearly 80 percent of the production-cost advantage of nuclear relative to coal. With ongoing subsidies to POUs nearly double those to IOUs, the impact on competitive viability is proportionally higher for publicly owned plants.

SUBSIDIES TO NEW REACTORS REPEAT PAST PATTERNS

Legacy and ongoing subsidies to existing reactors may be important factors in keeping facilities operating, but they are not sufficient to attract new investment in nuclear infrastructure. Thus an array of new subsidies was rolled out during the past decade, targeting not only reactors but also other fuel-cycle facilities. Despite the profoundly poor investment experience with taxpayer subsidies to nuclear plants over the past 50 years, the objectives of these new subsidies are precisely the same as the earlier subsidies: to reduce the private cost of capital for new nuclear reactors and to shift the long-term, often multi-generational risks of the nuclear fuel cycle away from investors. And once again, these subsidies to new reactors—whether publicly or privately owned—could end up exceeding the value of the power produced (4.2 to 11.4 ¢/kWh, or 70 to 200 percent of the projected value of the power).

It should be noted that certain subsidies to new reactors are currently capped at a specific dollar amount, limited to a specific number of

Methodology: How We Estimated Nuclear Subsidies

Identifying and valuing subsidies to the nuclear fuel cycle for this report involved a broad review of dozens of historical studies and program assessments, industry statements and presentations, and government documents. The result is an in-depth and comprehensive evaluation that groups nuclear subsidies by type of plant ownership (public or private), time frame of support (whether the subsidy is ongoing or has expired), and the specific attribute of nuclear power production the subsidy is intended to support.

Plant ownership

Subsidies available to investor-owned and publicly owned utilities are not identical, so were tracked separately.

Time frame of support

The data were organized into:

- **Legacy subsidies**, which were critical in helping nuclear power gain a solid foothold in the U.S. energy sector but no longer significantly affect pricing
- **Ongoing subsidies to existing reactors**, which continue to affect the cost of electricity produced by the 104 U.S. nuclear reactors operating today
- **Subsidies to new reactors**, which are generally provided in addition to the ongoing subsidies available to existing reactors

A further set of subsidies proposed for the nuclear sector but not presently in U.S. statutes is discussed qualitatively but not quantified.

Attribute of production

The following subcategories were modeled on the structure commonly used internationally (as by the Organisation for Economic Cooperation and Development):

- **Factors of production**—subsidies intended to offset the cost of capital, labor, and land
- **Intermediate inputs**—subsidies that alter the economics of key inputs such as uranium, enrichment services, and cooling water
- **Output-linked support**—subsidies commensurate with the quantity of power produced
- **Security and risk management**—subsidies that address the unique and substantial safety risks inherent in nuclear power
- **Decommissioning and waste management**—subsidies that offset the environmental or plant-closure costs unique to nuclear power

To enable appropriate comparisons with other energy options, the results are presented in terms of levelized cents per kilowatt-hour and as a share of the wholesale value of the power produced. Inclusion of industry and historical data sources for some component estimates means that some of the levelization inputs were not transparent. Where appropriate, a range of estimates was used to reflect variation in the available data or plausible assumptions.

reactors, or available only in specific states or localities. Therefore, although all the subsidies may not be available to each new reactor, the values shown in Figure ES-1 are reasonably representative of the subsidies that will be available to the first new plants to be built. Furthermore, it is far from clear whether existing caps will be binding. Recent legislative initiatives would expand eligibility for these subsidies to even more reactors and extend the period of eligibility during which these subsidies would be available.

KEY SUBSIDY FINDINGS

Government subsidies have been directed to every part of the nuclear fuel cycle. The most significant forms of support have had four main goals: reducing the cost of capital, labor, and land (i.e., factors of production), masking the true costs of producing nuclear energy (“intermediate inputs”), shifting security and accident risks to the public, and shifting long-term operating risks (decommissioning and waste management) to the public. A new category of subsidy, “output-linked support,” is directed at reducing the price of power produced. Table ES-1 shows the estimated value of these subsidies to existing and new reactors. The subsequent sections discuss each type of subsidy in more detail.

A. Reducing the Cost of Capital, Labor, and Land (Factors of Production)

Nuclear power is a capital-intensive industry with long and often uncertain build times that exacerbate both the cost of financing during construction and the market risks of misjudging demand. Historically, investment tax credits, accelerated depreciation, and other capital subsidies have been the dominant type of government support for the industry, while subsidies associated with labor and land costs have provided lesser (though still relevant) support.

Legacy subsidies that reduced the costs of these inputs were high, estimated at 7.2 ¢/kWh. Ongoing subsidies to existing reactors are much lower but still significant, ranging from 0.06 to 1.94 ¢/kWh depending on ownership structure. For new reactors, accelerated depreciation has been supplemented with a variety of other capital subsidies to bring plant costs down by shifting a large portion of the capital risk from investors to taxpayers. The total value of subsidies available to new reactors in this category is significant for both POUs and IOUs, ranging from 3.51 to 6.58 ¢/kWh. These include:

- **Federal loan guarantees.** Authorized under Title 17 of the Energy Policy Act (EPACT) of 2005, federal loan guarantees are the largest construction subsidy for new, investor-owned reactors, effectively shifting the costs and risks of financing and building a nuclear plant from investors to taxpayers. The industry’s own estimates,

Table ES-1. Subsidies to Existing and New Reactors

	Subsidies to Existing Reactors (¢/kWh)			Subsidies to New Reactors (¢/kWh)	
	Legacy	Ongoing			
Subsidy Type	**All Ownership Types**	**IOU**	**POU**	**IOU**	**POU**
Factors of production	7.20	0.06	0.96–1.94	3.51–6.58	3.73–5.22
Intermediate inputs	0.10–0.24	0.29–0.51	0.16–0.18	0.21–0.42	0.21–0.42
Output-linked support	0.00	0.00	0.00	1.05–1.45	0.00
Security and risk management	0.21–0.22	0.10–2.50	0.10–2.50	0.10–2.50	0.10–2.50
Decommissioning and waste management	No data available	0.29–1.09	0.31–1.15	0.13–0.48	0.16–0.54
Total	**7.50–7.66**	**0.74–4.16**	**1.53–5.77**	**5.01–11.42**	**4.20–8.68**
Share of power price	139%–142%	13%–70%	26%–98%	84%–190% (high)	70%–145% (high)
				88%–200% (reference)	74%–152% (reference)

Note: A range of subsidy values is used where there was a variance in available subsidy estimates. To determine the subsidy’s share of the market value of the power produced, legacy subsidies are compared to the Energy Information Administration (EIA) average 1960–2009 industrial power price (5.4 ¢/kWh). Ongoing subsidies are compared to EIA 2009 power prices for comparable busbar plant generation costs (5.9 ¢/kWh). Subsidies to new reactors are compared to EIA 2009 high- and reference-case power prices for comparable busbar plant generation costs (6.0 and 5.7 ¢/kWh, respectively); using the low case would have resulted in even higher numbers.

which we have used despite large subsequent increases in expected plant costs, place the value of this program between 2.5 and 3.7 ¢/kWh. Total loan guarantees are currently limited to $22.5 billion for new plants and enrichment facilities, but the industry has been lobbying for much higher levels.

Loan guarantees not only allow firms to obtain lower-cost debt, but enable them to use much more of it—up to 80 percent of the project's cost. For a single 1,600-megawatt (MW) reactor, the loan guarantee alone would generate subsidies of $495 million per year, or roughly $15 billion over the 30-year life of the guarantee.

- **Accelerated depreciation.** Allowing utilities to depreciate new reactors over 15 years instead of their typical asset life (between 40 and 60 years) will provide the typical plant with a tax break of approximately $40 million to $80 million per year at current construction cost estimates. Rising plant costs, longer service lives, and lower capacity factors would all increase the value of current accelerated depreciation rules to IOUs. This subsidy is not available to POUs because they pay no taxes.
- **Subsidized borrowing costs to POUs.** The most significant subsidy available to new publicly owned reactors is the reduced cost of borrowing made possible by municipal bonds and new Build America Bonds, which could be worth more than 3 ¢/kWh.
- **Construction work in progress.** Many states allow utilities to charge ratepayers for construction work in progress (CWIP) by adding a surcharge to customers' bills. This shifts financing and construction risks (including the risk of cost escalations and/or plants being abandoned during construction) from investors to customers. CWIP benefits both POUs and IOUs and is estimated to be worth between 0.41 and 0.97 ¢/kWh for new reactors.
- **Property-tax abatements.** Support for new plants is also available through state and local governments, which provide a variety of plant-specific subsidies that vary by project.

B. Masking the True Costs of Producing Nuclear Energy (Intermediate Inputs)

A variety of subsidies masks the costs of the inputs used to produce nuclear power. Uranium fuel costs, for example, are not a major element in nuclear economics, but subsidies to mining and enrichment operations contribute to the perception of nuclear power as a low-cost energy source. In addition, the under-pricing of water used in bulk by nuclear reactors has significant cost implications. The value of such legacy subsidies to existing reactors is estimated between 0.10 and 0.24 ¢/kWh, and the value of ongoing subsidies is estimated between 0.16 and 0.51 ¢/kWh. The value of such subsidies to new reactors is estimated between 0.21 and 0.42 ¢/kWh. Subsidized inputs include:

- **Fuel.** The industry continues to receive a special depletion allowance for uranium mining equal to 22 percent of the ore's market value, and its deductions are allowed to exceed the gross investment in a given mine. In addition, uranium mining on public lands is governed by the antiquated Mining Law of 1872, which allows valuable ore to be taken with no royalties paid to taxpayers. Although no relevant data have been collected on the approximately 4,000 mines from which uranium has been extracted in the past, environmental remediation costs at some U.S. uranium milling sites actually exceeded the market value of the ore extracted.
- **Uranium enrichment.** Uranium enrichment, which turns mined ore into reactor fuel, has benefited from substantial legacy subsidies. New plants that add enrichment capacity will receive subsidies as well, in the form of federal loan guarantees. Congress has already authorized $2 billion in loan guarantees for a new U.S. enrichment facility, and the Department of

Energy has allocated an additional $2 billion for this purpose. While we could not estimate the per-kilowatt-hour cost of this subsidy because it depends on how much enrichment capacity is built, the $4 billion represents a significant new subsidy to this stage of the fuel cycle.

- **Cooling water.** Under-priced cooling water is an often-ignored subsidy to nuclear power, which is the most water-intensive large-scale thermal energy technology in use. Even when the water is returned to its source, the large withdrawals alter stream flow and thermal patterns, causing environmental damage. Available data suggest that reactor owners pay little or nothing for the water consumed, and are often given priority access to water resources—including exemption from drought restrictions that affect other users. While we provide a low estimate of water subsidies (between $600 million and $700 million per year for existing reactors), more work is needed to accurately quantify this subsidy—particularly as water resources become more constrained in a warming climate.

C. Reducing the Price of Power Produced (Output-Linked Support)

Until recently, subsidies linked to plant output were not a factor for nuclear power. That changed with the passage of EPACT in 2005, which granted new reactors an important subsidy in the form of:

- **Production tax credits (PTCs).** A PTC will be granted for each kilowatt-hour generated during a new reactor's first eight years of operation; at present, this credit is available only to the first plants to be built, up to a combined total capacity of six gigawatts. While EPACT provides a nominal PTC of 1.8 ¢/kWh, payments are time-limited. Over the full life of the plant, the PTC is worth between 1.05 and 1.45 ¢/kWh. Under current law, PTCs are not available to POUs (since POUs do not pay taxes), but there have been legislative efforts to enable POUs to capture the value of the tax credits by selling or transferring them to other project investors that do pay taxes.

D. Shifting Security and Accident Risks to the Public (Security and Risk Management)

Subsidies that shift long-term risks to the public have been in place for many years. The Price-Anderson Act, which caps the nuclear industry's liability for third-party damage to people and property, has been a central subsidy to the industry for more than half a century.

Plant security concerns have increased significantly since 9/11, and proliferation risks will increase in proportion to any expansion of the civilian nuclear sector (both in the United States and abroad). The complexity and lack of data in these areas made it impossible to quantify the magnitude of security subsidies for this analysis. But it is clear that as the magnitude of the threat increases, taxpayers will be forced to bear a greater share of the risk. Subsidies that shift these risks are associated with:

- **The Price-Anderson Act.** This law requires utilities to carry a pre-set amount of insurance for off-site damages caused by a nuclear plant accident, and to contribute to an additional pool of funds meant to cover a pre-set portion of the damages. However, the law limits total industry liability to a level much lower than would be needed in a variety of plausible accident scenarios. This constitutes a subsidy when compared with other energy sources that are required to carry full private liability insurance, and benefits both existing and new reactors.

  Only a few analysts have attempted to determine the value of this subsidy over its existence, with widely divergent results: between 0.1 and 2.5 ¢/kWh. More work is therefore needed to determine how the liability cap affects plant economics, risk-control decisions, and risks to the adjacent population.

- **Plant security.** Reactor operators must provide security against terrorist attacks or other threats of a certain magnitude, referred to as the "design basis threat." For threats of a greater magnitude (a larger number of attackers, for example), the government assumes all financial responsibility, which constitutes another type of subsidy. It is difficult to quantify the value of this taxpayer-provided benefit because competing forms of energy do not carry similar risks. But it is important that plant security costs be reflected in the cost of power delivered to consumers, rather than supported by taxpayers in general.

- **Proliferation.** The link between an expanded civilian nuclear sector and proliferation of nuclear weapons or weapons technology is fairly widely accepted. It is also consistently ignored when assessing plant costs—much as investors in coal plants ignored the cost of carbon controls until recently. Though quantifying proliferation costs may be difficult, assuming they are zero is clearly wrong. These ancillary impacts should be fully assessed and integrated into the cost of nuclear power going forward.

E. Shifting Long-Term Operating Risks to the Public (Decommissioning and Waste Management)

The nuclear fuel cycle is unique in the types of long-term liabilities it creates. Reactors and fuel-cycle facilities have significant end-of-life liabilities associated with the proper closure, decommissioning, and decontamination of facilities, as well as the safe management of nuclear waste over thousands of years. The industry has little operational experience with such large and complex undertakings, greatly increasing the likelihood of dramatic cost overruns. In total, the subsidies that shift these long-term operating risks to the public amount to between 0.29 and 1.09 ¢/kWh for existing reactors and between 0.13 and 0.54 ¢/kWh for new reactors. The specific subsidies that do the shifting are associated with:

- **Nuclear waste management.** The federal Nuclear Waste Repository for spent fuel is expected to cost nearly $100 billion over its projected operating life, 80 percent of which is attributed to the power sector. A congressionally mandated fee on nuclear power consumers,

The Industry's Shopping List: New Subsidies Under Consideration

The following nuclear subsidies, as proposed in the American Power Act (APA) and the American Clean Energy Leadership Act (ACELA), would not necessarily be available to every new reactor, but their collective value to the industry would be significant:

- A clean-energy bank that could promote nuclear power through much larger loans, letters of credit, loan guarantees, and other credit instruments than is currently possible
- Tripling federal loan guarantees available to nuclear reactors through the Department of Energy, from $18.5 billion to $54 billion
- Reducing the depreciation period for new reactors from 15 years to five
- A 10 percent investment tax credit for private investors or federal grants in lieu of tax payments to publicly owned and cooperative utilities
- Expanding the existing production tax credit from 6,000 to 8,000 megawatts, and permitting tax-exempt entities to allocate their available credits to private partners
- Permitting tax-exempt bonds to be used for public-private partnerships, which would allow POUs to issue tax-free, low-cost bonds for nuclear plants developed jointly with private interests
- Expanding federal regulatory risk insurance coverage from $2 billion to $6 billion (up to $500 million per reactor), which would further shield plant developers from costs associated with regulatory or legal delays

earmarked for the repository, has collected roughly $31 billion in waste-disposal fees through 2009. There is no mechanism other than investment returns on collections to fully fund the repository once reactors close.

The repository confers a variety of subsidies to the nuclear sector. First, despite its complexity and sizable investment, the repository is structured to operate on a break-even basis at best, with no required return on investment. Second, utilities do not have to pay any fee to secure repository capacity; in fact, they are allowed to defer payments for waste generated prior to the repository program's creation, at interest rates well below their cost of capital. Third, the significant risk of delays and cost overruns will be borne by taxpayers rather than the program's beneficiaries. Delays in the repository's opening have already triggered a rash of lawsuits and taxpayer-funded waste storage at reactor sites, at a cost between $12 billion and $50 billion.

- **Plant decommissioning.** While funds are collected during plant operation for decommissioning once the plant's life span has ended, reduced tax rates on nuclear decommissioning trust funds provide an annual subsidy to existing reactors of between $450 million and $1.1 billion per year. Meanwhile, concerns persist about whether the funds accrued will be sufficient to cover the costs; in 2009, the Nuclear Regulatory Commission (NRC) notified the operators of roughly one-quarter of the nation's reactor fleet about the potential for insufficient funding. We did not quantify the cost of this potential shortfall.

CONCLUSIONS AND POLICY RECOMMENDATIONS

Historical subsidies to nuclear power have already resulted in hundreds of billions of dollars in costs paid by taxpayers and ratepayers. With escalating plant costs and more competitive power markets, the cost of repeating these failed policies will likely be even higher this time around. Of equal importance, however, is the fact that subsidies to nuclear power also carry significant opportunity costs for reducing global warming emissions because reactors are so expensive and require such long lead times to construct. In other words, massive subsidies designed to help underwrite the large-scale expansion of the nuclear industry will delay or diminish investments in less expensive abatement options.

Other energy technologies would be able to compete with nuclear power far more effectively if the government focused on creating an energy-neutral playing field rather than picking technology winners and losers. The policy choice to invest in nuclear also carries with it a risk unique to the nuclear fuel cycle: greatly exacerbating already thorny proliferation challenges as reactors and ancillary fuel-cycle facilities expand throughout the world.

As this report amply demonstrates, taxpayer subsidies to nuclear power have provided an indispensable foundation for the industry's existence, growth, and survival. But instead of reworking its business model to more effectively manage and internalize its operational and construction risks, the industry is pinning its hopes on a new wave of taxpayer subsidies to prop up a new generation of reactors.

Future choices about U.S. energy policy should be made with a full understanding of the hidden taxpayer costs now embedded in nuclear power. To accomplish this goal, we offer the following recommendations:

- **Reduce, not expand, subsidies to the nuclear power industry.** Federal involvement in energy markets should instead focus on encouraging firms involved in nuclear power—some of the largest corporations in the world—to create new models for internal risk pooling and to develop advanced power contracts that enable high-risk projects to move forward without additional taxpayer risk.
- **Award subsidies to low-carbon energy sources on the basis of a competitive bidding process across all competing technologies.** Subsidies

should be awarded to those approaches able to achieve emissions reductions at the lowest possible cost per unit of abatement—not on the basis of congressional earmarks for specific types of energy.

- **Modernize liability systems for nuclear power.** Liability systems should reflect current options in risk syndication, more robust requirements for the private sector, and more extensive testing of the current rules for excess risk concentration and counterparty risks. These steps are necessary to ensure coverage will actually be available when needed, and to send more accurate risk-related price signals to investors and power consumers.
- **Establish proper regulation and fee structures for uranium mining.** Policy reforms are needed to eliminate outdated tax subsidies, adopt market-level royalties for uranium mines on public lands, and establish more appropriate bonding regimes for land reclamation.
- **Adopt a more market-oriented approach to financing the Nuclear Waste Repository.** The government should require sizeable waste management deposits by the industry, a repository fee structure that earns a return on investment at least comparable to other large utility projects, and more equitable sharing of financial risks if additional delays occur.
- **Incorporate water pricing to allocate limited resources among competing demands, and integrate associated damages from large withdrawals.** The government should establish appropriate benchmarks for setting water prices that will be paid by utilities and other consumers, using a strategy that incorporates ecosystem damage as well as consumption-based charges.
- **Repeal decommissioning tax breaks and ensure greater transparency of nuclear decommissioning trusts (NDTs).** Eliminating existing tax breaks for NDTs would put nuclear power on a similar footing with other energy sources. More detailed and timely information on NDT funding and performance should be collected and publicized by the NRC.
- **Ensure that publicly owned utilities adopt appropriate risk assessment and asset management procedures.** POUs and relevant state regulatory agencies should review their internal procedures to be sure the financial and delivery risks of nuclear investments are appropriately compared with other options.
- **Roll back state construction-work-in-progress allowances and protect ratepayers against cost overruns by establishing clear limits on customer exposure.** States should also establish a refund mechanism for instances in which plant construction is cancelled after it has already begun.
- **Nuclear power should not be eligible for inclusion in a renewable portfolio standard.** Nuclear power is an established, mature technology with a long history of government support. Furthermore, nuclear plants are unique in their potential to cause catastrophic damage (due to accidents, sabotage, or terrorism); to produce very long-lived radioactive wastes; and to exacerbate nuclear proliferation.
- **Evaluate proliferation and terrorism as an externality of nuclear power.** The costs of preventing nuclear proliferation and terrorism should be recognized as negative externalities of civilian nuclear power, thoroughly evaluated, and integrated into economic assessments—just as global warming emissions are increasingly identified as a cost in the economics of coal-fired electricity.
- **Credit support for the nuclear fuel cycle via export credit agencies should explicitly integrate proliferation risks and require project-based credit screening.** Such support should require higher interest rates than those extended to other, less risky power projects, and include conditions on fuel-cycle investments to ensure the lending does not contribute to proliferation risks in the recipient country.

Chapter 1

Overview

A well-organized and effective nuclear industry lobby is now advocating for unprecedented public investment in new nuclear power plants. This investment is based on questionable environmental and energy security claims, as well as on cost estimates unrealistically derived from the controlled world of vendor estimates rather than from the far messier economics encountered when building real plants. Of still greater concern is that the cost projections for new reactors focus on private expenditures, often excluding the growing array of public subsidies to nuclear power. Without accounting for subsidies provided at every stage of the nuclear fuel cycle, it is difficult to understand the magnitude of public support, the real cost structure of the industry (public plus private costs), or the distortions that nuclear subsidies impose both on investment decisions and inter-fuel competition. This report explores in detail the current and proposed subsidies for nuclear power.

1.1. AN INTRODUCTION TO SUBSIDIES

The nuclear power industry in the United States receives subsidies through a wide variety of government policies and programs.[1] The subsidies discussed in this report derive from programs that have supported, and often continue to support, the existing fleet of reactors as well as programs that are available only to new reactors ("new-build"). Historical subsidies to the nuclear fuel cycle are included not only to provide perspective on current industry efforts to position nuclear power as a low-cost, unsubsidized option but also because these subsidies provide important insights into the financial risks that new and proposed initiatives may have on similar enterprises.

While a subsidy is most commonly thought of as a cash payment from the government, this is but one of the many ways that governmental policies transfer value to specific groups. In fact, many of the most important subsidies to the nuclear fuel cycle are those that shift business risks from facility developers, owners, and investors to taxpayers or other parties. Most of these subsidies involve little or no cash payments to industry from the government, at least in the short term. Rather, they may cap or shift accident, default, or long-term performance risks away from nuclear investors and operators to the public, thereby distorting market choices. Such subsidies tend to favor a financially risky technology over technologies that are much more financially secure.

A second important concept is that some government programs may provide important subsidies to a particular economic sector, even if those programs apply to other sectors as well. Thus the nuclear industry benefits from some programs that are open, but not limited, to uranium mining or nuclear power production—for example, accelerated depreciation on capital investments and special deductions for minerals extraction. It is important to include such programs in any discussion of subsidies to the nuclear power industry because the details on eligibility often create differential benefits across sectors; even broad-based programs can

[1] An appreciation of some of the core concepts of subsidy identification and measurement is useful when reading this report. Thus, in addition to the general information found in this chapter, a more detailed discussion of these concepts is given in Appendix B.

skew market choice away from options with certain investment and risk profiles. Thus accelerated depreciation reduces the cost of capital, which makes less capital-intensive approaches to providing energy services, such as energy conservation and efficiency, less attractive. For the purpose of this analysis, subsidy estimates for programs that more generally benefit nuclear power have been prorated to reflect only the share benefiting the nuclear fuel cycle.

Third, where government programs charge program beneficiaries for goods or services provided, these offsetting collections have been deducted from program costs so as to generate a net subsidy value. In some cases, such as those involving the Nuclear Regulatory Commission in recent years, offsetting collections fully cover all program costs. It is important, however, to evaluate offsetting collections on a timescale appropriate to the mission for which a program has been established. In the case of the Nuclear Waste Fund, positive cash flow and large accrued balances do not provide sufficient information for assessing whether there is a net subsidy to the activity, as the fund's objective is to finance a large and complex program over a centuries-long time span.

Finally, many of the subsidy values in this report are expressed as a range, which can more accurately convey data uncertainties or differences in input values. In some cases, the range presents the cost to government (at the low end) and the value to the recipient (at the high end). Estimate dispersion may also result from differing baselines. On tax subsidies, for example, the low estimate will reflect the lost revenue to the Treasury ("revenue loss value"). However, some of the tax subsidies are themselves exempt from taxation, boosting their value to the recipient. The high tax estimates will incorporate this difference using an "outlay equivalent" measure.

As noted above, some subsidies are available only to new reactors, some only to existing reactors, and others are accessible by both. To the extent possible, the following analysis highlights and quantifies these distinctions. Where programs that support nuclear power cannot be quantified, they are discussed qualitatively.

1.2. FRAMEWORK FOR EVALUATING CURRENT SUBSIDIES TO NUCLEAR POWER

This report examines subsidies to each stage of the nuclear fuel cycle. It begins with an introduction to the economics of nuclear power and then briefly summarizes the sector's historical subsidies. The subsequent sections evaluate the main federal programs already in existence to support the current and planned fleet of reactors, as well as a handful of new subsidy policies currently "in play" at the federal level.

Table 1 provides an overview of the key subsidies to the nuclear fuel cycle. The table's structure is modeled on a standard economic classification scheme used by the Organisation for Economic Cooperation and Development (OECD) in its tracking of agricultural subsidies (OECD 2008). The main subsidy categories are:

- **Output-linked support**, which involves subsidies that are commensurate with the amount of power produced. Market price support is one form of this approach, as it effectively forces consumers to pay for nuclear power even if it is more expensive than alternatives.
- **Subsidies to factors of production**, which aim to reduce the cost of the three core inputs: capital, labor, and land. For nuclear energy, capital costs dominate its ultimate cost of production; as a result, subsidies to capital are the most important in this sector. Capital subsidies are of two main types: attempts to reduce the cost of borrowing, generally by shifting investment risks away from the lender; and subsidies to reduce the after-tax cost of equipment or related infrastructure, independent of the cost of financing those purchases. Stranded cost recovery later allowed utilities to transfer their remaining above-market capital costs to ratepayers.
- **Subsidies to intermediate inputs**, which involve policies that alter the economics of key inputs such as uranium, enrichment services, and cooling water.

- **Security and risk-management** subsidies, which include programs put in place to deal with unique attributes of the nuclear industry but financed by other parties. Unless these costs are fully reflected in the price of nuclear power, alternative energy providers with more favorable risk and security profiles are disadvantaged.
- **Emissions and waste management** subsidies, like security and risk management support, hide important price signals. In this case, the subsidies artificially reduce environmental or reactor closure costs that are unique to the nuclear fuel cycle.

Though the magnitude and applicability vary by specific policy, the nuclear power sector receives subsidies at every stage of production. The characterizations of magnitude reflect estimates of impact in terms of the levelized cost of reactors. Because reactors produce so much electricity per year, a local property tax abatement worth $200 million to $300 million per reactor will typically be classified as "small" in magnitude because it is spread across millions of kilowatt-hours (kWh) during multiple years of production. In all cases, however, these are substantial sums of money that are not available for other uses in society because they are being politically directed to the nuclear sector.

In most of the rest of this report, key programs and policies pertaining to the above subsidy types are discussed in sequence. In total, we address the entire nuclear fuel cycle, from uranium mining, milling, and enrichment to conversion to electricity and delivery to consumers, long-term waste management and decommissioning. Ancillary issues such as subsidies to security and disposal of by-products are also examined.

1.3. CATEGORIZING THE SUBSIDY VALUES

To clearly demonstrate the broad range of subsidy programs provided to the nuclear power industry, the data in this report have been organized to show a number of important distinctions:

- **Point of intervention on the fuel cycle.** Subsidies are grouped according to the stage of the fuel cycle they affect so that the reader can more easily see where support is clustered (e.g., at the capital formation or waste management stage).
- **Use of a range estimate.** Subsidy values are normally presented as ranges, with varying sources or assumptions driving the differences between estimated high- and low-end values. This approach more accurately captures the uncertainty inherent in some of the values. However, it is important to note that the subsidies are substantial even among the low estimates.
- **Subsidy intensity.** Subsidy values are presented in terms of support per kWh of output on a levelized cost basis. This convention is important because the number and timing of new reactors is not yet known and because the metric can be more easily compared to subsidies affecting other energy sectors and to the value of the nuclear electricity being produced. Historical subsidies have been converted into per-kWh values, using generation of nuclear electricity over the relevant period of the program being analyzed. New subsidies assume a 85-percent (high estimate) to 90-percent (low estimate) lifetime reactor capacity factor—a value somewhat below some optimistic projections by industry but still well above historical weighted average capacity factors in the United States of less than 80 percent. Where available, data on the total size of the subsidy is also provided. Historical subsidy data have been scaled to 2007 dollars using the gross domestic product implicit price deflator for comparability with newer estimates.
- **Separation of support on a new-versus-existing basis.** Some subsidies apply only to new reactors, some apply only to existing ones, and others apply to both. This report shows these distinctions whenever possible, with the aim of highlighting the impact of subsidy policies on

new investment decisions, even when new reactor projects have not actually started to benefit from them.

- **Legacy policies.** Since the industry's inception, government programs have provided very large incentives to support nuclear power. Over the course of five decades, many of the policies have been modified or eliminated, and the facilities they helped to build have largely been depreciated. Although these subsidies may no longer affect the cost structure of existing reactors, understanding the scale of historical support is critical in evaluating the distortionary role of government support in shaping the current energy infrastructure. Subsidies to new reactors often follow a similar pattern. Legacy subsidies are presented separately from ongoing support to the current reactor fleet, showing up as zero for existing and new reactors. In some cases, however, the legacy subsidies arose from policy gaps that still exist (e.g., mining on federal land). In such areas, the programs are expected to continue subsidizing the nuclear fuel cycle.
- **Proposed policies.** New subsidy proposals are discussed in Section 8.3. They include both new subsidies and expansions and extensions to existing ones. If adopted, they will further skew the economic incentives for reactor investment.

The subsidy values shown for new reactors represent the value to a reactor of participating in the program. In some cases, access to a particular subsidy program is presently capped at a specific dollar amount or limited to a number of reactors. Therefore the value shown for a new reactor may not be available for all new reactors that get built. Presenting the full slate of subsidies is important, however, for demonstrating the magnitude of support for the first group of reactors that do get built. In addition, limitations on access to subsidies have routinely been relaxed or eliminated in many other areas of federal policy. Examples include routine renewals and extensions of expiring energy-related tax breaks, expanded eligibility for energy production tax credits (PTCs), and increased maximum eligible plant sizes for biofuel PTCs. Current lobbying efforts aim to achieve similar expansions in the nuclear area, including an increase in the number of reactors able to use the nuclear PTC, even more favorable accelerated depreciation, investment tax credits, and much higher limits for loan guarantees on new plants.

Subsidies per kWh of electricity produced are compared to the value of that electricity, based on data developed by the Energy Information Administration (EIA). These figures represent average generation prices for the country. Because this analysis did not evaluate subsidies to power transmission or distribution, the subsidies are benchmarked against the comparable "busbar" plant-generation costs.[2] Subsidies to existing reactors are benchmarked against 2009 prices (6.1 to 6.7 ¢/kWh); those for new reactors are compared to the average projected price over the next 15 years (5.7 to 6.3 ¢/kWh). The EIA runs reference, high-price, and low-price scenarios, but only the reference and high-price scenarios have been used here; comparisons to low-price scenarios would simply have strengthened this report's main conclusions.

2 Busbar costs include all the costs necessary to build and operate a nuclear reactor, but exclude transmission and distribution. If industrial end-user rates had been used instead, reference prices would have been only 4.5 to 7.5 percent higher and would not have significantly affected the subsidy-intensity values.

Table 1. Overview of Subsidies to Nuclear Power

Category	Examples	Magnitude	Subsidy to Existing Reactors?	Subsidy to New Reactors?
1. OUTPUT-LINKED SUPPORT	Subsidies linked to nuclear power production levels			
Market-price support Policies that allow nuclear to be sold at higher-than-market rates	Purchase mandates ("clean energy" portfolio standards)	Past proposals were large	No	Yes; exists at present only in Ohio
Payments based on current output	Nuclear production tax credit	Moderate	No	Yes
2. SUBSIDIES TO FACTORS OF PRODUCTION	Support to capital is the most important, though some subsidies are directed at labor and land as well			
Capital Subsidies to reduce the cost of financing, or the cost of capital equipment	Reactor loan guarantees or direct loans (domestic and foreign)	Very Large	No	Yes
	Accelerated depreciation	Moderate	Yes, though capital mostly written down	Yes
	Recovery of construction/work-in-progress (regulated utilities only)	Large	Yes, though new capital investments in existing fleet relatively small	Yes
	Government research and development	Moderate	Yes	Yes
	Tax-exempt public reactors; no required rate of return	Moderate	Yes	Yes
	Subsidized site approval and licensing costs	Small	No	Some
	Transfer of stranded asset liabilities	Large	Yes, though now a sunk cost	Some state rules lay groundwork for this
	Traditional rate regulation (return on "prudently incurred" investments even if not used or economically competitive)	Large	Yes, though now a sunk cost	In most states retaining traditional regulation
	Regulatory-delay insurance	Small to moderate	No	Some
Labor	Shifting of health-related liabilities to taxpayers	Moderate	Yes	Estimates assume no subsidy (i.e., that no new workers were harmed since 1992)
Land	Reduced property tax burdens for new plants at state or county level	Small to moderate	Probably	Yes
3. POLICIES AFFECTING THE COST OF INTERMEDIATE INPUTS	Subsidies to important inputs needed to make nuclear power			
Uranium	Subsidized access, bonding on public lands	Small	Yes	Yes
	Percentage depletion on uranium extraction	Small	Yes	Yes
	Legacy costs of mining, milling sites	Moderate	Yes	Yes
	Federal uranium-stockpile management	Small	Yes	Yes
Enrichment services	Below-market sales from government-owned facilities (prior to privatization in the United States)	Moderate	Yes	No; United States no longer a low-cost supplier
	Tariffs on imported enriched uranium	Small	May increase prices	May increase prices
	Federal liability indemnification for U.S. Enrichment Corporation; ambiguous requirements under Price-Anderson for newer private enrichment providers	Small to Moderate	Yes; may also slow market consolidation	Yes
	Monopoly agent for selling LEU derived from Russian HEU in warheads	Small	May increase prices to reactors	May increase prices to reactors
	Environmental remediation costs	Moderate	Yes	Yes, though contamination is a sunk cost
Cooling water	Free or subsidized use of large quantities of cooling water	Moderate	Yes	Yes

Table 1. Overview of Subsidies to Nuclear Power (continued)

Category	Examples	Magnitude	Subsidy to Existing Reactors?	Subsidy to New Reactors?
4. SUBSIDIES TO SECURITY AND RISK MANAGEMENT Government capping or direct provision of security and risk-management services	Price-Anderson cap on accident liability: reactors, contractors, fuel-cycle facilities, shippers	Believed to be large	Yes	Yes
	Nuclear Regulatory Commission services not paid by user fees	Small	User fees now cover costs	User fees now cover costs
	U.S. funding of proliferation oversight abroad by the IAEA	Small	No U.S. proliferation inspections	No U.S. proliferation inspections
	Plant security/low design-basis requirements for attacks	Moderate to large	Yes	Yes
5. SUBSIDIES TO DECOMMISSIONING AND WASTE MANAGEMENT	Tax breaks for reactor decommissioning	Small to moderate	Yes	Yes
	Nationalization of nuclear waste management	Large (risk reduction)	Yes	Yes

Chapter 2

A Review of Historical Subsidies to Nuclear Power and Their Drivers

There is a close relationship between the cost structure of nuclear power, the long-term safety and financial risks associated with some elements of the nuclear fuel cycle, and the high market risk that investors have placed on the technology since its inception. While nuclear power has some beneficial attributes (low operating costs, economies of scale, and low carbon emissions per unit of energy delivered), pricing transparency on *all* of its attributes most likely would have dampened past investment in nuclear power and shifted resources to alternative technologies. Subsidies, however, served to reduce capital costs and risks, shifting them from investors to the public. And just as substantial historical subsidies have protected and enabled the development and continued operation of nuclear power plants over the past 50 years, large new subsidies—both existing and proposed—are poised to artificially expand the technology's share of power markets in the future, potentially at the expense of lower-cost and lower-risk substitutes.

This chapter examines some of the features of nuclear energy that account for the technology's poor economics, and it documents past governmental support to the industry.

2.1. KEY FINANCIAL RISKS: CAPITAL COSTS AND "LONG-TAIL" OPERATING RISKS

Nuclear power plants require large capital investments with long lead times. Both of these attributes drive up plant costs—the first due to the scale of outlays, the second because of high financing costs during the construction phase.[3] While the focus of this section is on nuclear reactors, similar attributes plague other parts of the fuel cycle, such as enrichment and waste management facilities.

The importance of capital costs is clearly illustrated in Table 2, with the capital share at more than 80 percent of levelized costs, or more than 90 percent if one includes "capital-like" fixed operations and maintenance (O&M)—costs that can be adjusted, but not very quickly. Other estimates peg the capital share as high as 85 percent of levelized costs (Kaplan 2008: 38). In addition to the high share of capital costs, the rapid escalation of cost estimates, as well as their wide ranges, are good indicators of the uncertainty that cause investors to be wary of the nuclear sector.

Table 2. Capital Costs Dominate Nuclear Power Economics, Continue to Rise

Cost Shares	EIA Estimates
Capital costs, including transmission upgrades	82.3%
Fixed O&M	9.8%
Variable O&M, including fuel	7.9%

Source: EIA 2009a.

The competitiveness of a nuclear power plant is sensitive to cost escalation (both before and after construction has begun), to delays in completion, and to other market factors—such as changes in

[3] The industry is floating new proposals to build small-scale modular reactors. While these technologies may eventually be feasible, the trend in actual reactor projects has been toward larger reactors than in the past. The most commonly proposed reactors in the United States are the Westinghouse AP1000, which is rated at 1,100 megawatts (MW), and the Areva EPR, which is rated at 1,600 MW.

demand for electricity and changes in the prices of alternatives during the construction period.[4] A drop in electricity price that occurs between the start of construction and the time that the facility comes online can greatly erode plant economics. Nuclear power plants also enter the market in large supply increments, with a need to operate at high capacity utilizations in order to repay capital charges. This characteristic, which also applies to other basic industries (such as paper and steel), can reduce margins for producers and contribute to boom/bust dynamics. Power suppliers with high variable costs may be hurt disproportionately, even if their total levelized costs are lower.

Traditional regulation in most states, on top of other generous government subsidies, has shielded utilities from much of this risk. The rate-of-return framework enabled utilities to recover and earn a return on investments that were deemed "prudently incurred" (i.e., appeared reasonable at the time they were made), even if they later turned out not to be "used and useful" (i.e., were abandoned during construction or became uncompetitive as a result of changed market conditions).[5] The majority of new nuclear plants proposed in the United States today are in states still reliant on traditional regulation.

Because operating costs account for a much smaller share of levelized costs than do capital costs, they are often ignored. The logic here is somewhat circular: operating costs are low in part because of government subsidies. Most prominently, these subsidies shift the long-term, though uncertain, risks of accidents and nuclear waste management away from plant owners. In unsubsidized industries, these risks would affect current operations through elevated annual insurance costs and high waste management fees.

Nuclear power has two additional attributes that make it unattractive to investors. First, the period of risk exposure lasts too long. In most other sectors of the economy, the majority of the risks that investors take on last only several years, or a few decades at most. By contrast, nuclear operations span many decades—longer even than coal plants once post-closure periods prior to decommissioning are included. In particular, highly radioactive and extremely long-lived wastes are not only risky but also require oversight for centuries.

Second, a single negative event can wipe out decades of gains. Although the risk of nuclear accidents in the United States is considered quite low, it is not zero.[6] Plausible accident scenarios generate catastrophic damages, with corresponding levels of financial loss. This characteristic creates a large disconnect between private interests (which highlight an absence of catastrophic damages thus far) and public interests (which must consider the damage that would be caused in the case of even a moderate accident, as well as the inadequacy of financial assurance mechanisms or insurance-related price signals to address the challenge).

Unlike car accidents, where one event generally has no impact on the perceived risk to unrelated drivers or auto companies, risks in the nuclear sector are systemic. An accident anywhere in the world will cause politicians and plant neighbors everywhere to reassess the risks they face and question whether the oversight and financial assurance are sufficient. Generally, the cost implications of such inquiries will be negative for reactor owners.

All of these factors, in combination with a poor track record of financial performance on new plant construction, have led investors in nuclear power to demand much higher rates of return, to

[4] Thirteen of the 47 units listed as "under construction" by the International Atomic Energy Agency as of the end of June 2009 commenced construction more than 20 years ago; two additional units have been under construction for 10 years. (Schneider et al. 2009).

[5] A few states, such as Pennsylvania, applied a "used and useful" test for allowing a return on investment, a standard that was upheld by the U.S. Supreme Court (Duquesne Light Co. v. Barasch, 488 U.S. 299, 1989).

[6] Schneider et al. 2007.

shift the risks to other parties, or to steer clear of the nuclear power sector entirely.[7] These risks are real, and if they were visibly integrated into the nuclear cost structure, the resulting price signals would guide energy investment toward technologies that have more predictable and lower risk profiles.

2.2. FIFTY YEARS OF SUBSIDIES

Industry advocates like to emphasize nuclear power's low operating costs as an indication of the technology's competitiveness.[8] In addition to ignoring established subsidies to operating costs, the advocates also neglect to mention that building the existing reactor fleet has entailed massive capital costs and associated losses and write-downs. These costs—as much as $300 billion by some estimates (Schlissel et al. 2009)—have already been borne by investors and ratepayers for more than half a century.

Some in the industry continue to claim that any subsidies for new nuclear power plants will be transitional. They argue that short-term subsidies will allow the industry to gain operational experience with new reactor designs, and that after these "first-of-a-kind" costs have been amortized, the industry will be cost-competitive.[9] But the nuclear industry has been making the transitional-support argument since it rolled out the earliest civilian reactors. In 1954, General Electric stated in an advertisement placed in *National Geographic* that, "*We already know the kinds of plants which will be feasible, how they will operate, and we can estimate what their expenses will be. In five years—certainly within 10—a number of them will be operating at about the same cost as those using coal. They will be privately financed, built without government subsidy.*" Clearly, 5 or 10 years were not enough in the 1950s and '60s, and there is little reason to expect that present subsidy requirements will be short-term either.

The main historical subsidies to the nuclear industry, listed below, all remain in effect in one form or another at present—decades after they were initiated:

- **Accident liability**. Federal caps on liability from nuclear accidents were put in place in 1957 on a "temporary" basis, but they have been renewed ever since.
- **Publicly funded research and development**. Nuclear power captured almost 54 percent of all federal research dollars between 1948 and 2007 (Sissine 2008: 3) and nearly 40 percent of International Energy Agency (IEA) member-country energy research and development (R&D) between 1974 and 2007 (IEA 2009).[10] While spending in the United States has begun to favor other energy technologies in recent years (spending through 1993, for example, was more than 60 percent—see Figure 1, p. 47), in aggregate the bulk of funding has gone to nuclear. At present, the sector remains the dominant recipient of government-financed R&D in many other countries as well, based on data tabulated annually by the IEA.[11]
- **Capital subsidies**. Construction and financing costs have been a problem for nuclear reactors

[7] Moody's recently noted that its analysts "view new nuclear plants as a 'bet the farm' endeavor for most companies, due to the size of the investment and the length of time needed to build a nuclear power facility" (Moody's 2009: 4).

[8] A Nuclear Energy Institute press release (NEI 2001), for example, was titled "Nuclear Energy Surpasses Coal-Fired Plants as Leader in Low-Cost Electricity Production." While the statement did include information on other expenses, they were de-emphasized.

[9] Areva U.S. CEO Jacques Besnainou responded to questions about the implications of large cost overruns at new company plants in Finland and France by implying that these were one-offs: "I want to remind you that these are first-of-a-kind facilities and the problems we are facing are typical of the startup of construction of new nuclear reactors." (Yurman 2009a). However, Areva obviously knew that its fixed-price bid to build the Finland plant was for a first-of-a-kind unit, so in theory it would have already made allowances for this in its pricing. In reality, the Finland plant is now more than three years behind schedule and €2.7 billion over budget; something Areva did not likely plan for.

[10] Sissine (2009) notes that some of the early-years data on nuclear R&D may mix in some military reactor research. However, Koplow (1993) tabulated data from the same sources, excluding military support and separating support for fusion. That analysis found a similar pattern, albeit for a somewhat different time span (1950 to 1993): 49 percent of total R&D went to fission, with an additional 13 percent to fusion. Within the IEA, two-thirds of the R&D support for nuclear energy between 1974 and 2007 was for fission (IEA 2009).

[11] For the period of 1998 to 2007, nuclear R&D comprised more than 50 percent of total energy R&D in France and Japan, and more than 30 percent in Germany and the United Kingdom (IEA 2009).

since their inception. The major waves of domestic reactor construction were heavily subsidized through a mix of public supports, which included investment tax credits, accelerated depreciation, ratebasing of reactor costs, and recovery of construction interest from ratepayers prior to a plant's commencement of operations. At the back end, tax subsidies have reduced the cost of reactor decommissioning accruals.

- **Nationalization of waste-management risks**. The technical and financial risks of managing reactor and other fuel-cycle wastes tend to make investors skittish. These risks were effectively nationalized in the United States by means of a small fee on nuclear-generated electricity, thereby protecting plants at the expense of taxpayers. The governments of many other countries have also stepped in to absorb these risks at or below cost.

- **Mining and enrichment**. The U.S. government has managed uranium stockpiles since the industry's inception, and through 1966 immediately purchased all uranium as soon as it was mined (PNL 1978: 117). By 1971, the stockpile had reached 100 million pounds of U_3O_8, at which point the government began to sell some of it onto the market. Imported uranium was banned through 1975, and partially restricted through 1983 (PNL 1978: 124). In enrichment, the federal government historically took on all financial risk for building up capacity, and for many years it sold the enriched fuel to commercial reactors below cost. Below-cost sales appear to be a continuing issue today for some of the foreign enrichment companies as well. The U.S. enrichment picture, via the privatized U.S. Enrichment Corporation, now has a more complicated mix of policies that seem primarily aimed at keeping a U.S. firm in the enrichment market rather than keeping low-enriched uranium (LEU) prices low. Government subsidies to the sector globally, however, appear to spur overcapacity, generating artificially low fuel costs.

- **Proliferation**. Just as coal production generates carbon and other externalities that need to be integrated into pricing if economies are to make sound energy choices, the link between civilian nuclear power and nuclear weapons also cannot be ignored. As noted by Sharon Squassoni, director of the Proliferation Prevention Program at the Center for Strategic and International Studies, the "dual-use [civilian and military] nature of nuclear technology is unavoidable. For the five nuclear-weapons states, commercial nuclear power was a spinoff from weapons programs; for later proliferators, the civilian sector has served as a convenient avenue and cover for weapons programs" (Squassoni 2009a).[12] By artificially accelerating the expansion of civilian programs, subsidies to nuclear technology and fuel-cycle services worldwide exacerbate the already challenging problems of weapons proliferation. To date, the negative externality of proliferation has not been reflected in the economics of civilian reactors.

Even with these subsidies, the nuclear industry has not been competitive. This fact is illustrated by the waves of very large write-offs of nuclear-related capital investment and the transfer of repayment liability away from investors. Reactor projects have been abandoned during construction in large numbers. Between 1972 and 1984, these cancellations cost $40 billion to $50 billion in today's dollars, largely borne by ratepayers or taxpayers rather than the reactor owners (Schlissel et al. 2009: 11). An additional $150 billion in cost overruns on

[12] The "five nuclear-weapons states" is a formal title given to the United States, Russia (formerly the USSR), United Kingdom, France, and China under the non-proliferation treaty; they are not the only countries in the world with nuclear weapons.

completed plants also were passed onto ratepayers. Yet, problems remained. When electricity markets were deregulated, nuclear assets were among the most common uneconomic, or "stranded," assets. Nearly $110 billion (2007$) was transferred to ratepayers or taxpayers as charges independent of the nuclear power consumed (Seiple 1997). Stranded cost recovery for nuclear power brought the cost structure of the reactors down low enough for them to compete in deregulated power markets, largely by passing over-market generating-plant costs onto consumers in the form of transition charges.

There is no comprehensive record of historical subsidies to nuclear power that details support levels from the industry's inception. However, a review of a number of studies completed over the past four decades demonstrates government's central role in making the sector appear viable. Table 3 shows that subsidies were generally equal to one-third or more of the value of the power produced.[13] While such levels of support may not be surprising for very new industries with a small installed base, it is quite striking to see subsidy levels so high for a single industry—and sustained over five decades.

Table 3. Subsidizing Plant Construction and Operation

Period of Analysis	Federal Subsidy, $billions		Subsidy, ¢/kWh		Subsidy as % of Market Price*	Analysis	Notes
	Low	High	Low	High			
2008	-	-	5.0	8.3	113–189%	Koplow/Earth Track calculations of subsidies to new reactors	Share of national average wholesale rates, 2002–06
1947–99	178.0	-	1.5	-	NA	Goldberg/Renewable Energy Policy Project (2000)	Price-Anderson not estimated
1968–90	122.3	-	2.3	-	33%	Komanoff/Greenpeace (1992)	Price-Anderson not estimated
1950–90	142.4	-	2.6	-	NA	Komanoff/Greenpeace (1992)	
1989	7.6	16.2	1.4	3.1	32%	Koplow/Alliance to Save Energy (1993)	
1985	26.8	-	7.0	-	83%	Heede, Morgan, Ridley/Center for Renewable Resources (1985)	Price-Anderson not estimated
1981	-	-	5.9	12.3**	105%	Chapman et al./U.S. EPA (1981)	Tax expenditures only
1950–79	-	-	4.1	6.0	NA	Bowring/Energy Information Administration (1980)	Tax and credit subsidies not estimated

Source: Koplow 2009b.

*Applicable values for power were based on national average wholesale rates when available. For earlier years, the average retail rates to industrial customers were the closest available proxies, as EIA data on wholesale rates did not go back far enough.

** To err on the conservative side, only the low estimate has been used to estimate legacy subsidies in the subsequent report calculations.

[13] The actual subsidies were probably even higher, as many studies did not do a full tally of all subsidies in effect. In addition, the value of produced power in the earlier comparisons was overstated (due to data limitations) at the industrial retail rate. By contrast, the wholesale price would have provided a more accurate metric of competitiveness.

Chapter 3

Output-Linked Support

Government interventions linked to output increase the commodity price received by producers above what it would be in the absence of such intervention. Two policies are examined here: direct payments to producers, such as production tax credits, that are linked to their levels of production; and inclusion of nuclear power in electricity portfolio standards that mandate the use of specified forms of energy.

While there are no known U.S. tariffs on nuclear-generated electricity, there are tariffs on the import of enriched uranium.[14] The latter are addressed in Chapter 5's discussion of subsidies to intermediate inputs.

3.1. PAYMENTS BASED ON CURRENT OUTPUT

The Energy Policy Act of 2005 (EPACT) introduced a 1.8 ¢/kWh PTC for new nuclear reactors.[15] This PTC is limited in two ways. First, no single reactor can claim the credit for more than eight years. Second, under current law, a maximum of 6,000 megawatts (MW) of capacity nationwide will be able to claim the credit. The fact that the credit cannot be used until plant operations begin also reduces its value on a present-value basis—from roughly 25 percent of levelized costs to 15 percent, according to the Congressional Budget Office (CBO),[16] to roughly 1.05 ¢/kWh (Falk 2008: 32). On an outlay-equivalent basis, the value of the nuclear PTC is higher at 1.45 ¢/kWh (Earth Track calculations). Aggregate caps under existing rules are $750 million per year, or $6 billion in total on a nominal basis. Comparable outlay equivalent values are $1.1 billion per year and $8.6 billion in total.

An increased number of reactor developers applying for the PTC may result in lower realized values per kWh generated, as the national megawatt limit would be allocated across more applicants. Equally plausible, however, is that the program limits will be increased. Senator Lisa Murkowski (R-AK), for example, has proposed doubling the cap to 12,000 MW (Ling 2009a). Also, the American Power Act (APA) contained a provision that would raise the cap from 6,000 MW to 8,000 MW. Under the Bush administration, the President's Council of Advisors on Science and Technology proposed increasing the limits on PTC eligibility beyond 6,000 MW to enable the United States to meet a goal of 36,000 MW of new nuclear capacity by 2030.[17]

3.2. PURCHASE MANDATES FOR NUCLEAR POWER

Competitive markets give buyers wide latitude in choosing the products they wish to purchase, which creates pressure to keep prices low. By contrast, market price support entails policies that constrain consumer choice through regulation (such as purchase mandates) or narrowly targeted fees (such as tariffs). These policies force utilities or ratepayers to buy selected forms of electricity, even at higher prices. The subsidy is equal to the price premium multiplied by the quantity of power provided under the mandate. Carve-outs for specific

14 See, for example, NAEWG 2005.

15 The Energy Policy Act of 2005 indexed the PTC inflation. This indexing was stripped for nuclear power in the Gulf Opportunity Zone Act of 2005 (EIA 2006a: 21).

16 Based on a 15 percent reduction from the CBO's reference case for nuclear before subsidies of approximately $70/MWh.

17 See *www.ostp.gov/galleries/PCAST/PCAST-EnergyImperative_ExecSumm.pdf.*

resources act as "sub-mandates," which tend to increase the overall economic cost of the mandate.

Purchase mandates exist both in liquid transport fuel (via the federal renewable fuel standards, or RFS) and electricity markets (via various renewable portfolio standards, or RPS). RPS presently exist only at the state and regional level—though a variety of legislative efforts (e.g., The American Clean Energy and Security Act, H.R. 2454) aim to introduce a federal version (called a renewable electricity standard) as well. RPS price premiums interact with other policies. If an eligible resource is heavily subsidized in other ways—such as through tax credits—producers of that resource will probably be able to submit a lower bid under an RPS. Thus the price premium should be viewed as the incremental subsidy from the purchase mandate on top of other forms of support. Forty-five states, the District of Columbia, and a number of U.S. territories had some form of RPS by 2009. These jurisdictions covered the majority of the national electrical load (DSIRE 2009).

At present, nuclear power is included as an eligible resource in state RPS only in Ohio. The state's "Alternative Energy Portfolio," adopted in May 2008, allows up to half of the mandate (equal to 12.5 percent of total demand) to be met by advanced nuclear reactors, among other sources (Pew 2009). Similar proposals were also considered in Florida, Indiana, South Carolina, and West Virginia (Hiskes 2009; NEI 2009c; Platts 2009).

Proposals to include nuclear power in a federal clean energy portfolio standard have not yet succeeded. However, analysis of two past proposals by the EIA (EIA 2007, 2006b) indicate that if nuclear plants could be built at the EIA's projected cost (which is much lower than the costs currently projected by the industry), nuclear power would benefit substantially from such mandates. The first proposal opened a larger portion of power demand to clean energy requirements (60 percent by 2030), but with a lower cap on price premiums (2 ¢/kWh). Nuclear power captured 43 percent of the benefits under this plan, with a present-value benefit of $500 million. A second proposal had lower targets (20 percent by 2025, and reduced credits for nuclear). However, it allowed higher price premiums (up to 2.5 ¢/kWh). In this proposal, the EIA estimated that nuclear would capture one-third of the benefits, with a present value of $2.6 billion; price premiums on nuclear electricity from this mandate ranged from 1.5 to 2.0 ¢/kWh, roughly equal to 20 percent of the projected value of the power produced.

While these proposals did not pass, the issue remains very much alive. A provision of the American Clean Energy Leadership Act (ACELA, S. 1462) reported by the Senate Energy and Natural Resources Committee in 2009 included a renewable electricity standard (RES) that would allow utilities to make alternative compliance payments (ACPs) of 2.9 ¢/kWh to the states instead of developing renewable energy. The provision would also allow states to allocate the ACPs to build nuclear plants (or coal plants with carbon capture and storage) as well as for renewable energy facilities and energy efficiency programs.

Table 4. Output-Linked Support (Overview)

	Subsidies to Existing Reactors, ¢/kWh							Subsidies to New Reactors, ¢/kWh					Notes
	Total	Legacy		Existing: Low		Existing: High		Total	Low		High		
Subsidy Type		Low	High	IOU	POU	IOU	POU		IOU	POU	IOU	POU	
Nuclear production tax credit	NA							$6.0b–$8.6b	1.05	NA	1.45	NA	(1)

Notes:
(1) Statutory cap; limited to six reactors at present. PTC values shown have been levelized over license life so are less than the nominal 1.8 ¢/kWh value of the credit. High end represents outlay-equivalent measure. Low end is based on CRS/Falk (2008). Existing reactors received generous investment tax credits, but these no longer affect current operations. Assumed to be unavailable to POUs, though there may be ways to sell/transfer to IOU/investors using lease-back arrangements.

Chapter 4

Subsidies to Factors of Production

Production systems normally integrate three basic "factor inputs" in providing a good or service to the marketplace: capital (durable machines and equipment), labor (human inputs), and land. Because capital is by far the most important factor input for nuclear power, and for related fuel-cycle facilities as well, it is not surprising that the bulk of nuclear subsidy policies have targeted the capital component of production.

Thus, even though labor and land do receive some subsidies, this chapter focuses primarily on subsidies to capital. Capital subsidies fall into two main categories: policies that reduce the cost of funds (cost of capital) for nuclear investments, and policies that reduce the cost of the equipment purchased (independent of financing) with those funds. Subsidies to bring down the cost of capital to nuclear power include government loan guarantees or direct loans, both domestic and foreign; recovery of construction-work-in-progress (CWIP) from ratepayers prior to plant completion; construction of reactors by tax-exempt entities; and subsidized insurance against regulatory delays. Subsidies that reduce the after-tax cost of capital infrastructure itself include accelerated depreciation, government R&D, subsidies to site approval and licensing costs, and stranded cost recovery policies. These subsidy types are discussed below.

4.1. SUBSIDIES TO REDUCE THE COST OF CAPITAL

Because nuclear investments are large-scale and high-risk investments with long build times, the cost of capital is among the most important drivers of whether new reactors will be commercially competitive. The cost of capital, in turn, is primarily driven by risk. The industry argues that it is really the *perception* of risk that drives financing costs up, rather than the actual risks of operation. This interpretation is self-serving, as it overlooks the hundreds of billions of dollars in capital lost on past nuclear power investments—roughly $40 billion through abandoned projects and at least $150 billion in cost overruns. (Schlissel et al. 2009: 1).

During past decades, the regulated environment largely insulated investors from these losses, with taxpayers and ratepayers bearing the brunt. However, Wall Street is well aware that the deregulated markets of today may no longer offer such protection. Large cost overruns and construction delays on new reactors in Finland and France—countries generally recognized as having a workable regulatory and financial environment for nuclear—underscore this point. Further risks arise from declining natural gas and spot electricity prices over the past year, a clear indication of the substantial market risks facing any technology that takes five or more years to enter the marketplace.

Larger projects tend to pose higher risks because they are harder to manage and often very sensitive to changes in market conditions. Up-front delays can ripple through project completion schedules, with substantial cost impacts. Investors also worry that longer build times increase the risk of "guessing wrong" about market demand or price trends.

Most investments are a mixture of two main forms: equity and loans (debt). Equity investments provide the investor with a share in a company but not with guaranteed payments; they are therefore considered higher-risk and expected to earn a higher return. Because debt instruments stipulate contractual schedules for payment of interest and repayment of principal, they are normally considered less risky and carry lower expected returns than equity—even though there is still a risk of default and non-repayment. Debt is also cheaper because the cost of debt (in the form of interest payments) is tax deductible for corporations, whereas payments on equity (in the form of dividends) often are not.

Government guarantees on debt are a popular and lucrative subsidy to the nuclear sector. These guarantees transfer value to investors in two ways. By virtually eliminating the default risk on debt, interest rates even for high-risk projects drop to the "risk-free" rate of the U.S. federal government. In addition, the guarantees enable a much higher proportion of debt financing than would otherwise be possible, thus reducing the need to use higher-cost equity.

Discussions of the financing costs of new nuclear reactors too often focus on the financial risk at the *firm* level. This may be done implicitly, such as by using firm-level information on the cost of capital as a benchmark for the financing assumptions for a new nuclear reactor. Large coal projects may be used as proxies as well.[18] In both cases, costs are tweaked slightly upward to allow for the greater uncertainty of nuclear. This approach tends to understate the appropriate return targets for the nuclear project, as nuclear power is considered a much higher financial risk than either the overall firm or the large-power-plant proxies. Nevertheless, it is *project*-level risk that drives the cost of capital, and this is quite high for a new nuclear power plant—especially when the reactor is bigger than the owner's balance sheet, as would be the case for a new two-reactor facility built by most of the U.S. private utilities.

Project risks are driven by the nature of the project, the market, and the developer. Capital subsidies do not eliminate or reduce the underlying project risk. Rather, they merely transfer this risk from investors to other parties, such as ratepayers, taxpayers, or even the population surrounding a plant. The subsidies will reduce the cost of financing a new project, but only because other parties are now at risk when things go wrong.

Estimating credit subsidies is generally done in one of two ways, based either on the cost to government or the value to the recipient. Cost-to-government offers perhaps a better metric of direct taxpayer losses,[19] though value-to-recipient is a much better measure of the inter-fuel distortions that the subsidies will cause in the marketplace.

Cost-to-government estimates cover the administrative costs of overseeing the loan program, interest rates (in comparison to the government's cost of borrowing), and anticipated default levels. The Federal Credit Reform Act (FCRA) requires credit subsidies to be evaluated and reported on annually, based on changes in real or expected default rates. However, two aspects of FCRA tend to understate the cost of the credit programs. The first, albeit smaller, problem is that FCRA does not require recovery of administrative costs, and reported subsidies implicitly assume that credit programs have no cost of oversight. The second problem is much more important: the act evaluates borrowing subsidies relative to the government cost of funds, rather than to the market cost of funds for a project of similar structure and

---

18 A recent analysis by the CBO provides such an example. The report noted that, "In CBO's base-case assumptions, the cost incurred to finance commercially viable projects did not depend on which technology was used for a given project. That assumption would be justified if volatility in natural gas prices and the prospect of constraints on carbon dioxide emissions created cost uncertainties for conventional fossil-fuel technologies that were similar in magnitude to the uncertainties facing investments in nuclear technology." (Falk 2008: 13).
The CBO did look at alternative financing costs as well, though even the highest-cost option they considered is likely to be well below the actual cost of capital to a new merchant nuclear plant.

19 This approach normally compares the interest rate that the private party is charged to the Treasury's cost of borrowing. For small projects, this may be fine. On a systemic basis, however, the approach is problematic, as it implicitly assumes that the taxpayer deserves no risk premium on funds loaned to high-risk commercial endeavors. It also assumes that the borrower is too small to affect the overall government cost of debt—normally true, but perhaps less so if the scale of the program starts to run into the hundreds of billions of dollars, which is roughly the scale of additional loan guarantees that the U.S. nuclear industry hopes to obtain.

risk. While some of this variance may be captured by higher assumed default rates, a substantial subsidy to all borrowers will exist even if there is no actual default.

Industry testimony and presentations on credit programs normally focus on this "cost-to-government" measure, as it makes the program seem less expensive or distortion-inducing. However, it is the *intermediation value* (Koplow 1993) that is most important for high-risk, capital-intensive ventures such as nuclear power. The federal government is in effect making use of its high-grade credit line for a select set of recipients, allowing them to obtain a substantially lower cost of funds than would otherwise be possible. In fact, the higher-risk the activity, the greater the intermediation value relative to Treasury cost of debt. This means that the same government loan guarantee program can actually generate different levels of subsidy, depending on the relative risk of the borrower.[20]

Absent federal intervention, the risk profile of new reactors suggests that debt providers would require owners to hold a high share of equity in the reactor. Investors would also require returns both on debt and equity that would be too high for the energy produced by the project—even if it steered clear of bankruptcy—to compete in the marketplace.

While the nuclear industry views such requirements as a negative outcome, the rationing of credit based on borrower risk is actually a core function of capital markets, and one that is quite useful for society.[21] By requiring higher returns on riskier ventures, the markets provide strong incentives to find smaller-scale or more rapidly deployable solutions that pose lower financial and market risks yet still address the objectives (e.g., creating more low-carbon electricity) in comparable ways.

4.1.1. Title XVII Loan Guarantees

Title XVII of EPACT instituted large federal loan guarantees for "innovative technologies." As of July 2010, $18.5 billion in guarantees had been authorized for nuclear reactors and an additional $4 billion set aside for front-end fuel-cycle facilities such as enrichment.[22]

Although an important objective of the loan guarantee program was to build domestic energy capacity and reduce reliance on foreign countries, all four reactor developers slated to receive these loan guarantees will use reactors now manufactured by foreign firms (Smith 2009).[23] Further, dramatic escalations in the projected cost of new reactors has reduced the purchasing power of the existing loan guarantees to such an extent that they are now deemed insufficient, even for the above-mentioned four reactors. The U.S. Nuclear Infrastructure Council has stated that $38 billion in guarantees will be needed just to complete these plants (Blee 2009). To fill the gap, the industry is deploying two strategies. First, recipients with foreign partners are hoping to tap into foreign-government credit lines to supplement the support provided by U.S. federal guarantees. UniStar, for example, has been in negotiations with the French government for export credit financing that could approach an additional $10 billion (Smith 2009). Second, the industry is pushing

20 This is a feature of many subsidized-credit programs, and it gives rise to *adverse selection* risks. The highest-risk activities find the government program the "best deal" relative to high-cost or unavailable capital sources elsewhere, and as a result, the higher-risk projects dominate applications. Absent strong risk-screening capabilities by the government, the portfolio can end up being quite risky.

21 In comments on Title XVII loan guarantees submitted to the U.S. Department of Energy before the capital markets collapsed, Goldman Sachs noted that, "Because of the significant cost involved in the construction of nuclear power facilities, the 10-percent nonguaranteed portion of the loans could be considerable. There is not presently sufficient appetite in the capital markets for a nonguaranteed debt instrument with a subordinated security interest in the collateral to meet the financing needs of the nuclear power sector. Project sponsors would be forced to cover this gap with sponsor-level debt or parent guarantees, which would defeat the purpose behind the loan guarantee program of providing an economically viable way for energy companies to finance nuclear construction" (Gilbertson and Hernandez 2007). While these comments apply to the original proposed rule (the current rule guarantees up to 100 percent of the debt), they underscore the point that market rates on capital to new nuclear would be so high as to render the plants uncompetitive.

22 Southern Company and its partners in the Vogtle plant were awarded a conditional loan guarantee of $8.33 billion in February 2010. The other expected winners at the time were UniStar Nuclear Energy, NRG Energy, and Scana Corporation (Smith 2009).

23 UniStar will use an Areva reactor; NRG plans to use a reactor design developed by General Electric but now owned by Toshiba. Similarly, while Scana and Southern Company will use designs developed by Westinghouse, they too are now controlled by Toshiba (Smith 2009).

hard to greatly increase the amount of federal loan guarantees available to new reactor projects. Nuclear project developers requested more than $120 billion in U.S. Department of Energy (DOE) loan guarantees under Title XVII (Shively 2008), and the nuclear industry association indicated in Senate testimony that it would like a near-term loan-guarantee cap of roughly $93 billion (Fertel 2009).[24] Shortly thereafter, the Nuclear Energy Institute (NEI), the industry's main lobbying organization, issued a policy paper stating that the industry wanted a "permanent financing platform" for new reactor construction (NEI 2009d).[25]

4.1.1.1. Loan Guarantees Are an Unprecedented Expansion of the Government Role in Allocating Energy Capital

Title XVII, and its possible successor in the form of a federal "energy bank" known as the Clean Energy Deployment Administration (CEDA), places the federal government in an unprecedented position of deploying capital for energy-related capital infrastructure. Commitments to all eligible energy technologies under Title XVII and related authorizations have reached $111 billion at present, with nuclear capturing just under 20 percent of the total. Though not all authorizations have been deployed, the pace of awards is accelerating. As noted below, these subsidies differ in important respects from past federal forays into energy finance, and they therefore pose significant risks of financial loss and politicized allocation of capital across energy options. Nuclear reactors are among the highest-risk large-scale projects eligible for loan guarantees under this DOE program.

Unprecedented scale. With $111 billion in commitments to all eligible energy technologies, the DOE program already exceeds the combined commitments—to all sectors and all countries—of the Overseas Private Investment Corporation (OPIC) and the Export-Import Bank (Eximbank) of the United States, the country's main export-credit agencies (Table 5). Title XVII funding will be almost 10 times the energy-related financing provided by Eximbank, and equivalent to more than 45 years of DOE investment in energy R&D based on average funding levels between 1998 and 2007.

The technology and commercial risks of the projects funded under Title XVII are recognized as being quite high and as having elements similar to venture capital. Yet once again the comparative scale is striking. The Title XVII funding level is nearly three times the entire U.S. venture capital funding for all sectors in 2007—which, aside from the Internet-bubble years, was a peak funding year in the largest venture capital market in the world. Venture capital funding data for energy are pooled with the "industry" category, making segregation of energy-specific funding difficult to achieve. Nonetheless, even with the unrelated funding of "industry" ventures, the Title XVII funding support already exceeds the *cumulative* venture capital financing for combined energy and industry funding over the 14 years for which the PriceWaterhouseCoopers/National Venture Capital Association Money Tree funding survey data are available online.

At present, the overall program continues to operate under congressional oversight, and is governed by standard disclosure and risk-management rules set by FCRA. However, pending legislation could eliminate those controls entirely. Both the House energy and climate bill—the American Clean Energy and Security Act of 2009 (ACES)—and the Senate's ACELA bill would create an energy bank. Under ACES, the fund would be capitalized at $10 billion. While it is unclear what the eventual size of the fund would be or the amount of loan guarantees it could issue,

24 Marvin Fertel (head of the Nuclear Energy Institute) noted, in response to a question from Senator Lisa Murkowski on the appropriate size of the loan-guarantee program, that $93 billion in guarantees would be a reasonable target (Fertel 2009).

25 The NEI states that, "The nuclear industry regards $100 billion as a minimum acceptable additional loan volume for CEDA, in addition to the $111 billion already authorized for the Title XVII loan guarantee program" (NEI 2009d: 3).

Table 5. Credit Support to Nuclear: Unprecedented Size, Poor Diversification

	Total $millions	Average Support per Project $millions	Source
CREDIT SUPPORT UNDER TITLE XVII	111,000		(1)
Nuclear portion			
Reactors	18,500	4,625	(2)
Front-end facilities	2,000	2,000	(3)
Total nuclear	20,500		
Industry proposals for nuclear loan guarantees	122,000	8,714	(4)
NEI target for reactor loan guarantees	93,000		(5)
OTHER FEDERAL ACTIVITIES IN ENERGY ARE SMALLER, BETTER DIVERSIFIED			
U.S. export credit agencies			
OPIC, all instruments, all sectors, FY08	15,100	3–53	(6), (7)
Eximbank, all instruments, all sectors, FY08	58,500	5–25	(8)
Eximbank, energy and power sector, FY08	11,312	NA	(8)
U.S. DOE energy R&D (average, FYs 1998–2007)	2,266	NA	(9)
Federal high-risk financing far larger than private venture capital (VC)			
VC funding, all sectors, peak year (2007)	30,639	8	(10)
VC funding, energy and industry sector, peak year (2008)	4,576	13	(10)
Cumulative VC funding to energy and industry subcategory, 1995–2008 (2007$)	23,812	9	(10)

Sources:
(1) Detail: Title XVII + ARRA
(2) Smith 2009
(3) DOE 2009d
(4) Shively 2008
(5) Fertel 2009
(6) OPIC 2009
(7) OMB 2009
(8) Eximbank 2009
(9) Sissine 2008
(10) PriceWaterhouseCoopers and National Venture Capital Association 2009

CEDA would be subject to annual appropriations under FCRA, thus possibly providing a limit on the overall size of the fund due to ongoing congressional oversight. (Countering this constraint is the fact that some CEDA proponents are advocating exempting the bank from FCRA and corresponding appropriations requirements.) ACES would also limit eligible technologies to no more than 30 percent of the total loans issued. This provision would both limit the overall amount of the fund that could go to any one technology, and create pressure to prioritize technologies that can reduce carbon for the lowest cost and risk.

Under ACELA, the industry could gain virtually unlimited access to loan guarantees because it exempts CEDA from FCRA, creates an unlimited self-pay mechanism that allows entities to pay their estimated subsidy costs up front, establishes no cap on the amount of loan guarantees that could be issued by the fund, and contains no technology diversity requirements. This line of credit would eventually be reined in if the program experienced large losses, as payments would come out of the Treasury to cover shortfalls. However, there would be lag between when loan commitments were made and defaults started to become visible, generating tremendous incentives for borrowers to obtain binding commitments as early as possible.

The CBO estimated that under ACELA, approximately $100 billion would go to finance nuclear power plants based on current applications (CBO 2009:10).[26] The CBO also found that, "S. 1462 would modify the terms of DOE's loan guarantee program for advanced energy technologies, which was established under Title XVII of the Energy Policy Act of 2005. The bill would exempt the Title XVII program from the provisions in FCRA that require such programs to receive an appropriation. *The effect of this exemption would be to give DOE permanent authority to guarantee such loans without further legislative action or limitations* [emphasis added]" (CBO 2009: 9). The CBO added that it "expects that the challenges and constraints involved in estimating subsidy costs for such innovative projects make it more likely that DOE will underestimate than overestimate the fees borrowers are required to pay to offset the subsidy cost of the program" (CBO 2009: 9). Further, the detailed assumptions underlying this model would also be largely invisible to the public, as the Office of Management and Budget (OMB) has not made its calculations public, although a dispute between the OMB and DOE about how to calculate the risk and associated subsidy costs has become news (Behr 2009).

Highly concentrated project risks. Under the best of circumstances, ramping up a loan program of this scale would be tremendously challenging. However, the challenge is worsened by poor program structure. First, the loan guarantee rules allow the federal government to guarantee up to 100 percent of the debt, to a maximum of 80 percent of total project costs. This structure eliminates much of the incentive for debt providers to bestow due diligence on the projects. Second, because the project costs for large power generating stations run into the billions of dollars, the size of each loan commitment will greatly exceed the norm for federal lending to commercial enterprises. Whereas the average loan size in the export credit agencies is below $55 million (and usually much lower), the first Title XVII loan guarantee issued for a nuclear reactor in February 2010 was $8.33 billion, 150 times as much.

At $8.3 billion per reactor, $18.5 billion in nuclear loan guarantees will cover one more plant with a bit left over; it clearly will not cover the three remaining finalists. A bid for two Areva reactors in Canada came in at a price of $10.7 billion (U.S.) per reactor (Hamilton 2009). The DOE's guarantee of $8.3 billion for the Vogtle plant is nearly double the entire venture-capital funding for the energy-and-industry subgroup in 2008, the peak year for that segment, and more than three times the size (in 2007$) of the U.S. bailout of Chrysler in 1979 (CBO 2004), though with no taxpayer participation in the upside.

4.1.1.2. Problematic Incentive Structure Increases Risk of Loss, Size of Subsidy

The Title XVII loan guarantees place the federal taxpayer as guarantor of approved projects. Although the program does require lenders to "prepay" their estimated default risk prior to borrowing, the overall control structures on the large credit facility are weak within the DOE, the current program administrator (DOE 2009b; GAO 2008b; GAO 2010). Movement of the program

[26] The CBO estimate is likely to be on the low end because it did not assess the potential for new applications under an expanded and potentially unlimited program (CBO 2009: 10).

Table 6. Divergent Views on Appropriate Credit Subsidy Prepayment Illustrate Uncertainty and Risk of Program

Reference	Loss Rate	Admin. Fee	Total
DOE—Secretary of Energy (Ling 2009b)	10–30%		Standard-risk/high-risk scenarios
DOE—Secretary of Energy (NEI 2010a: 13)	0.5–1.5%		0.5–1.5% in relation to Vogtle Plant
DOE Office of Loan Guarantees—OPIC loss rates (Corrigan 2008)	1.5%	NA	NA
Calvert Cliffs 3 (Turnage 2007b: 43)	1.0%	0.5%	1.5%
Calvert Cliffs 3 (Turnage 2008: 24)	2.5%	1.0%	3.5% (6.0% stress case)
CBO (2003), OMB (2008), expected loss rate	50.85%	NA	50.85% with 50% recovery, yielding 25.4% net loss
Early-stage venture capital (Wilson 2007)	35%	NA	An additional 40% had mediocre returns

to CEDA seems unlikely to improve things, as the control structure set out in the enabling legislation also appears quite weak. Key structural risks involve underestimating default risks, poor incentive alignment between loan agents and project success, and systemic risks with nuclear power that suggest the recovery-rate assumptions for the general energy segment are too optimistic for nuclear-related lending.

Underestimating default risks. The current DOE program requires that borrowers, other sponsors, or Congress prepay the expected default risk and administrative costs of a particular loan commitment. If these estimates are too low, taxpayers will pay for the shortfalls, with no approval from Congress or the White House needed. Estimating default risks in advance for single commitments to large and complex projects is much more difficult than trying to estimate the performance of a diversified portfolio of projects. Clearly, lenders do not purposely provide funds to failing projects, and borrowers will spin projects as positively as they can to get the money.

Table 6 illustrates the challenges of coming up with reliable risk premiums, with a wide divergence in risk expectations. Company-produced data on Calvert Cliffs 3 show a doubling of risk premiums between 2007 and 2008, though even the higher end point probably remains far too low. The OMB placeholder risk estimate remains well above even the upper-end value put forth by the DOE. One DOE official in the loan-guarantee office remarked that the default profile of advanced energy loans was expected to be similar (at about 1.5 percent) to those made through OPIC, with technology risk offsetting country risk for the export-finance deals (Corrigan 2008). Yet the export-finance commitments are for smaller deals, and for many more of them—diversified not only across countries but many sectors as well.

Although both the Government Accountability Office (GAO) and the CBO have concluded that there are high risks of underestimating the default risks of commitments,[27] the nuclear industry has used the default-prepayment requirement to argue that it is receiving no subsidies at all from the program. For example, Richard Myers of the NEI argued that a "subsidy is when the federal government makes a payment to a private party. The DOE loan guarantee program works the other way around. The private parties make payments to the federal government in order to

[27] Both the nonpartisan CBO and GAO have concluded in their analyses of loan guarantees that calculating a subsidy cost is extremely difficult. According to the GAO, loan guarantees "could result in substantial financial costs to taxpayers if DOE underestimates total program costs" (GAO 2007a: 3). The CBO concluded that, "The challenges and constraints involved in estimating the subsidy costs for such innovative projects make it more likely that DOE will underestimate than overestimate the fees paid by the borrower" (CBO 2007b: 8). Even the DOE's own inspector general noted in a review of past loan-guarantee programs that agency officials had not always properly "evaluated proposals and potential sponsor's ability to perform and repay the loan" (DOE 2007: 2).

receive the loan guarantees. That's not a subsidy" (Myers 2007).[28]

If there were no clear financial benefit to the program, the industry would not be pushing so hard to create and expand it. In fact, in a January 2009 review of policies supporting nuclear power plant development, the NEI took a very different stance on the loan guarantees than in 2007, noting that, "To support financing of new nuclear plants, the most useful federal incentive is the loan guarantee program established by Title XVII of the Energy Policy Act of 2005" (NEI 2009: 4). Modeling of the levelized cost of electricity by the Congressional Research Service confirmed this general view, finding that "loan guarantees can turn nuclear power from a high-cost technology to a relatively low-cost option" (Kaplan 2008).

Nonetheless, the NEI used this "no subsidy" argument to push for excluding the loan guarantee program from FCRA oversight, a move that "would have given DOE essentially unlimited loan guarantee authority under EPACT" (Holt 2009: 7). Although prior efforts to bypass FCRA did not succeed, the nuclear industry continues to pursue this objective through federal energy and climate legislation.

Poor alignment between loan agents and program success. Many entrepreneurial finance models use co-investment and equity participation to align the interests of the funder with the long-term success of the funded venture. The government officials responsible for approving large high-risk loans have no such alignment. None of their personal money is at risk, they do not have equity in successful projects, and most failures will occur after they have moved on to other jobs. Debt guarantees provide another example. Because the government can cover the entire debt portion of deals, most of the deals will have no private debt providers. An important layer of due diligence and deal review is thus eliminated. Oversight problems, combined with very-high-value instruments, suggest that the program could be a target for political pressure in award decisions[29] (Koplow 2007a). Such pressures were clearly evident in the Fannie Mae mortgage program, an initiative with much smaller deal sizes.

Systemic risks in nuclear defaults magnify loss risks. The OMB's (2008) credit subsidy cost estimate assumes that 50 percent of the defaulted value of the loan guarantees can be recovered through subsequent restructuring. While the document acknowledges that the estimate is not empirical, a number of attributes suggest that recovery rates may be lower for nuclear power than most other energy technologies. The very factors that contribute to the bankruptcy could also result in much larger markdowns in the value of nuclear assets: technical problems with a reactor design, a shift in the market value for electricity, or a significant reactor accident somewhere in the world. Post-bankruptcy, government trustees would confront an operational reality with few alternative management teams able to step in to run the reactors—especially if the bankruptcy occurred prior to completion. Neither the prospect of nationalizing the reactor nor simply writing down the debt and allowing the old managers to stay in place is particularly appealing.

28 James Asselstine (Asselstine 2009: 8), managing director at Barclays Capital and former Nuclear Regulatory Commission commissioner, took a similar tack in recent Senate testimony, arguing that the default premiums might actually make money for taxpayers: "The self-pay amount is retained by the government regardless of whether the project defaults or not. If there is no default, the self-pay amount represents a financial return to the Treasury for agreeing to assume the risk during the period that the guarantee was in effect. Given a rational approach to implementation, in which projects are selected based on a high likelihood of commercial success with the loan guarantees, there should be minimal risk of default and therefore minimal risk to the taxpayer." This approach to risk pricing is a surprising one for a banker to be adopting, and Barclays would be unlikely to apply it to the bank's own business lines.

29 While the incentive structure in the DOE's proposed loan guarantee rules was already problematic, the U.S. Enrichment Corporation's comments indicated a desire to make the program even more tilted toward borrowers. Among its recommendations were higher loan guarantee limits; all debt guaranteed by the federal government (granted in the final rule); allowable project costs to be expanded to include subsidy costs and administrative fees, as well as management salaries and bonuses for project-related staff; subsidy costs to be funded by appropriations rather than by the borrower; and the federal limit on credit guarantees at 80 percent of project costs to remove requirements that the remaining 20 percent be equity (Barpoulis 2007).

4.1.1.3. Subsidy Value of Federal Loan Guarantees

Much of the debate on the DOE loan guarantee program has focused on its high default risk. This is certainly real; although the NEI's Myers pegs the default risk of nuclear-related loans at "close to zero,"[30] the CBO earlier expected upwards of 50 percent of the loans to default, with an ultimate loss of 25.4 percent of guaranteed principal (CBO 2003).[31] On $20.5 billion in authorized nuclear-related guarantees, this would translate into an expected loss in excess of $5 billion. This loss rate has been adopted by the OMB to illustrate the subsidy cost of the programs. The industry has worked hard to argue the value is speculative and actual losses would be lower (NEI 2010a).

Given the high risk of nuclear ventures, and their inability to access capital markets at all if government subsidy is absent, what matters most is the intermediation value of the loan guarantees. This value comes from two main sources. First, federal guarantees allow the plants to use a much higher share of debt (which is lower-cost than equity) than would otherwise be possible—up to 80 percent of total project costs under the EPACT rules. Second, the guarantees bring down the cost of that debt dramatically, as investors care only about the federal government's risk of default (close to zero) rather than the chance that the nuclear reactor developer will go bust.[32]

Together, these factors greatly reduce the cost of financing a new nuclear plant. UniStar, the company planning to build a new reactor at Calvert Cliffs in Maryland, provides a useful example. UniStar estimates that the loan-guarantee program will save it 3.7 ¢/kWh on a levelized-cost basis—a cost reduction of nearly 40 percent from the company's no-guarantee scenario (Turnage 2008: 24, 25). This translates into nearly $500 million per year in savings per reactor, or a nearly $13 billion present value over the 30-year term that the debt is allowed to remain outstanding. Interestingly, the industry valuation of the loan guarantee subsidy is more than twice the (still-significant) estimate of 1.54 ¢/kWh developed by the Congressional Research Service (CRS) (Kaplan 2008: 43). We assume that industry estimates of loan guarantee value incorporate more detailed information than would be available to government researchers. Thus the low-end value for the loan guarantees is not the CRS estimate but the higher value of 2.5 ¢/kWh, which is used by industry leader Exelon (Crane 2007: 4).

In fact, the actual subsidy from the loan guarantee could be higher, not lower, than the UniStar estimate. For example, the company assumed that a merchant plant could obtain debt capital at an annual cost of around 12 percent and equity at about 15 percent. This is well below the cost of funds in high-risk segments such as venture capital. UniStar also assumed a capital structure of 45 to 60 percent debt. In contrast, the nonpartisan Keystone study of nuclear economics issued in June 2007 estimated debt ratios of only 30 to 35 percent for a merchant plant (Keystone 2007). A Moody's survey of 38 integrated U.S. utilities found seven-year average debt levels at 43 percent of total capitalization for companies with no nuclear facilities, and 42 percent for 25 integrated utilities with some nuclear (Moody's 2009: 7). The risk level for new nuclear reactors, especially merchant new reactors, will be much higher.

Testimony by Constellation Energy executive Joe Turnage to the California Energy Commission in 2007 presented a dire picture that conflicted

30 Myers noted that, "We can't speak for the other nine technologies eligible for loan guarantees, but in the case of new nuclear plants the probability of default is pretty close to zero" (Myers 2007). This again raises the question "Why don't they finance the plants themselves?"

31 The CBO also assumed zero cost to government (Falk 2008: 10), on the basis that default risks could, and would, be properly estimated and paid into the Treasury by borrowers. This assumption seems highly optimistic.

32 Joe Turnage of Constellation Energy noted in testimony before the California Energy Commission that, "I get the federal loan guarantee so I get debt at Treasury plus a smidgen" (CEC 2007: 289). Fitch Ratings noted in a similar vein that, "If appropriately structured, a federal loan guarantee would merit the U.S. government's 'AAA' rating" (Hornick and Kagan 2006: 6).

with the financing assumptions he used in the UniStar cost estimates. Turnage remarked that, "It's not a fair assumption that non-recourse, non-guaranteed, and deeply subordinated debt will be available to these projects—at any price" (Turnage 2007b). Clearly, access to leverage has worsened dramatically since these statements were made, as a result of credit-market turmoil. Nuclear finance is also particularly vulnerable to the erosion in power prices, given reactors' long build times and need to run at high load factors to break even.

4.1.1.4. Credit Subsidies Quickly Mount in Pursuing a Nuclear Option

The aggregate subsidies that federal credit guarantees provide to the nuclear industry are significant. However, exact estimates depend on assumptions regarding the amount of credit ultimately committed, default and recovery rates versus industry prepayments, and the cost of capital for a merchant plant absent government subsidies.

Although there is not full agreement on these values, and some (such as the ultimate size of federal backing) are still in play, existing inputs do allow us to benchmark the subsidy cost for a number of useful scenarios.[33] Relevant cases include the existing authorizations and no more, authorizations on the order of those sought by the NEI in congressional testimony, and funding sufficient for the United States to meet its share of the Pacala-Socolow nuclear power wedge.[34] This last case assumes that a one-gigaton (Gt) per-year reduction in carbon dioxide equivalent (CO_2e) by 2050 from nuclear would require 1,071 gigawatts electrical (GWe) of gross new nuclear capacity in order to obtain a net 700 GWe after reactor retirements (Squassoni 2009b: 22). We further assume that roughly 24 percent of that global nuclear capacity increase will occur within the United States, based on its share of global installed electricity capacity.

The results, shown in Table 7, are striking. Current commitments will provide subsidies to recipient reactors of \$23 billion to \$34 billion over the 30-year life of guarantees, even if there is no default. If Congress increases the loan subsidies to meet industry targets of \$93 billion, the expected taxpayer loss would exceed \$20 billion, based on OMB loss estimates. However, even in the absence of any defaults, the intermediation value of these subsidies would be \$3.8 billion to \$5.7 billion per year, or a present value of \$115 billion to \$170 billion over the duration of the loan guarantees.

A key justification for pursuing the nuclear power option is its supposed leverage in helping the United States address global warming concerns. In this context, it is useful to note that investment on the scale needed to meet the U.S. share of a global nuclear power climate-change-reduction wedge, as calculated by Pacala and Socolow, would require more than \$1.2 trillion in loan guarantees—providing recipient firms with subsidies of \$50 billion to \$75 billion per year, or a present value of roughly \$1.5 trillion to \$2.3 trillion, over the life of the guarantees.

It is certainly possible that financial and construction markets would mature as so many new plants were built, reducing the subsidy required. However, it is equally possible that deployment or technical problems would trigger cost increases for all reactors (as has occurred in the past), that rising costs for all capital-intensive projects would exacerbate competitive challenges for nuclear, or that the technical-improvement and cost-reduction paths of other low-carbon technologies would be faster than

33 Values used are OMB net loss rates of 25.4 percent on nuclear loans; UniStar estimates of 2.5 percent default prepayment; and subsidy values (after default prepayments) of 2.5 to 3.7 ¢/kWh, with the lower bound based on Crane (2007) and the upper bound on Turnage (2008). All-in construction costs per kilowatt electrical were assumed to be \$6,000 (Moody's 2007), well below more recent estimates and bids; new reactors were assumed to have a lifetime capacity utilization of 90 percent.

34 In a widely cited 2004 paper, Stephen Pacala and Robert Socolow (2004) of Princeton University laid out a series of scenarios to bring down global carbon emissions. Each of their 15 strategies were deemed capable of reducing carbon by 1 billion Gt/year by 2050, though the researchers' work did not examine the relative costs of doing so. Their nuclear power wedge assumes that net new reactors replace coal-based electricity—a scenario that is most favorable for nuclear, as displacing other forms of power would have a lower net reduction in heat-trapping gases.

Table 7. Loan Guarantees Represent an Enormous Bet on Nuclear Power

			Government Cost	Intermediation Value to Recipient					
	Public credit extended	New GWe	Net loss rate	Levelized subsidy ($/MWh)		Annual subsidy value ($billions)		Subsidies over 30-year term of guarantee ($billions, present value)	
	$billions	@80% loan guarantee	$billions	Low	High	Low	High	Low	High
Current authorization									
Reactors	18.5	4	4.7	25.0	37.0	0.8	1.1	23	34
Front-end fuel cycle	2		0.5						
Fertel/NEI target	93	19	23.6	25.0	37.0	3.8	5.7	115	170
U.S. share of Pacala-Socolow wedge	1,236	257	314.2	25.0	37.0	50.7	75.1	1,522	2,253

those of nuclear. Given the magnitude of subsidies associated with ever-larger credit guarantees to the nuclear sector, careful consideration needs to be given to alternative ways to address climate-change mitigation that may be more cost-efficient.

4.1.2. Credit Support Associated with International Partners on Nuclear Projects

Much as the U.S. government moved in to help finance the U.S. nuclear industry, credit subsidies to nuclear projects are increasing internationally. This is happening in two areas: foreign-government credit subsidies to nuclear exports, including to the United States; and subsidized credit instruments within the U.S. export credit agencies (Eximbank and OPIC) for sending U.S.-sourced nuclear goods and services abroad.

There has been a concerted effort to expand international financing generally for exports of reactor components throughout the world. A U.S. Department of State memo (DOS 2008) on financing nuclear power projects in developing countries noted that, "The private sector is not ready to be 'partners' but will look to the public sector to mitigate virtually all risks associated with the first nuclear power plants placed in developing countries by providing sovereign guarantees of 100 percent of total NPP cost."

Although most of the multilateral development banks (MDBs) have implicit or explicit restrictions on nuclear-related loans, the United States, France, and Japan have funded research within the World Bank to reevaluate the competitiveness of nuclear power (Horner and MacLachlan 2008). In June 2009, many large OECD member governments agreed to extend enhanced financial support to the nuclear power sector, including the allowance of an 18-year repayment period and other favorable terms (OECD 2009). While the agreement does stipulate minimum interest rates, the minimums for nuclear reactor projects are identical to those for a standard project for terms up to 15 years. In year 16, there is a small 0.05 percent premium, rising to 0.1 percent in years 17 and 18 (OECD 2009). Given the higher risk of nuclear projects, the minimum rates are expected to provide a substantial subsidy to nuclear projects. Meanwhile, the process used to implement modifications to conventional loan terms has been criticized by public-interest organizations for a lack of transparency, including no public disclosure of proposals and virtually no opportunity for input or challenge (Norlen 2009).

Trade issues have also been on the table because subsidized financing for reactor projects can offer sizeable benefits to national firms, and for this reason it is prohibited under the World Trade Organization's (WTO's) Agreement on Subsidies and Countervailing Measures. An exemption to the agreement is granted if a WTO member country is a party to an international undertaking on official export credits that involves at least 12 original WTO members. The recent agreement on enhanced financing terms for nuclear power plants falls under the Arrangement on Officially Supported Export Credits, making the supports exempt subsidies under the WTO (OECD 2009). It is important to note, however, that even with a sanctioned exemption from the WTO agreement, the credits are still subsidies to nuclear power and will create distortions in energy markets.

4.1.2.1. Foreign Credit Support to U.S. Projects

Government financing for nuclear projects is increasingly common around the world. COFACE, the French export-credit agency, guaranteed €575 million in debt to Finnish utility TVO for purchasing an Areva reactor.[35] The Japan Finance Corporation, founded only in 2008, will serve a similar role for Japanese vendors selling abroad. Export financing can take a variety of forms, depending on the sponsoring country. In addition to loans and loan guarantees, export credits, direct investment, and political-risk insurance may be used.

Reactor projects in the United States involve many foreign partners. This linkage may explain why foreign export credit agencies (ECAs) are considering financial incentives to U.S. reactor projects. UniStar's plan for a new reactor at Calvert Cliffs is a useful example. The project already includes substantial direct investment by the French government through Areva. The project will also likely use Japanese reactor-vessel forgings, suggesting that there may be a Japanese interest as well. In fact, Joe Turnage of Constellation has noted that, "COFACE, the French Eximbank equivalent, and JBIC, the Japanese equivalent, [are] absolutely prepared to loan into these projects at attractive rates" (Turnage 2007b). George Vanderheyden, UniStar's president, noted as well that his firm hoped to bring down U.S. federal loan guarantees to 50 percent of the project cost, rather than 80 percent, through the participation of COFACE (Behr 2009). The firm was expected to receive a share of the $18.5 billion in U.S. federal loan guarantees and was also actively pursuing additional support—as much as $10 billion—from the French government (Smith 2009). In 2010, however, Constellation withdrew from the project, even though the DOE was prepared to award the project a $7.5 billion loan guarantee (Mufson 2010).

4.1.2.2. ECA Support of U.S. Nuclear Exports

Although it is uncommon for U.S. export-credit agencies to support nuclear projects abroad, such financing has occurred. For example, the U.S. Eximbank made a $5 billion commitment in 2005 to a U.S.-built reactor in China (Cogan 2005). Eximbank had also committed another $120 million in nuclear-related financing to Bulgaria, Lithuania, and Romania between 1999 and 2002 (Eximbank 2002, 2000, 1999).

The financial-subsidy value of these activities remains to be seen. It is likely that foreign lenders will expand the pool of subsidized capital available to nuclear projects beyond whatever caps are ultimately set by the U.S. government, and terms may also be more favorable. Direct ownership of U.S. nuclear interests by the French government, combined with the fact that nuclear power is one of France's strategic industries, suggests that highly favorable credit terms may be forthcoming.

35 Surprisingly, when a lawsuit was brought before the European Union for illegal state aid, the case was dismissed on the grounds that the utility had similar debt costs on other projects (EU 2007). This is not a particularly sound ruling, as nuclear is widely perceived to be more risky than other projects in TVO's portfolio and should have carried a risk premium.

4.1.3. Ratebasing of Construction Work in Progress

In a traditional regulatory regime, the capital component of rates associated with a new power plant reflects the cost of construction and the cost of financing the project. These costs typically are not charged to ratepayers until the plant is in commercial operation (often referred to as "used and useful"). This approach provides the most accurate estimate of the economics of the venture, as valuable resources tied up for many years have potential alternative uses. The approach also ensures that existing customers are not forced to pay for infrastructure they may never use.

The problem for developers of large and long-lead-time projects is that the financing costs worsen an already difficult capital-recovery challenge. Base-case power-plant-cost scenarios developed by the CRS estimated that the capital return portion alone of nuclear was higher than the *total* annualized costs of pulverized coal, natural gas, and geothermal technologies (Kaplan 2008: 39).

In a competitive market, pushing through new construction costs is not a possibility because cost recovery "is based entirely on output" (Bradford 2008: 4). Regulated utilities, however, are cost-plus operations with captive customers. Rule modifications that allow utilities to put costs related to new or proposed reactors into current charges enable the utilities to avoid the cost of accrued interest on plant investments. As shown in Table 8 (p. 38), a growing number of states have been modifying or reinstating rules to allow this sort of recovery, even if the reactors do not end up being built or are cancelled midstream (NEI 2009c). Sixteen states have policies in place that support the development of new reactors, including recovery of preconstruction costs and CWIP, though the specific policies and cost-recovery mechanisms may vary from state to state. In addition, other states have considered (but not yet adopted) new cost-recovery mechanisms in recent years. Other state-level incentives involve including nuclear as an eligible resource under an RPS. All told, these subsidies are layered atop federal ones, which is a key reason why 82 percent of all active reactor projects are targeting these states.

The savings to investors from early recovery of nuclear power plant construction through CWIP can be significant. Severance (2009: 22) noted that roughly one-third of total capital costs are associated with these early recovery costs. Having ratepayers finance nuclear construction through CWIP may reduce the cost of capital for plant investors as well.[36] The CRS estimates, based on its cost scenarios, that CWIP reduces the levelized cost of power from a nuclear reactor by 4.9 percent, or 0.41 ¢/kWh.[37] Using this subsidy figure as our low estimate for a 1,200 MW reactor with a 90 percent capacity factor, the incremental CWIP subsidy to the loan guarantees would amount to about $38 million per plant per year. The benefits are higher in the absence of loan guarantees, given that the baseline financing costs are higher as well.

The CRS relied on much lower cost assumptions than those that have been emerging in industry proposals. In addition, its estimates of the value of the loan guarantees (LGs) were much lower than the industry's own assessments. To estimate the value of CWIP under scenarios more similar to what the industry is assuming about the cost of plant construction and financing, we applied the ratio of the CRS's CWIP incremental value/LG value to published industry estimates for the LG value, which

[36] Fitch Ratings notes that, "For regulated U.S. utilities, the availability of a cash return on construction work in progress (CWIP) would reduce the construction risk" (Hornick and Kagan 2006: 3). This would be expected to result in lower capital costs.

[37] Kaplan (2008: 43, 44) estimates a levelized baseline scenario for nuclear at $83.22/MWh (the baseline assumes no nuclear incentives other than the nuclear PTC). This figure drops to $63.73/MWh after loan guarantees and CWIP. The value of loan guarantees alone are reported at $15.44/MWh, leaving a residual $4.05/MWh attributable to CWIP when the two policies are combined. The CRS used lower capital-cost values than more recent industry reports, a 90 percent capacity factor (Kaplan 2008: 96), and an assumed construction period of six years (Kaplan 2009a). Because all these assumptions are somewhat optimistic relative to past experience in the nuclear sector, it is likely that the value of CWIP for real projects will be even higher.

Table 8. Many State Policies Shift the Investment Risks of New Nuclear Plants from Investors onto Ratepayers

State	Legislation and Regulations Favorable to New Nuclear		New Units Expected as of April 2010	% Share
	In Place	Proposed		
Favorable state rules and regulation				
Florida	X	X	4	14.3%
Georgia	X		2	7.15%
Idaho	X			0.0%
Illinois		X		0.0%
Indiana		X		0.0%
Iowa	X			0.0%
Kansas	X			0.0%
Kentucky		X		0.0%
Louisiana	X		1	3.6%
Maryland	X		1	3.6%
Michigan	X		1	3.6%
Minnesota		X		0.0%
Mississippi	X		1	3.6%
North Carolina	X		2	7.1%
Ohio	X			0.0%
Oklahoma		X		0.0%
South Carolina	X	X	4	14.3%
Texas	X		6	21.4%
Utah	X			0.0%
Virginia	X		1	3.6%
West Virginia		X		0.0%
Wisconsin	X	X		0.0%
Subtotal			**23**	**82.1%**
No favorable state rules and regulations at present				
Alabama			2	7.1%
Missouri			1	3.6%
Pennsylvania			1	3.6%
New York			1	3.6%
Subtotal			**5**	**17.9%**
Total expected new nuclear units			**28**	**100.0%**

Sources: NRC 2010; NEI 2009c.

produced our high estimate of roughly $90 million per reactor year, or 0.97 ¢/kWh.

Peter Bradford, former chair of the New York State Public Service Commission, has cautioned that, "CWIP should not be seen as providing real savings in the sense that reduced concrete or labor costs do. Instead, risks and burdens are shifted from investors to customers as the customers replace investors and bankers as the supplier of capital needed to build the plant" (Bradford 2008: 5).

Ratepayers lost hundreds of billions of dollars in the first wave of nuclear reactor construction through canceled nuclear plants or above-market rates driven by plant cost escalation. The expansion of CWIP and other risk-shifting strategies at the state and public utility commission (PUC) levels are planting the seeds for a replay of the rate shock and defaults that plagued the last wave of new reactors.

4.1.4. Subsidies to Publicly Owned and Cooperative Utilities

While much of the discussion on subsidies to nuclear energy focuses on shifting costs and risks from investors, public and cooperative entities own nearly 17.5 percent of existing U.S. reactor capacity. Much of this figure involves fractional ownership of reactors operated by private utilities. However, there are some large direct owners as well, such as the Tennessee Valley Authority (TVA), which operates nearly 7 GW of capacity (NEI 2009a; APPA 2008a; Duff & Phelps 2008a). Public partners have also been involved in a number of the proposals for new reactors.[38]

Publicly owned utilities (POUs) include systems that are owned by governments, from the federal level down to localities. Cooperatives are member-owned, typically serving rural and less-populated regions.

While POUs are generally unable to receive tax breaks (PTCs, which can be captured and sold to taxable entities, are sometimes an exception), they do benefit from a variety of other important subsidies linked to their ownership structure.[39] They are exempt from state and federal taxation, for example, though they sometimes make small payments to municipalities in lieu of taxes and can access tax-exempt debt for expansion. Based on available data on revenues at POUs, the nuclear share of this tax exemption is worth about $100 million per year, or about 0.07 ¢/kWh of nuclear power generated by this industry segment.

New reactor projects, for example, have turned to Build America Bonds (BABs) for financing. These instruments were introduced by Congress in 2009 as part of the stimulus package, after default risks led investors to shun tax-exempt municipal bonds. BABs solve this problem with a taxable bond issue (spurring sales to tax-exempt investors such as pension funds) while directly crediting the issuing authority with a grant equal to 35 percent of the interest cost ("direct-payment" BABs enable municipalities to obtain the lower interest rates previously available on tax-exempt issues).[40] The North Carolina Municipal Power Agency has a $69 million nuclear issue, while the Nebraska Public Power District has issued $50 million for purposes that include nuclear. The full amount being deployed on nuclear projects is not known. The largest known nuclear issuer to date (the Municipal Electric Authority of Georgia, or MEAG, planning to issue nearly $2.5 billion in BABs for its investment in new reactors at Vogtle) described the use of proceeds only as "Electric light and power improvements; refunding notes." Once complete, the MEAG nuclear issuance would be among the five largest BAB issues in the country based on issuance data through April 2010. (BuildAmericaBondsOnline.com 2010).

In addition to tax-exempt debt, POUs are often not required to earn a market return on invested capital, and they are able to use capital structures (such as 100 percent debt) that would not be possible for a private entity because of investors' concerns about defaults.[41] All of these subsidies enable POUs to price power lower than investor-owned utilities (IOUs) or independent generators can.

Additional subsidies may also flow to POU power users because of rules that require favorable pricing on sales to surrounding communities or cooperative utilities. In some cases, such as TVA, the debt also benefits from implicit federal guarantees, which enable a lower borrowing rate.

38 The CRS listed Sumner 2 and 3 (South Carolina), Vogtle 3 and 4 (Georgia), North Anna 3 (Virginia), Bellefonte 3 and 4 (Alabama), and South Texas 3 and 4 (Texas) as facilities with public partners (Kaplan 2008: 42). If partners with substantial foreign-government ownership were included, this number would increase still further.

39 Some PTCs can be sold to investors by public utilities, thereby monetizing their value. The sale may actually boost the realized value relative even to private utilities, as the purchasers of the credits tend to be in the highest marginal tax brackets. Where direct sales are not possible, public utilities may sometimes set up complicated lease-back arrangements that effectively allow them to capture a portion of the tax subsidy. This approach is quite common for energy recovery systems at municipal landfills, for example, though it is less efficient than direct sales.

40 Direct-payment BABs are more lucrative to the municipality, but also more restriced in who can use them: tax-exempt issuers only; no private-activity bond applications are allowed. The bonds may also not be used to refund (and replace) outstanding bonds (IRS 2009). The "tax-credit bond" is another variant of the BAB program that allows bond holders to receive a tax credit equal to 35 percent of the interest stream (SIMFA, 2009).

41 Both the House climate bill and Senate energy bill would have allowed POUs to get federal loan guarantees, which is not possible (Boyd 2009).

Cooperative utilities also have some advantages, though not as many. While in general they are privately run, their cooperative structure allows them to escape from state and federal corporate income taxes. Unlike non-cooperative privately owned utilities, cooperatives can pass out dividend-like payments to "owners" (i.e., their customers) free of income tax. Finally, many cooperatives are able to access low-cost financing through programs such as the U.S. Department of Agriculture's Rural Utility Service.

While these subsidies flow to all public and cooperative power sources, the benefits to the nuclear sector are significant. Tax-advantaged debt and a lack of risk-adjusted return on invested capital requirements disproportionately favor higher-risk technologies such as nuclear. The combined impact of these subsidies on the delivered cost of power is large: the CRS estimates that POUs' financing benefits alone reduce the levelized cost of new nuclear electricity from $83.55/MWh to $52.25/MWh, a decrease of 3.13 ¢/kWh or nearly 38 percent (Kaplan 2008: 42). The benefits of avoided tax payments and low return on capital, which the CRS did not model, would further enhance the subsidies to a publicly owned reactor.

In private markets, if capital cannot be deployed at a return adequate to compensate the providers for the risk they have taken on, new investment in an enterprise ceases and it eventually shuts down. Alternatively, if the enterprise has some leverage to increase prices, it does so in order to adjust returns so that it may remain a going concern.[42] Public power does not face such pressures. In the three subsections that follow, two federally linked energy enterprises, TVA and the Bonneville Power Administration, provide useful insights, and subsidized lending through the U.S. Rural Utility Service is also discussed. Subsidies are summarized in Table 9.

4.1.4.1. Tennessee Valley Authority

TVA has six operating reactors providing nearly 7,000 MW of nuclear capacity. Work on a seventh reactor, long delayed, has been restarted. TVA is the largest public owner of nuclear capacity in the country. While its debt is not federally guaranteed, investors have generally assumed that the federal government would step in to prevent a bankruptcy. As a result, TVA has been able to borrow at artificially low rates—with a resulting savings in interest payments of $124 million to $189 million in 2006 alone (EIA 2008: 200).

Despite lower interest rates, TVA's debt burden is large. Further, the debt is disproportionately linked to investments in nuclear infrastructure. In 2006, for example, nuclear accounted for 29 percent of total generation, but roughly 64 percent of TVA's investment in generating assets (EIA 2008: 71, 206). This disparity is indicative of TVA's poor return on invested capital. Were it to earn an average return commensurate with what is earned by IOUs, TVA would need to boost incoming revenues by $500 million (EIA 2008: 210), most likely by increasing power prices. Of this amount, 64 percent or roughly $320 million would be attributable to investments in nuclear assets. Because this value was calculated using *average* returns across IOUs and TVA, however, the $320 million value actually understates the real subsidy to nuclear. With much higher investment risk than most other generating technologies, nuclear would require a significantly higher return on assets than other generating capacity in order to compensate.

The calculation should be adjusted in one other way as well. TVA has significant "deferred" assets, roughly half of which are nuclear reactors that are not presently operable. These are plants on which construction has been suspended, but the asset has not been declared a total loss and

[42] Adjustments may sometimes be slowed as a result of political concerns or interventions.

Table 9. TVA, BPA, and RUS Subsidies to Nuclear Power

	TVA		BPA		RUS		Notes
Nuclear share (%)							
Gross generation	29.0%		10.0%		6.0%		
Operating net generating assets	64.0%		10.0%				Prorated; no actual data
Total net assets	61.5%		28.6%				
Interest support	52.9%		55.9%		7%		EIA estimates
Subsidy metric ($millions/year)							
Interest rate subsidies							
vs. A IOU rate	124		191		305		
vs. Baa IOU rate	189		228		380		
Power underpricing	(421)		1,616				
Return on invested assets							
Operating assets only	509		294				
Including deferred assets	1,141		693				
Estimated nuclear share of subsidies ($millions/year)	**Low**	**High**	**Low**	**High**	**Low**	**High**	
Interest rate subsidies	66	100	107	127	18	23	(1)
Power underpricing	(269)		162				(2)
Return on assets	326	702	29	198			(3)

Notes:

(1) Low estimates assume that utility risk is equivalent to an A bond. The highest-rated bond evaluated by the EIA (Aaa) seems unrealistic for nuclear projects and was not used. The upper estimate (Baa rating) is believed to be more accurate.

(2) Negative values reflect TVA's power to sell at slightly higher rates than those of the surrounding utilities during the period of analysis. This situation likely reversed itself during surging electricity prices in 2007 and the first part of 2008. Values are prorated based on nuclear share of operating assets, though BPA's nuclear share of investment is likely higher than the 10 percent value shown.

(3) Return on asset values include the low EIA estimate multiplied by the net operating assets; the high end of the range uses the higher EIA estimate multiplied by the total nuclear share of investment, including plants not currently operating.

Sources: EIA 2008; USDA RUS 2008; TVA 2006.

written off. By including these deferred assets as part of the investment on which a return needs to be generated, a much higher annual revenue shortfall—$1.1 billion per year—occurs, of which about 62 percent ($700 million per year) is associated with nuclear investments.

4.1.4.2. Bonneville Power Administration

The Bonneville Power Administration (BPA), the largest of the federal power marketing administrations, is a much smaller nuclear player than TVA, with only one nuclear reactor. Nonetheless, like TVA, most of BPA's deferred investments in nonoperational plants are associated with nuclear investments gone bad.[43] BPA had $4 billion in nuclear-related deferred assets in 2006. Achieving a market rate of return on invested capital would have required an additional $294 million in revenues, excluding deferred nuclear plants from the rate base, or $693 million including it (EIA 2008: 211).

[43] These investments, the default of the Washington State Public Power Supply System due to nuclear cost overruns, were not direct investments of BPA but rather of Energy Northwest. BPA was the obligor, however, based on a net billing power arrangement (EIA 2008: 76). As with TVA, though the nonfederal debt of BPA does not benefit from an explicit federal guarantee, "the financial community treats the debt as though it was guaranteed" (EIA 2008: 77).

4.1.4.3. Rural Utility Service

The Rural Utility Service (RUS) of the U.S. Department of Agriculture (USDA) benefits from subsidies to capital formation similar to those enjoyed by TVA and BPA. The RUS is the successor to the Rural Electrification Administration (REA), and it continues the REA's mission to provide low-cost funding and credit support to rural electric utilities. As of 2005, RUS-supported utilities provided 7 percent of the country's electricity.

REA and RUS initiatives have provided quite large subsidies over time. They have come through a variety of mechanisms, including operating subsidies from Congress, grants, subsidized credit to electric utilities, forgiveness on interest payments associated with the REA's multibillion-dollar borrowing from the Treasury starting in the 1950s, and loan defaults (Koplow 1993).

Subsidized federal financing remains the favored source of capital for these rural enterprises. Nearly 70 percent of the long-term debt held by generation and transmission cooperatives as of the end of 2008 was sourced from the RUS. The reasons are the lower costs and better durations than what is available from the private sector. The USDA notes that higher interest rates would boost interest charges by "billions of dollars" that would have to "be absorbed by the rural electric members in the form of higher rates" (USDA RUS 2008: 20). RUS scenarios indicate an expectation that government-provided debt is 250 to 350 basis points (2.5 to 3.5 percentage points) lower than commercial rates (USDA RUS 2008: 23).

Defaults on then-REA loans were low through the late 1970s, probably due in part to the low interest rates and flexible repayment schedules (Koplow 1993: B4-27). Losses subsequently spiked up, in large part because of borrower participation in nuclear reactor projects that were running into financial trouble (GAO 2000: 22). Through 1988, for example, three-quarters of the REA's defaults were associated with nuclear investments; the remainder with coal (Morrison 1988: 13–37). The EIA notes that $3.2 billion in loans to three large borrowers were written off, and that "much of the problem debt was associated with loan guarantees for borrowers' investments in high-cost nuclear plants in the early 1980s" (EIA 2008: 88).

As of the early 1990s, nuclear accounted for about 8.5 percent of RUS-financed installed capacity (Koplow 1993: B4-29c). At present, rural electric generation and transmission cooperatives own partial stakes in a number of nuclear reactors, making up about 6 percent of its total capacity, though the nuclear share of all cooperative generation (including those not in the RUS program) is around 15 percent (USDA RUS 2008: 7, 23). Participation in proposed new nuclear reactors from this sector as of 2008 was 1.1 GW, about 5 percent of the total proposed nuclear capacity additions (USDA RUS 2008: 16, 19).

4.1.5. Regulatory Risk Delay Insurance ("Standby Support")

The Energy Policy Act of 2005 included a standby support program that provides government insurance against regulation-related delays. The insurance is available for the first six reactors that move into licensing within the United States, and it covers contingencies such as delays in timely review of inspections, tests, or documents by the Nuclear Regulatory Commission (NRC), "as well as certain delays associated with litigation in federal, state, or tribal courts" (Holt 2009: 6). While the program would not cover delays due to other factors, such as noncompliance with laws or safety issues, the litigation coverage does suggest there is a reasonably high likelihood of the government paying out under these policies.

The first two authorized reactors will each receive $500 million in insurance coverage, with the government covering 100 percent of all eligible costs. The next four reactors will each get a maximum of $250 million in delay coverage, though the government covers only half of the eligible costs (Holt 2009: 5). As with the loan guarantee program, insured parties make some up-front payment to cover an estimate of their risk. Major allowable costs covered under the policies include accrued interest on invested capital and the cost of replacement power (DOE 2006c: 46331). The magnitude of these costs for a multibillion-dollar reactor project suggests that even moderate delays are likely to exhaust the full amount of the insurance.

Analysts are split on the subsidy value of this program. The CBO has assumed that it provides no incremental subsidy, as the utility supposedly pays the subsidy cost of the policy (Falk 2008: 10). Harding (2009b) concurs, with a zero estimate based on the potential latitude of the regulatory authorities to claim that delays were the result of the investor rather than of the regulator and therefore not covered. Should such determinations be made, however, they would likely be litigated. The DOE did assign a positive subsidy value of at most $27 million present value for the larger contracts and roughly half as much for the smaller contracts (DOE 2006c: 46324). These estimates seem to be an attempt to price the policy on an actuarial basis.

As is the case with loan guarantees, however, if the subsidy value really were zero, the industry would have no reason to even apply for the coverage. In addition, government intermediation in insurance markets, as in lending markets, generally yields better terms and rates than a firm could ever obtain on its own. Bradford has estimated the value of the larger delay-insurance policies at 0.7 to 0.8 ¢/kWh if they are paid out (Bradford 2007).

While we do not believe a zero value of these policies is realistic, we nonetheless use a range of 0.0 to 0.8 ¢/kWh as the subsidy value.

4.2. SUBSIDIES TO REDUCE THE COST OF CAPITAL GOODS

In addition to targeting ways to shift investment risks to other parties (such as taxpayers), a number of government subsidies work to reduce the cost of capital purchases, independent of financing method. Quite often, this strategy also involves shifting costs to taxpayers. Three policies are explored here: accelerated depreciation benefits, cost-sharing on siting and licensing investments for new reactors, and government R&D support.

4.2.1. Accelerated Depreciation

Normal accounting rules allow capital investments to be deducted from taxable income over the service life of the investment. This approach helps to match investments with the multiyear services they provide, making the underlying economics of the activity more transparent. In most cases, partial or complete write-downs can be taken immediately (expensed) only if the capital value is impaired, as when a plant is damaged by fire. In contrast, accelerated depreciation shortens the write-off period by statute, regardless of actual service life, thus allowing for higher-than-normal deductions in the early years of the investment.[44] Funds that would have otherwise gone into government coffers remain inside the firm for other uses, acting as an interest-free loan.

Many different types of investments in the United States, including renewable energy resources, receive tax subsidies by means of accelerated depreciation. The larger the investment, and the more rapid the write-off relative to actual service life, the larger the subsidy will be. These rules vary by "asset class" and often generate differential benefits by type of asset or industry sector. More broadly, the policy diminishes the benefits of meeting market needs in capital-conserving ways.

[44] The Joint Committee on Taxation notes that the depreciation methods commonly used by investor-owned utilities "generally recover the cost of public utility property more rapidly for federal income tax purposes than do the methods used for ratemaking or financial accounting purposes" (JCT 2001: 3).

Nuclear power plants benefit from favorable depreciation rules, granting them an advantage over other thermal power plants. These rules primarily benefit reactor investments. However, because the bulk of capital investment in U.S. reactors was done decades ago, most capital at existing reactors is already heavily depreciated. As a result, accelerated depreciation benefits will be most pronounced for new reactors, reducing the break-even for new investments and directing investment into nuclear that might otherwise have gone into other sectors or energy types.

Economist Gilbert Metcalf at Tufts University has estimated that new reactors, with all assorted tax subsidies taken into account, have an effective tax rate of negative 99.5 percent. Whereas a positive tax rate reduces capital available for the taxed sector, a negative tax rate effectively serves as *a source* of capital to those firms. Accelerated depreciation is a significant contributor to this favorable rate; if it alone were used, the tax rate would rise to "only" negative 49.4 percent (Metcalf 2009).[45]

As shown in Table 10, there are four main depreciation categories related to nuclear power under the Modified Accelerated Cost Recovery System (MACRS). Nuclear reactors, with a service life of 40 to 60 years, can be entirely written off from taxes in only 15 years.[46] Assuming that the plant lasts 40 years, and taking an average value for estimated all-in construction costs (roughly $5,300 per kilowatt electrical, or kWe), levelized power costs are reduced by roughly $40 million to $80 million per year, or 0.3 to 0.7 ¢/kWh. The subsidy would be higher if upper-bound estimates for plant construction were used, if the baseline life for the reactors was assumed to be 60 years (as a result of license extensions) rather than 40, or if the lifetime capacity factor averaged less than 85 percent.

Accelerated depreciation for other capital in the nuclear fuel cycle has not been quantified but is discussed briefly below:

- **New investments in old reactors**. Although the original investments in existing reactors were completed long ago and have been written down, new investments for power uprates and license extensions can run into the hundreds of millions of dollars. An absence of cost data, however, precludes a more precise quantification of this value.
- **Mining and fuel-rod assemblies**. Special percentage depletion rules for the mining segment of capital (discussed in Chapter 5) likely provide more favorable deductions than do standard accelerated depreciation rules, as the special rules allow mine owners to recover more than 100 percent of invested capital. For fuel-rod assemblies, the tax-depreciation schedule appears fairly close to actual depreciation and therefore would not generate significant tax subsidies.[47]
- **Transmission and distribution infrastructure**. Accelerated depreciation subsidies to general electricity transmission and distribution give a broad advantage to centralized energy resources (of which nuclear is a large share), but these subsidies were not quantified in this study.

[45] As is so often the case, subsidies to nuclear power around the world are often similar to those of the United States. Moreover, while the capital write-off rules for U.S. reactors are generous, they are even more generous in many other countries, according to analysis by Ernst & Young. In the firm's review of countries making up 62 percent of international nuclear trade, it found that all had more favorable capital cost-recovery for nuclear investment than did the United States. Effective tax rates for nuclear investment in Canada, for example, were roughly half of the U.S. rates, and those in South Korea were only 20 percent (Ernst & Young 2007: 13, 14). Where border sales of electricity are common (as with the United States and Canada), these subsidies can be trade-distorting.

[46] While license extensions in the United States allow the reactor to produce power for up to 60 years, subsidy calculations assume only a 40-year life. This assumption is useful for two reasons: no commercial reactor has yet lasted 60 years, and license extensions often require large new investments in the plant.

[47] Nuclear fuel has a service life of four years, according to the U.S. Bureau of Economic Analysis (2004). The accelerated depreciation allowance under the MACRS assumes a longer service life of five years but allows a 200 percent declining-balance method. While the asset takes more than four years to write off, the majority of those write-offs are front-loaded in the first year or two of an investment. The net result is that the accelerated depreciation of fuel rods probably provides little incremental benefit to this asset.

Table 10. Depreciation Schedule for Assets Relevant to Nuclear Power

Asset Class	MACRS Life/Method	Discussion
Class 10.0 Mining	7 years 200% declining balance	Generally less generous than the 22% depletion allowance that uranium mines can also claim.
Class 49.2 Electric Utility Nuclear Production Plant	15 years 150% declining balance	Includes facilities and related land improvements. Depreciation is more favorable than for other steam-production technologies that have a 20-year depreciation period.
Class 49.121 Electric Utility Nuclear Fuel Assemblies	5 years 200% declining balance	Initial core and replacement core fuel assemblies. Excludes fuel assemblies in breeder reactors.
Class 49.14 Electric Utility Transmission and Distribution (T&D) Plant	20 years 150% declining balance	T&D assets are not unique to nuclear power, but they are important in that roughly 20% of the generation sent over the lines is from nuclear plants.

Sources: IRS 2008; JCT 2001.

4.2.2. Licensing Costs

Unlike with smaller-scale and less controversial resources, licensing a nuclear reactor is a multiyear, contentious affair. Like engineering costs, licensing costs are capitalized into the plant's overall cost basis. Policies that reduce the private share of these costs therefore have the effect of reducing the cost of plant and equipment, and with it the cost of the energy produced.

Historically, the nuclear licensing process first addressed construction and later the operation of a plant. A two-step approach is not uncommon when the manner of construction has a significant impact on the quality of operations—either in terms of public safety or in production quality. However, the nuclear industry complained that this two-step process opened projects to additional expensive delays, as plant opponents intervened to slow the commencement of operations. To address this concern, the NRC introduced a streamlined licensing process under its combined Construction and Operating License (COL). While the COL can accelerate licensing, critics argue that the approach implicitly assumes that all issues are already known at the time a plant is proposed (when its design may not yet be detailed) and that none will appear later during construction or under operation.

A related initiative to reduce oppositional delays is the early site permit (ESP) process. ESPs are essentially site preapproval—a determination that a particular site is suitable for a new nuclear reactor without having to commit to a particular design. Once granted, "there are many environmental and public health and safety issues that cannot be challenged for the duration of the permit, usually 10–20 years with the option of a 10–20 year extension" (Public Citizen 2006). A utility company can apply for a COL at any point during that period without having to revisit site-specific factors and contentions. While it is possible to raise new issues (e.g., related to safety concerns), the "bar" in trying to do so is very high.

The U.S. Department of Energy's Nuclear 2010 program has been paying half the costs of nuclear plant licensing for two industry consortia since 2004 (Holt 2009: 6, 9). One consortium is led by Dominion Energy, using a General Electric "economic simplified boiling water reactor" (ESBWR); the other is run by the NuStart Energy

Development Consortium, which is comprised of a number of nuclear utilities. In addition to also using an ESBWR, NuStart planned to deploy a Westinghouse AP1000 as well (Holt 2009: 10).[48] Agreements with reactor vendors were separated from the main consortia in 2007 to "provide improved visibility of the reactor vendor activities" (DOE 2009c). The NEI estimated that the Nuclear 2010 program will receive a total of roughly $730 million in government funding (NEI 2008). Annual support levels have varied, with $80 million in 2007, $134 million in 2008, and a closeout allocation of only $20 million in 2010 (Power Engineering 2009; DOE 2008: 595–598). Actual funding for 2010 was significantly higher at $105 million, although this appears at present to be a final allocation (Holt 2009: 10). Levelized subsidies per kWh of .06–.19 ¢/kWh are based on the capacity of the two main designs being supported, and assume each design, as licensed, will be applied to three reactors.

4.2.3. Research and Development

Every industry changes over time, and sustained investment in new technologies and products is required if a firm is to remain competitive. Making these investments requires diverting funds from other uses within the firm (including salaries and dividends) into more speculative research activities. Firms able to use government funding rather than their own for this activity obtain a competitive advantage.

Federal subsidies to R&D come from two main sources: R&D tax breaks and direct federal investments. R&D tax credits, as well as generous expensing provisions for R&D investment (normal tax rules would require that these costs be capitalized until the new innovation either failed or began making money), reduce the after-tax cost of R&D spending. These subsidies are broadly used in the economy to help create new technology. Their structure is based on the idea that private entities, rather than government bureaucrats, are best able to define the most promising areas in which to invest research dollars. While these tax subsidies certainly provide some incremental support to nuclear energy, they are less distorting than directed spending.

Meanwhile, in direct federal funding—the second major source of federal subsidies to R&D—nuclear has been a big winner over the past half-century. Over the long term, nuclear has captured the largest share of public energy R&D dollars not just in the United States but also across many of the nuclear member countries of the IEA.

Government subsidies to R&D are often predicated on an externality argument. Successful innovation brings many benefits, both direct and derivative, that cannot be captured by the private entity that funded the research. Rather, many of these gains leak into the broader society. As a result, in the absence of government intervention, society as a whole would underinvest in R&D. This line of reasoning is more persuasive regarding basic research that is many years removed from commercial applications and likely to apply to a wide array of commercial products. As the focus narrows and the time until commercialization shortens, the argument for public R&D funding diminishes.

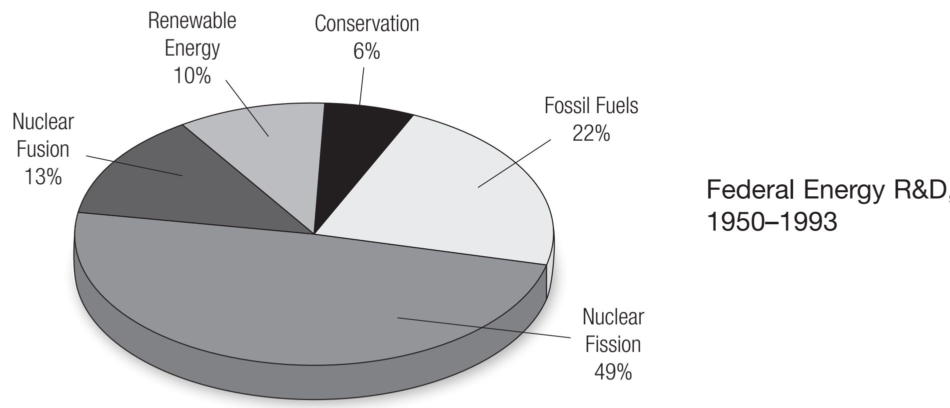
Yet even where there are some public externality arguments, government R&D often suffers from "selection bias." Political fiat or lobbying, rather than anticipated gains in terms of productivity, knowledge, or social welfare, can influence the deployment of research dollars.[49] As shown in Figure 1, fission R&D—even excluding federal research on military reactors—captured nearly half of all federal energy R&D funding between 1950 and 1993; fission and fusion combined received 62 percent, or six times the support for all renewable technologies put together.

---

48 The designs have run into some challenges in obtaining certification. The AP1000 design is officially certified but going through its seventeenth revision. Design completion is not expected until 2011. Meanwhile, the DOE has told utilities relying on the ESBWR design that they are unlikely to be eligible for loan guarantees. This turn of events has resulted in modification or cancellation of a number of proposed projects (Boyd 2009).

49 See, for example, Cohen and Noll 1991.

Figure 1. Nuclear Power Dominated U.S. R&D for More than 40 Years



Source: Koplow 1993.

In more recent years, the pattern, at least within the United States, has changed substantially. Nuclear fission captured less than 4 percent of the DOE R&D budget between 1994 and 2007, according to IEA data. Nuclear fusion actually captured a larger share—just over 10 percent—during that same period (IEA 2009).[50] Despite these shifts, the CRS has noted that nuclear energy, including both fission and fusion, remained the single largest beneficiary of DOE R&D, accounting for 28.3 percent of the total for FY1998 to 2007 and 53 percent for 1948 to 2007 (Sissine 2008).

Table 11. The Nuclear Share of Total R&D Spending Is Declining but Remains Dominant in Some Countries

	1974–2007	1998–2007
Canada	39.0%	28.8%
France	81.4%	72.5%
Germany	67.0%	41.0%
Japan	72.7%	67.2%
Sweden	15.2%	6.7%
United Kingdom	69.0%	32.7%
United States	38.1%	13.2%

Source: IEA Energy R&D Database; accessed April 10, 2009.

While most countries have reduced the total share of public R&D allocated to nuclear technologies, the degree of change has varied widely.[51] Some countries, such as France and Japan, continue to direct most of their energy-related resources to nuclear. Support in Canada, Germany, and the United Kingdom also remains high as a share of total spending (Table 11),[52] though the overall levels of R&D support to energy have gone down considerably.

In addition to Nuclear 2010 (which the DOE counts as R&D even though it focuses mostly on finalizing and licensing two designs, with an original goal of two new units up and running by 2010), the main themes in nuclear research are Generation IV (advanced) reactors, advanced fuel

50 This is most likely due to the U.S. contribution to the International Thermonuclear Experimental Reactor in Switzerland.

51 Totals include fusion, as countries do not always break the data into fission and fusion categories.

52 Schneider (2009) notes that the type of nuclear research supported varies by country. Germany, for example, limits expenses to safety and waste management. It does not fund R&D on new reactor technologies, reprocessing, or breeder reactors.

cycles (including reprocessing), an initiative to produce nuclear-generated hydrogen fuels (though zeroed out in the administration's FY2010 budget request), and a mixed-oxide fuel (MOX) facility (to convert surplus weapons plutonium into a fuel that commercial reactors can use). The MOX facility is ostensibly a nonproliferation program. However, like an earlier effort to blend down Russian weapons-grade uranium for use in U.S. reactors, the MOX program could well provide subsidies to the civilian sector in the form of reduced fuel prices. R&D spending of roughly $500 million per year in 2009 (0.06 ¢/kWh of nuclear electricity generated) is assumed to remain flat going forward.

The DOE also funds substantial additional research on basic nuclear reactions, fusion, and military reactor technologies. These programs may have some ancillary benefits to the civilian fission sector, but they are generally not addressed here.

4.2.4. Stranded-Asset Charges for Nuclear Power

"Stranded" asset charges represent a retroactive subsidy to capital. Historically, nuclear power has benefited from significant market price support, often through regulatory interventions. During deregulation of electricity markets, for example, $110 billion (2007$) in uneconomic investments in nuclear power capital was shifted from investors to ratepayers (Seiple 1997). The scale of this residual loss amounted to 1.05 ¢/kWh for every single kWh of net nuclear generation between 1957 and 1997. As some reactors had already paid off the majority of invested capital by the point of deregulation, the actual subsidies realized for the remaining plants would have been significantly above this average value.

The justification for this policy was that the investments had been made by regulated utilities and considered prudent by their respective utility commissions. As a result, these costs were converted to a surcharge (typically, per kWh consumed) on the electric bills of ratepayers in the nuclear utility's service territory. With its significant capital costs written down, nuclear power could then be sold at lower prices in the marketplace, thereby stemming the incentive of customers to seek out other (non-nuclear) supply options.

While stranded-asset charges are sunk costs from the perspective of current reactor operating decisions, they are relevant to new reactors reactors for three reasons. First, they clearly illustrate the challenging economics of capital-intensive reactors, which must remain profitable over long periods and under widely varying market conditions. Second, the precedent provides some reassurance to new investors in regulated utility districts that they will be made whole on capital expenditures that turn out to be uneconomic. This may reduce the risk premium charged on capital deployed in new plants. Third, to the extent that stranded-asset agreements do not allow utilities to reduce payouts should the electricity markets rebound, the policy highlights the challenges facing public-sector institutions in properly balancing incentives in the complex long-term deals that they make with the nuclear sector. This issue also arises with respect to management of nuclear waste and provision of enrichment services, and with very long-term power purchase agreements with new reactor developers.

4.3. SUBSIDIES TO LABOR

Labor is not a major cost element of nuclear power. As a result, any subsidies to labor would not be expected to significantly alter this energy resource's competitive position. Nonetheless, labor in the nuclear sector had been subsidized through 2007 by means of nuclear training grants to universities across the country, while proposals to target new federal funds for nuclear worker training have been included in pending climate and energy bills.[53] More important from a subsidy standpoint

[53] While many disciplines receive training support from the government and the value of this support to the nuclear industry was fairly small, it is included to ensure a complete picture of the subsidies available to this industry

are the large programs that compensate nuclear workers for health damages they have suffered during their tenure in the industry.

The University Reactor Infrastructure and Education Assistance Program boosted funding to universities with nuclear engineering curricula. The program supported reactors, staff, and students in an effort to reverse the decline in enrollments. Awards and fellowships totaled about $16 million in 2007 (DOE 2009a: 625). Since then, rising energy prices and increased interest in nuclear energy have boosted enrollment on their own, and the DOE did not request funding for this activity in 2008 or 2009. Nonetheless, the program was funded at $2.9 million in 2008 and $6.1 million in 2009 (DOE 2009f).

A well-functioning market should integrate occupational health into product prices; for example, wages in developed economies are normally higher in the more dangerous professions. In addition, both public and private health insurance and workers compensation programs can send important price signals that encourage the more dangerous industries to boost their investments in worker protection. Worker litigation can serve a similar role. None of this happened effectively in the nuclear sector, however, and hundreds of thousands of workers on both the military and civilian side have suffered injuries.[54]

Worker payments come through two federal programs, both of which are financed through general taxpayer revenues rather than fees on the nuclear industry:

- The **Radiation Exposure Compensation** program (RECA, administered by the U.S. Department of Justice) provides monetary compensation to uranium miners, uranium millers, ore transporters, on-site participants, and "downwinders." The last two categories apply primarily to people affected by fallout from weapons testing. The employment period of eligibility for this program was 1942 to 1971, so it does not affect most current workers. In any case, compensation payments of $50,000 to $100,000 per person are funded by taxpayers rather than by user fees on the industries that benefited from the uranium mining activities (OMB, 2008: 11-07, 11-08).
- The **Energy Employees Occupational Illness Compensation** program (administered by the U.S. Department of Labor) provides lump-sum payments and medical benefits to workers harmed by DOE operations. This program is also Treasury-funded, without requiring additional congressional appropriations, for incremental payments to uranium miners, millers, and ore transporters who may have benefited under RECA[55] (OMB 2008: 11-08).

The workers compensated through these programs were not primarily processing uranium for commercial reactors. However, in some cases they and their facilities supported both commercial and military sectors. To estimate the subsidy to civilian reactors, payments made only to categories related to nuclear power were included (Table 12, p. 50); that is, workers affected by weapons fallout, for example, were excluded. The remaining payments were then allocated between civilian and military sectors based on their relative shares of enrichment services, as measured by separative work units, or SWUs. These include only actual payments to workers at the three federal enrichment facilities during the period of eligibility (through

[54] In some respects, these are "sunk costs" of nuclear power: injured workers were harmed at facilities that no longer exist or because of practices that have been corrected. However, because they covered workers injured through 1971 (or early 1992 in the case of enrichment facilities), many existing reactors benefited directly from the services these workers provided. In addition, the costs usefully serve as a placeholder for occupational harm associated with workers at mines, plants, and fuel-cycle facilities in subsequent years that has yet to be recognized. However, the subsidy numbers in this report conservatively assume that workers in the industry have been properly protected since the period of eligibility for these programs ended, and that occupational heath and safety issues are not ongoing.

[55] Statutory language notes that: "Upon the exhaustion of amounts in the compensation fund attributable to the authorization of appropriations in section 7384g(b) of this title, the Secretary of the Treasury shall transfer directly to the compensation fund from the General Fund of the Treasury, without further appropriation, such amounts as are further necessary to carry out the compensation program."

Table 12. Taxpayer Payments to Uranium Workers for Occupational Injury

Program/Employee Category	Claims Approved	$Millions
Radiation Exposure Compensation Program		
Uranium miner	5,049	504
Uranium miller	1,225	113
Ore transporter	225	26
Total		**643**
Energy Employees Occupational Illness Compensation		
All categories	144,000	
Enrichment-plant workers		
Paducah, KY		489
Portsmouth, OH		349
Oak Ridge, TN		698
Total		**1,536**
Total uranium workers, both programs		**2,179**
Allocation to civilian versus military		
U.S. reactors		31%
Foreign reactors		19%
All civilian		50%
Military		50%
Implied share of worker payments attributable to civilian sector		1,089
Cents/kWh nuclear power during periods of eligible worker exposure		0.29

Sources: DOJ 2009; DOL 2009a, 2009b, 2009c; Warren 2007.

1971 for RECA; through February 1, 1992 for enrichment workers under EEOIC). Payments to other classifications of workers were ignored. Federal enrichment facilities were dual-use, serving both the military and civilian sectors. Therefore it makes sense to attribute part of the compensation paid to the work conducted on behalf of the civilian sector, and an SWU basis is a reasonable proxy for the relative utilization by the three plants.

The civilian share includes both SWUs used by domestic reactors and those sent abroad, totaling roughly 50 percent. Uranium mining and milling demand by sector is assumed to follow the same pattern as the use of enrichment services. Nearly $1.1 billion in payments has supported civilian nuclear workers through the beginning of 2009, or 0.29 ¢/kWh of nuclear electricity generated during the period of exposure covered by these programs. As workers age, the number of claims submitted is expected to taper close to zero by 2022 (GAO 2007b: 12).

4.4. SUBSIDIES TO LAND

Large industrial facilities routinely play municipalities off of each other in order to extract public funding, access tax-exempt debt, and obtain tax abatements. Because the siting decisions involve local or county governments, the most common abatements involve reductions in property taxes.

The justification for getting such financial breaks is normally focused on the new jobs that the plant will presumably bring. It is difficult to evaluate how often the promised jobs actually materialize, or whether they are of the promised wage levels and durations. Few municipalities make receipt of the tax breaks conditional on the actual delivery of the promised jobs, and evaluating incremental change versus what might have happened anyway because of other factors can be difficult.

But even if the promised jobs do materialize, property tax abatements for the case of nuclear reactors are puzzling. The industry suffers tremendously if projects are delayed for long periods of time because of siting problems. As a result, most new reactor project consortia choose to co-locate them with existing reactors.[56] Thus a company's bargaining position with municipalities should be relatively weak, as projects are from the outset largely limited to the handful of reactor sites it already owns that are suitable for new construction, access, and thermal loads.

Nonetheless, property tax abatements to lure these new facilities have been increasingly common. While the abatements are relatively small in terms of value per kWh of electricity generated over the life of the facility (0.16 ¢/kWh for the property tax abatements granted to Calvert Cliffs 3, for example), they are extremely large for local or county governments, in some cases amounting to a substantial portion of their tax base. In all likelihood, the municipalities would have achieved the same outcome without the tax loss. Some examples:

- **Constellation Energy**. In an effort to increase the chances of getting a new reactor in Lusby, MD, the Calvert County Board of Commissioners approved a 50 percent reduction in property taxes over the first 15 years of plant operations. The Calvert Cliffs 3 plant will be owned by UniStar Nuclear, LLC, a subsidiary of Électricité de France. The abatement is expected to save UniStar $20 million per year, for a total of $300 million. It pays only $15.5 million in annual property taxes, so the savings will exceed its entire current bill (Hopkins and Adams 2006). This property tax abatement for the new reactor is a sizeable subsidy for a county-level government to offer; it is roughly equivalent to 7 percent of the county's 2009 budget of $296 million, and larger than its entire annual debt service (Calvert County 2009). However, there is no consistent data to estimate these supports on a national basis.
- **Alstom Power Turbomachines** received $21 million in property tax abatements over 17 years for its new facility in Chattanooga, TN. Alstom has been chosen by UniStar to build at least four steam-turbine generators for its new European pressurized reactors. According to press reports, "the tax incentive package is believed to be one of the richest ever awarded in Hamilton County" (Pare 2008).
- **U.S. Enrichment Corporation** (**USEC**). USEC received property tax abatements worth $0.5 million to $1 million per year to build its new gas-centrifuge enrichment facility in Piketon, OH, the site of its old Paducah diffusion-enrichment facility (Fowler 2008; Huotari 2008). This sum is believed to be the biggest tax break the town has ever granted. USEC needed to build a new facility to stay in business, and it had only three possible sites—already in use—to choose from; a "greenfield" site would have generated public resistance, as well as opened USEC to much higher contamination liability. Also, existing contamination at the three enrichment sites remained the responsibility of the government when USEC was privatized, thus providing some leeway for the firm to avoid the large post-operational remediation that a new site would probably have brought.

[56] Only 8 of 31 active reactor applications as of July 2, 2009 were not located at the site of an existing operating plant (NRC 2009).

The granting of abatements at the county or local level is normally constrained by the fact that governments still need some revenues in order to operate. Not so in Texas. A 2001 state law allows local school districts to grant subsidies to businesses within their district through deferral of the school-tax portion of property taxes for up to 10 years. A state school-funding formula means that the subsidy is effectively reimbursed dollar-for-dollar by the state (Elder 2007). But while the state "absorbs the entire cost of the foregone property tax revenue through the school finance system," it has limited influence in what projects actually get approved (Lavine 2007).

Although the original objective of the Texas bill was to bring more manufacturing and research jobs into the state, it has become a popular way for providing sizable subsidies to energy projects, including wind-power facilities and oil-refinery modifications. In 2007, eligible energy projects were extended to include new nuclear power plants, at significant cost to the state: $40 million to $50 million a year for most of a 10-year period of eligibility (Elder 2007).

In just two years of eligibility, nuclear has already become the second-largest energy-sector beneficiary in Texas (Table 13). Nuclear's gross projected tax abatements exceed $500 million and account for nearly one-quarter of all benefits funded by Texas over the past eight years.[57] Even if all 500 promised jobs do materialize, the subsidy cost per new job will exceed $1 million—five to nearly 20 times the subsidy needed to bring the manufacturing and R&D jobs the law was originally targeting.

Table 13. Subsidies to Nuclear Power through the Texas Economic Development Act

Investment Type	Year Allowed	Number of Agreements	Total Gross Tax Benefit to Company, $millions	% of Total	Qualifying Jobs Created*	Subsidy/Job Created, $thousands
I. Overview by Sector						
All manufacturing	2001	23	875	41.5%	4,328	202
All R&D	2001	4	17	0.8%	295	58
Energy not included above		63	1,215	57.7%	967	1,256
Total			**2,107**	**100.0%**	**5,590**	**377**
II. Energy Breakout**						
Clean coal	2005	0	-	0.0%	-	NA
Wind	~2001	61	713	33.9%	467	1,528
Ethanol	~2001	1	7	0.3%	5	1,340
LNG terminals	~2001	2	84	4.0%	78	1,072
Low-sulfur diesel	~2001	1	12	0.6%	12	975
Refinery cogeneration	~2001	1	18	0.9%	10	1,830
Nuclear	**2007**	**2**	**501**	**23.8%**	**500**	**1,002**
All energy		68	1,335	63.4%	1,072	1,245
All others*		22	772	36.6%	4,518	171
Total			**2,107**	**100.0%**	**5,590**	**377**

* Job creation was self-reported by applicant, not audited.

** Energy totals in Sections I and II do not match exactly because some energy projects were related to manufacturing, or because R&D was included in those categories in Section I.

Sources: Texas Comptroller 2009; Lavine 2007.

57 If these projects are cancelled, the subsidies would not materialize.

Table 14. Subsidies to Factors of Production (Overview)

			Subsidies to Existing Reactors, ¢/kWh							Subsidies to New Reactors, ¢/kWh					Notes
			Total	Legacy		Existing: Low		Existing: High		Total	Low		High		
		Subsidy Type		Low	High	IOU	POU	IOU	POU		IOU	POU	IOU	POU	
A. Subsidies to Reduce the Cost of Capital	Cost of Funds	Title XVII loan guarantees								For $18.5b authorized, subsidies of $0.8b–$1.1b/yr; $23b–$34b present value over 30-year term of loan guarantees	2.50		3.70		(1)
		Foreign credit support to U.S. projects								Emerging issue; no known deals yet					(2)
		ECA support of U.S. nuclear exports								Emerging issue; minimal support so far					
		Ratebasing of construction work in progress (CWIP)	Not quantified							Worth ~$40m–$90m/plant/yr in reduced financing costs	0.41	0.41	0.97	0.97	(3)
		Public reactors: reduced cost of borrowing	Not quantified; mostly a legacy cost by now								NA	3.13	NA	3.13	(4)
		Public reactors: no tax on net revenues, per year	$0.1b				0.07		0.07			0.07		0.07	(5)
		Public reactors: tax-exempt bonds, per year	$0.2b–$0.3b/yr based on TVA, BPA, and RUS alone				0.25		0.32						(6)
		Public reactors: low return on capital, per year	$0.4b–$0.9b/yr based on TVA and BPA alone				0.58		1.48						(7)
		Regulatory risk delay insurance	NA							$2.0b face value for six policies	0.00	0.00	0.80	0.80	(8)
	Cost of Capital Goods	Combined legacy tax subsidies: accelerated depreciation, allowance for funds used during construction (AFUDC), investment tax credits		5.86	5.86										(9)
		Accelerated depreciation: new reactors and retrofits								$40m–$80m/plant/yr	0.33		0.70		(10)
		Licensing costs and site approval	NA							$0.8b total for two consortia	0.06	0.06	0.19	0.19	(11)
		Research and development	$515m for 2009			0.06	0.06	0.06	0.06	Expected to rise somewhat	0.06	0.06	0.06	0.06	(12)
		Stranded-asset charges	$110b through 1997	1.05	1.05										(13)
B. Labor Costs		Payments to injured workers, civilian share	$1.1b total payments for civilian portion	0.29	0.29										(14)
		Worker training support	$0.016b												(15)
C. Land Costs		Property-tax abatements	Unknown; often, local or state policies vary by reactor							Varies by project; quantified offers total $0.8b over 20–30 yrs; at most $20m/yr/plant	0.16		0.16		(16)
		Total		**7.20**	**7.20**	**0.06**	**0.96**	**0.06**	**1.94**		**3.51**	**3.73**	**6.58**	**5.22**	

Notes:

(1) Estimates from industry cost models (Exelon and UniStar), assuming relatively low construction costs. Not all facilities will receive guarantees under current law. Administration proposes to add $36 billion to current Title XVII programs. Proposed legislation would enable POUs to access loan guarantees as well.

(2) Similar value to U.S. loan guarantees. Assumes maximum loan guarantee is 80 percent of project capital and that foreign guarantees expand number of reactors subsidized but do not go above the 80 percent cap.

(3) CWIP rules determined at utility district level, not federal. Low estimate based on CRS (Kaplan 2008) values; high estimate scales CWIP value (with loan guarantees) for higher cost of capital and loan subsidy values (for Calvert Cliffs 3).

(4) Benefits calculated by Kaplan/CRS for reduced cost of financing (e.g., through municipal bonds, Build America Bonds). Does not include incremental benefits from tax exemption or low ROI hurdles for POUs.

(5) All tax-exempt power, per year. Subsidies to existing reactors based on POU share of total nuclear generation capacity. Assumes benefits for new reactors will be similar to those for existing fleet.

(6) Subsidies per kWh based on measured entities' share of nuclear generation as proxy for value to all public entities. Values for new reactors included in line item above "Public reactors: reduced cost of borrowing".

(7) Subsidies per kWh based on measured entities' share of nuclear generation as proxy for value to all public entities.

(8) Available to first six reactors, with lower coverage for reactors three through six. High estimate based on coverage levels available to first two units.

(9) Based on Chapman et al. 1981. That analysis did not break out each subsidy line item.

(10) Higher subsidy value associated with higher cost of capital assumptions. Rising plant costs, longer plant service lives, and lower capacity factors would all increase the subsidy value of current accelerated depreciation rules. Insufficient data on ongoing capital spending to generate an estimate for retrofits.

(11) Funds supporting two consortia; not available for all projects.

(12) 2009 appropriations; assumes R&D support will be similar to new reactors.

(13) Estimate based on survey done by Seiple (1998); per-kWh values reflect all net production from 1957–1997. Values are historical rather than ongoing subsidies.

(14) Historical subsidies reflect generation during 1940–1971, the time frame covered by the federal program. Assumes new workers are properly protected and that there will be no subsidy going forward.

(15) Small. Assumes program will not grow substantially as new reactors are built. See new legislative proposals.

(16) Can be material; example reflects abatements to Calvert Cliffs 3 during first 15 years of operation. Subsidies per job created are quite high. Subsidies are highly site-specific and not available to all projects. Unknown to existing plants.

Chapter 5

Subsidies to Intermediate Inputs

Because the building of both a nuclear-weapons and nuclear energy capability required establishing facilities for uranium mining, milling, and enrichment as well as for fuel fabrication, government interventions in these areas have been common. For much of the U.S. nuclear industry's history, government policies in these areas seemed focused on delivering inexpensive services to the civilian sector in order to facilitate the industry's growth. On the materials-procurement side, there was also an interest in building stockpiles of key nuclear inputs to protect the United States against a supply cutoff or other disruption. In recent years, the U.S. enrichment capability has become among the least efficient in the world. Current policies seem focused mainly on the survival of a U.S. firm in the enrichment market rather than on a commercial rationale for success.

This section explores subsidies to three core inputs to nuclear power: uranium mining and milling, uranium enrichment services, and cooling water.

5.1. SUBSIDIES TO URANIUM MINING AND MILLING

Subsidies to uranium mining and milling come through three main routes. First, special percentage-depletion allowances for uranium allow highly favorable tax treatment for this mineral. Second, "hardrock" mining on public lands, including uranium mining, is governed by the arcane and archaic Mining Law of 1872. This law, which has withstood numerous attempts at modernization, enables extraction of hardrock minerals with very low payments and no royalties, and it includes patenting provisions that allow public land to be privatized for only a few dollars per acre. Third, there are bonding requirements for post-mining restoration, but they are too modest, resulting in significant residual damage at uranium mines—a public health and safety obligation that falls to the taxpayer. The government has also historically sought to maintain a strategic stockpile of uranium, though the impacts of this effort on the industry have varied over time—sometimes reducing costs to users, and other times restricting cheaper supply and driving up prices (PNL 1978: 118–126).

5.1.1. Percentage Depletion for Uranium

As discussed in the section on accelerated depreciation, normal accounting rules aim to write off multiyear capital as it actually wears out. The write-off is capped at actual funds invested, though congressional tinkering often enables firms to write off investments more quickly. Percentage depletion is a totally different animal. Rather than writing off the investment amount, the mineral extraction industry can take deductions based on a portion of the market value of the minerals it has produced. Because percentage depletion is independent of costs, firms can actually deduct more from taxes than they invested.

The specific rules vary by mineral. Uranium falls into the highest tier of allowed percentage-depletion rate, at 22 percent of gross market value—subject to a limit of 50 percent of the net income of the taxpayer. The subsidy associated with *percentage* depletion is the incremental tax benefit from using percentage rather than *cost* depletion.[58] The statutory wording governing percentage depletion for uranium (26 USC Section 613) appears to allow U.S. taxpayers to take the generous tax breaks not only on U.S.-based mining activities but on U.S.-owned uranium operations abroad as well. Many of the other minerals covered under percentage-depletion rules receive a lower subsidy, or none at all, on foreign deposits.

Estimates of the subsidy value to uranium are hard to come by, however, as neither the Treasury nor the Joint Committee on Taxation breaks it out from other fuel minerals. An estimate by the Texas comptroller (2008) pegged uranium's share of this provision at an insignificant $0.5 million for 2006, and that for coal at less than $30 million. In contrast, the Joint Committee on Taxation estimated total subsidies from percentage depletion flowing to fuels other than oil and gas to average $160 million per year between 2008 and 2012 (JCT 2008: 62). This figure, which applies to coal and uranium, is more than five times the Texas comptroller's estimate.

Three factors call both of these estimates into question. First, there is little information on how they were developed. Second, there has been a strong resurgence in uranium prices in recent years: the weighted average price paid per pound of triuranium octaoxide (U_3O_8, commonly called "yellowcake") surged from $10.15 in 2001 to nearly $33 in 2007, according to EIA data. Spot market prices that tend to influence mining activities showed a much larger spike, from an annual average of $7.90 in 2001 to $88 in 2007, though the price has since fallen (Bonnar 2008).[59] These patterns would drive up percentage-depletion losses, due both to higher extraction rates and to a much higher market value of the ore produced (though the impact of spot prices on revenues was muted by the use of long-term contracts for many of the mines). And third, if ore-mining operations on U.S. public lands and many foreign mines could also take the tax break, expected losses would grow proportionally. It is useful to note that between 1994 and 2007 the share of domestic uranium purchased by the civilian sector dropped from more than 20 percent to less than 8 percent (Bonnar 2008).

Earth Track estimates that the subsidy value of percentage-depletion allowances for uranium is about $25 million per year.

5.1.2. Uranium Mining on U.S. Public Lands

While uranium mining on any land benefits from percentage-depletion allowances, its extraction from public lands can tap into a range of other subsidies as well. They include low taxes and fees, inadequate financial assurance against damage, and the shifting of large remediation costs to the taxpayer.

The removal of valuable resources from public land for use in private commerce represents the sale of a public asset. Governments (and taxpayers) share in the gains primarily through royalties, excise taxes, and other fees that the extracting entity pays. If those fees are too low, or nonexistent, taxpayers have given away wealth that must be made up in other ways, such as through higher personal income taxes. Financial-assurance mechanisms such as reclamation bonds play a related role in protecting taxpayer interests by ensuring that the party benefiting from the mining activity will leave the site in good condition, rather than as a liability for the state.

5.1.2.1. Royalty and Tax Regimes, Land Patenting

Federal lands. Under the terms of the antiquated Mining Law of 1872, uranium can be mined royalty-free from federal lands.[60] By contrast, federal

58 Uranium mining also receives subsidies on a cost-depletion basis, as the mines are assumed to last only seven years, and within that period assets can be depreciated using a highly favorable 200 percent declining-balance method. To the degree that cost depletion itself is heavily subsidized, the metrics for percentage depletion over cost depletion will understate the actual subsidy.

59 These are weighted-average spot prices, which more evenly reflect average price levels. However, during 2007 there were periods of much higher spot prices.

60 A small amount of land owned by the DOE and managed under its Uranium Leasing Program is an exception, as it does charge some royalties.

royalties for coal and oil range from 8 to 16.7 percent (Earthworks 2007).

Additional subsidies to claimants as a result of the Mining Law include no liability to help pay for cleaning up abandoned mines, as well as limited exposure to environmental regulations related to water quality and habitat protection (Pew 2009). Uranium-mine lands have been "patented" at a low cost of five dollars per acre or less.[61] Patenting turns valuable public land into private land that can then be used for a variety of purposes, including non-mining real estate development. Congress placed a moratorium on patenting in 1994, which it has renewed annually ever since—though it has not yet eliminated the practice entirely (Horwitt 2009).

The CBO estimated that hardrock mining income from royalty-free extraction on federal lands "would average roughly $1 billion per year" with net increases in Treasury royalty receipts of about $40 million per year (though not all attributable to uranium) (CBO 2007a: 29). However, the implied royalty rate in the CBO work of 4 percent is well below the royalty rates noted for other minerals.[62] Based on historical uranium-extraction rates, Earth Track estimates the low royalty rates would generate a small subsidy of roughly $5 million to $20 million per year. This subsidy would rise with extraction rates or the value of extracted minerals.

State lands. State law, rather than the Mining Law of 1872, governs hardrock mining from state-owned land in the West. Fees for uranium, which mirror those for other valuable commodities more closely, include royalties, severance taxes, mine license taxes, and resource excise taxes. In many cases, state fees are applied to extraction even from federal lands located within the state boundaries (GAO 2008b: 2). New Mexico, for example, levies a minimum 5 percent royalty on uranium from federal lands, though the state allows up to a 50 percent deduction for transportation and processing costs, yielding a 2.5 percent net rate. Uranium extraction from all lands in the state also pays a severance tax equal to 3.5 percent of taxable value, which translates to 1.75 percent of revenues (GAO 2008b: 22, 23). Rates in Utah are an 8 percent royalty on uranium from state lands, plus a severance tax for uranium on all lands equal to 2.6 percent of the proceeds received from the sale of yellowcake (GAO 2008b: 26).

Royalties are commonly based on a percentage of gross proceeds (basically, revenues), with no allowance for expenses. Some state-level royalties, however, including those for uranium, use a "net-proceeds"-based calculation that allows the deduction of certain expenses before royalties are calculated. While deducting costs may seem fair, such a system gives claim holders a strong incentive to pad costs or other expenses in order to reduce royalties owed. Too often, the manipulations end up short-changing taxpayers (Earthworks 2007).

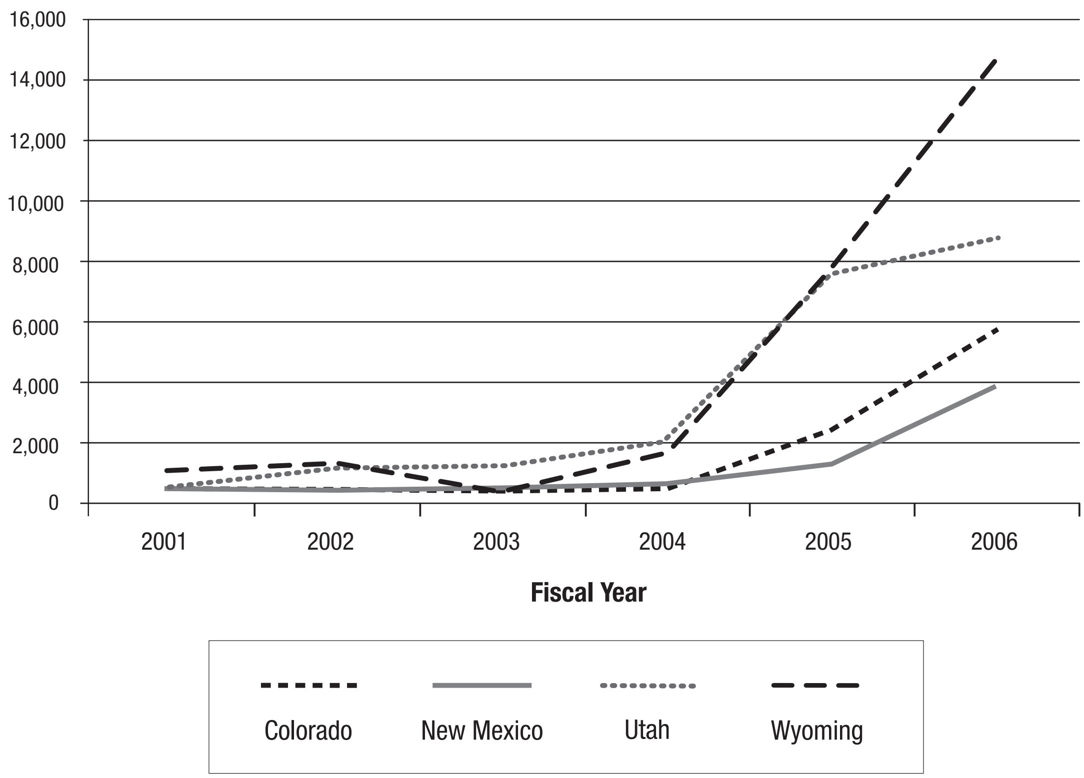
Rising mine activity means higher subsidies. Surging uranium prices in the past few years have greatly increased interest in uranium mining throughout the West:

- U.S. production had declined dramatically, but rose sharply in 2007 and remained high in 2008 (EIA 2009b). As of mid-2007, there were 35 permitted uranium mining projects in Colorado alone, all active but not yet producing (Carlson and Schwartz 2007).
- Analysis of Bureau of Land Management (BLM) data by the Environmental Working Group (EWG 2006) found that in 2006 uranium mining interests became some of the

[61] There are now annual maintenance fees of about $100/acre, which increase the cost of speculative landholding and patenting. This change has improved the situation somewhat, leading to some claims being relinquished (Humphries 2007)

[62] The lower rate reflected terms of a mining reform bill then under consideration that would have implemented a 4 percent royalty on existing mines and an 8 percent royalty on new mines.

Figure 2. Uranium Mining Claims



Source: BLM 2007, analyzed by EWG 2009.

largest claim holders in at least seven states.[63] By contrast, in May 2004 there were no uranium interests among the largest claim holders. Figure 2 shows how uranium claims overall in Colorado, New Mexico, Utah, and Wyoming increased from less than 4,300 in FY04 to more than 32,000 in FY06 (EWG 2009: 3).

- As of January 2009, there were more than 1,110 mining claims within five miles of Grand Canyon National Park, compared with just 10 in January 2003 (EWG 2009). Although the Department of Interior put a two-year hold on claims near the Grand Canyon in July 2009, many of the mining claims in the affected region can still be developed if the claim had been validated prior to the hold (Barringer 2009).

While the drop in uranium prices since 2007 may dampen mine activity somewhat, prices remain well above recent lows. The additional mining activity will result in substantially larger subsidies via patenting, royalty relief, and inadequate bonding. But as discussed in the next section, environmental liabilities from this activity (which will ultimately be borne by taxpayers) are expected to surge in coming years as well.

[63] Arizona, Colorado, New Mexico, Oregon, South Dakota, Utah, and Wyoming (EWG 2006).

5.1.3. Inadequate Bonding, High Legacy Costs

Production of uranium fuel rods requires significant upstream processing. Mining operations extract uranium ore, often at concentrations of 0.1 percent or lower. Uranium milling (crushing and chemical leaching) boosts the uranium content to roughly 80 percent, producing a dry yellow powder of U_3O_8. Subsequent processing converts U_3O_8 into uranium hexafluoride (UF_6), which is converted at enrichment plants into a gas that subsequently boosts the concentration of fissionable U-235 from 0.72 percent to the roughly 3.5 percent needed by most commercial reactors.

The mining and milling stages have historically been environmentally damaging, and available data (Table 15, p. 61) indicate the taxpayer cost to address these issues has rivaled the market value of the minerals extracted. Mining techniques through the 1970s consisted of traditional pit and surface extraction, leaving large quantities of contaminated "overburden," or tailings. Leaching processes have since dominated. "Heap-leach" techniques that bathed piles of ore in chemicals were used first, but they have been superseded by *in-situ* approaches that inject the leaching agents directly into the ground. From a mine operator standpoint, leaching is less expensive and facilitates extraction from lower-grade ore reserves. Thus *in-situ* mining accounts for 80 percent of the uranium ore produced in the United States at present (Clarke and Parker 2009: 70, 71; WNA 2009a). Cost savings aside, most researchers believe that leaching techniques inevitably result in degraded groundwater resources and migration of leachate (Clarke and Parker 2009). These environmental concerns are compounded by the fact that uranium is typically found in arid regions where groundwater resources are particularly valuable.

5.1.3.1. General Problems with Bonding

As noted by the CBO, "having the public bear risks in support of reclamation implies that some costs of the production of mined resources and oil and gas are not incorporated in their market prices" (Tawil 2003: viii). This situation, unfortunately, has been the norm for uranium mining operations in the United States, resulting in a subsidy to past operations. The anticipated problems with current mining techniques indicate the subsidy is ongoing.

The core challenge to remediation, both with respect to mining and milling, is that properly terminating operations, closing the site, and monitoring environmental performance over time all require substantial outlays of cash. Because these expenditures are needed after the revenue-producing activities have ceased, there is a high risk of nonperformance and site abandonment. While careful management of mining and milling operations can reduce the ultimate site-management costs, if operators think they can avoid incurring post-operational costs they will be less likely to make prudent (though perhaps costlier in the short term) environmental management decisions during the extraction phase.

Financial assurance requirements attempt to solve this problem by establishing backstop financing (such as reclamation bonds) prior to the start of operations, when the incentive to start mining is strong. If the operator does not pay directly, another private party does so. In addition to providing additional financial recourse for site cleanup, bonding fees themselves are thought to encourage better operational practices by setting higher premiums for riskier or messier activities or for less competent operators.

The reality is more complicated, however, with bonding often providing inadequate coverage levels. Mine operators will purchase bonds only up to the amount required by law. This amount is often far lower than the actual environmental damages at the mine site. For example, the CBO noted that, "There is evidence that the value of currently held financial assurances does not match the outstanding reclamation costs for the sites for which they were provided" (Tawil 2003: 2). Kuipers (2002) found that existing financial assurance was above the lower-bound estimate for reclamation and closure liability but less than 14 percent of the mid-range estimate and only 7 percent of the high-end estimate. Requiring bonding levels to deal only with the lowest-cost scenarios is clearly a pathway to financial distress. In fact, Parshey and Struhsacker (2009) report inadequate financial assurance to properly implement and complete the approved reclamation plans at nearly every bankrupt mine in the state of Nevada.

Sometimes the shortfall is politically motivated—through a desire that bonding requirements not be "onerous." At other times, regulatory officials set bonding rates at the expected or average cost of mine reclamation, implying that all sites with above-average costs would require taxpayer subsidy.[64] Existing bonds may also have coverage gaps, such as for natural resource damages or full site closure. Additional risks can arise through counter-party failures: the bonding agent cannot or does not make good on the financial assurance it has been contracted to provide.

A related challenge involves the strength of the underwriting market. The CBO notes that all surety bonds totaled just 1 percent of the premiums paid in property and casualty insurance in 2002, and that reclamation bonds were just 1 percent of surety bond premiums (Tawil 2003: 4). As a result, if reclamation bonds begin to underperform, underwriters fairly quickly reduce their exposure and withdraw from the market. From 2000 to 2003, a number of underwriters withdrew from the market or became insolvent. Mine operators either had to pay more for the bonding that was available; shift to other, perhaps less secure, financial assurance mechanisms; or simply go without coverage. Surety-bond usage as a financial assurance method dropped from more than 50 percent of coverage in 1999 to just under 20 percent by 2002 (Tawil 2003: 5–7).

5.1.3.2. Bond Subsidies to Uranium

While data on uranium-specific bond shortfalls could not be identified, two data sources provided insights into the subsidy: a GAO review of bonding shortfalls at a mixture of hardrock sites, and actual remediation costs at legacy uranium sites.

Large liabilities at hardrock sites. The GAO's review of bonding shortfalls at hardrock mines (a group that included gold, lead, copper, silver, and uranium) identified $2.2 billion in public spending on cleanup by the U.S. Environmental Protection Agency (EPA) alone between 1998 and 2007 (GAO 2008a: 5). This expenditure by no means addressed the full range of abandoned sites. There were at least 161,000 abandoned hardrock mining sites in 12 western states and Alaska (GAO 2008a: 13). The GAO analyzed a subset of 1,463 abandoned sites on BLM lands, finding a bonding shortfall of $61 million on roughly $1 billion of liability for reclamation—or about 6 percent (GAO 2008a: 15). The EPA estimated remediation costs at all domestic hardrock mine sites at $20 billion to $54 billion (EPA 2004, cited in Pew 2009).

Uranium-tailing remediation costs approach the value of ore. The federal Uranium Mill Tailings Radiation Control Act (UMTRCA) was passed in 1978 to formalize cleanup of uranium milling sites. Title I required DOE remediation of 22 sites that were inactive at the time of the act's passage, and Title II required NRC oversight of then-operating sites. Title I sites were estimated to cost approximately $1.5 billion in remediation as of December 31, 1999, or more than $15 per pound of U_3O_8 produced in 2007 dollars (Clark

64 This has been a common problem in establishing bonding levels for the plugging and abandonment of oil and gas wells. See Koplow and Martin 1998 for more discussion.

and Parker 2009: 78).[65] The DOE estimated that Title II facilities had a cost of closure roughly half that of the Title I sites, though still a total cost of nearly $600 million (EPA 2008a: 4–17). However, the DOE noted that with the exception of the Gas Hills West site in Wyoming, costs for Title II sites "may not be in the public domain because remediation was performed by private firms" (Bush 2009).

Peterson et al. (2008) noted that while groundwater remediation had been conducted at many of the Title II uranium milling sites, "remediation has not achieved background levels or maximum concentration limits and applications have been submitted to NRC for alternate concentration limits." This observation suggests that proper remediation of the Title II sites is likely to end up costing more than the value of ore produced, with a large fraction of the expense falling to the public sector.[66]

The remediation-cost figure for Title I sites is striking (Table 15). The cost per pound of U_3O_8 produced, even using values only through 1999 (scaled to 2007 dollars), exceeded the average value of uranium during the period tracked by the EIA prior to the commodity price spikes that began in 2006. Even with surging prices included, socialized remediation costs were still more than 80 percent of the value of the ore produced during the period. Assuming full remediation costs, including all Title I sites, Title II sites, and unfunded liabilities associated with uranium mine and enrichment facilities, the degree of subsidy to upstream processes would grow even more substantially.

To cover the cost of proper mine reclamation, it is reasonable to assume that the price per pound of U_3O_8 would need to have roughly doubled. Based on data from the World Nuclear Association (WNA 2009b) on the contribution of raw uranium prices to the delivered price of nuclear power, the underpricing of uranium has generated a subsidy to nuclear power of 0.13 to 0.32 ¢/kWh of resultant nuclear electricity produced. It is striking that this range exceeds what the industry currently pays the federal government to take full responsibility

Table 15. Remediation Costs at Mill Sites Alone Approach or Exceed the Value of the Ore Mined

	Average 2007$/lb U_3O_8	Socialized Remediation Cost as Share of Ore Value
Remediation cost through 1999		
Title I uranium milling sites*	$15.51	
Market value of U.S.-origin uranium ore		
Including commodity price spike: 1994–2008	$19.21	81%
Excluding commodity price spike: 1994–2005	$15.11	103%

*The DOE did not have more recent data compilations (Bush 2009).

Sources: Clarke and Parker 2009: 78; EIA 2009c.

65 Some of the sites posed quite significant health risks as well. Miller, Pomatto, and Hylko (2002) estimated that remediation at the Grand Junction and Salt Lake City UMTRA sites prevented more than 900 excess cancer deaths at a cost of less than $500,000 each.

66 The United States is not alone in experiencing uranium remediation costs that exceed the actual value of ore for which the mining activities were conducted in the first place. A review of reclamation costs incurred by the government of Germany for sites at Wismut indicate that—even excluding earlier reclamation expenditures—the cost per kilogram was $43, above the then-world price for uranium of about $26 (Diehl 2004).

for its nuclear waste from reactors. As current extraction methods remain environmentally damaging and bonding problems remain, we assume that this subsidy will accrue to new reactors as well.

The UMTRCA does not address mine sites. Rather, mine-site restoration "was typically regulated under a state-issued mining permit" (Bush 2009). This gap is potentially quite significant. The EPA estimates that more than 4,000 mines have a history of uranium production, with radioactive mining wastes estimated at 3 billion metric tons nationwide (Peterson et al. 2008: 27). Seventy-five percent of these mines are located in only four states: Colorado, Utah, Arizona, and New Mexico. EPA data indicate that roughly 90 percent of the uranium mines with known production are on federal land, the majority of which is managed by the Forest Service or the Bureau of Indian Affairs (EPA 2008b, v.2: 2–4, 2–7).

The remediation costs at many of these sites could be sizeable, given that much of the mining across the country predated environmental regulations. Mining operations were therefore regulated poorly or not at all, with sites improperly closed or remediated afterward. New Mexico found that, "over 50 percent of the uranium mines (137 of 259) have no record of any reclamation having occurred or currently required by a government agency" (Brancard 2008: 7). These sites are smaller than those at which cleanups have already been done. However, Brancard pegs the cost at $50 million or more, even when excluding environmental restoration, residential remediation, or waste removal. These other costs would of course "multiply the minimum estimate" (Brancard 2008: 7).

5.2. SUBSIDIES TO URANIUM ENRICHMENT

Natural uranium contains roughly 0.7 percent of the U-235 isotope used in civilian reactors. Enrichment applies technology, plus quite a lot of energy, to sort the isotopes, bringing the U-235 concentration up to about 3.5 percent, the preferred blend for most commercial light-water reactors.[67] Two enrichment approaches are in commercial use today. The gaseous diffusion process remains in operation at two facilities worldwide: Tricastin in France and Paducah in the United States. But gas centrifuge technology, being more efficient, has gradually been replacing the older gaseous diffusion approach. The gas centrifuge process is expected to provide nearly all enrichment services by 2017 (WNA 2009c). A third approach, laser separation, has been researched for many years, and at some point it may displace centrifuge technologies. While past efforts have been unsuccessful in commercializing this process (USEC scrapped its research program after billions in investment), General Electric-Hitachi is operating a pilot laser plant. The companies have plans for a commercial venture in North Carolina if the technology works out (MIT 2009: 13); they submitted an application for a commercial-scale operating license in June 2009.

Like fission reactors, uranium enrichment remains a very capital-intensive industry with significant economies of scale. But whereas the economics of nuclear power can be improved dramatically by achieving much higher capacity factors, enrichment operations have two constraints that reactors do not. First, the demand for enrichment services is much smaller than that for global electricity (one-seventh of which is nuclear), and it grows in accordance with slow incremental increases in the number of reactors or with the capacity factors in the existing reactor fleet. As a result, enrichment is more sensitive to global overcapacity and resultant price collapse than is electricity. Second, the same basic enrichment technologies

[67] CANDU (Canada deuterium uranium) reactors in Canada and Magnox (magnesium non-oxidizing) reactors in the United Kingdom are exceptions, using natural uranium as a fuel. Both technologies have been minor players in nuclear reactor markets, with limited commercial success.

can be used to produce either low-enriched non-explosive uranium for civilian reactor fuel or highly enriched uranium for weapons (HEU). Enrichment to normal reactor levels does most of the separative work required to achieve weapons-grade HEU.[68] In a conventional industry, firms can optimize production and supply multiple markets in whatever ways they choose to boost profits. Enrichment is different. Although a company's profitability certainly rises if it can more effectively utilize enrichment capability, the military overlap results in substantial constraints on its freedom of action.[69]

The combination of large-scale investments and constraints on the freedom to produce and sell product at will has made government involvement with uranium enrichment common throughout the world. The U.S. Uranium Enrichment Enterprise (UEE) was entirely government-owned until its privatization in 1998 (though operated as an independent public corporation between 1993 and 1998). It is now called the U.S. Enrichment Corporation, or USEC. While privately owned, the facility continues to rely heavily on its relationship and contracts with the federal government.

Evaluating government subsidies to enrichment is complicated by many factors. First, the subsidies have varied over time as the technology evolved and the market position of the United States changed. Second, evaluating subsidies pertaining to complex government-owned enterprises is always difficult. Books of account are often murky, interactions with related entities are common, and pricing of capital absorbed in facility and operations is often inaccurate or nonexistent. Enrichment is all the more complicated as a result of dual servicing of civilian and military sectors. Third, while enrichment services may be a straightforward business, two types of government initiatives—efforts to build and manage strategic stockpiles of uranium, and a large program with Russia to dilute HEU for use in the commercial sector—have affected the cost of key supplies and influenced market structure and profitability.

Data suggest that UEE's main role during the first decades of its existence was to subsidize civilian reactors through low-cost enrichment services. The HEU "down-blending" program has also resulted in reduced fuel prices to reactors. However, the years since the privatization of USEC have been marked as well by increased tariffs on foreign LEU and monopoly marketing arrangements for USEC on Russian HEU, which tend to prop up domestic prices and protect USEC against foreign enrichment providers. These policies may act as a *de facto* tax within the United States. The challenge is that government subsidies remain common to enrichment providers around the world and likely contribute to lower prices on enrichment services globally, despite U.S. tariffs on imports.

5.2.1. Subsidies to the Uranium Enrichment Enterprise

UEE emerged from government-owned facilities that provided enrichment services for military purposes, and it was operated as part of the DOE. Commercial customers were first served in 1969, and subsidies to enrichment in the ensuing 30 years took a number of forms. Foremost was below-market pricing of enrichment services. UEE enrichment services in 1986 sold for only $119 per SWU versus $170 to $190/SWU for its main competitors Eurodif and Urenco (GAO 1991: 38–40). In fact, the DOE's price was $12/SWU lower than UEE's average production cost, even excluding depreciation and a reasonable return on investment (Montange 1990: 8, 11).

The result was a large unrecovered taxpayer investment in enrichment, which totaled roughly $4.0 billion to $11.3 billion in 2007 dollars—even

68 Squassoni (2009a) notes, however, that it is costly to move from an enrichment configuration focused on producing LEU to one capable of producing HEU.

69 A distinction needs to be made between boosting the utilization of existing capital equipment, such as by achieving more SWUs per machine, and the much more expensive upgrading to more efficient enrichment machinery. In either case, however, enrichment facilities may be constrained by security factors in optimizing the plant's capacity utilization.

excluding the large additional subsidy to enrichment customers from UEE's operation as a non-profit, break-even enterprise. The low end of this range is based on an estimate by the DOE, an organization with an incentive to understate the degree of its mismanagement. As these estimates covered different periods of loss, a better metric is the annualized subsidy attributable to the civilian sector (after military SWUs). This amounted to roughly $270 million to $1,350 million per year in 2007 dollars (Koplow 1993).

Subsidized prices provided a windfall to power reactors, reducing operating costs by an estimated 0.08 to 0.22 ¢/kWh during much of this period. Additional subsidies came through inadequate accrual of funds to cover site decommissioning and decontamination (discussed below), the lack of required rate of return on invested capital within UEE, and its tax-exempt status. Because non-nuclear power generators did not have government-financed suppliers willing to bear significant supplier risk and sell to them at a loss, the UEE pricing arrangement clearly benefited civilian reactors.

In an effort to promote inexpensive and reliable nuclear fuels to support civilian reactor development, U.S. officials sometimes instituted imprudent policies. For example, UEE set up "take-or-pay" contracts with TVA that guaranteed UEE would purchase a minimum amount of power from TVA regardless of what UEE actually needed. This gave TVA the certainty it needed to build more generating plants. Meanwhile, UEE's goal was to ensure that it could obtain the extra electric power needed to boost its enrichment output so as to supply the many new nuclear reactor projects then expected to enter the market. However, UEE did not hedge these guaranteed purchases with its customer base (utility purchasers of enriched uranium that were planning new reactors) in order to ensure that any change in market conditions would not leave UEE on the hook to pay for all the power. That is exactly what happened: UEE was forced to take a $1.8 billion hit (equivalent to roughly $2.6 billion in today's dollars) when the growth of new reactors stalled due to economic factors and the accidents at Three Mile Island and Chernobyl (TVA 1991: F-15; DOE 1990: 32).

5.2.2. Environmental Contamination at Enrichment Sites

As was the case with uranium mining and milling sites, enrichment facilities grew increasingly contaminated over their decades of operation. Contamination is not uncommon at industrial facilities; however, the nature of business at the three federal enrichment sites generated a particularly expensive and hard-to-manage brew of toxic and highly radioactive elements.[70] Remediation activities, attributable both to the civilian and military sectors (given that UEE provided enrichment services to both) have proven complex and expensive.

Recognizing that there were no accruals from the years of the enrichment facilities' operations that could fund the cleanup, Congress created the Uranium Enrichment and Decontamination and Decommissioning (D&D) Fund as part of EPACT 1992. The terms for fund contributions, as stipulated by Congress, included a fee (adjusted for inflation) on nuclear utilities of $150 million per year for 15 years, beginning in FY1993, and capped at $2.2 billion. The government share was $330 million per year so as "to make [a total] annual contribution of $480 million" (Bingaman 2007: 1).

The pro rata shares were based on estimates of which entities benefited from the enrichment services over their lives, on a per-SWU basis—the standard measure of enrichment services. EPACT 1992 calculated that 31.4 percent of the SWUs produced by UEE went to domestic utilities. The remaining 68.6 percent covered not only services

70 Former UEE executive Longenecker (2007: 47) testified that while the DOE knew it would need to decontaminate and decommission (D&D) the gaseous diffusion plants at the end of their useful lives, "the assumption when I was managing the program was that D&D would be paid for out of annual revenues from the uranium enrichment program. That is, the cost of D&D would be expensed in the year that costs were incurred." The assumption that one could currently finance long-term site remediation and closure certainly seems like a risky one. A variety of pressures were forcing all types of firms to accrue known expenses, whether retirement benefits or site closure. But it is surprising that the DOE believed it would have sufficient revenues to expense this type of end-of-life expense from operating revenues.

to the government (i.e., the military) but also to foreign utilities, "for which there was no certain mechanism by which fees could be collected" (Warren 2007: 28). The actual SWU breakout estimated by the DOE in 1991 was 50 percent military, 50 percent commercial (Warren 2007: 42). Thus nearly 19 percent of the taxpayer contributions to the D&D fund ($130 million/year, or 0.02 ¢/kWh) represent a direct subsidy to foreign nuclear reactors.

The DOE estimated the cost of cleanup in 1987 at only $3 billion (Warren 2007: 26). Not surprisingly, however, the cleanups have been extremely complicated and much more expensive than originally expected. As a result, when the original 15-year fee collection authorized by EPACT 1992 expired, much work remained to be done. As of November 2007, continued efforts were needed at Oak Ridge, TN, and work had barely begun at facilities in Paducah, KY, and Portsmouth, OH. The shortfall in D&D funding is expected to range from $8 billion to $21 billion by the expected completion date in 2044 (Rispoli 2007).

To make up for this shortfall, Congress proposed extending fee collections for an additional 10 years, boosting the annual cap on collection to $700 million, but keeping the annual assessment on utilities at $150 million. Under this scenario, the annual subsidy from the U.S. taxpayer to foreign enrichment customers is $130 million per year.[71]

The industry, represented by Marvin Fertel of the NEI, has argued that it should no longer have to pay anything for site cleanup. Testifying in March 2009, Fertel blurred the lines between the public and private sectors when he asked for more than $90 billion in federal loan guarantees to help his industry build reactors and put taxpayer funds at risk for 80 percent of the construction costs (Fertel 2009). Yet in 2007 testimony, Fertel argued against industry responsibility for site cleanups, stating that, "These facilities were contaminated as a result of their use for Defense programs about 15 years prior to the provision of any services to the commercial sector. As such, the D&D burden would have been the same for the government if the facilities would [sic] never used to service the commercial sector" (Fertel 2007: 21).

Fertel also argued in 2007 that the price paid for enrichment should have included all relevant D&D costs, apparently ignoring the technical challenges in remediating these sites and the enormous benefits the nuclear industry accrued from the multilevel subsidies it received in enrichment for the first decades of reactor operation. He noted: "You don't have any choice but to buy it from this one supplier, who is the Federal Government, at this point, they're pricing it at whatever price they want, and you're paying for it" (Fertel 2007: 43). While complaining that the private sector wasn't *allowed* to build its own enrichment, Fertel doesn't claim that such services would have been cheaper if it had.

It is hard to imagine, in fact, how industry-provided services could have been cheaper. Warren (2007: 42) testified that in the 1960s "either the domestic industry could have built its own enrichment plants, or the government could make its facilities available. If the private sector had built its own plants, it would have been responsible for 100 percent of those cleanup costs. Instead, we thought it made better sense to take advantage of these existing facilities with the understanding that the private sector would pay—not only the variable cost of operating them—but pay toward the fixed plant investment."

The irony of the NEI's testimony was the implication that accurate pricing from UEE should be applied on a going-forward basis to other areas of the nuclear fuel cycle. Were full internalization of risks and costs associated with nuclear waste management, accident insurance, and the pricing of loan guarantees to flow through to nuclear electricity pricing today, domestic energy markets would certainly

[71] (68.6 percent share paid by government minus 50 percent share attributable to military SWUs) x $700 million in annual collections.

be more transparent and efficient. However, it is unlikely that the nuclear sector would attract much investment capital.

5.2.3. Potential Subsidies to the U.S. Enrichment Corporation

Although discussed for many years prior, UEE was finally privatized as USEC in 1998. The terms of the privatization involved a separation of legacy costs (all contamination prior to 1993 stayed with the taxpayer) from those assets with potential value (such as infrastructure, inventories, R&D, and contracts) that went into the new privatized entity. Three areas of potential USEC subsidization are examined here: the terms of the initial privatization deal, monopoly rights for USEC as sole agent to market LEU from Russian weapons stockpiles, and tariff protection awarded to the firm through a number of trade cases.

5.2.3.1. Terms of USEC Privatization

The terms of the USEC privatization warrant examination because these types of transactions can be at risk of corruption, with large losses to taxpayers as a result. Such outcomes seem not to have occurred with the USEC deal, though some elements of the privatization were controversial (see Table 16 for a summary of the main deal terms).

One allegation has been conflicts of interest among key staff. Falkenrath notes that, "During USEC's transition to full privatization, the USEC management team did everything in its power to improve its future commercial position by acquiring government assets and securing special privileges" (Falkenrath 2000: 39).

The USEC management team also advocated for an initial public offering (IPO) upon privatization, whereby USEC was floated on the New York Stock Exchange. The team did not want a direct buyout by Lockheed or General Atomics—two firms that had been interested in purchasing the entity—arguing that an IPO would earn more for the government. Silverstein and Urbina (1999) took a different view, suggesting that the then-managers of UEE were conflicted in their recommendation, given that a purchaser would likely have replaced most of the management team, while an IPO enabled existing managers to stay on. In reality, the IPO earned about the same as the buyout offers, not more. However, a number of the key managers did stay on in the new entity.

Controversy also arose over uranium stockpiles held by USEC. Between 1993 and 1998, the DOE transferred 45,000 metric tons of uranium to USEC "to help sustain it as a viable private enterprise." When USEC was finally privatized in July 2008 it included the uranium stockpile as an asset (GAO 2006a: 2). It also held a number of lucrative contracts. It is unlikely, however, that these deal elements by themselves provided any net subsidy to the privatized entity—so long as the underwriter (Goldman Sachs) properly set the IPO price on USEC shares. Pricing appears to have been quite accurate: the stock traded within a few percent of its initial $14.25 on July 23, 1998, then dropped lower in August 1998.

Contracting anomalies have been another concern. For example, USEC alleged that more than 20 percent of the stockpile it received was contaminated by technetium. The DOE agreed either to replace this material with clean uranium, as USEC requested, or to compensate USEC for the cost of cleaning it up (GAO 2006a: 3). Absent congressional funding, however, the DOE entered into a barter arrangement in December 2004 that allowed USEC to retain $62 million in proceeds it received from a different transaction (sale of blended Russian HEU). This strategy turned out to be illegal, as proceeds were required to go to the Treasury (GAO 2006a: 2). There was, however, no claim that USEC was unfairly compensated for the services provided.

There were also a number of concerns related to the Russian HEU contracts (discussed below).

Table 16. Key Terms in the USEC Privatization Deal

Government	USEC
Assets	**Assets**
» $1.4b in proceeds from IPO stock offering on USEC » $500m debt taken on by USEC and paid to the government » $1.2b in cash from accounts held by the corporation prior to sale » DOE indemnification for USEC operations (related to a nuclear incident or precautionary evacuation) so the firm would not need to purchase any liability insurance under the Price-Anderson Act	» $3.1b in assets and accounts receivable (including cash held at the Treasury, which the government may have retained; and 73 million pounds of uranium transferred to USEC between 1993 and 1998) » Exclusive rights to atomic vapor laser isotope separation technology ($1.7b invested by taxpayers); this was later determined to be nonviable » Sole agent to manage and sell Russian LEU blended down from warheads » Low-cost rental of two existing federal enrichment facilities and favorable power purchase contracts » Contracts worth $3.2b through FY00 and $7.4b through FY09
Liabilities	**Liabilities**
» D&D liability for contamination at all sites up to 1993, including cleanup and any related liabilities	» D&D liability for post-privatization contamination » $1.0b in other liabilities

Sources: USEC 2009: 43; GAO 2000: 32–34.

5.2.3.2. USEC Monopoly Role as Marketing Agent on U.S.-Russian HEU Deal

In 1993 Russia and the United States reached an agreement to convert Russian highly enriched weapons-grade uranium into LEU for reactors. The goal was twofold: to profitably divert material that posed substantial proliferation risks into a less risky form, and to generate cash flow to closed Russian nuclear facilities that would allow that country to continue employing scientists who might otherwise seek to market their nuclear know-how throughout the world—and in ways that might exacerbate security concerns (Neff 1998). USEC was appointed the sole marketing agent for this LEU within U.S. markets.

The deal made a great deal of sense in terms of nonproliferation, as leakage of this material or the spread of this know-how could have greatly threatened national and global security. However, because USEC had the missions both of serving the U.S. government and maximizing value for shareholders, the deal also created tensions between USEC's financial interests and the country's nonproliferation goals. Nobel laureate Joseph Stiglitz noted in 1998 that, "This potential conflict of interest could be a major threat to national security because of the crucial role of USEC in our nuclear nonproliferation efforts" (Stiglitz 1998, cited in Guttman 2001).

In terms of impact, the deal appears to have (a) successfully diverted substantial quantities of HEU from weapons markets, (b) reduced the cost of uranium fuels in the civilian sector, (c) eroded the market position of the U.S. mining and milling industry, and (d) boosted earnings to USEC. The deal also illustrates some of the conflicts of interest that can arise when nonproliferation goals intersect with profit motives. These challenges are likely to grow should reactor and fuel-cycle facilities expand throughout the developing world. Unfortunately, as nonproliferation expert Sharon Squassoni notes (though not in reference to USEC), "usually, profit wins over proliferation" (Squassoni 2009b).

Depressed prices for enrichment due to supply expansion. As noted above, USEC received large uranium stockpiles prior to privatization that gradually entered the LEU marketplace. In addition, substantial quantities of blended Russian HEU had the effect of depressing uranium prices (GAO 2000). The combination greatly increased the share of reactor demand that could be met with stockpiles rather than with freshly mined ore. The impact on the uranium mining and milling industries was immediate: while spending on exploration was $21.7 million in 1997, it was only $9 million in 1998 (GAO 2000: 20). Employment also fell sharply, though total nuclear fuel demand from utilities rose.

The mining and milling industries attributed the decline in their industry to USEC sales from inventory (GAO 2000: 18). USEC attributed the decline to mandated sales of Russian blended LEU, which led to the closure of USEC's Portsmouth enrichment facility in 2001, four years before the privatization agreement had permitted such closure (GAO 2000: 22). USEC argued that this action was required because it could not maintain sufficient capacity utilization at both of its plants.

USEC has pointed to the closure as evidence that the HEU deal, for which USEC has been the sole marketing agent since its inception, was a competitive negative. But the logic of this claim is unsupportable on two fronts. First, USEC had the right to terminate its role as marketing agent if the deal were really detrimental to its operations. While it discussed doing so, it never did. Second, the decline in pricing was an inevitable result of a surge in supply from the blended Russian HEU, something that would have occurred regardless of what marketing agent was used. The dislocations on pricing were similar to what happened in a number of other commodity markets, such as aluminum and steel, following the opening of the former Soviet Union's production capacity to global markets.

Conflicts between profitability of commercial operations and expeditious reduction of Russian HEU stockpiles. The HEU deal required that the U.S. government purchase at least 10 metric tons of Russian HEU per year for the first five years and at least 30 metric tons of HEU per year for the next 15 years. Although USEC was the sole agent for carrying out this task, the commercial contract did not contain matching terms—another indication of the government's failure to follow proper risk-management practices and procedures when structuring complex deals. The commercial contract stipulated that USEC had the *option* to purchase *up to* the levels stipulated in the government contract, and that the price would be renegotiated every year. The conflict was exacerbated by the fact that the U.S. government had pledged pricing of $82/SWU to the Russians—an attractive figure for them, given that the market value of an SWU at the time was roughly $110. The rub was that USEC also had financial pressures to maximize its profits, and it earned a higher margin on producing domestic SWUs than in marketing the Russian ones (Falkenrath 2000).

Ironically, the cost advantage that spurred this problem seems to have been caused in part by subsidies to USEC that predated formal privatization. Neff notes two factors: the transfer of below-market-value electricity supplies to the new government corporation, and the failure to charge a capital cost per SWU for the use of the enrichment plants. He suggests that these terms "not only destroyed any incentive to overfeed and thus buy the uranium, but it also subsidized USEC production costs for SWUs so that they were below what was promised Russia" (Neff 1998).[72]

A second source of conflict came through uranium pricing. The deal between governments paid roughly two-thirds based on enrichment content and one-third on the value of the basic uranium (the "feed"). The U.S. government set a price in its agreement with Russia, but the timing of the payment was contingent on the use or sale of the uranium by USEC. The provision gave USEC great power over when the Russians could monetize this part of the value chain.

The tensions between public purpose and private profit reached a head in 1996, when USEC's

[72] Enrichment plants can extract more U-235 from a set amount of uranium feed by applying more SWUs to the ore, or reduce the energy needed per unit of U-235 produced by "overfeeding" the volume of natural uranium through the enrichment process. There is a trade-off between enrichment costs, energy costs, and the cost to buy the ore and manage the residuals.

Table 17. Global Enrichment Market Shares, 2008 Estimate

Entity	% Market Share (SWU basis)	Country/Ownership
U.S. Enrichment Corporation (USEC)	26.0%	United States/private
TENEX	26.0%	Russia/government
Urenco	25.0%	United Kingdom, Netherlands, Germany/mostly government
Eurodif/Areva	21.0%	France, Iran, Spain, Italy/mostly government
Japan Nuclear Fuel Ltd. (JNFL)	1.0%	Japan/private consortium of users
China National Nuclear Corp. (CNNC)	1.0%	China/government
Total	**100.0%**	

Sources: Elliot 2009; company websites.

IPO was almost scuttled because it turned down an offer to take additional HEU. Facing termination of the IPO, USEC did enter a five-year deal at the government-agreed price (Falkenrath 2000: 42–43).

5.2.3.3. Tariffs on Enriched Uranium

Most enrichment capacity in the world is government-owned (Table 17). Many of the customers using the enriched uranium are government-owned as well, making even the application of the term "market" to enrichment services problematic. Construction of enrichment capacity has substantial national security objectives, and sales of enrichment services support a variety of objectives other than profit maximization—such as continuation of the domestic enrichment enterprise, continued provision of services to satisfy military needs, and promotion of expansion abroad. As a result, all decisions in the enrichment area, including those related to price and perhaps even to tariff rulings, have political dimensions.

Such political concerns are evident, for example, in U.S. policy. John Longenecker, a former deputy assistant secretary for uranium enrichment at the DOE, testified that he was troubled to see, 25 years after his involvement with domestic enrichment, that the United States was "more highly dependent . . . on uranium enrichment services than we are on crude oil. We actually import more of our uranium enrichment services for nuclear fuel than we do crude oil. The USEC market share of the world market is substantially less, almost half of what it was 20 years ago" (Longenecker 2007: 33).

As of 2007, 92 percent of the uranium used in U.S. reactors was imported, and foreign suppliers provided roughly 40 percent of the fuel conversion services (Squassoni 2009b, Bonnar 2008).

The ownership of some of these entities can be surprising. While the role of Techsnabexport (TENEX) as Russia's state-controlled uranium supplier and provider of uranium enrichment services is expected (RIA Novosti 2006), Iran's continued significant ownership share in Eurodif is perhaps less so. Eurodif remains mostly government-owned today, with current ownership shares as follows: 44.65 percent Areva NC S.A. (100-percent owned by AREVA S.A., which in turn is more than 90 percent owned by the French government); 25 percent Sofidif (60 percent owned by Areva NC and 40 percent by the Iranian Atomic Energy Organization); 11.11 percent Synatom (ultimately owned by GDF Suez, which is 36 percent owned by the French government); 11.11 percent Enusa (government of Spain); and 8.13 percent Enea (the Italian national oil company) (GDFSuez 2009; Schneider 2009; Eskow et al. 2007).

USEC faced significant competitive challenges post-privatization. Not only did the historical subsidies to the enterprise fade, but its technology was aging and more expensive than that of the competition and the firm was quickly losing market share. Successful prosecution of trade cases has helped USEC to stabilize its position. May 1992 brought a 115 percent duty on uranium imports from the former Soviet Union, including on any enrichment portion. This action primarily affected TENEX. The U.S. Department of Commerce did exempt the HEU shipments covered under the bilateral U.S.-Russian agreement from this case, but it then ignored that exemption (Falkenrath 2000: 46). In 2006, TENEX filed a lawsuit against the Commerce Department for the anti-dumping duties. It noted that restrictions on imports of Russian LEU "have been in force since the Soviet era" (RIA Novosti 2006), and had been harming it commercially. The case is another example of the interaction between power and nonproliferation goals. Afraid that an open market for Russian LEU would prove a more profitable use of Russia's enrichment capacity than would down-blending its HEU, thereby weakening nonproliferation goals, the DOE supported continued restrictions on the import of Russian LEU (Tobey 2008). But an agreement finalized in 2008 relaxed these restrictions, setting quantitative caps on allowable imports beginning in 2011. The allowed limits remain low through 2013 (when the HEU agreement expires), then grow tenfold in 2014 (ITA 2008). In May 2009, TENEX signed a $1 billion deal to supply enrichment services to U.S. utilities. More such deals are expected (STRATFOR 2009).

In 2001, the International Trade Commission (ITC) ruled that USEC's other two main competitors, Eurodif and Urenco, also subsidized LEU exports and that these subsidies harmed USEC. The ITC levied a 34 percent duty on Eurodif exports to the United States and a 2.23 percent duty on Urenco. The tariff differential reflected the degree to which the firms were judged to underprice enrichment services in the U.S. market. Mark Elliot, general manager of marketing at Urenco, said that USEC "accused Urenco of receiving state subsidies in the '70s and '80s and the ITC established that we were innocent of most accusations, but had not fully repaid a small number of subsidies according to their rules" (Armbruster 2002). Clearly UEE, USEC's predecessor, was also quite heavily subsidized during that same period—another indication that price signals in the global enrichment market were murky.

The ITC also found that Électricité de France, a large French utility primarily owned by the French government, bought Eurodif's uranium at 13 percent above market prices, generating excess revenues that Eurodif could deploy to undercut USEC enrichment pricing in U.S. markets by nearly 20 percent (Armbruster 2002). The ruling was overturned in 2005, not because there were no subsidies but rather on the technical grounds that enrichment was a service, not a product, and therefore not subject to U.S. anti-dumping laws. The U.S. Supreme Court rejected this interpretation in January 2009 in a unanimous decision, noting that contractual terms were not sufficient justification to bypass trade law. As a result, the tariff on French imports stands (Stuckle 2009).

It is clear that U.S. enrichment services have historically been subsidized, and that the main foreign consortia have been subsidized as well. The trade cases are likely accurate in picking up these distortions, though perhaps not in an even-handed way, given U.S. government involvement in the sector. In the short term, even USEC notes that a removal of tariffs on foreign producers would "result in a sharp decline in market prices," though it attributes the decline to "unfairly low" prices that the French producers would offer (Sewell 2007: 29, 32). Sewell also argues that domestic enrichment capacity is a national security issue and that the closure of the USEC plant would put "this nation's energy security at risk" (Sewell 2007: 29).

Though the interplay of these various government forces is impossible to gauge precisely, a number of trends can be discerned. First, it is likely that aggregate production capacity for enrichment services is higher than it would otherwise be, as uneconomic production capacity is retained in the market on national security grounds. Second, it is also likely that, on average, the cost per SWU is lower than it would have otherwise been, due to a combination of overcapacity and construction and operating subsidies. This trend includes improper pricing of risk in the cost of capital deployed in the enrichment sector, underaccrual of capital for D&D, and inadequate internalization of accident liability. Third, through artificially low SWU prices these subsidies affect reactors around the world, not just in the United States.

Recent developments suggest new front-end facilities will benefit from the same degree of capital subsidization, as the DOE has said it will make $4 billion in loan guarantee authority to new enrichment technology. Much building is currently planned for the U.S. market, and government support appears inevitable for USEC's plans to replace its current high-cost technology with lower-cost technology, despite the fact that the firm has been experiencing rapid cost escalation: a $3.5 billion estimate at the end of 2008 was "double the original estimate five years ago and $1.2 billion more than just a year earlier" (Kinney 2008). Although USEC's application for a $2 billion loan guarantee on its new centrifuge facility in Piketon, OH, was rejected by the DOE, USEC and the DOE later announced an agreement to delay a final loan guarantee application until 2010. USEC updated and resubmitted its loan guarantee application in July 2010 (USEC 2010).[73]

In addition to the Piketon plant, Louisiana Energy Services, a subsidiary of Urenco, is building the National Enrichment Facility in Eunice, NM. Areva Enrichment Services has proposed the Eagle Rock Enrichment Facility near Idaho Falls, ID. Together, these plants would bring online more than 16 million SWUs of capacity by 2012 or 2013. The GE-Hitachi enrichment plant in Wilmington, NC, would add another 3.5 million to 6 million, making the new U.S. capacity as high as 22 million SWUs—or almost 29 million SWUs, including the existing USEC facility in Paducah (STRATFOR 2009). In May 2010, the DOE awarded Areva a $2 billion loan guarantee for the Idaho plant, while neither GE-Hitachi nor Urenco had filed for loan guarantees for front-end facilities at the time this report was finalized.

Total global SWU production in 2007 was only 46 million (Vance 2009: 7). Thus, if the surge in new reactors does not materialize, enrichment facilities could come under pricing pressure over the next five years or so. Enrichment market projections by Urenco (Elliot 2009: 10) indicate that an excess of enrichment capacity is anticipated both in 2010 and 2015. In capital-intensive industries, supply gluts normally cause prices to fall to

[73] USEC 2010. USEC, Inc. News Release: USEC submits update to loan guarantee application, August 3, 2010. *http://www.usec.com/NewsRoom/NewsReleases/USECInc/2010/2010-08-03-USEC-Submits-Update-To.htm*, accessed 13 August 2010.

short-term break-even rates that are just enough to pay operating costs.[74] If glut conditions persist, capital providers will lose out; for at least some of these facilities, that would mean taxpayers.

5.2.4. Enrichment and Proliferation

Enrichment and reprocessing facilities represent the most serious risk of weapons proliferation resulting from civilian nuclear power. The enrichment process "is essentially the same whether the end product is reactor fuel or nuclear weapons"—one reason why governments have historically owned the capability (Falkenrath 2000: 36). Reprocessing is essentially the same for both purposes as well, although the quality of the plutonium extracted at the end of the process varies, depending on whether commercial power-plant fuel is separated or the spent fuel is more lightly irradiated (as occurs in a research or production reactor). At present, U.S. expenditures on reprocessing are fairly modest, though the idea remains active; recent energy legislation has contained elements that promote reprocessing (Boyd 2009). Historically, however, reprocessing was a significant component of the U.S. nuclear research budget, with billions spent on technology development efforts such as the Clinch River Breeder Reactor or on cleaning up research sites such as the West Valley facility in New York.

With noncontroversial products such as toothpaste, cost cutting is mostly a positive thing: reduced production costs simply mean lower-priced tubes for everyone. The situation is quite different with uranium enrichment. Smaller-scale enrichment technologies, lower enrichment costs, or both, can degrade governments' ability to prevent, slow, or even detect the production and proliferation of weapons-grade material. Thus a push to build new and artificially lower-cost enrichment capacity via government subsidies—in order to supply an array of new reactors that are being built because of government subsidies—makes no sense.

5.3. SUBSIDIES TO COOLING WATER USED AT NUCLEAR PLANTS

Water for cooling is a critical input to all thermal energy technologies, especially for many of the older plants that rely on "open-loop" or "once-through" cooling systems. Thus the power sector—including nuclear—is a major water user. In 2000, for example, thermoelectric power generation was responsible for 39 percent of all freshwater withdrawals in the United States, comparable in scale to the total amount of water used for irrigated agriculture (DOE 2006: 9). In France, thermal power plants accounted for 55 percent of all freshwater withdrawals in 2002, four times the quantity consumed in agriculture and roughly 10 percent of all precipitation (IFEN 2005). Based on DOE consumption data in Table 18, a single 1,000 MW open-loop reactor with a 90 percent capacity factor will withdraw between 540 million and 1.4 billion gallons *per day*.

The large quantities of water used in the nuclear power sector are driven by the reliance on once-through cooling systems. While most of the water is returned to streams rather than consumed, the return flows are generally hotter and more contaminated than the intake. In addition, the intake process often harms wildlife, as does the interruption of stream flows. Gunter et al. (2001) found that 47 percent of reactors used once-through cooling alone, with another 10 percent using once-through plus a cooling tower. Thirty-two percent of the reactors relied only on cooling towers, and 11 percent used a cooling pond or reservoir.

74 USEC notes this risk in its 2008 annual report: "Decisions made by our foreign competitors may be influenced by political or domestic policy rather than by commercial considerations. For example, our foreign competitors may elect to increase their production or export of LEU, even when not justified by market conditions, thereby depressing prices and reducing demand for our LEU, which could adversely affect our revenues, cash flows, and results of operations" (USEC 2009: 38).

Table 18. Comparative Use of Water across Energy Technologies

Production Process	Energy Technology	Withdrawal, gals/MWh	Consumption, gals/MWh	Notes
				(1) (3) (4)
Mining, processing	Coal—conventional		5-74	
	Coal—slurry	110–230	30–70	
	Nuclear		**45-150**	(2)
Open-loop cooling	Fossil/biomass/waste	20,000–50,000	~300	(5)
	Nuclear	**25,000–60,000**	**~400**	**(5)**
	Natural gas CC	7,500–20,000	100	(5)
Closed-loop tower	Fossil/biomass/waste	300–600	300–480	
	Coal IGCC	~250	~200	
	Nuclear	**500–1,100**	**400–720**	
	Natural gas CC	~230	~180	
	Geothermal steam	~2,000	~1,400	
	Solar trough	760–920	760–920	
	Solar tower	~750	~750	
Closed-loop pond	Fossil/biomass/waste	500–600	~480	
	Nuclear	**800–1,100**	**~720**	
Evaporation from storage	Hydroelectricity		4,500	(6)

Source: DOE 2006.

Notes:

(1) Ignores small incremental water use associated with activities such as equipment washing and emissions treatment.

(2) Includes both mining and enrichment. A shift to centrifuge technologies for enrichment would cut the water intensity of this stage by 25 percent or more, as compared to gaseous diffusion (DOE 2006a: 56).

(3) Excludes dry-cooling technologies (which use zero water), as they apply only to wet and cool climates and have been deployed at less than 1 percent of U.S. plants, mostly smaller ones (DOE 2006a: 40).

(4) Figures should be taken as indicative, as many of the sources relied on by the DOE are more than a decade old.

(5) The consumption associated with open-loop cooling systems is primarily linked to increased downstream evaporation, which is associated with higher water-return temperatures (DOE 2006a: 65).

(6) All water bodies have evaporation issues; it is not clear whether the figure for hydroelectric water consumption includes baseline evaporation or not.

The historical preference for once-through cooling in nuclear reactors was influenced by its relatively low cost. Some newer plants have adopted more advanced closed-loop cooling systems, either because of insufficient nearby water resources or water regulations (which may restrict use to targeted volumes of water or limit the level of thermal loading in return feeds) (Lochbaum 2007: 6). Closed-loop facilities are also at lower risk of forced shutdown during droughts, a problem that is particularly challenging for nuclear reactors given their operators' desire to rarely shut down. In 2003, Électricité de France shut down one-quarter of its nuclear plants in France because of drought. Similar shutdowns were enforced in Michigan in 2006 and in the southeastern United States in 2007 (Morrison et al. 2009: 26; Public Citizen 2007). Despite the potential benefits, Boyd (2009) notes that none of the new proposed reactors are closed-loop. At least one, however, is wet-dry, which means that it is only dry when water levels are low.

Table 18 indicates that nuclear fission is among the most water-intensive energy technologies on a per-unit-of-energy-produced basis. Consumptive use is higher for uranium extraction than all other sources evaluated in the mining sector. For closed-loop plants with cooling towers, nuclear power's water intensity (use per kWh of energy produced) exceeded that of fossil-fuel power plants. Open-loop plants rank relatively low in terms of net consumption, but have the highest withdrawal rates of the technologies evaluated, with substantial environmental effects.

Water subsidies to reactors come from two main sources: plants that pay little or nothing for the water they use, and inadequate restraints or penalties regarding environmental damages that even the nonconsumptive use of water may cause. Associated damages can be significant; Lochbaum (2007) notes that Southern California's San Onofre plant entrained (i.e., killed) 3.5 million fish in 2003 alone. This was more than 30 times the number of fish affected by the 10 other plants in the same coastal region *combined*.

5.3.1. Cost of Cooling Water Used by Reactors

Data on the water consumption fees faced by nuclear reactors were difficult to obtain. But a variety of national water experts queried for this report suggested that utilities pay little or nothing for their use of cooling water (Gleick 2009; Hightower 2009; Mayer 2009). The experts' responses illuminate the multiple challenges in properly characterizing this issue.

First, because the permitting and fee decisions are typically made at the local level, they are likely to vary widely among reactors. Regional variation in water regimes also plays a role. For example, western states are governed by water rights (for which withdrawals up to those rights would be free to the rights owners), whereas eastern states apply permit limits (though withdrawals up to the specified levels also would generally be free) (Hightower 2009; Simpson 2009).

Second, the source of water affects the likelihood of fees being levied. Municipal withdrawals, though uncommon for cooling purposes, would pay fees; respondents noted a handful of cases where wastewater flows were utilized (Gleick 2009; Grigg 2009; Hightower 2009; Mayer 2009). Surface-water usage seems rarely to incur any fees at all. Charges that may exist—e.g., a capacity charge levied by the Susquehanna River Basin Commission (SRBC)—seem primarily set to cover regulatory expenses. Such charges do not appear to be conventional consumption charges. Withdrawal rights may be grandfathered as well if industrial uses predated the local or regional-river-basin regulatory authorities. In some cases, these grandfathered water-usage rights seem to be automatically endowed on new owners (Epstein 2008: 8). Consumptive use of groundwater seems more likely to incur fees, though respondents thought the rates would be well below market value (Simpson 2009).

Third, as with electric power, there is more to the accurate pricing of water withdrawals than raw quantity. Higher fees during periods of scarcity, or when users exceed permitted withdrawal rights or violate quality restrictions (e.g., thermal loading) on returns, would be important elements of accurate price signaling. Respondents were unable to identify situations where these types of charges have been in place.

Fees within the Susquehanna River Basin are illustrative. Consumptive withdrawal has been a problem, as has been the assurance of water adequacy during low-flow periods. The SRBC has addressed the challenge with what it calls a "consumptive use fee," originally at 14 cents per

1,000 gallons, scheduled to double in January 2010 (Dagan 2008, Dehoff 2009).

The fee is hardly a strong impetus for behavioral change; at current rates it brings in only $1 million from all users of the entire river basin (Dagan 2008). Further, it can be waived by providing water storage to assist the SRBC in meeting demand during low-flow periods. All three nuclear reactors in the basin have chosen this option, and as a result they incur no consumption fees for cooling water. PPL Electric Utilities, the operator of two reactors within the SRBC, is permitted to withdraw up to 66 million gallons of surface water per day from the Susquehanna River and up to 125,000 gallons per day of groundwater (Jones 2007). An estimated 30 million gallons per day are used consumptively at PPL's Susquehanna Steam Electric Station (Epstein 2008: 9). Absent the firm's fee waivers, this reactor alone would pay $3 million per year in water charges at the January 2010 rates.

Given the waivers, however, it is clear that the SRBC's fee is more of a capacity charge than a conventional usage fee. The fee is not levied on nonconsumptive withdrawals, and it does not vary by flow levels or water-return condition. The rate is instead based on the SRBC's cost of developing storage on behalf of two of the three nuclear power plants in the region (Dehoff 2009); it has no bearing on the market value of the services or resources provided. While the SRBC can levy penalties for exceeding permit limits, they are not integrated into the fee structure.[75]

A related issue is how to manage water scarcity in a system for which there is no pricing scheme. This issue was tested in October 2008, when construction resulted in low flows to the Susquehanna River. With insufficient flows for all users, the SRBC administratively cut flows to fossil-fuel plants in order to ensure adequate cooling water for the Three Mile Island nuclear reactor (Dagan 2008). But generally there is no indication that the reactors pay a higher fee for senior water rights. In fact, within Pennsylvania, nuclear power plants are exempt from drought restrictions (Epstein 2008).

The value of these water subsidies can be estimated in two ways. First, pricing comparables both on the consumptive and nonconsumptive uses of surface water can be obtained and applied to flows within the nuclear sector.

Second, water subsidies can be based on the recognition that if water were not free, reactors would not have been built with open-loop cooling. This observation suggests that the cost difference between open-loop cooling and cooling towers could provide a lower-bound estimate of the value of water subsidies. It is a lower bound because the value of the water consumed may be well in excess of the cost of reducing it; and also because even with cooling towers, consumption would remain well above zero, generating subsidies on residual consumption. Nonetheless, the EPA's estimate of the cost to convert all open-loop thermal plants to closed-cycle cooling, developed in the course of rule-making to regulate plant cooling water, was approximately $2.7 billion to $3.5 billion per year (Vicini 2009; EPA 2002). The nuclear share of this cost was $600 million to $700 million per year, or $12 million to $14 million per year for each of the 48 nuclear units relying entirely on once-through cooling (0.16 to 0.18 ¢/kWh). Due to the greater flexibility on capital deployment for new reactors, we assume the water subsidy for new reactors to be only half the current rate, or 0.08 to 0.09 ¢/kWh.

Given that the EPA rejected this conversion option as being too expensive, the cost-benefit analysis implicitly values the reduced withdrawals, and their ancillary ecosystem effects, at only 4.3 cents per 1,000 gallons.

75 For example, PPL was fined $500,000 in 2001 for water consumption above the levels authorized by the SRBC (Jones 2007).

Table 19. Subsidies Affecting the Cost of Intermediate Inputs (Overview)

		Subsidies to Existing Reactors, ¢/kWh							Subsidies to New Reactors, ¢/kWh					Notes
		Total	Legacy		Existing: Low		Existing: High		Total	Low		High		
Subsidy Type			Low	High	IOU	POU	IOU	POU		IOU	POU	IOU	POU	
A. Uranium Mining and Milling	Percentage depletion	~$25m/year							Expected to continue					(1)
	Inadequate royalties for mining on U.S. public lands	~$5m–$20m/year based on historical production levels							Expected to continue					(2)
	Inadequate bonding, high legacy costs	Known portion ~$2.1b covered by taxpayers			0.13		0.32		Expected to continue	0.13	0.13	0.32	0.32	(3)
B. Uranium Enrichment	Below-market pricing of enrichment services	$4.0b–$11.3b civilian portion, during gov't ownership of enrichment	0.08	0.22					Increasing role of foreign governments; subsidy unknown					(4)
	Unfunded legacy costs for environmental remediation	$130m/yr taxpayer subsidies associated w/legacy costs attributed to enrichment sales to foreign reactors	0.02	0.02										(5)
	Tariffs on enriched uranium													(6)
	Loan guarantees								$4 billion LGs authorized					(7)
C. Cooling Water	Free or subsidized use of cooling water	$0.6b–$0.7b/yr			0.16	0.16	0.18	0.18	Expected to continue	0.08	0.08	0.09	0.09	(8)
Total			0.10	0.24	0.29	0.16	0.51	0.18		0.21	0.21	0.42	0.42	

Notes:

(1) Small. Availability will scale with fuel demand as more reactors are built.

(2) Small. Subsidies will rise with levels of domestic mining activity.

(3) Assumes continued under-bonding; environmental concerns with extraction methods are generating current liabilities similar to the portion of historical ones quantified.

(4) Estimates of historical underpricing at UEE, not continuing subsidies to existing reactors.

(5) Assumes fees on domestic producers remain in effect to cover cost overruns rather than being allowed to expire. Ongoing subsidies to legacy production represent the share of remediation associated with enrichment services sold to foreign reactors.

(6) At present, border protection drives LEU prices up, but global prices are lower than they would be without government ownership. Net impact is indeterminate.

(7) In May 2010, the DOE announced it would double the available loan guarantees to uranium enrichment facilities from $2 billion to $4 billion. *www.lgprogram.energy.gov/press/052010.pdf.*

(8) Based on EPA-estimated cost to add cooling towers to reactors using once-through cooling; unit subsidies are based on share of generation only at reactors with no cooling towers. New reactors are assumed to be half the cost.

Chapter 6

Subsidies to Nuclear Security and Risk Management

One of the great advantages of properly regulated market systems is that the expected risks associated with business activities get integrated into the prices of the goods and services produced. There is rarely only one way to meet any particular market demand (e.g., energy services), and integrating risk into pricing allows and encourages the market to migrate toward lower-risk supply chains whenever possible.

As discussed with respect to government loan guarantees for nuclear reactors, activities deemed to entail a high financial risk will pay a higher cost of capital. In all cases, this worsens their competitive standing relative to less-risky alternatives; in some cases, high capital costs may render them entirely uncompetitive. A similar process occurs with physical risks, and the signaling mechanism may also flow through the price of capital—or through the cost of risk syndication via mechanisms like insurance. This section discusses the four main areas of subsidy to nuclear security and risk management: caps on private liability for nuclear accidents via the Price-Anderson Act;[76] taxpayer funding of industry oversight functions provided by the NRC; inadequate requirements for plant security; and the acceleration of nuclear weapons proliferation via expansion of the civilian nuclear sector.

6.1. INSURANCE CAPS ON ACCIDENT LIABILITY

Nuclear power is not the only energy source receiving protection from accident risk through federal subsidies. Other examples include risk reduction from catastrophic dam failures, coal-mining accidents, and oil spills. Similar protections are being proposed for large-scale carbon capture and sequestration projects as well. However, the issue is particularly important for nuclear power; the industry itself acknowledges that commercial reactor development probably would not have occurred without the Price-Anderson Act's caps on private liability.[77]

Although the probability of a large nuclear accident within the United States is considered quite low, that risk is not zero. Further, the damages from even a moderate accident are potentially so enormous that they would likely bankrupt the firm involved. Costs resulting from a large release of radiation from a damaged nuclear reactor or spent-fuel pool at a U.S. facility could exceed $100 billion (Beyea, Lyman, and von Hippel 2004, cited in Lochbaum 2007).

Moreover, risks in the nuclear power industry are systemic. An accident in one place has ripple effects throughout the industry, given that many reactors rely on the same technologies, were built by the same contractors, or employ similar defenses (in the case of a terrorist attack). Even when systems and technologies are not overlapping, an accident anywhere raises public concern everywhere, and reactor oversight (and associated regulatory and remediation compliance costs) are likely to rise.

One economic response to this problem would be to include the price of risk of the entire nuclear fuel cycle into insurance contracts or other methods

---

[76] First implemented in 1957, the act establishes statutory limits on liability for accidents at nuclear reactors, contractors, transporters, and research and fuel-chain facilities.

[77] A group of nuclear contractors, for example, noted to the DOE that, "A lack of Price-Anderson protection would lessen competition by eliminating most, if not all, well-capitalized, competent bidders" (Energy Contractors Price-Anderson Group 1998: 9).

of syndicating risk, and let prices rise where they may. If insurance coverage were not available or only available at very high costs, innovative risk-management tools such as risk pooling (as is done under Price-Anderson) or catastrophe bonds could be developed. If even these tools proved to be inadequate or too expensive, markets would be directed toward alternative and less expensive ways to meet the demand for energy services.

Unfortunately, the political response to the problem of high risk in the nuclear industry has followed the opposite path. The statutory caps on the level of private accident insurance that the industry is required to carry under the Price-Anderson Act essentially dampen the impact of risk on the price of nuclear power, and they weaken the political and economic incentives to increase the level of private insurance coverage.

6.1.1. Overview of Price-Anderson

As noted with many of the credit subsidies, policies such as liability caps do not actually reduce the risks of a particular activity. At best, they *shift* the risks from operators and investors onto taxpayers and surrounding populations. At worst, poorly structured liability subsidies may actually increase the risks of an accident because they eliminate important third-party monitoring and pricing signals that voluntary risk-bearing agents such as insurers can provide through site audits, premium setting, and policy renewal decisions.

The Price-Anderson Act was first passed in 1957 to address what was supposed to have been a temporary shortfall in the availability of private coverage for nuclear accidents. In reality, the act has repeatedly been renewed, most recently in 2005. There is little evidence that the industry favors shouldering its own risks in the future either: a group of nuclear industry executives in 2004 listed extension of the liability cap as imperative for continued growth of the industry.[78] Consequently, any nuclear facility built while any iteration of Price-Anderson was in force is now covered for its entire operating life, even if the act is not renewed. The latest renewal extended liability cap protections to any new eligible facilities that come online or under contract prior to the end of 2025.

While evaluations of Price-Anderson normally focus on its impact on reactor economics, the act actually covers every party involved in the nuclear power market, albeit at different levels. Table 20 shows that some segments have much weaker protections than others. Of particular note is the lack of standardized coverage guidelines for enrichment facilities. While this may not have been an issue in 1957 when the federal government ran all enrichment sites, it takes on additional importance now that USEC has been privatized and four additional consortia (which include foreign partners) propose to build new sites in the United States. Ironically, these uneven levels of protection may also be a source of incremental subsidy to enrichment facilities. For example, USEC is indemnified by the DOE and does not need to purchase any of its own insurance for third-party liability.[79]

6.1.2. Mandated Liability Coverage Is Small Relative to Potential Damages

Price-Anderson mandates two tiers of coverage for nuclear reactors. The first is a conventional liability insurance policy that provides $375 million in primary coverage per reactor. As of 2008 (with somewhat lower coverage levels than now in effect), the average annual premium for a single-unit reactor site was $400,000; the premiums for a

[78] The DOE's "Decision-Maker's Forum on a Unified Strategy for Nuclear Energy" listed Price-Anderson at imperative 2. They noted that, "The guarantees of reason supplied by Price-Anderson are especially necessary if we are to see a continuing renaissance of nuclear power in the United States that includes the construction of new generation reactors. The technical, financial, and social uncertainties of investing in next generation power plants can be reduced appreciably if Congress acts to renew Price-Anderson" (INEL 2004).

[79] The USEC Privatization Act (PL 104-134) gives USEC a perpetual lease to the enrichment facility rather than selling it to the company outright. Section 3107(f) reads, "Any lease executed between the Secretary and the Corporation or the private corporation, and any extension or renewal thereof, under this section shall be deemed to be a contract for purposes of section 170d of the Atomic Energy Act of 1954 (42 U.S.C. 2210[d])."

Table 20. Statutory Requirements by Market Segment for Third-Party Liability Coverage, per Operating Unit or Contractor

Market Segment	Primary Coverage	Retrospective Premiums	Potential Issues
Reactors and transporters	$375m	» $117.5m (5% covers legal only, not compensation) » Maximum $17.5m payment/yr » Lower for small reactors	» Delays in fund availability » Default on multiyear payments » Total fund shortfalls » Coverage gaps (spent fuel or waste at interim storage sites; transport if not to or from a reactor; theft or sabotage) » Fragmented responsibility for allocating compensation fund[80]
Enrichment facilities	Coverage not mandated by Price-Anderson	None required	» Facility-specific requirements deemed acceptable by NRC » USEC indemnified by DOE[81]
Nuclear fuel fabricators	$200m	None required	
Uranium mine and mill sites	Some coverage for extraction under Price-Anderson[82]		
DOE contractors	None	$12b total coverage	DOE can sue for negligence
Private research reactors	As set by the NRC, with federal indemnity up to $500m above that limit	None	
University research reactors	$250k self-insurance	$500m/unit DOE coverage	DOE coverage may exclude damage to university property

Sources: ANI 2010; Carroll 2009; Holt 2010.

second or third reactor at the same site are discounted to reflect a sharing of limits (NRC 2008a). While coverage has increased incrementally over time, these increases are small: on an inflation-adjusted basis, coverage is less than 10 percent higher than the $60 million in primary insurance required under the original act 50 years ago. The lack of useful actuarial data may have justified lower-than-appropriate limits in the 1950s. However, improved data since that time, as well as the greater sophistication of insurance underwriting, should result in primary insurance policies that are substantially larger than today's Price-Anderson requirements.

A second tier of coverage under Price-Anderson involves retrospective premiums paid into a common pool by *every* reactor if *any* reactor in the country experiences an accident with damages exceeding the primary insurance cap. The retrospective premiums have a gross value of $111.9 million available for damages, with an optional 5 percent surcharge available for legal costs only (bringing the combined total to $117.5 million) (ANI 2010, Holt 2010). Retrospective premium payments are capped at $17.5 million per year per reactor and thus can take seven years or more to be paid in full. Some additional coverage is available via the Stafford Disaster Relief and Emergency Assistance Act: if the president declares a nuclear accident an emergency or major disaster, disaster relief could flow to first responders. Stafford Act funds would also come from taxpayers, and thus would be subsidies as well.

[80] Carroll 2009.

[81] Donald Hatcher, director of risk management at USEC, noted in 1998 comments to the DOE that the "continued applicability of the Price-Anderson indemnification after privatization ensures the public that privatization will not diminish the ongoing responsibility of the U.S. government for nuclear incidents at the DOE plants" (Hatcher 1998). Having the government rather than the site operator shoulder the liability for accidents may, however, weaken the incentives to site-owner USEC to invest in appropriate risk management.

[82] Carroll (2009) notes that Kerr-McGee Corp. v. Farley, 115 F 3d 1498 (10th Cir. 1997) brings extraction under Price-Anderson by pre-empting state suits for injuries arising from uranium mining and processing.

Table 21. Price-Anderson Insurance Coverage in the Event of an Accident at a Nuclear Reactor

	Nominal	Present Value	Notes
Total payments from affected reactor to off-site parties			
Primary insurance, $millions	$ 375.0	$ 375.0	(1)
Retrospective premiums, $millions	$ 117.5	$ 77.7	(2) (3)
Total liability	$ 492.5	$ 452.7	
Additional resources from other reactors (retrospective premiums)			
Retrospective premiums, $millions	$ 12,219.5	$ 8,080.0	
Total available to off-site parties	**$ 12,712.0**	**$ 8,532.7**	
Adequacy of coverage—accident scenario at Calvert Cliffs 3			
Balt/WDC MSA 2000 population, millions		7.6	(4)
Total insurance coverage, $/person in Balt/WDC MSA		$ 1,123	(5)
Total coverage provided by single unit under Price-Anderson requirements, $/person		$ 60	(5)

Notes:

(1) Price-Anderson coverage requirements were last revised in January 2010 (ANI 2010).

(2) Retrospective premiums are capped at $17.5m/year, so each reactor will need more than six years of payments to fully pay its amount due. Calculations assume 105 reactors, 104 currently in operation plus Calvert Cliffs 3. Statutory retrospective premiums of $111.9m/reactor can have a 5 percent surcharge levied (for legal costs only), raising the total to $117.5m/reactor.

(3) Multiyear payments have essentially been discounted at 12 percent. This reflects UniStar (the developer of the Calvert Cliffs 3 project) financing assumptions of 50 percent debt at 12 percent and 50 percent equity at 18 percent, less a 3 percent assumed inflation rate.

(4) Bureau of the Census. 2001. Ranking tables for metropolitan areas: 1990 and 2000. Online at *www.census.gov/population/www/cen2000/briefs/phc-t3/tables/tab03.txt*, accessed January 13, 2010.

(5) Aggregate coverage available per person before the Price-Anderson cap is reached, plus Calvert Cliffs 3 portion of that coverage per person in the surrounding region.

Source: Koplow 2009b updated for January 2010 coverage changes.

As shown in Table 21, retrospective premiums provide the vast majority (nearly 95 percent) of available coverage for any nuclear accident.

At present, the U.S. system provides the largest pool of coverage for a nuclear accident of any country in the world.[83] However, this distinction may be more of an indication of the severity of coverage shortfalls in other countries than a tribute to U.S. rules and regulations. In terms of gross value, the available funds for U.S. compensation are well in excess of $12 billion; however, the funding drops to roughly $8.5 billion on a net-present-value basis. While the present value of available coverage is not usually discussed by the industry when outlining provisions for an accident scenario, it is a more appropriate metric given the seven-year lag between an accident and final retrospective-premium payments. In reality, both U.S. and global storm events have exceeded this level of damage, an indication that the limits likely would not be sufficient for nuclear accidents.[84] While the pool of available coverage has grown over the past 50 years,

83 Regarding the conventions governing third-party liability for European reactors, for example, even the newer conventions that are not yet in force provide a maximum of $1.1 billion in coverage for which the nuclear operator (rather than the state) is liable (Faure and van den Borre 2008: 239).

84 Even ignoring the facts that not all storm damage is insured and that Insurance Information Institute figures do not include publicly provided payments under the National Flood Insurance Program, six of the 10 most costly U.S. insurance catastrophes and all ten of the worst global ones (all since 1991) have exceeded the available aggregate coverage (on a present-value basis) that Price-Anderson provides for reactors (Insurance Information Institute 2010).

that period has also seen sharp increases in the populations that could be affected by an accident, in the value of real estate and infrastructure within potentially affected areas, and in court recognition (via jury awards) of ancillary damage—such as environmental damages and lost wages for injured workers—from accidents.[85]

A simple evaluation of coverage per person, should an accident occur at a reactor located close to a population center, helps to illustrate this point. Table 21 uses as an example a reactor at Calvert Cliffs, located near Washington, DC, and Baltimore, MD. Available coverage, including pooled premiums from all other reactors (as stipulated under Price-Anderson), barely tops $1,100 per person in the Baltimore/Washington combined statistical area. This small amount would need to cover not only loss of property from an accident but also morbidity or mortality. The portion paid by Calvert Cliffs to cover the off-site accident risk from its own operations (Tier 1 coverage plus its share of Tier 2) would be a mere $60 per person affected. While the extent of the injuries would vary with the specifics of an accident, the weather at the time, and patterns of local settlement and construction, for a metropolitan area of this size it is clear that the coverage provided by Price-Anderson is not large.

6.1.3. Structural Problems with Price-Anderson Reduce Quality and Quantity of Coverage

Price-Anderson coverage for the reactor segment of the fuel cycle is more stringent than for other fuel-cycle participants and facilities, with larger pools to pay damages and greater private responsibility for coverage. Yet even in this segment the coverage suffers from important structural problems, as outlined below. These limitations suggest that actual collections in a real accident would be lower than the cap and that covered events could be narrower. Both factors would reduce the already insufficient resources available to pay for damages.

- **Retrospective-premium payments may lag the need for funds**. Many accident scenarios would generate a surge of damages immediately. However, the retrospective premiums, being capped at $17.5 million per year, may be insufficient to meet the immediate need.[86]
- **The seven-year lag in payments increases risks of default**. Much can happen in seven years, especially given the systemic risks and worsened operating margins that the nuclear sector would face after any major accident. Reliance on post-event funding paid over many years suggests that the likelihood of full funding is low. In addition, Price-Anderson actually allows these payments to be waived by DOE under certain circumstances of financial distress.[87]
- **Increasing concentration in reactor ownership exacerbates nonpayment risks**. Because retrospective premiums are due per reactor, the financial stresses on a single parent organization that owns many reactors will be multiplied if the sector sees an erosion of operating conditions. Strong industry consolidation in recent years has greatly concentrated this risk. As of February 2009, for example, a single firm (Exelon) was the sole owner of 12 reactors and a partial owner of seven more (NEI 2009a).

---

85 Kenneth Hall (Hall 1986: 173–174), an insurance manager for General Electric, commented on these trends at hearings for the 1986 Price-Anderson reauthorization: "The only real change, other than the effect of passage of time through inflationary periods, since the original passage of Price-Anderson has been the violent and revolutionary changes in our legal tort system, most of which have occurred over the last 10-year period. The changes have greatly increased the unpredictability of the probable dollar damages resulting from any major accident, whether it be nuclear or nonnuclear in nature, and make a system such as Price-Anderson only more essential for the period beyond 1987." Lempert (2009: 13) notes that a U.S. reactor accident similar to Chernobyl would likely have far higher damages "because of the higher property values that exist here, medical-care costs that are far greater than in Russia, and the high monetary value we place on negligently taken human lives or negligently caused cancers and serious injuries."

86 These amounts are adjusted for inflation every five years (Holt 2009: 18).

87 See 42 U.S.C. Section 2210(b)(2)(A). Assuming a company survives, the waivers accrue interest until paid only at the government's cost of funds. Because this cost is so much lower than that of a nuclear reactor, the law creates a financial incentive for reactors to delay payment of the retrospective premiums.

- **Ownership structure may increase nonpayment risks**. Reactors are increasingly owned by stand-alone limited liability corporations (LLCs), a form that allows tax-free pass-through of income to partners while also providing them with a limited liability not found in traditional partnership structures. A GAO assessment of reactor ownership structure in 2004 found that nearly 30 percent of all reactors were owned by stand-alone LLCs, though the present share is likely much higher. The GAO did not think this ownership structure was a concern, as American Nuclear Insurers (ANI) requires letters of guarantee from parent firms that they would step in to cover any retrospective premiums that the LLC could not (GAO 2004: 1). However, while ANI "believes that the bond for payment of retrospective premiums is legally binding and obligates the licensee to pay in," this belief has not been tested in court (GAO 2004: 8).
- **ANI insurance does not protect against systemic defaults**. If a firm defaults on retrospective premiums, "NRC reserves the right to pay those premiums on behalf of the licensee and recover the amount of such premiums from the licensee" (GAO 2004: 8). The NRC applies these rules to any type of firm, including LLCs. However, with asset-poor LLCs, the ability to collect from parent companies—or from any unit if the sector is under distress following an accident—may be limited. ANI will cover defaulted payments, though only up to three defaults and only in the first year,[88] and ANI notes that, "Any additional defaults would reduce the amount available for retrospective premiums." ANI would try to collect what it had paid in from licensees later on (GAO 2004: 8), though this still means that only a small portion of the retrospective premiums owed would have been paid. Moreover, ANI, like the Securities Investor Protection Corporation (SIPC), could be exhausted by a single large event if multiple licensees were unable to pay.[89]
- **Interaction of Price-Anderson and Terror Risk Insurance Act is not clear**. Does Price-Anderson cover terrorist attacks? We have received differing interpretations from experts on this issue, and Congress or the NRC should clarify the underlying policy. The larger the range of events not covered under the premium-financed Price-Anderson program, the larger the resultant subsidy to the industry.[90]

6.1.4. Availability of Related Insurance Products Is Already Greater than the Supposed Maximums for Third-Party Damages

As noted above, primary insurance coverage levels have barely increased on a real-dollar basis in 50 years. The industry maintains that the underwriting capacity that would allow it to buy larger amounts of primary coverage does not exist. What is unclear, however, is whether this alleged lack of higher insurance levels is really a market structure issue or just an issue of price—whether with higher premiums the needed larger policies would emerge from marketplace insurance providers.

Evidence from related insurance markets suggests that the limitations may indeed be price-driven. This is because higher limits have emerged in a related market sector, involving the nuclear utilities' wish to protect *themselves* from risk rather than third parties. A new reactor at Calvert Cliffs,

88 At the time of the GAO report, this amounted to 3 x $10 million or $30 million. Presumably the coverage would now be capped at $52.5 million.

89 SIPC operates as a mutual insurance mechanism for the securities industry. If a financial institution or brokerage is shut down due to bankruptcy or any other reason, and securities are missing, SIPC steps in to replace them. Brokerage firms pay into SIPC's compensation fund, and all of them publicize SIPC coverage as an important protection for account holders. Coverage limits are $500,000 per account, with a maximum of $100,000 for cash deposits. However, the Bernard Madoff scandal, the first large claim to hit SIPC, risked bankrupting the compensation fund. The *New York Times* noted that among the 8,800 claims then filed, most had a valid right to the full $500,000 in coverage. "If all claims follow that pattern, the expense to SIPC for Madoff claims could approach $4.4 billion—a sum the taxpayers would have to cover if SIPC could not" (Henriques 2009).

90 Lempert (2009:15) notes that "even though the apparent risk of a nuclear reactor disaster increased dramatically after 9/11, feedback to those operating nuclear reactors through insurance-premium adjustments could not have been great, if it existed at all."

Table 22. Available Coverage for On-Site Damage and Business Interruption Is Far Higher than Industry-Stated Maximum for Third-Party Damages

	Coverage $millions
Calvert Cliffs 3 insurance for property and business operations*	
Property insurance	
Nuclear property	$ 500
Blanket excess	$ 2,300
Non-certified terror event**	$ 3,200
Accidental outage coverage	$ 490
Total available	**$ 6,490**
Ratio of insurance cover for on-site risks to required Price-Anderson coverage for all off-site damage	14.3

*Hypothetical coverage rates based on existing coverage for operating reactors.

**Certified terror events covered under other policies. Non-certified terror events covered by a shared $3.2b limit across properties per 12-month period. If only one incident, the entire amount would be available.

Source: Constellation Energy Group Form 10-K, for period ending December 31, 2009.

for example, must carry a total of only about $450 million (present value—see Table 21) in liability coverage for off-site damages under the Price-Anderson Act. This includes both Tier 1 insurance and Tier 2 retrospective premiums. In contrast, based on a review of financial filings with the Securities and Exchange Commission, Constellation Energy's insurance coverage for damage to its own property and interruption of service is more than 14 times as high, at more than $6 billion[91] (Table 22).

6.1.5. Subsidy Value of Price-Anderson Caps

Whenever statutory caps on liability are below reasonably expected damages, a subsidy has been conferred on the recipient. Quantitatively, this subsidy is equal to the premiums that would be required to purchase full coverage, less any premiums actually paid for the partial coverage under Price-Anderson. Valuing this amount is not easy, as it requires some data on the probability distribution both of accidents and damages. Heyes (2002) estimated the subsidy value at between 0.5 and 2.5 ¢/kWh. These values should be viewed as indicative rather than precise, however, as even Heyes believed that additional work was needed to develop more accurate values.

Meanwhile, much has changed in energy markets of late that could affect the subsidy value of Price-Anderson. The challenge is that these factors (summarized in Table 23, p. 84) are working in both directions, and without much additional research it is difficult to predict whether the net result would be higher or lower insurance subsidies to the nuclear sector.

The CBO's Falk also provides an estimate of the subsidy value of Price-Anderson caps. He pegs the subsidy at less than $600,000 per reactor-year (Falk 2008: 29) but provides little detail on the methodology used; thus an independent observer cannot say whether the assumptions behind such a

91 Based on Constellation Energy Group's Form 10-K filing with the U.S. Securities and Exchange Commission for the period ending December 31, 2009.

Table 23. Impact of Industry Changes on Price-Anderson Subsidy Values Is Difficult to Predict

Factors Suggesting Estimate Is Too High	Factors Suggesting Estimate Is Too Low
» Better management and efficiency from plant consolidation » Higher capacity factors reduce subsidy per kWh (and might reduce risk per kWh if the risk is associated more with unit capacity than with output) » Newer technologies may be safer » Increased internal spending on plant security post-9/11	» Non-reactor beneficiaries are excluded » Coverages for own property purchased by a single firm (e.g., Duke Power) exceed Price-Anderson cap for entire country » Real increase in reactor coverage of only 10 percent in 50 years » Large increase in density and value of off-site assets (real estate and people) » Risk of Tier 2 nonpayment arising from single-asset LLC structure, increasingly concentrated ownership patterns, and counter-party risks for ANI » Increased risk (or awareness of risk) of attack post-9/11

Source: Updated from Koplow 2005.

low number make sense. An examination of liability subsidies in France by Fiore estimates reactor subsidies at 3.3 million euro or less per reactor-year, translating into well below 0.1 ¢/kWh (Fiore 2008). Fiore provides more detail on the basis of the estimate than does Falk, enabling reviewers to suppose that accident probabilities are based on a reactor core meltdown, reduced by the likelihood that such an accident would be contained. It is not clear, however, whether the risk of different scenarios (e.g., an attack rather than an accidental release, or an event involving stored fuel) have been added to the accident risks. Similarly, the model evaluates damages above 10 billion euro, but there may be a gap in the modeled subsidy for lesser accidents that are still above internalized coverage levels. Finally, it would be helpful if timing issues and financial risks of nonpayment, even for this first tier of coverage, were included in the estimates.

The low estimates both from Falk and Fiore raise a key question. If the value of the liability caps are really so insignificant, why has the industry fought for more than half a century to retain the program? Fitch Ratings, for example, noted that the extension of Price-Anderson in 2005 "was vital to encouraging further nuclear investment" (Hornick and Kagan 2006: 6). Beyond the potential problems with estimating the liability subsidy, it may be that much of the value of the cap comes from reductions in the capital cost that investors are willing to take in order to lend to the sector. That is, even though nuclear capital costs are, and have historically been, high relative to other generating options, they would have been even higher in the absence of Price-Anderson.

For practical purposes, this study adopts a range estimate of 0.1 to 2.5 ¢/kWh for the value of the Price-Anderson subsidy ($800 million to billions per year). In the interest of improving this estimate, high-priority research items for the near term should include: more extensive updating and evaluation of the subsidy value of the liability cap, the financial security of payments mandated under existing liability rules, and the ability to use alternative risk-syndication tools to boost private responsibility for liability coverage. Subsidies related to liability caps are important not only in the United States but also in every other country with a civilian nuclear sector.

6.2. REGULATORY OVERSIGHT

One way to encourage sound management of activities that are perceived as potentially dangerous is through regulatory oversight. Regulations may constrain the behavior of private actors so as to achieve an outcome that is more aligned with social objectives or that helps avoid major damages to human health or the environment. In the case of energy, because not every resource entails the same complexity or risk, different fuel cycles may require dramatically different levels of oversight. Wind energy, for example, has no fuel that requires extraction. In contrast, coal mining disrupts the environment in a variety of ways and also causes injuries and fatalities to workers worldwide; therefore a complex oversight system exists in most developed countries to try to reduce these costs.

Normally, regulatory oversight is best provided by public, regional, or national government entities. However, to ensure that such oversight does not subsidize riskier forms of energy due to the high cost of regulating such enterprises, it is appropriate to finance the responsible agency through user fees rather than from general tax revenues. This approach is widely used in the United States and across divergent industries—from mining to pharmaceuticals. While user fees have been shown to be problematic at some federal agencies, this underscores the need to separate the issue of cost recovery from oversight, to prevent agency capture by the very industry it is supposed to regulate.

The nuclear industry in the United States is regulated by the NRC. Created by the Energy Reorganization Act of 1974, the NRC's mission is to ensure that civilian uses of nuclear materials are carried out in a manner protective of health, safety, environmental quality, and national security. In particular, the NRC regulates most aspects of civilian power plants, as well as the licensing of transporters and disposers of radioactive materials.

Oversight of nuclear reactors and related enterprises is expensive—the NRC's total budget now exceeds $1 billion per year—and with the surge of new reactor projects expected in the coming decade, the cost of NRC oversight will likely continue to rise. Prior to 1987, the general taxpayer paid the NRC's costs, with the exception of some licensing and inspection fees that were paid by beneficiary entities. Management Information Services, Inc., estimates that total expenditures to oversee the civilian nuclear industry by the NRC and its predecessor, the Atomic Energy Commission, have been $11 billion (after offsetting fees) since 1975 (MISI 2008: 14). This is equal to about 0.2 ¢/kWh generated during those years.

In 1987, federal law for the first time required that fees on regulated entities cover 33 percent of the NRC's expenses. At that point, the commission instituted annual fees on licensees to supplement its other revenue sources. Today, fees on licensees are expected to cover roughly 90 percent of the NRC budget. However, the NRC may first subtract "the amounts appropriated from the Nuclear Waste Fund (NWF), amounts appropriated for Waste Incidental to Reprocessing (WIR) activities, and amounts appropriated for generic homeland security activities" (NRC 2009a).

The remaining 10 percent not recovered by fees supports activities that either are judged not to provide a direct benefit to licensees—international assistance, for example—or in which the NRC has yielded authority to state governments for regulation of some nuclear activities, such as control over radioactive sources. Net appropriations for these exempt activities have been approximately $150 million per year in 2008 and 2009—roughly 16 percent of the NRC's total budget (NRC 2008b). Though not addressed in this report (NRC subsidies for operating and new reactors are estimated at zero), some of these activities may constitute subsidies to civilian nuclear power in general, even if they are not of direct benefit to individual licensees.

6.3. PLANT SECURITY

Security planners rarely theorize about a group of armed terrorists raiding a wind farm, blowing up the machines, and making off with key plant components. Replace "wind farm" with "nuclear reactor" and the scenario is part of national security planning throughout the world. From the perspective of protecting critical infrastructure, distinctions between energy resources are quite significant in this area. So too are the security resources (whether public or private) needed to protect them, although nuclear facilities are not the only energy-related concern.

What is clear is that the greater the consequences of a plant security breach, the more time and money the owners of such facilities should be required to spend on protecting against it. If nuclear reactor operators do not adequately design facilities, train staff, or secure infrastructure, their spending under the rubric of security may be too low. The associated savings may improve their competitive position relative to other energy resources, though at a cost of increased public risk. Similarly, if reactor owners are assisted in their security planning and operations by the U.S. military or other government agencies, this support provides a *de facto* subsidy to nuclear power vis-à-vis energy technologies that do not require or receive comparable levels of protection.

Nuclear power security is a contentious area, with the industry arguing that its facilities are well secured and its staff well trained, and opponents arguing that they are not. It is clear, however, that nuclear reactors are a target for many terrorist organizations, and that a successful attack could cause enormous damage. The benchmark for evaluating plant security is referred to as the "design basis threat" (DBT)—the scenario against which the NRC evaluates in-plant system security. Critics of the existing system have argued that:

- The NRC's evaluation of catastrophic accident risk relies on the assumption that multiple safety systems are unlikely to fail simultaneously. However, the NRC does not give comparable weight in its regulations and procedures to events in which deliberate damage rather than accident is the cause (Gronlund et al. 2007: 32), even though attackers could design attacks, using widely published information, to specifically cause such multiple failures.
- NRC regulations have historically included accident planning, but they did not mandate planning for attack or sabotage scenarios.[92] At present they still exclude terrorist attack scenarios from environmental impact studies and do not treat the risk of attack on a spent-fuel pool with appropriate seriousness (Gronlund et al. 2007: 32–33).
- The DBT prior to 9/11 was wholly inadequate, based on "three attackers, armed with nothing more sophisticated than handheld automatic rifles, and working with the help of a single 'passive' insider whose role was limited to providing information about the facility and its defenses" (Gronlund et al. 2007: 32–33).
- A 2003 update involved an increased number of attackers, an active but nonviolent insider, communications capability allowing attackers to hit more than one target at once, and use of a wider range of weapons. However, the DBT still excludes attacks from the air and is also believed to exclude rocket-propelled grenades (a common weapon in conflict zones worldwide).
- According to the GAO, the industry had pressed the NRC to remove attack characteristics it believed were too costly to defend against, and further that the NRC had based the DBT on a scenario that a private security force could handle, though without specifying any criteria for making that judgment (GAO 2006b: 10–11).
- Despite the weak standards, when the NRC ran mock DBT-level attacks pre-9/11, the reactors still failed about 50 percent of the time (Boyd 2009; Lyman 2009). Since 9/11, the

92 A draft rule that the NRC issued in May 2009 does address this objective to some extent (Lyman 2009).

> test program reportedly has improved, with an average 5 percent failure rate between 2004 and 2008 (Lyman 2009). However, details on these tests have been spotty, and have never been verified (Boyd 2009).

At present there is insufficient information to quantify cost savings associated with inadequate plant security, and thus this area should be the object of future research. Even if one assumes that security beyond the level of the DBT should be the responsibility of government, it is necessary to determine whether the DBT itself is politically, rather than technically, driven, and whether there should be a mechanism for recovering government security costs from plant owners. Meanwhile, governments have not stepped in to play this role; for instance, National Guard troops are no longer present at reactor perimeters.[93] This may change in the not-too-distant future, however, given that nuclear power requires a much higher level of government security than other forms of electric power generation. Public provision of this support, or allowing such support to go unprovided over the short term, both create an artificial operating advantage for the reactors.

6.4. NUCLEAR PROLIFERATION FROM THE CIVILIAN SECTOR

The spread of nuclear materials throughout the world is a major security concern—the link between nuclear power development and nuclear weapons proliferation is widely recognized—and a growing civilian nuclear sector makes the situation even worse.[94] The International Security Advisory Board of the U.S. Department of State agrees, noting that, "The rise in nuclear power worldwide, and particularly within Third World nations, inevitably increases the risks of proliferation" (ISAB 2008: 1). This risk is much greater if the chosen path for civilian nuclear involves enrichment or reprocessing capabilities, something that "represent[s] quite dangerous paths to proliferation that are not effectively addressed by current international law or treaties," according to the board (ISAB 2008: 3).

Subsidies to nuclear reactor technology exacerbate proliferation concerns both by boosting the "latent proliferation" risk and by increasing opportunities for illicit diversion.[95] Latent proliferation exists if a company does not actually build any weapons but establishes the capabilities to build them. Under a latent proliferation scenario, "a nation's nuclear power facilities give it the capability to quickly make nuclear weapons" (Gronlund et al. 2007). Nuclear proliferation expert Henry Sokolski notes that, "A large reactor program brings any nation quite a ways down the road to acquiring an option to build bombs" (Grossman 2008). If the diversion or theft of materials from the civilian sector cannot be detected quickly or at all, the latent proliferation concern from nuclear power expansion can become an active one.

Proliferation conduits involve far more than just physical infrastructure. The increased number of people trained in closely related fields and the ability of a country to mask purchases of suspect materials through civilian activities are just as important.

Given this power-to-weapons linkage, it is appropriate to assign associated incremental costs to nuclear power that too often are ignored or dismissed as an abstract military issue. Analytic approaches such as "activity-based costing" (ABC) can be helpful in evaluating the large expansions in nuclear reactors planned worldwide. ABC

93 After the attacks on the US September 11, 2001, at least seven states deployed national guard troops to secure nuclear reactor perimeters (Hebert 2001). In some cases, this continued for years. Patrols at the Indian Point reactor in New York did not end until November of 2008 (Associated Press 2008).

94 See Lovins et al. (1980) for an early exposition of this linkage.

95 Additional details can be found in Gilinsky et al. (2004).

recognizes that "general" administrative or oversight costs are in reality often linked to specific activities and program objectives. For example, if a harbor is fine for all ships desiring to use it other than oil tankers, and $100 million is invested in deepening channels so that oil tankers may be accommodated, this entire amount would be assigned to oil transport—not averaged across all users. If not for the large tanker, no harbor modifications would have been needed. This approach is commonly used in many industries in order to understand the economics of particular investments or lines of business.

It is clear that higher costs to nuclear power may result from increased monitoring requirements, greater military expenditures, or, theoretically, the damages from an attack (or credible threat thereof). While many of these costs are difficult to quantify, Sokolski notes it may be possible to quantify "the probability of failing to detect a military diversion" from a civilian program, as well as the costs of "improving the odds of detecting such diversions in a timely fashion" (Sokolski 2009).

From a policy planning perspective, the fact that civilian expansion is a major conduit to latent or real proliferation is enough to justify integrating its associated costs into the price of nuclear power. The civilian sector need not be the *only* source of proliferation to justify taking this approach. Structurally, the approach is similar to integrating carbon fees, designed to reduce the risks of global warming, into the cost of coal. Many energy costing scenarios now routinely model heat-trapping-emissions fees into the levelized costs of fossil energy, especially when comparing power options. Comparisons between the costs of nuclear and a coal plant that implements carbon capture and sequestration are starting to become more routine.

In contrast, the costs of nuclear proliferation have never been integrated into the levelized costs of nuclear energy. It may turn out that the costs are small, or that additional work is needed to quantify them. Regardless, they are an important component of the decision to subsidize massive expansion in the civilian sector and therefore need to be included in cost analyses.

However, moving from recognition of the linkage to actually quantifying the proliferation costs of nuclear power expansion is not easy. There are plausible arguments that the incremental proliferation risks of conventional reactors *within the United States* are fairly small, but if this country pursues subsidized reactor construction, many other nations may follow suit. The "low-incremental-risk" arguments work only in countries with a pre-existing base of fuel-cycle facilities, nuclear weapons, and strong oversight of both civilian and military sectors. Such arguments cannot be made for the promotion of reprocessing; for the construction of subsidized reactors or fuel-cycle facilities in countries lacking in governance, technical capabilities, or the rule of law; or for the export of technology that may enhance latent proliferation risks even from low-incremental-risk countries.

Large subsidies are clearly a main factor driving the renewed utility interest in nuclear power, both in the United States and Europe. Subsidies probably underlie much of the Asian investment as well, though transparency of government operations in Asia is not nearly as advanced as in some western nations. Along with the expected surge in reactors is a renewed interest in expanding enrichment capabilities and constructing new reprocessing plants. All three areas are capital-intensive production systems. Once they are built, operators are under immense pressure to utilize them heavily, perhaps resulting in questionable decisions regarding the exportation of resulting products or technologies.

6.4.1. International Atomic Energy Agency

A central element of the International Atomic Energy Agency's (IAEA's) mission is "to prevent civilian nuclear fuel facilities from being used for weapons purposes" (Holt 2009: 21). The IAEA is supported by regular contributions from member states (the United States normally provides about 25 percent of the budget), by voluntary contribution of funds, and by in-kind contributions of time and equipment. IAEA mission areas—including nuclear power, fuel cycle, and nuclear science; nuclear safety and security; and nuclear verification—have substantial expenses linked to civilian power. These elements account for roughly 55 percent of the IAEA's regular budget (IAEA 2008b) and the majority of expenditures funded by voluntary contributions (IAEA 2009a: 84).

Regular U.S. funding comes from the Department of State, while additional financial and in-kind contributions are made through the DOE's National Nuclear Security Administration (NNSA). In 2008, regular U.S. contributions totaled $94 million of a total IAEA budget of $390 million. Additional support via the NNSA included $51.8 million in voluntary financial contributions and $53 million in in-kind support (NNSA 2009). Based on the program mix above, at most $52 million of the regular budget and $50 million or so from the voluntary contributions were linked to promotion or oversight of international nuclear power. Given that the IAEA's "nuclear safety and security" and "nuclear verification" work areas appear to include some tasks related to nuclear-related activities outside the power sector (e.g., radiation detection at public events), we conservatively estimate the subsidy to the civilian power sector at roughly $50 million per year.

Table 24. Subsidies Affecting Security and Risk Management (Overview)

	Subsidies to Existing Reactors, ¢/kWh							Subsidies to New Reactors, ¢/kWh					Notes
	Total	Legacy		Existing: Low		Existing: High		Total	Low		High		
Subsidy Type		Low	High	IOU	POU	IOU	POU		IOU	POU	IOU	POU	
Price-Anderson cap on accident liability	$800m to billions per reactor			0.10	0.10	2.50	2.50	Expected to continue	0.10	0.10	2.50	2.50	(1)
Unfunded regulatory oversight	$11b since 1975 not covered by user fees	0.21	0.21					No longer occuring					(2)
Weak plant-security standards	Not quantified							Expected to continue					
Proliferation externalities	Not quantified							Expected to grow					
International Atomic Energy Agency	~$50m/year related to civilian activities							Expected to continue					(3)
Total		0.21	0.22	0.10	0.10	2.50	2.50		0.10	0.10	2.50	2.50	

Notes:

(1) Based on Fiore 2009 and Heyes 2002. Ignores nonreactor liabilities. The large range indicates a need for detailed reassessment of this issue.

(2) Assumes NRC fees cover all costs since 1991. Legacy costs are undercollections/kWh prior to 1991.

(3) Small. Costs are associated with foreign nuclear activities, though U.S. promotion of nuclear development abroad is one driver of foreign activity in the sector.

Chapter 7

Subsidies to Decommissioning and Waste Management

This section explores key federal subsidies affecting the waste management and post-closure management portions of the nuclear fuel cycle. Of particular importance are the subsidies to reactor decommissioning and the nationalization of waste management responsibilities.

7.1. SUBSIDIES FOR REACTOR DECOMMISSIONING

Many types of energy-related capital investments require end-of-life decommissioning, deconstruction, or site closure. These actions are typically expensive, yet cash outlays to cover them occur after the operating revenues have ceased. The requirement for large expenses at a time of business cessation creates a great risk to society of improper facility closure or outright abandonment.

Nuclear power is not the only energy source to be so challenged. Many dams, for example, have virtually no financial provisions for decommissioning. Oil and gas wells are frequently sold to smaller and smaller operators as production levels decline. With each ownership transfer, well-production levels (and associated revenues) decline while the time until payments are needed to plug wells comes closer, and the new owners are smaller and less financially able (Koplow and Martin 1998). What places nuclear in a separate category is the presence of a great deal of radioactivity within the reactor core and related components, a higher anticipated cost than these other sources, and the very long time frame during which nonoperating reactors may require site security and monitoring.

Decommissioning subsidies occur in two main ways. First, owners may inadequately accrue for proper shutdown, effectively shifting the costs to the taxpayer—especially if the owners go bankrupt or otherwise abandon the facilities. Second, governments provide subsidies to utilities for setting aside the needed funds, such as by taxing nuclear decommissioning trust (NDT) funds at a lower rate than other business operations.

Additional subsidies may be provided at the local level. Texas, for example, offers a taxpayer guarantee to NDTs for the first six new nuclear reactors in the state to commence construction by January 15, 2015. Because reactors have historically been high-cost electricity suppliers, if full capital recovery is included in rates, new plants in Texas face a fairly high risk of being "bypassed" in competitive markets (to the extent that prices for alternative electricity supplies remain lower). If this were to occur, power sales could be insufficient to fully accrue adequate decommissioning costs during operations. To address this risk, states often require lump-sum payments into NDTs for large portions of the expected cost. The Texas rule (PURA Section 39.206) allows a firm to provide financial assurance that it can fund 16 years of NDT contributions, after which it can use funds accrued in its NDT to pay for end-of-life costs. Avoiding up-front payments is a lower-cost option for the firm but a much higher risk to taxpayers. To address the risk of funding insufficiency in the case of default, the rule stipulates that a non-bypassable charge would be instituted on retail electric customers in the state (Duff & Phelps 2009b: 11). During deregulation, PUCs converted capital recovery on uncompetitive nuclear plants into mandatory charges for all PUC customers (see Section 3.1). Texas is effectively guaranteeing the same policy in advance of the first concrete being poured.

7.1.1. Funding Adequacy Remains Uncertain

The United States took important steps to address the problem of inadequate accrual for NDTs in the late 1980s. Prior to that time, few utilities made any provision to accrue for decommissioning at all (MacKerron 1989: 107), and whatever funds had accrued could be held inside the company as bookkeeping entries even while the actual cash was spent to cover other expenses. Thus there was no guarantee that the money would actually be there when needed. In 1988, the NRC promulgated rules that required such funds to be held in independent trusts. This rule-making addressed the most critical risk: to prevent decommissioning funds from being raided or lost in a bankruptcy. Comparable procedures have not been used in all countries. The United Kingdom, for example, accrued billions of pounds to decommission nuclear infrastructure. But poor financial controls resulted in much of the decommissioning funds being used to support operating expenses, and little remained for the intended purpose (Schneider et al. 2009: 83).

Although the use of external trusts solved one important risk of decommissioning funding, uncertainty remained as to whether reactor owners would have enough time to accrue the funds needed to finance the plant shutdown. Two issues drove these concerns. First, there was little actual experience with reactor decommissioning to guide cost estimates, and financial models were generating rapidly escalating values. Second, there was a well-founded concern, especially after deregulation, that the power produced by nuclear reactors was so expensive that many would need to shut down prior to the end of their license life, with accumulated trust funds falling well short of what would be needed to decommission them.[96]

Actual decommissioning costs for modern light-water reactors that have run for decades are still largely unknown. However, a number of other market shifts have reduced the risks of widespread shortfalls. First, stranded cost rules eliminated many of the capital recovery pressures for existing reactors, allowing them to remain operating in competitive markets. This write-off effectively lengthened by decades the time period over which the reactors would be able to accrue the needed funds. Second, higher capacity factors at these reactors brought down costs per kWh. Coupled with rising energy prices, operating margins at the reactors improved, consequently eliminating most discussions of premature closure. Third, NRC license extensions have been granted on a regular basis, extending the time frame—up to an additional 20 years—over which decommissioning funds can be accrued.[97]

Rule changes that allowed the trusts to invest in a diversified asset base, rather than just low-yielding credit instruments, also boosted the ability of portfolio growth to help fund decommissioning costs over the long term.[98] According to Duff & Phelps (an investment firm that invests on behalf of NDTs), equity constitutes the majority of NDT

96 A third potential risk comes from inadequate accruals by owners during the years in which a plant is operational. The GAO notes that federal licensees must only provide a "statement of intent" that decommissioning funds would be supplied when necessary (GAO 2003: 5). This does not seem to have been a problem, however, as real funding has taken place.

97 As of the end of June 2009, the NRC had granted license extensions for 54 of the 104 operating U.S. reactors.

98 At the inception of NDTs in 1984, allowable investments were restricted to treasuries, municipal bonds, and bank certificates of deposit. This policy was shifted to a "prudent investor" standard in 1993, likely to enable a higher rate of growth in assets. As of 2007, investor-owned utilities had a median equity allocation in their trust funds of 55 percent, while public power entities were normally restricted from investing in equities at all in their trust funds (Duff & Phelps 2008a: 4, 7). Although the recent market pullback has caused substantial reductions in the value of NDT assets, a broader mix of assets has historically boosted risk-adjusted portfolio growth rates over the long term.

holdings.[99] While equities tend to be more volatile, they have demonstrated a higher return over the long term than bonds or cash.

Much uncertainty remains, however. Short-term losses are one worry; NDTs lost more than 20 percent of their value between December 2007 and December 2008—a drop of more than $9 billion after new contributions (Duff & Phelps 2009b: 4). In June 2009, the NRC notified owners of 26 reactors (25 percent of the operating U.S. fleet) about decommissioning fund shortfalls. The deficits ranged from $12 million to $204 million (Burgdorfher 2009). Annual funding rates also were well down, at $562 million for 2008 versus $1 billion or more for 2001 to 2004. However, this shift may be due in part to license extensions that lengthen the period of accrual (Duff & Phelps 2009b: 4).

An analysis performed a few years ago by the GAO illustrates the difficulty of trying to assess funding adequacy for a highly uncertain cost many years in the future. The agency's survey of 222 individual utility trust funds and 99 utility owners (Williams 2007: 1052) was quite sensitive to asset performance assumptions. With pessimistic assumptions, 181 of 222 funds analyzed were below the benchmarked need.[100] With the most optimistic assumptions, only 18 were below the benchmark (Williams 2007: 1079).

The longer time frame for accrual of decommissioning funds and the general long-term upward trends in markets suggest that investment performance will return to historical norms that may be sustained over time. Indeed, the stabilization of capital markets during 2009 and 2010 support such a conclusion. Of greater concern, however, is whether the ultimate costs of decommissioning will be higher than current assumptions, resulting in shortfalls at a time when there is no opportunity to recover additional funds from ratepayers. There is much to suggest that there may be problems:

- **Decommissioning-cost assumptions are volatile year to year**. Data collected by Duff & Phelps show a worrying year-to-year volatility in the average estimated cost to decommission reactors as well as variation by type of owner. The average decommissioning cost per kWe for investor-owned reactors as of December 31, 2007 was $594, dropping to $550 a year later. For publicly owned reactors, the trend was the opposite, with average cost estimates rising from $470/kWe in 2007 to $510/kWe in 2008 (Duff & Phelps 2009a, 2007). While it is not possible to identify the causes of this variance, the shifts indicate that there is no consensus on costs and that other factors (e.g., available cash from operations) may influence assumptions about decommissioning.
- **Decommissioning-cost estimates continue to escalate well above the rate of inflation**. This trend has increased the target NDT accrual by more than $4.6 billion over the past two years alone (Gram and Bass 2009).
- **Investment gains from delaying decommissioning are offset by the loss of specific knowledge**. While a longer period to accrue funds for decommissioning—even in the post-closure period—has traditionally been considered a plus, Schneider notes that this assumption is not always valid. For example, "the benefit of radioactive decay in the case of delayed decommissioning is offset by the knowledge loss" about the facility and the skills needed to properly decommission it. Some countries, such as France, require immediate reactor decommissioning (Schneider 2009).

[99] The composition of NDT funds at present can be approximated based on a 60 percent share in the Standard & Poor's 500 and the remaining funds allocated similarly to Barclays Capital Aggregate Index (Duff and Phelps 2009b).

[100] The number of trust funds can exceed the number of reactors for two reasons. First, many reactors are fractionally owned, and each owner requires its own segregated trust fund. Second, the original legislation allowed for either a qualifying or a nonqualifying trust, and over time, one of each might exist for a given ownership position. Recent changes in the law have made trust-fund consolidation easier, thus reducing this problem.

Even assuming that utilities accurately predict the cost to decommission a facility, if the growth in NDT assets is slower than the rate of decommissioning-cost escalation, a shortfall will be likely. Between 1986 and 2008, the NRC's minimum cost estimates for decommissioning grew at a compound annual rate averaging 7.8 percent (Duff & Phelps 2009a). Assuming that decommissioning assets were invested in a portfolio comprised of 60 percent Standard & Poor's 500 and 40 percent Barclays Capital Aggregate Index (Duff & Phelps 2009b), NDT returns during that same period would have averaged roughly 9.5 percent for a net gain above cost escalation. However, while NDT earnings are taxed at a low rate, they are still taxed. Using a 20 percent federal rate and an incremental 3 percent average state rate, after-tax returns for IOUs drop to 7.3 percent, about 0.5 percent lower than the escalation in expected decommissioning costs. IOU balances were $30 billion as of December 31, 2008 (Duff & Phelps 2009a), generating an annual deficit of $145 million. Because POUs are not taxed at all, investment returns keep up with need, generating a surplus over cost escalation of about $85 million per year, even assuming a lower equity share (and returns) for POU NDTs. The net shortfall between the two sectors is $60 million per year.

Two points are important here. First, even if industry-wide calculations suggest little net deficit, the shortfalls could be quite large for specific plants. Second, these shortfalls could build greatly because of the lost compounding of investment earnings year to year if returns lag cost escalation, and small changes in the yield gap that could result in much larger (or smaller) deficits over time.

7.1.2. Tax Breaks to Decommissioning

The most important current tax break for NDT funds is a lower tax rate on fund income than applies to corporate income.[101] IOUs pay only a 20 percent federal rate on NDT earned income, versus the conventional rate of 35 percent for institutions of a scale similar to NDTs. POUs, of course, pay no tax at all on their NDT earnings at either the state or federal level. This tax exemption is highly valued; when the New York Power Authority gave up its ownership in nuclear facilities, it retained its NDT fund "largely to preserve its tax-exempt status" (Duff & Phelps 2009b: 3).

As shown in Table 25, these tax savings are worth between $450 million ($340 million for IOUs and $110 million for POUs) and $1.1 billion per year ($840 million for IOUs and $260 million for POUs). This amount is sufficient to fund three-quarters (Earth Track calculations) or all (using Joint Committee on Taxation estimates for revenue loss) of the annual contributions made to NDTs in 2007. While the exact share will fluctuate year to year based on NDT investment performance and annual contribution levels, it is clear that much of the annual cost of providing for proper site closure is borne not by plant owners or customers (via slightly higher energy prices) but by the general taxpayer. As the fund accrual rises, and annual contributions decline due to life extensions, the tax subsidy on fund earnings can be expected to finance all of the required contributions under most plausible scenarios.

As with so many other aspects of the nuclear fuel cycle, this shifting of costs and responsibilities is not only expensive for the U.S. Treasury, but also harms competing energy resources by eroding the

101 The tax treatment of NDTs is somewhat complicated. Prior to EPACT 2005, there were specific rules about two different types of NDTs: "qualifying" and "nonqualifying." Qualifying trusts had a lower federal tax rate (20 percent since 1996); non-qualifying trusts had a standard corporate tax rate on income, but received a federal dividends-received deduction—such that only 30 percent of the income received from equity investments was taxed federally (Duff & Phelps 2008a: 5). By allowing tax-free transfers of stocks and bonds, EPACT made it easier for utilities to migrate assets from nonqualified to qualified trusts.

Table 25. Value of Tax Breaks for Nuclear Decommissioning Trusts

	IOUs	POUs	Total	Notes
Funding levels				
NDT sizes, 12/31/07, $billions	38.0	5.8	43.8	(1)
Actual contributions to NDTs, 2007, $billions	0.449	0.109	0.558	(1)
Comparative tax rates and liability				
After-tax average returns	5.6%	3.0%		(2)
Pretax return equivalent	9.1%	4.8%		(3)
Adjusted pretax return equivalent	6.0%	4.8%		(4)
Pre-tax earnings on NDTs, $billions/year	2.28	0.27	2.55	
Conventional corporate tax rate, federal	35.0%	35.0%		
Incremental state tax	3.0%	3.0%		
Estimated conventional rate	38.0%	38.0%		
Actual tax rate on NDTs	20.0%	0.0%		(5)
Incremental state tax	3.0%	0.0%		(6)
Estimated NDT tax rate	23.0%	0.0%		
Tax rate subsidy	15.0%	38.0%		
Tax savings due to special NDT rates				
Annual tax savings, calculated, $billions	0.34	0.11	0.45	
Annual tax savings, JCT estimate, $billions	0.84	0.26	1.10	(7)
Share of annual contributions funded through special tax breaks				
Calculated	76.2%	97.5%	80.3%	
Using JCT estimates	187.1%			(7)

Notes:

(1) Duff & Phelps 2007.

(2) IOU-modeled returns from Williams 2007. Lower value is applied to POUs to reflect greater restrictions on holding equities in NDTs.

(3) Assumes a corporate marginal tax rate (combined state and federal) of 38 percent.

(4) GAO-modeled returns were high relative to long-term historical performance of US bond and equity markets, so were scaled back to more realistic levels.

(5) Private NDTs receive a subsidized 20 percent tax rate on income; POUs pay no tax.

(6) Assumes average state taxes of 3 percent, though some of them also tax NDTs at a lower rate. POUs would pay no state taxes.

(7) Average revenue losses/year for 2008–2012 (JCT 2008: 63). JCT data include IOU exemptions only; tax exemptions of public institutions, even when there are large privately owned enterprises in the same market segment, are generally ignored. POU high value was estimated assuming the same ratio of high/low estimates as applied in IOU values.

price differentials that should be directing consumers to the most cost-effective power-supply options.

7.2. NUCLEAR WASTE

High-level radioactive waste must be isolated and managed for thousands of years. At any point during such periods, accident or theft can happen, bringing with it potential liabilities to the waste generator and site manager (should they still be in operation). A sound waste repository is quite difficult to site and build, and it faces severe risks of cost escalation. The combination of technical complexity and long-lived risk exposure is not one that investors or owners find very attractive. These factors could well have made civilian nuclear power "uninvestible," or at the very least, further worsened its already challenging economics.

Subsidies associated with nuclear waste management come from three main sources: nationalization of responsibility for nuclear waste, the long-term deferral of large one-time payments for older waste (predating federal legislation) that will go to the repository, and payments necessitated by imprudent contracting practices.

7.2.1. Nationalizing Responsibility for Nuclear Waste Management

The willingness of the federal government to assume responsibility for this technically and politically challenging enterprise in return for a small (0.1 ¢/kWh) surcharge on nuclear power is an often-overlooked but quite important subsidy. Through nationalization, a very large and uncertain fixed cost has been shifted to a very small and predictable variable cost. In terms of operational risk, federally run nuclear waste management entails one of the most valuable subsidies granted to the nuclear sector. National ownership gives rise to three subsidy areas of concern. First, there is no required return on nearly $100 billion in invested taxpayer capital (section 7.2.1.1), and great risk that the fees charged on current operations will prove inadequate even to finance the repository on a break-even basis (section 7.2.1.2). A third issue involves a lack of precision in how the military and commercial shares of totals costs are allocated (section 7.2.1.3). Though not quantified, historical assessments of the commercial costs have decreased since 1980.

Although the NWF surcharge was created by the Nuclear Waste Policy Act of 1982, government responsibility started earlier. In a detailed evaluation of subsidies to nuclear energy initiated by the EIA in 1980, analyst Joseph Bowring noted that, "Government responsibility for ultimate waste disposal removes significant uncertainties from those investing in nuclear power production" (Bowring 1980: 63). U.S. civilian reactors generate about 2,000 metric tons of highly radioactive spent fuel per year (Holt 2009: 19), with additional materials coming from fuel-cycle facilities.

In recent years, most discussion about the NWF has focused on the large amount of money sitting in its trust account and whether these funds have been spent well or fast enough. The collected amount is quite large: through FY2009, $31 billion had been credited to the fund from industry, the defense sector, and accrued interest (Cawley 2010). Of this total, about $23.6 billion remained unspent. In looking at this surplus, some analysts have concluded either that there is no subsidy to nuclear waste management or that the fund balance should actually be used to offset subsidies received in other forms (MISI 2008: 16; Bezdek and Wendling 2007).[102]

These conclusions err in two respects. First, the NWF, like the Social Security Trust Fund and many others, is accruing funds over a long period

[102] They note that, "Federal disbursement for nuclear energy is shown as negative because through 2003 the Nuclear Waste Fund had accumulated a $14-billion surplus" (Bezdek and Wendling 2007: 48).

of time to pay for a very large and uncertain future liability. Thus the adequacy of funds collected must be evaluated on an actuarial basis against the present value of these expected liabilities. Large current surpluses may still generate insufficient funds for the future, indicative of fees that are too low (and hence a source of subsidy) rather than too high. In fact, the DOE's own assessments of fee adequacy note that funding for the entire enterprise between 2046 and 2133 will be dependent on investment earnings, given that it assumes the last fee payments from utilities will arrive in 2046 (OCRWM 2008a: 1).

Second, the very structure of the NWF and associated federal services constitute an enormous subsidy to the nuclear power sector even if there are no additional funding shortfalls. In essence, the program nationalizes responsibility for nuclear waste management, providing it as a government service to private industry on, at best, a break-even basis.[103] Ancillary subsidies from this decision—ranging from the tax-exempt status of the federal enterprise to the uncompensated risk-bearing by the taxpayer—greatly reduce the financial cost of nuclear waste management to the private sector.

7.2.1.1. Break-Even Operation of Repository: No Return on Invested Capital

The repository is a complex and expensive undertaking, yet is to be operated on a break-even basis. This results in lower prices for waste management services than should apply because there is no return on investment to reward the providers of capital (i.e., taxpayers) for putting so much money at risk for so long.

The value of this subsidy can be estimated using comparable returns on investment (ROIs) from private firms in the nuclear industry. Based on capital actually invested in the repository to date, an ROI equal to that earned by lower-risk nuclear power leader Exelon (5.12 percent over 2005–09 period, according to Thompson Reuters—a figure lower than the 7.85 percent average ROI for the electricity sector overall), and an 80 percent civilian share of total costs, the subsidy from the nuclear waste repository operating on a break-even basis is substantial. Even assuming all cost estimates for the repository are correct, nuclear plants would need to charge an extra $700 million to $1.2 billion per year, equal to roughly 0.08 to 0.15 ¢/kWh. Thus, applying even low-end return hurdles for government provision of long-term nuclear waste services would result in the industry's contribution to the NWF almost doubling or more.

This subsidy will escalate sharply as the capital invested in the facility grows. The DOE estimates the total system life-cycle cost of the facility at $96.2 billion (OCRWM 2008b: 1). The civilian share of ROI on invested capital (in 2007$) reaches $2 billion per year by 2033, $3 billion per year by 2053, and continues to rise. This approach will tend to *understate* the true subsidy since the capital risk for operating an already-built nuclear facility (i.e., the Exelon ROI proxy) is significantly lower than trying to build and manage a nuclear waste repository. Appropriately using ROIs much higher than 5.12 percent would result in commensurately higher subsidies to nuclear.

While it might seem strange to have a government entity tax itself to pay the same government, the approach makes good sense from the perspective of energy-market neutrality and is widely applied in other areas. Television shows airing on a network pay for ad space on that network to promote their show, and public-transit authorities pay for ad space on their own vehicles. In all these cases, the rates are set to reflect the scarcity value and opportunity cost of the resources being consumed.

103 While the details vary by country, government responsibility for long-term waste management has been more or less replicated around the world.

The core reality is that operating the repository as a tax-free entity requiring no return on capital has the effect of reducing the price to the nuclear sector for dealing with its wastes. Because nuclear power's competitors have no such options, competitive distortions are introduced.

7.2.1.2. Underestimating the Cost of the Repository

It is not at all clear, however, that the DOE's expectation of how much it will cost to build and operate the repository even on a tax-exempt break-even basis will be realized. The costs of "megaprojects" normally run well beyond their original estimates. The fact is that the billions invested in the planned repository at Yucca Mountain may well be lost entirely due to performance issues. A recent decision by the Obama administration not to proceed with that site is an indication of this concern.

In estimating the subsidy to nuclear power, costs are allocated between civilian and military sectors, based on their respective contributions of spent nuclear fuel. The cost assessment in July 2008 estimated that more than 80 percent of the repository is linked to the civilian sector (OCRWM 2008b: 2). That analysis estimated total life-cycle costs (in constant 2007$) had grown by more than a third, from $69.7 billion to $96.2 billion.

While the DOE believes the current fund is adequate, attempts to have it adjust automatically for inflation have failed (see, for example, GAO 1992). Stanford economist Geoffrey Rothwell also believes that the waste fee is low by a factor of three, given what he anticipates will be very high cost escalation in the nuclear power sector. He believes that the fee should be boosted from 0.1 ¢/kWh to 0.3 ¢/kWh as early as possible in order to boost the solvency of the fund (Rothwell 2005), an increase of 0.2 ¢/kWh. In theory, annual or other periodic reviews can address such problems. But that can work only if there is sufficient operating life remaining at reactors when financing shortfalls are discovered so that the contribution rate may be appropriately adjusted. If large numbers of new reactors are not built in this country, it is quite possible that shortfalls will be discovered only as many of the existing fleet's reactors are retiring or already closed—at which point collecting higher surcharges will not be possible.

In its evaluation of fee adequacy, the DOE's Office of Civilian Radioactive Waste Management (OCRWM) evaluated 28 scenarios and concluded that collections would be sufficient so long as a single repository (rather than two) were required, and that funds could be deployed as needed for the stated mission of the Nuclear Waste Trust Fund. To avoid having to build a second repository, the DOE assumed that Congress would overturn existing limits on the total tonnage allowed for disposal at the Yucca Mountain site (OCRWM 2008b: ES2). Since that report was published, the Obama administration has announced its intent not to use the Yucca Mountain site. In any case, most analysts believe that a significant number of new reactors would bring the required number of repositories, wherever their location, to at least two.

As noted above, all calculations that the OCRWM performs on fee adequacy have embedded within them the idea that waste management should earn no profit for taxpayers, despite its great risk and despite the fact that no other energy resources require similar services. Nor do the OCRWM's calculations assume that taxpayers earn a return on capital for invested taxpayer funds. An energy-neutral approach to costing would assume not only that the waste-receiving entities set fees to earn operational surpluses but also that they pay taxes on those surpluses.

Based on the Rothwell estimate for shortfalls, and net nuclear generation in 2008, our high estimate assumes a subsidy of $1.6 billion per year from underestimating the true cost of the tax-exempt, break-even repository. Our low estimate is zero, assuming current fees are adequate.

7.2.1.3. Long-Term Reduction in Commercial Share of Total Costs

The share of total costs attributed to the commercial sector has also varied substantially over time. The most recent fee-adequacy assessment notes a rising commercial share (from 72.2 to 80.4 percent of the total) between 2001 and 2007 (OCRWM 2008b: 33). This rise is attributed to expectations of increasing amounts of spent nuclear fuel. However, over a longer timescale it is the defense share that has actually grown: from 14.9 percent with one repository in 1990 (OCRWM 1990: 13) to 19.6 percent in 2007 (OCRWM 2008b: 33). Clearly there is substantial uncertainty associated with some of the core assumptions of the model. The trend is worth watching; with estimated life-cycle costs of the facility at $96 billion, each 1 percent shift in responsibility saves the commercial sector nearly $1 billion in life-cycle fees. The 4.7 percent drop between 1990 and 2007 shifts $4.5 billion in life-cycle fees from the commercial to the military sector. As additional research would be needed to evaluate whether any portion of this shift is not based on changes in waste flows, we have not ascribed any subsidy to existing or new reactors from this item.

7.2.2. Subsidies Related to One-Time Assessments and Capital Reserve Fees

At the inception of the NWF, future waste generation was to be paid using a surcharge on nuclear-generated electricity. However, a one-time payment was also levied in order to pay for wastes generated in years prior to the fund's origination but that would use the resultant repository as well. The rules on making the one-time payment were generous, however. As of the end of 2008, nearly 30 years since the fund's inception, utilities in 10 states had still not paid their one-time assessments (OCRWM 2008c).[104] Cumulative one-time fees owed on that date were $3.2 billion, a figure that included both the original principal and accumulated interest (OCRWM 2008c), albeit with interest compounded at a quite-low federal short-term rate.

The likely reason why so much money remains outstanding is that the interest rates on the debt to the NWF are well below the cost of capital for the firms paying in. The Nuclear Waste Policy Act gave utilities three payment options: payment in full by June 1985, with no interest; 40 quarterly payments; or a future lump-sum payment (including interest) prior to delivery of the first waste to the repository.

This arrangement provides two important subsidies to the utilities that have deferred payments. First, the utility's cost of capital is far higher than the interest rate it is being charged (the 13-week Treasury bill rate). Between 1985 and 2007, the interest rate on the 13-week T-bills averaged 4.7 percent. Even under the unlikely assumption that all nuclear utility debt would be rated at the highest corporate credit rating (Aaa), the fees paid were still well below the 7.6 percent cost of corporate Aaa bonds during that period. The weighted-average cost of capital (incorporating firms' more expensive equity components of funding operations) was higher still. While the spread between Treasury and corporate debt has been narrowing a bit as interest rates overall have declined, corporate Aaa borrowers still paid an interest rate that was 1.2 percentage points higher than 13-week T-bills in 2007. The spread, with lower-grade corporate Baa bonds at nearly double this rate (at 2.1 percentage points), resulted in a savings of roughly $37 million to $66 million per year for the industry's continued deferral of one-time fees. As of November 2009, 13-week T-bill rates were hovering near zero (0.04 percent), at a time when private borrowing for firms had risen in cost due to general credit market problems.

104 Interest until the first payment accrued at the 13-week Treasury bill rate, compounded quarterly between April 7, 1983, and the date of the first payment. If the 40-quarterly-payment approach were then chosen, the rate would shift to the 10-year Treasury note rate in effect at the time (OCRWM 1989: 39).

Second, even though the utilities will not be able to ship waste to the repository until they pay their outstanding one-time-fee deficits, they are nonetheless reserving capacity in this very expensive undertaking while putting no capital at risk. This is a striking contrast from how normal capital infrastructure markets work. Consider a case from the nuclear industry itself. Securing rights to purchase heavy reactor forgings from Japan Steel Works required deposits estimated at \$100 million, which were needed to reserve limited forging capacity for an ultimate purchase worth \$300 million to \$350 million. The effective reserve rate was 28 to 33 percent of the total forging cost (Takemoto and Katz 2008). This was capital on which the purchasing firm could no longer earn a return, and which it had at risk should plans change. Contracts for jet airplanes also routinely carry very large reserve fees, which often are lost if orders get cancelled.

For a \$96 billion waste repository, comparable reserve ratios for the 80 percent of the project attributable to the commercial sector would have been on the order of \$22 billion to \$26 billion. A mid-range value of 30 percent would have resulted in a reserve fee of just over \$23 billion, which would cost the industry roughly \$1.2 billion per year to finance at Exelon's ROI. The lower end of this range is comparable to the *entire collection* of fees over the past 30 years from the NWF fee surcharge on electricity generated by nuclear reactors.

7.2.3. Payouts for On-Site Management of Existing Wastes

A final source of subsidy is linked to the poor risk-sharing on contracts that the DOE entered into with private utilities to provide waste services. Not only did the DOE promise to take a small fee by which the "utilities are relieved of further financial obligation for waste disposal" (GAO 1990a: 2), it agreed to do so according to a fixed time schedule. The original contracts obligated the DOE to begin taking the waste by 1998 (Wald 2009).

Given the scale of the endeavor, combined with its technical and political complexity, the resultant delays and cost overruns have hardly been surprising. Private contracts would have incorporated this uncertainty into clauses that more fairly shared the associated costs and risks among participating parties. The DOE contracts did no such thing, and the enterprise has turned out quite badly for the taxpayer. As the initial deadlines were missed, scores of suits were launched against the DOE for breach of contract—suits that the government has thus far mostly lost.

Through June 2010, more than 72 lawsuits had been filed, covering most holders of contracts for nuclear waste disposal at the repository. Eleven of the lawsuits have been settled, with payouts through July 2010 of nearly \$725 million. An additional \$1.1 billion was awarded in other judgments, though some post-trial motions remained in process (Cawley 2010: 4,5). So far, the federal government has spent more than \$150 million in litigation costs as well (Hertz 2009).

The DOE has estimated total liabilities of \$13.1 billion for the period 1998 to 2020, though it acknowledges that new suits will be launched if repository delays continue (Cawley 2010). The CBO notes that the industry is challenging the way the DOE has calculated the costs, and if the plaintiffs are successful the public liability will likely be higher than the department's estimates (Cawley 2009). Earlier estimates put total taxpayer exposure at \$35 billion to \$80 billion (Berlin 2004); the utilities themselves have alleged damages on the order of \$50 billion (Hertz 2009). Assuming that these liabilities are paid out over 15 years, improper risk-sharing on repository contracts will generate subsidies to the industry ranging from 0.15 ¢/kWh (using the DOE liability figure) to 0.6 ¢/kWh (using the utilities' estimate of liability). These costs are *in addition* to shortfalls in the ultimate cost of funding the repository, as more appropriate risk-sharing in contracts would have resulted in the utilities internalizing this risk of delay or loss. We assume that DOE will correct the risk-sharing deficiencies in contracts executed with new facilities, and hence ascribe no subsidies for this item for new reactor sites.

Settlements are not the only challenge, however. Spending on Yucca Mountain between 1983 and 2009 totaled $10.4 billion, but the project has now been abandoned. The nuclear industry has intimated it may demand repayment of the more than $20 billion collected in nuclear waste fees that have not yet been spent (Fertel 2009), and in July 2009 the industry submitted a letter to the secretary of energy requesting suspension of future payments into the fund (Seeley 2009). Meanwhile, some states are threatening to withhold funding from local reactors. Maine approved a resolution urging Congress to reduce collections, and Minnesota and Michigan have both introduced legislation to establish a state escrow fund rather than send payments to the federal government (Tetreault 2009). A formal lawsuit was launched in April 2010 by 16 nuclear utilities and the NEI to stop collection of the NWF fee entirely (Wald 2010). To the extent that these maneuvers reduce the funding base to the NWF, the taxpayer subsidy to nuclear waste management will increase.

Table 26. Subsidies Related to Emissions and Waste Management (Overview)

	Subsidies to Existing Reactors, ¢/kWh							Subsidies to New Reactors, ¢/kWh					Notes
	Total	Legacy		Existing: Low		Existing: High		Total	Low		High		
Subsidy Type		Low	High	IOU	POU	IOU	POU		IOU	POU	IOU	POU	
Decommissioning shortfalls: cost escalation exceeds investment returns on accrued funds	$60m/year							Expected to rise linearly with new plants					(1)
Decommissioning shortfalls: cost estimates much lower than actual costs	Not quantified							Not quantified					(2)
Tax breaks to decommissioning	$0.3b–$0.8b/yr for IOUs; $0.1b–$0.3b/yr for POUs			0.05	0.08	0.13	0.19	Expected to rise linearly with new plants	0.05	0.08	0.13	0.19	(3)
Break-even operation of repository: no return on invested capital	$700m to $1.2b/yr based on current investment; rising to $2.3b–$4.0b/yr			0.08	0.08	0.15	0.15	Expected to rise at least linearly w/new plants; more sharply if more repositories are needed	0.08	0.08	0.15	0.15	(4)
Underestimating the cost of the repository; nuclear waste fee collections too low	Shortfall estimated at between $0–$1.6b/yr			0.00	0.00	0.20	0.20	Expected to rise at least linearly w/new plants, due to multiple repositories	0.00	0.00	0.20	0.20	(5)
Long-term reduction in commercial share of total costs	4.7% drop in commercial share from 1990–2007; $4.5b in avoided repository costs							Reductions would benefit all reactors still operating					(6)
Deferred one-time assessment into NWF with low interest rate	$3.2b total; $37m–$66m/yr in avoided financing costs industry-wide			0.005	0.005	0.008	0.008	Not applicable to new reactors					(7)
No required capacity-reservation fee to access federal repository	30% reserve fee on break-even repository: $23b commercial share; $1.2b/year in avoided finance charges												(8)
Payouts for on-site waste management due to poor risk sharing on waste management contracts	Estimated $12b–$50b in total liabilities			0.15	0.15	0.60	0.60	Assumed zero					(9)
Total		0.00	0.00	0.29	0.31	1.09	1.15		0.13	0.16	0.48	0.54	

Notes:

(1) Net shortfall from facilities where after-tax return is lower than escalation in decomissioning cost estimates. Not quantified or negligible.

(2) Not quantified, though this is deemed a large potential risk.

(3) Assumes NDT funding pace for new reactors is similar to that for existing ones. Higher rate of funding would increase value of subsidy.

(4) Estimate is for civilian share of liabilities only. Assumes existing cost estimates are accurate and repository earns ROI similar to Exelon (5.1 percent); high estimate includes compounding of interest. Subsidy from no ROI escalates sharply over time as total investment rises.

(5) Estimated shortfalls due to cost escalation and inadequate returns, per Rothwell 2005; includes civilian share only.

(6) Not quantified. Conservatively assumes that the reduced commercial share is entirely due to shifts in wastes to be managed rather than partially due to political pressure.

(7) Deferral at very low interest rates has already lasted 25 years; includes civilian payments only.

(8) Estimate is for civilian portion only. Large capital investments usually require capacity-reservation fees of 25 percent of the delivered cost of the good/service or more. Nuclear comparables have reserve fees of 28 to 33 percent. Not quantified on a levelized cost basis.

(9) Payments over 15 years needed to make up expected reimbursements based on DOE (low) and industry (high) estimates. Assumes new reactors will not get this option.

Chapter 8

Total Subsidies to the Nuclear Power Industry and Related Policy Recommendations

This report has sought to comprehensively document the many subsidies provided to nuclear power throughout all stages of the fuel cycle—from the mining of the uranium used to fuel the reactors to the disposal of radioactive waste and the decommissioning of the plants. The range, nature, and variety of these subsidies make it difficult to get a full picture of their magnitude and distribution. Yet a full picture is needed to understand the economics of nuclear power. It is also a critical input in comparing emerging energy options and in evaluating demands from the industry for even greater subsidies, which mask the real cost of building new nuclear reactors and related infrastructure.[105]

We have grouped subsidies to the nuclear industry into three categories: legacy, ongoing, and new. Legacy subsidies affected reactor and fuel-cycle economics in the past—sometimes serving as a central impetus to build plants—but are not believed to affect pricing decisions any longer. In contrast, ongoing subsidies to existing reactors continue to affect the economics of nuclear power, often by subsidizing operating costs, making the power from these plants appear more economical than it actually is. Subsidies to new reactors distort the economics of new reactor proposals, tilting decisions on new power capacity toward nuclear and away from other energy options.

This chapter is divided into four sections. The first two discuss the total subsidies we calculated for the existing U.S. nuclear fleet and for new plants, respectively. The third section qualitatively discusses industry efforts to further expand or increase nuclear subsidies through proposed legislation. The final section presents a number of policy recommendations based on the findings in this report.

8.1. TOTAL SUBSIDIES TO EXISTING NUCLEAR REACTORS

Existing nuclear reactors have benefited from large historical subsidies, primarily in the form of investment incentives. Although these programs may no longer affect current plant economics, this historical or "legacy" support substantially improved the market economics of the reactors at the time they were built. Without them, many of these reactors would not have been built; those that were would have been forced to charge ratepayers even higher fees for the power produced. Legacy subsidies also provide useful insights into how new subsidies are likely to operate, as many new subsidy proposals adopt part or all of the earlier approaches.

A portion of the older subsidies remains in effect today, continuing to artificially reduce the cost of current plant operations. These ongoing programs will provide an incremental level of support for new reactors as well. Table 27 (p. 104) illustrates the range and magnitude of both kinds of subsidy.

Table 27 shows that existing nuclear facilities have received material support through most of the categories of subsidization we identified in Chapter 1.

105 Appendix A provides an overview of all the subsidies that have been discussed throughout this report. While the underlying policies vary, they fall into two main categories: reducing the financial risks of large capital investments, and transferring unpredictable "long-tail" costs—from accidents or radioactive waste management—to taxpayers through caps or government-provided or -supported services.

Legacy subsidies to capital formation were particularly important, as were the shifting of accident risks and the uncertain costs of waste management onto taxpayers.

Table 27. Subsidies to Existing Reactors (¢/kWh)

	Legacy		Ongoing			
			IOU		POU	
Subsidy Type	Low	High	Low	High	Low	High
I. Output-linked support	0.00	0.00	0.00	0.00	0.00	0.00
II. Factors of production	7.20	7.20	0.06	0.06	0.96	1.94
III. Intermediate inputs	0.10	0.24	0.29	0.51	0.16	0.18
IV. Security and risk management	0.21	0.22	0.10	2.50	0.1	2.5
V. Decommissioning and waste management	NA	NA	0.29	1.09	0.31	1.15
Total	**7.50**	**7.66**	**0.74**	**4.16**	**1.53**	**5.77**
Share of market power price	139%	142%	13%	70%	26%	98%

Note: Legacy subsidies are compared to the EIA average 1960–2009 industrial power price (5.4 ¢/kWh). Subsidies to existing reactors are compared to 2009 power prices entailing comparable busbar plant generation costs (5.9 ¢/kWh).

In total, we estimate the value of legacy subsidies to nuclear power were at least 7.5 ¢/kWh—equivalent to nearly 140 percent or more of the value of the power produced from 1960 to 2008. In other words, the value of government subsidies to the first generation of nuclear reactors actually exceeded the value of the power produced by those plants.

Ongoing subsidies to existing reactors show a much broader range. However, even at the low end, these subsidies are important. The low-end estimate for subsidies to investor-owned reactors (0.7 ¢/kWh) may seem relatively small at 13 percent of the current value of power produced, but it is more than 35 percent of nuclear production costs (O&M plus fuel costs, without capital recovery), which are often cited by the main industry association as a core indicator of the resource's competitiveness (NEI 2010b). In fact, including even the lowest estimate for ongoing subsidies in today's power prices would erode nearly 80 percent of the production cost advantage of nuclear relative to coal.

The estimated low-end benefit to publicly owned power is double this amount (1.5 ¢/kWh, or 26 percent of the value of power produced). This represents 75 percent of reported nuclear production costs—enough to render them higher than those for coal. Ongoing subsidies to POUs exceed those to IOUs because of ongoing tax subsidies to public power and an artificially low required return on assets. In contrast, the subsidies most important to IOUs for reducing the cost of capital, including investment tax credits and accelerated depreciation, have diminished in importance as these decades-old investments have been written off.

High-end estimates illustrate the same general trends, but in an even more striking way. Ongoing subsidies to existing reactors of roughly 4 to 6 ¢/kWh are large—70 to nearly 100 percent of the value of power produced. Given that these values *exclude* the massive legacy subsidies to the plants, their magnitude is impressive. The source of variance between the low and high estimates for existing reactors comes from widely differing estimates in five main areas:

- **Accident risks.** The Price-Anderson cap on third-party liability in the case of a nuclear accident, at the high estimate of 2.5 ¢/kWh, is the single largest subsidy to the existing reactor fleet, and generated the largest spread between high and low subsidy values (the low-end estimate is only 0.1 ¢/kWh). Despite its long existence, there have been few analytic assessments of this important subsidy—especially for non-reactor beneficiaries of the subsidy in the fuel cycle—and little in the way of supporting data on which a more robust analysis could be based.
- **Low or no ROI expected on large public investments.** Nuclear power has entailed large public investments in infrastructure not required by other energy sources. The lack of reasonable ROI from this taxpayer investment

creates substantial benefit for the nuclear fuel cycle. The range in these estimates is driven by different plausible ROI assumptions.

Although data could not be compiled on all public investments in nuclear reactors, two areas are examined. For reactors, available data on TVA and BPA indicate that artificially low rates of return have been an important source of subsidy, allowing lower-cost power sales from these units. With the high estimate of this subsidy approaching $1 billion per year for these two administrations alone, subsidies to the nuclear generation from TVA and BPA approach 1.5 ¢/kWh.

While low ROI requirements in federal power marketing administrations have at least gotten some attention in the past, investments in the Nuclear Waste Repository are likely to be equal or larger in scale, with total projected life-cycle costs estimated at nearly $100 billion. Even based on capital deployed to date, the facility should be collecting $0.7 billion to $1.2 billion more from commercial users each year to earn an ROI commensurate with what lower-risk Exelon (running already-built reactors) would earn under similar circumstances. The ROI shortfall rises sharply with the level of investment, growing to billions of dollars per year. Stated another way, based on projected cash-spend rates to date, the NWF fee should be at least double the present fee, *even if cost projections for the repository were accurate*. Note that this estimate still has the taxpayer bearing most of the investment risk. In private markets, such as those for nuclear reactor vessels or jet airplanes, reserve fees of 25 percent or more are common, with the manufacturer capturing the investment earnings during the interim. The absence of such payments reduces the waste-management costs for all existing reactors.

- **Additional subsidies to the Nuclear Waste Repository.** Precisely estimating the cost of a massive project such as the Nuclear Waste Repository is not possible, and such projects often experience large cost overruns. The high subsidy estimate assumes the ultimate costs will be much higher than current projections because of a variety of factors, such as significant cost escalation (relative to investment earnings) and technical surprises, which would require an additional 0.2 ¢/kWh to run a break-even waste operation. The project risks can be clearly seen in a slew of litigation initiated by utilities against the repository for failure to deliver on time, with an estimated cost to the U.S. taxpayer of $12 billion to $50 billion. This translates to 0.15 to 0.6 ¢/kWh in incremental subsidies to the nuclear industry, reflective of risk sharing in complex contracts by the federal government on a scale that would never happen among private parties. Our analysis assumes zero subsidies in this category for new reactors, on the basis that the government would not make the same grievous contract mistake again.
- **No payments for cooling water.** When most of the existing reactor fleet was built, little consideration was given to the economic or ecological impacts of massive withdrawals of cooling water. As pressure on resources has grown, property rights have become more defined. For example, restrictions on air-pollutant emissions from power plants have increased. In addition, although a kilowatt-hour of energy may be a commodity, markets have recognized that other attributes of that energy (e.g., whether it is delivered during peak versus nonpeak hours, whether the utility can interrupt delivery if supplies are constrained) need to be integrated into the price of electricity. But water use in electricity generation has yet to be integrated in this way—and nuclear reactors are the most intense water users per kilowatt-hour of electricity produced. This amounts to a large subsidy to all thermal electric plants; the value to nuclear reactors is estimated to be nearly 0.2 ¢/kWh. Additional research is needed to further refine

individual-reactor estimates; actual values are likely to vary widely by reactor location and be a more important factor in reactor siting than at present.

- **Tax breaks for decommissioning.** Special reduced tax rates for decommissioning trust funds are the final major subsidy to existing reactors. With an estimated worth of 0.1 to 0.2 ¢/kWh ($450 million per year to $1.1 billion per year), the tax savings on trust-fund earnings are often as large as the new contributions that companies make to the funds.

While ongoing subsidies to reactors remain a critical element in the competitiveness of nuclear power, legacy subsidies to capital formation and other parts of the nuclear fuel cycle were also important. If legacy subsidies are added to subsidies that reduce the cost of ongoing operations, this support amounts to between 8 ¢/kWh and 12 ¢/kWh for POUs—a staggering 150 to 220 percent of the value of the power produced. While this level of support has not been available every year, it is reflective of capital and operating support that subsidized the development of our existing reactor fleet. Even at the low end of our calculations, this support is well above the value of the power produced. Among the findings of interest:

- **Stranded nuclear costs.** Despite large subsidies to capital formation, nuclear plants remained high-cost suppliers when they had to recover capital as well as operating costs. When power markets were deregulated, nuclear reactors constituted the largest share of uneconomic (or "stranded") generating plants, at nearly $110 billion (2007$)—or more than 1 ¢/kWh on average, based on all nuclear electricity generated from the inception of the industry through 1997, when the estimate was made. Subsidies to specific reactors could be much higher.
- **Regulatory oversight.** Although nuclear power plants require more complex regulatory oversight than virtually any other energy source, taxpayers were still paying for most of it prior to 1991. The $11 billion in taxpayer-financed oversight of civilian nuclear power amounted to roughly 0.2 ¢/kWh during the period—a subsidy that exceeds utility funding for nuclear waste disposal at the federal repository.
- **Compensation to injured workers.** Nuclear workers at mining, milling, enrichment, and other fuel-cycle facilities incurred a variety of occupational injuries and illnesses associated with their work. Federal payments to workers of record prior to 1971 (under RECA) and 1992 (under the Energy Employees Occupational Illness Compensation Program Act) supported both the civilian and military sectors. The civilian share of payments was roughly $1.1 billion, or nearly 0.3 ¢/kWh of nuclear power produced during the period of occupational claims under the programs. Later occupational injuries are not covered in these statutes.
- **Environmental damage from uranium mining and milling.** Domestic uranium-extraction activities have been poorly controlled, leaving expensive cleanups for the taxpayer. Even based on a limited set of milling sites for which there are data, remediation costs at these sites sometimes actually exceed the value of the ore mined.
- **Below-market sales of enriched uranium.** While the privatized USEC is struggling to survive, its predecessor, the government-owned UEE, led the world in enrichment services for many decades. UEE provided these services below cost, resulting in a large accumulated deficit to the U.S. Treasury—even though during much of this time UEE had enough of a market lead over its competitors that it could have sold at a higher price to cover its costs. In total, below-market sales were worth roughly 0.1 to 0.2 ¢/kWh to U.S. reactors.

8.2. TOTAL SUBSIDIES TO NEW REACTORS

Legacy and ongoing subsidies to existing reactors may be important factors in keeping the facilities operating, but they are not sufficient to attract new investments in nuclear infrastructure. Thus a growing array of new subsidies that target not only reactors but also other fuel-cycle facilities has been rolled out in the past decade. The objectives of these policies are identical to those of the largest subsidies of the 1970s and '80s: to reduce the private cost of capital for new nuclear reactors and shift "long-tail" risks of the nuclear fuel cycle away from investors. Table 28 shows the range of subsidies available to new reactors.

Table 28. Subsidies to New Reactors (¢/kWh)

	IOU		POU	
Subsidy Type	Low	High	Low	High
I. Output-linked support	1.05	1.45	0.00	0.00
II. Factors of production	3.51	6.58	3.73	5.22
III. Intermediate inputs	0.21	0.42	0.21	0.42
IV. Security and risk management	0.10	2.50	0.10	2.50
V. Decommissioning and waste management	0.13	0.48	0.16	0.54
Total	**5.01**	**11.42**	**4.20**	**8.68**
Share of high power price	84%	190%	70%	145%
Share of market power price	88%	200%	74%	152%

Note: Subsidies are compared to EIA 2009 power prices entailing comparable busbar plant generation costs (high: 6.0 ¢/kWh; reference: 5.7 ¢/kWh).

Total estimated subsidies to new reactors are much higher than those for ongoing operations at existing plants: 4.2 to 11.4 ¢/kWh—or between 70 and 200 percent of the projected value of the electricity they would produce over the next 15 years.

While subsidies to existing reactors favored POUs over IOUs (since much of the generous support to private capital occurred decades ago), this pattern reverses itself for new facilities. Large subsidies available to new private capital investment drive this shift. They include:

- **Federal loan guarantees.** At present, the nuclear industry has access to $18.5 billion in federal loan guarantees under the Title XVII program for new reactors, although the industry is seeking to expand that amount. These loan guarantees will provide the single largest subsidy to new investor-owned reactors, at 2.5 to 3.7 ¢/kWh (after default prepayments and administrative fees), according to industry estimates. These estimates still have favorable assumptions regarding capital costs and lifetime operating factors, suggesting that the true subsidy value may be higher still. On the POU side, the ability to access lower-cost debt due to preferential tax treatment will result in savings of more than 3 ¢/kWh for participants in new publicly owned reactors.
- **Construction work in progress.** CWIP allowances, whereby companies start recovering their nuclear investment well before plant operations begin, greatly reduce interest costs by shifting the financing burden to ratepayers. This policy provides an incremental subsidy of 0.4 to 1.0 ¢/kWh on top of federal loan guarantees. CWIP subsidies in the absence of loan guarantees would be much higher.
- **Accelerated depreciation.** Accelerated depreciation, which allows utilities to write off the value of their plants over a much shorter time frame than the useful life of those assets, provides IOUs with a subsidy benefit of 0.3 to 0.7 ¢/kWh for new plants.
- **Production tax credits.** PTCs for new reactors will provide an additional 1.1 to 1.5 ¢/kWh.[106] At present, the PTC could not be claimed by every reactor that might be built, although legislative initiatives have tried to raise the current 6,000 MW limit.
- **Accident risk, decommissioning, and nuclear waste management.** All the programs that apply to existing reactors in these areas will also apply to new reactors. In most cases, the subsidy levels

106 Because values represent the levelized PTC over the life of the facility, they are lower than the 1.8 ¢/kWh statutory value that is available only for eight years.

will be similar. There are a few exceptions, however. If new reactors force the country to build a second waste repository, the subsidies associated with nuclear waste management could rise substantially. Similarly, Price-Anderson caps on accident liability are poorly characterized in the area of nuclear enrichment facilities, with the initial legislation not requiring any coverage at all. The industry is no longer dominated by a federally owned enrichment infrastructure; instead, foreign governments and firms are involved, and liability requirements need to be spelled out much more clearly.

- **Cooling water.** We have not seen any efforts to correct the lack of fees for water use in the thermal power sector, and we expect this subsidy to continue. In fact, most new plants that have been proposed will continue to use intensive once-through cooling. But because water efficiency can be designed more easily into new reactors than into a retrofit for existing reactors, water-subsidy values for new plants are conservatively estimated to be half those of the existing reactor fleet.
- **Uranium mining.** U.S. oversight of uranium mining on public lands remains weak, and fees remain low. As a result, historical subsidies to mining and site remediation (due to inadequate bonding) are expected to continue for new plants. Mining interest has increased dramatically in recent years relative to historical averages, which could cause lost royalty and remediation costs to spike in the near term.

8.3. THE INDUSTRY IS SEEKING GREATLY EXPANDED SUBSIDIES FOR NEW REACTORS

The nuclear power industry is seeking billions in new subsidies and other incentives (through federal climate and energy legislation) that would shift massive construction, financing, operating, and regulatory costs and risks from the industry and its financial backers to U.S. taxpayers. If adopted, these new subsidies will only further mask nuclear power's considerable costs and risks. They will also put more cost-effective and less risky carbon-reduction measures—measures that could be implemented much more quickly—at a disadvantage.

As we have demonstrated, the nuclear industry will already benefit from considerable subsidies provided by EPACT 2005 for new reactors, as well as any future price on carbon emissions. Proposed legislation would extend or expand existing subsidies, as well as introduce a suite of new ones. If adopted, the magnitude of new support to the industry could actually exceed what is already provided by existing statutes.

Two key Senate bills that were under consideration at the time this report was written—the American Power Act (APA) and ACELA—contained significant new subsidies for the nuclear industry. While not all of those subsidies would be available to every project, the collective impact would be significant, because companies would be able to pick and choose among a wide range of subsidies best suited to a variety of partnership and financial structures. This report does not attempt to quantify these subsidies, which has been done elsewhere.[107] New subsidies could take the following forms:

- **A clean-energy bank.** ACELA would create a new federal financing entity (CEDA) to promote the domestic development and deployment of clean energy technologies. As drafted, CEDA would be exempted from FCRA, which would allow the fund to provide potentially unlimited loan guarantees to large, well-capitalized entities (like the nuclear industry) that would be able to pay their estimated subsidy costs up front. Subsidy cost estimates are widely expected to be too low, and become an immediate taxpayer liability if this proves true. In addition, even with no default, the expanded loan guarantees would offer large borrowing subsidies to the nuclear industry, further distorting

107 See, for example: Koplow 2010; UCS 2010.

competition across energy technologies and fuels. CEDA would not be required to prioritize financial support for technologies capable of reducing the most heat-trapping emissions per dollar invested, exacerbating the program's risks of large taxpayer costs and market distortions.[108]

- **Expanded Title XVII DOE loan-guarantee program.** The APA would triple the authority for nuclear loan guarantees through the government's existing program, from $18.5 billion to $54 billion. These new loan guarantees would result in the allocation of more than half of Title XVII funding to nuclear energy.
- **Shorter accelerated depreciation period.** The APA would reduce the already favorable depreciation period from 15 years to five years for new reactors. This would allow the nuclear industry to claim substantially larger tax deductions and much lower tax payments for assets with a life expectancy of 40 to 60 years, significantly reducing its tax burden and increasing its after-tax profit. The nuclear industry claims that such a provision would put nuclear power on par with renewable energy technologies under the federal tax code; however, the dollar value of the subsidy would be much greater for nuclear than for renewables because of the large disparity between the actual asset life and the allowed tax write-off period for these projects.
- **Ten percent investment tax credit.** The APA would significantly reduce the industry's tax liability while tilting emerging energy markets toward large, capital-intensive projects and away from less risky, more cost-effective low-carbon energy alternatives.
- **Federal payments for new reactors in lieu of tax credits.** The APA would provide municipal and cooperative utilities with federal grants in lieu of tax payments, which would require taxpayers to cover 10 percent of these utilities' investment in new reactors.
- **Expanding the production tax credit.** The APA would expand the existing 1.8 ¢/kW credit from 6,000 MW to 8,000 MW for the first nuclear power plants to come online; it would also allow tax-exempt entities to allocate their available credits to private partners—despite the fact that POUs do not pay taxes.
- **Allowing tax-exempt bonds for public-private partnerships.** The APA would allow publicly owned utilities to issue tax-free, low-cost bonds for nuclear plants developed jointly with private interests. Depending on public/private ownership structures, plants could be eligible for a broad combination of subsidies.
- **Expanded federal regulatory risk insurance.** The industry is already able to obtain $2 billion in total coverage to shield as many as six reactors from costs associated with regulatory and legal delays (a protection unavailable to other low-carbon technologies). The APA would expand this coverage to $6 billion and 12 reactors, and expand the circumstances and time frame under which it would be provided. The legislation would also enable any contract on which no claim has been made to be "reused" by other reactors.

In many of these areas, industry proposals would go even further (NEI 2009d). The NEI has proposed merging Title XVII funding into the more favorable rules of CEDA, including exemption from FCRA oversight, and providing more than $210 billion in total loan guarantee capacity, along with no cap on the share of funding that could go to nuclear. The NEI also wants a 30 percent investment tax credit available for both new reactors and capacity "uprates" (i.e., improvements that increase

108 Even if loan guarantees were the only capital subsidy available to new reactors, the potential credit support under CEDA is staggering. To achieve the U.S. portion of a nuclear Pacala-Socolow "wedge" of carbon reductions, at least $1.5 trillion of new investment would be needed (1,070 GWe of new capacity to achieve a net 700 GWe after closures, of which 24 percent is assumed to be in the United States). Of this U.S. investment, 80 percent, or more than $1.2 trillion, could be federally guaranteed. Such a program could have a levelized annual subsidy value to the nuclear sector of $50 billion to $75 billion. Over the 30-year life of the program, this could amount to a present-value transfer of between $1.5 trillion and $2.3 trillion.

generating capacity) at existing facilities; companies could take this credit in the form of a grant, effectively providing cash rebates even before the reactor is operating. Finally, the NEI wants public entities to be allowed to transfer PTCs to private partners, the cap to be removed entirely, and tax credits to be indexed for inflation. Other proposals would modify APA and ACELA language to include more-favorable payout terms under the regulatory risk insurance program, provide tax credits for worker training, include nuclear offsets in any renewable energy mandate, and further streamline reactor licensing (with the effect of further reducing public input and legal challenges).

8.4. POLICY RECOMMENDATIONS

This analysis clearly demonstrates that the nuclear industry has benefited and continues to benefit from the substantial public largesse that has been marshaled to support this complex, risky, and expensive technology. Given the large subsidies that have been available to this industry since its inception, as well as the subsidies available to a limited number of new reactors, any new subsidies must be clearly viewed in the context of what has come before—as well as the costs and risks of continuing to heavily subsidize this mature industry in the future.

The following recommendations have been developed to guide policy makers in deciding whether to convey even greater subsidies to the industry. These recommendations also address those areas where subsidies have been identified but are not well understood or quantified, and further research and analysis is needed.

- **Reduce, not expand, subsidies to the nuclear power industry.** Public subsidies to this industry are lucrative and highly concentrated funding for a narrow set of technologies and firms. They should not be expanded to cover more generating capacity than current government policies allow, nor should new categories of subsidies be created. Doing so would make the U.S. taxpayer responsible for considerable additional costs and economic risks—risks that should be borne by the industry. In particular, new loan guarantees above and beyond those already authorized by Congress in EPACT 2005 would expand government involvement in an arena where it is poorly equipped to engage.

  Federal involvement in markets should instead focus on encouraging firms involved in nuclear power—some of the largest corporations in the world—to create new models for internal risk pooling and to develop advanced power contracts that enable high-risk projects to move forward without additional taxpayer risk. The following recommendations discuss where existing subsidies to the industry should be reduced or eliminated.

- **Award subsidies to low-carbon energy sources on the basis of a competitive bidding process across all competing technologies.** Subsidies should be awarded to those approaches able to achieve emissions reductions at the lowest possible cost per unit of abatement—not on the basis of congressional earmarks for specific types of energy.

  Most federal programs that benefit nuclear power are technology-specific subsidies to mitigate such problems as the high cost of capital or nuclear waste management. While such programs offer targeted ways for Congress to provide subsidies to constituents, they are not well structured to achieve a successful energy market transformation to a low-carbon future. To the extent that taxpayer subsidies are extended, they should be awarded on the basis of a technology-neutral competitive auction, with successful bidders chosen on the basis of their bids to accept the lowest subsidy per kilowatt-hour delivered.

- **Modernize liability systems for nuclear power.** Liability systems should reflect current options in risk syndication, more robust requirements for the private sector, and more extensive testing of the current rules for excess risk concentration and counterparty risks. In light of rising populations and property values surrounding nuclear plants, together with the fact that storm damage frequently exceeds the total available coverage under the Price-Anderson Act, it is clear that the current risk-pooling system is inadequate to cover a major nuclear accident. The $20 billion trust fund BP has established to cover its expected damages from the Gulf of Mexico oil spill, for example, is nearly 2.5 times the nuclear industry's liability coverage for all off-site damage on a present-value basis. Moreover, the systemic risks that resulted from the recent financial sector meltdown underscore potentially similar counterparty risks with Price-Anderson retroactive premium payments.

Coverage levels for all stages of the fuel chain need to be more carefully mapped out—new enrichment facilities seem particularly vulnerable—to ensure that coverage levels are adequate and that payments will be available even when accounting for the inevitable pressure on the industry following any accident. Expanded risk-syndication approaches to boost private coverage should be pursued, including catastrophe bonds, more underwriters, and higher capital requirements, even if these requirements result in a higher cost of insurance to the utilities. Finally, more comprehensive analytic work on the subsidy value of liability caps and potential over-concentration of accident exposure is needed to properly inform future energy investments in the United States and abroad.

- **Establish proper regulation and fee structures for uranium mining.** For too long, uranium mining has been conducted with insufficient regulation, resulting in cleanup costs that appear to exceed the value of the ore mined—making this, in effect, a value-subtracting industry. Policy reforms are needed to eliminate outdated tax subsidies, adopt market-level royalties for uranium mines on public lands, and establish more appropriate bonding regimes for land reclamation.

- **Adopt a more market-oriented approach to financing the Nuclear Waste Repository.** The federal government faces scores of lawsuits for late delivery of waste disposal services, with related liabilities in the tens of billions of dollars. The nuclear industry has demanded a freeze on the collection of fees that nuclear power users pay for the federal break-even waste repository, and it has stated that it may seek the return of all accrued balances as well.

Beyond addressing these claims, the federal government should recognize that its nationalized waste management service has actually guaranteed capacity for nuclear waste with little or no down payment by industry producers, further undermining the economics of the energy industry by giving nuclear power an undue advantage. The government should also recognize that it has received no return on this investment, which could ultimately amount to some $100 billion. Historic contract terms have shifted all of the performance risk from repository beneficiaries to taxpayers.

Therefore, the government should take a more market-oriented approach to providing waste services to new reactors. This should include requiring sizeable waste management deposits by the industry, a repository fee structure that earns an ROI at least comparable to other large utility projects (or, more appropriately, comparable to other projects of similar scale and risk), and more equitable sharing of financial risks if delays occur.

- **Incorporate water pricing to allocate limited resources among competing demands, and integrate associated damages from large withdrawals.** In many parts of the country, water is a more valuable commodity than the energy it is being used to produce. Yet cooling water is free or nearly so to virtually all thermal power plants in the country. Federal research should delineate water-pricing strategies, both for consumptive and non-consumptive use, at all power plants in order to establish appropriate benchmarks for setting water prices that will be paid by utilities and other consumers, using a strategy that incorporates ecosystem damage as well as consumption-based charges. In addition, water users receiving priority access to the resource should pay fees for that benefit. With appropriate water charges, the nuclear industry would quickly adopt a variety of water-reduction technologies both through retrofits of existing plants and design modifications on new plants. Moreover, ecological damage from operations would decline.

- **Repeal decommissioning tax breaks and ensure greater transparency of nuclear decommissioning trusts.** Subsidizing nuclear plant decommissioning creates an entry barrier for energy technologies that do not have complicated decommissioning considerations. Therefore, eliminating existing tax breaks for NDTs would put nuclear power on a similar footing with other energy sources. More detailed and timely information on NDT funding and performance should be collected and publicized by the NRC. The variability of key estimates across plants and reporting years, such as decommissioning funding needed per kilowatt-hour, indicates that important data remain relatively soft and additional analysis is needed.
- **Ensure that publicly owned utilities adopt appropriate risk assessment and asset management procedures.** Nuclear investments were a source of large losses for public power utilities during the last investment cycle. POU administrators should not repeat the mistake now that some are seeking to partner in building new reactors; instead, POUs and relevant state regulatory agencies should review their internal procedures to be sure the financial and delivery risks of nuclear investments are appropriately compared with other options.
- **Roll back state construction-work-in-progress allowances and protect ratepayers against cost overruns by establishing clear limits on customer exposure.** A growing number of states are implementing CWIP and other favorable risk-reduction and cost-recovery approaches to enable the construction of large-scale power plants, including nuclear reactors. These programs unfairly subsidize costly and capital-intensive technologies at the expense of smaller-scale, renewable, and demand-side alternatives that rarely require—or may not even be eligible for—such assistance.

  Where they exist, states should roll back these automatic cost-recovery mechanisms to level the energy playing field for all technologies. To the extent that CWIP is allowed, states should establish clear limits on customer exposure to cost overruns once plant construction expenses exceed a preset level. States should also establish a refund mechanism for instances in which plant construction is cancelled after it has already begun.
- **Nuclear power should not be eligible for inclusion in a renewable portfolio standard**. A number of recent legislative proposals have included nuclear power in purchase preference standards. Such proposals would generate significant incremental subsidies to eligible power sources. Nuclear power is low-carbon and therefore will already benefit from any carbon constraints. But additional support through inclusion in a renewable portfolio standard is unwarranted because, unlike other resources deemed renewable and currently eligible under such standards, nuclear power is an established, mature technology with a long history of government support. Furthermore, nuclear plants are unique in their potential to cause catastrophic damage (due to accidents, sabotage, or terrorism); to produce very long-lived radioactive wastes; and to exacerbate nuclear proliferation.

- **Evaluate proliferation and terrorism as an externality of nuclear power**. Proliferation of civilian reactors and fuel-cycle facilities could abet the spread of materials that can be used to make nuclear weapons. To reduce this risk, the costs of preventing nuclear proliferation and terrorism should be recognized as negative externalities of civilian nuclear power, thoroughly evaluated, and integrated into economic assessments—just as global warming emissions are increasingly identified as a cost in the economics of coal-fired electricity.

- **Credit support for the nuclear fuel cycle via export credit agencies should explicitly integrate proliferation risks and require project-based credit screening.** Nations with large nuclear power suppliers have been moving to increase trade in nuclear parts and services by establishing more favorable rules for financing this trade through national export credit agencies and multi-lateral lending institutions. In the past, the pricing of this credit support has been based on other utility projects, without recognizing the relatively higher financial risks of nuclear power plant projects. Any future credit supports should require higher interest rates than those extended to other, less-risky power projects, and include conditions on fuel-cycle investments to ensure the lending does not contribute to latent proliferation risks (i.e., the risk of the recipient country gaining the ability to transition quickly from civilian nuclear power to weapons development).

References

American Nuclear Insurers (ANI). 2010. *Need for nuclear liability insurance.*

American Public Power Association (APPA). 2009a. 100 largest public power utilities by generation, 2006. In *2008-09 Annual Director & Statistical Report.*

American Public Power Association (APPA). 2009b. U.S. electric generating capacity and generation by fuel type, 2007. In *2009-10 Annual Directory & Statistical Report.*

Armbruster, S. 2002. EU prepares for U.S. nuclear trade war. *BBC News*, October 3.

Asselstine, J.K. 2009. Statement to the Senate Committee on Energy and Natural Resources. February 12.

Associated Press. 2008. National guard ends reactor patrols. *Boston Globe*, November 3.

The Bank of New York (BONY). 2006. *Preparing for shutdown: Shifting attitudes toward nuclear decommissioning trusts.*

Barpoulis, J. 2007. Letter from John Barpoulis, senior vice president and chief financial officer of USEC, to Howard Bergstrom, U.S. DOE, regarding “Comments on notice of proposed rulemaking, RIN 1901-AB21 loan guarantees for projects that employ innovative technologies.” June 29.

Barringer, F. 2009. Ban set on mining claims adjacent to Grand Canyon. *New York Times*, July 20.

Behr, P. 2009. Nuclear power: A key energy industry nervously awaits its “rebirth.” *Environment & Energy Daily*, April 27.

Berlin, D. 2004. *Nuclear waste storage.* Citizens Against Government Waste. September 23.

Beyea, J., E. Lyman, and F. von Hippel. 2004. Damages from a major release of ^{137}Cs into the atmosphere of the United States. *Science and Global Security* 12:125–139.

Bezdek, R., and R. Wendling. 2007. A half century of U.S. government energy incentives: Value, distribution, and policy implication. Management Information Services International. *International Journal of Global Energy Issues* 27(1):42–60.

Bingaman, J. 2007. Discussion at a hearing on uranium enrichment of the Senate Committee on Energy and Natural Resources, November 15. S-Hrg 110-307.

Blee, D. 2009. Testimony of David Blee, executive director of the U.S. Nuclear Infrastructure Council, before a Senate Republican conference hearing, June 8.

Bodman, S. 2005. Remarks prepared for Energy Secretary Sam Bodman for the 2005 Carnegie International Nonproliferation Conference, Washington, DC, November 7.

Bonnar, D. 2008. *Uranium marketing annual report.* Washington, DC: Energy Information Administration.

Bowring, J. 1980. *Federal subsidies to nuclear power: Reactor design and the fuel cycle.* Pre-publication draft. Washington, DC: Energy Information Administration.

Boyd, M. 2009. Personal communication from Michele Boyd of Physicians for Social Responsibility to the author, July 1.

Bradford, P.A. 2008. Recent development affecting state regulation of nuclear power. *Regulatory Assistance Project Issuesletter,* July.

Bradford, P.A. 2007. New nuclear plants and climate change. Congressional presentation, April 20. Online at *www.congresswatchdog.org/documents/BradfordCongressionalBriefing.pdf*, accessed January 13, 2010.

Brancard, B. 2008. Hardrock mining: Issues relating to abandoned mine lands and uranium mining. Testimony of Bill Brancard, director of the Mining and Minerals Division of the New Mexico Energy, Minerals, and Natural Resources Department, before the U.S. Senate Committee on Energy and Natural Resources, March 12.

BuildAmericaBondsOnline.com. 2010. Online database of BAB bond issuance run by Financial Technology Laboratories, Inc. Online at *http://buildamericabondsonline.com/?page_id=263,* accessed April 19, 2010.

Bureau of Economic Analysis (BEA). 2004. BEA depreciation estimates. Washington, DC. Online at *www.bea.gov/national/FA2004/TableCandtext.pdf*, accessed December 21, 2009.

Bureau of Land Management (BLM). 2007. *Uranium mining claim activity in CO, NM, UT, and WY*.

Burgdorfer, B. 2009. NRC says six utilities have fund shortfalls—WSJ. *Reuters*, June 20.

Bush, R. 2009. Personal communication from Richard Bush, Office of Legacy Management of the U.S. Department of Energy, to the author, June 17.

California Energy Commission (CEC). 2007. Transcript of the Committee Workshop of the California Energy Resources Conservation and Development Corporation in the matter of *Preparation of the 2007 Integrated Energy Policy Report, Volume II*. June 28.

Calvert County, MD. 2009. *Budget summary: FY2009 commissioners report*.

Carlson, C., and J. Schwartz. 2007. Uranium mining in Colorado. *Earthworks*, June.

Carroll, S. 2009. Personal communication from Simon Carroll, member of the Nuclear Liabilities Financing Assurance Board, UK, to the author, July 1.

Cawley, K. 2010. The federal government's responsibilities and liabilities under the Nuclear Waste Policy Act. Testimony of Kim Cawley, chief of the Natural and Physical Resources Estimate Unit of the U.S. Congressional Budget Office, before the House Committee on the Budget, July 27. Online at *http://www.cbo.gov/ftpdocs/117xx/doc11728/07-27-NuclearWaste_Testimony.pdf*, accessed August 9, 2010.

Cawley, K. 2009. The federal government's responsibilities and liabilities under the Nuclear Waste Policy Act. Testimony of Kim Cawley, chief of the Natural and Physical Resources Estimate Unit of the U.S. Congressional Budget Office, before the House Committee on Budget, July 16. Online at *budget.house.gov/hearings/2009/07.16.2009_Cawley_Testimony.pdf*, accessed January 13, 2010.

Cawley, K. 2007. The federal government's liabilities under the Nuclear Waste Policy Act U.S. Congressional Budget Office. Testimony of Kim Cawley before the House Committee on Budget, October 4. Online at *www.cbo.gov/doc.cfm?index=8675&type=0*, accessed January 13, 2010.

Chapman et al./U.S. EPA. 1981. *Energy production and residential heating: Taxation, subsidies, and comparative costs*. Duane Chapman, Kathleen Cole, and Michael Slott of Cornell University for the Ohio River Basin Energy Study. U. S. Environmental Protection Agency Office of Research and Development.

Clarke, J., and F. Parker. 2009. Uranium recovery and remediation of uranium mill tailings: Russian and U.S. experience. In *Cleaning up sites contaminated with radioactive materials: International workshop proceedings*. Washington, DC: National Academies Press.

Cogan, P. 2005. $5 billion preliminary commitment approved by Ex-Im Bank for proposed U.S.-built nuclear power plants in mainland China. Export-Import Bank press release, February 18.

Cohen, L., and R. Noll. 1991. *The technology pork barrel*. Washington, DC: Brookings Institution Press.

Congressional Budget Office (CBO). 2009. *Cost estimate: H.R. 1462, American Clean Energy Leadership Act of 2009*. September 30.

Congressional Budget Office (CBO). 2007a. *Cost estimate: H.R. 2262, Hardrock Mining and Reclamation Act of 2007*. October 29.

Congressional Budget Office (CBO). 2007b. *Cost estimate: S. 1321, Energy Savings Act of 2007*. June 11.

Congressional Budget Office (CBO). 2004. *Estimating the value of subsidies for federal loans and loan guarantees*. August.

Congressional Budget Office (CBO). 2003. *Cost estimate for S. 14, Energy Policy Act of 2003*. May 7.

Constellation Energy Group (CEG). 2009. *Form10-k*. December 31.

Cooper, M. 2009. *The economics of nuclear reactors: Renaissance or relapse?* Institute for Energy and the Environment, Vermont Law School. June.

Corrigan, D. 2008. Personal communication from Dick Corrigan of the U.S. DOE's Office of Loan Guarantees to the author, January 25.

Crane, C. 2007. Statement for the record of Christopher Crane, senior vice president of the Exelon Corporation and president and chief nuclear officer of Exelon Nuclear, before the Subcommittee on Energy and Air Quality, Committee on Energy and Commerce of the U.S. House of Representatives, April 24.

Dagan, D. 2008. When Susquehanna runs dry, who should pay? *Central Penn Business Journal*, May 9.

Database of State Incentives for Renewables & Efficiency (DSIRE). 2009. Rules, regulations & policies for renewable energy. University of North Carolina. Online at *www.dsireusa.org/summarytables/rrpre.cfm*, accessed December 21, 2009.

Dehoff, A. 2009. Personal communication from Andrew Dehoff, director of planning and operations of the Susquehanna River Basin Commission, to the author, May 18.

Department of Energy (DOE). 2010. The DOE offers conditional loan guarantee for front end nuclear facility in Idaho. Online at *www.lgprogram.energy.gov/press/052010.pdf.* May 20.

Department of Energy (DOE). 2009b. *Audit report: The Department of Energy's loan guarantee program for innovative energy technologies*. DOE/IG-0812. Office of the Inspector General.

Department of Energy (DOE). 2009c. Nuclear power 2010. Online at *www.ne.doe.gov/np2010/activities.html*, accessed January 13, 2010.

Department of Energy (DOE). 2009d. 800 to 1000 new jobs coming to Piketon: Department of Energy to accelerate cleanup work while USEC further develops ACP technology. Press release, July 28. Online at *energy.gov/news2009/7702.htm*, accessed January 13, 2010.

Department of Energy (DOE). 2009e. FY2010 statistical table by appropriation. May 6. Online at *www.cfo.doe.gov/budget/10budget/Content/ApropStat.pdf.*

Department of Energy (DOE). 2009f. *S*ecretary Chu announces funding for 71 university-led nuclear research and development projects. Press release, May 6. Online at *www.energy.gov/news2009/7383.htm*, accessed January 13, 2010.

Department of Energy (DOE). 2008. Nuclear energy. In *FY2009 Congressional Budget Request, V. 3.*

Department of Energy (DOE). 2007. *Special report: Loan guarantees for innovative energy technologies.* DOE/IG-0777. Office of the Inspector General.

Department of Energy (DOE). 2006a. *Energy demands on water resources.* Report to Congress on the Interdependency of Energy and Water, December.

Department of Energy (DOE). 2006b. Standby support final rule fact sheet, August 4. Online at *nuclear.gov/pdfFiles/standbySupportFinalRule080406FactSheet.pdf*, accessed January 13, 2010.

Department of Energy (DOE). 2006c. Standby support for certain nuclear plant delays: Final rule. *Federal Register* 71(155).

Department of Energy (DOE). 1990. *Uranium enrichment annual report.*

Department of Justice (DOJ). 2009. *Radiation Exposure Compensation System: Claims to date. Summary of claims received by 04/28/2009, all claims.*

Department of Labor (DOL). 2009a. *Cumulative EEOICPA compensation paid—Portsmouth gaseous diffusion plant, through 31 January 2009.* Office of Workers' Compensation Programs.

Department of Labor (DOL). 2009b. *Cumulative EEOICPA compensation paid—Paducah gaseous diffusion plant, through 31 January 2009.* Office of Workers' Compensation Programs.

Department of Labor (DOL). 2009c. *Cumulative EEOICPA compensation paid—Oak Ridge gaseous diffusion plant K-25, through 31 January 2009.* Office of Workers' Compensation Programs.

Department of State (DOS). 2008. International finance and investment for nuclear power projects in developing countries: Implementation of the U.S.-Russia Declaration on Nuclear Energy and Nonproliferation. Memo circulated at the "Sochi Summit" involving Presidents Bush and Putin, April.

Diehl, P. 2004. *Uranium mining in Eastern Germany: The WISMUT legacy.* WISE Uranium Project. Online at *www.wise-uranium.org/uwis.html*, accessed December 21, 2009.

Duff & Phelps. 2009a. *Nuclear decommissioning 12-31-08 funding status.*

Duff & Phelps. 2009b. *Nuclear Decommissioning Trust ("NDT") investment management: Summary of NRC, IRS, FERC and FASB rules & regulations, July 2009 update.*

Duff & Phelps. 2008a. *Nuclear Decommissioning Trust ("NDT") investment management: Summary of NRC, IRS, FERC and FASB rules & regulations, June 2008 update.*

Duff & Phelps. 2008b. *Nuclear decommissioning 12-31-07 funding status.*

Duff & Phelps. 2007. *Nuclear decommissioning 12-31-07 funding status.*

Earthworks. 2007. *A hardrock mining royalty: Case studies and industry norms.* October 2.

Elder, R. 2007. Tax breaks become a tool for shaping Texas energy policy. *Austin American-Statesman*, June 3.

Elliot, M. 2009. Enrichment: Present and projected future supply and demand. Seminar by Mark Elliot, director of marketing and sales for Urenco, at IEA, Vienna, January 29.

Energy Contractors Price-Anderson Group. 1998. Response to the U.S. Department of Energy notice of inquiry concerning preparation of report to Congress on the Price-Anderson Act. January 30.

Energy Information Administration (EIA). 2009a. 2016 levelized cost of new generation resources. In *Annual energy outlook 2010*, December.

Energy Information Administration (EIA). 2009b. Domestic uranium production report. Online at *http://www.eia.doe.gov/cneaf/nuclear/dupr/dupr.html*, accessed April 19, 2010.

Energy Information Administration (EIA). 2009c. Uranium purchased by owners and operators of U.S. civilian nuclear power reactors. Online at *www.eia.doe.gov/cneaf/nuclear/umar/summarytable1.html*, accessed January 12, 2010.

Energy Information Administration (EIA). 2008a. *Federal financial interventions and subsidies in energy markets 2007.* SR/CNEAF/2008-01.EIA.

Energy Information Administration (EIA). 2008b. *Annual energy outlook 2008.*

Energy Information Administration (EIA). 2008c. Tables 10, 11, and 16 in *Uranium marketing annual survey* (2003–2007).

Energy Information Administration (EIA). 2007. *Energy market impacts of a clean energy portfolio standard: Follow-up.* SR/OIAF/2007-02.

Energy Information Administration (EIA). 2006a. *Annual energy outlook 2007.*

Energy Information Administration (EIA). 2006b. *Energy market impacts of a clean energy portfolio standard.* SR/OIAF/2006-02.

Environmental Protection Agency (EPA). 2008a. *Technical report on technologically enhanced naturally occurring radioactive materials from uranium mining, Volume 1: Mining and reclamation background.* EPA 402-R-08-005. Office of Radiation and Indoor Air.

Environmental Protection Agency (EPA). 2008b. *Technical report on technologically enhanced naturally occurring radioactive materials from uranium mining, Volume 2: Investigation of potential health, geographic, and environmental issues of abandoned uranium mines.* EPA 402-R-08-005. Office of Radiation and Indoor Air.

Environmental Protection Agency (EPA). 2004. *Cleaning up the nation's waste sites: Markets and technology trends.* 2004 edition. EPA-542-R-04-015. Office of Solid Waste and Emergency Response.

Environmental Protection Agency (EPA). 2002. *Economic and benefits analysis for the proposed Section 316(b) Phase II Existing Facilities Rule.* EPA-821-R-02-001.

Environmental Working Group (EWG). 2009. EWG analysis of Bureau of Land Management's LR2000 database. January 2009 download.

Environmental Working Group (EWG). 2006. Uranium fever fuels new land rush: Mining claims on U.S. public lands up 47%. Press release, December 14.

Epstein, E. 2008. Three Mile Island Alert Inc.'s comments on Susquehanna River Basin Commission's draft comprehensive plan for water resources of the Susquehanna River Basin. Submitted to Paul Swartz, executive director, SRBC, August 18.

Ernst & Young. 2007. *International comparison of depreciation rules and tax rates for selected energy investments.* Prepared for the American Council for Capital Formation.

Eskow, L., et al. 2007. Brief for respondents Eurodif S.A., Areva NC S.A., and Areva NC, Inc., in the Supreme Court of the United States, Nos. 07-1059 & 07-1078, United States of America v. Eurodif S.A. et al.; USEC, Inc. et al. vs. Eurodif S.A. et al.

European Union (EU). 2007. *State aid: Commission concludes that French state guarantee for Finnish nuclear power plant operator TVO does not constitute aid*. September 26.

Export-Import Bank (Eximbank). 2009. *Annual report 2008.*

Export-Import Bank (Eximbank). 2002. Summary of minutes of meeting of board directors, December 19.

Export-Import Bank (Eximbank). 2000. Summary of minutes of meeting of board directors, February 10.

Export-Import Bank (Eximbank). 1999. Summary of minutes of meeting of board directors, August 13.

Fahys, J. 2009. Tons of tainted tailing are on the move—finally. *Salt Lake Tribune*, May 4.

Falk, J. 2008. *Nuclear power's role in generating electricity*. Washington, DC: Congressional Budget Office.

Falkenrath, R. 2000. Uranium blues: Economic interest vs. national security. *The Milken Institute Review*, Fourth quarter.

Faure, M., and B. van den Borre. 2008. Compensating nuclear damage: A comparative economic analysis of the U.S. and international liability schemes. *William & Mary Environmental Law and Policy Review* 33(1)219–287.

Fertel, M. 2009. Testimony of Marvin Fertel, senior vice president and chief nuclear officer of the Nuclear Energy Institute, before the Committee on Energy and Natural Resources, U.S. Senate, March 18.

Fertel, M. 2007. Testimony of Marvin Fertel, senior vice president and chief nuclear officer of the Nuclear Energy Institute, at a hearing on uranium enrichment of the Senate Committee on Energy and Natural Resources, November 15. S-Hrg 110-307.

Fiore, K. 2008. *The nuclear liability limit in the OECD conventions: An implicit subsidy*. Maastricht University Faculty of Law working paper, January.

Ford, C. 2008. Nuclear technology rights and benefits: Risk, cost, and beneficial use under the NPT's Article IV. Presentation by Christopher Ford of the Hudson Institute to the joint Carnegie/Nonproliferation Policy Education Center conference "Comparing Electricity Costs," New York, December 1.

Fowler, B. 2008. USEC break big for OR [Oak Ridge]. *KnoxvilleBiz*, September 3.

GDFSuez. 2009. Shareholding structure as of 12/31/2008. Online at *www.gdfsuez.com*, accessed April 22.

General Accounting Office (GAO). 2004. *Nuclear regulation: NRC's liability insurance requirements for nuclear power plants owned by limited liability companies*. GAO-04-654.

General Accounting Office (GAO). 2003. *Nuclear regulation: NRC needs more effective analysis to ensure accumulation of funds to decommission nuclear power plants*. GAO-04-32. Online at *www.gao.gov/new.items/d0432.pdf*, accessed January 13, 2010.

General Accounting Office (GAO). 2000. *Nuclear nonproliferation: Implications of the U.S. purchase of Russian highly enriched uranium*. GAO-01-148.

General Accounting Office (GAO). 1992. *Nuclear waste: Status of actions to improve DOE user-fee assessments*. GAO/RCED-92-165.

General Accounting Office (GAO). 1991. *Uranium enrichment: DOE needs to pursue alternative AVLIS deployment options*. GAO/RCED-91-88.

General Accounting Office (GAO). 1990a. *Nuclear waste: Changes needed in DOE user-fee assessments to avoid funding shortfall*. RCED-90-65.

General Accounting Office (GAO). 1990b. *Financial audit: Rural Electrification Administration's financial statements for 1988 and 1987*. AFMD-90-73.

Gilbertsen, H.J., and A. Hernandez. 2007. Supplemental comments in response to notice of proposed rulemaking on loan guarantees for projects that employ innovative technologies (RIN 1901-AB21). 72 *Federal Register* 27471, May 16. Submitted by Goldman Sachs to Howard Bergstrom, U.S. Department of Energy, July 2.

Gilinsky, V., M. Miller, and H. Hubbard. 2004. *A fresh examination of the proliferation dangers of light water reactors*. Prepared for the Nonproliferation Policy Education Center.

Gleick, P. 2009. Personal communication from Peter Gleick of the Pacific Institute to the author, May 5.

Goldberg/Renewable Energy Policy Project. 2000. *Federal energy subsidies: Not all technologies are created equal.* Marshall Goldberg for the Renewable Energy Policy Project. Research report No. 11, July.

Government Accountability Office (GAO). 2010. Department of Energy: Future options are needed to improve DOE's ability to evaluate and implement the loan guarantee program. GAO-10-627.

Government Accountability Office (GAO). 2008a. Hardrock mining: Information on abandoned mines and value and coverage of financial assurances on BLM land. Statement of Robin Nazzaro, director of National Resources and Environment, before the Committee on Energy and Natural Resources of the U.S. Senate, March 12. GAO-08-574T.

Government Accountability Office (GAO). 2008b. Hardrock mining: Information on state royalties and trends in mineral imports and exports. Letter from Robin Nazzaro, director of Natural Resources and Environment, to Senator Harry Reid, Senator Jeff Bingaman, and Representative Nick Rahall, July 21. GAO-08-849R.

Government Accountability Office (GAO). 2008c. *Department of Energy: New loan guarantee program should complete activities necessary for effective and accountable program management.* GAO-08-750.

Government Accountability Office (GAO). 2007a. *DOE's loan guarantee program.* GAO-07-339R.

Government Accountability Office (GAO). 2007b. *Radiation Exposure Compensation Act: Program status.* Letter from Stephen Caldwell, director of Homeland Security and Justice Issues, to the House and Senate Committees on the Judiciary. GAO-07-1037R.

Government Accountability Office (GAO). 2006a. *U.S. Enrichment Corporation privatization: USEC's delays in providing data hinder DOE's oversight of the uranium decontamination agreement.* GAO-06-723.

Government Accountability Office (GAO). 2006b. *Nuclear power plants: Efforts made to upgrade security, but the Nuclear Regulatory Commission's design basis threat process should be improved.* GAO-06-388.

Gram, D., and F. Bass. 2009. Funds to shut nuclear plants fall short. Associated Press, June 17.

Grigg, N. 2009. Personal communication from Neil Grigg, water resource specialist and professor of civil and environmental engineering at Colorado State University, to John Simpson, Rocky Mountain Institute, on behalf of the author, April 29.

Gronlund, L., D. Lochbaum, and E. Lyman. 2007. *Nuclear power in a warming world: Assessing the risks, addressing the challenges.* Cambridge, MA: Union of Concerned Scientists.

Grossman, E. 2008. Intelligence report sees higher nuclear risks as technology spreads. *Global Security Newswire*, November 21.

Gunter, L., P. Gunter, S. Cullen, and N. Burton. 2001. *Licensed to kill.* A joint report of the Humane Society of the United States, the Nuclear Information and Resource Service, the Safe Energy Communication Council, and Standing for Truth About Radiation.

Guttman, D. 2002. Testimony of Dan Guttman on the Price-Anderson Act Reauthorization before the Subcommittee on Transportation, Infrastructure, and Nuclear Safety of the Committee on Environment and Public Works, U.S. Senate, January 23.

Guttman, D. 2001. The United States Enrichment Corporation: A failing privatisation. *Asian Journal of Public Administration* 23(2)247–272.

Hall, K.C. 1986. Statement by Kenneth C. Hall, insurance consultant at the General Electric Company, to the Subcommittee on Nuclear Regulation, Committee on Environment and Public Works, U.S. Senate, regarding reauthorization of the Price-Anderson Act, May 13.

Hamilton, T. 2009. $26B cost killed nuclear bid. *Ontario Star*, July 14.

Harding, J. 2009a. Economics of new reactors and alternatives. Presentation by Jim Harding of Harding Consulting at the Carnegie/NPEC Conference, February.

Harding, J. 2009b. Personal communication from Jim Harding of Harding Consulting to the author, April 3.

Harding, J. 2007. Economics of nuclear power and proliferation risks in a carbon-constrained world. *Electricity Journal* 20(10)65–76.

Hatcher, D.J. 1998. Letter from Donald J. Hatcher, director of risk management at the U.S. Enrichment Corporation to the U.S. Department of Energy pursuant to "Notice of inquiry ('NOI') concerning preparation of a report to Congress on the Price-Anderson Act, 62 Fed. Reg. 68272 (Dec. 31, 1997)." January 30.

Hebert, H.J. 2001. Seven states using National Guard to help secure reactors. *Daily Record* (Ellensburg, WA), November 1.

Heede, Morgan, Ridley/Center for Renewable Resources. 1985. *The hidden costs of energy.* Rick Heede, Rick Morgan, and Scott Ridley for the Center for Renewable Resources.

Henriques, D. 2009. Victims of Madoff seek claims overhaul. *New York Times*, June 8.

Hertz, M. 2009. Testimony of Michael Hertz, deputy assistant attorney general at the Civil Division, U.S. Department of Justice, before the Committee on the Budget, U.S. House of Representatives, concerning "Budgeting for nuclear waste management," July 16.

Heyes, A. 2002. Determining the price of Price-Anderson. *Regulation* 5(4)26–30.

Hightower, M. 2009. Personal communication from Michael Hightower of Sandia National Laboratory to the author, May 11.

Hiskes, J. 2009. No "renewable" nukes and coal for Indiana. *Grist*, April 30.

Holt, M. 2010. *Nuclear energy policy.* RL33558. Washington, DC: U.S. Congressional Research Service. May 27.

Holt, M. 2009. *Nuclear energy policy.* RL33558. Washington, DC: U.S. Congressional Research Service. December 10.

Hopkins, J.S., and P. Adams. 2006. Calvert County solicits reactor. *Baltimore Sun*, August 9.

Horner, D., and A. MacLachlan. 2008. U.S. working with allies to change global rules for nuclear financing. *Platts*, October 23.

Hornick, R., and A. Kagan. 2006. U.S. nuclear power: Credit implications. In *Global Power/North America Special Report*, Fitch Ratings, November 2.

Horwitt, D. 2009. Personal communication from Dusty Horwitt of the Environmental Working Group to the author, April 28.

Humphries, M. 2007. *Mining on federal lands: Hardrock minerals.* RL33908. Washington, DC: U.S. Congressional Research Service.

Huotari, J. 2008. USEC gets tax break worth $5m. *The Oak Ridger*, September 3.

Idaho National Energy Laboratory (INEL). 2004. *Decision-makers' forum on a unified strategy for nuclear energy.* U.S. Department of Energy.

Institut Français de l'Environnement (IFEN). 2005. Les prélèvements d'eau en France et en Europe. *Les données de l'environnement 104,* July.

Insurance Information Institute. 2010. *The ten most costly catastrophes, United States.* Online at *www.iii.org/media/facts/statsbyissue/catastrophes/*,; and *The ten most costly world insurance losses*, 1970-2000. Online at *http://www2.iii.org/international/rankings/*. Both accessed August 20, 2010.

Internal Revenue Service (IRS). 2009. *Build America Bonds and direct payment subsidy implementation.* IRS notice 2009-26.

Internal Revenue Service (IRS). 2008. *How to depreciate property.* Publication 946.

International Atomic Energy Agency (IAEA). 2008a. *Annual report 2007.*

International Atomic Energy Agency (IAEA). 2008b. *The agency's budget update for 2009.*

International Energy Agency (IEA). 2009. Energy RD&D database, accessed April 10.

International Security Advisory Board (ISAB). 2008. *Report on proliferation implications of the global expansion of civil nuclear power.* U.S. Department of State.

International Trade Administration (ITA). 2008. Amendment on the agreement suspending the antidumping investigation on uranium from the Russian Federation. *Federal Register* 73(28) 7705–7708.

Joint Committee on Taxation (JCT). 2008. *Estimates of federal tax expenditures for fiscal years 2008-12.* JCS-2-08.

Joint Committee on Taxation (JCT). 2001. *Federal tax provisions affecting the electric power industry*. JCX-54-01.

Jones, C. 2007. Susquehanna River Basin Commission fined PPL Corp. $500,000. *The Citizens Voice*, September 15.

Kaplan, S. 2009a. Personal communication from Stan Kaplan of the U.S. Congressional Research Service to the author, May 14.

Kaplan, S. 2009b. Personal communication from Stan Kaplan of the U.S. Congressional Research Service to the author, June 11.

Kaplan, S. 2008. *Power plants: Characteristics and costs*. Washington, DC: U.S. Congressional Research Service. RL34746.

Keystone. 2007. *Nuclear power joint fact-finding*. The Keystone Center. June.

Kinney, T. 2008. Funding "iffy" for Ohio uranium enrichment plant. Associated Press, November 8.

Komanoff, C., and C. Roelofs. 1992. *Fiscal fission: The economic failure of nuclear power*. Komanoff Energy Associates, for Greenpeace.

Koplow, D. 2010. Review of accelerated depreciation, investment tax credit, and production tax credit provisions of Senator Kerry's and Senator Lieberman's American Power Act. Memorandum to Friends of the Earth. Cambridge, MA: Earth Track, Inc. June 17.

Koplow, D. 2009a. Energy transition: Mapping an appropriate role for government. Presentation by the author at a joint seminar (Is Subsidizing Commercial Energy Projects the Best Way for America to Achieve Its Energy Goals?) hosted by the Nonproliferation Policy Education Project and the Heritage Foundation, Washington, DC, March 24.

Koplow, D. 2009b. Nuclear power as taxpayer patronage: A case study of subsidies to Calvert Cliffs Unit 3. Forthcoming in *Expanding nuclear power: Weighing the costs and risks*, edited by H. Sokolski. Washington, DC: Strategic Studies Institute.

Koplow, D. 2007a. Comments submitted by the author to Howard Bergstrom, U.S. Department of Energy, pursuant to Notice of Proposed Rulemaking for RIN 1901-AB21 "Loan Guarantees for Projects that Employ Innovative Technologies."

Koplow, D. 2007b. *Biofuels—At what cost? Government support for ethanol and biodiesel in the United States, 2007 update*. Geneva: Global Subsidies Initiative.

Koplow, D. 2005. Nuclear power in the U.S.: Still not viable without subsidy. Presentation by the author at the Nuclear Power and Global Warming Symposium sponsored by the Nuclear Policy Research Institute, Warrenton, VA, November 7–8.

Koplow, D. 1993. *Federal energy subsidies: Energy, environmental, and fiscal impacts*. Washington, DC. Alliance to Save Energy.

Koplow, D., and A. Martin. 1998. *Fueling global warming: Federal subsidies to oil in the United States*. Washington, DC: Greenpeace.

Kouts, C. 2009. Statement by Christopher Kouts, acting director of the Office of Civilian Radioactive Waste Management, U.S. Department of Energy, before the Committee on the Budget, U.S. House of Representatives, July 16.

Kuipers, J. 2002. Testimony of Jim Kuipers of the Center for Science in Public Participation at a hearing (Availability of bonds to meet federal requirements for mining, oil and gas projects) of the Subcommittee on Energy and Mineral Resources of the U.S. House Committee on Resources, July 23.

Lavine, D. 2007. School property tax abatements under HB 1200 (2001). Austin, TX: Center for Public Policy Priorities.

Lempert, R. 2009. Low probability/high consequence events: Dilemmas of damage compensation. University of Michigan Law School working paper 09-005.

Ling, K. 2009a. Nuclear power: Senate GOP to offer plan for industry incentives, reprocessing. *Environment & Energy Daily*, May 5.

Ling, K. 2009b. DOE: Loan guarantees "beginning to be released"—Chu. *Environment & Energy Daily*, March 17.

Lochbaum, D. 2007. *Got water?* Cambridge, MA: Union of Concerned Scientists.

Longenecker, J.R. 2007. Testimony of John R. Longenecker, former deputy assistant secretary for uranium enrichment at the U.S. Department of Energy, at a hearing on uranium enrichment of the Senate Committee on Energy and Natural Resources, November 15. S-Hrg 110-307.

Lovelock, J. 2004. Nuclear power is the only green solution. *The Independent*, May 24.

Lovins, A. 2009. Does a big economy need big power plants? Guest post on the *Freakonomics* blog, *New York Times*, February 9.

Lovins, A., L.H. Lovins, and L. Ross. 1980. Nuclear power and nuclear bombs. *Foreign Affairs*, Summer.

Lyman, E. 2009. Personal communication from Ed Lyman of the Union of Concerned Scientists to the author, July.

MacKerron, G. 1989. The decommissioning of nuclear plant: Timing, cost and regulation. *Energy Policy* 17(2)103–108.

Management Information Services, Inc. (MISI). 2008. *Analysis of federal expenditures for energy development.* Prepared for the Nuclear Energy Institute.

Massachusetts Institute of Technology (MIT). 2009. *Update of the MIT 2003 future of nuclear power.* Cambridge, MA: MIT Energy Initiative.

Mayer, P. 2009. Personal comunication from Peter Mayer of Aquacraft, Inc. to the author, April 23.

Metcalfe, G. 2009. *Taxing energy in the United States: Which fuels does the tax code favor?* Prepared for the Center for Energy Policy and the Environment at the Manhattan Institute.

Miller, M., C. Pomatto, and J. Hylko. 2002. *Using risk-based corrective action (RBCA) to assess (theoretical) cancer deaths averated compared to the (real) cost of environmental remediation.* Proceedings of the Waste Management '02 Conference, Tucson, AZ, February 24–28.

Montange, C. 1990. *Stopping a budget meltdown: Reorganizing the federal uranium enrichment program.* Washington, DC: National Taxpayers Union.

Moody's. 2009. *New nuclear generation: Ratings pressure increasing.* Moody's Global Infrastructure report 117883.

Moody's. 2007. *New nuclear generation in the United States: Keeping options open vs. addressing an inevitable necessity.* Moody's Corporate Finance. October.

Morrison, J., et al. 2009. *Water scarcity & climate change: Growing risks for businesses & investors.* Report by the Pacific Institute for Ceres.

Morrison, S. 1988. *Rural electric cooperative defaults: Origins, current status, and implications.* Washington, DC: U.S. Congressional Research Service.

MSB Energy Associates. 2008. *Major federal tax breaks that lower investor-owned electric company costs and U.S. Treasury revenues, 2006.* Prepared for the American Public Power Association.

Mufson, S. 2010. Constellation Energy shelves plan for Calvert Cliffs reactor. *Washington Post*, October 13.

Munson, D. 2005. *Water use by electric utilities in the Great Lakes.* Washington, DC: Northeast-Midwest Institute.

Myers, R. 2007. Nuclear energy and loan guarantees, Parts II and III. *NEI Nuclear Notes* blog, October 25.

National Nuclear Security Administration (NNSA). 2009. *NNSA contributions to the IAEA.* U.S. Department of Energy.

Neff, T.L. 1998. Privatizing U.S. national security: The U.S.-Russian HEU deal at risk. *Arms Control Today* 28(6).

Nicola, S. 2009. Swedish nuclear revival confirms European trend. UPI.com, February 6.

Norlen, D. 2009. Personal communication from Doug Norlen, policy director at Pacific Environment and member of ECA-Watch, to the author, July 2.

North American Energy Working Group (NAEWG). 2005. *Guide to federal regulation of sales of imported electricity in Canada, Mexico, and the United States.*

Nuclear Energy Agency (NEA). 2005. *Projected costs of generating electricity: 2005 update.* International Energy Agency. Paris. Organisation for Economic Cooperation and Development.

Nuclear Energy Institute (NEI). 2010a. *The clean energy loan guarantee program's credit subsidy fee: A review of a recent paper by the center for American Progress.* Washington DC.

Nuclear Energy Institute (NEI). 2010b. U.S. electricity production costs and components, 1995–2009. May. Online at *http://www.nei.org/filefolder/US_Electricity_Production_Costs_and_Components.xls*, accessed September 20, 2010.

Nuclear Energy Institute (NEI). 2009a. *U.S. nuclear power plant operators, owners, and holding companies.* Washington, DC.

Nuclear Energy Institute (NEI). 2009b. *Status report: Policies that support new nuclear power plant development.* Washington, DC.

Nuclear Energy Institute (NEI). 2009c. *State legislation and regulations supporting nuclear plant construction.* Washington, DC.

Nuclear Energy Institute (NEI). 2009d. *Legislative proposal to help meet climate change goals by expanding U.S. nuclear energy production.* Washington, DC.

Nuclear Energy Institute (NEI). 2008. *Nuclear power 2010: A key building block for new nuclear power plants.* Washington, DC.

Nuclear Energy Institute (NEI). 2007. *Fact sheet: Decommissioning of nuclear power plants.* Washington, DC.

Nuclear Energy Institute (NEI). 2001. Nuclear energy surpasses coal-fired plants as leader in low-cost electricity production. News release, January 9. Online at *http://www.fraserinstitute.org/commerce.web/product_files/GlobalPetroleumSurvey2009.pdf.*

Nuclear Regulatory Commission (NRC). 2010. Expected nuclear power plant applications, updated January 4. Washington, DC.

Nuclear Regulatory Commission (NRC). 2009. Variable annual fee structure for power reactors: Advance notice of proposed rulemaking. *Federal Register* 74(56)12735–12735.

Nuclear Regulatory Commission (NRC). 2008a. *Nuclear insurance and disaster relief funds.* Washington, DC.

Nuclear Regulatory Commission (NRC). 2008b. FY2009 budget. Press briefing, February 4. Washington, DC.

Nye, P. 2007. Reactor renaissance. *Rural Electric Magazine*, November.

Office of Civilian Radioactive Waste Management (OCRWM). 2008a. *Fiscal year 2007: Civilian radioactive waste management fee adequacy report.* Washington, DC: U.S. Department of Energy.

Office of Civilian Radioactive Waste Management (OCRWM). 2008b. *Analysis of the total system life cycle cost of the Civilian Radioactive Waste Management Program, fiscal year 2007.* Washington, DC: U.S. Department of Energy.

Office of Civilian Radioactive Waste Management (OCRWM). 2008c. Table: Purchaser fee payments to the Nuclear Waste Fund as of December 31, 2008. Washington, DC: U.S. Department of Energy.

Office of Civilian Radioactive Waste Management (OCRWM). 1990. *Nuclear Waste Fund fee adequacy: An assessment.* Washington, DC: U.S. Department of Energy.

Office of Civilian Radioactive Waste Management (OCRWM). 1989. *Annual report to Congress.* DOE/RW-0216. Washington, DC: U.S. Department of Energy.

Office of Management and Budget (OMB). 2009. *Federal credit supplement: Budget of the U.S. government, FY 2010.*

Office of Management and Budget (OMB). 2008. Table 6: Loan guarantees: Assumptions underlying the 2009 subsidy estimates. *Federal credit supplement: Budget of the U.S. government, FY09.*

Organisation for Economic Cooperation and Development (OECD). 2009. *2009 sector understanding on export credits for nuclear power plants.* Trade and Agricultural Directorate. Paris.

Organisation for Economic Cooperation and Development (OECD). 2008. *OECD's PRODUCER support estimate and related indicators of agricultural support: Concepts, calculations, interpretation, and use (The PSE manual).* Paris.

Overseas Private Investment Corporation (OPIC). 2009. *OPIC 2008 annual report.*

Pacala, S., and R. Socolow. 2004. Stabilization wedges: Solving the climate problem for the next 50 years with current technologies. *Science*, August 13, 968–972.

Pacific Northwest Laboratory (PNL). 1978. *An analysis of federal incentives used to stimulate energy production.* Battelle Memorial Institute. Prepared for the U.S. Department of Energy. PNL240-REV. December.

Pare, M. 2008. Chattanooga gives Alstom Power $21 million tax abatement lasting 17 years. *Chattanooga Times Free Press*, June 27.

Parshley, J.V., and D.W. Struhsacker. 2009. *The evolution of federal and Nevada state reclamation bonding requirements for hardrock exploration and mining projects: A case history documenting how federal and state regulators used existing regulatory authorities to respond to shortcomings in the reclamation bonding program.* Spokane, WA: Northwest Mining Association.

Peterson, D., et al. 2008. DOE remediation of uranium mills: A progress report. *Southwest Hydrology* 7(6)26–29.

Pew Center on Global Climate Change. 2009. *Ohio adopts alternative energy portfolio standard.* Online at *www.pewclimate.org/node/5922*, accessed on December 22, 2009.

Platts. 2009. Florida Senate committee passes compromise clean energy bill. *Platts News*, April 1.

Power Engineering International. 2009. DOE budget lifts renewables, cuts nuclear and coal. May 6.

PriceWaterhouseCoopers and the National Venture Capital Association. 2009. *Money tree report* data extract. Online at *www.pwcmoneytree.com/MTPublic/ns/nav.jsp?page=historical*, accessed December 22, 2009.

Public Citizen. 2007. *Nuclear power can't stand the heat.* August. Online at *www.citizen.org/documents/HotNukesFactsheet.pdf*, accessed January 13, 2010.

Public Citizen. 2006. *What is an early site permit?* People's Alliance for Clean Energy, for Public Citizen. Online at *www.citizen.org/documents/espbrochure.pdf*, accessed January 13, 2010.

RIA Novosti. 2006. Russia's state uranium exporter sues U.S. Commerce Department. *RIA Novosti*, July 13.

Rispoli, J.A. 2007. Testimony of James A. Rispoli, assistant secretary for environmental management at the DOE, at a hearing (on uranium enrichment) of the Senate Committee on Energy and Natural Resources, November 15. S-Hrg 110-307.

Rothwell, G. 2005. Personal communication from Geoffrey Rothwell of Stanford University to the author, October 24.

Schlissel, D., M. Mullet, and R. Alvarez. 2009. *Nuclear loan guarantees: Another taxpayer bailout ahead.* Cambridge, MA: Union of Concerned Scientists.

Schlissel, D., P. Petersen, and B. Biewald. 2002. *Financial insecurity: The increasing use of limited liability companies and multi-tiered holding companies to own nuclear power plants.* Report by Synapse Energy Consulting prepared for the STAR Foundation and Riverkeeper, Inc.

Schneider, M. 2009. Personal communication from Mycle Schneider to the author, June 29.

Schneider, M., et al. 2009. *World nuclear industry status report 2009.* Prepared for the German Federal Ministry of Environment, Nature Conservation, and Reactor Safety.

Schneider, M., et al. 2007. *Residual risk: An account of events in nuclear power plants since the Chernobyl accident in 1986.* Brussels: European Green Party.

Securities and Financial Market Association (SIMFA). 2009. Fact sheet about Build America Bonds.

Seeley, T. 2009. Utilities seek to suspend nuclear waste payments (Update 1). *Bloomberg.com*, July 8.

Seiple, C. 1997. Stranded investment: The other side of the story. *Public Utilities Fortnightly*, March 15.

Severance, C.A. 2009. Business risks and costs of new nuclear power. *Climate Progress*, January 7.

Sewell, P.G. 2007. Testimony of Philip G. Sewell, senior vice president of American centrifuge and Russian HEU, U.S. Enrichment Corporation, before the International Trade Commission in the matter of "Low enriched uranium from France," October 11. Investigation number 731-TA-909 (review).

Shively, B. 2008. DOE announces loan guarantee applications for nuclear power plant construction. Press release from the Office of Public Affairs, U.S. Department of Energy, October 2.

Silverstein, K., and I. Urbina. 1999. Insider enrichment. *The Nation*, November 25.

Simpson, J. 2009. Personal communication from John Simpson of the Rocky Mountain Institute to the author, April 29.

Sissine, F. 2009. Personal communication from Fred Sissine of the U.S. Congressional Research Service to the author, August 11.

Sissine, F. 2008. *Renewable energy R&D funding history: A comparison with funding for nuclear energy, fossil energy, and energy efficiency R&D*. RS22858. Washington, DC: U.S. Congressional Research Service.

Smith, R. 2009. U.S. chooses four utilities to revive nuclear industry. *Wall Street Journal*, June 17.

Sokolski, H. 2009. Personal communication from Henry Sokolski, executive director of the Nonproliferation Policy Education Center, to the author, July 2.

Squassoni, S. 2009a. Personal communication from Sharon Squassoni, senior associate in the Nuclear Policy Program of the Carnegie Endowment for International Peace, to the author, July 10.

Squassoni, S. 2009b. *Nuclear energy: Rebirth or resuscitation?* Washington, DC: Carnegie Endowment for International Peace.

Stiglitz, J. 1998. This privatization proposal is radioactive. *Wall Street Journal*, June 2.

STRATFOR. 2009. Russia: A uranium deal for U.S. power plants. May 27. Online at *www.stratfor.com/analysis/20090527_russia_uranium_deal_u_s_power_plants*, accessed December 22, 2009.

Stuckle, E. 2009. USEC welcomes Supreme Court decision. U.S. Enrichment Corporation press release posted on *Reuters Business Wire*, January 26.

Takemoto, Y., and A. Katz. 2008. Samurai-sword maker's reactor monopoly may cool nuclear revival. *Bloomberg.com*, March 12.

Tawil, N. 2003. *Bonding for reclaiming federal lands*. Washington, DC: U.S. Congressional Budget Office.

Tennessee Valley Authority (TVA). 2006. Form 10-K (annual report), filed December 15, 2006 for the period ending September 30, 2006.

Tennessee Valley Authority (TVA). 1991. Information statement, August 12.

Tetreault, S. 2009. States balk at paying into nuclear waste fund. *ReviewJournal.com*, April 8.

Texas Comptroller. 2009. Report of the Texas Economic Development Act.

Texas Comptroller. 2008. *The energy report 2008*. Online at *www.window.state.tx.us/specialrpt/energy/*, accessed January 13, 2010.

Tobey, W. 2008. Testimony of William Tobey of the National Nuclear Security Administration, U.S. Department of Energy, at a hearing ("The HEU suspension agreement") of the Senate Committee on Energy and Natural Resources, March 5.

Turnage, J. 2008. New nuclear development: Part of the strategy for a lower carbon energy future. Presentation at the International Trade Administration's Nuclear Energy Summit, October 8.

Turnage, J. 2007a. A strategic analysis of the investment opportunity for advanced nuclear generation. Presentation at the MIT American Nuclear Society Seminar Series, March 12.

Turnage, J. 2007b. Testimony before the California Energy Commission, as printed in the *Transcript to the Committee Workshop before the California Energy Resources Conservation and Development Corporation* in the matter of "Preparation of the 2007 Integrated Energy Policy Report," June 28.

Union of Concerned Scientists (UCS). 2010. Billions of dollars in subsidies for the nuclear power industry will shift financial risks to taxpayers. June 30. Online at *http://www.ucsusa.org/assets/documents/nuclear_power/Nuclear-Subsidies-in-APA-and-ACELA.pdf.*

United Kingdom Department for Business Enterprise & Regulatory Reform (UK BERR). 2008. *Meeting the energy challenge: A white paper on nuclear power*. Government Cm 7296. London. Online at *www.berr.gov.uk/files/file43006.pdf*, accessed December 22, 2009.

U.S. Department of Agriculture Rural Utility Service (USDA RUS). 2008. *Rural electric power generation and capacity expansion*. Washington, DC.

U.S. Enrichment Corporation (USEC). 2009. *Energy security delivered by USEC: 2008 annual report*.

Vance, R. 2009. Current and future market trends in nuclear fuel supply. IAEA seminar on nuclear fuel supply, Vienna, January 26.

Vicini, J. 2009. U.S. court upholds power plant cooling water rule. *Reuters*, April 1.

Wald, M. 2010. U.S. sued over nuclear waste fees. *New York Times*, April 5.

Wald, M. 2009. Future dim for nuclear waste repository. *New York Times,* March 6.

Wald, M. 2008. As nuclear waste languishes, expense to U.S. rises. *New York Times*, February 17.

Warren, W. 2007. Testimony of Wesley Warren, director of programs at the Natural Resources Defense Counsel, at a hearing (on uranium enrichment) of the Senate Committee on Energy and Natural Resources, November 15. S-Hrg 110-307.

Williams, D.G. 2007. U.S. nuclear plant decommissioning funding adequacy—by individual funds, utilities, reactors, and industry-wide—assessed by Monte Carlo and baseline trend methods: 1998, 2000, 2001, and 2004. *Energy Economics* 29(5)1050–1100.

Wilson, F. 2007. *Failure rates in early stage venture deals.* New York: Union Square Ventures.

Wiser, R., and G. Barbose. 2008. *Renewables portfolio standards in the United States: A status report with data through 2007.* Berkeley, CA: Lawrence Berkeley National Laboratory.

Woodall, B. 2008. Areva unit seeks permission for U.S. permit for uranium enrichment. *Reuters*, December 31.

World Nuclear Association (WNA). 2009a. *The nuclear fuel cycle*. London.

World Nuclear Association (WNA). 2009b. *Information papers: The economics of nuclear power*. London. Online at *www.world-nuclear.org/info/inf02.html*, accessed December 22.

World Nuclear Association (WNA). 2009c. *Uranium enrichment*. London. Online at *www.world-nuclear.org/info/inf28.html*, accessed January 8, 2010.

Yurman, D. 2009a. Areva U.S. CEO talks with nuclear bloggers. The Energy Collective blog, June 7. Online at *theenergycollective.com/TheEnergyCollective/42417*, accessed December 22.

Yurman, D. 2009b. GE-Hitachi files with NRC for laser enrichment plant. Idaho Samizdat: Nuke Notes blog, July 6. Online at *djysrv.blogspot.com/2009/07/ge-hitachi-files-with-nrc-for-laser.html*, accessed December 22.

Appendix A: Total Subsidies to Nuclear Reactors (Overview)

		Subsidies to Existing Reactors, ¢/kWh							Subsidies to New Reactors, ¢/kWh					Notes
		Total	Legacy		Existing: Low		Existing: High		Total	Low		High		
Subsidy Type			Low	High	IOU	POU	IOU	POU		IOU	POU	IOU	POU	
I. Output-Linked Support	Nuclear production tax credit	NA							$6.0b–$8.6b total	1.05	NA	1.45	NA	(1)
I. Output-Linked Support	**Total Section I**		**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**		**1.05**	**0.00**	**1.45**	**0.00**	
II. Subsidies to Factors of Production – A. Subsidies to Reduce the Cost of Capital – Cost of Funds	Title XVII loan guarantees								For $18.5b authorized, subsidies of $0.8b–$1.1b/yr; $23b–$34b present value over 30-year term of loan guarantees	2.50		3.70		(2)
	Foreign credit support to U.S. projects								Emerging issue; no known deals yet					(3)
	ECA support of U.S. nuclear exports								Emerging issue; minimal support so far					
	Ratebasing of construction work in progress (CWIP)	Not quantified							Worth ~$40m–$90m/plant/yr in reduced financing costs	0.41	0.41	0.97	0.97	(4)
	Public reactors: reduced cost of borrowing	Not quantified; mostly a legacy cost by now								NA	3.13	NA	3.13	(5)
	Public reactors: no tax on net revenues, per year	$0.01b				0.07		0.07			0.07		0.07	(6)
	Public reactors: tax-exempt bonds, per year	$0.2b–$0.3b/yr based on TVA, BPA, and RUS alone				0.25		0.32						(7)
	Public reactors: low return on capital, per year	$0.4b–$0.9b/yr based on TVA and BPA alone				0.58		1.48						(8)
	Regulatory risk delay insurance	NA							$2.0b face value for six policies	0.00	0.00	0.80	0.80	(9)
II. – A. – Cost of Capital Goods	Combined legacy tax subsidies: accelerated depreciation, allowance for funds used during construction (AFUDC), investment tax credits		5.86	5.86										(10)
	Accelerated depreciation: new reactors and retrofits								$40m–$80m/plant/yr	0.33		0.70		(11)
	Licensing costs and site approval	NA							$0.8b total for two consortia	0.06	0.06	0.19	0.19	(12)
	Research and development	$515m for 2009			0.06	0.06	0.06	0.06	Expected to rise somewhat	0.06	0.06	0.06	0.06	(13)
	Stranded asset charges	$110b through 1997	1.05	1.05										(14)
II. – B. Labor Costs	Payments to injured workers, civilian share	$1.1b total payments for civilian portion	0.29	0.29										(15)
	Worker training support	$0.016b												(16)
II. – C. Land Costs	Property tax abatements	Unknown; often, local or state policies vary by reactor							Varies by project; quantified offers total $0.8b over 20–30 yrs; at most $20m/yr/plant	0.16		0.16		(17)
	Total Section II		**7.20**	**7.20**	**0.06**	**0.96**	**0.06**	**1.94**		**3.51**	**3.73**	**6.58**	**5.22**	

Subsidy Type			Subsidies to Existing Reactors, ¢/kWh							Subsidies to New Reactors, ¢/kWh					Notes
			Total	Legacy		Existing: Low		Existing: High		Total	Low		High		
				Low	High	IOU	POU	IOU	POU		IOU	POU	IOU	POU	
III. Subsidies Affecting the Cost of Intermediate Inputs	A. Uranium Mining and Milling	Percentage depletion	~$25m/year							Expected to continue					(18)
		Inadequate royalties for mining on U.S. public lands	~$5m–$20m/year based on historical production levels							Expected to continue					(19)
		Inadequate bonding, high legacy costs	Known portion ~$2.1b covered by taxpayers			0.13		0.32		Expected to continue	0.13	0.13	0.32	0.32	(20)
	B. Uranium Enrichment	Below-market pricing of enrichment services	$4.0b–$11.3b civilian portion, during gov't ownership of enrichment	0.08	0.22					Increasing role of foreign governments; subsidy unknown					(21)
		Unfunded legacy costs for environmental remediation	$130m/yr taxpayer subsidies associated w/legacy costs attributed to enrichment sales to foreign reactors	0.02	0.02										(22)
		Tariffs on enriched uranium													(23)
		Loan guarantees								$4 billion LGs authorized					(24)
	C. Cooling Water	Free or subsidized use of cooling water	$0.6b–$0.7b/yr			0.16	0.16	0.18	0.18	Expected to continue	0.08	0.08	0.09	0.09	(25)
	Total Section III			**0.10**	**0.24**	**0.29**	**0.16**	**0.51**	**0.18**		**0.21**	**0.21**	**0.42**	**0.42**	
IV. Subsidies Affecting Security and Risk Management		Price-Anderson cap on accident liability	$800m to billions per reactor			0.10	0.10	2.50	2.50	Expected to continue	0.10	0.10	2.50	2.50	(26)
		Unfunded regulatory oversight	$11b since 1975 not covered by user fees	0.21	0.22					No longer occuring					(27)
		Weak plant security standards	Not quantified							Expected to continue					
		Proliferation externalities	Not quantified							Expected to grow					
		International Atomic Energy Agency	~$50m/year related to civilian activities							Expected to continue					(28)
	Total Section IV			**0.21**	**0.22**	**0.10**	**0.10**	**2.50**	**2.50**		**0.10**	**0.10**	**2.50**	**2.50**	

	Subsidy Type	Subsidies to Existing Reactors, ¢/kWh							Subsidies to New Reactors, ¢/kWh					Notes
		Total	Legacy		Existing: Low		Existing: High		Total	Low		High		
			Low	High	IOU	POU	IOU	POU		IOU	POU	IOU	POU	
V. Subsidies to Decommissioning and Waste Management	Decommissioning shortfalls: cost escalation exceeds investment returns on accrued funds	$60m/year							Expected to rise linearly with new plants					(29)
	Decommissioning shortfalls: cost estimates much lower than actual costs	Not quantified							Not quantified					(30)
	Tax breaks to decommissioning	$0.3b–$0.8b/yr for IOUs; $0.1b–$0.3b/yr for POUs			0.05	0.08	0.13	0.19	Expected to rise linearly with new plants	0.05	0.08	0.13	0.19	(31)
	Break-even operation of repository: no return on invested capital	$700m to $1.2b/yr based on current investment; rising to $2.3b–$4.0b/yr			0.08	0.08	0.15	0.15	Expected to rise at least linearly w/new plants; more sharply if more repositories are needed	0.08	0.08	0.15	0.15	(32)
	Underestimating the cost of the repository; nuclear waste fee collections too low*	Shortfall estimated at between $0–$1.6b/yr			0.00	0.00	0.20	0.20	Expected to rise at least linearly w/new plants, due to multiple repositories	0.00	0.00	0.20	0.20	(33)
	Long-term reduction in commercial share of total costs	4.7% drop in commercial share from 1990–2007; $4.5b in avoided repository costs							Reductions would benefit all reactors still operating					(34)
	Deferred one-time assessment into NWF with low interest rate	$3.2b total; $37m–$66m/yr in avoided financing costs industry-wide			0.005	0.005	0.008	0.008	Zero					(35)
	No required capacity reservation fee to access federal repository	30% reserve fee on break-even repository: $29b commercial share; $1.5b/year in avoided finance charges												(36)
	Payouts for on-site waste management due to poor risk sharing on waste management contracts	Estimated $12b–$50b in total liabilities			0.15	0.15	0.60	0.60	Assumed zero					(37)
	Total Section V		**0.00**	**0.00**	**0.29**	**0.31**	**1.09**	**1.15**		**0.13**	**0.16**	**0.48**	**0.54**	
Total Subsidies, ¢/kWh			**7.50**	**7.66**	**0.74**	**1.53**	**4.16**	**5.77**		**5.01**	**4.20**	**11.42**	**8.68**	
Subsidy/Value of Power	Share of power price	5.4 ¢/kWh	139%	142%	-	-	-	-	6.0 ¢/kWh (high case)	84%	70%	190%	145%	(38)
	Share of power price	5.9 ¢/kWh	-	-	13%	26%	70%	98%	5.7 ¢/kWh (reference case)	88%	74%	200%	152%	(38)

Notes:

(1) Statutory cap; limited to 6 reactors at present. High end represents outlay-equivalent measure. Low end based on CRS/Falk (2008). Existing reactors received generous investment tax credits, but these no longer affect current operations. Assume not available to POUs. May be able to sell/transfer to IOU/investors.

(2) Estimates from industry cost models (Exelon and UniStar), assuming relatively low construction costs. Not all facilities will receive guarantees under current law. Administration proposes to add $36 billion to current Title XVII programs. Pending legislation may enable POUs to access loan guarantees as well.

(3) Similar value to U.S. loan guarantees. Assumes maximum loan guarantee is 80 percent of project capital and that foreign guarantees expand number of reactors subsidized but do not go above the 80 percent cap.

(4) CWIP rules determined at utility district level, not federal. Low estimate based on CRS (Kaplan 2008) values; high estimate scales CWIP value (with loan guarantees) for higher cost of capital and loan subsidy values (for Calvert Cliffs 3).

(5) Benefits calculated by Kaplan/CRS for reduced cost of financing (e.g., through municipal bonds, Build America Bonds). Does not include incremental benefits from tax exemption or low ROI hurdles for POUs.

(6) All tax-exempt power, per year. Subsidies to existing reactors based on POU share of total nuclear generation capacity. Assumes benefits for new reactors will be similar to those for existing fleet.

(7) Subsidies per kWh based on measured entities' share of nuclear generation as proxy for value to all public entities. Values for new reactors included in line item above "Public reactors: reduced cost of borrowing".

(8) Subsidies per kWh based on measured entities' share of nuclear generation as proxy for value to all public entities.

(9) Available to first six reactors, with lower coverage for reactors three through six. High estimate based on coverage levels available to first two units.

(10) Based on Chapman et al. 1981. That analysis did not break out each subsidy line item.

(11) Higher subsidy value associated with higher cost of capital assumptions. Rising plant costs, longer plant service lives, and lower capacity factors would all increase the subsidy value of current accelerated depreciation rules. Insufficient data on ongoing capital spending to generate an estimate for retrofits.

(12) Funds supporting two consortia; not available for all projects.

(13) 2009 appropriations; assumes R&D support will be similar to new reactors.

(14) Estimate based on survey done by Seiple (1998); per-kWh values reflect all net production from 1957–1997. Values are historical rather than ongoing subsidies.

(15) Historical subsidies reflect generation during 1940–1971, the time frame covered by the federal program. Assumes new workers are properly protected and that there will be no subsidy.

(16) Small. Assumes program will not grow substantially as new reactors are built. See new legislative proposals.

(17) Can be material; example reflects abatements to Calvert Cliffs 3 during first 15 years of operation. Subsidies per job created are quite high. Subsidies are highly site-specific and not available to all projects. Unknown to existing plants.

(18) Small. Availability will scale with fuel demand as more reactors are built.

(19) Small. Subsidies will rise with levels of domestic mining activity.

(20) Assumes continued under-bonding; environmental concerns with extraction methods are generating current liabilities similar to the portion of historical ones quantified.

(21) Estimates of historical underpricing at UEE, not continuing subsidies to existing reactors.

(22) Assumes fees on domestic producers remain in effect to cover cost overruns rather than being allowed to expire. Ongoing subsidies to legacy production represent the share of remediation associated with enrichment services sold to foreign reactors.

(23) At present, border protection drives LEU prices up, but global prices are lower than they would be without government ownership. Net impact is indeterminate.

(24) In May 2010, the DOE announced it would double the available loan guarantees to uranium enrichment facilities from $2 billion to $4 billion. *www.lgprogram.energy.gov/press/052010.pdf.*

(25) Based on EPA-estimated cost to add cooling towers to reactors using once-through cooling; unit subsidies are based on share of generation only at reactors with no cooling towers. New reactors are assumed to be half the cost.

(26) Based on Fiore 2009 and Heyes 2002. Ignores nonreactor liabilities. The large range indicates a need for detailed reassessment of this issue.

(27) Assumes NRC fees cover all costs since 1991. Legacy costs are undercollections/kWh prior to 1991.

(28) Small. Costs are associated with foreign nuclear activities, though U.S. promotion of nuclear development abroad is one driver of foreign activity in the sector.

(29) Net shortfall from facilities where after-tax return is lower than escalation in decomissioning cost estimates. Not quantified or negligible.

(30) Not quantified, though this is deemed a large potential risk.

(31) Assumes NDT funding pace for new reactors is similar to that for existing ones. Higher rate of funding would increase value of subsidy.

(32) Estimate is for civilian share of liabilities only. Assumes existing cost estimates are accurate and repository earns ROI similar to Exelon (5.1 percent); high estimate includes compounding of interest. Subsidy from no ROI escalates sharply over time as total investment rises.

(33) Estimated shortfalls due to cost escalation and inadequate returns, per Rothwell 2005; includes civilian share only.

(34) Not quantified. Conservatively assumes that the reduced commercial share is entirely due to shifts in wastes to be managed rather than partially due to political pressure.

(35) Deferral at very low interest rates has already lasted 25 years; includes civilian payments only.

(36) Estimate is for civilian portion only. Large capital investments usually require capacity-reservation fees of 25 percent of the delivered cost of the good/service or more. Nuclear comparables have reserve fees of 28 to 33 percent. Not quantified.

(37) Payments over 15 years needed to make up expected reimbursements based on DOE (low) and industry (high) estimates. Assumes new reactors will not get this option.

(38) Power prices from EIA data. Legacy subsidies are compared to average 1960-2009 industrial power prices. Subsidies to existing reactors are compared to 2009 power prices entailing comparable busbar plant generation costs. Subsidies to new reactors are compared to EIA average projected electricity price per kWh over the next 15 years (2010-2024) entailing comparable busbar plant-generation costs. High price and reference cases are used; the low price scenario was ignored but would have generated even higher subsidies/power value ratios.

Appendix B: Understanding Subsidies*

A basic understanding of subsidy policies' core issues is helpful in reading this report. The following points provide an introduction to subsidy evaluation and try to clarify a number of areas of frequent confusion:

Not just cash. Government subsidies are often thought of as cash payments from a government to an individual or firm. While cash grants are indeed subsidies, there are many other, and more complex, methods that governments use to transfer value to the private sector. They include reduced tax rates, government-provided loans or insurance at below-market rates, guarantees on private loans, special requirements or bans that affect either the target technology or its alternatives, and surcharges or tariffs on competing products.

Time frame of the analysis. Subsidy values change annually and they can be volatile, fluctuating as programs are phased in or out or as production levels or interest rates vary. Annualizing subsidy values that are recognized in a single year but accrued over a longer period can help provide a more accurate picture of government support over time. Where large new subsidies have been implemented but not yet taken up in new construction, it is important to also present a marginal assessment of how these subsidies will affect new plant decisions.

Subsidy magnitude—cost to government versus value to recipient. Estimating the size of complex government subsidies can be difficult. Often, estimates must be made against a baseline. For example, the baseline for taxes is that all firms pay income taxes in a particular way, with standard rates across all industries. Baselines for loan programs would be how much the government pays for the credit it uses in order to make subsidized loans to recipient (targeted) sectors. The subsidy would be the deviation between standard and preferential tax or credit rates.

A second measurement approach estimates the value to the recipient. This value-based approach provides a more accurate measure of the level of distortions that government policies can create. For example, many government tax credits generate special "income" to private industry that is effectively tax-exempt. This generates an incremental subsidy value to the recipient, often referred to as the *outlay equivalent*. Similarly, government loans to a high-risk venture may be made at, or even slightly above, the government's cost of borrowing. However, that rate, which is still far below what the borrower would have been able to obtain on its own, generates an incremental *intermediation value* of the government credit support. Loan guarantees to new high-risk ventures have quite a high intermediation value to borrowers, as they bring the effective interest rate down to the "risk-free" rate of the U.S. Treasury.

Subsidy magnitude—offsetting collections. Many government programs collect fees to support activities related to the target technology. These fees are netted from support levels to generate a net subsidy value. If the fees actually exceed the outlays, the program would be treated as a *de facto* tax. However, this determination is made on a long-term actuarial basis, not based on annual cash balances. A program could generate a net subsidy despite a current cash balance.

* This section is based on Koplow 2007b.

Subsidy specificity. A related issue involves subsidy policies that are available to multiple sectors of the economy. From the perspective of trade policy, many of these subsidies are considered “nonspecific” and therefore not trade-distorting. In addition, some economists might argue that because such subsidies are offered to many industries, they benefit no single one disproportionately. We disagree. Some of the “general” programs might actually contain special terms that do provide disproportionate benefit to one particular technology e.g., accelerated depreciation—than to its competitors. Programs such as loan guarantees or indemnification may be worth far more to sectors deemed particularly risky, creating disproportional benefits relative to competing energy resources.

Market impacts. Subsidy-magnitude data provide an overview of public transfers to the private sector. But the impact that these transfers have on patterns of research, investment, or production is a different issue, and one that is far more difficult to ascertain. Some subsidies may have predominantly wealth-related effects in that they move money from one party to another but have little effect on the structure of markets. In highly competitive global markets with open borders, subsidies can affect the mix of suppliers (e.g., domestic versus foreign) without materially affecting the product mix. Other subsidies can have efficiency effects in that they do alter market equilibrium in material ways, impeding the most efficient or appropriate diversification of suppliers or resources.

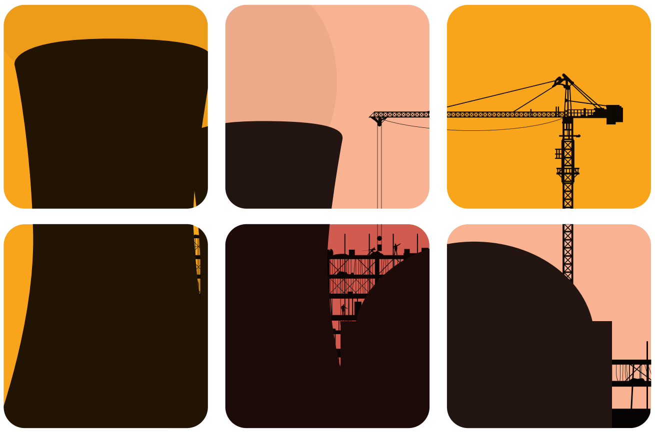
Subsidy incidence. Related to the issue of market impacts is the question of which party actually ends up benefiting from a subsidy. There is an inclination to assume that the original recipient of a subsidy program is the one that benefits. But this is not always the case. A new sales tax may be shared partly by the consumer and partly by the supplier, based on their relative market power—even though each would like the other to foot the entire bill. Subsidies are no different.

State and federal interactions. A complication regarding tax subsidies in particular is the interaction between different tax jurisdictions. Many, but not all, federal tax breaks are accepted at the state level, thereby reducing state taxes as well, though the rules regarding what is allowed or disallowed are often state- or provision-specific. Overall, however, this particular interaction increases subsidy magnitude. Working in the opposite direction are state-level subsidies that boost taxable income on federal tax returns. They can reduce the realized benefit from the state provisions and tend to reduce the subsidy magnitude.

Appendix C: Abbreviations Used in This Report

ABC	Activity-based costing
ACELA	American Clean Energy Leadership Act
ACES	American Clean Energy and Security Act of 2009
ACP	Alternative compliance payments
ANI	American Nuclear Insurers
APA	American Power Act
BAB	Build America Bonds
BLM	Bureau of Land Management
BPA	Bonneville Power Administration
CBO	Congressional Budget Office
CEDA	Clean Energy Deployment Administration
COFACE	Compagnie Française d'Assurance pour le Commerce Extérieur
COL	Construction and operating license
CRS	Congressional Research Service
CWIP	Construction work in progress
D&D	Decontamination and decommissioning
DBT	Design basis threat
DOE	Department of Energy
DOS	Department of State
ECA	Export Credit Agency
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPACT	Energy Policy Act of 2005
ESBWR	Economic simplified boiling water reactor
ESP	Early site permit
EWG	Environmental Working Group
Eximbank	Export-Import Bank of the United States
FCRA	Federal Credit Reform Act
GAO	Government Accountability Office (General Accounting Office prior to July 2004)
Gt	Gigaton
GW	Gigawatt
GWe	Gigawatt electrical
HEU	Highly enriched uranium
IAEA	International Atomic Energy Agency
IEA	International Energy Agency
IOU	Investor owned utility
IPO	Initial public offering
ISAB	International Security Advisory Board (U.S. Department of State)
ITC	Investment tax credit
JCT	Joint Committee on Taxation (U.S. Congress)
kWe	Kilowatt electrical
kWh	Kilowatt-hour
LEU	Low-enriched uranium
LG	Loan guarantee
LLC	Limited liability corporation
MACRS	Modified Accelerated Cost Recovery System
MDB	Multilateral development bank
MEAG	Municipal Electric Authority of Georgia
MISI	Management Information Services, Inc.
MOX	Mixed-oxide fuel
MW	Megawatt
MWh	Megawatt-hour
NDT	Nuclear decommissioning trust
NEI	Nuclear Energy Institute
NNSA	National Nuclear Security Administration
NPP	Nuclear power plant

NRC	Nuclear Regulatory Commission
NWF	Nuclear Waste Fund
O&M	Operations and maintenance
OCRWM	Office of Civilian Radioactive Waste Management
OECD	Organisation for Economic Cooperation and Development
OMB	Office of Management and Budget
OPIC	Overseas Private Investment Corporation
POU	Publicly owned utility
PPL	Pennsylvania Power and Light
PTC	Production tax credit
PUC	Public utility commission
R&D	Research and development
REA	Rural Electrification Administration
RECA	Radiation Exposure Compensation Act
RES	Renewable electricity standard
RFS	Renewable fuel standard
ROI	Return on investment
RPS	Renewable portfolio standard
RUS	Rural Utility Service
SIPC	Securities Investor Protection Corporation
SRBC	Susquehanna River Basin Commission
SWU	Separative work unit
TENEX	Techsnabexport
TVA	Tennessee Valley Authority
UCS	Union of Concerned Scientists
UEE	Uranium Enrichment Enterprise
UMTRCA	Uranium Mill Tailings Radiation Control Act
USDA	United States Department of Agriculture
USEC	United States Enrichment Corporation
WIR	Waste incidental to reprocessing
WNA	World Nuclear Association
WTO	World Trade Organization



NUCLEAR POWER:

Still Not Viable without Subsidies

The nuclear industry is calling for unprecedented public investment in new nuclear power plants. Its argument is based on questionable environmental and energy-security claims, as well as highly optimistic cost projections that often exclude the array of public subsidies nuclear power has received since its inception more than 50 years ago. Without a full accounting of these subsidies, it is difficult to make wise decisions about our energy future.

This report details—for the first time—the many subsidies provided to nuclear power throughout all stages of the fuel cycle, from plant construction and uranium mining to plant decommissioning and the disposal of radioactive waste. Giving even more subsidies to this mature industry after decades of generous government support would further mask the true costs and risks of building new reactors and related infrastructure, while shifting even more of those costs and risks to U.S. taxpayers.

Additional subsidies would also provide nuclear power with an unfair competitive advantage over emerging renewable energy solutions such as solar and wind, which can reduce global warming emissions faster and more cost-effectively than nuclear power, and with less risk. The nuclear industry already stands to benefit from any future price placed on global warming emissions; this report clearly shows why any additional subsidies to this industry are both unnecessary and unwise.

National Headquarters
Two Brattle Square
Cambridge, MA 02138-3780
Phone: (617) 547-5552
Fax: (617) 864-9405

West Coast Office
2397 Shattuck Ave., Ste. 203
Berkeley, CA 94704-1567
Phone: (510) 843-1872
Fax: (510) 843-3785

Washington, DC, Office
1825 K St. NW, Ste. 800
Washington, DC 20006-1232
Phone: (202) 223-6133
Fax: (202) 223-6162

Midwest Office
One N. LaSalle St., Ste. 1904
Chicago, IL 60602-4064
Phone: (312) 578-1750
Fax: (312) 578-1751

Web: www.ucsusa.org

Email: ucs@ucsusa.org

Union of Concerned Scientists
Citizens and Scientists for Environmental Solutions