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OPTIMAL RESPONSE TO A SHIFT IN REGULATORY REGIME: THE CASE OF THE US NUCLEAR POWER INDUSTRY

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SUMMARY

This paper studies the impact of the March 1979 Three Mile Island (TMI) accident on the regulation of nuclear power plants (NPPs) and its consequences for the operating behaviour and profitability of the US nuclear power industry. We treat the TMI accident as a 'natural experiment' that caused a sudden, unexpected, and permanent increase in the intensity of safety regulation by the US Nuclear Regulatory Commission (NRC) and a shift towards increased disallowances of operating costs by state and local public utility commissions (PUCs). We analyse the nuclear power industry's reaction to this shift in regulatory regime using detailed monthly data on NPP operations collected by the NRC. One of the industry's responses was to increase the planned durations between refuellings from 12 months in the pre-TMI period to 18 months in the post-TMI period. We estimate a simple dynamic programming (DP) model of NPP operations that shows how an operator optimally balances the potential increases in capacity utilization rates associated with longer operating cycles against the increased costs of unplanned and forced outages associated with longer cycles. Under the maintained hypothesis that NPP operators seek to maximize expected discounted profits, we use the NPP operating data to infer profit functions for NPPs in the pre- and post-TMI periods. The estimated profit functions reveal that utilities have been responsive to NRC regulation insofar as they impute a significantly higher cost to 'imprudent' operation of a reactor in the post-TMI period than in the pre-TMI period. The results show that utilities responded optimally to the change in regulatory regime since the DP model predicts that optimal planned operating cycles were approximately 12 months in the pre-TMI period and 18 months in the post-TMI period. We find that while NPPs appear safer in the post-TMI period (in terms of having a lower rate of forced outages), they are also substantially less profitable: over 90% of the expected discounted profits from continued operation of existing NPPs have been eliminated in the post-TMI period. However, since most of the investments in existing NPPs are already sunk and given the high costs of plant decommissioning, the DP model predicts that utilities will continue to operate NPPs rather than shut them down. Interestingly, we find that the hypothesis of expected discounted profit maximization provides a much better approximation to NPP operating behaviour in the post-TMI period than in the pre-TMI period.

> I believe the Three Mile Island accident formally and finally broke the ties connecting the Nuclear Regulatory Commission (NRC) to the development of nuclear power, which was part of its heritage from the Atomic Energy Commission (AEC). I will not argue the issue as to how much of a link existed in the regulatory side of the AEC or whether it was a major influence in the early years of the NRC. Certainly many accused the NRC of such a link. The Three Mile Island accident has severed any such ties. The Three Mile Island accident was a catharsis. In Greek tragedy, such a catharsis must occur, for a purging. The Three Mile Island accident was the NRC's catharsis, and it now becomes a regulatory agency. It remains to be seen whether these changes will be similar to those in aircraft

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licensing regulation, where the regulatory framework inspired increased growth, or whether it will be similar to rail passenger regulation in the United States, where there is hardly any rail passenger service left to regulate.

John Ahearne, NRC Commissioner and Acting Chairman (1981)

1. INTRODUCTION

This paper studies the impact of the March 1979 Three Mile Island (TMI) accident on the regulation of nuclear power plants (NPPs) and its consequences for the operating behaviour and profitability of the US nuclear power industry. The accident, which arose from combination of equipment malfunctions and operator errors, resulted in a partial core meltdown, a release of radioactive steam from the containment building, and over $4 billion in clean-up costs, liability and litigation. Following the accident, the Nuclear Regulatory Commission (NRC) introduced its TMI Action Plan. It mandated changes in operator training, stricter licensing requirements, retrofits of control room instrumentation and certain components of the NPP cooling system, increased plant inspections and reporting requirements, and unprecedented multi-year shutdowns of plants. Due to substantial increases in construction costs, lead-times, and operating expenses from stricter regulations there have been no new orders for NPPs since TMI and over 100 orders for NPP have been cancelled, some involving plants that were nearly complete, resulting in losses of tens of billions in sunk planning and construction costs. The nuclear industry has claimed that these new regulations are excessively stringent, and are responsible for the 'fact' that nuclear energy is no longer competitive with fossil fuel.[1] A 1988 survey of nuclear utility executives identified operating costs followed by NRC ratcheting of its regulatory requirements as their main concern (EIA, 1991, p. 2).

We treat the TMI accident as a 'natural experiment' that lead to an unexpected and permanent increase in the intensity of safety regulation by the NRC, and a shift towards increased scrutiny of operating costs by state and local public utility commissions (PUCs). The shift in regulatory regime was reinforced by increasingly vigorous opposition to NPP construction and operations by the US public. The pre-TMI regulatory regime can be characterized as 'soft': NRC regulators believed built-in engineering safety features of NPPs guaranteed that accidents 'couldn't happen' so that intrusive safety monitoring of NPP operations was unnecessary, and PUCs generally allowed utilities to pass on increases in construction and operating costs to consumers as higher electricity prices. The post-TMI regulatory regime can be characterized as 'hard': a post-mortem report on TMI by the Kemeny Commission (1979) led to a shake-up within the NRC, which emerged with new leadership and greater willingness to shut down unsafe reactors, mandate equipment retrofits, and tighten licensing and training requirements. Increased NRC-mandated surveillance and maintenance operations led to substantial increases in the durations of refuelling outages, and significant increases in operating and maintenance costs. At the same time, PUCs became less willing to allow utilities to pass on these increased operating and maintenance costs to consumers, as reflected by a significant increase in the probability of cost disallowances in rate-making decisions.

[1] By 1990 the total generation expenses for the median cost nuclear plant was 4·69 cents per kilowatt hour compared to 2·76 cents per kilowatt hour for a median cost coal plant (EIA, 1992). The cost of 4·69 cents for nuclear power includes 2·79 cents per kilowatt hour of capital related expenses, i.e. the annuitized sunk investment costs, taxes, depreciation, etc. If we restrict the comparison to *unsunk* operating costs (e.g. operating, maintenance, and fuel expenses), nuclear power is still cheaper than fossil fuels: 1·81 cents per kilowatt hour for the median cost nuclear plant versus 2·25 cents per kilowatt hour for the median cost coal plant. We argue that only the unsunk costs are relevant for studying the effect of TMI on the operating decisions and profitability of *existing* NPPs.

The NRC's stricter regulations appear to have had a payoff in terms of increased safety: for example, the National Research Council (1992) reports that the rate of unplanned automatic scrams decreased from an average rate of 7·4 per plant in 1980 to 1·6 in 1990.[2] However, it is difficult to determine how much of this change is due to tightened safety regulation since technological progress and industry-wide and plant-specific learning also account for part of the steady improvement in NPP reliability. David, Maude-Griffin, and Rothwell (1995) used a Cox proportional hazard model to study the durations between successive unplanned outages of a sample of US NPPs. They found there were substantial reductions in the risk of unplanned outages after TMI: the mean duration between unplanned outages more than doubled from 26 days before TMI to 53 days after TMI. They concluded 'The estimates suggest that there were substantial reductions in the risk of unplanned outages after TMI, that these reductions were concentrated in the plants that had the highest levels of unplanned outage risk prior to TMI, and that most of the risk reduction occurred several years after the TMI accident' (p. 1).[3] However, although forced outages occur less frequently, we show in Section 2 that the fraction of time spent in forced outages has actually *increased* in the post-TMI period. This anomalous finding is a result of increased durations of forced outage spells and suggests that it may not be so simple to prove that stricter safety regulations have actually improved NPP safety in the post-TMI period.

As a step towards a more informed cost/benefit analysis of NRC regulation, this paper attempts to quantify the impact of the NRC's stricter safety regulations on the expected present discounted profits of existing NPPs.[4] To address this issue we first need to understand how TMI affected the operations of existing NPPs and whether operators responded 'optimally' to the change in regulatory regime. Previous research has provided separate studies of TMI's impact on operating and maintenance (O&M) costs (e.g. EIA 1988, 1991, 1995), and capacity utilization rates (e.g. Stoller Corporation, 1987,1989). The approach we adopt here allows us to model TMI's impact on (O&M) costs and capacity utilization in an integrated fashion, and to quantify the impact on the expected discounted profits of NPPs. We study the nuclear power industry's reaction to the shift in regulatory regime using detailed monthly data on NPP operations collected by the NRC. One of the industry's responses was to increase the planned durations between refuellings from 12 months in the pre-TMI period to 18 months in the post-TMI period.[5] We formulate and estimate a simple dynamic programming (DP) model of NPP operations that shows how an operator optimally balances the potential gains from increased capacity utilization rates associated with longer operating cycles against the increased costs of unplanned and forced outages associated with longer cycles. In each period the operator decides whether to operate the reactor, or shut it down for preventive maintenance or refuelling, or to close the plant permanently. Maintenance during periodic refuelling and planned midcycle

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[2] The term 'scram' refers to the rapid, typically automatic insertation of the reactor control rods into the reactor core to halt nuclear fission and prevent the core from overheating.

[3] Since NRC regulatory policy is designed to make major nuclear accidents 'rare events' it is extremely difficult to quantify the impact of the post-TMI safety regulations on the probability of having a major accident. Therefore most studies have focused on higher-frequency events such as scrams, unplanned outages, or forced outages (to be defined in Section 3). The NRC did not consider TMI to have been a catastrophic or even a severe accident. In 1986 it estimated that there was a 12% probability that a core meltdown accident would occur at an operating NPP in the US over the next 20 years. See US General Accounting Office (1986).

[4] The reduced profits of existing NPPs is only part of the total social costs of the stricter safety regulations. The other major component is the forgone profits of *potential* NPPs including the profits that would have been generated by the NPPs that were cancelled in the wake of the TMI accident.

[5] Other behavioural responses, discussed in Rothwell (1995), include changes in the organizational structure at NPPs.

outages partially 'regenerates' the NPP, reducing the risk of unplanned forced outages in succeeding periods. Under the maintained hypothesis that NPP operators seek to maximize expected discounted profits, we use the NRC operating data to infer profit functions for NPPs in the pre and post-TMI periods.

The estimated profit functions reveal that utilities have been very responsive to NRC regulation insofar as they perceive a significantly higher cost to 'imprudent' operation of a reactor in the post-TMI period. Our results indicate that utilities responded optimally to the change in regulatory regime: the DP model predicts that 12-month planned operating cycles were approximately optimal in the pre-TMI period and 18 month cycles were optimal in the post-TMI period. While NPPs appear to be safer in the post-TMI period (in terms of having a lower rate of forced outages), they are also substantially less profitable: over 90% of the expected discounted profits from continued operation of existing NPPs were eliminated in the post-TMI period. However, because most of the investments in existing NPPs are already sunk and given the high costs of plant decommissioning, the DP model predicts that utilities would still rather continue to operate NPPs rather than shut them down. Thus, our estimates do not suggest the need for immediate concern over premature NPP closures in the near future: barring major problems, the DP model predicts that NPPs will continue to operate until very near the end of their 40-year licensed lifespans.[6] Interestingly, we find that the hypothesis of expected discounted profit maximization provides a much better approximation to NPP operating behaviour in the hard post-TMI era than in the soft pre-TMI era. The results suggest that a combination of hard safety regulation and operating cost disallowances in the post-TMI era, combined with an eroding cost advantage for nuclear power from steadily falling fossil fuel prices could have created stronger incentives for utilities to operate their NPPs in a cost-efficient manner.

Section 2 provides some background on NPP regulation by the NRC and state PUCs. It reviews previous studies of the impact of the shift in regulatory regime on NPP operating and maintenance costs and operating practices. For purposes of our analysis we divide the period of our data set (1975–93) into three intervals: (1) pre-TMI from 1975 to 1979; (2) TMI transition from 1980 to 1983; and (3) post-TMI from 1984 to 1993. We show that much of the uncertainty about NRC's regulatory policies was resolved during the TMI transition period. In addition most of the NRC-mandated retrofit investments were installed during this period. By comparing the pre- and post TMI periods (and excluding the TMI transition period) we avoid the need to explicitly model utilities' changing expectations about regulatory policy. We also avoid modelling (potentially involuntary) investments in NRC-mandated retrofits, which we treat as part of the sunk capital investment in the post-TMI period. Furthermore, during the TMI transition period there was considerable industry-wide re-evaluation of NPP management practices. We argue that industry-wide learning could be another reason why our rational dynamic programming model provides a better approximation to NPP operations in the post-TMI period than during the pre-TMI period.

Section 3 uses a dynamic programming model of NPP operations developed in Rothwell and Rust (1995) to estimate monthly NPP profit functions and corresponding discounted profits (value functions) for the pre- and post TMI periods. The DP model imposes the maintained hypothesis that utilities adopt operating strategies for their NPPs that maximize expected discounted profits subject to rate-of-return and safety regulation. This assumption is not

[6] 'Major problems' include cracks in the reactor vessel due to neutron embrittlement and pressurized thermal shock. These problems contributed to the 1991 closure of the Yankee Rowe reactor.

tautological since it abstracts from issues of managerial incompetence, 'satisficing' behaviour, and other forms of irrational behaviour. However due to the complexity of the regulations imposed by the NRC and PUCs, we do not attempt to model regulatory constraints in detail. Instead, we adopt a 'revealed preference' approach that estimates unrestricted profit functions in the pre- and post TMI periods, respectively. The estimated profits of alternative operating decisions can be viewed as 'shadow prices' that reflect the net impact of the NRC safety regulations and PUC rate-of-return regulations. One of the main contributions of this paper is to show how the shift in regulatory regime affected utilities' profit (objective) functions.

An important issue is whether regulation succeeds in inducing firms to undertake socially efficient operating decisions, or whether it creates distortions that lead them to operate inefficiently. Limited liability implies that an NPP operator's perception of the private costs of a nuclear accident are far less than the social costs. This leads to the presumption that utilities will place too little weight on safety in their investment and operating decisions—at least in the absence of safety regulation. It is very difficult to determine whether NRC safety regulation induced utilities to place the correct weight on safety in either the pre- or post-TMI regulatory regimes, and we do not attempt to address this issue in this paper. However, conditional on any given NRC regulatory regime (i.e. ignoring whether it places too little or too much weight on safety), there is an issue of whether PUC rate-of-return regulation creates an incentive for utilities to spend too much on operating and maintenance expenditures. As is well known from the literature on regulation (see e.g. Kahn, 1971, or Joskow and Schmalensee, 1983), typical implementation of rate-of-return regulation (and the closely related 'automatic fuel adjustment clauses' described in Section 2) can lead to a form of cost plus electricity pricing where increases in a utility's operating costs can be passed on to the consumer as higher regulated electricity prices. This creates a presumption that utilities may not have strong incentives to minimize expected discounted operating costs.[7] In this paper we assume that electricity prices are exogenously determined by state PUCs.[8] In such an environment, it is easy to show that an operating strategy that maximizes expected discounted profits is equivalent to one that minimizes expected discounted operating costs (subject to NRC regulatory constraints). Following Joskow and Schmalensee (1985) and Che and Rothwell (1995) we assume that a combination of regulatory lags and a positive probability that regulators will disallow operating cost increases in rate-making decisions induces utilities to act as expected discounted cost minimizers. Although we cannot test this hypothesis directly, it seems to be a good first approximation. It has received empirical support in a recent study of NPP operating and maintenance costs by the Energy Information Administration which noted that 'over the 1974–1993 period, all the power plants owned by investor-owned utilities were subject to cost-based regulation. Under this form of regulation, the utility can recover all prudently expended costs. It is well known that under such a regulatory scheme, the potential for cost disallowance is a major incentive to minimize costs' (EIA, 1995, pp. 21–2). In Section 2 we show that operating cost disallowances and other performance-based regulatory incentive schemes increased substantially in the post-TMI period.

Section 4 compares the optimal behaviour predicted by the DP model in the pre- and post-TMI regimes and shows that it closely approximates actual NPP operations. In particular, the DP

[7] Other features of regulatory policy, such as whether the PUCs allow abandoned plants to be part of the rate base, can have distortionary impacts on utility behaviour as noted by Cox and Gilbert (1991): 'Stockholders may not be reimbursed for investments that are sunk in abandoned plants, which may make management reluctant to abandoned a project' (p. 262).

[8] That is, we ignore strategic aspects such as the nuclear industry's possible attempts to influence the NRC and PUCs by various rent-seeking and lobbying activities.

model predicts that 12-month planned operating cycles were optimal in the pre-TMI regulatory regime but that 18-month planned operating cycles were optimal in the post-TMI regime. This prediction corresponds to the observed switch in NPP operating practices, which we believe provides strong support for the hypothesis that rate-of-return regulation had minor disincentive effects on dynamic cost minimization. However we do find that the estimated DP model provides a substantially better fit to NPP operations in the hard post-TMI period than in the soft pre-TMI period. We take this as indirect evidence that increased use of incentive-based regulatory schemes by PUCs in the post-TMI period probably did have a strong independent impact on NPP operations by encouraging the industry to adopt operating strategies that are very close to optimal. Section 5 offers some concluding observations and suggestions for further research in this area.

2. IMPACT OF TMI ON REGULATION, OPERATION, AND OPERATING AND MAINTENANCE COSTS OF US NPPS

This section discusses NPP regulation, including a more detailed discussion of how the March 1979 TMI accident precipitated a change in regulatory regime. We also present new evidence on how the change in regulatory regime affected NPP operations and led to major increases in operating and maintenance costs.

NPPs are subject to safety regulation by the Nuclear Regulatory Commission (NRC) and rate-of-return and price regulation by state Public Utility Commissions (PUCs).[9] The rationale for safety regulation by the NRC and PUCs is clear: due to limited liability, the private costs of a major nuclear accident are far less than the social costs. This creates a presumption that private entrepreneurs will place too little weight on safety considerations in their investment and operating decisions for NPPs. Indeed the 1957 Price–Anderson Act gave NPP operators special legal protection by limiting compensation for damages arising from a major nuclear accident, indemnifying both the manufacturer and the operator of the plant. See Dubin and Rothwell (1990).

In exchange for Price–Anderson protection the nuclear industry was subjected to safety regulation by the Atomic Energy Commission (and later by its successor, the NRC). The AEC had been criticized for placing too much weight on the commercial exploitation of nuclear power and placing insufficient weight on public safety. The NRC was created through the Energy Reorganization Act of 1974, one purpose was to divorce safety regulation from the promotion of commercial development of new energy sources by the Energy Research and Development Agency (which ultimately evolved into the Department of Energy). However, in the initial years this reorganization did not succeed in breaking the 'ties connecting the NRC to the development of nuclear power, which was part of its heritage from the AEC,' as noted in the opening quotation by John Ahearns, acting Chairman of the NRC following the TMI accident. After the March 1979 accident at TMI–2, President Carter appointed an independent commission headed by John Kemeny, President of Dartmouth College, to investigate the accident and evaluate 'the NRC's licensing, inspection, operation, and enforcement procedures' (Kemeny, 1979, p. 1). Following a six-month investigation the Kemeny Commission found that

[9] For example, PUCs can determine where new NPPs are located and can regulate how existing NPPs dispose of spent nuclear fuel. In the absence of a permanent waste repository most NPPs store spent fuel rods in on-site storage pools. Once filled, a PUC decision disallowing further expansion of the storage pools would effectively force the shutdown of the NPP. In some cases PUCs have directly terminated NPP operating licenses such as in the case of the San Onofre plant in California which was discovered to have been built near a seismic fault zone.

there was a 'mindset' in the NRC consisting of a 'preoccupation of everyone with the safety of equipment, resulting in the downplaying of the importance of the human element in nuclear power generation. We are tempted to say that while an enormous effort was expended to assure that safety-related equipment functioned as well as possible, and that there was backup equipment in depth, what the NRC and the industry have failed to realize sufficiently is that the human beings who manage and operate the plants constitute an important safety system' (p. 10). The commission concluded 'To prevent nuclear accidents as serious as Three Mile Island, fundamental changes will be necessary in the organization, procedures, and practices—and above all—in the attitudes of the Nuclear Regulatory Commission and, to the extent that the institutions we investigated are typical, of the nuclear industry' (p. 7).

The Kemeny Commission report led to significant internal changes within the NRC, including the appointment of John Ahearns as acting Chairman. In the year after the accident the NRC introduced its TMI Action Plan, which emphasized reductions in operator errors via control room redesign, increased training, and closer monitoring of NPP operations including surprise plant inspections and increased reporting requirements for abnormal operating events. The NRC mandated retrofits of NPP control room instrumentation and certain elements of the NPP cooling systems that required large investments and extended shutdowns in many plants throughout the USA. The NRC's expanded monitoring lead to unprecedented multi-year shutdowns of plants that the agency deemed to be operating unsafely. Rahn *et al.* (1984, Section 19.3) estimated that in 1979 alone, NRC-mandated shutdowns resulted in a loss of 12% of industry electrical generation capacity, or about 30 billion kilowatt-hours of potential output. In addition to plant shutdowns, NRC regulations contributed to a dramatic decline in NPP availability factors by increasing the median duration of refuelling outages from 8·3 weeks in the period 1974–8 to 14·7 weeks in 1983 (Stoller, 1989, Section 4). The industry has claimed that these increased durations were largely the result of additional NRC-imposed surveillance and maintenance requirements (National Research Council, 1992, p. 51).

Figure 1 provides clear graphical evidence of the shift in regulatory regime by plotting the number of NRC fines per operating plant, the level of capital additions costs, and the total non-fuel operating costs over the period 1974 to 1993 (data taken from EIA, 1995). The dollar amounts of NRC fines are not as important as the public relations impact of having safety violations publicized, especially given the dramatic increase in anti-nuclear sentiment following TMI. We see that the average number of fines per plant increased from 10% in 1979 to nearly 50% in 1980, reaching 100% by 1989. The second panel shows there was a dramatic increase in capital additions costs after 1979.[10] Most of this increase represents the impact of the NRC-mandated retrofits of control room instrumentation and cooling systems. We see that these costs peaked in 1984, reflecting the fact that most of the NRC-mandated retrofits were installed in the five year period following the TMI accident.[11] The final panel of Figure 1 plots non-fuel operating and maintenance expenditures, which accounts for approximately 70% of the average non-capital production expenses for US NPPs. We see that these expenses also accelerated rapidly after 1979, peaked in 1984, and then flattened out. Most of these expenses were for increased training of plant operators and additional maintenance staff.[12] Between 1979 and 1989 training personnel in the US nuclear industry increased eightfold and floor space devoted to

[10] Capital additions costs are expenditures that can be capitalized for accounting and tax purposes.

[11] A recent report found 'For some recently completed case studies, roughly 50 percent of the capital additions were the result of regulatory compliance actions. The other 50 percent were largely due to repair or replacement of plant components' (EIA, 1995, p. vii).

[12] Approximately 67% of O&M expenses are labour related and only 33% are for expenditures for maintenance material and supplies (EIA, 1995).

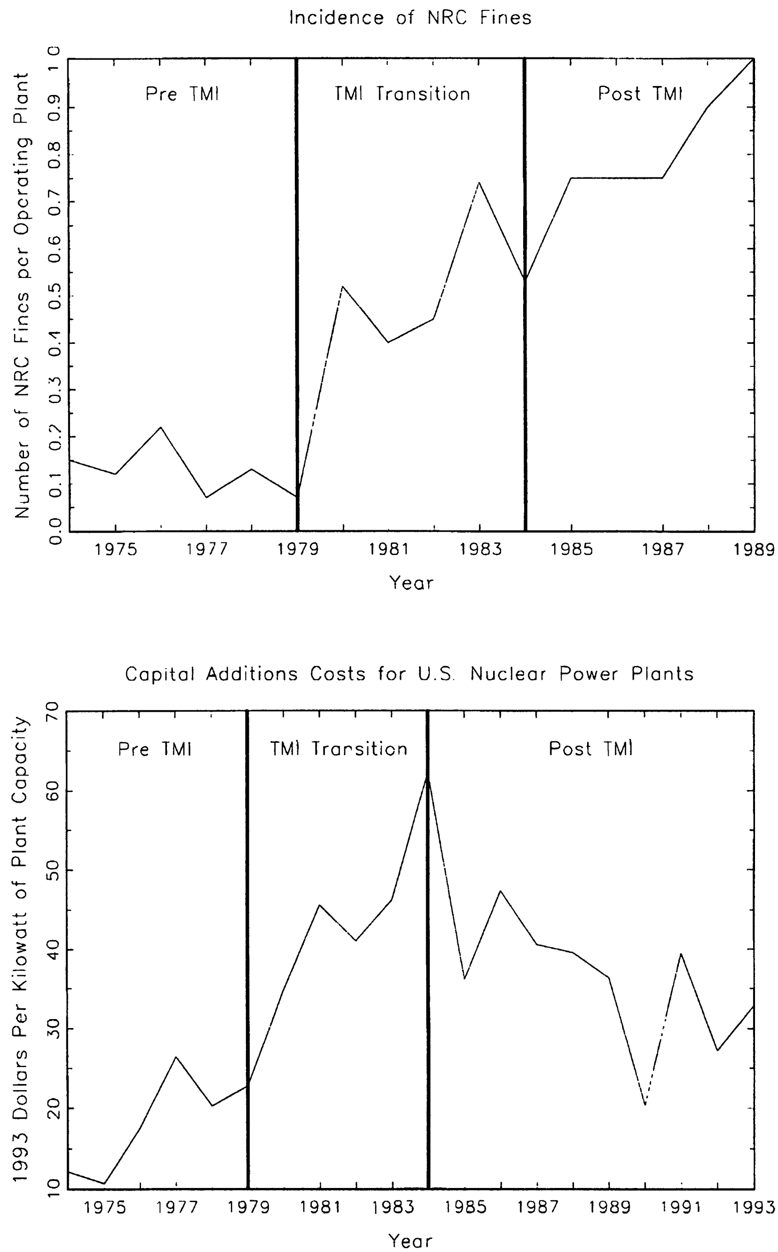


Figure 1. Effects of NRC regulatory shift on fines, capital additions, and operating costs of US NPPs

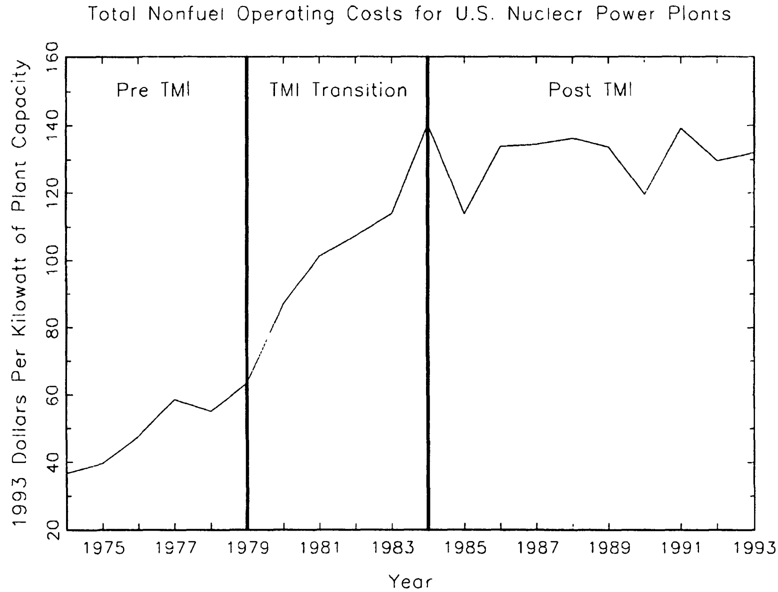


Figure 1. *Continued*

training increased more than sixfold (Moore, 1989). Although other factors such as plant ageing and changes in costs of materials and labour could also be responsible for the O&M cost escalation, a 1995 regression study of NPP O&M and capital additions costs by the Energy Information Administration concluded that NRC regulatory actions were responsible for the largest share of NPP O&M cost escalation between 1975 and 1992 (see also Nuclear Management and Resources Council, 1992).

Figure 1 suggests that the four-to-five year period following TMI should be regarded as a 'transition period' during which the impacts of the TMI were assimilated and translated into new regulatory policies. This transition period began with the publication of the Kemeny Commission report that precipitated a change in NRC leadership and staffing, which in turn led to new, stricter regulatory policies. Most of the NRC-mandated retrofits were installed during this period, which can be regarded as a temporary period of unusually excessive downtime for the industry.[13] By the end of this transition period, capital additions had stabilized, and it is reasonable to assume that much of the uncertainty about the future course of NRC regulatory policy had been resolved. Thus, for purposes of this analysis we divide the 1974–93 period into three intervals: (1) pre-TMI (1974–9); (2) TMI transition (1980–83); and (3) post-TMI (1984–93).

In addition to the shift in NRC safety regulation, there was a shift in regulatory treatment of NPPs by state PUCs. Intensified safety regulation and revised construction codes following TMI led to construction delays and cost overruns. PUCs increased their scrutiny of NPP construction and operating costs and began disallowing utilities from including imprudent costs in their rate bases, transferring these costs to the utilities' stockholders. A 1992 National Research Council report found 'The state public utility commissions have demonstrated the

[13] For an analysis of the adoption of one of these retrofits, the Safety Parameter Display System, see Dubin and Rothwell (1989).

incurred costs that the commissions have deemed imprudent will not be recovered. This is an authority of utility commissions that has seldom been used before. It has been primarily applied to nuclear, rather than fossil, power plants. ... During the 1980's rate based disallowances totaled about $14 billion for nuclear plants, but only about $0·7 billion for non-nuclear plants' (p. 41, 182).

In order to reduce rates to consumers PUCs began implementing incentive schemes to increase productivity and decrease operating costs (see Joskow and Schmalansee, 1985; Che and Rothwell, 1995). Most of these incentive programs focused on increasing-capacity factors. There have been three types of incentive programs. The most common approach is to apply stringent prudence tests to expenditures at a poorly performing NPP. The second is to modify the cost-of-service regulation by a monetary reward or penalty applied to the performance level outside a band around a target capacity factor. A third approach is a performance-based pricing mechanism with fixed prices. By 1992 there were over 20 incentive programmes applied to NPPs: many of these focused on NPP performance; a few addressed fuel and operating costs.

Figure 2 plots the number of special incentive regulation programmes used by PUCs over the period 1975–92 (data taken from Landon, 1993). The figure provides further evidence of the shift in regulatory regime following the TMI accident: we see dramatic growth in the use of incentive programmes in the TMI transition period and a levelling off in the post-TMI period. A plot of the probability or number of operating cost disallowances by PUCs (not shown) also shows evidence of a change in regulatory regime, reflecting a much higher level of regulatory scrutiny in the post-TMI period. Because of these changes to traditional rate-of-return regulation, the assumption that utilities attempted to minimize costs subject to safety regulation is reasonable first approximation, particularly in the post-TMI period.

The remainder of this paper focuses on how the shift in regulatory regime documented above affected NPP operations and profitability. One of the immediate responses on the part of the

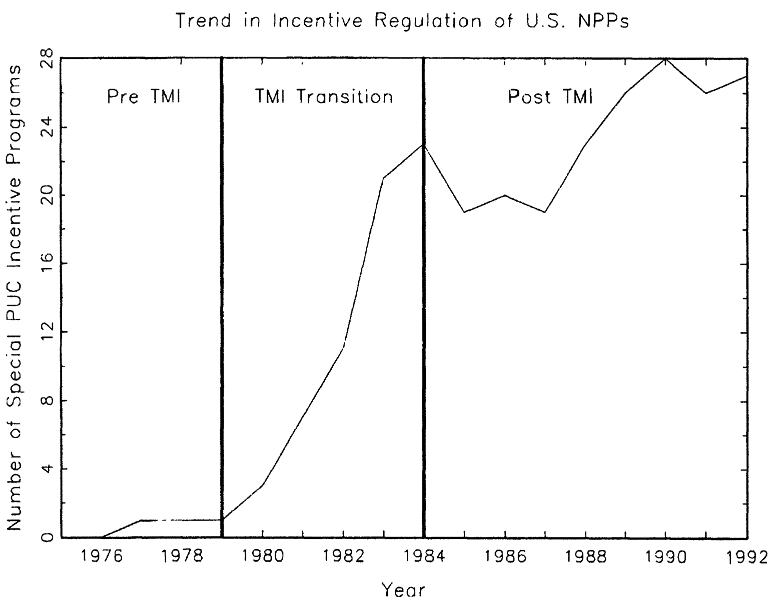


Figure 2. Trend in use of incentive-regulation programmes by PUCs

nuclear industry was to create the Institute of Nuclear Power Operations (INPO), a self-monitoring body charged with detecting poor nuclear plant performance, disseminating information on improved plant management practices, accrediting reactor personnel, and assisting member utilities in eliminating deficiencies via regular on-site plant evaluations (Pate, 1988; Moore, 1989). By the end of 1980, all US utilities that were operating or constructing NPPs were members of INPO, and by 1985 INPO had more than 400 employees and an annual budget of $44 million.

Clearly, the only way to assess the real impact of the shift in regulatory regime and the role of INPO is via direct analysis of plant-level operating data. This study uses data on NPP operations collected by the NRC in its publication, *Licensed Operating Reactors—Status Summary Reports*. These data, described in more detail in Rothwell and Rust (1995), contain detailed data on reactor operations, including the length of operating spells and outage spells in hours and the reason for outages. Although the NRC data distinguish eight different types of outages, for the purposes of this study we will consider three main types of outages: (1) refuelling, (2) planned, and (3) forced. The NRC defines a forced outage as any plant shutdown or significant power reduction that cannot be delayed until the weekend when power demand is lower.[14] Our dataset provides operating histories on 116 NPPs that were operating between January 1975 and December 1993, yielding a total of 19,453 reactor-month observations.

Figure 3 plots the mean number of forced outages per month using the NRC data. The figure shows that the number of forced outages has been steadily decreasing over time, although

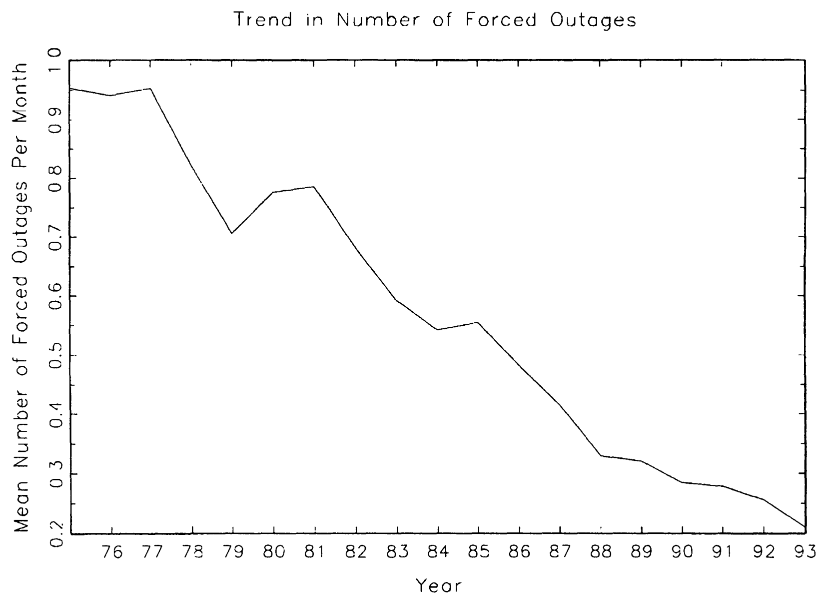


Figure 3. Trend in mean number of forced outages per reactor-month

[14] Due to arbitrariness of the NRC definition of forced outage, it follows that some unplanned outages are classified as planned outages. These outages reflect unexpected events that were not deemed to be sufficiently serious to force the operator to shut down the unit before the weekend. We will argue that these classification errors are inconsequential because of the monthly time aggregation employed and our specification of the DP model, which does allow us to distinguish fully between planned and unplanned outages.

interrupted by significantly increased outage rates in 1980 and 1981. These increases reflect the impact of NRC shutdowns of plants it deemed to be operating unsafely in the wake of the TMI accident. As we noted in the introduction, since some reductions in forced outage rates have been from plant-specific learning and general technological progress (including steady improvements in fuel rod reliability, a major cause of forced outages), it is practically impossible to infer the independent impact of stricter NRC safety regulations from time-series data alone.

Figure 4 plots the trends in NPP monthly availability factors. The availability factor is the ratio of the time the plant was available for production during the month to the total number of hours in the month. The availability factor (or service factor) is closely related to the *capacity factor*, the ratio of power actually generated over a month to the amount that would have been generated if the plant ran continuously at 'maximum dependable capacity' (MDC). The two measures differ to the extent that a NPP runs at less than its MDC due to load following, end-of-cycle coastdowns, and power reductions from equipment problems. This study uses plant availability factors as our measure of productivity since it was much easier to compute from the available NRC data. Figure 4 shows that availability factors fell precipitously in 1979, reflecting the NRC's industry-wide shutdowns of NPPs in the wake of the TMI accident. Availability factors continued to remain at very low levels during the TMI transition period, reflecting in part the extra downtime needed to install the NRC-mandated retrofits. After bottoming out in 1984, availability factors began to climb back to the pre-TMI levels.

Figure 5 plots the trends in the duration of refuelling outages and operating spells, i.e. the durations between successive refuellings. Refuellings have always been complex and lengthy operations for US-style pressurized water reactors since they require removal of the head of the reactor vessel and control rods. The top panel of Figure 5 shows that before TMI refuellings took about 1500 hours, but refuelling durations increased substantially after TMI, peaking at nearly 2500 hours in 1983. As we noted earlier, one reason for the increase in the duration of

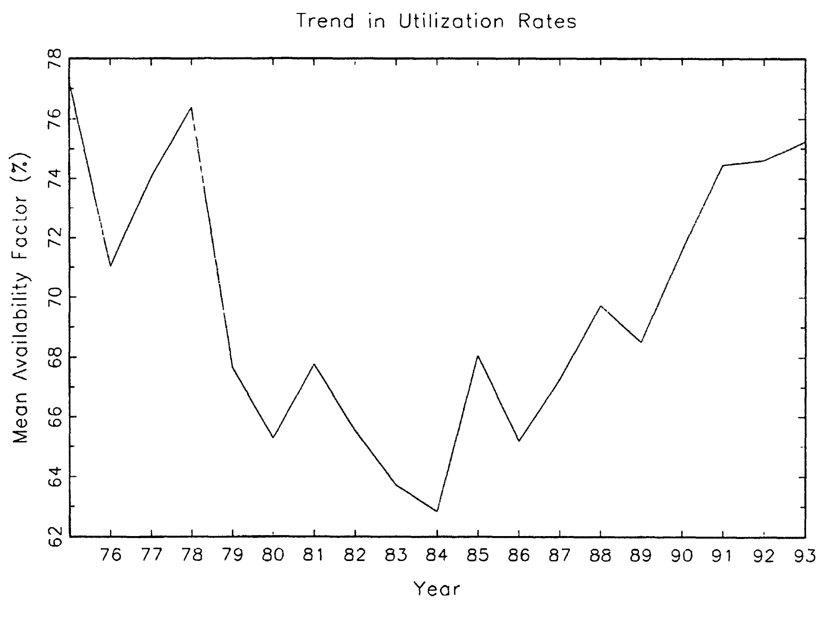


Figure 4. Trend in NPP availability factors

refuelling outages was additional NRC-imposed maintenance and surveillance activities such as ultrasonic inspection of key reactor vessel welds and inspections of cooling system safety valves, etc. After 1983 refuelling durations declined, but levelled off at a permanently higher level of approximately 2000 hours. The increase in refuelling durations is another factor (in addition to downtime for equipment retrofits) behind the reduction in NPP availability factors during the TMI transition period. This increase represents a significant opportunity cost of lost

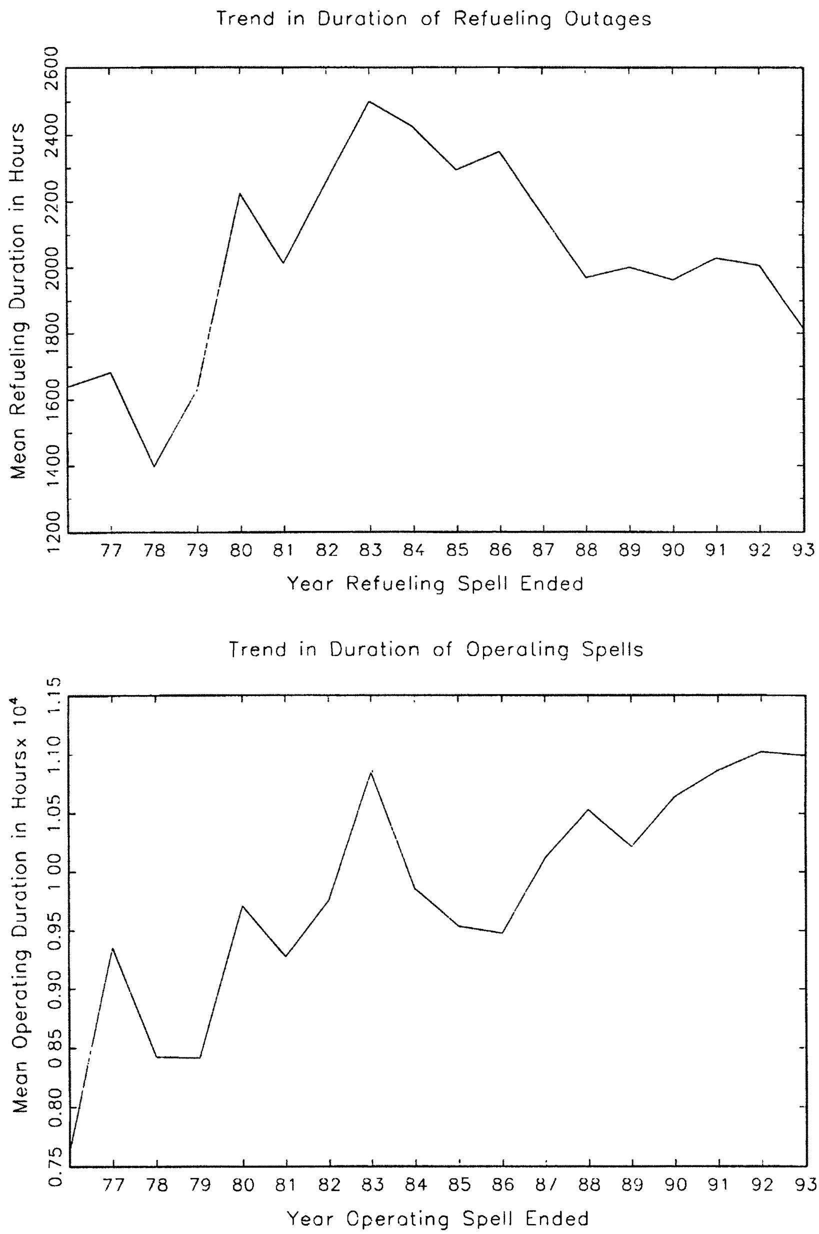


Figure 5. Trend in mean durations of refuelling and operating spells

power generation: the cost of replacement power for a 1 gigawatt reactor is about $1 million/day, so that a permanent 500-hour increase in refuelling durations would reduce utility revenues about $20 million annually (assuming refuellings occur annually). The second panel of Figure 5 plots the trend in the durations of operating cycles, i.e. the duration between successive refuellings. We see that utilities responded to the increased refuelling durations by increasing the duration of operating cycles from about 7500 hours (10·4 months) in 1976 to 11,000 hours (15·2 months) in 1993.

The reason longer operating cycles improve capacity utilization rates is straightforward: abstracting from unplanned shutdowns and load following, a plant with an operating duration of O months and a refuelling duration of R months will have a long-run capacity factor of $O/(O+R)$, which is monotonically increasing in operating duration, O. For example, if refuellings occur annually and last 2 months, the plant's maximum capacity factor (assuming no forced outages) is 84%. By moving to 24 months between refuellings the maximum capacity factor improves to 92%. These calculations assume that the duration of a refuelling outage does not increase with the length of the previous operating cycle, an assumption that Rothwell and Rust (1995) and Stoller (1987, 1989) have verified from statistical analysis of NPP operating data. An implication of this simple formula for the capacity factor is that the potential gain to moving to longer operating cycles is greater the longer the mean refuelling duration R. For example, if $R = 3$ months, the increase in capacity factor of moving to 18 month operating cycles is 7·7% versus only 3·8% if $R = 1{\cdot}5$ months. This factor could explain a finding in the study by Stoller (1987): 'The very best performers have remained on short cycle for a variety of reasons, one of which being that they have a smaller incentive to change to long cycles.' (p. 2–12).

There are two important tradeoffs in moving to longer operating cycles: (1) longer cycles involve a higher cost of nuclear fuel per unit of time, and (2) longer cycles could lead to higher rates of planned and unplanned outages toward the middle and end of an operating spell. Fuel costs increase during long cycles for at least two reasons: first, long cycles require higher quantities or higher enrichment levels in the nuclear fuel; second, fuel efficiency is lower the longer the operating cycle. Rothwell and Rust (1995) show that the forced outage rate increases with the duration since the last refuelling, at least after 12 months of operation. The utility needs to balance the benefits of less frequent refuelling outages against the increase in fuel costs and the increased rate of planned and unplanned outages associated with longer operating cycles, especially towards the end of an operating spell.

Given the very low level of uranium prices, the increased fuel costs are more than outweighed by the reduced opportunity costs of lost power generation due to longer operating cycles: 'The overriding consideration, however, is that the replacement of three annual cycles by two 18-month refuellings holds the possibility of reducing total outage time.' (Rahn *et al.*, 1984, p. 488). For example, the Stoller Corporation (1987 and 1989) performed an illustrative cost-benefit calculation of the gains from moving from a 12-month operating cycle to an 18-month cycle. Their calculations show that the improvement in capacity factor under an 18-month cycle leads to a $9·5 million reduction in the opportunity cost of lost power generation (on an annual basis). This outweighs the $6·9 million increase in annual nuclear fuel costs. However, nearly half of the latter increase is due to the 500 MWh increase in output in moving from a 64·4% capacity factor under 12-month refuellings to a 68·8% capacity factor under an 18-month operating cycle. The Stoller reports concluded that the high opportunity costs of lost power generation during refuelling outages favoured longer 18- and 24-month refuelling cycles. Further, an average NPP could increase its capacity factor by 3 to 7 percentage points by increasing the operating cycle from 12 to 18 months, although the gain is lower for more efficient NPPs with shorter average refuelling durations. These benefits are probably the reason why 'most of the US utilities have adopted fuel cycle lengths longer than twelve months. Only a small number of BWRs and PWRs continue to refuel (annually)' (Stoller, 1989, p. 6-2). The Stoller report lists a variety of other factors that impact the determination of optimal length of operating cycle. One of the most important of these other considerations is to coordinate outages to occur in seasons of lowest power demand, namely the autumn and spring. The DP model in Section 3 explicitly accounts for seasonal variations in power demand and replacement power costs.

Figure 6 summarizes the shift in the distribution of operating cycle durations that occurred during our sample period. We see that in the pre-TMI period, the mean and the mode of the distribution was approximately 11 months, whereas in the post-TMI period the mode shifted to 15 months. This shift in the *realized durations* of operating cycles corresponds to a shift in the *planned durations* in operating cycles from 12 months in the pre-TMI period to 18 months in the post-TMI period. Unexpected events such as forced outages could lead a NPP operator to refuel earlier or later than planned. The DP model estimated in Section 3 allows NPP operators to react to unexpected events (both observed and unobserved to the econometrician) in their determination of the optimal time to initiate a refuelling outage.

Figure 7 presents plots of two other significant trends in NPP operations: the decline in the percentage of time lost due to planned and forced mid-cycle outages. The top panel of Figure 7 plots the percentage of time spent in planned outages between successive refuellings. These planned mid-cycle outages are a much more common occurrence in the pre-TMI period, accounting for approximately 6–7% of mid-cycle downtime. In the post-TMI period planned outages accounted for only about 3% of mid-cycle downtime. It appears that NPP operators are conducting more of their preventive maintenance operations during the longer refuelling outages in the post-TMI period. The bottom panel of Figure 7 shows that there has also been a downward trend in the percentage of time lost from forced mid-cycle outages. The rate of

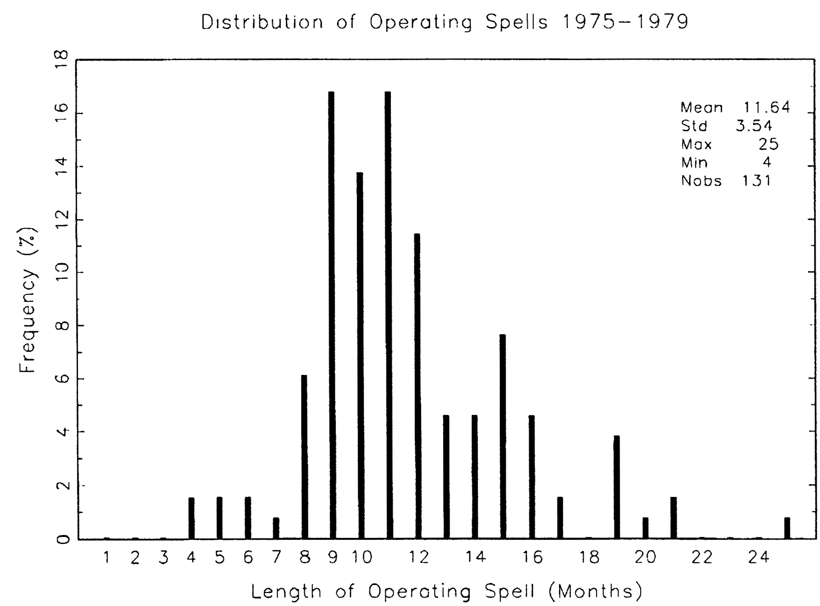
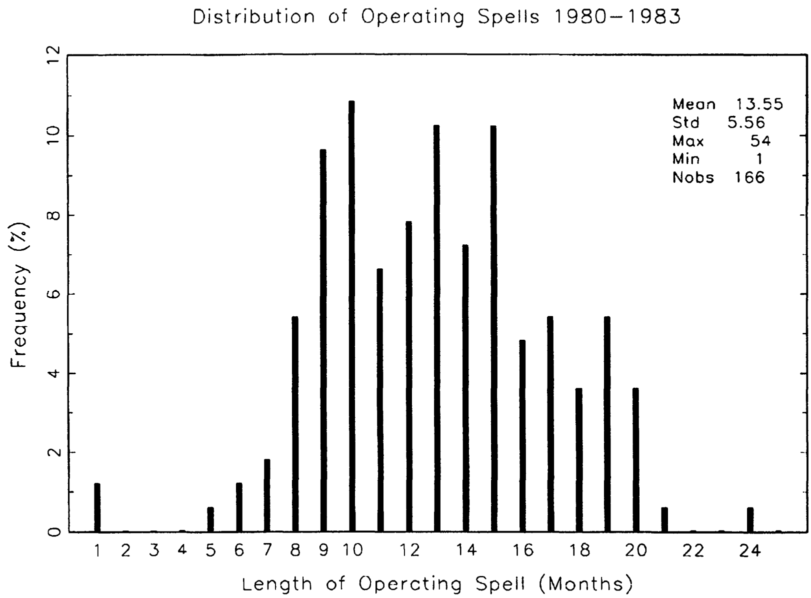


Figure 6. Discretized distributions of operating spell durations pre- and post-TMI



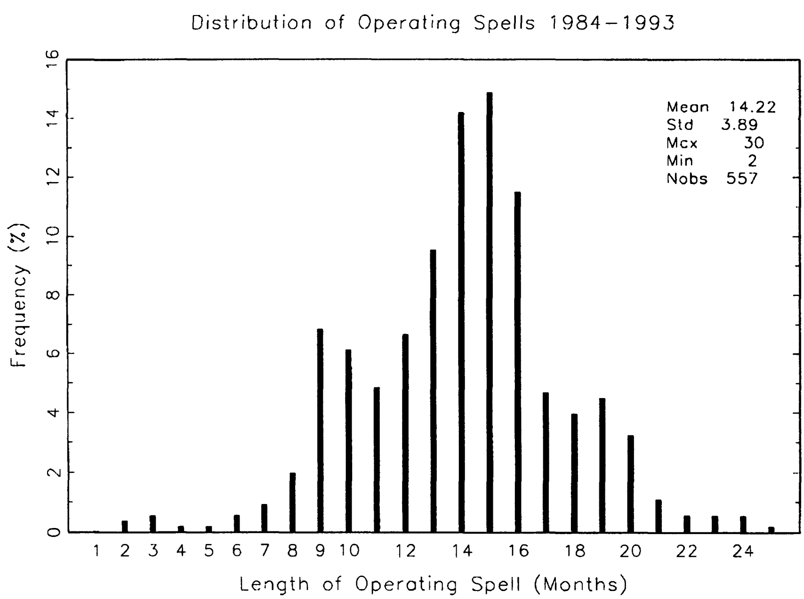
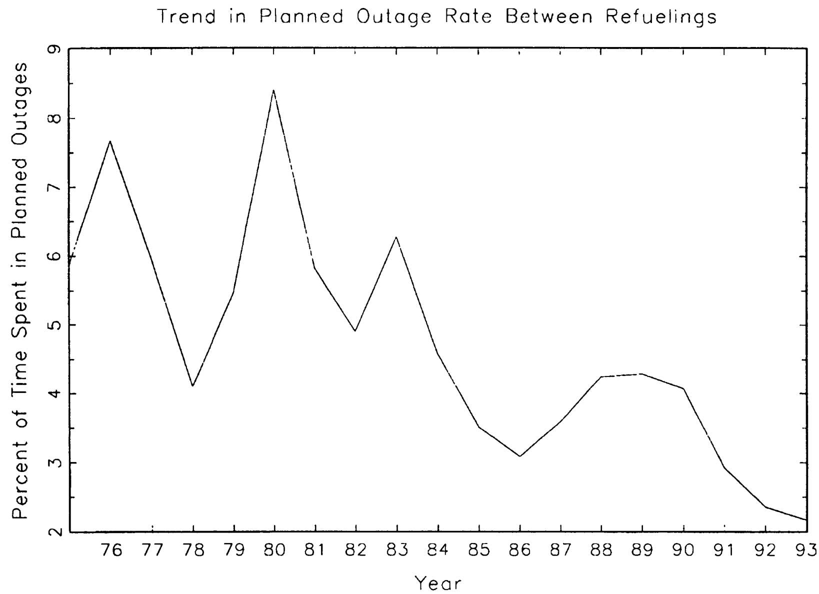


Figure 6. *Continued*



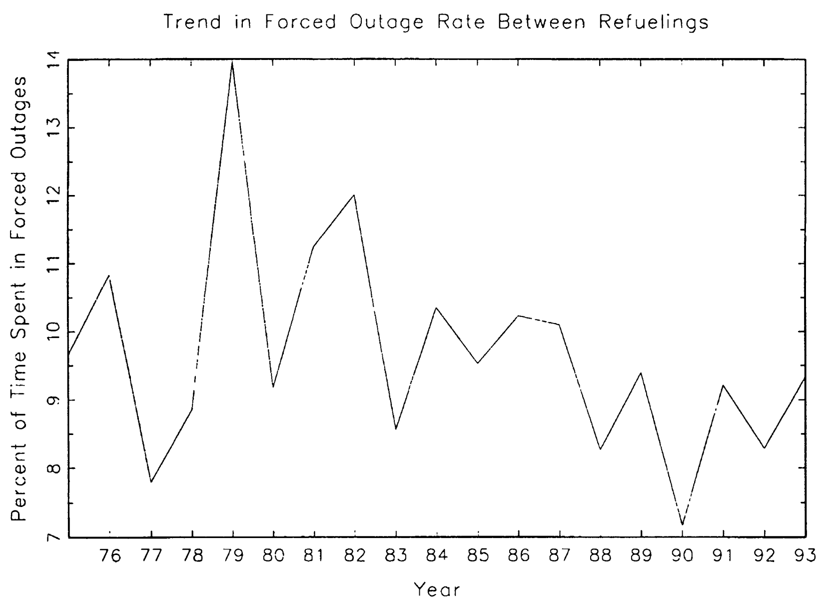


Figure 7. Trend in time lost from planned and forced outages between refuellings

decline in the fraction of time lost from these outages is far less steep than the rate of decline in the *number* of outages displayed in Figure 3. Thus while the number of forced outages steadily decreased over time (and the duration between successive force outages has nearly doubled), the duration of each forced outage has increased in the post-TMI period. While there are fewer outages, NPP operators spend more time investigating them and taking corrective action when they occur.

Table I summarizes the changes in NPP operations that occurred over our sample period. The table provides a breakdown of the time NPPs spend in each of four possible states: (1) operating, (2) refuelling, (3) forced outages, and (4) planned outages. It is apparent that refuellings account for a largest share of NPP downtime, and that the 4 percentage point increase in time spent in refuelling constitutes one of the most dramatic shifts in NPP operating behaviour from the pre-TMI period to the post-TMI period. The increase in refuelling durations appears to account for the bulk of the 3 percentage point drop in the fraction of time NPPs were operating. The other major change was a 2 percentage point decline in the fraction of time spent in planned outages and a 1 percentage point *increase* in the fraction of time spent in forced outages. This result reinforces the conclusions drawn from Figure 6: NPP operators appear to conduct more of their preventive maintenance during refuelling outages in the post-TMI period.

Although Figure 3 shows that the *frequency* of forced outages has declined dramatically in the post-TMI period, Table I shows that the *fraction of time* spent in forced outages has actually increased. This implies that the average duration of a forced outage is longer in the post-TMI period than in the pre-TMI period, which may reflect a strategy of more thorough investigation and repair of problems after they occur. However there is another possible explanation for the increase in time spent in forced outages in the post-TMI period: by moving to longer operating cycles, NPPs may be losing more time to more 'serious' forced outages that tend to occur toward the end of the operating cycle. Indeed, Rothwell and Rust (1995) show that the fraction of time lost due to forced outages increases very rapidly after 18 months since last refuelling, which provides indirect evidence that forced outages that occur toward the end of the operating cycle tend to be more serious. If this is the case, it leads one to question whether NPP operations are unambiguously safer in the post-TMI period: the gains in safety due to increased refuelling durations may have been partially offset by decreases in safety due to the move towards longer operating cycles and less frequent mid-cycle preventive maintenance outages. However, as we see in Section 5, the estimates of the DP model support the former explanation: the increase in the fraction of time spent in forced outages appears to be a result of more 'prudent' operation of a NPP.

Table I. Summary of US nuclear power plant operations

	1975–79	1980–83	1984–93
Percentage of time operating	73·08	65·55	70·11
Percentage of time refuelling	12·15	17·63	16·15
Percentage of time in forced outages	9·40	9·14	10·39
Percentage of time in planned outage	5·37	7·68	3·35
Total Reactor/Hours	2,485,176	2,440,656	8,831,736
Total Reactor/Months	3402	3341	12,088

3. A DYNAMIC PROGRAMMING MODEL OF OPTIMAL NPP OPERATIONS

In this section we formulate a dynamic programming (DP) model designed to capture the main features of NPP operations. The model is a direct application of the DP model developed in Rothwell and Rust (1995), which was inspired by the DP model of Sturm (1991, 1995) and the descriptive statistics in Rothwell (1989). The DP model is based on the maintained hypothesis that NPP operators control their plants to maximize expected discounted profits from electricity generation subject to technological and regulatory constraints imposed by the NRC and state PUCs. The DP specification consists of a vector of *state variables*, s_t, a *control variable*, a_t, a *profit function*, $\pi(a, s)$, a *discount factor*, $\beta \in [0, 1]$, and a *transition density* $\lambda(s' \mid s, a)$, representing the stochastic law of motion for the state of the NPP. We briefly review the DP model here, but refer the reader to Rothwell and Rust (1995) for details on the specification, solution, estimation, and goodness of fit testing of the estimated DP model.

The DP problem is in discrete time and NPP operating decisions are assumed to be made at the start of each month. We assumed monthly intervals so the predictions of the DP model match our monthly NRC data. In reality, the operator must control the NPP in continuous-time. Our model abstracts from the details of the minute-by-minute decisions made by the operator such as the adjustment of control rods and concentrations of moderators in the reactor coolant and complicated details of the fuel management strategy. Instead, our model focuses on the larger-scale decisions about plant utilization and shutdowns, the timings of planned outages for refuellings and preventive maintenance, and whether a plant should be closed for decommissioning. We assume that any strategy specifying the 'big picture' decisions governing NPP operations can be implemented by an optimal continuous-time strategy that specifies the minute-by-minute details.

Since the plant operator clearly observes more signals about the plant's current operating status than are available in the NRC data, we assume that the state variable, s_t, can be partitioned into two components $s_t = (x_t, \varepsilon_t)$, where x_t is an *observed state vector* and ε_t is an *unobserved state vector*. The operator observes both components, but the econometrician observes only x_t. We can think of the unobserved state vector as reflecting the myriad of information displayed on the NPP's control room panels. This information includes the reactor's temperature, pressure, and neutron flux; status checks on hydraulic valves and pressure relief devices; measurements of coolant flow, water chemistry, radioactivity levels, electrical output and transients; etc. The NPP operator weighs the consequences of various operating decisions given the full set of signals and takes the best action. We assume that the result of this decision process can be summarized by a vector of current net benefits (or costs if negative) to each operating decision the operator can take. Thus, we will interpret ε_t as a vector with the same number of elements as the possible values of the control variable, a_t, so that $\varepsilon_t(a)$ represent the operator's assessment of the net cost or benefit to taking action a conditional on all available information. Since the full set of information available to the NPP operator is unobserved, we treat ε_t as a latent random vector with a distribution that we will specify below.

Following the general framework of Rust (1987, 1988, 1995) we assume that the operator's current period profit from taking action a for a NPP that is in current state (x, ε) is given by the function $\pi(a, x, \varepsilon)$ with additively separable representation

$$\pi(a, x, \varepsilon) = \mu(a, x, \phi) + \varepsilon(a) \tag{1}$$

where ϕ is a vector of unknown profit function parameters to be estimated. We assume that the vector of state variables (x, ε) evolves according to a controlled Markov process with transition density $\lambda(x_{t+1}, \varepsilon_{t+1} \mid x_t, \varepsilon_t, a_t)$ and that the plant operator chooses an optimal operating strategy

$a_t = \alpha_t(x_t, \varepsilon_t)$ that maximizes the plant's expected net present value $V_0(x, \varepsilon)$ given by

$$V_0(x, \varepsilon) = \max_{(a_0, \ldots a_T)} E\left\{\sum_{t=0}^{T} \beta^t \pi(a_t, x_t, \varepsilon_t) \,|\, x_0 = x, \varepsilon_0 = \varepsilon\right\} \tag{2}$$

The horizon, T is determined by the NRC's 40-year operating license.[15] We assume λ can be factored as

$$\lambda(x_{t+1}, \varepsilon_{t+1} \mid x_t, \varepsilon_t, a_t) = p(x_{t+1} \mid x_t, a_t, \psi) q(\varepsilon_{t+1}) \tag{3}$$

where ψ is a vector of unknown parameters characterizing the transition density for the observable part of the state and control variables. Equation (3) is known as a *conditional independence assumption* since it implies that ε_{t+1} is independent of ε_t conditional on (x, a_t). Under the additional assumption that the marginal distribution of ε_t is Type I extreme value, the *conditional choice probabilities* $P_t(a \mid x)$ are given by the classical *multinomial logit* formula:

$$\begin{aligned} P_t(a|x) &= \int I\{a = \alpha_t(x, \varepsilon)\} q(\mathrm{d}\varepsilon) \\ &= \frac{\exp\{v_t(x, a)\}}{\Sigma_{a' \in A_t(x)} \exp\{v_t(x, a')\}} \end{aligned} \tag{4}$$

where the v_t represent *expected value functions* given by the recursion formula

$$v_t(x, a) = \mu(x, a, \phi) + \beta \int \log\left[\sum_{a' \in A_t(x')} \exp\{v_{t+1}(x', a')\}\right] p(\mathrm{d}x' | x, a, \psi) \tag{5}$$

The v_t functions are related to the value function $V_t(x, \varepsilon)$ by the identity:

$$V_t(x, \varepsilon) = \max_{a \in A_t(x)} [v_t(x, a) + \varepsilon(a)] \tag{6}$$

The set $A_t(x)$ represents the set of feasible actions available to the operator in state x at time t and will be specified shortly.

We compute the solution to the DP model by backward induction on the recursion equation (5). The implied stochastic process for the observed state and control variables $\{x_t, a_t\}$ constitutes the DP model's prediction of the optimal strategy for running, refuelling, and closing a NPP. These predictions, however, depend on a vector $\theta = (\beta, \phi, \psi)$ of unknown parameters specifying the discount factor, the unknown parameters of the profit function, and law of motion for the state variables. We estimate θ by maximum likelihood as follows.

The NRC data provide observations on the realization of the observed state and control variables for the 116 US NPPs that were operational at the same point during our sample period. Denote these data by $\{x_t^i, a_t^i\}$, $t = \underline{t}_i, \ldots, \bar{t}_i$, $i = 1, \ldots, 116$. Given the conditional choice probability $P_t(a \mid x)$ in equation (4) and the decomposition of the transition density $\lambda(x', \varepsilon' \mid x, \varepsilon, a)$ in equation (3), it is straightforward to estimate the unknown parameter vector $\theta = (\beta, \phi, \psi)$ by

[15] Although there is a possibility that the operator could apply to the NRC for a licence extension, no plant has been granted an extension, so we have no observations of this in our sample. Therefore, we will initially assume a 40-year life, which corresponds to $T = 480$ in our monthly DP model. For similar reasons we have ruled out the possibility that the operator will undertake major investments, such as thermal annealing, designed to extend the life of the NPP. We are not aware of any such investments to date. Given that there is much scientific uncertainty about the potential benefits of these actions (see e.g. Shah and McDonald, 1992, p. 64), it seems unlikely that utilities would regard these as profitable investments, so we feel it is reasonable to ignore them.

maximum likelihood using the (full) likelihood function

$$L_f(\theta) = \sum_{i=1}^{116} \sum_{t=\underline{t}_i+1}^{\bar{t}_i} \log[P(a_t^i | x_t^i, \theta) p(x_t^i | x_{t-1}^i, a_{t-1}^i, \psi)] \tag{7}$$

In this paper we estimated θ in a two-stage process: ψ is estimated from the partial likelihood function $L_1(\psi)$ given by

$$L_1(\psi) = \sum_{i=1}^{116} \sum_{t=\underline{t}_i+1}^{\bar{t}_i} \log[p(x_t^i | x_{t-1}^i, a_{t-1}^i, \psi)] \tag{8}$$

and the remaining parameters are estimated from the partial likelihood function $L_2(\beta, \phi \mid \hat{\psi})$ given by

$$L_2(\beta, \phi | \hat{\psi}) = \sum_{i=1}^{116} \sum_{t=\underline{t}_i+1}^{\bar{t}_i} \log[P(a_t^i | x_t^i, \beta, \phi, \hat{\psi})] \tag{9}$$

Rust (1988) established the consistency and asymptotic normality of the two-stage and full maximum likelihood estimators.[16]

In the remainder of this paper we will adopt a structural approach to inference and interpret observed NPP operating histories as realizations of controlled stochastic processes. The reduced-form analysis in the previous section provided strong evidence that the stochastic processes governing plant availability and forced outage rates are non-stationary due to the shift in regulatory regime following the TMI accident. Additional non-stationarity arises from the steady reduction in forced outage rates noted in Figure 3. While some of this reduction is a result of the change in regulatory regime, much of the reduction is due to technological progress and firm and industry-specific 'learning-by-doing' (see e.g. Joskow and Rosanski, 1979, Lester and McCabe, 1993). We account for the non-stationary from the shift in regulatory regime by estimating the DP model separately for the pre- and post-TMI periods. We account for non-stationarities due to technological progress and learning-by-doing by allowing the rate of forced outages to decline with the age of the reactor.[17] We caution the reader that any long-term forecasts of electricity output from this version of the DP model are based on the implicit assumption that there will be no major changes in electricity prices, technology, or regulatory policies throughout the forecasting period.

Rothwell and Rust (1995) discuss the issue of plant-level heterogeneity in operating performance. Despite the evidence of systematic plant-specific differences in NPP performance and reliability given in David *et al.* (1991, 1995), it is difficult to find observable factors that

[16] The covariance matrix for the parameters (β, ϕ) will not be consistently estimated from the second-stage partial likelihood due to estimation noise in the first stage parameters $\hat{\psi}$. One can use the two-stage estimates of θ as a starting point for maximization of the full likelihood function $L_f(\theta)$, yielding consistent estimates of the covariance matrix and fully efficient estimates of θ.

[17] It is very difficult to disentangle age and time effects in our dataset. Thus we have not attempted to identify the separate effects of technological progress, plant level learning-by-doing, efficiency improvements associated with transition to an equilibrium fuel cycle, and age related deterioration. Our estimates can be viewed as the net effect of these separate factors. Identical problems are encountered in trying to separately identify age and time effects in regression studies on NPP O&M costs: see e.g. Chapter 2 of EIA (1995). The DP model does allow us to separate the combined effects of these factors from the 'horizon effect' created by the 40-year NRC operating license. We explore age effects more fully in Rothwell and Rust (1996).

correlate well with these differences. This suggests that the returns to developing a model that accounts for heterogeneity could be small in view of the substantial econometric and computational problems involved.[18] Therefore, we have decided to start with a simple model that treats all NPPs as homogeneous. In future work we plan to generalize our model to account for effects such as plant size, reactor manufacturer, and utility-specific differences in NRC and PUC regulatory policies.

As we noted in Section 2, we have not attempted to model the complexities of NRC and PUC regulatory constraints in detail. Instead, we have adopted a 'revealed preference' approach of estimating an unrestricted profit function for NPPs in the pre- and post-TMI periods that reflects the net impact of these regulations as 'shadow prices', i.e., the utility's perceived net gain or loss to taking actions in various operating states. However, we do explicitly model one of the main effects of the shift regulatory regime: the impact of NRC's additional maintenance and surveillance requirements on the duration of refuelling outages. As noted in Section 2, refuelling durations have increased significantly in the post-TMI period. Figure 8 plots non-parametric estimates of the exit rates from refuelling in the pre- and post-TMI periods, respectively. We see that the exit rate from refuelling in the post-TMI period is uniformly lower than the exit rate in the pre-TMI period. The shift in exit rates corresponds to an increase in the expected duration of a refuelling outage of 0·73 months, or about 22 days. Recalling that the opportunity cost of lost power generation for a 1 gigawatt reactor is about $1 million per day,

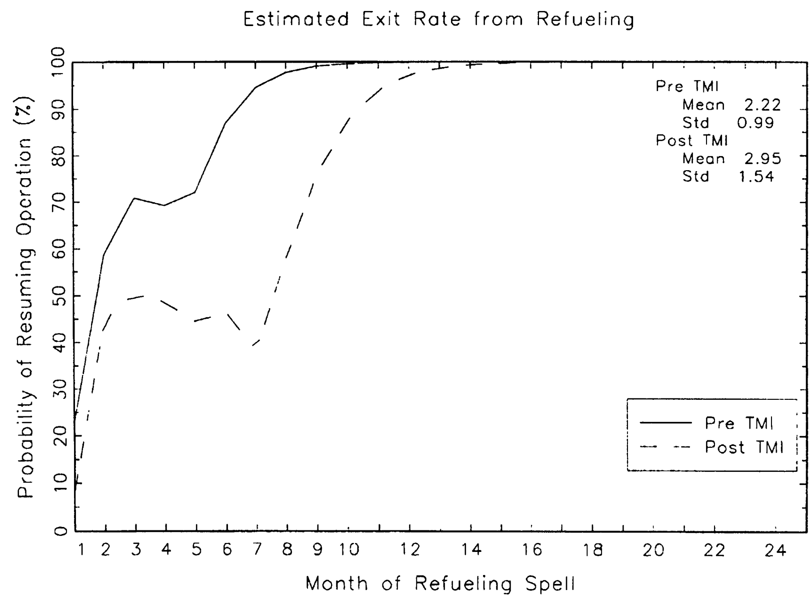


Figure 8. Non-parametric estimates of exit rates from refuelling outages pre- and post-TMI

[18] Accounting for heterogeneity involves separate solutions of the DP problem for each different 'type' of NPP. Because of the unique characteristics of each NPP, each separate plant could be considered a different type, requiring the solution of 116 separate DP problems at each evaluation of the likelihood function. See David and Rothwell (1995) on the lack of standardization in the US nuclear power industry as compared to the French nuclear power industry.

this increase in refuelling durations implies a significant increase in generating costs in the post-TMI period.

In view of the large increase in refuelling durations, the large opportunity cost of plant downtime, and the fact that the change occurred only after the stricter post-TMI safety regulations were in force, it seems reasonable to suppose that the increase in refuelling durations was an involuntary response by utilities to increased NRC maintenance and surveillance requirements rather than a voluntary change in behaviour in response to new information. Therefore in this paper we adopt the assumption of *exogenous refuelling durations*, i.e. that refuelling durations are exogenously determined random variables beyond the control of the plant operator. Figure 9 reproduces Figure 6-1 from Stoller (1989) that plots the distribution of the difference between actual and planned durations of refuelling outages for PWRs. We see that refuellings are subject to substantial uncertainties: 60% of refuelling outages lasted 2 or more weeks longer than *ex ante* plans. Although the deviation of actual durations from planned durations does not necessarily prove that the plant operator lacks control over refuelling durations, this conclusion is supported by surveys of plant operators in (Stoller, 1989, and National Research Council, 1992). Sturm (1991, 1995) also adopted this assumption: 'The combined effects of the plant manufacturer's recommendations, "sound engineering practice", and regulatory constraints may be such that the refuel duration is a random variable beyond the immediate control of the operator' (Sturm, 1995, pp. 10–11). In summary, our DP model assumes that the operator has full control over the time when a refuelling outage commences, but once initiated, the operator cannot control how long the refuelling and associated preventive maintenance and surveillance activities will take. In our

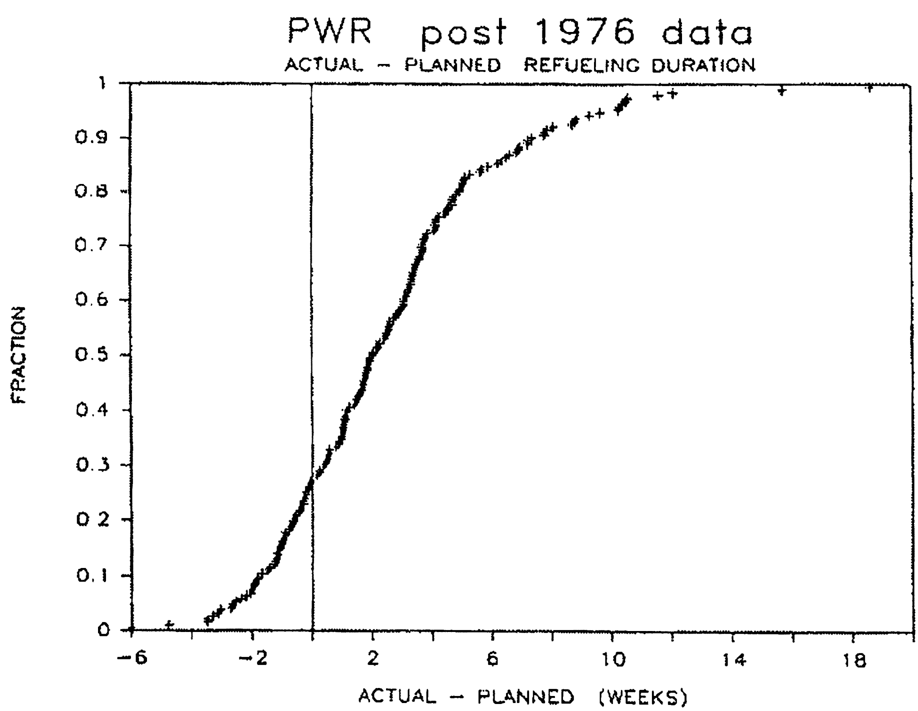


Figure 9. Distribution of difference in actual and planned durations of refuelling outages for PWRs

model the operator treats the overall duration of a refuelling outage as an exogenous random variable with known distribution.[19]

We now turn to a detailed description of the (observed) state and control variables in our model.

State variable $x_t = (r_t, f_t, d_t)$ where:
r_t = *type of spell in previous month*:
  $r_t = 0$ if the previous month was part of a refuelling spell
  $r_t = 1$ if the previous month was part of an operating spell
f_t = *NPP signal in current month*:
  $f_t = 0$ no signals that require initiation of a forced outage are received during the month
  $f_t = 1$ operator receives signals requiring one or more forced outages
  $f_t = 2$ operator receives signal that refuelling outage will continue another month
d_t = *duration of spell in previous month*:
  d_t = duration of refuelling spell if $r_t = 0$
  d_t = duration of operating spell if $r_t = 1$

Control variable $a_t \in A_t(x_t) = \{1, \ldots, 8\}$, given by:
$a_t = 1$ close the NPP
$a_t = 2$ refuel the NPP
$a_t = 3$ shut down NPP (i.e. run plant at 0%)
$a_t = 4$ run the plant between 1% and 25% capacity
$a_t = 5$ run the plant between 26% and 50% capacity
$a_t = 6$ run the plant between 51% and 75% capacity
$a_t = 7$ run the plant between 76% and 99% capacity
$a_t = 8$ run the plant at 100% of its potential output.

The timing of plant signals and operating decisions is as follows: at the start of period t the plant operator knows the state r_t of the plant in the previous month, i.e. whether it was in a refuelling spell or an operating spell. The operator also knows the duration d_t of this spell. At the beginning of the month the operator receives a signal (f_t, ε_t) summarizing the NPP's operating condition for the current month. Conditional on this signal and the plant's state in the previous month, the operator chooses the action a_t that yields the highest expected net present value of operating profits. Given a_t and (x_t, ε_t), the spell type of the current month is determined. The plant operator updates r_{t+1} and d_{t+1} (according to rules that will be detailed shortly), new values of $(f_{t+1}, \varepsilon_{t+1})$ are realized, and the NPP operator makes a new decision in period $t+1$. Our assumption that the NPP operator observes a signal at the start of the month summarizing the NPP's status for the rest of the month is an idealization designed so that our discrete time model could mimic the actual control process that occurs in continuous time. Given our interpretation of our DP model as an approximation of the actual continuous time control process, we do not regard our assumptions about the timing of signals and operating decisions as reflecting 'clairvoyance' by the operator. Instead, our model abstracts from the exact timing

[19] We experienced problems trying to estimate an 'endogenous refuelling' version of the DP model where the duration of refuelling outages is under the full control of the plant operator. Without good information on technological and regulatory constraints influencing the refuelling duration it is difficult for the DP model to explain why an operator would ever choose to be down for refuelling for more than the minimal time given the high opportunity costs of NPP downtime. Since the NRC data do not provide information on potential problems discovered in surveillance inspections during refuelling outages (information that could be useful in explaining why most NPPs have refuelling outages that last significantly longer than the minimal time needed for recharging the core) the DP model attempted to fit the data by making refuelling appear to be a 'profitable' rather than a costly activity.

of forced outages within a month in order to focus attention on the more important issues of the output levels and timing of refuellings for which a monthly time interval is appropriate. We believe that the errors arising from our monthly approximation to the continuous-time control process are negligible in comparison to other specification errors in our model (such as the assumption that $\{\varepsilon_t\}$ is IID).

Under our definition of state and control variables, a 'forced outage' corresponds to the pair $(a_t = 3, f_t = 1)$, whereas a 'scheduled outage' corresponds to the pair $(a_t = 3, f_t = 0)$. Not all forced outages, however, lead to complete shutdowns for the entire month. Many signals represent 'false alarms' that require only brief shutdowns of the plant. For example, combinations such as $(a_t = 7, f_t = 1)$, can be interpreted as the result of brief shutdowns following one or more false alarms. Forced outages can occur for a variety of reasons. Our definition of the f_t state variable does not distinguish the number or cause of the forced outage: conditional on the event that one or more forced outage signals occurred, we assume that all the additional information about the number and severity of these outages is captured by the unobserved state variable ε_t.

Now we turn to the specification of the transition density $p(x' \mid x, a, \psi)$. The laws of motion for the state variables r_t and d_t do not require estimation:

$$r_{t+1} = \begin{cases} 0 & \text{if } f_t = 2 \text{ and } r_t = 0, \text{ or } a_t = 2 \\ 1 & \text{otherwise} \end{cases}$$
$$d_{t+1} = \begin{cases} d_{t+1} & \text{if } r_{t+1} = r_t \\ 1 & \text{otherwise} \end{cases} \tag{10}$$

Plant closure is assumed to be an absorbing state: once the operator chooses action $a_t = 1$ there are no future operating decisions to be made. Although decommissioning a NPP takes time, our model simply accounts for the expected discounted costs involved in the plant closure as a one-time charge. If the plant has not been closed before the end of its operating license at $T = 480$, then we assume that the operator is forced to close in the final period, i.e. $A_{480}(x) = \{1\}$.

The law of motion for the NPP status variable f_t is probabilistic, and its probability distribution is derived from two conditional probabilities denoted by p_{of} and p_{ro}, defined by

p_{of}: probability of one or more forced outages occurring during an operating spell
p_{ro}: probability of coming up (i.e. resuming operation) from a refuelling outage.

The probability, p_{ro}, reflects the exogenous refuelling specification of the DP model where refuelling durations are assumed to be beyond the control of the operator. The estimates of this probability are implied by the non-parametric estimates of the exit rates given in Figure 8. Given these probabilities, we can define the law of motion for f_t. If the plant was in a refuelling spell the previous month $(r_t = 0)$, or if the plant operator decides to initiate a refuelling outage this month $(a_t = 2)$, then f_{t+1} is given by:

$$f_{t+1} = \begin{cases} 0 & \text{with probability } p_{\text{ro}}(1 - p_{\text{of}}) \\ 1 & \text{with probability } p_{\text{ro}}\, p_{\text{of}} \\ 2 & \text{with probability } (1 - p_{\text{ro}}) \end{cases} \tag{11}$$

Recall that $f_{t+1} = 2$ denotes continuation of the current refuelling spell, which occurs with probability $(1 - p_{\text{ro}})$. If the plant was operating in the previous month $(r_t = 1)$ and the operator chooses to continue the operating spell ($a_t > 2$), then f_{t+1} is given by

$$f_{t+1} = \begin{cases} 0 & \text{with probability } p_{of} \\ 1 & \text{with probability } (1 - p_{of}) \end{cases} \tag{12}$$

Figure 10 plots the estimated p_{of} functions, which give the probabilities of experiencing a forced outage as a function of the duration since last refuelling. We see that these functions have a classic *bathtub shape*, i.e. failure probabilities are initially high, decrease to a minimum level, and then increase again. Bathtub-shaped failure probabilities are well known in the engineering literature (see e.g. Glaser, 1980) since they are characteristic of many machine maintenance and replacement problems. In NPPs, we observe significantly higher rates of unplanned outages after a cold start-up in the first month following a refuelling outage. This effect has also been documented in statistical analyses by Stoller (1987, 1989), and Sturm (1991).[20] The graph also shows how the model captures the serial correlation in forced outages and combined effects of plant ageing, plant and industry, level learning-by-doing, and technological progress. For example, a forced outage in the previous month ($f_t = 1$) greatly increases the probability of having a forced outage in a subsequent month. We find the net effect of technological progress and learning-by-doing (which tends to reduce the rate of forced outages) outweighs the effect of

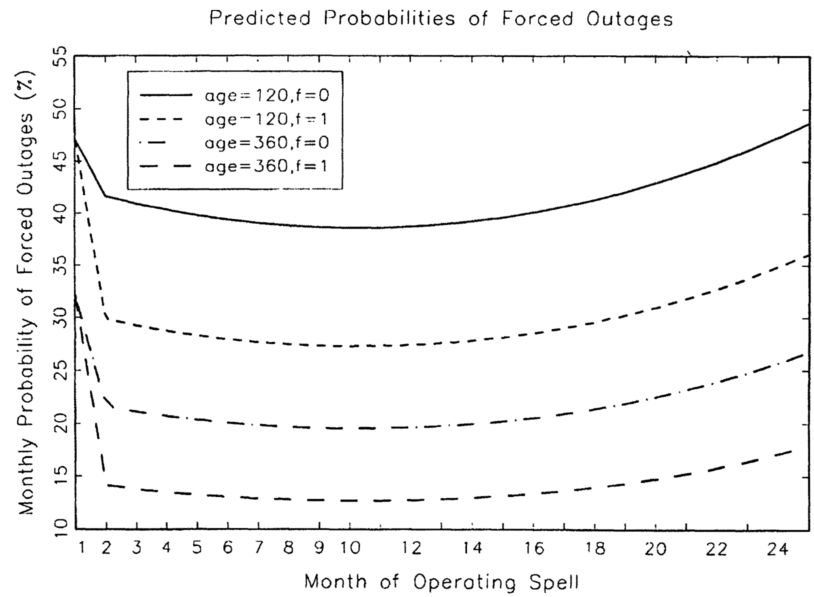


Figure 10. Estimated probability of forced outages during an operating spell, p_{of}

[20] Stoller (1989) argues that the observed upturn could be spurious, due to selectivity bias. Plants that have systematically high failure rates tend to have longer operating cycles due to the accumulation of mid-cycle outages. The higher failure rates observed for NPPs with long operating cycles might be capturing spurious duration dependence rather than true structural duration dependence. After controlling for firm-specific failure propensities by sample-splitting methods, Stoller (1989) argued that within-cycle probabilities of forced outages are monotonically declining with duration since last refuelling. However, Rothwell and Rust (1995) use more efficient fixed effects econometric methods to control for plant level heterogeneity and find that hazard rates for forced outages begin to increase after 12 months since last refuelling.

plant ageing (which tends to increase the rate of forced outages). The net impact is for the rate of forced outages to decline monotonically with the age of the plant.

The NPP's profit function $\pi(a_t, x_t, \varepsilon_t)$ was specified in equation (1). Let $u(a)$ denote the level of electricity generated by the plant, given the utilization decision, a (i.e. the product of the plant's size and its capacity factor). Let p_t denote the price of electricity at time t. The specification of the $\mu(a_t, x_t, \phi)$ term in the additive-separable decomposition of profits in (1) is given by

$$\mu(a_t, x_t, \phi) = \begin{cases} -\phi_{\mathrm{d}} & \text{if } a_t = 1 \text{ (close the plant)} \\ -c_{\mathrm{r}}(x_t, \phi_{\mathrm{r}}) & \text{if } a_t = 2 \text{ (refuel the plant)} \\ p_t u(a_t) - c_{\mathrm{o}}(x_t, u(a_t), \phi_{\mathrm{o}}) & \text{if } a_t > 2 \text{ (operate the plant at level } a\text{)} \end{cases} \tag{13}$$

where $c_{\mathrm{r}}(x, \phi_{\mathrm{r}})$ denotes the expected cost of refuelling in state x; $c_{\mathrm{o}}(x, u, \phi_{\mathrm{o}})$ denotes the expected cost of operating a plant at utilization level u in state x; and ϕ_{d} denotes the present value of costs associated with closing and decommissioning the plant (see Pasqualetti and Rothwell, 1991, for a detailed analysis of the costs of NPP decommissioning). The unknown parameter vector $(\phi_{\mathrm{d}}, \phi_{\mathrm{r}}, \phi_{\mathrm{o}})$ will be specified in more detail in the next section.

Without independent data on NPP operating costs, our 'revealed preference' approach is incapable of identifying the location and scale of the utility's profit function using only the NRC data on operating histories.[21] The reason is simple. It is easy to see from equation (2) that we obtain the same optimal decision rule $(\alpha_0, \ldots, \alpha_T)$ from any monotonic affine transformation of the profit function, $\delta_1 \pi(a_t, x_t, \varepsilon_t) + \delta_2$ where δ_1 and δ_2 are constants and $\delta_1 > 0$. Therefore, we must impose an arbitrary normalization of location and scale. To simplify our model, we assume that the price of electricity is constant over time, except for seasonal variations. This is a reasonable approximation since the real price of replacement power (1989 dollars per kilowatt per day) did not vary greatly over the period of our sample, increasing from about 0·38 in 1975 to about 0·52 in 1981 and then steadily decreasing back to 0·32 by 1992 (see Figure 13, EIA, 1995). We also do not find substantial changes in the operating behaviour of NPPs of different size. It is convenient, therefore, to normalize the profit function by dividing π by the product of the plant's maximum dependable generating capacity and the electricity price p. The scale normalization is completed by assuming that the normalized error term ε_t has a standard Type I extreme value distribution. The location normalization can be imposed by assuming that $\mu(a, x, \phi) = 0$ for a prespecified state and decision pair (a, x). By normalizing this way, we avoid the need to carry the electricity price and the plant's size as additional state variables in the DP model. While this normalization dramatically reduces the computational burden of solving the DP model, it entails the implicit assumption of constant returns to scale in NPP generation of electricity. Rothwell and Rust (1995) relax this assumption, but are unable to identify any convincing evidence of scale effects.[22]

4. ESTIMATION RESULTS FOR THE PRE- AND POST-TMI PERIODS

This section presents structural estimation results for the DP model presented in Section 3. Specifically, we estimate the parameter vector $\theta = (\beta, \phi)$ specifying the discount factor and

[21] The operating cost data are reported annually for all units at a plant site. Therefore, to assign costs to refuelling and operating periods would be an extremely difficult task that we leave to future research.

[22] Rothwell (1990, p. 227) finds that scale effects depend on reactor manufacturer: 'Therefore, one cannot reach general conclusions regarding the relationship between size and the capacity factor for all reactors, as previous papers have done.'

the unknown parameters of the profit function in the pre- and post-TMI periods, respectively.[23]

As we discussed in the introduction, we have estimated an unrestricted version of the profit function $\mu(a, d, f, \phi)$ defined in terms of a 23×1 vector of coefficients given in Table II. As we noted at the end of Section 3, we cannot identify the level of profits from the NRC data on NPP operations alone, so we make arbitrary identifying normalizations of the location and scale of profits. The location normalization is that cost associated with decommissioning NPP is zero, i.e. $\mu(1, d, f, \phi) = \phi_c = 0$.[24] The scale normalization is accomplished by dividing the profit function π by the product of the price of electricity (assumed constant over time and the same for all plants) and the plant's size and assuming that the normalized unobserved components ε that enter the profit function in equation (1) have a standardized Type I multivariate extreme value distribution. Note that the unrestricted specification also includes monthly dummies to reflect seasonal variations in the opportunity cost of an outage. We also imposed an identifying normalization that the dummy coefficient for November is zero.[25] There was one final identifying normalization that we were forced to impose, required by the fact that there were no observations of NPP decommissionings in the pre-TMI period. Without an additional normalization, the

Table II. Definitions of profit function coefficients, ϕ

Parameter	Description
ϕ_c	Expected present discounted value of costs of decommissioning NPP
ϕ_r	Expected cost of refuelling plant, $\mu(2, d, f, \phi) = \phi_r$
$\phi_{r,f=1}$	Additional cost of refuelling plant if a forced outage signal is received, $\mu(2, d, 1, \phi) = \phi_r + \phi_{r,f=1}$
$\phi_d,\ u>0$	Effect of operating cycle duration on expected profits (given positive utilization)
$\phi_{u \in (0,0\cdot25]}$	Expected profit of utilization between 0% and 25%, $\mu(4, d, f, \phi) = \phi_{u \in (0,0\cdot25]} + d\phi_{d,u>0}$
$\phi_{u \in (0\cdot25,0\cdot50]}$	Expected profit of utilization between 25% and 50%, $\mu(5, d, f, \phi) = \phi_{u \in (0\cdot25,0\cdot50]} + d\phi_{d,u>0}$
$\phi_{u \in (0\cdot50,0\cdot75]}$	Expected profit of utilization between 50% and 75%, $\mu(6, d, f, \phi) = \phi_{u \in (0\cdot50,0\cdot75]} + d\phi_{d,u>0}$
$\phi_{u \in (0\cdot75,1)}$	Expected profit of utilization between 76% and 99%, $\mu(7, d, f, \phi) = \phi_{u \in (0\cdot75,1)} + d\phi_{d,u>0}$
$\phi_{u=1}$	Expected profit after 100% utilization, $\mu(8, d, f, \phi) = \phi_{u=1} + d\phi_{d,u>}$
$\phi_{u=0,f=1}$	Expected profit of shutting down NPP in response to a forced outage signal, $\mu(3, d, 1, \phi) = \phi_{u=0,f=1}$
$\phi_{u=100,f=1}$	Reduction in expected profit due to decision to operate NPP at 100% availability given a forced outage signal, $\mu(8, d, 1, \phi) = \phi_{u=1,f=1} + \phi_{u=1} + d\phi_{d,u>0}$
$\phi_{\mathrm{dec}}, \ldots$	Adjustment to profit for an outage in December, January, etc.

[23] We also estimated separate probabilities p_{ro} and p_{of} that determine the law of motion for the state variables in the pre- and post-TMI periods as described in Section 3.

[24] Note this normalization involves the additional maintained hypothesis that the expected present value of decommissioning costs does not vary over time.

[25] We were able to conveniently include monthly dummies without a twelvefold expansion of the state space by synchronizing the plant age modulo 12. To accomplish this we made slight adjustments to the ages of each NPP to guarantee that whenever the plant age in months was evenly divisible by 12 the month in question would be December of the given calendar year. Thus, *month* = *age mod* 12.

maximum likelihood algorithm attempted to push the probability of plant decommissioning to zero to fit the pre-TMI data. Given that we have already normalized plant decommissioning costs to be zero in the pre-TMI period, the maximum likelihood algorithm attempted to drive the other coefficients (corresponding to the profits of continuing to operate the NPP) to $+\infty$. We were able to ensure the convergence of the parameter estimates by normalizing the value of profits corresponding to running the NPP at 100% utilization with no forced outage signals at $\phi_{u=1} = 2{\cdot}93$, the estimated value for the post-TMI period. This is probably *not* a good assumption. The results in Section 2 show that operating and maintenance costs in the post-TMI period were substantially higher than corresponding costs in the pre-TMI period. In addition real electricity prices were slightly lower in the post-TMI period than in the pre-TMI period. Thus, our assumption that $\phi_{u=1}$ is the same in the pre- and post-TMI periods is extremely optimistic. However, we will show below that even when we impose this optimistic identifying normalization, the estimates of the remaining identified parameters imply that over 90% of the expected discounted gains to continued operation of an NPP evaporated in the post-TMI period.

Tables III and IV present the parameter estimates of the unrestricted profit function in the pre- and post-TMI periods, respectively. These estimates were computed from the two-stage partial likelihood estimator described in Section 3.[26] The estimates assume a monthly discount

Table III. Unrestricted structural estimates of monthly profit function parameters: pre-TMI

Parameter	Estimate	Standard error	t-statistic
ϕ_c	0	0	∞
ϕ_r	−1·82	0·52	−3·5
$\phi_{r,f=1}$	−2·33	0·25	−9·2
$\phi_{u=0}$	−0·04	0·32	−0·1
$\phi_{u=0,f=1}$	−4·03	0·54	−7·4
$\phi_{u\in(0,0{\cdot}25]}$	−1·82	0·20	−9·0
$\phi_{u\in(0{\cdot}25,0{\cdot}5]}$	−0·96	0·14	−6·8
$\phi_{u\in(0{\cdot}50,0{\cdot}75]}$	−0·15	0·11	−1·3
$\phi_{u\in(0{\cdot}75,1)}$	1·52	0·08	19·2
$\phi_{u=1}$	2·93	0	∞
$\phi_{u=1,f=1}$	−3·44	0·14	−24·3
$\phi_{d,u>0}$	−0·05	0·01	−5·5
ϕ_{dec}	0·30	0·46	0·7
ϕ_{jan}	−1·07	0·44	−2·4
ϕ_{feb}	−0·60	0·44	−1·4
ϕ_{mar}	−0·92	0·44	−2·1
ϕ_{apr}	0·07	0·37	0·2
ϕ_{may}	0·35	0·36	0·9
ϕ_{june}	0·28	0·37	0·8
ϕ_{july}	−0·36	0·39	−0·9
ϕ_{aug}	−0·89	0·43	−2·0
ϕ_{sep}	−1·03	0·39	−2·6
ϕ_{oct}	−0·06	0·43	−0·1

$L_N = -0{\cdot}893$
$N = 2342$

[26] The estimated standard errors have not been corrected to account for the effect of estimation error in the first stage estimates of the parameters ψ entering the transition density $\lambda(s' \mid s, a, \psi)$. However, if the information matrix is block diagonal, the estimated covariance matrix is consistently estimated by our two-stage procedure.

Table IV. Unrestricted structural estimates of monthly profit function parameters: post-TMI

Parameter	Estimate	Standard error	t-statistic
ϕ_{c}	0	0	∞
ϕ_{r}	−3·44	0·20	−16·8
$\phi_{r,f=1}$	−3·09	0·14	−21·9
$\phi_{u=0}$	−0·54	0·14	−3·9
$\phi_{u=0,f=1}$	−4·04	0·22	−17·6
$\phi_{u\in(0,0\cdot25]}$	−2·12	0·10	−20·9
$\phi_{u\in(0\cdot25,0\cdot5]}$	−1·58	0·09	−18·2
$\phi_{u\in(0\cdot50,0\cdot75]}$	−0·74	0·07	−10·1
$\phi_{u\in(0\cdot75,1)}$	0·54	0·07	8·3
$\phi_{u=1}$	2·93	0·07	39·6
$\phi_{u=1,f=1}$	−5·89	0·15	−40·5
$\phi_{d,u>0}$	−0·06	0·005	−12·5
ϕ_{dec}	−0·37	0·23	−1·6
ϕ_{jan}	−1·21	0·21	−5·9
ϕ_{feb}	−0·98	0·19	−5·2
ϕ_{mar}	−0·87	0·17	−5·0
ϕ_{apr}	−0·14	0·17	−0·8
ϕ_{may}	0·08	0·18	0·4
ϕ_{june}	−0·34	0·19	−1·8
ϕ_{july}	−0·77	0·20	−3·9
ϕ_{aug}	−1·19	0·21	−5·8
ϕ_{sep}	−1·47	0·19	−7·9
ϕ_{oct}	−0·38	0·21	−1·8

$L_N(\hat{\phi}, \hat{\psi}) = -0{\cdot}733$
$N = 11282$

factor of $\beta = 0{\cdot}999$ that corresponds to an annual real discount rate of 1·2%. We experimented with different discount factors and found that the likelihood was basically flat (with an extremely small positive slope) for $\beta < 0{\cdot}999$. Thus we were unable to identify the precise value of β although it is clear that since the likelihood function falls rapidly for $\beta < 0{\cdot}99$ we can easily reject the hypothesis that utilities have high discount rates. Overall, the DP model tells us that utilities are definitely not myopic and that they appear to make their decisions with a high weight on the future consequences of current actions.

Consider first the pre-TMI profit function estimates, which must be interpreted relative to the identifying normalization that $\phi_c = 0$ and $\phi_{u+1} = 2{\cdot}93$, i.e. that the cost of decommissioning a reactor and the profits obtained from running at 100% utilization are the same in the pre- and post-TMI periods. As expected, refuelling the NPP is estimated to be a costly activity with a per month loss of $\hat{\phi}_r = -1{\cdot}82$. Although the actual magnitude of this estimate is not meaningful, it is meaningful to compare it to the estimated profits corresponding to other possible actions. For example, the estimates indicate that a refuelling outage is significantly more costly than a preventive maintenance outage: $-1{\cdot}82 = \hat{\phi}_r < \hat{\phi}_{u=0} = -0{\cdot}04$. This seems to be reasonable given that refuelling outages are the single most time and labour-intensive regular maintenance activity at an NPP, involving thousands of individual work orders and requiring many more maintenance personnel than at any other point in the year (see e.g. Rahn *et al.*, 1984, p. 488). The estimates also show that a refuelling outage that is initiated following a forced outage, $\hat{\phi}_{r,f=1} = -2{\cdot}33$ is costlier still, which also seems reasonable. However, notice that the estimates imply that a preventive maintenance outage initiated in response to a forced outage signal,

$\hat{\phi}_{u=0,f=1} = -4{\cdot}03$, is significantly more costly than a refuelling outage that is initiated in response to a forced outage signal. This finding also appears to be reasonable: due to seasonal and manpower scheduling constraints, refuelling outages are designed to occur at pre-designated times. Therefore, NPP operators typically do not have as much flexibility to initiate 'premature' refuelling outages following a forced outage event. In fact, we show that the DP model correctly predicts that operators are substantially *less* likely to initiate a refuelling outage in response to a forced outage signal. On the other hand if a forced outage signal is sufficiently severe that it leads the operator to shut down the plant for an entire month or longer, it is quite likely that it was due to a fairly serious—and costly—failure.

The estimated profits of increasing utilization levels, ($\hat{\phi}_{u\in(0,0{\cdot}25]}$, $\hat{\phi}_{u\in(0{\cdot}25,0{\cdot}50]}$, $\hat{\phi}_{u\in(0{\cdot}50,0{\cdot}75]}$, $\hat{\phi}_{u\in(0{\cdot}75,1]}$), increase monotonically, as expected. However, a potentially anomalous finding is that $0 > \hat{\phi}_{u=0} > \hat{\phi}_{u\in(0{\cdot}50,0{\cdot}75]}$. Given that the plant is operating at an availability factor of 0 in the former case compared to an average availability factor of 68% in the latter, one would expect that the revenue from electricity generation would outweigh the costs, making it significantly more profitable for the operator to choose $u \in (0{\cdot}50, 0{\cdot}75]$ than $u = 0$. There are several possible explanations for this result. First, since NPPs are designed for baseload operation, an unexpected outage could have very serious consequences for the utility in the event it is unable to find replacement power on short notice. An operator will typically only decide to shut down a plant for a scheduled preventive maintenance outage with sufficient advance notice to ensure that a reliable source of replacement power is secured. However, the decision to operate the plant for only a fraction of the month, such as $u \in (0{\cdot}50, 0{\cdot}75]$, will typically be due to one or more unplanned shutdowns in response to unexpected problem signals. Most of these shutdowns will occur on short notice, making it more difficult for the utility to secure the cheapest source of replacement power.[27] Compounding the problem, stop–start operation of NPPs is highly stressful to the reactor vessel, since each time the reactor is started or stopped there are massive fluctuations in pressure and temperature over very short periods of time. Reactors are designed to withstand a maximum number of such events over their lifetime, so operators seek to avoid unexpected shutdowns (and especially reactor scrams) whenever possible.[28] An equally important consideration is that unreliable, stop-start operation of a reactor can attract the scrutiny of the NRC and state PUCs, in some cases leading the NRC to initiate an extended shutdown of the plant for surveillance, or possibly even to de-rate the plant (i.e. reduce the maximum allowable power generation level, the plant's maximum dependable capacity). A final possible reason why $\hat{\phi}_{u=0} > \hat{\phi}_{u\in(0{\cdot}50,\,0{\cdot}75]}$ is that preventive maintenance shutdowns may have an 'investment value' in terms of reductions in future operating costs or forced outage rates that we have not modelled explicitly.[29] For all of these reasons the estimates

[27] Some utilities bave bilateral trading agreements with other utilities to help reduce the risk and costs of the substantial intertemporal variability in tbe output of their baseload NPP units. We would expect that the cost of unplanned outages to be lower for such utilities. For an interesting analysis of the gains to more elaborate multilateral trading mechanisms over power grids, see White (1995).

[28] Reactor start-ups and shutdowns are also time-consuming: Rahn *et al.*, (1984) estimate the average time for a cold start-up of an NPP is 13 hours. A minimum of 18 hours is required for sufficient depressurization of the reactor vessel following a shutdown to enable the operator to open and inspect key components of the reactor vessel and cooling system.

[29] Rothwell and Rust (1995) were unable to detect an 'investment value' of preventive maintenance and refuelings in the sense that longer or more frequent maintenance or refuelling outages were not associated with lower rates of forced outages in succeeding periods. However, it is possible that longer or more frequent outages reduce the severity and costs of subsequent outages, so that the estimated value of $\hat{\phi}_{u=0}$ could be picking up the present discounted value of the reduction in future operating costs. To model more accurately the costs of unplanned outages and the benefits of preventive maintenance shutdowns it is likely that we will need to formulate a continuous time model of NPP operations.

of $\phi_{u=0}$ and $\phi_{u \in (0{\cdot}50, 0{\cdot}75]}$ should be interpreted as 'shadow values' that reflect not only the current profits corresponding to these two decisions, but also the net expected present discounted value of future costs and benefits. In this sense, we acknowledge that our profit function coefficient estimates are not fully 'structural' and do not necessarily represent *current* profits or losses corresponding to various actions, but instead may also capture present values of future profits and losses. While this suggests the need for caution in the interpretation of the results (and the need for more detailed modelling of NPP operations in order to separately the current profits of various actions as opposed to discounted future profits), given that our ultimate goal is to compare NPP *value functions* in the the pre- and post-TMI periods, the fact that our profit function estimates are not fully structural does not create a problem.[30] It is somewhat comforting to note, howevers that $\hat{\phi}_{u \in (0{\cdot}75, 1)} > \hat{\phi}_{u=0}$. We interpret this as saying that at sufficiently high utilization rates, the revenues from power generation outweigh the present and future costs of stop–start operation.

Most of the remaining profit coefficient estimates seem quite sensible. Note that the estimation results imply that operators perceive a huge penalty to ignoring a forced outage signal and continuing to operate a reactor at 100% availability. We view this penalty as a 'shadow value' reflecting the operator's aversion to the potential consequences of this 'imprudent' behaviour which could include a severe accident such as a meltdown of the reactor core or a catastrophic accident such as a rupture and explosion of the reactor vessel and containment building.[31] The negative coefficient on the duration variable, $\phi_{d,u>0} = -0{\cdot}052$ indicates that the per period costs of operating the reactor increase with duration since last refuelling. This seems to indicate that outages and other problems which occur later in the operating cycle tend to be more severe and expensive to repair than those that occur earlier in the operating cycle. The coefficient estimates on the monthly dummy variables should be interpreted as reflecting seasonal variations in the opportunity cost of preventive maintenance or refuelling outages (cost of replacement power) due to seasonal variations in the demand for electricity. As expected, we find that the estimated cost of an outage are the lowest in the spring and autumn and highest in the late summer and winter months when electric power demand is at its peak.

We now turn to the post-TMI estimates in Table IV. Since seven NPPs were decommissioned in the post-TMI period we were able to estimate all of the-profit function parameters except for the arbitrary scale normalization of the variance of ε and the location normalization $\phi_c = 0$. In general the coefficient estimates for the post-TMI period have the same interpretations as in the pre-TMI period. The most striking difference is that *nearly every coefficient estimate is lower in the post-TMI period than in the pre-TMI period.* The only coefficient that increased in the post-TMI period was $\hat{\phi}_{\text{mar}}$, the dummy variable adjusting profits for an outage that occurs during the month of March, but the increase is neither behaviourally nor statistically significant. Assuming that our location and scale normalizations are the same in the pre- and post-TMI periods,[32] this finding implies that an NPP of the same age will have lower expected discounted profits in the hard post-TMI regulatory regime than in the soft pre-TMI regulatory regime.

[30] It does create a problem if we want to use the estimated DP model for cost–benefit analysis of other potential regulatory regimes. In that case it is necessary to predict how the estimated profit coefficients would be affected under each alternative hypothetical regulatory regime.

[31] The 1986 explosion at the Ukranian Cbernobyl plant was a direct result of such imprudent behaviour (the reactor operators deliberately disabled a computerized safety override system), although it was compounded by the inherent instability of the Soviet-style graphite core reactor design.

[32] Although we impose the same normalizations on the variance of ε and the value of ϕ_c in the pre- and post-TMI periods, it is possible that the actual variance of ε or the expected costs of decommissioning shifted between the two periods, so that the normalizations would not be comparable. We discuss this issue further below.

The other striking finding is that when we compare the magnitude of the decreases in the two sets of coefficient estimates, *the coefficients showing the greatest decreases are the coefficients representing the costs of refuelling outages and the costs of 'imprudent' operation of the reactor*, $\hat{\phi}_{\mathrm{r}}$, $\hat{\phi}_{\mathrm{r},f=1}$, and $\hat{\phi}_{u=1,f=1}$. These results are exactly what we would expect given the nature of the shift in regulatory regime in the post-TMI period. In particular, the fact that the relative costs of refuelling outages have increased is consistent with the discussion in Section 2 about the increased maintenance and surveillance requirements the NRC imposed on plant operators during refuelling outages. So not only do refuelling outages take significantly longer in the post-TMI period (resulting in higher opportunity costs of lost power generation), we also find that the direct labour and materials costs per unit of time spent in refuelling have increased substantially as well. The largest decrease in any of the estimated coefficients was the 2·45 unit drop in $\hat{\phi}_{u=1,f=1}$, the profits associated with decision to ignore a forced outage signal and to continue running the reactor at 100% availability. As we discussed earlier, this coefficient can be interpreted as the present discounted costs of lost future profits due to 'imprudent' operation of the reactor. Thus, our estimates suggest that the perceived cost of imprudent reactor operation increased dramatically in the post-TMI period. In this sense, it seems that the NRC's stricter safety regulations have been particularly effective.

On the other hand, the coefficient estimate for $\hat{\phi}_{u=0,f=1}$, the cost of an unplanned outage in response to a forced outage signal, is virtually the same in the pre- and post-TMI periods. To the extent that a complete shutdown of the plant in order to investigate and repair damage due to a forced outage reflects 'prudent' operation of the reactor, it appears that the harder post-TMI safety regulations have done nothing to encourage or discourage this course of action. However, the reader should keep in mind that given the large decreases in the other coefficient estimates, the *relative* value to 'prudent' operation of the reactor substantially increased in the post-TMI period. This is evident from the comparative plots of plant availability factors in the pre- and post-TMI periods in Figure 12: operators reduce plant availability in response to a forced outage signal to a much greater extent in the post-TMI period than in the pre-TMI period. For example, Figure 12 shows that for a reactor that has been operating 6 months since last refuelling, plant availability falls by 15 percentage points in response to a forced outage signal in the post-TMI period compared to only 5 percentage points in the pre-TMI period. This difference in behaviour corresponds to both a greater propensity to initiate a forced outage and an increased duration of the forced outage once initiated. We interpret the result as showing that operators tend to take forced outage signals more seriously in the post-TMI period, and they also tend to spend more time investigating the causes of an outage and making necessary repairs so that the outage will not happen in the future. To the extent this reflects more prudent reactor operation, we conclude that *operators are significantly more likely to respond prudently to problem signals in the post TMI period than in the pre-TMI period.*

The coefficients corresponding to partial utilization of the reactor, $\hat{\phi}_{u\in(0,0\cdot25]}$, $\hat{\phi}_{u\in(0\cdot25,0\cdot50]}$, $\hat{\phi}_{u\in(0\cdot50,0\cdot75]}$, and $\hat{\phi}_{u\in(0\cdot75,1)}$ also show large relative decreases in the post-TMI period. As discussed above, these coefficients reflect the operator's aversion to frequent stop–start operation of the reactor. We interpret these decreases as reflecting utilities' perceptions of significantly increased penalties to unsteady operation of a reactor in the post-TMI period. The estimated monthly dummy coefficients change by a much smaller amount in the post-TMI period, with an average decrease of 0·34 unit. The implied seasonal variation in the opportunity cost of an outage is basically unchanged: the post-TMI estimates indicate the best time to begin a refuelling outage is May or June, just as in the pre-TMI estimates.

We note in passing that differences in the coefficient estimates in Tables III and IV are both behaviourally and statistically significant. For example we estimated a single DP model for the combined sample which imposed the hypothesis that the profit function was the same in the pre- and post-TMI periods. A likelihood ratio test of the hypothesis of parameter stability is easily rejected with a likelihood ratio test statistic of 372 with 37 degrees of freedom.[33] We now turn to a comparative analysis of the operating behaviour predicted by the DP model in the pre- and post-TMI periods. Rothwell and Rust (1995) provide a more detailed statistical analysis of the DP model's ability to fit the data: their overall conclusion is that the DP model provides a very good approximation to actual NPP operations. However we find that the DP model does a much better job of approximating NPP operating behaviour in the post-TMI period than in the pre-TMI period. This is evident by comparing the average likelihood values in Tables III and IV: the average likelihood value is $-0{\cdot}893$ in the pre-TMI period versus $-0{\cdot}733$ in the post-TMI period. The difference in fit of the two models is visually apparent in Figure 11, which compares predicted (labelled DP, for dynamic programming) versus actual (labelled NP, for non-parametric) estimates of the probability of refuelling as a function of the duration of the current operating spell. Looking at the top panel of Figure 11, we see that in the pre-TMI period, the DP model underpredicts the rapid rise in the refuelling hazard function that begins at 7 months and peaks at 11 months. The fact that the estimated hazard function declines for durations in excess of 18 months is purely a small sample problem and should be ignored.[34] We interpret the fact that the DP model is unable to explain the very rapid rise and peak in the refuelling hazard function at 11 months as potential evidence that NPPs behaved according to a rule of thumb that refuellings should occur every 12 months in the pre-TMI period. However, the DP model does correctly predict that operators are less likely to initiate a refuelling outage after receiving a forced outage signal in both the pre- and post-TMI periods.

Figure 12 compares the predicted versus actual NPP availability factors as a function of duration since the last refuelling. The DP model does a good job of predicting the decline in availability, which is due to the increased probability of refuelling and also the increased probability of forced outages resulting from the 'bathtub-shaped' probability of forced outages displayed in Figure 3. The main prediction error occurs in the post-TMI period, where the DP model substantially overpredicts availability in the first month of an operating cycle in the event of no forced outages. As explained in Rothwell and Rust (1995), this is due to 'fine tuning outages' that occur just after a plant is successfully brought up from a refuelling outage. The graphs show that 'fine tuning outages' seem to be a phenomenon of the post-TMI period.[35] However, the most striking difference in NPP operating behaviour in the pre- and post-TMI periods reflected in Figure 12 has already been discussed above: namely, the fact that plant operators seem to react much more 'prudently' to forced outage signals in the post-TMI period.

Figure 13 compares the estimated value functions in the pre- and post-TMI periods. The figure plots the value functions corresponding to several different utilization decisions for an NPP plant that is 366 months old as a function of the duration since the last refuelling, i.e. $v_t(x, a)$ for $t = 366$ and $x = (1, 0, d)$, where v_t is defined in equation (5) of Section 3. Recall that these value functions do not include the effects of the unobservable state variables ε: the 'full' value function $V_t(x, \varepsilon)$ equals the maximum value of $v_t(x, a) + \varepsilon(a)$, for $a \in A_t(x)$ as shown in equation (6). However, we can think of the $v_t(x, a)$'s plotted in Figure 3 as reflecting

[33] The degrees of freedom equals the number of utility function coefficients (23) plus the number of coefficients used to estimate the transition probabilities.

[34] Recall from the top panel of Figure 6 that very few plants had realized cycle lengths in excess of 18 months in the pre-TMI period.

[35] It would be easy to eliminate this prediction error by simply including a dummy variable for the event that $\{d = 1\}$, but this would not solve the puzzle as to why fine tuning outages were used in the post-TMI period, but do not seem to have been used in the pre-TMI period.

the optimal 'planned' operating strategy when the effects of the unobserved state variables ε are fixed at their unconditional expected values. The top panel of Figure 13 shows that for a plant with $t = 366$ and $f = 0$ (i.e. no forced outage signal), the optimal planned operating strategy is to run the plant at 100% availability for months 1 to 11 of the operating cycle and then commence a refuelling outage on the twelfth month. Thus, the DP model predicts that 12 month *planned* operating cycles were indeed optimal in the pre-TMI period. However when we account for the

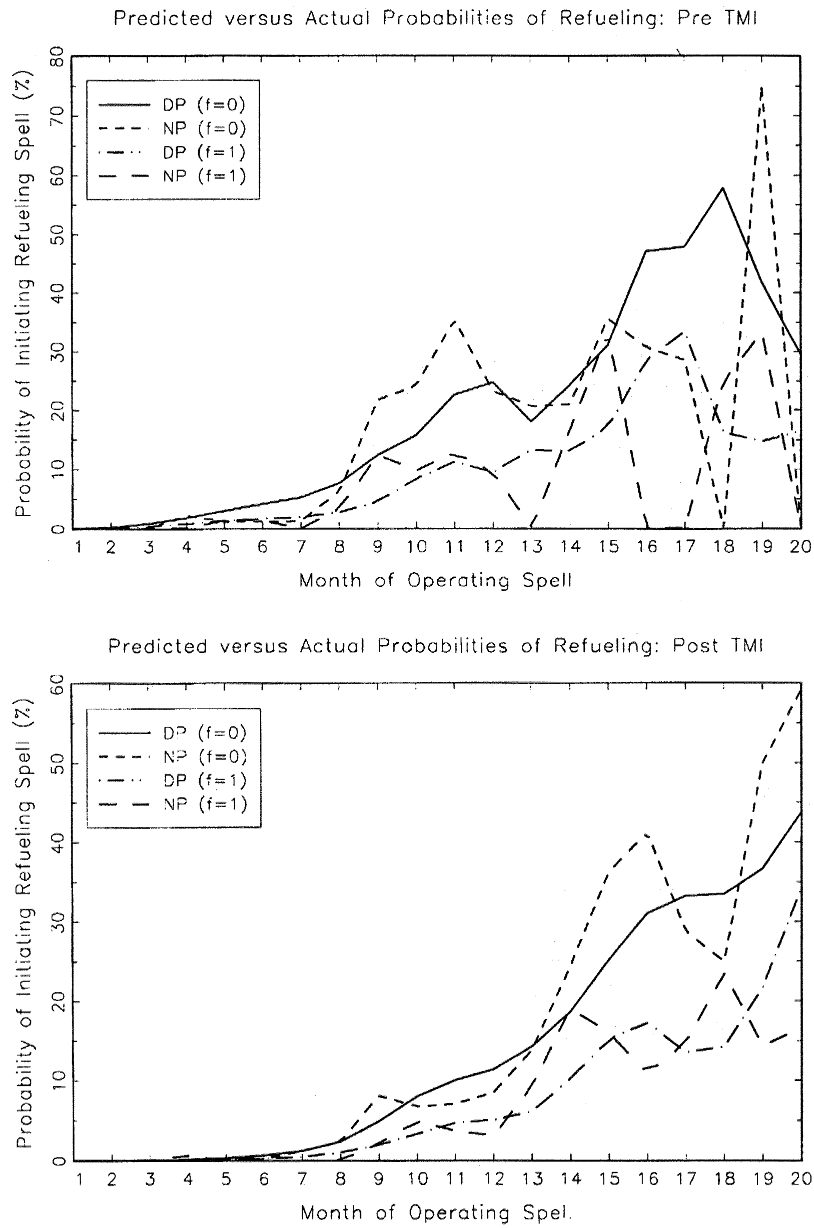
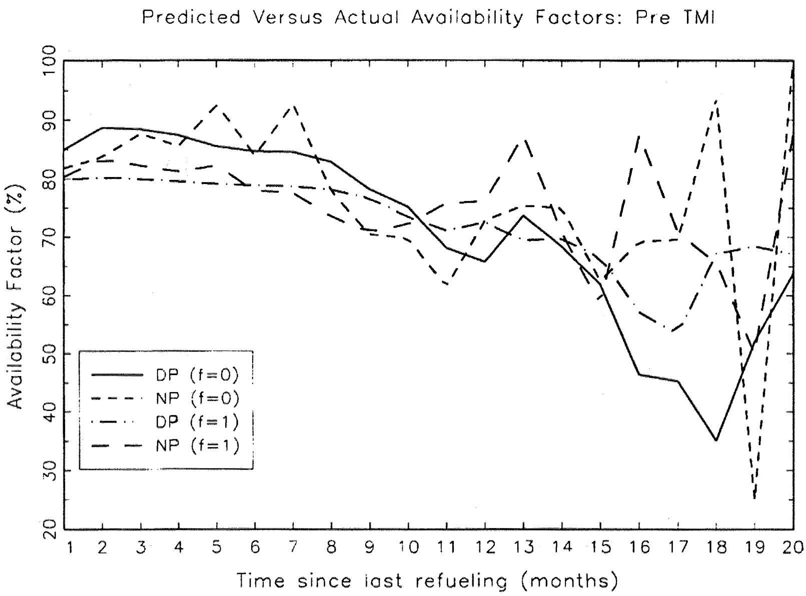


Figure 11. Probability of refuelling by duration since last refuelling, pre- and post-TMI

fact that the $\varepsilon(a)$ terms are shifting these curves up and down by random amounts over time, it follows that the realized duration of the operating cycle will frequently depart from plan. Forced outages also have a major impact on the optimal planned length of the operating cycle. As noted above, the occurrence of a forced outage in the previous month reduces the likelihood that the operator will initiate a refuelling outage in the current month. Figure 13 plots the case $f_t = 0$, i.e. no forced outages in the previous month. If $f_t = 1$, the optimal planned operating



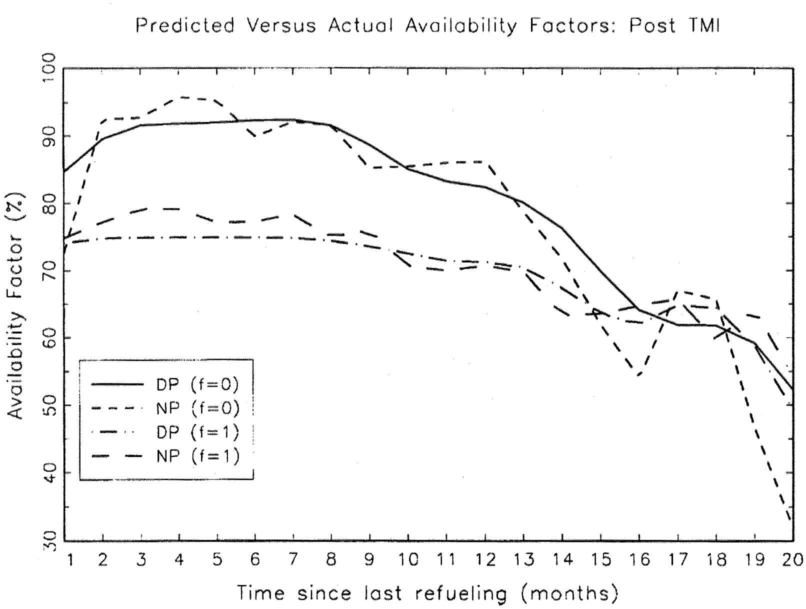


Figure 12. Availability factors by duration since last refuelling, pre- and post-TMI

cycle lengths shift to 16 and 21 months in the pre- and post-TMI periods, respectively. Due to the shape of the of value function in Figure 13 and the distributions of the ε_t and f_t shocks, we find that the distribution of realized durations of operating cycles has a peak at 10 months in the pre-TMI period, consistent with the actual distribution of operating spell durations in the top panel of Figure 6. Turning to the bottom panel of Figure 13 we see that in the post-TMI period the optimal planned duration of an optimal cycle is 18 months, which matches the nuclear

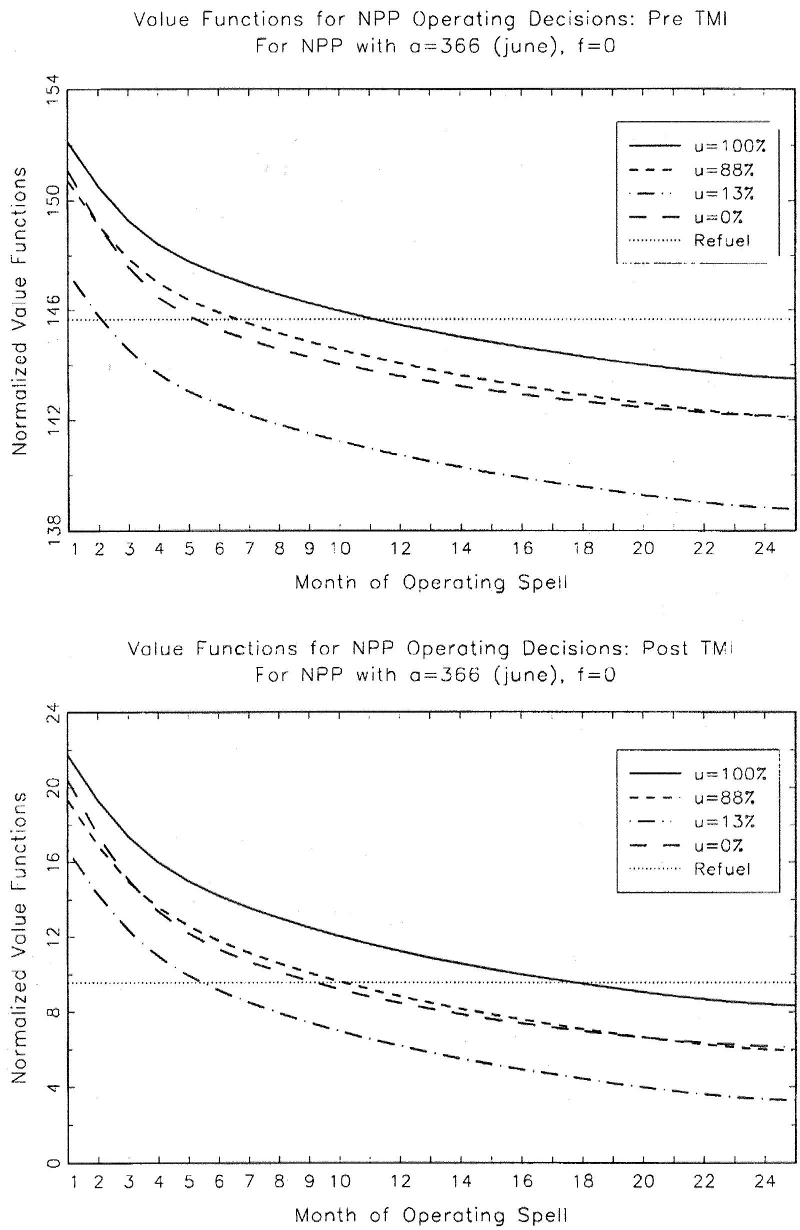


Figure 13. Estimated value functions by duration since last refuelling, pre- and post-TMI

industry's shift to 18-month planned operating cycles reported in Section 2. Note that due to the shape of the 'bathtub' hazard function for forced outages (see Figure 10) and the fact that shape of the value functions changed in the post-TMI period, the distribution of realized operating spell durations changes even though the distribution of the unobserved ε shocks is assumed to be unchanged. When we compute the distribution of realized operating spells implied by the DP model, we find it has a mean of 14 months and a mode of 15 months, corresponding closely to the actual distribution of realized operating spell durations given in the bottom panel of Figure

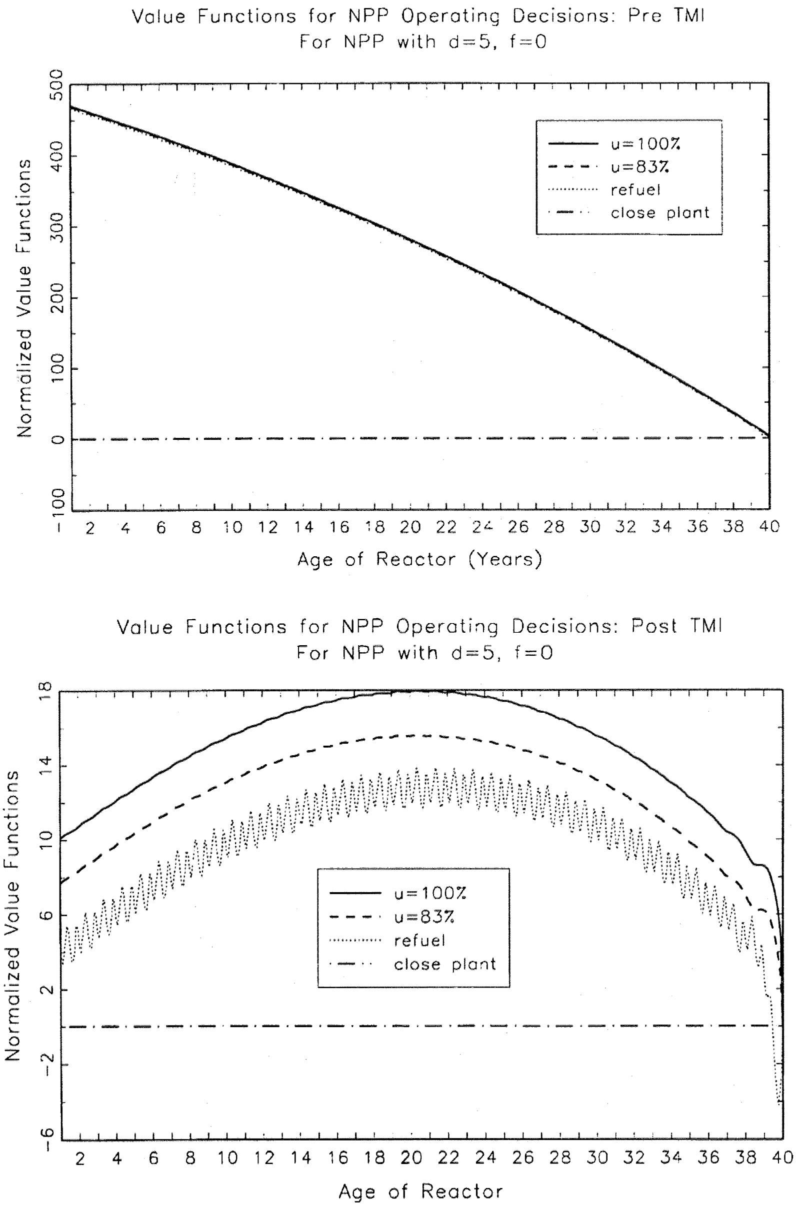


Figure 14. Value functions by plant age, pre- and post-TMI

6. Thus, we conclude that the DP model supports the hypothesis that the shift in NPP operating behaviour from 12-month planned operating cycles in the pre-TMI period to 18-month planned operating cycles in the post-TMI period constituted an 'optimal response' to the stricter post-TMI regulatory environment. However the fact that the DP model fits the data significantly better in the post-TMI period than in the pre-TMI period provides some evidence that a combination of industry learning and improved regulatory incentives lead utilities to adopt operating strategies that were much closer to optimal in the post-TMI period.

Figure 14 plots the value functions as a function of the age of the reactor in the pre- and post-TMI regimes. The difference in the shapes of the value functions is striking. The top panel shows that the expected present discounted value of profits is monotonically decreasing in the pre-TMI period, starting from a level of over 450. The value functions decline monotonically due to the finite horizon effect of the NRC's 40-year operating licence: as the reactor ages there are fewer remaining years in its licence and therefore fewer years over which operating profits can be earned. However, the bottom panel shows that in the post-TMI period value functions have a concave shape, initially increasing and then decreasing.[36] The reason for the shift in the shape of the value function is due to the fact that NPP operations are substantially less profitable in the post-TMI period. Operating profits start out at only 10 units in the post-TMI period, increase to a maximum of 18 units and then decline monotonically thereafter. The reason why the value function first rises and then falls is due to the combined effects of 'learning-by-doing' and technological progress. Recall from Figure 10 that our estimation results reveal that older NPPs are systematically more reliable than newer NPPs in the sense that their rates of forced outages are lower. Since forced outages are very costly, it follows that newer NPPs are less profitable than older NPPs. Thus, the value function initially starts to increase because per period profits increase monotonically with age. However, eventually the horizon effect outweighs the learning-by-doing effect.

We conclude this section with Figure 15 which summarizes the cost of the stricter post-TMI regulatory regime in terms of reduced expected discounted profits to NPP operation. Unfortunately, due to our arbitrary location and scale normalizations we are unable to estimate these losses in dollar terms using the NRC data on NPP operations alone. However under some additional assumptions we can estimate the *relative operating losses* entailed in moving from the pre- to the post-TMI regulatory regime. Define the *expected gains*, $G_t(x)$ to continued operation of an NPP as follows:

$$G_t(x) = v_t(x, 8) - v_t(x, 1). \tag{14}$$

Recalling that $a = 8$ denotes the decision to run the plant at 100% availability and $a = 1$ denotes the decision to decommission the plant, it follows that, $G_t(x)$ represents the additional profits (or reduction in losses) from continuing to run the NPP for one more period (until period $t + 1$) compared with the alternative of decommissioning the plant in period t.[37] By definition, $G_{480}(x) = 0$ since the operator is assumed to be forced to decommission the plant at the expiration of the 40-year NRC operating licence. Now, if $v_t(x, a)$ denotes the *true* expected discounted profits of an NPP, given our arbitrary identifying normalizations the value we estimate will be some linear transformation, $\hat{v}_t(x, a) = \delta_1 v_t(x, a) + \delta_2$, for some constants δ_1 and δ_2. Now if we

[36] The periodic oscillation of the value of refuelling is due the effect of seasonal variations in the price of electricity. There are similar variations in the value of refuelling in the pre-TMI period, but due to the relative scale of the graph, these variations are too small to be seen by the naked eye.

[37] Decommissioning may actually take many periods to carry out, but we assume that nevertheless the costs of this action have a well-defined expected present value which can be treated as an immediate cost in period t.

let $\hat{v}_t^1(x, a)$ and $\hat{v}_t^2(x,a)$ denote the *estimated* expected value function in the pre- and post-TMI periods, respectively, it is easy to see that when we compute the ratio of the relative gains in the pre- and post-TMI periods, the arbitrary normalizing constants δ_1 and $_2$ drop out:

$$\frac{G_t^2(x)}{G_t^1(x)} = \frac{\hat{v}_t^2(x, 8) - \hat{v}_t^2(x, 1)}{\hat{v}_t^1(x, 8) - \hat{v}_t^1(x, 1)} = \frac{v_t^2(x, 8) - v_t^2(x, 1)}{v_t^1(x, 8) - v_t^1(x, 1)} \tag{15}$$

Thus, even though we cannot identify the *absolute magnitude* of reductions in expected discounted *profits* in the post-TMI period. we can identify the *relative magnitude* of the reductions in expected discounted *gains.*[38]

Figure 15 plots the reduction in gains to continued NPP operation, defined as $1 - G_t^2(x)/G_t^1(x)$ as a function of plant age t for a fixed value of x.[39] We see from Figure 15 that over 90% of the gains to continued operation evaporated in the stricter post-TMI regulatory environment. This estimate is a lower bound on the losses in profits since our estimates of the profit function are based on the normalizing assumption that $\phi_c = 0$ in both the pre- and post-TMI periods and that the profits associated with operating at 100% availability, $\phi_{u=1}$, are the same in the two periods. As we showed in Section 2, operating and maintenance costs are significantly higher in the post-TMI period (due mostly to increased staffing requirements), so that $\phi_{u=1}$ should actually be higher than the value of 2·93 that we used as our identifying normalization in the pre-TMI period. Second, there is good reason to believe that the expected costs of decommissioning a NPP increased in the post-TMI, especially after 1990 when the Department of Energy announced further delays in securing a permanent nuclear waste repository.

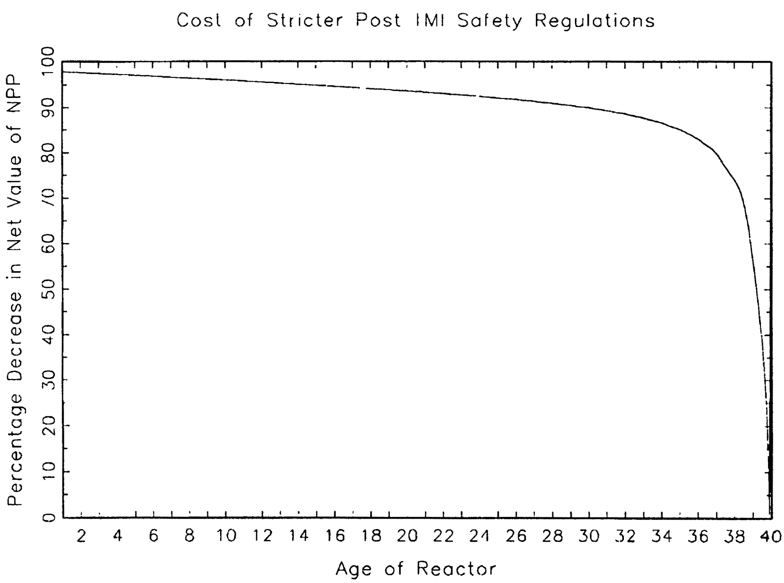


Figure 15. Impact of post-TMI regulatory regime on expected discount gains to continued operation

[38] Note an important implicit assumption underlying the calculation in equaion (15) is that the normalizing constants δ_1 and d_2 are the same in the pre- and post-TMI periods. We will discuss this further below.

[39] The specific value of x used here is $x = (1, 5, 0)$. The results in figures are not sensitive to the choice of a particular value of x.

5. CONCLUSION

We believe that the results in Section 4 provide strong evidence that the nuclear power industry reacted optimally to the shift in regulatory regime following the March 1979 accident at Three Mile Island. We have formulated and estimated a simple dynamic programme of optimal operation of an NPP and found that it provides a good approximation to actual NPP operations, especially in the post-TMI period. The DP model accounts for a number of important behavioural responses to the new regulatory regime, including a shift from 12- to 18-month planned operating cycles. The DP model explains this shift in behaviour as an attempt by the industry to offset declines in plant availability resulting from a significant increase in the duration of refuelling outages caused by additional NRC maintenance and surveillance requirements. Although we imposed the maintained hypothesis that utilities maximize expected discounted profits subject to regulatory constraints in both the pre- and post TMI periods, the finding that the DP model provides a better fit to behaviour in the 'hard' post-TMI regulatory regime than in the 'soft' pre-TMI regulatory regime may be an indication that a combination of industry learning and increased use of incentive-based regulatory schemes by state PUCs (including a significantly higher probability of operating cost disallowances) created stronger incentives for utilities to operate their NPPs in a cost-efficient manner.

Our results indicate that the social costs of the stricter post-TMI regulatory environment have been substantial, since even under optimistic maintained assumptions we find that over 90% of the expected discounted gains to continued operation of the 109 remaining NPPs in the USA have been eliminated in the post-TMI period. It is important to note that the cost of reduced operating profits at existing NPPs represents only a small portion of the total social costs of the new regulatory regime: this analysis ignores the substantial costs of the NRC-mandated retrofits, the huge increase in construction costs and lead times for new NPPs, the loss in profits of the 100 plus NPPs that were cancelled following the TMI accident, and the loss in profits of *potential* NPPs that may have had positive net present values under the pre-TMI regulatory regime but which almost certainly have negative net present values under the post-TMI regulatory regime. While the DP model indicates that most of the profits to NPP operation have been eliminated in the post-TMI regulatory regime, it also shows that there is no immediate cause for concern that the remaining 109 NPPs will be decommissioned in the near future. The reason is that now that investments in NPPs are sunk, continued operation is currently a much less costly alternative than immediate decommissioning. However, given the huge increase in the cost of investing in new NPPs and the large reduction in discounted profits of existing NPPs, we see little chance that new NPPs will be constructed under the current regulatory regime.

On the positive side, the results in Section 4 provide strong evidence that utilities have been very responsive to the stricter NRC safety regulation in the post-TMI period. In particular, we find that the perceived costs to 'imprudent' reactor operation were significantly higher after the NRC introduced its TMI action plan. The change in regulation has led plant operators to treat problem signals more seriously by increasing the duration of forced outage spells for more thorough diagnosis and repair of the problems leading to the outage. We noted in Section 2 that the improvement in reactor safety resulting from the NRC's increased maintenance and surveillance requirements during refuellings may have been partially offset by the industry's move to longer operating cycles. This is due to the fact that more frequent and/or more serious equipment failures tend to occur at the end of a longer operating cycle, as confirmed by the 'bathtub-shaped' probability of forced outages as a function of the duration since the last refuelling, and our finding that per period operating costs increase monotonically with the duration since last refuelling. However, we believe that any decrease in plant safety due to longer operating cycles is more than offset by the increase in safety due to more prudent reactor operation. We believe that increased prudence—as opposed to decreased safety—is responsible for the paradoxical finding that the fraction of time lost due to forced outages actually increased in the post-TMI period even though the number of forced outage events per unit of time declined significantly.

While we believe our DP model provides a reasonable first approximation to NPP operations, there are many directions in which the model could be extended in order to yield a more detailed and realistic model. One of the highest priorities is to integrate data on electricity revenues (including the price of electricity as an explicit state variable), EIA data on operating and maintenance costs, and the NRC data on NPP operations. This would help us to identify the actual levels of NPP profits in the pre- and post-TMI periods. Together with more detailed modelling of the future costs and benefits of various operating decisions, we may be able to obtain fully 'structural' parameter estimates, allowing us to predict how the industry would respond to a variety of alternative regulatory regimes.

Another important area for future research is build a more detailed model of the impact of regulatory constraints, including modelling expectations and the 'game' between the utility and the regulatory authorities. Our DP model predicts that operators should have adjusted instantaneously to the new regulatory regime, at least once the uncertainty about the details of the new regime were resolved. However, it is apparent from the graphs of the trends in operating behaviour presented in Section 2 that more complicated dynamics are involved. Part of these dynamics may be driven by changing expectations of regulatory constraints. But it is unclear whether changes in expectations alone can explain these dynamics. We think it is also likely that there are important learning dynamics involved: not all utilities can be assumed to be using optimal operating strategies. There is clear evidence of heterogeneity in plant characteristics and management abilities: some utilities may be doing a much better job of optimizing than others, and some utilities may have inherently more reliable NPPs than others. One possible direction for future research is to specify a model that includes a variety of plausible rules of thumb for NPP operations in addition to the rational DP approach presented here. Following the pioneering work of Grether and El Gamal (1995), it may be possible to estimate a mixture model that identifies which utilities are behaving optimally and which are behaving according to various plausible, but suboptimal rules of thumb. We could then use this framework to see how the change in regulatory regime affected the proportion of utilities that adopt various operating strategies. However, this approach leads to some challenging identification problems: is poor performance at a particular NPP due to a 'lemon' reactor or incompetent management?

A final and still more challenging project would be to build a model that could explain the learning dynamics that would lead a utility to discard an existing suboptimal rule of thumb governing its NPP operations and to undertake the investment in computation costs necessary to determine an optimal operating strategy. Presumably the incentives to making the switch are an increasing function of potential losses involved in following a given rule of thumb. However, if the utility has not actually determined the optimal operating strategy, how would it know what the potential losses are?

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