B5: Other Federal Interventions Into Energy Markets

List of Tables

Other Federal Interventions Into Energy Markets

"Other" interventions is a catch-all category for the numerous remaining ways in which the federal government intervenes in energy markets. There are three main types of intervention covered in this chapter: the **Assumption of Legal Risks, Changes in Market Rules**, and **Federal Procurement of Energy Services for Internal Use**. Most of these interventions involve changing the rules under which private entities operate rather than the payment of direct financial subsidies from the federal government. The impact on market structure and the viability of emerging energy sources is extremely large nonetheless.

The assumption of legal risk reduces the costs of production for certain private entities in the energy sector by indemnifying them against accidents or other mishaps, or by shifting these risks from the producer to the public. Changes in market rules alter regulations governing the access to energy markets, pricing, and terms of sale. These changes can dramatically alter the risks and rewards (increase or decrease) of particular economic activity. Federal procurement of energy products and services affects energy markets through purchase preferences, and through the volume of products and services demanded. Each category is described in more detail below.

Assumption or Shifting of Legal Risks/Indemnification

Federal laws or actions may transfer private market risk to the federal government, or to the populace at large. Since private markets charge a price for risk-bearing, intervention in this arena to reduce the risks borne by particular energy producers can reduce (sometimes dramatically) the cost structure of the industry. Where risks are very difficult to predict or measure, such as with nuclear reactor accidents, federal intervention to limit or cap risks may be the main factor enabling the industry to develop.

The federal government reduces the legal risks for private industry in a number of ways. It may cap the amount of money that the private sector must pay in the case of an accident through statute, such as with the Price-Anderson Act covering nuclear reactor accident liability. It may also promise to pay for damages directly itself, through indemnification of the private party. The Price-Anderson Act also has an indemnification component.

The government may also run or finance insurance programs directly (as it does with crop-insurance), or guarantee repayment of loans (as it does with many loan guarantee programs). While all of these examples have some similarities, we separate them into federal indemnification, and federal insurance and loan guarantees. Insurance programs and guarantees are included under the federal agencies section of the report since risk assessments are done as a normal part of the on-going activities of a federal agency, and beneficiaries may be charged at least part of the cost of the services.

Indemnification or risk shifting is different. A statute says, in essence, if there is an accident, "the federal government will pay all/part of the damages," or "the company is not responsible for damages exceeding a certain amount." There is no charge for this service (although some conditions may have to be met). As a result, there are no on-going operations to measure risk, adjust the expected cost of these programs, etc.

Liability caps without federal indemnification reduce private risks by shifting them to surrounding populations, or to future taxpayers. In neither case do the unwilling recipients of the risks get compensated for their exposure. The Price-Anderson Act, for example, does not statutorily protect accident victims above the levels of private insurance and federal indemnification. The allowance for utilities to underaccrue funds to finance the decommissioning of their nuclear power plants shifts the risks for shortfalls to future ratepayers or taxpayers. Both actions reduce the costs of nuclear power today.

The implications of these risk-based subsidies are important. In addition to reducing the current cost of power generated by more risky methods, risk-subsidies hide the risks of current options. Current decision-makers may not be able to evaluate which of their current options pose the lowest societal risks. They may also have less of an incentive to make choices which minimize these risks, since they do not bear the full costs of poor decisions. This issue is worthy of additional research.

At least two areas are not included in this section due to data limitations, but should be examined in future research. These are the liability caps recently placed on transporters for oil spills, and issues associated with damages from coal mine subsidence, which historically were not always borne by the mine-owner.

Price-Anderson Act Nuclear Liability Cap and Contractor Indemnification

Background

The Price-Anderson Act was enacted in 1957 to facilitate the growth and expansion of the commercial nuclear industry. The perceived risk of enormous catastrophic losses in the case of a nuclear accident made private insurers unwilling to back the industry. The technology was new and much was unknown about the operating characteristics of commercial fission. Similarly, without any historic actuarial information on which to base rates, nuclear insurance seemed a dangerous proposition indeed for commercial insurance firms.

Price-Anderson solved much of this problem. First, the Act indemnified all contractors and suppliers who design and build commercial nuclear plants; or who operate federal nuclear fuel cycle, research, or disposal facilities from liability in the case of an accident - even in the case of gross negligence. This indemnification includes all parties involved with nuclear waste transport from commercial reactors all over the country to the proposed disposal facility in Nevada.[1] Second, the Act capped the losses for which the insurers and the utilities would be liable in the case of an accident.

A two-tier system of coverage was set up. The first tier is comprised of "normal" insurance, where utilities purchase coverage up to a certain limit, and pay annual premiums. Private insurance companies have been hesitant to increase their coverage for nuclear accidents. Thus, first tier insurance availability has remained constrained over the past 35 years. The second tier is comprised essentially of guarantees to pay a certain amount of money retrospectively in the case of an accident. These two components together now provide coverage up to the statutory limit set by the Price-Anderson Act. To the extent that losses exceed the insurance cap, the federal government would be the only source to pick up the tab. Since only the value of the liability cap for utilities has been estimated here (benefits to other contractors, operators, and transporters are excluded), the estimates which follow are likely to be too low.

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[1]According to an Office of Civilian Radioactive Waste Management in DOE, by the year 2020 there will be over 220,000 spent fuel assemblies to transport even if there are no new orders for reactors. With the assemblies grouped into shipping casks, tens of thousands of individual trips would be required to move the assemblies to disposal sites. These trips would cover between 27 and 65 million miles, depending on assumptions used regarding the available disposal points. (Rothwell, 12-14).

Table B5-1: Evolution of Price-Anderson Liability Coverage

	1957 Act	Reauthorization or Amendment Year		
		1965 and 1966	1975	1988
1st Tier: Private Insur. - Total Premium-Financed Insur. Available	$60m	Between $60 and $125m	$125m	$160m
2nd Tier: Retrospective Premiums	$0	$0	$5m x 53 reactors in 1975 = $260m	$63m x 110 reactors in 1988 = $6,930m; Since a maximum of $10m/yr. may be charged to each reactor, the present value of $63m over 6 1/2 years, discounted at 8.55%[2] is $51.2m.
Total Private Coverage, All Reactors in Operation[3]	$60m Plus fees utilities paid the Atomic Energy Commission for $500m In indemnification.	$60 - $125m, plus indemnification fees.	$385m, plus indemnification fees.	$7,090m nominal; $5,792m present value (adjusted for 6 1/2 yr. payout of retrospective premiums).
Additional Federal Indemnification				Subject to Congressional Action; nothing promised.
Other Conditions Added		-No fault feature added -Statute of limitations added		-No more than $10m/reactor of the retrospective premium would be assessed each year.
Indemnification of Contractors				
DOE Nuclear Contractors (including waste transport and disposal)	$500m, indemnified by the government even in cases of gross negligence			$7.2 billion liability limit via federal indemnification. Penalties for contractors who violate safety rules are possible.
At Commercial Reactors	Indemnified by utilities, up to utility insurance limit			
At Small Research Reactors	$500m, with damages above $250k indemnified			

Sources: Holt; Dubin and Rothwell

[2] The present value of the retrospective premium payment will fluctuate with the prevailing interest rates at the time the payments are made. This rate is the 3-year Treasury bond rate for 1989, and approximates the minimum discount factor for that year. Since the private utilities have much higher borrowing costs than the federal government, delaying the payment of the premium is more valuable to them. For example, the average bond rate grade BBB utilities (utilities with nuclear plant and past cost overruns would be more likely to be rated in this category) in 1989 was 9.993%. At this rate, the present value of the $63m premium is $49.7 million, and the total present value of private coverage for reactor accidents is $5,627 million.

[3] The Price-Anderson Act mandated a $560 million pool to cover accidents. The difference between this level and the sum of retrospective premiums and commercial insurance coverage was made up through government indemnification of the utilities in return for a fee. In 1984, this figure passed the required $560m level, at which point the minimum pool size increased by $5m with each new reactor that came on line. (Holt, 3).

The Liability Cap

The Price-Anderson Act liability limit has gradually increased over time (see Table below). The total private coverage available (first-tier plus second-tier insurance) increased from $60 million in 1958 to $7,153 million in 1988. This increase came from a number of sources. First, the amount of private, first-tier premium-financed insurance available has increased from $60m to $160m during this period. In addition, a second tier of liability coverage in the form of retrospective premiums was added in 1975 and increased in 1988. This provision created a statutory obligation for each utility to pay a set amount of money after an accident into the cleanup pool. The cleanup pool grew both due to statutory increases in the contribution per reactor and from an increase in the number of nuclear reactors in operation. The maximum payment was increased from $5 million in 1975 to $63 million per reactor in 1988.

The retrospective premiums are responsible for most of the growth in utility coverage for nuclear accidents. In fact, the "increase" in the first tier insurance availability is actually a decrease in real terms. Using the GNP implicit price deflator, $160 million in 1989 dollars is equivalent to only $36.9 million 1957 dollars[4] versus the $60 million available in 1957.

The 1957 Act mandated a minimum of $560 million in utility responsibility for an accident. This level was not actually achieved until 1984. Between 1957 and 1984, the shortfall was covered by the Atomic Energy Commission (and then the Nuclear Regulatory Commission beginning in 1975) in return for a fee from the utilities. (Holt, 2). We do not know how closely this "fee" resembled an insurance premium, although it can be safely assumed that it was less expensive to the utilities than the alternative of buying private coverage. Above the second tier coverage, no additional payments are guaranteed. Proposals for a third tier of coverage, in the form of an additional $8 billion in indemnification from the federal government, were defeated in the 1988 reauthorization. Congress stated only that it "will take whatever action is deemed necessary and appropriate" to provide additional compensation. (Holt, 3).

Subsidy to the Commercial Nuclear Power Sector

The commercial nuclear power sector receives a subsidy via the liability cap and indemnification provisions of the Price-Anderson Act. Without the law, the utilities would be forced to purchase private market insurance to cover far larger amounts - if such insurance were even available. The underlying assumption behind this claim is that many damage scenarios of a nuclear accident exceed the $7.2 billion in total coverage available. Thus, using a distribution of expected damages multiplied by the probability of those accident scenarios occurring, a number of researchers have generated estimates of the uncovered liability. To the extent that Congress steps in to pay damages in excess of $7.2 billion, these uncovered liabilities are borne by taxpayers. An absence of such action by Congress shifts the risk bearing to the citizens in the accident region.

Subsidy Estimates

1) Professor Jeffrey Dubin at the California Institute of Technology, and Professor Geoffrey Rothwell at Stanford University estimated the value of the Price-Anderson Act subsidy to nuclear utilities using NRC expected loss scenarios, and the implicit rate of return required by insurers on the first tier insurance provided. They differ from other researchers in that they include a range of accident severities, with more severe accidents having a lower probability.

Dubin and Rothwell calculate a liability subsidy of $60 million per reactor-year prior to the 1988 amendments and $22 million per reactor-year after. The value of the subsidies in 1989 was $2.746 billion,

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[4]Implicit price deflator data are from the Economic Report of the President, 1991, p. 290.

and the cumulative subsidy between 1959 and 1989 was $128.5 billion.[5] (Dubin and Rothwell, 8). Their calculations use a $560 million limit for liability insurance between 1959 and 1982, although federal indemnification formed most of that coverage for much of that time (beginning at $500 million, and dropping finally to zero in 1984). (Holt, 3). To the extent that federal fees for indemnification represented token payments rather than risk premiums, the actual subsidy during this period (1959-1982) would have been even higher.

2) Pennsylvania Insurance Commissioner Herbert Dennenberg, using Atomic Energy Commission estimates for worst-case damages, calculated a subsidy of $23.5 million/reactor-year in testimony before the Atomic Safety Licensing Board in 1973. This is equivalent to $60.0 million in 1989 dollars. With 110 reactors, this amounts to $6.6 billion/year.[6] However, this estimate assumes that the probability of an accident with damages between $40 and $60 million is equal to the probability of a loss of $40 billion. (Dubin and Rothwell, 3). In addition, since it was done in 1973, the estimate does not reflect the increase in utility liability for accidents through retrospective premiums.

3) CIGNA insurance company studied the cost of providing limited nuclear risk policies (property loss only) to Pennsylvania homeowners at $25-$30 per home in 1984$. Using estimates of the number of homes (4.4m) and nuclear reactors in the state at the time (five), Bossong estimated the cost at $25.5-$31.1 million/reactor-year in 1989$. (Bossong, 7). Assuming similar insurance rates across the country, the CIGNA study yields a crude approximation of the value of Price-Anderson of ($25.5-$31.1) x (110 reactors) = $2.8 - $3.4 billion per year.

4) Other estimates presented by Bossong, but calculated by various other groups range from a minimum of $832 million to $10 billion per year. (Bossong, 9). We judged the $10 billion/year estimate, produced in a 1984 National Audubon study, to be problematic for two reasons. First, it ignores the probability distribution of an accident. Second, it does not accrue the payment for damages over a realistic time frame.

The $832 million estimate (1989$; scaled from $750m in 1986$) assumes that coverage for off-site damage (which is not required due to the Price-Anderson Act above statutory limits) costs the same as coverage for on-site damage (which the utilities currently buy). However, this estimate assumes coverage only to the amount of $1.7 billion. Since many accident scenarios project more than $1.7 billion in aggregate damage, full coverage, even using this estimation approach, would likely be higher. (Bossong, 8).

Summary

It is clear that Price-Anderson provides some form of a subsidy, though the estimates as to the magnitude vary. The estimate we judge most valid is the Dubin and Rothwell study for a number of reasons. First, it is the only estimate that incorporates the changes in the 1988 Reauthorization Act. Second, it most explicitly addresses the issue of a range of probabilities for accidents. However, even this estimate measures only the value of the Price-Anderson subsidy to utilities. Federal indemnification of contractors is not included. We estimate the value of the Price-Anderson insurance cap to nuclear utilities to be a minimum of $832 million per year, with our best guess estimate of $2.75 billion per year.

Sources

[5] Dubin and Rothwell estimates scaled to 1989 dollars using the GNP implicit price deflator.

[6] The total number of reactors is 110 since the Shoreham reactor never began operation. (EIA, Monthly Energy Review, Feb. 1990, p. 86.

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Underaccrual for Nuclear Decommissioning Costs

With most industries, shutting down operations is not much of a problem. Rent the office space, sell off or throw away the leftover assets, and you're on your way. Nuclear fission stands in stark contrast to this. In addition to the radioactive waste, which must be monitored for hundreds of years, the utility plant itself must be carefully sealed or removed, a process called "decommissioning."

Decommissioning may be done three ways. *Immediate dismantlement* involves radioactive decontamination of the site as soon as the plant retires. *Temporary storage* "mothballs" the nuclear plant for a specified number of years to allow much of the shorter-lived radioisotopes to decay prior to dismantling the plant. *Entombment* encases all of the radioactive components in steel or concrete to shelter the surrounding population from radioactivity. The problem with entombment is that the radioactivity lasts far longer than the tomb. (Hindman, 5). Any of these methods require the expenditure of large sums of money at the end of the plant's life.

Financial problems with decommissioning arise if the nuclear utility does not have sufficient funds on hand at the time of decommissioning to pay the cost. Such a fund shortfall could be the result of either underestimating the costs of the decommissioning process, or of insufficient accrual of the funds necessary during the operating life of the plant. In either case, the decommissioning would have to be funded either by the taxpayers, or by a tax on the customers of the utility at that point in time. In neither case do those who used the nuclear-generated electricity pay the full private costs of providing that power (even ignoring environmental and health externalities).

Estimating the Underaccrual for Nuclear Decommissioning

Our interest in nuclear decommissioning is to estimate the likely size of the current underaccrual for decommissioning, at least a portion of which will probably be borne by the taxpayer. This estimate requires a number of parts, each which are addressed in more detail later.

- How much will plants cost to decommission? The higher the cost, the more money that should be put aside today.
- When will the plants be decommissioned? Depending on the method of decommissioning chosen, funds accrued during the plant's operating life can continue to earn interest (if the real interest rate is, in fact, positive) between the point of closure and the beginning of decommissioning expenses 0-60 years later. Further complicating the matter is the fact that the cost of decommissioning a plant and disposing of the radioactive waste could rise slower or faster than inflation in the interim.
- How much will decommissioning trust funds earn in interest? The higher the yields, the lower the current accruals need to be to build up the necessary decommissioning reserves.
- How much money do nuclear utilities plan to put aside, and how close is this to the amount likely to be needed?
- What portion of the decommissioning shortfall is likely to be borne by the general taxpayer rather than by the utility's future ratepayers?

How Much Will Decommissioning Cost?

Estimating the expected cost of decommissioning is complicated by a lack of industry decommissioning experience, different methods of estimating expected decommissioning cost, the type of decommissioning to be done (e.g., prompt dismantlement vs. entombment), rapid inflation in the cost of decommissioning, and differing assumptions regarding economies of scale and learning in the decommissioning process.

Lack of Experience. There have been no real examples of the decommissioning process on which to base cost estimates. The only fully decommissioned commercial plant in the United States was the Shippingport reactor in Pennsylvania. However, this reactor was very small. As a result, DOE entombed the reactor pressure vessel in concrete and shipped it by barge for burial in Hanford, WA. (Hindman, 10). Most of the reactors now in operation will have to be dismantled prior to shipping - a complicated and potentially costly process.

While experience with decommissioning is quite limited, it is interesting to note that utilities assume decommissioning will cost an average of \$211/kW of capacity (Strauss and Kelsey, 60,61), while the actual amount paid for the supposedly easier to handle Shippingport reactor was a whopping \$1361/kW (Fry, 96). Similarly, the weighted average expected decommissioning costs for reactors which are no longer in operation and are either being mothballed or in the process of being decommissioned, is \$742/kW (Fry, 96,97), three-and-one-half times as big as the expected cost for the industry overall.[7] Even if the particularly expensive Three Mile Island plant is excluded, these utilities expect a weighted average decommissioning cost of \$466/kW.

And even these figures may be too low. The estimated cost for decommissioning the Yankee Rowe plant increased after the plant was closed. In 1989 Yankee Atomic estimated that decommissioning of its Yankee Rowe plant would cost \$116 million. When it announced the closure of the plant in summer of 1992, the decommissioning cost estimate had almost doubled in real terms, to about \$220 million (\$245 million in 1992\$). This was due to "increased costs for staff and for disposal of the radioactive waste." (Chandler, 25). The expected costs of decommissioning the Fort St. Vrain Reactor, already included in the group of retired reactors above, has jumped from the \$242 million cost included in our average to close to \$300 million (1989\$) currently. (Johnson and De Rouffignac). Neither of these plants are likely to be the last example of this type of cost escalation as the decommissioning date approaches.

Cost Estimation Methodology. There are two basic approaches to estimating the cost of decommissioning: site-specific estimates, and generic estimates. Historically, the generic estimates often assumed that decommissioning costs would be some proportion of plant construction costs. (Fry, 88). Site-specific estimates are essentially engineering studies of plant closure, and often yield very different results. In one study comparing the decommissioning cost estimates (Strauss and Kelsey, 67), site-specific estimates (in \$/kW) were found, on average, to be 58 percent higher than the generic cost estimates. This discrepancy suggests that the current industry expectations, based on the generic method, are too low.

Type of Decommissioning. The costs for prompt dismantlement of reactors, versus temporary storage and mothballing differ. Mothballing may reduce final decommissioning costs but incurs interim security and maintenance costs. Since 95 percent of the reactor decommissioning estimates currently available assume prompt dismantlement and removal (Strauss and Kelsey, 65) we assume the same in estimating decommissioning shortfalls. It is important to note, however, that while reactors are now entering the decommissioning stage, no waste repository is yet operating. Therefore, immediate dismantlement is not be a viable option for utilities yet.

Depending on the real interest rate earned on funds (which may be either positive or negative), and on inflation rates in the cost of decommissioning operations and radioactive waste disposal, delaying dismantlement could either reduce or increase the present value cost of decommissioning. (See Rothwell for a model to calculate the optimal waiting time to decommission). The annual security costs to maintain

[7] According to Fry (p. 92), "decommissioning cost estimates for retired reactors may be less uncertain than estimates for operating reactors" since many costs have already been incurred, radiation levels which must be handled are known, and the regulatory environment is also known.

and watch a mothballed nuclear plant during temporary storage are estimated at up to $15 million/year. (Johnson and De Rouffignac). Paying these costs for 60 years would eat through an initial principal of $443 million, even if that principal were earning our most generous expected real return of 2.7%. This is a level significantly higher than the current expected total decommissioning costs for most of the nation's reactors -- and this accrual would leave no money at the end to pay for the actual decommissioning. The "holding cost" of temporary storage erodes gains from additional interest or reduced costs from radioactive decay.

Economies of Scale and Learning. Implicit in many of the current estimates for decommissioning costs is the assumption that costs per kW of capacity fall for larger reactors (economies of scale), and that costs for reactors decommissioned later will fall due to lessons learned, and technologies developed, in earlier decommissioning efforts. While there clearly has not been enough operating experience to determine the likelihood of these gains with any accuracy, a number of researchers have suggested the gains are not likely to be that large.

Fry (p. 101) concludes that the "limited experience available shows a marked lack of scale economies," although he is careful to point out the the current sample is small and not necessarily representative. In contrast, Strauss and Kelsey found that "[s]maller plants cost more to decommission on a per kW basis than do larger plants." (Strauss and Kelsey, 65). One explanation for this difference is that Fry analyzed plants that have already been shut and in some cases began to be dismantled, while Strauss and Kelsey analyze the projected decommissioning costs for operating reactors.

Cantor compares the cost of decommissioning with the original cost of commissioning the nuclear reactors, and points out that both economies of scale and of learning were anticipated but not realized during plant construction. (Cantor, 110). She presents a number of possible explanations for why these gains were not realized, including regulatory uncertainty and operating problems leading to construction changes; and the clustering of reactor construction in time, as well as a lack of standard reactor designs, inhibiting the transfer of lessons learned. (Cantor, 111, 113).

According to Cantor, since decommissioning will be less clustered than plant construction was, learning may be more transferable. However, the non-standard reactor designs and the potential additional regulatory changes suggest that the degree to which decommissioning experience is transferable between reactors will be limited. (Cantor, 114).

The current utility estimated costs for decommissioning assume significant economies of scale and learning (Fry, 103). To the extent that these economies are not realized, current decommissioning accruals are likely to be too small.

Real Increases in Estimated Cost Components. Cost estimates for nuclear decommissioning have been rising dramatically over time. Since 1976, the average real rate of increase in decommissioning cost estimates has been about 16 percent per year. (Biewald and Bernow, 235). While utilities routinely include a contingency factor in their cost estimates for decommissioning, this factor is generally only 25%, a level that "would have allowed for only one-sixteenth of the cost growth that actually occurred" since 1976. (Biewald and Bernow, 235). While part of this increase is due to a lack of actual decommissioning experience, part is also due to a changing regulatory environment and rapidly rising costs of radioactive waste disposal.

When Will the Plants be Decommissioned?

Different methods of decommissioning require vastly different time frames. Prompt dismantlement begins at the end of the facility life. According to a NISA survey, the average facility had 31 years of its 40 year operating life remaining in 1989 (NISA, 12). Our calculations of annual decommissioning payments are based on this expected lifetime. However, the 15 U.S. units that have closed so far operated an average of only 12.7 years,

> and with the average per-kilowatt cost of running a nuclear plant now edging higher than the cost of a coal-fired plant, Department of Energy officials now say privately that 25% of the remaining reactors may be closed in the next decade for economic reasons. (Johnson and De Rouffignac).

To the extent that the average reactor life proves shorter than 40 years, our calculated annual underaccrual in decommissioning funds will be too low.

Temporary storage would keep the facility "mothballed" following shutdown for very long periods. Some arguments in favor of mothballing facilities for as long as 100 years have been made (MacKerron, 105), since during this time frame, the decay of Cobalt-60 may allow readier access to the reactor core. This would facilitate much simpler dismantling of the core. While a 100-year waiting period may have some technological benefits, the current NRC limit is 60 years.

If the nuclear decommissioning trust is earning positive real returns, the interim costs are small, and the expected costs and regulations associated with decommissioning are stable, the delay might also reduce the cost to rate payers. However, in line with our "beneficiary should pay" approach, we assume that the entire cost of decommissioning (excluding interest to be earned during any waiting period) should be paid during the operating life of the facility. Therefore, decommissioning payments in all cases are assumed to stop at the point of reactor shutdown, regardless of the method of decommissioning chosen.

The attached estimates assume further that all reactors will be promptly dismantled. This assumption was made because 95% of the utility decommissioning estimates make the same assumption. To the extent that real returns on decommissioning trusts, inflation of decommissioning costs, and regulatory certainty favor temporary storage over immediate dismantlement, our estimates may be too high. However, current trends in each of these parameters suggests that the opposite is true, and that most reactors will be immediately dismantled, so long as a waste repository exists at the time of closure.

How Much Will Decommissioning Trusts Earn in Interest?

The real (inflation-adjusted) yield on trust principal will have a dramatic effect on whether the fund ends up in deficit or surplus for any particular expected cost range. Real yields are affected by a few key variables: the type of securities held, the duration of investment, and the tax-treatment of trust earnings. These variables are, in turn, influenced by the type of decommissioning trust set up. We describe these trusts first, and then discuss each of the variables.

Types of Decommissioning Trusts

Decommissioning Trusts are special funds created by the nuclear utilities to accrue funds during the reactor's operating life in order to pay for reactor decommissioning at the end of the reactor life. Until the end of the 1970s, very few utilities made any provision to accrue for decommissioning. (MacKerron, 107). Prior to 1988, funds for decommissioning could be held internally. Thus, utilities could accrue the funds on paper, but there was no guarantee that the cash would actually be there when needed. In 1988, the Nuclear Regulatory Commission promulgated rules which required the creation of external trusts. This significantly reduced the risks of "commingled funds or default." ("Utilities Move Closer to Nuclear Decommissioning External Trust Compliance," 21).

The NRC rules created two types of allowable trust funds: a qualified nuclear decommissioning trust, and a nonqualified decommissioning trust. While these trusts differ in their tax treatment, and in the eligibility of utilities for each type of tax treatment, both are now external trusts, and recent changes in the law have made them more similar than they used to be.

Qualified Nuclear Decommissioning Trust. Qualified trusts enable utilities to deduct trust contributions from current taxes. In return, income generated by the trust investments is taxed. Prior to 1994, this income is taxed at the full corporate rate of 34%. Due to the Energy Policy Act of 1992, the tax rate on decommissioning trusts was reduced to 22% beginning 1994, and to 20% in 1996. (DOE, EPACT Summary, 25).

Prior to the Energy Policy Act of 1992 (EPACT), the allowable investments for qualified trusts were limited to the lowest risk securities (Treasury bonds, state and local municipal bonds, and demand deposits at banks or insured credit unions). These are often called "Black Lung" securities because they are the same family of investments allowed for Black Lung trust funds, as set out in the Black Lung Act. EPACT removed these restrictions, effective December 31, 1992. (DOE, 10/15/92, 25). However, the annual amounts which may be contributed into a qualified trust are limited by IRS rulings (Rogers, 70), and this limit may be too low to meet projected needs.

Nonqualified Nuclear Decommissioning Trusts. Prior to EPACT in 1992, nonqualified trusts were free to invest in a wider range of options than qualified trusts, including corporate bonds, stocks, and real estate. However, local law and regulatory agencies may restrict the expected risk level of the portfolio (Weinblatt et al, 207), and qualified trusts may now invest in the same types of investments.

The tax treatment of nonqualified trusts differs from that of qualified trusts in that no current deduction is allowed for contributions, but income earned by the fund is taxed at the utilities' actual tax rate, which may be below 34%. (Weinblatt et al, 207). In essence, income from nonqualified trusts may be offset by all the tax preferences the utility may have available (subject to limits such as the Alternative Minimum Tax). (Tuschen, 218). Once decommissioning begins, expenses paid from a nonqualified trust may be deducted against taxable utility income going back to 1984. (Tuschen, 221). Finally, as a corporate trust, 70% of dividend income is exempt from taxation. (Rogers, 70).

<u>Which Type of Fund to Use</u>. The choice of funds is determined by three main factors: the timing of the contribution, the size of the contribution, and the marginal tax rate of the utility. Since only contributions related to operations in the nuclear plant after 1984 may be put into a qualified trust, all prior decommissioning accruals must be held in a nonqualified trust. (Tuschen, 218). In addition, funds which exceed the IRS's annual allowable contribution must also be put into a nonqualified trust. (Rogers, 70).

The utility's marginal tax rate affects the choice of trust funds because the utility must balance the benefit of the current deduction of trust fund principal against the benefit from the lower tax rate on trust fund investment income. Where the value of the current tax deduction outweighs the higher tax rate on investment income, the utility will use a qualified trust, and vice-versa. (Weinblatt et al, 207). The recently passed reductions in the tax treatment of income from external qualified trusts and freeing up of investment choices will make the economics of qualified trusts much more attractive.

<u>Type of Securities Held</u>

Qualified trusts were limited by statute to very low risk municipal and Treasury bonds, and bank demand deposits, though, as mentioned above, this is no longer the case. The high marginal tax rate on income from qualified trusts at the 34% tax rate currently in effect suggests that most current investments will be in tax-exempt municipal bonds (Hiller, 194), although some may also go into Treasury securities. The reductions of the tax rate to 22% and then to 20% in the coming years may shift the desired mix of securities towards taxable securities somewhat.

Since income of public power and cooperatives is not taxed, their investment choices are not influenced by tax liability. As a result, they are more likely to invest in low-risk taxable securities, such as Treasury bonds. Overall, however, publicly-owned and cooperative power providers own only about 8% of the nation's nuclear capacity. (Tuschen, 219).

However, the past restrictions on the types of assets held do not seem to be the main reason that nuclear utilities are holding such low risk securities. According to the NISA survey, which was done before investment restrictions were removed in the Energy Policy Act of 1992, even if the restrictions were removed (as they are now), tax-exempt bonds (which are now mostly municipal) would remain the primary investment held by the decommissioning trusts, although holdings of higher yield bonds and equities would rise somewhat. (NISA, 18). Perhaps this risk aversion is due, in part, to the fact that a loss of principal in the fund's early years yields large interest losses during the life of the fund, and that this risk outweighs the incremental value of higher, riskier yields. (Hiller, 194).

Maturity of Securities Held

Although longer-term securities generally offer higher yields than shorter-term issues, this increased yield carries with it larger inflation and interest rate risk. Guessing the wrong inflation rate, and being locked into 30-year bond issues, could greatly hurt the ability of the fund to keep up with inflation.[8] Since the cost of decommissioning is rising so quickly, even above general inflation levels, most analysts recommend an investment strategy focused on shorter-term issues to avoid additional inflation risk. The trade-off here is one of lower yields in return for lower inflationary risk. (Hiller, 197). Following the analysis of Hiller and others, we assume that funds are invested into shorter-term securities in our calculation of decommissioning shortfalls.

Expected Yield

Following the above discussion, we use yields on shorter-term, low risk securities, adjusted for taxation and inflation (because our cost estimates are in real dollars). However, the pending reduction in the tax rate on qualified trusts reduces the incentive to invest in tax-exempt bonds, and the nonqualified trusts may also have significant holdings in corporate bonds.

An additional issue involves what historical period of real returns provides an appropriate proxy for the expected yields going forward on the decommissioning trusts. For decommissioning scenarios involving temporary storage, time frames of up to 100 years may be involved between now and the dismantlement of the reactor. With immediate dismantlement, the time frame of concern may be more like 30 years. We therefore include data on historical real returns for both 1926-1990, and for 1966-1990. Empirically, yields in the more recent time frame are lower than for the 1926-1990 period (see worksheet, part 2A).

A final issue involves the type of inflation adjustment done to nominal yields in order to generate the real return. Most figures are adjusted for the general inflation level. However, as mentioned above, nuclear decommissioning costs have been rising far more rapidly than general prices. We found one estimate that incorporated this into their yield estimate (Borson et al, 12), and this rate is significantly below the expected yield we use in our high estimate of the decommissioning underaccrual. We chose not to use this yield because it potentially double-counts decommissioning cost estimates, accounting for cost increases both in the expected yield, and in the expected decommissioning cost per kW.

[8] Although secondary markets for long-term debt introduce liquidity into the holding of long-term bonds, if interest rates rise, the bonds could only be sold at a discount, and liquidity does not ameliorate the implications of mis-guessing inflation.

Analysts who have tried to estimate the likely returns on decommissioning trusts have not found them to be promising. For example, Weinblatt et al (pp. 209, 211) analyzed real returns on a variety of investments between 1960-1988 and concluded that only stocks provided real after tax returns during the period, investments which are generally considered riskier than municipal bonds, and would be unlikely to be used for any major part of the trust portfolio.

How Much Money do the Nuclear Utilities Plan to Put Aside?

The NRC requires a minimum decommissioning fund of $105 to $135 million, depending on the plant type or size. (GAO/RCED-88-184, 3). A General Accounting Office survey of decommissioning costs found that most experts believed the NRC figures were too low, and that estimates went as high as $3 billion per reactor. (GAO/RCED-88-184, 1). The Yankee Rowe plant, which is the oldest and smallest commercial reactor in the country, is expected to cost close to twice (the actual cost may rise still further) the top end of the NRC minimum fund requirement.[9] Larger plants are likely to cost even more. (Chandler, 25).

Above, we noted that the utilities estimate an average decommissioning cost of $211/kW, and that utilities closer to (or already in) the decommissioning phase expect costs which average between $466 (with Three Mile Island excluded) to $742/kW (TMI included) of capacity.

Their past and current contributions to decommissioning trusts, however, require optimistic assumptions at all levels in order to break even in time for decommissioning. According to the NISA survey in 1989, utility contributions would yield a pre-tax kitty of $355/kW if invested entirely in corporate bonds.[10] Incorporating even some of the expected real decommissioning cost increases, and yields which more closely match the portfolios that the utilities are currently holding would provide a much smaller kitty at the point of plant closure.(see worksheet, parts 2B and 2C). Since the lower accrual is due, in part, to an expected negative real interest rate, holding the funds during a 30-60 year interim storage period would increase the shortfall, not decrease it.

Due to accruals which are most likely below even the current expected cost, and to costs which can be expected to rise significantly as time goes on, there is little chance that current accruals will be sufficient to cover the cost of decommissioning the nation's nuclear plants.

Who Pays the Shortfall?

Fear of large, uncovered decommissioning liabilities which had to be paid by the taxpayers was the driving factor behind the NRC regulations requiring that decommissioning trusts be held external to the utility. According to the NRC,

> in the event of bankruptcy there is not reasonable assurance that either unsegregated or segregated internal reserves can be effectively protected from claims of creditors and therefore internal reserves cannot be made legally secure.[11]

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[9] Both the NRC requirements and the cost of Yankee Rowe used in this comparison are in nominal dollars. This contrasts to the use of 1989$ for all other parts of this section.

[10] As of early 1989, NISA estimated that $2.9 billion was held in decommissioning trusts, and that new funds were being collected at a rate of $583 million/year. (NISA). A recent NRC estimate placed the aggregate funds in early 1993 at about $4 billion (Johnson and De Rouffignac), suggesting that annual accruals may not be as high as NISA had anticipated.

[11] U.S. NRC, "General Requirements for Decommissioning Nuclear Facilities," Final Rule, Federal Register, V. 53, #123, June 27, 1988, p. 24033. Cited in Borson et al, p. 43.

The creation of external trusts alleviated much of the concern that accrued funds would not be available to actually decommission the facilities. However, the NRC regulations did not address who pays the cost of decommissioning if the accrued funds, for whatever reason, are insufficient to do the job. Insufficient accruals may be paid either by customers, utility shareholders, or through increased returns on trust assets. In every case, the taxpayer is the residual risk bearer since decommissioning is not a discretionary expenditure, and the costs must be paid by somebody. These options are each addressed in turn.

Increasing the price of its power to consumers in order to make up any fund shortfall initially seems the most favorable option from the perspective of a taxpayer. However, this solution has two drawbacks. First, if charges are placed on current nuclear power users while more comprehensive power wheeling increases inter-regional competition, consumers have greater opportunity to avoid buying nuclear-generated electricity. This reduced demand could result in lower decommissioning collections than would have happened without the surcharge, increasing the risks of default on decommissioning obligations. Secondly, if charges are passed onto future power users (as would occur if accruals at plant closure were too low), than future users would be subsidizing current users. In addition, wheeling would enable future users to bypass the more expensive nuclear utility as well.

Shareholders may also pay for decommissioning shortfalls through a loss of their equity. This would occur if decommissioning shortfalls are not allowed into the rate base (or, indirectly, if consumers bypass the nuclear utility through wheeling). The "shareholder pays" scenario also has potential costs to the taxpayer. First, the unfunded decommissioning bill will alter the financial stability of the utility leading to a reduced bond rating, and possibly also to default. For example, the debt rating for Public Service of Colorado, the owner of the soon-to-be dismantled Fort St. Vrain reactor, has had its debt rating reduced four times since the reactor was shut down. (Johnson and De Rouffignac).

Shortfalls could also potentially be made up through investing in higher-yield, higher-risk securities. The strategy of investing in higher risk securities brings with it an increased risk of defaulting on the ultimate obligations. This strategy is as likely to increase the shortfall through defaults as it is to decrease it through higher real yields.

In all of these cases, the health, safety, and proliferation issues associated with bankrupt, undecommissioned power plants suggests that the federal government would have no choice but to pay the shortfall from general tax revenues. Whether the default is triggered by customer bypass of utilities owning nuclear capacity (made possible by wheeling), through a high risk investment strategy, or by default or bankruptcy, the unfunded liability rests with the taxpayer.

It would be unrealistic to assume that no nuclear utilities will default on their decommissioning liabilities. For example, 11 nuclear utilities (assuming only 1 reactor per utility, this equals 10% of the U.S. reactors) are considered to have a significant risk of defaulting on their nuclear waste lump-sum assessments for the Nuclear Waste Fund. It is unlikely that these utilities will be in any better shape to pay for decommissioning. This example provides strong evidence that at least some defaults are likely.

Increased competition in energy markets (which increases the risk of consumer bypass of traditional monopolies), coupled with rapidly escalating decommissioning cost estimates, suggests that the taxpayer liability for decommissioning may be substantial. A recent increase in premature reactor closures due to poor operating economics greatly increases the unfunded portion of decommissioning costs, increasing the risks of defaults still further.

In our low estimate, we assume that the taxpayer will bear no liability for decommissioning shortfalls. In our high estimate, we assume that 25 percent of the shortfall will be borne by the taxpayer. This 25 percent figure begins with the 10% of the industry considered likely to default on Nuclear Waste Fund obligations, and adds a 15% additional default rate on <u>unfunded</u> decommissioning costs to account for the competitive and regulatory pressures described above. Even in the high estimate, we implicitly assume a zero default rate on planned trust contributions.

Clearly, this estimate is uncertain. However, we consider the estimate to be extremely conservative. The market forces and trends outlined above suggest that the defaults could be very large. In addition, our estimate of the size of expected shortfalls does not incorporate the impact of premature plant closings. Since premature plant closures greatly increase the magnitude of unfunded decommissioning costs, and since up to 25 reactors may close prematurely over the next 10 years (Parshley et al, 1), a large portion of the planned trust contributions are at some risk of not being made. This risk, which would greatly increase the size of the decommissioning shortfall, offsets the risk of overstating the default rate on the unfunded liabilities.

About the Estimate

We estimated the underaccrual for decommissioning by comparing the expected future value of the current trust funds plus planned future payments through the average plant closure (based on data from the NISA survey) to various estimates for the expected cost of decommissioning. The period of trust accrual is based on the NISA survey, which reports the average reactor to shut in 2020. Different assumptions were made about real rates of return on invested assets and on the appropriate measure of decommissioning costs per kW of capacity, and these led to a wide range of estimates for the shortfall.

Our low estimate for the shortfall uses generous real rates of return on invested assets, assumes that the current utility projections for decommissioning costs are correct, that no utilities will default on their decommissioning obligations, and that decommissioning costs should be prorated downward based on the capacity factor of the reactor.[12]

Our high estimate uses the historical real interest rate on shorter-term government securities to better represent the actual types of assets held by the funds, and the utility decommissioning cost estimates for reactors which have already shut down. We also use the design capacity of all operating and closed reactors rather than the operating capacity of the reactors which remain open, since this entire capacity must be decommissioned. Even the high estimate does not incorporate the manner in which real cost increases in decommissioning will escalate the realized costs even for the subset of reactors already closed but not yet decommissioned.

Both high and low estimates spread the total decommissioning shortfall over the 40-year life of an NRC license. Licensing extensions or premature closure (which seems more likely at this point in time) will both impact the size of decommissioning shortfalls expected.

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[12]Lower capacity factors lead to reduced levels of radioactivity in the core and associated equipment. This lower radioactivity could potentially be large enough to change the economics of decommissioning somewhat (Lapides, 274). However, it is also likely that above a certain level of capacity enough radiation builds up to make full cost decommissioning necessary, and others have questioned whether the decommissioning savings from reduced usage would be significant (Marriott, 2/8/93).

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Nuclear Decommissioning Shortfall

Part 1: Current Collection of Funds and Expected Accrued Funds by End of Plant Life

Industry Data, as of 1989:

	$/MW Capacity		Comments/Source
Average Trust Size	30,400		NISA, 9
Average Annual Collection	6,000		NISA, 12
Ave. Remaining Plant Life	31	Years	NISA, 12; assumes an average facility life of 40 years.
Expected Trust Size at Maturity	649,000		NISA, 12
Implied Annual Nominal Yield	5.68%		Calculated

Part 2: Calculation of Real Value of Current Accruals

A. Historic Real Yields on Invested Securities

		Real Returns - Pre-Tax		Real Returns - After-Tax		
Security Type	Period	Arith. Mean	Geomet. Mean	Arith. Mean	Geomet. Mean	Source
L-T Gov't Bonds	1926-1990	1.80%	1.40%	0.60%	0.20%	Siegel, p. 31
L-T Gov't Bonds	1966-1990	1.60%	0.90%	-0.70%	-1.30%	Siegel, p. 31
L-T Corporate Bonds	1926-1991	2.70%	2.20%			Ibbotson, p. 105.
S-T Gov't Bonds	1926-1990	0.60%	0.50%	-0.20%	-0.30%	Siegel, p. 31
S-T Gov't Bonds	1966-1990	1.30%	1.20%	-0.50%	-0.60%	Siegel, p. 31

Other Point Estimates of the Real Return on Nuclear Decommissioning Trusts

Return on Investments	1.00%	Borson, et al p. 4; based on interviews with utility analysts.
Return, net of expected cost increases	-1.93%	Borson et al, p. 4; assuming that cost estimates for decommissioning are likely to double over the remaining lives of the facilities (which is likely).

B. Plausible High and Low Returns on Decommissioning Trusts

(See Text for Discussion of appropriate interest rate proxies)

Maximum, from Part A	2.70%	This assumes the Trusts hold all corporate bonds, which seems unlikely given the current mix of assets and apparent risk preferences.
Minimum, from Part A	-0.60%	Uses short-term rates, per discussion in text of likely portfolio mix.

Excludes lowest estimate of -1.93% since this would double-count some (though not all) of the decommissioning cost inflation.

C. Value of Current Trust Fund Contributions, Using Real Rather than Nominal Interest Rates

Average Trust Size	30.4	$/kW Capac.	NISA, 12
Average Annual Collection	6	$/kW Capac.	NISA, 12
Ave. Remaining Plant Life	31	Years	NISA, 12; assumes an average facility life of 40 years.

	Low Est.	High Est.	
Real Yield on Investments	2.70%	-0.60%	Higher interest rates will ultimately yield a smaller shortfall in accrued funds.
Value of Trust at End of Plant (per kW) Life Using Real Yields	354.8	195.4	Calculated

Part 3: Estimates of the Cost of Decommissioning

A. Based on Utility Decommissioning Studies (average) 211 1989$/kW of capacity; Standard deviation of 96 $/kW; Strauss & Kelsey, pp. 60, 61.

B. Based on Experience Decommissioning Shippingport

Total Cost (Millions of 1989$)	98	Fry, p. 96.
Size (kW)	72,000	
Decom. Cost/kW Capacity	1,361.1	

Unit cost may be too high due to higher cost for first reactors, and for smaller reactors in general.
Unit cost may be too low due to ability to move entire reactor core in one piece. This will not be possible with larger reactors.

C. Based on the Expected Costs to Decommission Reactors Already Removed from Active Production

Reactor	Capacity (MWe)	Est. Decom. Costs (Mil. 1989$)		Decom. Cost $/kW
Entombed Reactors				
Hallam	76	10.0		132
Piqua	11	3.1		282
BONUS	16	5.1		319
Fully Dismantled Reactors				
OMRE (approx. capacity)	4	0.9		225
SRE (approx. capacity)	6	24.5		4,083
Elk River	22	14.6		664
Shippingport	72	98.0		1,361
Fully Mothballed Reactors				
Dresden 1	220	129.0		586
Pathfinder	58	81.0		1,397
Humboldt Bay	65	73.6		1,132
Partly Mothballed Reactors				
Fermi 1	61	23.3		382
Peach Bottom 1	46	4.6		100
Three Mile Island 2	961	1,350.0		1,405
Fort St. Vrain	343	242.0		706
Reactors Not Yet Dismantled				
LaCrosse	65	24.3		374
Indian Point	275	96.1		349
Rancho Seco	963	242.0		251
Total	3,264	2,422.1	Wghtd. Ave.	742
			TMI 2 Excluded	466

Source: Gene Heinze Fry, "The Cost of Decommissioning U.S. Reactors: Estimates and Experience," in The Energy Journal, 1991, V. 12, pp. 96, 97.

	1989$/kW	1989$/kW	
Weighted Ave. Expected Cost of Decom. for Reactors Out of Prod.	742	466	Note 1; lower value excludes Three Mile Island
Expected Cost, All Nuclear Utilities	211	211	
Expected Cost, Retired Reactors/ Expected Cost-Operating Reactors	3.5	2.2	

Notes:

(1) Since these utilities are much closer to paying for decommissioning (and in some cases have already started to pay) one would expect their cost estimates to be more precise than for the general mix of operating nuclear utilities. If this is true, and if there are not enormous economies of learning (see text for discussion), then it suggests that operating utilities are likely to have large decommissioning shortfalls at the time of plant closure.

Part 4: Estimating Aggregate Shortfalls for Plant Decommissioning

A. Net kW of Nuclear Generating Design Capacity in the United States

	Mil. Net kW	
Peak Net Summer Operating Capability	100.5	EIA, MER, 3/92, p. 101. Peak capacity was July 1990. Undercounts since units shut prior to 7/90 excluded.
Komanoff and Roelofs, as of 12/91	102.5	Komanoff and Roelofs, p. 9.
Aggregate Domestic Plant Capacity*	104.2	Strauss and Kelsey, pp. 60, 61; plus excluded units from Fry, p. 96.

*Whether or not a plant operates up to its design capacity, all parts of the plant get radiated and must be decommissioned.

B. Fund Shortfall per kW of Nuclear Capacity

1. Based on Above Data		Utility Ave.	Shipping-port	Non-Operating Plants, Wghtd. Ave. Excluding TMI	
Estimated Decom. cost/kW capacity		211.0	1,361.1	465.5	From Part 3
Expected Value of Current Accruals					
	Low Estimate	354.8	354.8	354.8	From Part 2C. Since a higher accrual yields a lower expected deficit, the low estimate is acribed the high end of the expected value of current collections
	High Estimate	195.4	195.4	195.4	
Expected Shortfall (Surplus)/kW					
	Low Estimate	(143.8)	1,006.4	110.8	
	High Estimate	15.6	1,165.7	270.1	
Industry Size (mil kW)					
	Low Estimate	100.5	100.5	100.5	From Part 4A
	High Estimate	104.2	104.2	104.2	From Part 4A

Part 4B, continued

		Utility Ave.	Shipping-port	Non-Operating Plants, Wghtd. Ave. Excluding TMI	
Projected Fund Shortfall (Surplus) (Millions of 1989$)					
Low Estimate		(14,447)	101,139	11,133	Aggregate shortfall in 1989$
High Estimate		1,624	121,465	28,145	Aggregate shortfall in 1989$
Calculated Annual Payment Necessary to Avoid Shortfall					
Low Estimate					
Years	40	(205)	1,435	158	While an average of 31 years remained until reactor closure in 1989 (NISA), we spread the decommissioning shortfall over the entire expected life of the reactor - 40 years.
Interest Earned	2.70%				
High Estimate					
Years	40	46	3,407	789	
Interest Earned	-0.60%				

2. Komonoff and Roelofs estimate:

Aggregate Deficiency in 1989 ($Millions)	186	Komonoff and Roelofs, p. 15 (top).

3. Public Citizen Estimates

	$Mils	
Annual Required Payment to Meet Utility Expected Cost	727	Borson et al, p. 4
Ave. Annual Funds Collected through 1989	399	
Annual Shortfall in 1989	328	
Annual Required Payment to Cover Expected Costs Using More Realistic Cost Inflators	1060	Borson et al, p. 47.
Ave. Annual Funds Collected through 1989	399	
Annual Shortfall in 1989	661	

C. Summary of 1989 Decom. Deficiency Estimates

	Low	High	Rationale for Including/Excluding in Estimate
Utility Projected Need	(205)	46	Included as low estimate; any surplus would be returned to rate payers or shareholders.
Shippingport Experience	1,435	3,407	Shippingport is averaged in with reactors no longer operating (below). This mix is a better cost indicator.
Expected Costs for Reactors no longer Operating	158	789	Used as high estimate. Best available cost indicator, given current experience.
Komonoff and Roelofs	186	186	Within chosen low/high range.
Public Citizen, based on utility assumptions	328	328	Within chosen low/high range.
Public Citizen, including projected cost escalation	661	661	Within chosen low/high range.
Minimum/Maximum	(205)	3,407	
Chosen range	(205)	789	See rationale for choices above.

Part 5: Share of Shortfall Paid by the Taxpayer, Rather than by the Future Ratepayer

	Low Est.	High Est.	
Estimated Annual Decomm. Shortfall (Surplus) for 1989	(205)	789	
Percent of surplus returned to ratepayers/shareholders	100.00%	N/A	
Net Shortfall	0	789	
Default Rate on Decommissioning Deficit	0.00%	25.00%	See discussion in text.
Expected Annual Cost of Defaults to Taxpayers	0	197	

Sources:

(1) Borson, Daniel et al. "Payment Due: A Reactor-by-Reactor Assessment of the Nuclear Industry's $25+ Billion Decommissioning Bill," (Washington, DC: Public Citizen Critical Mass Energy Project, Oct. 11, 1990).

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Changes in Market Rules Governing Energy Market Access, Pricing, or Terms of Sale

Dating back at least as far as the early part of the century, the federal government has almost continuously intervened in energy markets to "correct" problems with supply, demand, prices, or all three. Some of these interventions were justified, such as with worker health and safety, and environmental regulations,[13] and did, in fact, correct market failures. In many cases, however, this intervention led to later market failures -often to be corrected, of course, with further government intervention. These policies have distorted market signals and disrupted transitions to other sources of energy. The purpose here is simply to catalog the interventions rather than to evaluate their economic justification. **The provisions listed here are market interventions. They may increase or decrease the cost of energy, and may or may not constitute a subsidy.**

This chapter categorizes and presents a number of such government interventions. **It is not a comprehensive listing and does not include environmental, health, or safety regulations.** In addition, although direct intervention occurs at both state and federal levels, only the federal level is presented here. State regulations may compound or counteract federal intervention.

Changes in Market Rules differs from the other types of government action in a simple way. Tax expenditures provide incentives for companies to change behavior through reduced tax burdens. Agency intervention works to change behavior through providing new options, such as R&D support or subsidized financing. Changes in Market Rules regarding pricing or supply and demand conditions bring about change through government edict or direct market activity.

Federal edicts are regulatory in nature and involve the prohibition or requirement of certain behaviors which are unrelated to externalities. Federal actions involve the government management of its own resources, especially in markets where it is a swing supplier. For example, the decision to open up (or close) certain lands to mining can have significant market ramifications.

There are four generic impacts of direct federal intervention with market forces:

- Restriction or expansion of supply of a particular energy source
- Restriction or facilitation of market entry or exit
- Restriction or expansion of demand for a particular energy source
- "Correction" of prices which are deemed incorrect

All of these effects are ultimately expressed in the relative prices of energy types. In addition, each intervention often leads to large increases or decreases in private wealth. While quantifying these shifts is beyond the scope of this report, it is usually at least possible to determine whether an intervention increased or decreased costs for a particular sector.

Introduction

A brief description of federal intervention on the supply and demand sides, and with market pricing follows. Each type of intervention is then presented in more detail in later sections.

[13] Although many argue with the manner, speed, or degree of these interventions.

Changes in Market Rules on the Supply Side, Other Than Price

Federal regulatory influence over energy supply takes three main forms. First, as the proprietor of a substantial portion of the country's fuel resources (both known and inferred), decisions on how much of what fuels to release from "inventory" have large ramifications on prevailing market prices.[14] Land grants also play a major role here as well. Second, many private energy-related activities must be licensed. Federal licensing guidelines and practices also influence the price and availability of particular forms of energy. Market entry restrictions are also a type of licensing, and are controlled through laws which require minimum performance standards. Finally, the government may intervene directly with private suppliers. These supply interventions may take the form of restrictions of the number or type of sellers, the allowable quantities sold, or the type of material sold, all of which affect the profitability and feasibility of a particular form of economic behavior.

Changes in Market Rules on the Demand Side Other than Price

Federal intervention on the demand side has also affected choice in energy markets. Demand intervention has followed two main paths: import restrictions and required purchases by private interests also affect choice in the energy market. The influence that the federal government exerts on market structure through its demand for energy products and services for internal use is presented separately later in this chapter.

Price Controls

Price controls have been enacted for particular energy types a number of times. Generally, the controls were rigid administrative dictums that quickly fell out of sync with the ever-changing market realities. As a result, market disequilibrium was created yielding shortages when set prices fell below consumer pressure and/or general inflation driving costs upward. For example, severe energy shortages in the 1970s were due, in part, to the fact that domestic price controls, coupled with oil import restrictions, discouraged U.S. producers from responding to sharp increases in international oil prices. Price regulation in electric and natural gas utilities based on average rather than marginal cost is another type of price regulation which creates distortions of its own, although only wholesale rates are set at the federal level.

[14]Government ownership of energy resources can affect energy markets in a number of ways. Subsidization of energy-related operations with general tax revenues is covered in the chapter on federal agency interventions. This chapter deals simply with the power to shape market structure that the government holds by controlling a large percentage of particular resources, even if direct operations are not subsidized with general taxes.

Table B5-2: Summary of Federal Intervention With Energy Markets through Regulations on Pricing, Access, Terms of Sale, or Through Energy Procurement for Internal Use[15]

(Listed by Point of Intervention, Not Point of Impact)

Market Intervention	Fuels Affected	Status	Impact on Market
Supply Side Interventions Other than Price			
Federal Ownership of Natural Resources	Coal, Oil, Gas, Uranium, Geothermal, Electricity	Active	Variable
Licensing and Rights of Way			
Licensing of Fuel Minerals	Coal, Oil, Gas	Active	Variable
Licensing of Hardrock Minerals	Uranium, Synfuels	Active	Decreases Costs due to Antiquated Law
Licensing of Hydroelectric Facilities	Hydroelectric	Active	Variable
Land Grants for Rights-of-Ways	Coal, Oil, Gas, Electric	Active	Facilitated Market Development; current impacts centered on transmission-line and pipeline rights-of-way.
Licensing of Patents from Government Energy Research	All Fuels and Efficiency; Likely to be Correlated with R&D Spending Mix	Active	Decreases Cost of Innovation
Interference With Rights and Options of Private Suppliers			
Export Restrictions			
Restriction of Nuclear Exports	Fission	Active	Increases Costs by Reducing Utilization of Economies of Scale
Restriction of Timber Exports	Wood	Active	Negligible
Restriction of Crude Oil Exports	Oil	Active	May Slightly Reduce Domestic Oil Prices Regionally
Restrictions on Production Decisions			
Connally Hot Oil Act Restrictions on Intrastate Production	Oil	Inactive	Decreased Long Term Costs by Maintaining Drilling Pressures; Increases Short Term Energy Costs
Jones Act Restrictions of Use of Foreign Shipping Vessels	Oil, Coal	Active	Increases Cost of Transport
Restrictions on Choice of Fuels for Electric Utilities	Oil, Gas, Coal	Inactive	Increased Costs of Electricity Production
Transport Restrictions on Gas Pipelines	Gas	Inactive	Increased Cost of Transport
Contractual Abrogation During Natural Gas Shortage in 1973	Gas	Inactive	Increases Costs by Increasing Market Uncertainty
Monopoly Problems With Electric Wheeling	Electricity	Active[16]	Increases Costs by Precluding Arbitrage Between Power Districts
Restrictions on Organization Form of Utilities	Electricity	Active	Prevents Monopoly Pricing; May also Increase Costs by Reducing Administrative Economies of Scale
Residential Conservation Service Provision of Efficiency Audits	Efficiency	Inactive	Potentially Decreases Costs Through Demand Reduction

[15] Since these interventions affect the market clearing conditions, each may potentially also affect the market for energy efficiency as a substitute for increased consumption.

[16] Although the Energy Policy Act of 1992 gives FERC the power to force utilities to wheel power.

Market Intervention	Fuels Affected	Status	Impact on Market
Performance Thresholds			
Automobile and Appliance Efficiency Standards	Efficiency	Active	May increase cost of manufacture and of purchase; will generally reduce life-cycle costs of ownership
CAFE Exceptions for Multi-Fueled Vehicles	Methanol, Ethanol	Active	May decrease efficiency improvements of automobile fleet
Required Conservation Efforts to Get Access to Federal Power from WAPA	Efficiency	Active	Will probably decrease utility operating costs
Direct Ownership of Capacity			
Release of Fission Power Technology to Private Industry	Fission	Inactive	Facilitated Market Development
Direct Federal Ownership of Uranium Enrichment Services	Fission	Active	Decreases Costs Through Below-Cost Sales (Quantified in Agency Chapter)
Direct Federal Ownership of Electric Generation	Electricity	Active	Decreases Regional Costs Through Subsidized Infrastructure Development (See Agency Chapter)
Direct Intervention on the Demand Side Other than Prices			
Import Restrictions			
Import Restrictions on Uranium	Fission	Inactive	Protects Domestic Producers; Increases Costs to Industry
Oil Import Quotas and Allocations	Oil	Inactive	Increased Domestic Production in Short Run; Will Reduce it in the Long Run; Increases Prices by Restricting Lower-Cost Supplies
Required Purchases of Particular Energy Services			
PURPA required purchases	Gas, Coal, Renewables	Active	Increased Market Access for Small Scale Power
Oil Overcharge Fund Allocation to Efficiency Projects	Efficiency	Active	Increases Demand for Efficiency Services
Price Controls			
Petroleum Price Controls	Oil	Inactive	Reduced Domestic Prices, Reduced Domestic Production, Created Supply Shortages
Oil Pipeline Rates	Oil	Inactive	Facilitated Markets in Early Years; After Established, Impact Depends on Actual Prices Set and Monopoly Characteristics of the Line
Natural Gas Price Controls	Gas	Inactive	Led to Shortages from Below-Market Pricing
Wholesale Utility Rate Regulation and Average Cost Pricing	Natural Gas and Electricity	Active	Reduces Pressures to Improve Cost Efficiency; Distorts Price Signals Regarding Need for Marginal Capacity

Key To Table:

Inactive Status - Refers to Interventions that have expired, been eliminated, or were one-time grants.
Variable Impact - Intervention can increase or decrease prices, market certainty, or market interest depending on how applied.
Facilitated Market Development - Refers to interventions which, had they not occurred, would have made widespread use of the fuel unlikely.

Changes in Market Rules on the Supply Side

Federal Ownership of Energy Resources

As shown in the chart below, the federal government is the direct owner of a significant portion of the country's energy resources. Therefore, government decisions regarding the timing and scope of the development of federal resources has a large impact on energy markets through changes in aggregate supply.

Table B5-3: Estimated Federal Ownership of Energy Resources

Commodity	Estimated Percent of U.S. Total Supply On Federal Lands
Coal	33%
Oil[17]	21% - 80%
Gas	16% - 40%
Uranium Reserves	40%
Uranium enrichment capacity[18]	50% of non-Soviet *world* supply
Geothermal Fields	60%
Total Electrical Generating Capacity[19]	9%
Share of Hydroelectric Generating Capacity	44%

Sources: DOE, 4/90, 131, 181; EESC brief, 43; Stat. Abstract '90, Table 966; Abel, 3.

[17] Widely divergent estimates for oil and gas reserves reflect the variety of sources used and the uncertainty surrounding the size of reserves.

[18] May not include reprocessing capabilities of spent fuel from breeder reactors. The break-up of the Soviet Union has led to a huge influx of enriched uranium from that area, at very low prices. While this has greatly reduced the market power of DOE, DOE did have significant market power during much of main developmental period of U.S. commercial nuclear power.

[19] Includes hydroelectricity. Federal facilities generate or distribute 12 percent of the nation's electricity. The municipal, cooperative, and investor-owned utilities that purchase power from the federal facilities supply about 29 percent of the nation's electricity to end users. (GAO/RCED-92-13, 32). Regionally, the impact can be even higher. Bonneville Power Administration supplies half of the electricity used in the Pacific Northwest and owns 80 percent of the region's transmission network. (GAO/RCED-92-13, 34).

Licensing and Rights-of-Way Grants for Energy Related Activities

Even when the government does not own the energy resource, or has released access to resources it does own, licensing and rights-of-way decisions have direct impact on profitability and timing of the conversion of raw materials into energy.

Licensing of Fuel Minerals on Federal Land. As described above, the quantity and timing of access to federal energy resources affects the resulting market equilibrium. Leases are regulated under the Mineral Leasing Act and the Mineral Leasing Act for Acquired Lands. Tracts open for bid are determined by the Secretary of the Interior, although most now are subject to Congressional approval. Open energy tracts are then bid for in competitive auctions. Foreign firms may participate in these auctions so long as their home country allows U.S. firms similar access to resources there. (Baldwin et al, 4).

For most minerals (and virtually all fuel minerals), lessees receive only mineral rights, pay royalties to the government for resources extracted, and post bonds to ensure sites are reclaimed to current government standards. As with all government policies, there are exceptions. Particular bids may not be competitive; particular tracts may not be reclaimed. Historically, the Minerals Management Service which is responsible for collecting royalty payments, did not receive proper payment on account of inadequate control systems.[20]

Licensing of Hardrock Minerals on Federal Land. Hardrock minerals, which now include only uranium, and bituminous and asphaltic sands, in the energy category, are governed by the Mining Law of 1872. The Mining Law is a remnant of the gold rush days, and was created to encourage the settlement of the West. The Law provides the ability to transfer mining claims on federal lands into private ownership of all land rights. This process, known as patenting, requires only that the miner do $100/year of work on the claim to retain it, and pay a fee of between $2.50 and $5.00 per acre to transfer all rights from the government to themselves. Since 1872, 3.2 million acres of public land have been sold in this way. (GAO/RCED-89-72, 2).

Although few energy minerals are affected by the law currently, oil and gas claims were eligible for patenting until 1920.[21] (Hocker and Udall, 20). Federal lands designated as wilderness areas and national parks (135 million of a total of 727 million owned by the government) are also exempt from the Mining Law. Between January 1, 1978 and September 30, 1987, 5,526 acres were patented primarily for uranium and 1,598 acres were patented for asphaltic sands. (GAO/RCED-90-111, 3).

Licensing of Hydroelectric Facilities. The 1935 Federal Power Act requires federal licensing of any hydroelectric projects built on navigable waterways. (Weekly Bulletin, 7/23/90, B18). The licensing is carried out by the Federal Energy Regulatory Commission, and licenses are limited to a maximum of 50 years. The licensing process takes an average of five years. (DOE, 4/90, 102). Licensing is subject to environmental and land use restrictions.

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[20] See, for example, U.S. GAO, Mineral Revenues: Options to Accelerate Royalty Payment Audits Need Further Consideration, June 1989 (GAO/RCED-89-167) or U.S. GAO, Debt Collection: Interior's Efforts to Collect Delinquent Royalties, Fines and Assessments, June 1987 (GAO/AFMD-87-21BR).

[21] Oil shale remains eligible for patenting if the claims were filed prior to 1920. One oil shale patent claim, for 84,000 acres in Colorado, was patented in the 1980s. (GAO/RCED-90-111, 3).

Land Grants for Energy Rights-of-Way. Federal direct involvement in energy markets is clearly exhibited through historical gifts of rights-of-way, without which many forms of power would not be possible. Rights-of-way use the federal power of eminent domain to allow uses deemed socially beneficial to take precedence over private land ownership rights. Grants enabled the construction of pipelines (benefitting oil and gas), transmission lines (benefitting electricity), railroads (benefitting coal), and highways (benefitting refined oil products).

These grants often involve large amounts of land. For example, between 1850 and 1978, 94.5 million acres of land grants were made for railroads. (Cone et al, 185). The Federal Power Act, for example, requires that the Department of Interior pre-identify corridors for all types of uses on federally managed lands to minimize the impact on other land uses. This includes transportation and electric transmission corridors. (Zimmerman, 14). Federally-owned power facilities utilize federal eminent domain powers.

Rights-of-way are also provided by state governments. Municipal, cooperative, and investor-owned utilities generally receive state eminent domain powers as part of the utility franchise. However, the exercise of those rights is subject to state ratification, and environmental and land use restrictions. This right is usually not available to non-utility generators. (Zimmerman, 11, 14).

Licensing Federal Research. The federal government spends billions of dollars per year on research and development ($16 billion in 1990). The largest single agency source of research funds is the Department of Energy. Other agencies, including the National Science Foundation, the National Institute of Standards and Technology, and the Department of Interior also conduct research that is related to energy. The process and cost with which the government transfers (through patents and licensing) knowledge and technology gained in these efforts to the private sector can determine the direction of new private sector activity. (GAO/RCED-91-80).

Intervention With the Rights and Options of Private Suppliers

By carefully defining who can and cannot do what energy-related activity in what jurisdiction and during what time period, the federal government has exerted significant influence on the shape of energy markets. Interventions have included export restrictions, restrictions on production decisions, performance thresholds, and direct ownership of suppliers.

Export Restrictions

Export of Nuclear Technologies. Due to the ability to use some commercial nuclear technology for military purposes, export of these items is carefully controlled. This increases costs to U.S. industry, since it precludes the use of available scale economies.

Timber Exports. Restrictions on the sale of timber harvested from federal lands have been in existence in one form or another since 1897, when harvests could be used only in the state or territory in which the federal forest resided. (Thomas, 3). Export restrictions from the United States as a whole have been in effect since 1968. Provisions prohibit the export of all logs from federal land west of the 100th meridian (which bisects Texas and the Dakotas) except for species declared by the Secretary of Agriculture and the Secretary of Interior to be "surplus" to domestic needs. Set to expire in 1971, the ban has been renewed every year since on an annual rider to the Interior and Related Agencies Appropriation Act. (Beuter, 19). The purpose of these restrictions is to protect regional jobs in the milling and wood products sectors. The impact on these provisions on the use of timber as a fuel is likely to be minor since the value of fuelwood is too low relative to the cost of transport to major buyers, primarily located in Asia.

Crude Oil Export Bans. The Export Administration Act of 1979 places restrictions on the export of Alaskan North Slope oil that effectively bans its export without special certification by the President that export is in the national interest. In addition, export of much of the oil produced from other areas also cannot be exported. This includes

> domestic crude transported by pipeline over certain rights-of-way, petroleum produced from the Naval Petroleum Reserve, and oil produced from the outer continental shelf. (GAO/RCED-91-21, 2).

Removal of the ban on export of Alaskan oil would substitute shipments to the Pacific Rim for current shipments to eastern U.S. ports. Oil producers would likely receive higher returns, while independent producers on the West Coast and the U.S. tanker shippers would be hurt. Domestic oil prices might increase slightly. (GAO/RCED-91-21, pp. 7-11). Total oil imports would likely increase, although net imports might decrease as increased imports were more than offset by increased exports of Alaskan crude.

Restrictions on Production Decisions

Interstate Oil Compact Commission and the Connally Hot Oil Act, 1935. The Act allowed states to restrict intrastate oil production and prohibited export of oil in excess of state mandated limits to other states. (Mead, 230). The purpose was to slow the rapid growth in drilling activity that was quickly depleting well pressure in exploited fields. The Act seemed to stabilize oil production while also driving up prices and returns on drilling, benefitting industry participants. (Cone et al, 197-198).

The Jones Act. The Jones Act was passed in 1915 to ensure the continued existence of a U.S.-built merchant marine which was threatened by cheaper foreign vessels. The Act restricts shipping of certain commodities, including coal and oil, between U.S. ports to U.S.-built vessels. These vessels generally have a higher cost of operation, thereby increasing the cost of fuel shipment. (Cone et al, 218). In addition, the current construction costs at American shipyards are estimated to be about twice as high as those prevailing internationally. (Hassel, 12).

Transport Restrictions. Until 1975, the Federal Power Commission prohibited the transportation of intrastate gas in interstate pipelines. (Cone et al, 232).

Overriding Existing Contractual Agreements. In January 1973, the Federal Power Commission intervened in natural gas markets to deal with gas shortages (caused by the regulated prices). The FPC overrode all existing contracts between parties in this market and allocated existing supplies first to households, then to commercial establishments, and finally, with the lowest priority, to industrial users. (Cone et al, 238).

Monopoly Problems Regarding Wheeling in the Federal Power Act. Wheeling, or the transmission of power generated by one utility over another's transmission lines, was not required by the Federal Power Act.[22] As a result, the United States is divided into a series of smaller monopoly power districts, across which there may be large price disparities. Since electricity may be transmitted over long distances,

[22] Since electricity follows the path of least resistance, there will always be some unintended transport of power over transmission lines owned by another party, but hooked into the power grid. This power flow does not respect contractual arrangements between parties, and has been generally assumed to be about equal in each direction. In cases where "large amounts of electricity flow in substantially the same direction over a period of time, utilities in the unintended path of that flow have found that both their generation and their use of the transmission grid have been adversely affected." (Zimmerman, 19). These flows make wheeling more difficult to manage.

access to transmission systems in a competitive power market would reduce price disparities in electricity to the cost of transmission. (OTA, 70-78). The Energy Policy Act of 1992 has taken steps in this direction by giving FERC the power to require that a utility provide transmission services under certain circumstances. (DOE, 10/15/92, 12). Note that this is a case where additional intervention is being discussed.

Restrictions of Organizational Form of Utilities. The Public Utility Holding Company Act of 1935 was created to control highly concentrated ownership of utilities through successive holding corporations and their charging excessive rates. The law restricts organizational forms of utilities which would hinder effective regulation of the facilities. In tandem with monopoly territory grants, the Act has some side-effects. For example, PUHCA

> confine[s] a holding company's utility operations to a single geographic area and requires utility holding companies to maintain simple corporate and financial structures. (GAO/RCED-92-52, 2).

In addition, PUHCA virtually prohibits diversification to avoid cross-subsidization between regulated and unregulated business segments. (Abel, 1). The restrictions on monopoly pricing decrease the cost of power. The restrictions on organizational structure and diversification may increase the cost of power by reducing some opportunities for administrative economies of scale.

Residential Conservation Service. Required utilities to provide free or low cost audits to customers to identify opportunities for efficiency improvements. The requirement is no longer in effect.

Performance Thresholds

Some federal laws set minimum performance thresholds for products or services in order for them to be marketed. Pollution control regulations do this to force producers to incorporate the negative externalities of their production into the cost of their product.[23] Such laws are too numerous to mention here. Other thresholds may be created to focus R&D efforts in a particular way, to reduce the security risks of reliance on non-indigenous energy supplies, or to reduce negative externalities of pre-cursor economic activities (e.g., of electricity production needed to power a fluorescent lamp).

Corporate Average Fuel Efficiency Standards. Initially passed in 1975, these standards required that the average of all cars sold by a manufacturer (its fleet) meet minimum miles per gallon efficiencies beginning in 1978. Some exceptions are made for manufacturers of specialty cars or of very low production numbers, although such cars must generally pay a "gas guzzler" surcharge. Tax receipts under the gas guzzler provision are presented chapter B3.

The Alternative Fuels Promotion Act of 1988 modified CAFE calculations to provide an incentive for alternative fueled vehicles. First, the Act bases CAFE calculations only on the vehicles consumption

[23] The manner in which these costs are internalized may vary both in efficiency and magnitude. Pollution taxes or permits force producers to explicitly pay for their use of environmental quality. Regulatory requirements force changes in way that products are made, forcing companies to pay for the capital upgrades to meet the requirements. All three methods increase the costs of pollution-intensive production and ultimately of pollution-intensive products to some degree.

of gasoline; second, the Act assumes for the purposes of this calculation that the gasoline content of all the blends is 15%. (Behrens, 6). In actuality, blends such as gasohol contain up to 90% gasoline.[24]

Appliance Efficiency Standards. Federal minimum efficiency standards for all major residential appliances and for fluorescent light ballasts set entrance thresholds to these markets. A study by Lawrence Berkeley Laboratory estimated that the net savings to consumers (the present value of reduced energy costs minus the increase in the initial purchase price) from the standards were about $25 billion.[25]

Required Conservation Programs to Receive Inexpensive Federal Power. The 1984 Hoover Power Plant Act requires federally-owned Western Area Power Administration to include certain requirements in sales contracts to customer utilities. Customer utilities must undertake certain conservation efforts or else risk WAPA withholding a portion of their power allocation. (GAO/RCED-92-13, 35).

Direct Ownership of Capacity

Federal ownership of energy resources (i.e., other than raw materials) exerts direct influence over supply and pricing through its control of production decisions and access to productive inputs. Where viable private sector activity is feasible, government activity can crowd it out. Activity in areas where private enterprise is not currently viable can crowd out the private sector in markets for close substitutes. Government activity may impede the transition to new markets based on changes in technology which make previously harsh climates for the private sector attractive.

Two additional points bear note. First, federal monopolies can be regional rather than national (e.g., TVA versus uranium enrichment services). Second, even government monopolies don't benefit from profits since they don't get to keep all of their profits.[26] As a result, emphasis may be on expanding the enterprise scope or size rather than maximizing monopoly profits. This may be accomplished by underpricing services and making up deficits through Congressional appropriations.

Fission Power Technology. Until the Atomic Energy Act of 1954, private ownership or operation of nuclear reactors was illegal. (Cole et al, 128).

Uranium Enrichment Services. The federal government has been the sole owner of the three domestic enrichment facilities (Oak Ridge, Paducah, and Portsmouth) since their inception in 1943. Although efforts at privatization are currently underway, the two remaining facilities (Oak Ridge has been shut down) are still federal property and still supply half of the world's enrichment services outside of the former Soviet Union. Market share was maintained despite international competition through selling services below cost and making up the difference through Congressional appropriations. Seventy percent of the electricity used by the Portsmouth facility (and all of the amount used by Oak Ridge) were supplied by the Tennessee Valley Authority, also government-owned. Power pricing decisions by TVA therefore

[24] The Energy Policy Act of 1992 expands eligibility for the alcohol fuel excise tax exemption on a pro-rated basis to fuel blends containing only 5.7 or 7.7 percent alcohol. (DOE, 10/15/92, 26). This expansion increases the size of the CAFE alternative fuels loophole.

[25] Joseph H. Eto et al., Lawrence Berkeley Laboratory, The Regional Energy and Economic Impacts of the National Appliance Energy Conservation Act of 1987, June, 1988, pp. 15, 16, 19; cited in OTA (1991), p. 56.

[26] Some federal enterprises, such as Bonneville Power Administration, technically do retain excess revenues for future use, although they do not accrue to individual employees.

play an important role in determining the cost of enrichment services (see Tennessee Valley section of Agency Interventions chapter for more detail on TVA pricing of power sales to uranium enrichment).

Electric Generation. While the federal government directly owns only 8 percent of total domestic electrical generation capacity (Stat. Abstract '90, Table 966), its market share in certain parts of the country, such as the Pacific Northwest, is substantial. For example, the Bonneville Power Administration controls about 50% of the generating capacity and 80% of the transmission capacity in the Pacific Northwest. (GAO/RCED-92-13, 34).

Changes in Market Rules on the Demand Side

Through restrictions on the procurement decisions of consumers the federal government has shaped energy market investments, market share, and profitability.

Import Restrictions

Import Restrictions on, and Overpurchasing Of, Uranium. Until the adoption of the Canada Free Trade Compact in 1988, the U.S. restricted imports of foreign uranium, thereby protecting the domestic industry. Further back, the Atomic Energy Commission had also overbought and stockpiled uranium to keep demand up. Only uranium imported for enrichment and re-export was allowed into the U.S. Not only did this allow the uranium producers to earn a profit, but it supported the scale of mining necessary to maintain an industry capable of expansion at relatively stable prices once demand picked up from the commercial sector as the Atomic Energy Commission expected. These restrictions improved the profitability of domestic mines but increased the costs of the consumers of enriched uranium in the process. (Bowring, 45; Montange, 8).

Oil Import Quotas and Oil Allocation. Oil import quotas were instituted in 1959 by President Eisenhower, under pressure from domestic independent producers. These producers were afraid of being forced out of business by cheap foreign oil supplies from the multinationals. (Mead, 231). Import quotas were allocated among refiners using historical data and a sliding scale favoring small refiners (Cone et al, 214), and remained in effect until May 1973. In combination with extensive tax benefits, the quotas created pressures to "drill America first," depleting domestic supplies to a point significantly above the world price.

Required Purchases of Particular Energy Services

Energy Supply and Environmental Coordination Act of 1974. Passed following the 1973 oil embargo, the Act authorized the Federal Energy Agency, under certain conditions, to prohibit the use of oil and gas by facilitates able to use coal. Declining demand for energy following the price shocks reduced the need for new power plants, limiting the impact of the Act. Nonetheless, the Act encouraged utilities to direct their planning, R&D, and investments towards a future of coal and nuclear plants. The Act also instituted a bureaucratic process to issue licenses for fuel switching. (Cole et al, 58).

Powerplant and Industrial Fuel Use Act of 1978. Similar to the 1974 Act, DOE required certain facilities to switch from oil or gas to an alternative fuel, generally coal. It also prohibited the use of oil or gas as a primary energy source in new electric powerplants and major fuel-burning installations. (Cole et al, p. 59). While this Act has been repealed, it has significant residual impacts through the fuel mix of the installed energy infrastructure.

Public Utility Regulatory Policy Act (PURPA). PURPA was created to encourage the production of electricity from alternative fuels by requiring electric utilities to purchase power generated by "qualifying"[27] facilities for their "avoided cost" - the amount it would have cost the utilities to generate the electricity themselves. The law exempts these facilities from regulation under another law, the Public Utilities Holding Company Act of 1935.[28] In addition, they are exempted from cost-of-service regulation required of utilities under the Federal Power Act. (Newcomb, 61).

Where the purchase price of power is at peak load rates but the utility is not yet out of capacity, PURPA can confer a subsidy on the alternative fuels. Similarly, where the alternative fuels purchased under PURPA are not secure (in that they rely on uncontrollable events such as weather patterns), utilities argue that the required purchases don't help to avoid the costs of capacity increases, since they need to secure backups to the PURPA power as well.[29] Finally, PURPA favors small-scale power even when large scale power may be a more efficient way to meet market demand.

Some arguments about PURPA-related subsidies seem unjustified. Where power purchases are contracted for and then demand falls below peak so that the utility no longer needs the purchased PURPA power, arguing that PURPA is forcing unneeded expenditures is not valid. Had the plant invested in new capacity during the supply-constrained period, it would also be stuck with surplus capacity in the case of declining demand. PURPA power is no different. Claims that utilities are forced to pay more than their full avoided cost from PURPA qualifying facilities is mitigated by the fact that FERC has the power to preempt the states in this circumstance.

Price Controls

Price controls can't really be separated from effects on supply or demand since incorrect pricing mechanisms will soon have repercussions on supply and demand decisions. However, for clarity we have separated them out.

Emergency Petroleum Allocation Act of 1973. This Act set up a dual-tiered pricing system which differentiated between "old" oil and "other". Old oil consisted of oil from properties producing at or below their 1972 production levels. "New" oil, which consisted of stripper wells and increased capacity in old wells (termed "released" oil), were allowed to sell at market prices, thereby providing an incentive to increase domestic production. Old oil, which was now cheaper due to price controls, had to be allocated to prospective buyers by the FEA. In 1976, the "released" oil program was eliminated in the Energy Policy and Conservation Act. Although the prices were indexed to inflation, in actuality, they rose more slowly than inflation and more slowly than costs. As the set prices fell further and further below market prices, domestic supplies fell and imports increased. (Cone et al, 203). Price controls for oil were totally eliminated by 1981.

Oil Overcharge Funds. The price regulation gave rise to another federal intervention, oil overcharge funds, which were legal settlements with firms that did not abide by the set prices. Oil

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[27] Qualifying facilities included renewable energy sources less than 80 MW, and which derive more than 50% of their power from waste, biomass, or other renewable, and which use fossil fuels as the source of less than 25% of their input. Also eligible are most cogeneration plants (so long as they both produce electricity and waste heat for industrial use in an efficient manner) and small hydroelectric facilities. (EESC, 63; Rader et al, 55).

[28] PUHCA regulates utilities as monopoly enterprises. PURPA facilities are exempt since, as independent power producers, they only sell power at wholesale rates and do not have the monopoly power of other utilities to set rates. (Abel, 4).

[29] This claim is mitigated by the fact that 70 percent of PURPA capacity as of October 1989 was for gas- and coal-fired facilities. (FERC, iv, x).

overcharge funds were collected through court settlements with oil companies. The settlements were the result of oil company violations of oil price controls which were in effect from 1973 to 1981. (GAO/RCED-88-119BR, 1). Though the violations all occurred prior to 1981, disbursements of collected funds did not begin until 1985 (though the funds owed did accrue interest during this period).

A number of settlements created the pools of money. In accordance with court orders, Congress structured the disbursement of the funds. These are described in more detail below. Through the end of FY 1989, $6.56 billion in overcharge funds had been disbursed, and about $1.8 billion either awaited disbursement or was expected from pending settlements. (Gelb, 1,4). Overcharge funds are expected to run out by the mid-1990s. (GAO/HRD-91-1BR, 24). The individual payments are presented below:

Direct Payments and Subpart V Proceedings. Overcharge funds are disposed in five major ways. Where injured parties can be easily identified, *direct payments* are made to the injured parties. Where injured parties are more difficult to assess, cases are referred to DOE's Office of Hearings and Appeals (OHA). OHA must allow claimants to file for refunds in accordance with Subpart V of the Emergency Petroleum Allocation Act of 1973. Payments made via this process are called *Subpart V Proceedings* payments. Any excess funds can be given to States for uses which generally include energy purchase assistance for low-income residents and energy efficiency improvements. (Gelb, 5).

Warner Amendment Payments. Another Congressional provision is known as the *Warner Amendment.* The Warner Amendment specifically required DOE to disburse up to $200 million in overcharge funds to the States and territories. The funds are allocated in proportion to each state or territory's consumption of refined petroleum products between 1973 and 1981. Funds could be used only for weatherization, energy conservation planning, energy efficiency improvements, alternative energy use, or purchase of energy services for low-income citizens. (Gelb, 7).

PODRA Payments. The *Petroleum Overcharge Distribution and Restitution Act* of 1986 allows up to $200 million per year in overcharge funds not payable to an identified injured party to support four energy conservation grant programs for states, run by DOE. These programs include the State energy Conservation Plan, the Energy Extension Service, the Institutional Conservation Program, and the Weatherization Assistance Program, in proportion to their shares of direct Congressional appropriations. (Gelb, 8).

Exxon, Stripper Well, and Texaco Settlements. The last category includes specific large settlements for price control violations. These are grouped under the *"other"* heading on the Oil Overcharge spreadsheet. Three of the major settlements have collected a total of approximately $5,196 million. The Exxon settlement in 1986 was for $2,098 million and was earmarked for the same programs as the Warner Amendment. The Stripper Well Case involved the misclassification of wells as "Stripper Wells," to enable them to charge more for the oil under the price controls at the time. The Stripper Well case was finally settled in July 1986 with $1.85 billion disbursed through September 1989, although additional collections were expected. The Stripper Well funds went both to private injured parties and to the federal government and the States. Funds to the government from this settlement may be used for any of the programs identified in the Warner Amendment (above), as well as for administrative expenses and attorney's fees as well. (Gelb, 11,12).

The last major settlement was with Texaco for misclassifying its oil, again to take advantage of exceptions to the set prices under the oil price controls. A total of $1,250 million from this settlement is to be distributed in the same pattern as the Stripper Well settlement. (Gelb, 9-11).

Most of the funds allocated to States from oil overcharges were earmarked for conservation, energy efficiency, low-income energy assistance, or alternative energy development. For example, between 1981 and 1990, $813 million in overcharge funds was disbursed to the Low Income Energy Assistance

Oil Overcharge Fund Collections and Disposition Through FY89
(Millions of Nominal Dollars)

Mode of Disposition	Category of Recipient Private Sector	States	U.S. Treasury and SPR	Total	
Direct payments to identified injured parties	492	36	0	528	
Subpart V proceedings	288	73	0	361	
Warner Amendment distribution	0	200	0	200	
Petroleum Overcharge Distribution and Restitution Act	0	248	0	248	
Other (Note 2)	659	3,358	1,209	5,226	
Total	1,439	3,915	1,209 (Note 3)	6,563	
In escrow, awaiting disposition				890	
Estimated future recoveries			Less than	1,000	Gelb, 1

Sources and Notes:

(1) Data are from Bernard Gelb, "Oil Overcharge Restitution: Regulations, Enforcement, and Distributions," (Washington, DC: Congressional Research Service. Nov. 13, 1989), p. 4. CRS 89-622 E.

(2) on, Stripper Well, and Texaco settlements.

(3) Includes $50 worth of crude oil contributed to the Strategic Petroleum Reserve (SPR).

Disposition for Energy Support, by Year

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	Source/Notes
LIHEAP			23	18	6	27	185	160	174	111	109	(1)
All Oil Overcharge Funds to the States		25	210	40.5	40.5	2874.2	138	293.4	293.4			(2)

Sources and Notes:

(1) LIHEAP, "Summary Statistics on HHS Energy Assistance Programs, FY 1981-1992," 1/23/92.

(2) U.S. GAO. "Energy Conservation: States' Expenditures of Warner Amendment Oil Overcharge Funds," May 1988, p. 13. GAO/RCED-88-119BR. Data for 1984 and 1985 were estimated by GAO. Data for 1988 and 1989 were estimated by splitting the difference of total overcharge disbursements to the states from above minus disbursements between 1982 and 1987 shown here.

Program. (LIHEAP Statistics, 1/23/92). However, some funds support attorney's fees and administrative costs.

These funds represent one example of the cost of changes in market rules. These changes can shift wealth of billions of dollars between one sector of the energy market and another, or between producers and consumers.[30] We do not include the cost of any of these changes in market rules in our subsidy estimates. Unless we were able to quantify most of them, including one or two would misrepresent the nature of this type of federal intervention.

Oil Pipeline Rates. To encourage pipeline companies to expand in the 1920s, the federal government directly intervened to allow higher rates of return than was allowed for most public utilities. (Cone et al, 215).

Natural Gas Price Controls. Tariffs for transporting natural gas were set by Congress in 1938. In 1954, a Supreme Court ruling expanded the price controls to the wellhead price of gas flowing in interstate commerce as well as the act of transporting such gas. Due to below-market prices set by the Federal Power Commission, shortages developed. (Mead, 231). The Natural Gas Policy Act of 1978 was enacted to remove some of the problems with earlier gas pricing schemes and resulting shortages. The intent of the Act was to partially deregulate wellhead prices by 1985, and still more by 1987. In July 1989, Congress passed the Natural Gas Wellhead Decontrol Act, which ended wellhead price controls totally by January 1993. (DOE, 4/90, 58).

Utility Rate Regulation and Average Cost Pricing. While most rate setting is done at the state level, federal utility rate regulation usually sets wholesale power rates on a rate-of-return basis. This method is intended to provide "fair" returns on invested capital based on the estimated demand for power. Rate regulation cuts both ways. Since it caps pricing, returns may be reduced. However, rate regulation also helps reduce risks of utility default by providing rates designed to cover costs. This reduces the utility's cost of capital since they can use more debt (which is cheaper than equity), and get a lower interest rate on borrowing due to a lower default risk. Rate regulation also reduces utility incentives to improve their cost structure. In recent years, there has been more uncertainty over whether particular expenditures would be allowed (determined as "prudent" by the utility rate board) than was historically the case. This trend increases the utility cost of capital somewhat.

Setting rates to reflect the average cost of power provision for a given mix of plants in a utility also creates significant distortions. In a free market, the market price is equal to the marginal cost of the least efficient producer, signalling appropriate times for market entry or exit.[31] Average cost pricing obscures these signals and slows market reaction to a changing cost structure somewhat. There is some movement away from average cost rate regulation at the federal level, and even towards direct competition among suppliers.

[30]This differs from both the Price-Anderson Act's cap on nuclear liability and the underaccrual for nuclear decommissioning, where the costs are borne by the general taxpayer.

[31]Transmission lines are (for now) a natural monopoly. Therefore, the "marginal cost of the least-efficient producer" is meaningless since there is only one producer. However, the power production is not a monopoly, especially once demand-reduction services are included in the market. Therefore, average cost pricing for generation capacity will hide market signals to the power-production segment. A 1987 study by the World Resources Institute estimated that increasing electricity prices to reflect the marginal costs of generation would reduce demand U.S. aggregate electricity demand by 27% and reduce economic subsidies (as opposed to government subsidies) by about $61 billion/year. (Kosmo, 41). We do not know how changes in laws governing electric utilities since 1987 affects the validity of this estimate.

Federal Procurement of Energy Services for Internal Use

The federal government is the largest consumer of energy in the United States, spending $8.7 billion in 1989 to heat and power federal facilities, and fuel its transportation fleet. While some of this spending goes into efficiency improvements to federal infrastructure, this accounts for only $45 million, or 0.5 percent of total energy spending (1.3 percent of total spending on energy costs in federal buildings). (Hopkins, 2,14).

The choices made as a consumer of energy services can have a significant impact on products and services produced by the private sector. There are currently a few laws governing federal procurement of energy services (see Table below). Some, such as those governing improvements in energy efficiency, simply try to make federal agencies behave more as they would in a competitive market in the procurement of energy services.

Table B5-4: Summary of Interventions from Federal Procurement of Energy Services for Internal Use

Federal Procurement Provision	Fuels Affected	Status	Impact on Market
Procurement of Energy Services for Government Use	All Fuels	Active	Variable; Can Create Markets
Energy Efficiency Requirements in Government Buildings and Vehicles	Efficiency	Active	Moves Energy Procurement Practices Closer to Behavior in a Competitive Market
Federal Procurement Preference for Gasohol	Gasohol	Active	Increases demand for gasohol
Federal Procurement Preference for Alternative-Fueled Vehicles	Gasohol, Natural Gas	Active	Increases demand for alternative-fueled vehicles; increases costs of federal fleet procurement
Implementation of Energy Efficiency Efforts in Federal Power Projects	Efficiency	Active	Increases demand for efficiency services; may decrease energy costs to the government
Required Purchases of Coal by the Department of Defense	Anthracite Coal	Active	Protects Domestic hard coal miners; increases energy costs to the Department of Defense
Overpurchase of Uranium	Fission	Inactive	Protects Domestic Producers; Increases Costs to Taxpayers

Energy Efficiency of Government Buildings and Vehicle Fleet. The Federal Energy Management Improvement Act of 1988 requires a 10 percent reduction in energy consumption in federal buildings by 1995. (GAO/GGD-92-22, 2). Executive Order 12579 (April 1991) by President Bush increased this to 20 percent. The Bush Executive Order also directed federal agencies to reduce motor vehicle consumption of gasoline and diesel fuel by at least 10 percent by 1995. (GAO/T-RCED-92-73, 3).

Procurement of Gasohol. Executive Order 12261 (Jan. 5, 1981), "Gasohol in Federal Motor Vehicles," requires federal agencies procuring unleaded gasoline to give preference to gasohol whenever feasible. The Order was in line with the Energy Security Act of 1980 which sought to reduce dependence on imported oil. Authority for carrying out the order was delegated to DOD for the military fleet and to the General Services Administration for the civilian fleet. (GAO/T-RCED-92-73, 2).

Procurement of Alternative Fuel Vehicles. Under the auspices of the Alternative Motor Fuels Act of 1988, DOE is the lead agency for ensuring that the maximum practical number of automobiles and light-duty trucks procured for the federal fleet each year be powered by alternative fuels. In 1990, DOE, through the General Services Administration, was successful in procuring 65 automobiles capable of running on both alcohol and gasoline. In 1991, they were successful in procuring 50 natural-gas powered vans. In neither case was the government able to purchase as many alternative-fueled vehicles as they had sought. (GAO/T-RCED-85, 11-14).

The extra costs of the 1990 purchases (over regular gasoline-powered vehicles) was approximately $540,000 over the life of the vehicles. Most of this was due to the unavailability of the desired car size in the alternative-fueled model. Including only costs associated with the ability to use multiple fuels reduces the incremental cost of the alternative fueled-vehicles to $4,140/car, or a total of $269,000 for the 65 automobiles purchased in 1990. (GAO/T-RCED-85, 18).

Implementation of Conservation and Efficiency Efforts. The Pacific Northwest Electric Power Planning and Conservation Act of 1980 directs the Bonneville Power Administration to "use conservation to the extent possible" to meet energy supply requirements. (GAO/RCED-92-13, 34). Methods include technology transfer, encouraging adoption of energy-efficient building codes, and financial and technical assistance to electricity customers. The legislation also empowers BPA to place on 10-50 percent surcharge on wholesale power rates to customers if they do not implement effective demand-side management programs. Similarly, the Western Area Power Administration (WAPA) is empowered under the 1984 Hoover Power Plant Act to withhold part of a customer utility's power allocation unless they undertake energy conservation efforts. (GAO/RCED-92-13, 35).

Required Purchases of Coal. The Department of Defense has been required to purchase anthracite coal since 1962. The law was passed in response to declining production of anthracite coals, and initially required U.S. bases in Europe to burn U.S. fuel. At the time, U.S. anthracite was the best substitute for the German coke that had been used previously. As old boilers were converted to oil, and as environmental concerns prompted reducing the burning of coal, the use of anthracite at U.S. military bases in Germany declined.

During 1986-89, required coal purchases amounted to 272,100 metric tons of anthracite per year at an estimated cost of $20 million annually although actual need was far below that level. The cost of anthracite was $33/metric ton more than the bituminous coal DOD usually uses. As of 1988, DOD already had an estimated 10-year supply of anthracite in storage or in transit for European bases. (DOC, Hard Coal Assist, 139).

Overpurchase of Uranium. See description accompanying import restrictions on uranium, found on page B5-28.

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Federal Energy Subsidies:

Energy, Environmental, and Fiscal Impacts

Technical Appendix
(Appendix B)

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The Alliance to Save Energy
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