Indian Point Retirement Options, Replacement Generation, Decommissioning / Spent Fuel Issues, and Local Economic / Rate Impacts

Prepared for

The County of Westchester
and
The County of Westchester Public Utility Service Agency

June 9, 2005

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County Executive Andrew J. Spano
Michaelian Office Building
148 Martine Avenue
White Plains, NY 10601

Re: Indian Point Retirement Options and Associated Issues / Impacts

Dear County Executive Spano,

Levitan & Associates, Inc. is pleased to provide the County of Westchester and the County of Westchester Public Utility Service Agency with this report that identifies retirement options for the Indian Point Energy Center. Our report covers the legal and regulatory background of acquisition through condemnation, likely sources of replacement power and the associated rate impacts, decommissioning and spent fuel management issues, economic impacts of retirement, and estimated compensation amounts that could be due Entergy under an acquisition scenario or through a consensual agreement for a voluntarily shutdown. Our scope of work did not include quantifying the broad array of safety and homeland security issues that have the potential to impact the value of Indian Point.

Despite having fewer years of operation left under its existing operating licenses, Indian Point's value has increased since Entergy purchased the units in 2000 and 2001. The increased value is due to improved performance, higher market prices for its energy output, and the opportunity to extend its licenses for an additional twenty years. License extension, however, will be expensive and risky. In order to extend its operating licenses, Indian Point will have to convert to a closed-cycle system using cooling towers that will avoid harming Hudson River fish stocks, but will reduce plant performance and require a nine-month shutdown. Other repairs and improvements would be expected to bring the total cost of license extension to approximately $1 billion. Although our analysis indicates that this cost would be outweighed by the earnings from operating an additional twenty years, voluntary retirement may be a viable option. Local, state, and federal stakeholders should cooperate to provide Entergy with sufficient compensation and encourage on-site replacement generation that could mitigate the impacts that retirement will have on the local economy.

If an agreement to retire Indian Point were announced at least three-to-four years in advance, we expect that market prices, possibly bolstered by downstate utility actions, would encourage sufficient replacement generation. System reliability objectives would be safeguarded and market capacity prices would be virtually unchanged, provided such replacement generation was commercialized on a timely basis. However, if the two Indian Point units were retired before the licenses expired in 2013 and 2015, we expect market

energy prices to increase. The typical Westchester residential bill would increase by $1.55/month based on standard New York Public Service Commission consumption data. Ratepayers in New York City, Long Island, and the Albany area would see smaller increases, while residents in the western part of the State would be relatively unaffected. Early retirement would also cause power plant air emissions to increase. We were not asked to investigate how cost-effective conservation, load management, distributed generation, and renewable energy sources could replace Indian Point or mitigate these rate impacts.

Retirement, whenever it occurs, will inevitably impose local impacts due to reductions in property tax payments, employment, and local spending on goods and services. The Hendrick Hudson School District receives over 80% of those property tax payments, about one-third of its annual revenues. Many adverse impacts would not materialize until five-to-ten years, as employment and local spending would continue during decommissioning and spent fuel activities. On the positive side, retirement would improve the health of the Hudson River fisheries and provide public safety and homeland security benefits. While the preferred way to avoid or mitigate the local impacts would be to promote the development of on-site replacement generation, license extension, with the attendant construction of cooling towers, would almost certainly preclude that option.

If Indian Point was acquired through condemnation, Entergy would be entitled to just and reasonable compensation. We estimate such compensation to range from $1.8 billion to $2.7 billion, assuming a two-to-three year condemnation process beginning in 2005. Acquisition would also saddle the condemnor with $241 million of spent nuclear fuel costs and nuclear decommissioning risks. However, the high cost of license extension presents a window of opportunity. Since we estimate that cooling tower construction will take about three years, a consensual agreement reached before 2011 would allow Entergy to avoid the high incremental capital outlays yet continue to operate Indian Point through the end of the license terms. Compensation in this scenario would range from $0.5 billion to $1.4 billion, much less than the condemnation scenario.

The compensation estimates assumes that the U.S. Nuclear Regulatory Commission would approve license extension. Any risk of license extension would lower our dollar estimates. In either case the County could, in theory, fund its share of any compensation payment through General Obligations Bonds that would require a public referendum. We caution that a large bond issuance has the potential to impair the County's high credit rating and would have to satisfy municipal finance regulations.

For these reasons, retiring Indian Point will require a combined local, state, and federal effort that balances the rights of the plant owner with the public's mandate for security. A replacement gas-fired plant at the site is feasible and would offer advantages to all of the stakeholders. New York State, perhaps through the New York Power Authority, could support negotiations with Entergy and contribute to any arrangement for compensation and replacement generation.

Levitan & Associates, Inc. greatly appreciates the opportunity to have assisted Westchester and the County of Westchester Public Utility Service Agency. On behalf of the entire project team, we thank you for the privilege of this engagement.

Sincerely yours,

Seth G. Parker
Vice President & Partner

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GLOSSARY AND ACRONYMS

a/c	– Alternating Current
Algonquin	– Algonquin Gas Transmission
AN01&AN02	– Arkansas Nuclear Units 1&2
BWR	– Boiling Water Reactor
CapEx	– Capital Expenditures
CAPM	– Capital Asset Pricing Model
CFR	– Code of Federal Regulations
CL&P	– Connecticut Light and Power
CO_2	– Carbon Dioxide
Con Edison	– Consolidated Edison Company of New York, Inc.
COWPUSA	– County of Westchester Public Utility Service Agency
CTA	– Competitive Transition Assessment
d/c	– Direct Current
DCF	– Discounted Cash Flow
DEC	– N.Y. Department of Environmental Conservation
DECON	– Radioactive materials are removed or decontaminated
DOE	– U.S. Department of Energy
DPUC	– Connecticut Department of Public Utility Control
EBITDA	– Earnings Before Interest, Taxes, Depreciation, and Amortization
EDPL	– Eminent Domain Procedure Law
EIA	– U.S. Energy Information Agency
Entergy	– Entergy Corporation
ENTOMB	– Radioactive materials are encased and maintained / monitored.
EPA	– U.S. Environmental Protection Agency
FEIS	– Final Environmental Impact Statement
FMV	– Fair Market Value
GAO	– U.S. Government Accountability Office
GGNS	– Grand Gulf Nuclear Station
GO	– General Obligation (County tax-exempt bonds)
GTCC	– Greater Than Class C (nuclear waste)
IP	– Indian Point Energy Center
IP1	– Indian Point Unit 1
IP2	– Indian Point Unit 2
IP3	– Indian Point Unit 3
IRR	– Internal Rate of Return
ISFSI	– Independent Spent Fuel Storage Installation
ISO-NE	– Independent System Operator-New England
ktons	– Thousand Tons
kWh	– Kilowatt-Hour (a measure of energy)
LLC	– Limited Liability Corporations
MAC	– Monthly Adjustment Charge (charged by Con Edison)
MPF	– Market Price Forecast
MW	– Megawatt (a measure of capacity; equivalent to 1,000 kW)
MW_{th}	– Megawatt of thermal energy (1 MW_{th} can generate approximately 0.3 MW)

MWh	– Megawatt-hour (equivalent to 1,000 kWh)
NEI	– Nuclear Energy Institute
NO_x	– Nitrogen Oxides
NPDES	– National Pollutant Discharge Elimination System
NRC	– U.S. Nuclear Regulatory Commission
NYISO	– New York Independent System Operator
NYPA	– New York Power Authority
NYPSC	– New York Public Service Commission
NYSERDA	– New York State Energy Research and Development Authority
O&M	– Operations and Maintenance
ORPS	– New York Office of Real Property Services
PASNY	– Power Authority of the State of New York
PILOT	– Payment in Lieu of Tax
PJM	– Pennsylvania-New Jersey-Maryland Interconnection
PPA	– Power Purchase Agreement
PWR	– Pressurized Water Reactor
PWSCC	– Primary Water Stress Corrosion Cracking
RB	– River Bend
RFP	– Request for Proposal
RG&E	– Rochester Gas & Electric, part of Energy East Corporation
ROE	– Return on Equity
ROIC	– Return on Invested Capital
RPV	– Reactor Pressure Vessel
SAFSTOR	– Nuclear facility is maintained / monitored to allow radioactivity to decay
S&P	– Standard & Poor's
SEC	– U.S. Securities and Exchange Commission
SEQR	– State Environmental Quality Review
SNF	– Spent Nuclear Fuel
SO_2	– Sulfur Dioxide
SPDES	– State Pollution Discharge Elimination System
TMI	– Three Mile Island
U-235	– Uranium 235
U-238	– Uranium 238
W3	– Waterford 3
WACC	– Weighted Average Cost of Capital
WIDA	– Westchester County Industrial Development Agency
Zones A-E	– Western and Northern New York
Zone F	– Capitol District
Zones G,H,& I	– Westchester and rest of lower Hudson River Valley
Zone J	– New York City
Zone K	– Long Island

Limitation of Liability

This report has been prepared for the County of Westchester and the County of Westchester Public Utility Service Agency for the sole purpose of evaluating economic, technical, and certain legal issues surrounding the operation and retirement of the Indian Point Energy Center. The findings and conclusions contained herein depend on the assumptions identified in this report. While Levitan & Associates, Inc. believes these assumptions to be reasonable, there is no assurance that any specific assumption will actually occur and we make no assurances except those explicitly set forth herein. Levitan & Associates, Inc., the County of Westchester, and the County of Westchester Public Utility Service Agency do not make any warranty, expressed or implied, with respect to the use of information or methods disclosed in this report, and do not assume any liability with respect to the use of information or methods disclosed in this report.

Executive Summary

Introduction

In June 2004, Levitan & Associates, Inc. (LAI), a Boston-based management consulting firm specializing in the energy industry, was retained by the County of Westchester (Westchester or the County) and the County of Westchester Public Utility Service Agency (COWPUSA) to evaluate economic, technical, and certain legal issues surrounding the operation and retirement of the Indian Point Energy Center (IP). Since 9/11, IP has been a lightning rod for safety and security concerns. In response to these concerns, the County has expressed an interest in assessing the feasibility of alternative options to facilitate IP's retirement. In conducting this analysis, LAI has been assisted by WPI, a nuclear advisory firm specializing in plant decommissioning, safety, and spent nuclear fuel (SNF) advisory services.

LAI has identified and evaluated two options for the County to facilitate IP's retirement: acquire the plant by condemnation or reach a consensual agreement to voluntarily retire the plant with IP's owner, Entergy Corporation (Entergy). LAI assessed IP's current and expected performance, estimated the economic impacts of retirement, identified the likely sources of replacement generation and impact on customer rates, calculated the compensation due Entergy, and described the requisite decommissioning and SNF activities. LAI's scope of work did not include the breadth of safety and homeland security issues associated with ongoing operation of IP, or the potential for alternative energy technologies to replace it.

Background

When the New York power market was deregulated in the late 1990s, utilities divested their power plant assets. Some power plants have power purchase agreements (PPAs) with utilities and other load-serving entities that establish power quantities and prices. The majority of power plants in New York State are merchant plants that do not hold PPAs and compete to sell their output at market prices administered by the New York Independent System Operator (NYISO). Since wholesale power markets became competitive, Entergy has acquired various nuclear power plants in New York and New England, including IP.

There are three nuclear units at the IP site. Indian Point 1 (IP1) and Indian Point 2 (IP2) were sold by Consolidated Edison Company of New York, Inc. (Con Edison) to Entergy in September 2001. IP1 was deactivated in 1974, and will be decommissioned at a later date in conjunction with the decommissioning of IP2 and Indian Point 3 (IP3). Entergy purchased IP3 along with the FitzPatrick station from the New York Power Authority (NYPA) in November 2000. The nominal generation capacity of each IP unit is about 1,000 megawatts (MW). IP therefore represents about 5% of the total installed generation capacity throughout New York State. In terms of energy output, IP2&3 collectively account for about 10% of New York's electricity requirements. IP2&3's Nuclear Regulatory Commission (NRC) operating licenses are scheduled to expire in 2013 and 2015, respectively. In accord with industry trends, Entergy could apply for license extensions for up to an additional twenty years, provided certain operating, environmental, and safety conditions are met.

Entergy is a Louisiana-based integrated energy holding company with both utility and non-utility business segments. Entergy owns and operates five utility-owned and five non-utility nuclear power plants; the non-utility plants are located in New York and New England. Since Entergy acquired IP from Con Edison and NYPA, the units have operated at relatively high capacity factors. After Entergy completed the acquisitions, skyrocketing natural gas and oil prices have materially increased the market value of IP's output. Average market energy prices in Westchester increased 26% from 2001 to 2004. Moreover, the outlook on premium fossil fuel prices, coupled with regulatory changes in New York promulgated by NYISO, portend continued pressure on market energy and capacity prices for the foreseeable future. Thus the value of IP has improved since Entergy's acquisition. Against this backdrop, the County and COWPUSA have a limited number of strategic options to shut down IP.

Findings

- There are two principal options to retire IP early – acquisition through condemnation or a consensual agreement with Entergy for a voluntary shutdown. Either option will require compensating Entergy for lost profits net of avoided costs and capital expenditures (CapEx). Condemnation would also involve the assumption of decommissioning and SNF responsibilities, as well as financial risks. Entergy would retain those responsibilities and risks under a consensual agreement.

- A condemnation process is likely to take several years, depending on how quickly the condemnation was sought and whether Entergy contests the original compensation offer. If the condemnation was successful, Entergy would be entitled to just and reasonable compensation. For example, if the process started now and was completed by January 1, 2008, we estimate that Entergy would have to be paid $1.4 - $1.8 billion in compensation for lost profits through the current license terms, plus $0.3 - $1.0 billion for the twenty year license extension period. While the decommissioning funds should be sufficient to cover decommissioning activities, the condemnor would become responsible for SNF costs that we estimate at approximately $241 million over the following six years.

- Under a consensual agreement in which Entergy would voluntarily retire IP, Entergy would retain the responsibilities and risks of nuclear plant ownership. Entergy may be receptive, given the high cost (estimated at $1 billion), uncertain financial return, and likely political quagmire associated with operating beyond the current NRC license terms. Assuming a January 1, 2010 agreement / payment date and a 2013/15 retirement date, *i.e.* at the end of the existing license terms, we estimate the value of Entergy's lost profits to be $0.5 - $1.4 billion for the twenty year license extension period. These values do not account for any risk that the NRC could deny Entergy's request for license extension, which would lower our compensation estimates.

- LAI estimated the ranges of compensation values under each option by forecasting IP revenues, expenses, and cash flow, then applying high and low discount rates that reflect the risks of a merchant nuclear plant. The wide range in compensation values is due to the high and low discount rates as well as the effect of compounding over

time. Any change in the payment dates assumed in the retirement options identified above would change our compensation estimates.

- Condemnation of IP by the County is legally difficult and financially risky. On the other hand, a consensual agreement should be achievable and could involve other stakeholders such as the State of New York, NYPA, New York City, and other utility and government stakeholders. The challenge for a consensual agreement would be to convince Entergy to retire IP voluntarily and, ideally, develop replacement generation on the IP site.

- Retirement of IP presents economic and rate impacts beyond compensation costs. These impacts will inevitably occur whenever IP ceases operation, so the question is not *whether* there will be impacts from IP retirement; the question is *when* these impacts will occur. Many of these impacts could be avoided or mitigated by development of on-site replacement generation. Local impacts would include loss of payments in lieu of tax (PILOT), the bulk of which go to the Hendrick Hudson School District. Local employment and spending benefits would disappear about ten years after retirement, once the site is decommissioned and SNF is in dry storage. Local community support activities would cease, and power plant emissions would increase.

- The largest quantifiable positive impact of retiring IP would be the improved health of the Hudson River fisheries, which would benefit residents beyond the local communities. These fisheries would also benefit if IP is converted to closed-cycle cooling, although Hudson River water may still be required for emergency cooling. While retiring IP would result in public safety and security benefits, we have not tried to quantify those benefits. A minor benefit of retiring IP would be that the County could avoid emergency service costs.

- The greatest negative impact of retiring IP before its license expires in 2013/15 would be a rise in market energy prices, even with the timely addition of replacement generation. We estimate that a minimum of three-to-four years is required from the time IP's retirement is announced to develop and construct new power plants. Retirement through a consensual agreement with Entergy, or if Entergy was unable to extend the NRC licenses, should provide sufficient lead time to develop replacement generation on the IP site or elsewhere in the downstate region. In practice, lenders and investors are unlikely to rely on uncertain market prices to justify new merchant projects. Therefore downstate utilities might decide to offer PPAs to assure their customers of sufficient resources. It is not known how the New York Public Service Commission (NYPSC) would react to a new PPA commitment. If necessary, the NYISO or NYPA could make short-term arrangements to assure bulk power security.

- Since Entergy has not yet filed an application with the NRC to renew IP's licenses, our working assumption has been that IP will be retired at the end of the existing license terms. Therefore a voluntary retirement on the same dates would impose virtually

identical economic and electric rate impacts on County and New York residents – retirement in 2013/15 would not impose any additional economic or rate impacts.

- Extending the NRC licenses will likely cost Entergy over $1 billion, principally to convert from a once-through cooling system using the Hudson River to a closed-cycle system using cooling towers. Constructing the towers will require a local zoning variance, each IP unit would have to be shut down for roughly nine months for the conversion, and future plant performance would suffer. In spite of these hurdles, the economics of license extension appear favorable from Entergy's perspective, unless gas prices decline materially (thus lowering the value of IP output) or conversion costs are higher than expected. However, the significant costs and risks provide the County, State, NYPA, and other interested stakeholders a window of negotiating opportunity through about 2010, after which cooling tower construction would probably need to commence. We believe that the cooling towers would require considerable space on the IP site and preclude any chance for on-site replacement generation.

- Converting the IP units to gas-fired generation is not feasible. However, the existing site is well-suited for new replacement gas-fired generation, particularly with the existing high-voltage transmission infrastructure and the Algonquin Gas Transmission (Algonquin) interstate natural gas pipeline adjacent to the site, provided that cooling towers for the nuclear units are not installed. It is not the County's legal responsibility to replace the generation capacity to maintain adequate reserve margins if IP were to retire. Nevertheless, on-site replacement generation has the potential to avoid or mitigate the costs and impacts of a voluntary retirement.

- The development of on-site replacement generation could be facilitated through a variety of mechanisms. For example, surplus property on the site could be leased to a generation developer if Entergy itself did not want to develop a replacement plant. Alternatively, the market risks of on-site replacement generation could be avoided through a PPA with a credit-worthy purchaser such as NYPA or others who can re-sell the power to retail customers. While COWPUSA has the authority to enter into a long-term PPA and provide retail service to Westchester residents, it does not have a large customer base and may not be able to effectively compete with Con Edison. A third mechanism, providing tax-exempt financing for an on-site replacement plant, may not be possible under current federal tax provisions, although Congress could adopt legislation that would make such an option possible.

- SNF will be stored in specially-designed dry casks on-site starting next year. It is anticipated that the SNF will eventually be shipped to Yucca Mountain, the nation's planned SNF repository in Nevada. Entergy will have to bear the on-site SNF storage costs until then, and remove any non-radioactive materials. We estimate that it will take ten years after retirement until all SNF and radioactive materials could be removed, provided Yucca Mountain is opened in 2010 as planned. This date may slip due to recent licensing delays, which will require additional quantities of SNF to be stored on-site over a longer period of time.

- Other radioactive materials will be stored on-site until a disposal site is licensed. The IP decommissioning funds should be adequate to cover decommissioning costs, assuming that the three IP units will be decommissioned in an integrated program.

Recommendation

Acquiring IP through condemnation is not recommended because it would require assuming nuclear decommissioning and SNF management responsibilities, and is fraught with financial costs and risks that have the potential to impose material economic hardships. *A consensual agreement is the better option*, in which the County, together with other stakeholders such as the State, NYPA, and New York City, can muster political pressure to discourage relicensing and can negotiate and fund a financial compensation and replacement generation package. The high CapEx associated with license extension, coupled with the potential uncertainties surrounding the NRC approval and local zoning process, offers a *window of opportunity* to negotiate a retirement date, perhaps at the end of the current NRC license terms. Reaching a consensual agreement no later than year-end 2010, with the support of the State and its Congressional delegation, would allow sufficient time for replacement generation to be developed, including on the IP site, by 2013/15. Other strategies to induce Entergy to retire IP early through State or federal action appear unprecedented, but are possible with State and Congressional support.

A consensual agreement to voluntarily retire IP would provide sufficient time to structure the best possible solution for Westchester residents. We recommend that a consensual agreement include on-site replacement generation to avoid or mitigate the costs and impacts of IP retirement. An on-site gas-fired combined cycle replacement plant, for example, would provide benefits to Entergy and the State as well. Entergy would have an attractive investment opportunity in New York, and State residents (outside of Westchester) would enjoy the bulk of the benefits from improving the health of the Hudson River fisheries. The State should participate in a consensual agreement and be part of the IP solution.

Acquisition by Condemnation

The ability to acquire IP through a condemnation proceeding is based on principles of eminent domain. Our evaluation of applicable regulations indicates that this option is feasible but risky. In brief, the condemnor would have to conduct a public hearing, make a public determination to condemn and acquire the plant, offer a price based on a property appraisal, and then file a petition that is accepted by the Westchester Supreme Court. This option has some significant drawbacks and entails difficult ownership responsibilities:

- If IP were immediately deactivated upon acquisition, the condemnor would have to obtain management expertise that satisfies stringent NRC standards to decommission the units and handle radioactive materials. SNF would remain on the site at least a decade, obligating the condemnor to provide appropriate security measures. The availability and cost of obtaining this nuclear expertise are highly uncertain.

- The existing decommissioning funds, designed to cover the costs to decommission the radioactive materials, should be adequate. However, there is no guarantee, and any shortfall would impose significant decommissioning costs on the condemnor. The funds do not cover the cost to store the SNF, or to remove non-radioactive materials.

- Under New York law, Entergy would be entitled to just and reasonable compensation for the condemnation of IP. The compensation amount would be set by a court-ordered appraisal and reflect then-prevailing market, operating, and regulatory conditions, and therefore could be higher than our estimate.

- The County or New York State could be the condemning authority, thereby assuming all attendant responsibilities and risks. Since retiring IP benefits State residents beyond Westchester County, it may make sense for NYPA to be responsible for decommissioning and SNF activities.

Present Value Summary – Acquisition in 2008 versus Retirement in 2013/15
(2008 $ millions; excludes indirect impacts; assumes no replacement generation)

Costs	Shared by Stakeholders
Entergy Compensation	
Original License Term	$1,465 - $1,831
Renewal Option	$ 289 - $ 913
Sub-Total	$1,754 - $2,744
Spent Nuclear Fuel	$ 241
Total	$1,995 - $2,985

Rate / Economic Impacts	County	New York State
Electric Market Impact	$ 216	$ 1,742
Economic Impacts *(benefits in parenthesis)*		
Property Taxes	$ 143	$ 143
Employment	$ 123	$ 820
Local Spending	$ 89	$ 341
Community Support	$ 6	$ 6
County Emergency Planning	($ 35)	($ 35)
Corporate Income Tax	$ 8	$ 167
Hudson River Fisheries	($ 220)	($ 2,198)
Air Emissions	$ 2	$ 41
Sub-Total	$ 116	($ 715)
Total	$ 332	$ 1,027

For purposes of this analysis, we have assumed that condemnation proceedings would commence immediately, and IP would be acquired and shut down on January 1, 2008. Two types of costs arise under the acquisition option: (i) compensation due Entergy and taking on

the SNF responsibilities, and (ii) electric rate and economic impacts. We estimate compensation due Entergy at $1.75 - $2.74 billion, plus the condemnor would become responsible for $241 million of SNF costs. We estimate the State-wide rate and economic impacts at $1.03 billion, of which the County would shoulder 21%. All of these costs and impacts are expressed in present value terms as of January 1, 2008, as itemized in the summary tables above, and are relative to our base case assumption of IP retirement in 2013/15 at the end of the existing license terms.

- The largest cost component is compensation due Entergy. LAI provided a low and high range of compensation values due to uncertainty about a key valuation assumption, the appropriate discount rate for Entergy's future revenues from IP2&3. The low end of the compensation range, $1.75 billion, is associated with a high discount rate of 20%, the high end of our estimate of Entergy's cost of funds (combined debt and equity) for a merchant nuclear power facility. The high end of the compensation range, $2.74 billion, is associated with a low discount rate of 14%, the low end of our estimate of Entergy's cost of funds. We assumed that Entergy would receive full credit for lost earnings over the license extension period. Any risk that the NRC would not approve license extension would lower the estimated value for the license extension period. Ideally, the County could participate jointly with the State, NYPA, New York City, and other stakeholders, in the acquisition and compensation arrangement.

- The condemnor would incur SNF costs, estimated at $241 million. The existing decommissioning funds should be adequate to cover all decommissioning costs.

- The present value of the electric market impact on the County is estimated at $216 million, and $1.74 billion for the entire State. Estimated rate impacts reflect our assumption that long-term utility PPAs provide a 50% hedge against higher market energy prices. Typical residential bills in Westchester would increase $1.55/month if IP retires before 2013/15, and by about $0.73/month in New York City.

- Total direct economic impacts (excluding electricity prices) are estimated to have a negative present value of $116 million for the County and a positive present value of $715 million for the entire State as follows:

  - Lost PILOT revenues from 2008 through 2015 would total $143 million for the County; the rest of the State would not be directly affected.

  - Significant manpower would be required at the site for decommissioning and SNF activities, so that reduced employment and local spending would not affect the County for five-to-ten years. The present value of lost wages would total $123 million in the County and $820 million in the entire State.

  - Reduced local spending on goods and services would total $89 million in the County and $341 million in the entire State.

- Reduced local community support, *e.g.* monetary contributions and employee volunteer efforts, would total $6 million in the County and would not affect the rest of the State.

- Reduced County emergency planning expenses would save the County $35 million and would not affect the rest of the State.

- Lost corporate income taxes would total $167 million in the State, and $8 million to the County, assuming a 5% allocation (consistent with County / State population ratio).

- The health of Hudson River fisheries would improve and provide significant *benefits* estimated at $2.2 billion for the State. Lacking a good basis for assigning this benefit, we assumed that a nominal 10% would accrue to County residents.

- Emissions of air pollutants from power plants across New York State would increase. We estimate the impact to be $41 million for the State, of which $2 million would be allocable to the County based simply on population.

Voluntary Retirement

Westchester, in conjunction with the State, NYPA, New York City, and other stakeholders could negotiate a consensual agreement for Entergy to retire IP. A voluntary retirement would avoid the costs and risks of an acquisition, keep in place Entergy's operation and management resources, and provide significant flexibility to arrange a compensation package and develop replacement generation on site:

- A voluntary retirement could be agreed upon with an actual shutdown date at some date in the future to allow sufficient time for market participants to replace IP's capacity in an orderly fashion. In our view, the announced retirement of IP would encourage market participants to replace substantially all of the generation capacity in the downstate region, possibly supported by long-term PPAs offered by downstate utilities. A minimum of three-to-four years would be adequate to develop replacement generation to assure system reliability. While there are many power plant sites that could be developed, on-site replacement generation is preferred as it could avoid or mitigate the local economic impacts of retiring IP.

- Entergy would request substantial compensation in exchange for agreeing to retire IP and to not pursue license extension. However, retiring IP at the end of the current license terms would allow Entergy to avoid the costs and risks associated with the license extension process, including NRC approval and the requisite zoning variance. LAI's estimate of the CapEx for license extension is over $1 billion for cooling towers and other plant repairs / improvements. The NRC has not rejected any license extension applications to date, but approval of Entergy's application is not certain given IP's unique siting and cooling system challenges.

- If Entergy retires IP by 2013/15 and does not construct the cooling towers, there would be sufficient acreage for a gas-fired power plant. Three years ago, Entergy proposed the addition of an on-site gas-fired plant, but subsequently withdrew its application. COWPUSA has the authority to purchase power from an on-site replacement plant through a PPA, but currently sells power only for economic development purposes. Providing retail service would be a major step for COWPUSA and would impose associated administrative and operational costs. LAI considered a strategy for COWPUSA to buy power directly from the on-site generator to avoid transmission charges, but that strategy was not effective. In addition, the Monthly Adjustment Charge (MAC) component levied by Con Edison for Westchester residents will be equalized, removing a potential cost advantage for COWPUSA.

- Ignoring PSC directives to encourage retail choice and competition among generators, it would be preferable for a utility with a large retail customer base, such as NYPA or Con Edison, to enter into a long-term PPA for on-site replacement generation, perhaps in conjunction with COWPUSA. A PPA with credit-worthy counterparty such as NYPA or Con Edison would also assure project financeability.

- There would be no electric market and economic impacts because IP would be retired on the same date as in our base case assumption, 2013/15.

Present Value Summary – Voluntary Retirement in 2013/15
(2011 $ millions; excludes indirect impacts; assumes no replacement generation)

Costs	Shared by Stakeholders
Entergy Compensation	
Original License Term	n/a
Renewal Option	$ 495 - $1,376
Sub-Total	$495 - $1,376
Spent Nuclear Fuel	n/a
Total	$495 - $1,376

We have assumed that a consensual agreement with Entergy would be reached by January 1, 2011, to retire IP at the end of the existing license terms. In this case, the only cost that would be incurred is the compensation cost due Entergy. Entergy would remain responsible for SNF and decommissioning. In effect, Entergy's option to extend IP's licenses would be bought out. We estimate compensation due Entergy at $0.5 - $1.4 billion in present value terms as of January 1, 2011, the assumed payment date. As before, the compensation range is due to the uncertainty of the discount rate that would be developed in the negotiations. Entergy would continue to be responsible for SNF costs, and the rate and economic impacts would be no different than if IP were shut down on its "natural" retirement dates at the end of the existing license terms.

As with the acquisition option, the compensation amounts that we estimated represent an upper limit, because we ascribed full value to the cash flows Entergy would earn during the

twenty year license extension period. We effectively assumed that Entergy faces no risk of the NRC rejecting the application for license extension. While there is some uncertainty surrounding the relicensing effort, we have not tried to calculate either the likelihood of NRC rejection of Entergy's application for IP license extension or the resulting change in the compensation value.

State and Federal Action

Any action by the state or federal government to require Entergy to retire IP prior to the expiration of the current operating licenses would be unprecedented. In such an event, the State or federal government would likely provide the compensation due Entergy. The State would be bound by similar eminent domain regulations as the County, but the regulatory basis and condemnation process for federal action was not part of LAI's scope of work. However, State and congressional support for County actions could greatly improve the chances of a successful negotiating outcome and reduce the County's compensation burden. Congressional action would likely be needed to obtain tax law changes that would make tax-exempt financing possible for replacement generation on the IP site.

License Extension

The NRC licenses for IP2&3 expire on September 28, 2013 and December 12, 2015, respectively. In light of the high value of energy and capacity in downstate New York and pressures on oil and gas producers throughout North America, we believe that the forward economics would support Entergy's decision to apply for a twenty year license extension. In order to receive NRC approval, Entergy will have to demonstrate that all of the systems, structures, and components that are critical to IP's safe operation can continue to function for the term of the license extension. IP's proximity to New York City and the efficacy of its Emergency Evacuation Plan would not be considered in a *typical* license extension process under existing NRC regulations. Given the strong public and political attitudes about IP, the NRC may not view an application from Entergy for license extension as typical.

In order to continue operating beyond the term of the initial licenses, the New York Department of Environmental Conservation (DEC) has required Entergy to convert from the existing once-through cooling system that utilizes Hudson River water to a closed system with cooling towers. We estimate that the future cost of converting to cooling towers plus other repairs and improvements that would likely be undertaken will be $1 billion. Conversion would require that each unit be shut down for roughly nine months, plant output would be reduced by roughly 4% due to pumping requirements and other internal loads, and plant operation and maintenance costs would increase due to age-related problems. The closed-cycle cooling design will likely be scrutinized by the NRC in any application for license extension, and cooling towers will require a zoning variance from the Village of Buchanan.

The NRC has approved extension requests for 30 nuclear plants at 17 sites to date, and has not denied any requests. However, Entergy does face some risk that IP's application for license extension will not be approved, particularly verifying that the plant design, including conversion to the closed cooling cycle, meets current safety standards. The effectiveness of

opposition from New York State interveners before the NRC is unknown. If the NRC denied Entergy's application for license extension, the County and other stakeholders would not have to fund compensation costs. However, we do not recommend relying on such a strategy.

From an economic perspective, we calculate that license extension would be cost-effective in relation to the value of capacity and energy from the units over the anticipated twenty years of extended plant life. However, if the CapEx requirement is higher than our $1 billion estimate, if the NRC approval is for less than twenty years, or if power prices are lower than our forecast, Entergy may be less inclined to pursue license extension, and our compensation estimates would be lower.

Replacement Generation

We believe that announcing IP's retirement at least three-to-four years in advance will allow sufficient time to develop replacement generation. One scenario we examined contemplates the postulated immediate retirement of IP, an unrealistic assumption that would by definition preclude sufficient time for replacement generation, thereby threatening the reliability of the state's bulk power system. The immediate retirement of IP would cause energy and capacity prices to soar. To ensure resource adequacy, we would expect NYISO to implement a number of expensive short-term fixes to ensure grid security prior to the commercialization of new generation resources.

If IP were to be retired, LAI believes that the resulting market price signals would be attractive for replacement generators. It may nevertheless be necessary for downstate utilities to backstop the development of replacement capacity through PPAs. While the current financial markets are wary of lending to projects that have merchant risk, projects with PPAs provide credit support that facilitate debt and equity financing. Whether those downstate utilities could be reasonably assured of recovering all PPA costs is outside the scope of this inquiry.

We examined the range of possible replacement generation options and concluded that they would likely be gas-fired and located in the downstate region. This conclusion is consistent with possible replacement generation at the IP site and with proposed combined cycle plants in Orange and Rockland counties over the last few years. Generation additions in upstate New York would not be economic without expensive transmission upgrades. Assuming utility support through PPAs, the requisite generation capacity would likely be permitted and developed on a timely basis. Other infrastructure improvements, in particular, increasing gas pipeline deliverability, would also be required. Major electric transmission improvements would not be necessary in light of the existing transmission infrastructure from IP southward.

Replacing IP's capacity may be facilitated, in part, by New York's Renewable Portfolio Standard that requires utilities to increase their purchases of renewable energy over the next decade. How much new capacity and energy could be derived from renewable technologies in the downstate New York region was outside our scope of work.

It is not feasible to convert any of the existing IP units to gas-fired operation. However, the site is well-situated for new gas-fired combined cycle replacement generation so long as cooling towers are not installed, which would utilize valuable remaining space. Entergy proposed developing 330 MW of new gas-fired simple cycle generation at the IP site three years ago, but later withdrew the application. We believe the remaining on-site acreage is sufficient for more than 330 MW of new generation. Algonquin traverses the site and IP's retirement would free up electric transmission capacity. Although Algonquin is fully subscribed with virtually no surplus capacity throughout the winter season, planned pipeline projects and expansions should make the IP site attractive for new gas-fired generation. Expensive pipeline upgrades on Algonquin would be required to provide firm year-round deliveries. The quality of non-firm transportation during the winter is uncertain, particularly in light of complex market dynamics associated with new gas supplies entering the system. To the extent a new combined cycle plant received an air emissions permit that allowed burning distillate oil up to 30 days per year, non-firm service might still entail interruptions during the heating season.

While it is not Westchester's legal responsibility to replace IP capacity, facilitating the development of replacement generation at the IP site is one way that the costs and economic impacts of IP's retirement could be avoided or mitigated. In this regard, COWPUSA may be able to support NYPA's efforts to execute a PPA and purchase power from the replacement plant. While both utilities have large customer bases, neither party would be obligated to do so. In fact, Con Edison has taken a number of steps to lessen its reliance on PPAs in response to state regulatory initiatives to promote competition. Alternatively, part of the IP site could be purchased and leased to a developer, which would maintain PILOT and local spending as well as provide construction opportunities. We do not recommend that COWPUSA consider plant ownership given the competitive market pressures and operational challenges. The National Academy of Sciences has recently been asked to conduct a study for the U.S. Department of Energy (DOE) to identify and evaluate conventional and alternative energy options to replace IP. For its part, the County may also want to pursue cost-effective conservation, load management, distributed generation, and renewable energy sources in Westchester.

Valuation

LAI estimated the value of IP using standard appraisal techniques. The preferred technique for an income-producing property, referred to as the Earnings Approach, requires forecasting revenues and expenses, and discounting the resulting cash flows back to a specified date using an appropriate discount rate. LAI forecasted IP revenues using a system dispatch simulation model that reflects the hourly power market operation under existing regulations and expected levels of plant performance. Expenses were forecasted based on a detailed economic study of IP prepared by the Nuclear Energy Institute (NEI), a nuclear industry policy organization, as well as on publicly available data. Other local economic impacts, including property taxes, employment, and local spending, were considered separately.

The derivation of the appropriate discount rate applicable to IP's cash flows is challenging. In addition to market risk attributable to all merchant generation owners who merchandise

output without the benefit of a compensatory PPA, nuclear plant owners face a broad spectrum of discernible risks, such as safety compliance, decommissioning, SNF, mishap repairs, latent technical defects, extended outages, and changes in government regulation. In order to bound the range of reasonable plant values applicable to IP, LAI estimated a high discount rate of 20% and a low of 14%. The higher discount rate provides a lower plant value / compensation payment, and vice versa. We did not include a risk premium for possible NRC rejection on Entergy's application for life extension, which would depress plant values and compensation estimates. In our valuation estimates, we have assumed that once IP ceases operating, the decommissioning funds can be utilized to recover all costs of removing and storing radioactive materials. Non-decommissioning costs, such as SNF management and disposal of non-radioactive structures, cannot be recovered from the funds and would have to be borne by the owner.

LAI utilized a different discount rate to calculate the present value of rate and economic impacts. Evaluating these impacts from the County's point of view, we estimate that the County's financing cost is approximately 4.0% based on the cost of issuing tax-exempt debt.

Tax-Exempt Financing

If IP were acquired through condemnation or if Entergy agreed to a voluntary shutdown, we believe that compensation could be funded by issuing tax-exempt general obligation (GO) bonds. If the County were the acquiring entity, it would have to acquire an ownership interest, or else develop a business structure with the assistance of legal counsel that satisfies the State's municipal finance regulations without being exposing to nuclear plant ownership-type risks. However, acquisition by the County would be problematic as a large GO issuance would stretch the County's debt capacity and probably lower the County's AAA credit rating. A lower rating would increase the cost of debt to compensate Entergy as well as the cost of any future County debt issuances. For these reasons, it might be better to have the State or NYPA, which has the experience to manage the IP asset, issue the bonds. It may be possible for Entergy to remain responsible for decommissioning and SNF management through an easement or sale and lease-back transaction, provided the NRC accepted this arrangement.

We do not believe COWPUSA or the Westchester County Industrial Development Agency (WIDA) could have a role in funding Entergy's compensation. COWPUSA does not have statutory authority to either issue bonds or to own power generating facilities. WIDA issues Revenue bonds that must be supported by a pledge of revenues from the ultimate borrower. However, WIDA or another issuing authority might be able to facilitate on-site replacement generation by issuing tax-exempt debt if Congress supported changes to federal tax law.

Decommissioning and Spent Fuel Management

Decommissioning, *i.e.* the removal of all radioactive materials that are controlled under the NRC licenses, does not include SNF and non-radioactive material. The removal and long-term storage of SNF is the responsibility of the DOE. It is expected that SNF will be stored on-site and eventually shipped to Yucca Mountain starting no earlier than 2010, although that date is uncertain. Non-radioactive material, such as cooling towers, water inlet structures, and

buildings, would be removed by Entergy or successor site owners using conventional methods. The IP site will be decommissioned by placing highly radioactive materials, including the reactor vessel and other structural materials, in special containers that will likely have to be stored on site for the foreseeable future. Currently, no licensed disposal site exists for IP's highly radioactive materials, although Yucca Mountain may be able to accept such waste if its license is amended.

After removal from the reactor vessels, SNF is stored in on-site storage pools for five years to allow the fuel to cool down. Since Yucca Mountain will not open until at least 2010 and IP is running out of storage pool space, Entergy has received approval for, and is constructing an Independent Spent Fuel Storage Installation (ISFSI) on-site. SNF that has cooled sufficiently will be removed from the storage pools, placed in dry storage casks, and stored at the ISFSI until they can be shipped to Yucca Mountain. Upon retirement, we estimate that it will take ten years to remove all of the SNF from the IP site.

There are separate decommissioning funds for each of the three IP units. The IP1&2 funds and liabilities were transferred to Entergy. NYPA retained the fund and liability for IP3 but has the right to require Entergy to assume the liability provided that it is assigned the decommissioning fund. A report by the U.S. Government Accountability Office (GAO) indicates that IP1 was under-funded, and funding for IP2&3 was adequate. However, it is reasonable to assume that Entergy will be able to conduct an integrated decommissioning effort for all three units that will reduce costs, in which case we believe that the combined decommissioning funds will be sufficient.

Economic Impacts

Retiring IP, without simultaneous development of on-site replacement generation, would result in the loss of PILOT, jobs, and local spending, higher emissions of certain air pollutants, and higher electricity bills. On the other hand, the County's emergency planning costs would decline and the health of the Hudson River fisheries would improve. These impacts will result whenever IP is retired, but could be avoided or mitigated if replacement generation is developed at the site. Consistent with standard socio-economic analysis, we used economic multipliers to estimate the secondary, or indirect, economic impacts in Westchester and throughout the State.

- Entergy executed agreements that established a PILOT schedule of $18.8 million in 2005, escalating to $26.8 million by 2014. The Hendrick Hudson School District receives over 80% of these payments and would be most affected by the loss of PILOT, which accounts for one-third of its revenues. Remaining PILOT is shared among the town of Cortlandt, the Verplanck Fire District, and the County. A PILOT schedule for on-site replacement generation would have to be negotiated among Entergy and these parties. We believe that the ISFSI currently being installed on-site will not alter the existing PILOT schedule.

- If IP is retired PILOT would cease unless replacement generation is developed on-site. IP2&3 would be subject to much lower property taxes at then-current rates. While

IP's retirement may increase property values for nearby homeowners, property tax rates may be higher to make up for lost PILOT.

- Entergy has announced plans to reduce IP personnel in the next two years, at which point the direct and indirect contribution to Westchester is expected to be $26 million/year. Whenever IP is retired overall staffing levels will be reduced gradually because decommissioning personnel will be required for approximately ten years. Once that work is completed and the SNF is removed for disposal, the site can be re-used. Development of on-site replacement generation could provide another source of employment. The number of jobs would actually increase while decommissioning, SNF storage, and construction activities for on-site replacement generation were taking place.

- IP spends approximately $12 million/year on goods and services in Westchester, and $55 million on a state-wide basis. These payments will also gradually disappear as decommissioning and SNF work are completed, but development of on-site replacement generation could avoid or mitigate these impacts.

- We estimate, on an indicative basis, New York power plant emissions of nitrogen oxides (NO_x) will increase by 4.0% and sulfur dioxide (SO_2) by 2.6% if IP is retired, as other plants, new and existing, will have to operate additional hours every year. According to statistics from the U.S. Environmental Protection Agency (EPA), power plants are responsible for approximately one-eighth of New York NO_x emission and one-half of SO_2 emissions. Therefore the overall state-wide increase from retiring IP would be about 0.5% and 1.4%, respectively.

- Monetary contributions and IP employee volunteer efforts to the local community, which totaled $0.3 million in 2002 and $1.2 million in 2003, may continue at a lower level once IP retires, until decommissioning was completed and SNF was removed from the site. We estimated 2005 contributions of $0.8 million, escalating with inflation as long the plant continues to operate. However, if Entergy were to develop replacement generation on the IP site it may be expected to continue monetary and volunteer contributions to the local community.

- The County would have to continue providing emergency services as long as SNF remains on site. These services cost Westchester $4.2 million in 2002, net of contributions from the State, and could be substantially reduced after IP is retired.

- We estimate the value of fish mortality due to using Hudson River water for cooling to be $309 million based on mortality statistics developed by the DEC and standard industry fish values. Retiring IP would eliminate this impact significantly except for a small amount of cooling water that may be required for the SNF storage pools. Since residents throughout the State would benefit from improving the health of fish stocks in the Hudson River, we recommend that the State play a role in fostering a consensual agreement and in compensating Entergy.

Electric Rate Impacts

- There are three types of wholesale electricity products: energy that is metered and paid for based on usage, capacity to ensure sufficient energy supplies and paid for regardless of usage, and ancillary services products required to maintain a stable and efficient bulk power system. All customer bills include charges for these wholesale products as well as for local delivery. Energy is the largest component and comprises roughly one-third of a residential bill for a customer consuming 500 kilowatt-hours per month (kWh/month). Utilities purchase energy and capacity for their customers in two ways: from the market at prices that reflect daily and hourly conditions, and through long-term PPAs with generators. PPAs provide retail customers with some insulation from short-term changes in market prices.

- IP has a low operating cost and is normally dispatched whenever it is available. If IP retired prior to 2013/15, market energy prices in Westchester and the Hudson River Valley would increase by an average of 8.4%, even with the timely addition of replacement generation. Market energy prices in New York City would likely increase by an average of 3.8%, and slightly less on Long Island. Elsewhere in New York, we expect less than a 1% impact. If IP voluntarily retired in 2013/15, there would not be any market price impact compared to the base case assumption of retirement at the end of the existing license terms. Our expectation of sufficient and timely replacement generation would leave market capacity prices unchanged.

- If IP retired in 2008, typical residential bills in Westchester would increase by an average of about $1.55/month though 2015 and about one-half of that amount in New York City. In the unrealistic scenario in which IP was retired immediately without replacement generation, market energy and capacity prices would soar and service reliability would be impaired until short-term generation measures were implemented.

Action Plan

The County's goals of retiring IP, minimizing economic and rate impacts on County and State residents, and maintaining system reliability are not inherently incompatible. While an immediate shutdown would have serious consequences, the County could pursue its goals through an orderly retirement strategy. We recommend that the County spearhead an agreement with New York State, Entergy, NYPA, and other stakeholders that focuses on two key initiatives – voluntary retirement in 2013/15 at the end of the current NRC license terms and encouraging on-site gas-fired replacement generation. This would allow Entergy to continue earning profits for the term of the current NRC licenses as originally envisioned, avoid the high cost of license extension, and pursue an on-site investment opportunity that takes advantage of existing infrastructure. Local communities and school districts could preserve some level of PILOT, employment, and local spending on goods and services. Lastly, an agreement reached by year-end 2010 would allow sufficient time for Entergy and other developers to install sufficient replacement generation.

1. PLANT BACKGROUND AND PERFORMANCE

1.1. PLANT HISTORY

Con Edison was the owner and developer of the IP site that covers 239 acres in the Village of Buchanan. IP1 entered commercial operation in 1962 but was shut down in 1974 due to concerns over the emergency core cooling system. IP2 entered commercial operation in August 1974 and IP3 became commercial in August 1976. The combined nominal generation capacity of IP2&3 is about 2,000 MW. Together they represent 5.3% of the New York's in-state generation capacity, and generate 10.1% of the State's electrical energy requirements.[1]

In 1976 Con Edison sold IP3 to NYPA. In November 2000 NYPA sold IP3 to Entergy.[2, 3] At the time of the sale NYPA executed a PPA to purchase the entire IP3 output (*i.e.* capacity, energy, and ancillary services) through 2004. In addition, NYPA and Entergy executed a Facilities Agreement for NYPA to share in any savings should Entergy purchase additional nuclear units in New York (including IP2), and a Value Sharing Agreement for NYPA to share in the revenues from IP3 in the event that the average market price level exceeds certain predefined levels. NYPA and Entergy agreed to negotiate in good faith for NYPA to purchase the total output beyond the term of the original PPA. The parties did not extend the PPA, but NYPA agreed to purchase 500 MW of energy and capacity from IP from 2005 to 2008 as a result of a competitive Request for Proposal (RFP).[4]

In September 2001 Con Edison sold IP1&2 to Entergy. At the time of the sale, Con Edison agreed to purchase the capacity of IP2, less up to 20 MW, through 2004 under a Capacity Purchase Agreement, with an option to continue purchasing capacity thereafter. Con Edison also agreed to purchase the energy of IP2, less auxiliary power and 45 MW of station use, through 2004 under a separate PPA. Con Edison has arranged to purchase decreasing amounts of energy and capacity from 2005 to 2009.[5]

Entergy operates IP under Operating Licenses granted by the NRC. The NRC license for IP2 is due to expire on September 28, 2013 and the license for IP3 is due to expire on December 12, 2015. Entergy could apply for up to twenty year license extensions for each unit, as described later on in this report.

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[1] Based on 2003 data. IP2&3 provide a higher percentage of the State's energy requirements compared to their capacity contribution because the units are base loaded and operate at high capacity factors.

[2] The sale of IP3 was part of a larger transaction in which Entergy also acquired the James A. FitzPatrick nuclear power plant in Oswego, New York.

[3] Entergy owns the IP assets through limited liability corporations (LLC) – Entergy Nuclear Indian Point 2, LLC, and Entergy Nuclear Indian Point 3, LLC. Each LLC is a wholly-owned subsidiary of Entergy Nuclear Holding Company #1, which is itself a wholly-owned subsidiary of Entergy. LAI has not distinguished among these entities for the purpose of this study.

[4] NYPA 2004 Annual Report, page 26.

[5] Capacity purchase data from Con Edison 2004 Form 10-K filing, page 147. Energy purchase data from Entergy 2004 Annual Report, page 39.

1.2. ENTERGY BUSINESS SEGMENTS

Entergy is an integrated energy company engaged in electric power production, retail electric distribution, energy marketing and trading, and gas transportation. Entergy is a large corporation, with annual revenues of $9.2 billion in 2003 and earnings of just under $1.0 billion. The company is organized into three primary business segments:

- Entergy's utility business segment includes electric utilities in Arkansas, Louisiana, Mississippi, and Texas, as well as a small amount of natural gas distribution activities. These electric utilities own and operate five rate-based nuclear plants – Arkansas Nuclear One (units 1&2), Grand Gulf, River Bend, and Waterford 3.

- Entergy owns and operates five non-utility (*i.e.* merchant) nuclear power plants in New York and New England, including IP2&3, FitzPatrick, Pilgrim, and Vermont Yankee. Entergy provides services to those and other nuclear plant owners. Entergy's utility-owned and non-utility nuclear assets make it the second-largest nuclear generator in the U.S.

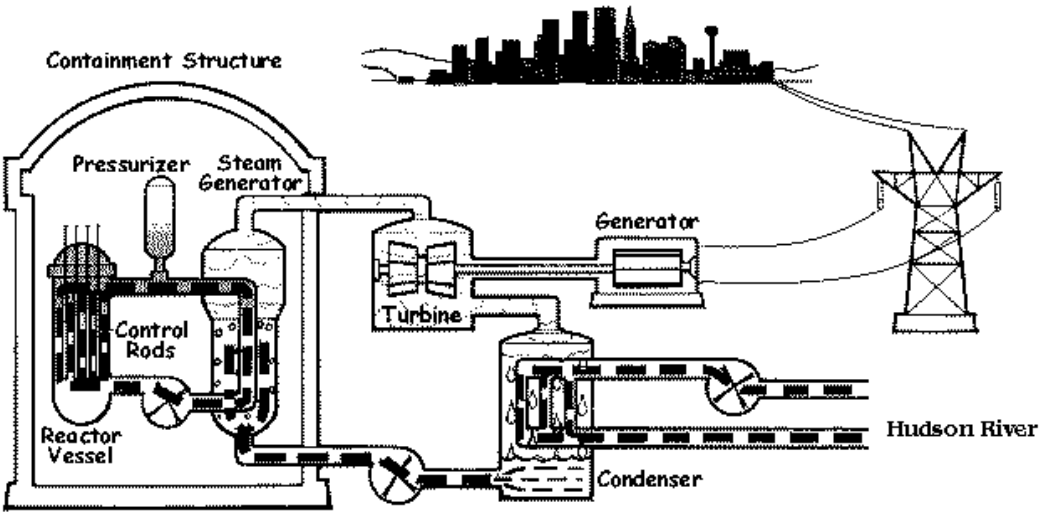
- Entergy's Energy Commodity Services used to provide trading services and gas transportation / storage services through Entergy-Koch, LP, but that business was being divested as of September 2004. Entergy's Energy Commodity Services used to own and operate non-utility wholesale power assets, but most of those assets have been divested as well.

1.3. PRESSURIZED WATER REACTORS

Of the several types of nuclear power reactors in the world, only Pressurized Water Reactors (PWRs) and Boiling Water Reactors (BWRs) are in commercial operation in the U.S. There are currently 104 nuclear power plants licensed to operate in the U.S., of which 69 are PWRs and 35 are BWRs. The 104 nuclear power plants together generate about 20% of U.S. electrical requirements. In BWRs, water is heated by nuclear fuel and boils to steam in the reactor vessel. The steam is then piped directly to the turbine, driving the electric generator and producing electricity.

The IP units are PWRs with primary and secondary water loops. Each unit has a containment structure that houses the primary loop components, including the reactor vessel, pressurizers, and a steam generator. The reactor vessel uses nuclear fuel rods that contain uranium to heat the primary loop water to about 620°F. The amount of heat is modulated by control rods that can absorb nuclear radiation within the reactor vessel. The water in the primary loop is maintained in a liquid state by keeping it under tremendous pressure, about 2235 psig, using pressurizers.

Figure 1 – Diagram of Pressurized Water Reactor



The heat from the primary loop (shown in yellow / red) is transferred to the secondary loop (shown in blue) within the steam generator. Primary loop water from the reactor vessel and the secondary loop water in the steam generator that is turned into steam never mix to keep most of the radioactivity within the containment structure. The secondary loop water is vaporized and used to drive a steam turbine that is connected to an electrical generator, producing electricity. The steam loses pressure and temperature in this process, and is then directed to a condenser that cools the steam, effectively drawing it through the turbine and improving the system's efficiency. The condensed secondary loop water is then pumped back into the steam generator.

Both U.S. nuclear reactor types use essentially the same fuel, a solid material containing two isotopes of uranium atoms. One isotope, U-235, makes up less than 1% of natural uranium but fissions readily. The other isotope, U-238, makes up most of natural uranium but is practically non-fissionable. Enrichment increases the concentration of U-235 in the uranium to 3%-5%, enabling the reactor to be smaller than if it were fueled with natural uranium.

Nuclear fuel typically is replaced after 3-6 years in the reactor. Most of the U-235 is fissioned by then, and trapped fission fragments begin to reduce the efficiency of the chain reaction. In most plants, one-third of the fuel rods are replaced every 12-18 months, although longer periods, up to 24 months, are becoming more common.[6] SNF must be stored on-site until the radioactivity decreases to manageable levels. A more detailed discussion of the IP plant and SNF issues is provided in a later section of this report.

[6] One-third of the fuel in each IP unit is replaced every 24 months.

1.4. Plant Performance

Power plant performance is best expressed in terms of capacity, how much electrical energy can be delivered into the transmission grid, and capacity factor, the amount of power generated in a year expressed as a percentage of the amount that could be generated if the plant were to operate at 100% capacity in every hour of the year.[7] This section also addresses the expected operating lives of the units.

Recent and near-term expected operating improvements and system analyses have allowed Entergy to increase the capacity ratings of IP2&3. However, we expect their capacities will be lower after 2013/15 if the plant is converted from once-through cooling using water from the Hudson River to a closed system using cooling towers. While IP2&3's capacity factors have improved to a combined average of 94.3% since Entergy acquired the plants, we believe that an 85% capacity factor is a more reasonable long-term assumption based on a variety of factors, including Entergy's own expectations at the time the NRC licenses were transferred.

1.5. Capacity Rating

NYISO establishes summer and winter capacity ratings for each plant in the State.[8] NYISO capacity ratings depend on tests that demonstrate the actual amount of power that can be delivered to the transmission grid.[9] As of January 1, 2004, IP2&3 had summer and winter ratings as noted in Table 1 below.

Table 1 – 2004 Net Capacity Ratings[10]

Season	IP2	IP3
Summer	987.6 MW	993.1 MW
Winter	985.5 MW	1,001.4 MW

The NYISO ratings are based upon actual plant tests and are good indicators of the amount of power that IP2&3 can deliver for sale. LAI used the NYISO ratings, adjusted for NRC-approved "uprates" (*i.e.* increases in capacity ratings), for system modeling and financial analysis purposes. The NRC regulates the maximum thermal power level at which a nuclear power plant may operate, which in turn determines the unit's electric capacity. The NRC has granted the following increases in IP2&3 thermal capacity ratings in the past two years:

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[7] Power plant efficiency is expressed in terms of heat rate.

[8] NYISO is a not-for-profit organization formed in 1998 as part of the restructuring of New York State's electric power industry. NYISO is responsible for the reliable, safe and efficient operation of the State's major transmission system and administers an open, competitive, and nondiscriminatory wholesale electricity market in the State.

[9] Power plants have gross generation ratings equal to the total amount of electric power generated before accounting for station loads, *e.g.* pumps, lighting, instrumentation. The net rating is the amount of power that can be delivered into the transmission grid after providing those station loads.

[10] Source: NYISO.

- The NRC approved a 1.4% increase in IP3's rating in November, 2002, due to improved feedwater flow measurement that reduces uncertainty. We believe that the NYISO values incorporate this increase.

- The NRC approved a 3.26% increase in IP2's rating in October, 2004, due to minor component upgrades, *e.g.* valves, pumps. LAI believes that the resulting NYISO rating will increase by a similar percentage, equivalent to 32.2 MW.

- In June 2004 Entergy submitted an application to further increase the thermal capacity rating of IP3 by 4.85% that the NRC approved on March 24, 2005. We believe that the NYISO rating of IP3 will increase by approximately 48.2 MW.

The last two uprates have been incorporated into the IP capacities for 2005-2013/15 as shown in Table 2 below.

Table 2 – Changes in Net Capacity Ratings
(summer ratings)

	IP2	IP3
Current Rating	987.6 MW	993.1 MW
NRC Uprates	+ 32.2 MW	+ 48.2 MW
2005-2013/15	1,019.8 MW	1,041.3 MW
Decrease due to cooling towers	- 4%	- 4%
After 2013/2015	979.0 MW	999.6 MW

While these recent and near-term expected improvements have allowed Entergy to increase the capacities of IP2&3, conversion to cooling towers after 2013/15 would lower their net output. First, the units will face increased station loads due to pumping required for cooling towers, particularly if the towers are sited on the bluff approximately 100 feet above the level of the river. Second, the cooling towers will not be as effective in lowering the cooling water temperature, particularly during the hot summer months, thereby lowering the efficiency of the units. As further explained in Attachment 1, we estimate that cooling towers will decrease the capacity ratings of IP2&3 by 3%-5% per unit. We have assumed a mid-point value of 4%, as shown in Table 2.

1.6. Capacity Factor

Power plants can rarely operate at 100% capacity factors because of scheduled outage activities (*e.g.* regular maintenance, refueling), unplanned outages (also referred to as forced outages), and increased surveillance requirements often required for older plants. These activities can require a plant to be operated at part-load or to be temporarily shut down. In order to estimate the near-term and long-term capacity factors for IP, LAI examined a number of data sources, including Entergy's expected capacity factor estimate, historical IP capacity factors, capacity factor data for Entergy's other nuclear plants, the problem of unanticipated extended outages as addressed in a speech by NRC Chairman Nils J. Diaz (excerpts of which

are provided on page 9), and other factors. LAI believes that an 85% capacity factor for both IP units is reasonable for simulation modeling and financial analysis purposes over the long term. This capacity factor assumption excludes the period IP2&3 would be shut down, estimated at nine months per unit, if the once-through cooling systems are replaced by hybrid cooling towers in the license extension scenario.[11]

Entergy's Expected Capacity Factor – In its application to the NRC to acquire the IP2 license, Entergy estimated that it will "operate IP2 at an average capacity factor of 85%." In response to a request for additional information, Entergy justified the 85% value based on its success at other plants, the capital improvements made by Con Edison just prior to the sale, improving fleet performance, and Entergy's experience with IP3.[12]

Indian Point Capacity Factor – Prior to Entergy's purchase, IP2&3 had significant operational problems in the 1990s that resulted in poor availability and low capacity factors. Through 2004, the lifetime capacity factors for IP2&3 are 64.7% and 60.5% respectively, reflecting many years of poor performance prior to Entergy ownership.[13] Plant capacity factors since Entergy acquired the plants have improved and are listed in Table 3 below.

Table 3 – Reported Capacity Factors[14]

Year	IP2	IP3	Indus. Avg.
2001	n/a	93.9%	89.4%
2002	90.7%	98.3%	90.3%
2003	90.9%	97.6%	87.9%
2004	89.5%	101.7%	90.5%
Averages	90.4%	97.9%	89.5%

The capacity factors for IP2&3 were high compared to the industry averages listed above, but we do not expect IP's capacity factors to continue at these levels for three key reasons:

- IP2 was sold to Entergy in a better-than-average condition. Con Edison spent over $150 million to replace the four steam generators in IP2 just before sale to Entergy as well as other major enhancements to plant equipment (*e.g.* new plant simulator, new condenser tubes and tube sheets, new main feedwater heaters, a new optimized high-pressure turbine rotor). These enhancements have allowed IP2 to achieve high capacity factors for the first few years of Entergy operation, but we expect the plant to return to a more typical level of performance as equipment and systems age, and as maintenance and CapEx requirements increase.

[11] LAI accounted for the nine month shutdowns in our financial projections.

[12] Response to the NRC's *Request for Additional Information Regarding License Transfer Application*, April 16, 2001.

[13] NEI Report *U.S. Nuclear Power Plant Capacity Factors (MDC Net).*

[14] Source: NEI.

- The plant and industry capacity factor data reported by NEI and incorporated in Table 3 appear skewed on the high side. For example, the 2004 NEI capacity factor data for that year have twenty plants with capacity factors above 100%, leading us to suspect that the NEI data underestimates the actual plant capacities.[15] In particular, the NEI capacities for IP2&3 are listed as 956 MW and 979 MW, respectively, which are about 6% less than the estimated 2005-2013/15 capacities provided earlier in Table 1. Using lower capacities for calculating capacity factors makes plant capacity factors appear higher than if more accurate capacity values were used. If we recalculate IP2&3's 2004 capacity factors using the estimated capacities of 1,019.8 MW and 1,041.3 MW, the capacity factors would be reduced by 5.6% and 6.1%, respectively.

- Industry capacity factor data according to NEI has increased significantly in the past few years and may not be sustainable. For example, while the average capacity factor for 2002-04 was 89.6% as listed in Table 4, the average for the proceeding three year period, 1999-2001, was 87.6%, a value in line with our long-run expectation for IP.[16]

Table 4 – Historical Nuclear Industry Capacity Factors[17]

Years	Cap Factors.
Avg. 2002-04	89.6%
Avg. 1999-2001	87.6%
Avg. 1996-98	75.2%

- The NEI data does not include units on extended outages that are repairing or replacing major pieces of equipment. For example, the NEI data excludes Brown's Ferry Unit 1, which was shut down in 1985 but is scheduled to return to service in 2007.

Capacity Factors at Other Entergy Plants – Entergy owns and operates five utility rate-based nuclear plants: Arkansas Nuclear Units 1 & 2 (AN01 and AN02), Grand Gulf Nuclear Station (GGNS), River Bend (RB), and Waterford 3 (W3). The chart in Table 5 below, taken from the NRC's letter of August 27, 2001 approving the transfer of the IP2 license, provides historical capacity factor data for these five plants. These plants had an average capacity factor of 85.7% over the period that Entergy had operating responsibility.

[15] One plant, Arkansas Nuclear One unit 2, has a reported capacity factor of 114.5%.

[16] The average industry capacity factor for 2004 was 90.5% according to NEI data.

[17] Source: NEI.

Table 5 – Historical Capacity Factors (%) for Entergy Utility Nuclear Plants[18]

	ANO1	ANO2	GGNS	RB	W3
1985	70.90	63.50	54.20		68.80
1986	48.80	70.60	42.20		77.50
1987	65.00	87.90	77.90		78.90
1988	53.80	65.60	95.60	88.20	69.20
1989	46.10	72.80	78.40	58.40	80.80
1990	56.30	94.90	74.00	68.20	91.40
1991	89.31	81.47	91.15	81.56	77.25
1992	79.43	73.04	81.39	33.60	80.72
1993	83.66	97.72	78.88	64.13	97.05
1994	98.30	89.47	96.03	59.59	84.23
1995	81.63	75.76	77.32	96.72	82.44
1996	85.61	93.73	89.38	83.44	94.54
1997	99.01	92.56	102.91	83.21	71.37
1998	84.89	91.50	87.43	95.54	91.54
1999	91.69	82.85	79.91	69.58	79.02
2000	87.29	69.86	100.79	89.43	89.78
Ave. Before EOI	56.82	75.88	70.38	65.68	77.77
Ave. After EOI	88.08	84.80	88.52	82.50	84.79

NOTE: Data listed above the double line are for years prior to the facilities being operated by EOI. Although EOI became the operator for ANO 1 & 2, GGNS, and W3 in 1990, the NRC staff considers the performance of these plants for that year to be predominantly influenced by the management practices of the previous owners.

Unanticipated Extended Outages – IP2&3 are currently on 24-month fuel cycles in which approximately one-third of the fuel in each unit is replaced. Refueling takes about 40 days. For the remaining IP2&3 license term (*i.e.* without license extension), we anticipate that there may be one or more extended outages per unit depending on work that emerges as a result of equipment inspections or due to scheduled equipment replacement. In addition to refueling outages, other unanticipated outages will inevitably occur as a result of equipment malfunction, condenser performance, or other events.

The subject of unanticipated extended outages was addressed in the following quote from a speech NRC Chairman Diaz gave to the Institute of Nuclear Power Operations 25th Annual CEO Conference, which was held on November 3-4, 2004.[19]

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[18] EOI refers to Entergy Operations Inc.

[19] NRC Speech No. S-04-018, U.S. NRC Chairman Nils J. Diaz at the Institute of Nuclear Power Operations 25th Annual CEO Conference, November 3-4, 2004

"At this point, I will take a few minutes to discuss with you one perspective on the existing data on nuclear power plant events, shutdowns and extended shutdowns by reviewing the distribution of extended shutdowns during the last 25 years, beginning after Three Mile Island (TMI) and therefore not including the shutdown of TMI-2….You may be a bit surprised by the fact that there have been at least 140 unplanned shutdowns lasting six months or longer since 1979. Excluded are some plants that permanently shutdown for economic or political reasons, in our judgment. Also excluded are routine shutdowns for planned maintenance or modifications, regardless of the length of the shutdown…

"…There were approximately 418 unplanned shutdown months (or 35 reactor shutdown years) from 1996 through 2004. It is not until 1999, or even 2001, that a very significant reduction was maintained.

"A brief analysis of the 52 unplanned shutdowns since 1979 lasting longer than a year reveals a set of reappearing causes. One could group the causal factors as shown in Table 1:

Apparent Cause	No. of Shutdowns Longer than One Year	Shutdowns Avg. length (months)
Design basis or licensing basis	18	38
Material degradation	15	16.5
Management issues	12	25
Equipment failures	7	19

"I would like to point out that, based on the numbers in Table 1, issues relating to 'design basis or licensing basis' contributed to about 50 percent of the total industry-wide shutdown time (for shutdowns since 1979 lasting longer than a year). If you add "management issues" to these, the combination contributed almost three quarters of the total industry-wide shutdown time."

Age-Related Degradation of Components – The IP units are relatively old and will require increasing levels of surveillance and maintenance in the future as structures and equipment age and become degraded. Age-related degradation is a generic term applicable to virtually all structures and components. Aging degradation concerns considered to be significant for PWR reinforced concrete containment structures include:

- Loss of strength and modulus due to elevated temperatures.
- Scaling, cracking, and spalling due to freeze-thaw cycles.
- Increase of porosity and permeability, cracking, and spalling due to leaching of calcium hydroxide, attack by aggressive chemicals, and reaction with aggregates.

- Age-related degradation is also applicable to all components. For example, the age-related degradation concerns and mechanisms for IP2&3 primary coolant loop piping, valves, and fittings are as follows:
    - Primary water-induced stress corrosion cracking of high temperature / high pressure systems and equipment.
    - Increase in ductile-to-brittle transition temperature of the primary coolant loop piping due to thermal embrittlement.
    - Leakage of safety and relief valve flanges and bolts due to boric acid corrosion and normal wear.
    - Leakage and crack initiation / growth in nuts and bolts due to stress relaxation corrosion cracking.
    - Loss of strength in integral supports due to fatigue over time.

While age-related degradation is a concern at IP, the in-service inspection and monitoring programs are designed to address issues as they arise. Any items would be repaired and/or replaced during maintenance outages as described above. Given the current state of IP2&3, there is a low probability of any major age-related degradation problems through the end of the current NRC license terms. However, if IP continues to operate under an extended NRC license, the probability of such problems, which typically can only be mitigated at substantial expense, will increase.

1.7. Operating Life

In LAI's opinion, it is likely that the plant will continue to operate through the term of the current IP licenses, unless (i) the County is successful in acquiring IP, (ii) Entergy voluntarily agrees to retire IP, or (iii) a catastrophic event were to occur. As discussed in the Plant Valuation section of this report, there are economic advantages for Entergy to apply to the NRC for license extensions of lengths of up to twenty years despite IP's unique challenges regarding Entergy's ability to verify IP's design basis against current standards and to satisfy emergency planning / evacuation regulations. Therefore two sets of financial valuations, provided in Section 4, were conducted – one assuming IP is retired at the end of the current license terms and one assuming the IP licenses were extended for an additional twenty years.

2. LEGAL AND REGULATORY ISSUES

2.1. INTRODUCTION

In its original RFP regarding IP, the County requested a comprehensive review of the strategies to acquire IP through condemnation actions. LAI also considered an alternative strategy of negotiating a consensual retirement with Entergy. We have identified a number of advantages and concerns associated with each option to retire IP as discussed below.[20]

The acquisition and voluntary retirement options would both be expensive because the County would have to pay compensation to Entergy in either case. However, a voluntary retirement has a number of advantages, principally avoiding the significant responsibilities, costs, and risks associated with nuclear plant ownership, even one that is no longer actively generating electricity. Voluntary retirement also would provide Westchester with significant flexibility in structuring a compensation package and provide the opportunity to coordinate the closure of IP with the development of replacement generation on the site, which would help mitigate any adverse economic consequences. Proceeding with a voluntary retirement would also permit the State and other stakeholders to participate in the negotiations and share in payment of compensation to Entergy. Moreover, we are not aware of any nuclear power plant that has ever been acquired or retired through condemnation proceedings.

This section provides an overview of state and county eminent domain laws, NRC regulations, and other legal and regulatory issues that would govern the acquisition or voluntary negotiated retirement option. We describe the possible roles of the County and COWPUSA, including opportunities to oppose license extension.

2.2. EMINENT DOMAIN LAWS

Acquisition of IP through condemnation proceedings would be governed by New York State's Eminent Domain Procedure Law (EDPL), enacted in 1977 and made effective July 1, 1978. EDPL provides "the exclusive procedure by which property shall be acquired by exercise of eminent domain." The previous Condemnation Law had been used only where a condemning authority did not have its own eminent domain statutes, which made for confusing and inconsistent results. The EDPL provides a more uniform basis for obtaining more consistent eminent domain results throughout the state.[21] The County is authorized to exercise the power of eminent domain under §74 of the General Municipal Law, which allows

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[20] We do not know if a state or federal action could require Entergy to retire IP, but this would be an unprecedented event. A consideration of such an action was outside our scope of work. In such an event, the action could trigger liability to pay compensation to Entergy.

[21] The Green Island Power Authority tried to acquire by eminent domain a 6 MW hydroelectric project in the late 1990s from Niagara Mohawk Power Corporation, but was unsuccessful. We are not aware of any successful power plant acquisition by eminent domain in New York.

municipal corporations (such as the County) to take and hold real property, and to acquire title of such property by condemnation if it is unable to agree with the owners for the purchase.[22]

In addition, the County is authorized to acquire power generation property under §360 of the General Municipal Law that provides "Notwithstanding any general or special law, any municipal corporation may construct, lease, purchase, own, acquire, use and/or operate any public service within or without its territorial limits, for the purpose of furnishing to itself or for compensation to its inhabitants, any public service similar to that furnished by any public utility company specified in article four of the public service law".

The prerequisites for the lawful use of eminent domain are as follows:

- Due Process of Law – The County must follow the expressed provisions of the EDPL to ensure due process.

- Notice and Hearing – EDPL lays out specific requirements for public notice and hearings that would permit Entergy to contest the condemnation.

- Public Use Required – The *sine qua non* of the sovereign power of eminent domain is that the property taken must serve a public purpose and use. EDPL provides for judicial review of a condemnor's determination of public use.

- Compensation – The requirements of due process are satisfied where there are provisions made for just and reasonable compensation for property taken by eminent domain, and payment is made without unreasonable delay.

- Waiver of Right of Due Process - Constitutional due process protections against a taking of property in eminent domain may be waived. Such waiver, however, must be voluntary and cannot be contrary to public policy or public morals. Waiver may be made orally, or by implication as where the owner accepts payment for the taking.

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[22] In addition to the power of eminent domain, the County also has what is referred to as "police power" that is used to regulate, or even take away, an owner's ability to use and enjoy his property in order to promote or conserve the public safety, health, and morality. The government exercises police power in a variety of ways, such as by adoption of legislation. Local government, towns and villages, may use this power by such means as zoning and subdivision controls. However, due to federal law, it is highly doubtful that the County could adopt regulations restricting the ability of Entergy to operate IP. *Skull Valley Band of Goshute Indians v.Nielson*, 376 F.3d 1223 (10th Cir. 2004) addresses the use of police power to adopt safety regulations concerning disposal of nuclear waste. Assuming that regulation were possible, the most fundamental difference between the exercise of eminent domain and police power is that an acquisition under the power of eminent domain gives rise to just and reasonable compensation to the owner, while losses arising from the exercise of police power have been traditionally viewed as non-compensable. However, both the United States Supreme Court and the New York courts have recognized that if a regulation calls upon a property owner to sacrifice all economically beneficial uses in the name of the common good that leaves the property economically idle, the owner has suffered a taking of property for which compensation must be paid. *See Palazzolo v. Rhode Island*, 533 U.S. 606 (2001); *Smith v. Town of Mendon*, 4 N.Y.3d 1, N.Y.S.2d (2004). If the County were to attempt to acquire IP or close it by police power, it would be anticipated that Entergy would strongly argue that such an attempt violates federal law and, even if permissible, would require the County to pay compensation to Entergy.

- Property That May Be Taken – Generally all private property, both real and personal, is subject to the sovereign power of eminent domain. A private corporation's property may be taken by eminent domain in the same manner as the property of a private individual.[23]

It should also be noted that the State of New York could act as the condemning authority as well as the County, so long as all the requirements noted above were met by the contemplated acquisition.

2.3. Eminent Domain Process

Public Hearing – The first step in the eminent domain process would be for the condemning authority to issue a notice that it is conducting a public hearing on an eminent domain matter. The notice must be given between 10 and 30 days prior to the hearing by publishing notice in at least five successive issues in a daily paper of general circulation in the area. In addition, the statute now requires that notice be served upon the record owner of the property as shown on the real estate tax billing records. At the hearing, the condemning authority must outline the public purpose, proposed location, or alternative locations of the public project. The public would be invited to participate in this hearing and a record must be kept of the proceedings.

Within ninety days of the hearing, the condemning authority shall make public its determination and findings concerning the project and publish a brief synopsis in at least two successive issues of an "official" newspaper. The synopsis must be served upon the record owner according to the tax billing records. The determination and findings shall specifically note (i) the public use, benefit, or purpose to be served by the proposed project, (ii) the approximate location of the project and reasons for the selection of the site, (iii) the general effect of the proposed project on the environment and residents of the locality, and (iv) other relevant factors.[24]

There is an exemption for this initial hearing requirement if the condemning authority must submit the information noted above to a local, state or federal subdivision in order to obtain a permit or license. While the County would indeed have to submit such information to state and federal agencies to take over IP's environmental permits and nuclear operating licenses,

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[23] A proceeding to take real property includes any rights, interests, or easements and appurtenances. Lands under water adjacent to upland property are deemed appurtenances to the upland property and part of the taking, and so would include any IP property or rights, etc., that extend into the Hudson River.

[24] The principle of Public Use is recognized by the EDPL which provides for judicial review of a condemnor's determination following a pre-acquisition hearing as to the public use, benefit, or purpose served by the proposed project. In determining whether the use is in fact public or private, a court may look beyond a legislative declaration as to the nature of the use. However, an express declaration in the statue authorizing the taking of property that the taking is for a public use is common and legislative findings in this respect are entitled to great weight if properly supported.

LAI suggests that it would be prudent to keep an initial public hearing under the condemnation option.[25]

Within 30 days of publishing the determination and findings by the condemning authority, any aggrieved party can seek review by the Appellate Division, *i.e.* the initial level of appeals court in New York State. The court's scope of review is limited to whether:

- The proceeding was in conformity with the federal and state constitutions.
- The proposed acquisition is within the condemning authority's statutory jurisdiction or authority.
- The condemning authority's determination and findings were made in accordance within the procedures of Article 2 of the law that deals with notifying the public of the determination of need and location of a public project as required, and Article 8 of the Environmental Conservation Law, the state's environmental quality act.
- A public use, benefit or purpose will be served by the proposed acquisition.

Note that this review does not consider value, but merely the steps taken to announce the project and determination of public good.

Appraisal and Offer – At this point in the condemnation process, the property to be acquired by the condemning authority would be appraised on behalf of the authority by a certified appraiser.[26] The condemning authority shall have the right to inspect the property prior to vesting of title in the authority. The condemning authority is under a statutory obligation to establish an amount it believes represents just compensation for the property. The condemning authority would then make a written offer to the property owner to acquire the property. Whenever possible, the condemning authority should make the offer prior to acquiring the property and should, whenever possible, include within the offer an itemization of the total direct, the total severance or consequential damages, and benefits as each may apply to the property.[27]

The property owner may either accept the offer as payment in full or reject the offer and instead elect to accept such offer as an advance payment, in which case such election would not prejudice the owner's right to claim additional compensation. Upon the acceptance of the written offer, the condemning authority would enter into an agreement or stipulation with the owner providing for payment pursuant to such arrangement either as payment in full or as an

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[25] The statute specifically exempts projects involved in proceeding under Articles 7 and 8 of the Public Service Law covering transmission projects and major electric generating facilities, respectively. Article 8 was replaced by Article 10 which expired at the end of 2002.

[26] A timeline is provided as Attachment 2.

[27] We note that the owner holding, using or occupying the property acquired by this process would be liable to the condemning authority for the fair and reasonable value of such holding, use or occupancy from the date of the acquisition to the date the property is vacated and possession is surrendered to the condemning authority.

advance payment. The offer would be deemed rejected in the event that the owner fails or refuses to notify the condemning authority in writing within 90 days that the offer is accepted.

Condemnation Proceedings – Under the EDPL the County may commence proceedings to acquire IP up to three years after the conclusion of the latter of:

- Publication of its determination and findings concerning the public need and location of the project (referred to as an acquisition map) pursuant to Article 2 of the EDPL;
- The date of the order or completion of the procedure that constitutes the basis for exemption from making such pre-acquisition determinations and findings; or
- Entry of the final order or judgment on judicial review.[28]

The condemning authority would begin the process of obtaining an order to acquire the property and for permission to file the acquisition map by presenting a verified petition to the State Supreme Court in the judicial district where the property to be acquired is situated, in this case Westchester County. The condemning authority would also file a notice of the proceeding with a description of the property and the names of the land-owners in the office of the County Clerk where the property is located.

At least 20 days prior to the return date of the petition, the condemning authority must serve a notice of time, date, and place of the proceeding upon the property owners as well as a proposed acquisition map. Between 10 and 30 days before the return date of the application, the condemning authority would advertise such action and map for ten successive issues in a general circulation newspaper in the area.

The condemning authority would then present the State Supreme Court with a petition stating that the appropriate procedure has been followed. The property owner may appear and interpose a "verified answer" which must contain a specific denial of each material allegation of the petition questioned by the owner in a manner constituting a defense to the proceeding.

Unless the court adjourns the application, the court would direct the immediate filing and entry of the order granting the condemning authority's petition and file it, along with the acquisition map, in the office of the county clerk in which the property is located. Upon the filing of the order and the acquisition map, the acquisition of the property would be considered complete and title to the property would be vested in the condemning authority.[29]

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[28] If the County were to fail to commence proceedings to acquire IP before the expiration of the three-year period, the condemnation effort would be deemed abandoned, and the County would have to complete the pre-acquisition hearing and publication requirements again prior to restarting the acquisition proceedings.

[29] Note that if, after acquisition, the condemning authority abandons the property and the property has not been materially improved, the condemning authority may not dispose of the property or any portion of it for private use within 10 years of the acquisition without first offering the former owner a right of first refusal to purchase the property at the amount of the fair market value at the time that the former owner is offered the property.

Compensation Appeal – Once the order and acquisition map are filed, the condemning authority would serve a notice of acquisition upon the owner within thirty days or publish such information for ten consecutive days in a paper of general distribution in the area. If the owner believes that the monetary offer for the property is insufficient, the owner must file a claim for damages within three years from the later of the date of notice of acquisition or date of vesting of title. The State Supreme Court in Westchester would have jurisdiction in the case of IP, and would have the authority to determine the compensation due Entergy. The Court would also have the jurisdiction to determine all questions relating to title and priority of interests relative to the acquisition. In the course of this proceeding, the Court may be faced with appraisals submitted by the owner as well as the one that the condemning authority is required to prepare and submit.

The Court, after hearing the testimony and viewing the appraisals, would determine the compensation due to the owner for damages as the result of the acquisition. The decision of the Court would result in the preparation and entry of an appropriate judgment. The owner would be entitled to lawful interest from the acquisition date to the actual payment date. The Court has the power to make a final and binding determination of value, and there would be no assurance that the County's estimated compensation would not be significantly exceeded. This is a major risk of the condemnation option.

If either party were to file an appeal, the condemning authority would pay such portion of the award to the Court from which appeal has not been taken. If an appeal is filed by any party, the condemning authority may deposit in a special interest-bearing account all or any part of the amount directed to be paid in the award other than any advance payment already made.

In the event that the condemning authority abandoned the procedure to acquire the property or a court of competent jurisdiction determined that the condemning authority was not legally authorized to acquire the property, the condemning authority would be obligated to reimburse the property owner an amount for actual and necessary costs, disbursements, and expenses including reasonable attorney, appraisal, and engineering fees, and other expenses actually incurred by the owner because of the condemnation procedure.

It should also be noted that Entergy could attempt to prevent or delay the condemnation through the commencement of litigation in federal or state court. Thus, it should not be assumed that the condemnation process would be as clear-cut as presented and it may be assumed that condemnation efforts would entail substantial litigation costs, involving attorneys' fees, experts' fees and other significant expenses.

2.4. Compensation under New York Law

The amount of compensation that the County would have to pay Entergy pursuant to the Supreme Court's final order is called an "award". New York courts have disapproved of the practice of making lump sum awards that do not identify the sources and estimates of value. Instead, the courts make separate findings as to the amount awarded for the direct taking and the amount awarded for consequential damages, if any, setting forth the basis for each amount. Any award paid to Entergy must be "just" in an exercise of eminent domain. Under state law, consideration must be given to market value, improvements, direct loss, and

consequential loss in determining the measure of damages. There are no fixed rules and there are no inflexible formulae to determine a specific dollar amount to be awarded in a condemnation proceeding. Only the goal is fixed – a just and reasonable award that is the fair equivalent of the loss actually incurred. Such amount is usually expressed as the amount a prudent buyer might be expected to pay a willing seller in the open market, usually referred to as fair market value (FMV).[30]

The taking of public utility property (such as a power generating facility) by eminent domain presents unique problems of valuation. There are few comparable sales to assist in determining FMV, and a limited market for such property (in the usual sense). The usual method of fixing the value of appropriated property by ascertaining its FMV, and the principal that compensation is measured by the loss to the owner, not the benefit or worth of a property to the taker, are not applicable to a taking of public utility property if they will result in a manifest injustice to the owner or to the public. Moreover, a taking of public utility property involves not only the physical assets but also the business, the two being practically inseparable. Lastly, the purpose of the taking must be considered, *i.e.* whether the condemnor is seeking removal of the property or the continued operation as a going concern. Thus, no rigid measure is prescribed for the determination of just compensation, and one must exercise judgment according to the circumstances of the particular case.

Valuation Methods – There are three standard valuation methods that are typically used to estimate the FMV of properties – the Income Approach, Comparable Sales Approach, and Reproduction or Replacement Cost Approach. For properties that have a going concern value such as IP, the Income Approach is most often utilized, and the other valuation methods are often used to support the Income Approach. LAI has considered values for IP using all three approaches, but has relied on the Income Approach to calculate the compensation amounts as described in the Plant Valuation of this report.

- The Income Approach relies on an estimate of the future net income or cash flow that can be reasonably realized from the property. The future cash flow is usually discounted to arrive at a present equivalent value of those future cash flows. Alternatively, the net income expected to be earned can be capitalized by a percentage figure representing the acceptable return that a willing buyer could anticipate on his investment. In either case the discount factor or the capitalization rate must reflect the benefits and risks of the subject property, market conditions, and other key determinants of value. LAI has prepared a discounted cash flow (DCF) estimate of IP's value based on reasonable and supportable estimates of revenues, expenses, and net income that would accrue to Entergy.

- The Comparable Sales Approach (also referred to as Market Data Evaluation) relies on an analysis of data from sales of comparable properties. Comparability does not

[30] FMV is based on the highest and best use to which the property could be put and not on any such limited use to which a particular owner might happen to be putting it to at the time of the its appropriation. Thus FMV could be predicated upon a higher and better use than that for which the property is currently being utilized, but this is not relevant to the IP property.

necessarily connote many sales, and it does not necessarily mean identical properties. In this case comparable properties are domestic nuclear plants that are exposed to market risks, *i.e.* merchant plants that are not utility rate base property. There have been seven financial transactions involving merchant nuclear plants that have market risk since the first IP unit was sold to Entergy.

- The Reproduction Cost Approach involves estimating the cost of reproducing the subject property as long as the property would be replaced in kind. A similar method, the Replacement Cost New Less Depreciation Approach relies on the current cost of a property of equivalent function built to current standards and under current conditions. Both the Reproduction and Replacement Cost Approaches include all reasonable and necessary expenditures in the recreation of the existing or an equivalent structure.

Past Appraisals – The New York Office of Real Property Services (ORPS) is a state entity whose purpose is: "To lead the State's efforts to support local governments in their pursuit of real property tax equity." ORPS is governed by a Board of five members appointed by the Governor, with the advice and consent of the Senate. The Board chairperson is designated by the Governor, and their eight-year terms are staggered so that no two members' terms expire in the same year. The Board oversees administration of real property assessments in New York State, including (i) estimating the full value of real property in towns and cities for equalization purposes, (ii) assisting local governments to improve the administration of their property assessment and tax systems so they are equitable for taxpayers, and, (iii) training and certifying assessors and county directors of real property tax services.

While an appraisal for tax purposes is not necessarily the same as an appraisal for eminent domain purposes, ORPS prepared a valuation of IP for the Town of Cortlandt's 2001 tax equalization rate. However, IP currently makes PILOT payments under agreements dated January 1, 2002 that were negotiated with Cortlandt, the Hendrick Hudson School District, and the County. While ORPS does not prepare valuations for any property covered under a PILOT agreement, informal discussions with ORPS indicated that the Income Approach, using a DCF calculation, would be the most appropriate method in valuing IP, and that the Cost Approach and the Comparable Sales Approach would be less useful. This is entirely consistent with LAI's approach in this report.

2.5. Westchester County Laws and Regulations

Chapter 233 of the Westchester County Charter, entitled Board of Acquisition and Contract, §233.21, describes the conditions and the process under which the County may acquire property by condemnation. It should be noted that this section was placed in the Charter in 1948 and hence prior to the passage of the EDPL:

> "The County Board may, or shall, when required by law, authorize the acquisition by the county of title to, or any interest in, real property for any purpose… Wherever and whenever in any general, special or local law it is provided that property may be acquired 'by condemnation' or 'by condemnation proceedings' or by similar methods, the county is hereby

> authorized and empowered to acquire title thereto under the provisions of this title."

§233.31(1) of the Charter continues as follows:

> "Whenever the County Board has authorized such acquisition and has made an appropriation therefore, the Board of Acquisition and Contract may acquire the property by purchase, condemnation or otherwise, and if the property is to be acquired by condemnation, the compensation to be made to the owner or owners thereof shall be ascertained pursuant to the provisions of this title."

Subsection 2 of §233.31 of the County Charter is aimed at the possibility that the County might acquire "utility property":

> "If the property or any interest therein to be acquired hereunder is owned or held and used for a public utility purpose by a public or private corporation, the county, at its own option, may (a) allow such corporation, in lieu of any and all damages, without expense, loss or damage, directly or indirectly to it, to continue the use of the same for such purpose, with, however, not rights in excess of those existing previous to such acquisition or inconsistent with the use for which the property or interest with the use for which the property or interest is be acquired, or (b) may allow such corporation, in lieu of any and all damages, the use of such other real estate owned by the county or to be acquired for the purposes of this title as will afford a practical route, location or use for such public utility purpose and is commensurate with and adapted to its needs, provided also that such corporation shall not directly or indirectly be subject to any expense, loss or damage by reason of such change in route or location, but such expense, loss or damage shall be borne in like manner as the expenses incurred for carrying out the provisions of this title, or (c) may direct that compensation or damages be ascertained and awarded to such corporation, in which case such corporation shall be governed by the provisions of section 233.81 of this article."

Thus it appears that section (b) above describes the ability of the County to provide alternative real estate for Entergy to use to construct another generation facility to replace IP, if required.

2.6. County of Westchester Public Utility Service Agency

Chapter 875 of the Westchester County Charter, *Public Utility Service Agency*, lays out COWPUSA's rights and responsibilities.[31] The legislation creating COWPUSA was drafted in 1982 and the legislation was passed in that year by a public referendum. The introductory language notes that the County had been concerned for some time with the high cost of electricity in the Con Edison service area and its effect on the economic growth and well being of the County. The charter provision states "The creation of a County Public Utility

[31] Provided as Attachment 3.

Service Agency will enable the county to contract for or otherwise purchase or acquire lower cost electric energy in the form of hydroelectric power and other economical forms of electricity from the State of New York or from any state agency, municipal, public or private corporation."

- §875.31(1) under Powers and Duties states "the agency, on behalf of the county, shall have the power to establish, construct, lease, purchase, own, acquire, and/or operate a public electric utility service within and/or without the territorial limits of the county for the purpose of furnishing to the county or for compensation to inhabitants of the Con Edison Service Areas of the county any electric service similar to that furnished by any public utility company…"

- Subsection (2)(f) states that the agency "Shall have the authority to enter into contracts, leases and other instruments and to acquire, hold and dispose of real or personal property necessary and convenient to the exercise of its powers."

- Subsection (3) states "Nothing herein should be construed as authorization for the county or the agency on behalf of the county to exercise any power of condemnation or to establish generation, distribution, and/or transmission facilities separate from the Con Edison generation, distribution, and/or transmission system in the Con Edison Service Area of the county."

COWPUSA does not have the power to own and operate generation facilities if the County wanted either to continue operating IP for some period of time or to play an active role in replacing the lost IP capacity. Thus COWPUSA could not be the municipal corporation that would condemn the IP property and take over ownership. However, COWPUSA could operate a "public utility service" in which it would buy power on a wholesale basis and sell power on a retail basis to residents in Westchester. In particular, COWPUSA could purchase power from a replacement power plant owned and operated by Entergy, thereby encouraging replacement generation at the IP site. The merit of COWPUSA purchasing power under a PPA would hinge of COWPUSA's ability to develop a significant customer base.

2.7. Tax-Exempt Financing

Tax-exempt financing is considered in this assignment for three distinct potential purposes: (i) providing a compensation payment to Entergy to retire IP under a voluntary agreement, (ii) compensating Entergy for the acquisition of the existing IP plant through eminent domain, and (iii) financing a replacement plant at the IP site. There are three possible issuers of such debt: the County, WIDA, and COWPUSA if the enabling legislation were broadened to allow the agency to allow it to own and operate a power plant and to issue tax-exempt bonds to purchase an existing asset or own an asset.[32]

[32] Any changes to the COWPUSA legislation would involve approvals by the County legislature and, possibly, by public referendum; COWPUSA's authority could potentially be expanded by state legislation.

Tax-exempt debt is a low-cost way to raise funds due to the bondholder's ability to avoid paying federal and state income taxes on the interest and principal income. The County has an AAA credit rating, the highest available and the same rating as the federal government, indicating that rating agencies believe the risk of County default is very low. Any bonds would be GO bonds that would obligate the County and its residents, through tax revenues, for repayment of principal and interest. Any County GO issuance over $10 million must be approved though a public referendum. As of September 2004, the County had total debt outstanding of $705.7 million and net indebtedness of $563.1 million, equivalent to 9.6% of the County's net debt limit of $5.79 billion.[33]

The County's AAA credit rating means the cost of raising debt funds would be low, especially compared to corporations.[34] However, a large issuance, *e.g.* on the order of $1 billion or more, would likely cause the County to receive a lower credit rating, raising the cost of debt for this and future issuances. Informal discussions indicate that the credit rating would slip in the event of an issuance of the size necessary to fund the compensation payment to Entergy for IP. If the County were to issue GO bonds, the standard practice is to issue series of bonds with varying maturities that result in level principal payments. Under recent market conditions, the average interest rate for a series of GO bonds that had a twenty year final maturity would be 3.8%-4.0%; a thirty year final maturity would be 4.2%-4.3%. These interest rates reflect the anticipated reduction in the County's credit rating to AA or A. The cost to each of Westchester's one million residents for a $1 billion tax-exempt GO bond issuance would be about $70 per year over twenty years, or $55 per year over thirty years if debt service payments were spread out over a longer period of time.[35]

Based on informal discussions with County's staff and others, a general description of each of the three issuers and the advantages / disadvantages are as follows:

- The County can issue GO bonds for public purposes subject to a County bonding limit and other restrictions. The County has sufficient debt capacity to pay Entergy, but credit rating would likely be impaired. In addition, it may be more difficult to issue GO bonds under the voluntary retirement arrangement. The County may be required to have an ownership-type interest to satisfy State regulations concerning municipal finance. This issue requires additional investigation, probably with the County's bond counsel, and any debt issuance to compensate Entergy without an ownership-type interest in IP may require State and County legislation.

- The WIDA is an intermediary for borrowers that use the funds for investments that benefit County residents. Any WIDA bonds would be Revenue Bonds in which revenues earned by the borrower would be pledged to the bondholders. Interest and principal payments could only be made from borrower revenues, and neither the County nor the WIDA would be responsible for any contributions. Revenue bonds

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[33] The County debt limit is 7% of the five year average full valuation of taxable real estate.

[34] By way of comparison, Entergy is rated BBB.

[35] Based on these estimated interest rates, LAI assumed a County discount rate of 4.0% for this assignment.

may be tax-exempt provided the underlying investment satisfies IRS and state rules. The WIDA has significant flexibility to issue debt, but is subject to a state volume cap that limits the amount of debt that can be issued in any one year.[36] If IP were acquired through acquisition or were voluntarily retired there would not be any revenue stream to support WIDA bonds. However, it may be possible for WIDA to facilitate on-site replacement generation if the relevant federal tax laws were changed to permit the se of tax-exempt financing for the private use of a new power plant.

- COWPUSA does not currently have any authority to condemn, issue debt, or own power generation, transmission, or distribution facilities. If COWPUSA were authorized to issue debt, it is likely that it would be restricted to power generation, transmission, and distribution assets in keeping with the spirit of its original purpose, and thus may not be able to issue debt to compensate Entergy under a voluntary retirement arrangement. Bonds issued by COWPUSA would avoid a state volume cap allocation and would not be subject to local furnishing rules.

Acquisition of IP – If the County were to acquire IP by eminent domain, the County could issue GO bonds (subject to the conditions identified above).[37]

Voluntary Retirement – If Entergy were to retire IP under a consensual agreement, Entergy would retain ownership of the plant. One of the potential issuers of any debt needed to fund the payment of compensation to Entergy would be Westchester County, since there would not be a revenue-generating asset immediately in place that could support WIDA Revenue Bonds. In the event that the County wanted to compensate Entergy through another mechanism, GO bonds could also be used to purchase a portion of the IP site not required for decommissioning or SNF purposes. We do not have sufficient information about the site and plant layout to estimate the potential acreage that could be purchased, or the price per acre that the County could reasonably pay. The County would need to be assured that any GO bond issuance satisfied New York municipal finance regulations.

Replacement Plant – If Entergy were convinced to retire IP and construct replacement generation at the IP site, it appears that tax-exempt financing may not be possible under present law. The County is prohibited from using GO bonds for private purposes. WIDA can issue Revenue Bonds, but financing a replacement power plant may not qualify for tax-exempt status. Power plants whose output was consumed locally used to be able to qualify for tax-exempt treatment of debt prior to 1997, but that option, referred to as "local furnishing" or the "two county rule", is no longer available.[38] Westchester could urge its

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[36] New York State caps the total amount of public tax-exempt financing that can be issued annually. Issuers must receive an allocation of the annual volume cap in advance.

[37] Legal and financing issues regarding the ability of New York State to acquire IP by eminent domain was outside the scope of our assignment.

[38] Prior to 1997, power plants that could demonstrate that all of their output was consumed within an area no larger than (i) a city and one contiguous county, or (ii) two contiguous counties, could qualify for tax-exempt debt financing under local furnishing provisions. The IRS has tightened the requirements for a number of categories that qualify for tax-exemption. As of January 1, 1997, the owner of such a power plant (cont'd)

Congressional representatives to amend the tax code to permit such a financing. Further, as noted above, COWPUSA does not currently have authority to finance a power plant.[39] Our findings regarding the potential issuers of tax-exempt bonds are summarized in the table below:

Table 6 – Sources of Tax-Exempt Financing

	Payment to Entergy	IP Acquisition	Replacement Plant
Westchester County	Yes	Yes	No
Westchester IDA	No	No	Unlikely
COWPUSA	No	No	Not presently

2.8. Nuclear Regulatory Commission Regulations

License Transfers – Nuclear power plants have traditionally been built for, owned, and operated by electric utility companies. In general, these utilities have regulatory and fiduciary responsibilities for operations and decommissioning that are based on a single owner over the plants' life-cycle. Over the past decade, deregulation, competitive market forces, and other economics of ownership have led to many nuclear plants changing hands. In every case the NRC has approved the transfer of the plant asset, *i.e.* ownership, and operating authority, *i.e.* license. In Table 7 we list the approved license transfers as of year-end 2003.

An applicant must satisfy a variety of technical and financial qualifications regarding the ability to own and operate a specific nuclear plant in order to receive NRC approval to take over an operating license.[40] The federal requirements that govern NRC approval include, but are not limited to, the following sections of the Code of Federal Regulations (CFR):

- 10 CFR Part 2, Subpart M - Public Notification, Availability of Documents and Records, Hearing Requests and Procedures for Hearings on License Transfers
- 10 CFR 50.33 - Contents of applications, general information
- 10 CFR 50.38 - Ineligibility of certain applicants
- 10 CFR 50.40 - Common Standards for issuing a license
- 10 CFR 50.75 - Reporting and recordkeeping for decommissioning planning
- 10 CFR 50.80 - General guidance for transfer to licenses

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would have to demonstrate that it has been actively involved in the local furnishing of electricity in Westchester prior to that date. It does not appear that Entergy could satisfy this requirement.

[39] See footnote 26

[40] Section 184 of the Atomic Energy Act of 1954 and NRC regulations 10 CFR 50.40.

- 10 CFR 50.140 - Financial protection requirements and indemnity agreements

Table 7 – Nuclear License Transfers[41]

Plant	Old Licensee	New Licensee
Three Mile Island-1	GPU Inc.	AmerGen
Pilgrim	Boston Edison Co.	Entergy
Clinton	Illinois Power Co.	AmerGen
Oyster Creek	GPU Inc.	AmerGen
FitzPatrick	NY Power Authority	Entergy
Indian Point 3	NY Power Authority	Entergy
Nine Mile Point 1 & 2	Niagara Mohawk Power Corp.	Constellation Energy
Peach Bottom 1, 2 & 3	Conectiv	Exelon/PSEG
Hope Creek	Conectiv	Exelon/PSEG
Salem 1 & 2	Conectiv	Exelon/PSEG
Millstone 1	Northeast Utilities	Dominion Energy
Millstone 2	Northeast Utilities	Dominion Energy
Millstone 3	Northeast Utilities	Dominion Energy
Indian Point 1 & 2	Con Edison and NYPA	Entergy
Vermont Yankee	Vermont Yankee	Entergy
Seabrook Unit 1	N. Atlantic Energy Service	FPL Group.
Beaver Valley 1 & 2	Dusquesne Light Co.	Inter-Utility
Davis-Besse	Toledo Edison Co.	Inter-Utility
Perry	Cleveland Elec. Illuminating	Inter-Utility
Duane Arnold	IES Utilities	Inter-Utility
Kewaunee	Wisconsin Public Service	Inter-Utility
Point Beach 1 & 2	Wisconsin Public Service	Inter-Utility
Monticello	Northern States Power	Inter-Utility
Prairie Island 1 & 2	Northern States Power	Inter-Utility

Technical requirements focus on the applicant's ability to operate and maintain the plant safely. The applicant must demonstrate the appropriate staff size, training, nuclear power plant management experience, etc. The NRC evaluates the applicant's financial qualifications to fund all operations, including maintenance, repairs, as well as decommissioning and spent fuel management, *i.e.* on-site storage and future shipment to Yucca Mountain. The NRC also requires owners to put in place sufficient insurance and to obtain funds necessary to operate the plant safely.

The County does not currently have the ability to meet most of the NRC's requirements. In theory, it would be possible for the County to put in place a management / operating / maintenance team to take over IP and satisfy the NRC's regulations. The County would have three options in this regard: (i) hire experienced and capable staff internally, (ii) execute a contract with Entergy to utilize the existing IP staff, or (iii) execute a contract with another

[41] Source: NRC and NEI

company that can operate (or at least maintain) IP and then transition to decommissioning and spent fuel management. In practice, however, any option that would allow the County to take over IP would be expensive, difficult, and would take several years to implement. In addition to the many operational hurdles, the ownership of a nuclear plant would subject the County to significant and potentially expensive risks.

License Extension – Entergy operates IP2&3 under Operating Licenses granted by the NRC that will expire on September 28, 2013 and December 12, 2015, respectively. In order to obtain license extensions, Entergy would have to prepare and submit applications several years prior to the expiration dates that address safety (especially the aging of systems, structures, and components) and environmental issues.[42] The NRC staff would then conduct a thorough evaluation of these issues and prepare reports. Safety findings would then be presented to the Advisory Committee on Reactor Safeguards, an independent group comprised of academic and scientific experts that reviews NRC staff reports. Safety and environmental reports prepared by NRC staff are subject to public review and meetings, and formal adjudicatory hearings may be required. The entire process can take many years, so owners apply for license renewals as much as five years or possibly longer, before the initial expiration date.

Recent experience indicates that nuclear plant owners are requesting and receiving twenty year life extensions at the end of their initial license terms unless (i) there has been an accident (*e.g.* Three Mile Island 2); (ii) there is a significant technical problem such as nozzle cracking, boric acid leakage, or corrosion, or economic conditions of significant nature or magnitude makes continued operation impractical or uneconomic; or (iii) in the case of a municipal utility, there was significant public pressure and a willingness by the residents to shut down and bear the decommissioning and replacement power costs (*i.e.* Rancho Seco). There have been a number of plants that have been shut down, especially for technical or economic reasons.[43] In every other instance, the NRC has granted license extensions to the nuclear plant owners that have requested them. A list of plants that have received license extensions is provided below.

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[42] 10 CFR 54 and 10 CFR 51, respectively.

[43] Plants that have been shut down prior to or at the end of their NRC license term include Zion 1&2, Millstone 1, Maine Yankee, Connecticut Yankee, Trojan, San Onofre 1, Yankee Rowe, Shoreham, Fort St. Vrain, Rancho Seco, Three Mile Island 2, Dresden 1, Peach Bottom Unit 1 and Indian Point 1.

Table 8 – Nuclear Plant License Extensions[44]

Plant	Owner	Extension Date
Calvert Cliffs, Units 1&2	Baltimore Gas & Electric	3/23/00
Oconee Nuclear Station, Units 1, 2, & 3	Duke Energy	5/23/00
Arkansas Nuclear One, Unit 1	Entergy Operations, Inc.	6/12/01
Edwin I. Hatch Nuclear Plant, Units 1&2	Southern Nuclear	1/7/02
Turkey Point Nuclear Plant, Units 3&4	Florida Power & Light	7/17/02
North Anna, Units 1&2 and Surry, Units 1&2	Virginia Electric & Power	3/20/03
Peach Bottom, Units 2&3	Exelon Generation	5/7/03
St. Lucie, Units 1&2	Florida Power & Light	10/2/03
Fort Calhoun Station, Unit 1	Omaha Public Power	11/4/03
McGuire, Units 1&2 and Catawba, Units 1&2	Duke Energy	12/3/03
H.B. Robinson Nuclear Plant, Unit 2	Carolina Power & Light	4/19/04
R.E. Ginna Nuclear Power Plant, Unit 1	Rochester Gas & Electric[45]	5/19/04
V.C. Summer Nuclear Station, Unit 1	S. Carolina Gas & Electric	4/23/04
Dresden Units 2&3, and Quad Cities Units 1&2	Exelon Generation	10/28/04

In addition to IP, there are three other nuclear power stations with a total of four reactors in New York. Rochester Gas & Electric commenced the license renewal process in August of 2002 for the 497 MW R.E. Ginna plant, now owned by Constellation Energy. The final NRC approval occurred just under two years later. The license for the 840 MW J.A. FitzPatrick plant expires in October 2014. The licenses for Nine Mile Point 1&2 expire in August 2009 and October 2026, respectively.

Entergy has filed license extension applications for the two units at its utility-owned Arkansas Nuclear One station. The NRC approved an extension for Unit 1 in June 2001, and is scheduled to issue a decision for Unit 2 in August 2005. Entergy planned to submit an application to extend the license for the non-utility Pilgrim nuclear plant in December 2004, and filed a *Proposed Schedule of Submittal of License Renewal Applications* that envisioned five additional applications over the next three years.[46] An *Updated Schedule* was submitted to the NRC on May 19, 2005 that identifies a January 2006 application date for Pilgrim. Although the plant identities are not specified in either the *Proposed Schedule* or *Updated Schedule*, it is likely that the applications to extend the IP2&3 licenses are included.

If the NRC did not approve license extension for IP2&3, Entergy would have to cease operations and commence decommissioning and SNF activities as described in section 5 of this report. While this scenario would provide the County with its desired outcome without incurring compensation costs, we reiterate the point that the NRC has not denied an application to date. Therefore LAI does not recommend that the County rely on a strategy of convincing the NRC to reject Entergy's application to extend the IP licenses.

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[44] Source: NRC

[45] Constellation Energy recently purchased the R.E. Ginna plant.

[46] Accension Number ML031280234

Challenges for IP License Extension – Current power prices in New York, buoyed by high natural gas and oil prices, improve the economics of nuclear power plant life extension. In downstate New York, market energy prices during on-peak hours are strongly correlated with commodity gas prices. Increasingly, downstate market energy prices during off-peak hours are correlated with gas prices as well. The outlook for natural gas prices over the remainder of this decade reflects tight supplies and robust demand; hence, a material decline and sustained reduction in commodity prices is not likely. Against the backdrop of high fossil fuel prices, Entergy's commitment to nuclear power coupled with NYISO's fuel diversity and bulk power security requirements are likely to result in Entergy's application to the NRC for license extensions for IP2&3.

Nevertheless, IP has many unique challenges that must be met in order to be relicensed, including receiving approval of the design to convert the once-through river water cooling system to closed-cycle cooling towers. While presently outside the NRC's typical license extension scope of review, ongoing security concerns and emergency evacuation plans also represent compelling regulatory challenges. If security concerns and emergency evacuation issues are added to the NRC's scope of review as the County has recently urged, the issue of relicensing may become more problematic for Entergy and any relicense could be conditioned upon security and evacuation requirements that involve substantial costs to Entergy. Moreover, the application for license extensions would undergo a review process that would include public involvement; hence, interveners may raise the adequacy of plant changes and modifications, both those already installed and any that need to be installed, to ensure that the plant is built and operated to current standards. While there may be systems and/or components at IP2&3 that are "grandfathered" against current regulatory requirements, most are not grandfathered and could be challenged. We believe that the principal challenges for Entergy to satisfy NRC requirements are as explained below:

- Design Verification – Like all plants built in the 1960s and 1970s, IP2&3 were designed to meet the nuclear design standards in place at that time. In order to have their licenses extended, Entergy will have to demonstrate that all safety-related systems, structures, and components meet current, more stringent, design and construction standards, which may require additional design work and CapEx. Examples of these design standards include fire protection systems / requirements (*e.g.* cable separation and alternate reactor shutdown capabilities), seismic design, and upgrading / implementing the necessary quality assurance programs. During the re-licensing process, the NRC will examine the proposed closed-cycle cooling system that would be included with Entergy's license extension application. The NRC will focus on safety considerations, including the design, location, and component safety classification and construction requirements of the proposed closed-cycle cooling system. This would include potential impacts to IP's systems, structures, and components that are important to safety if the proposed closed-cycle cooling system, including the cooling towers, were to fail, as well as how Entergy has incorporated an "ultimate heat sink" to provide emergency cooling in the closed-cycle design. In addition, the NRC is currently reviewing its relicensing criteria and it is possible that more stringent standards may be imposed.

- Emergency Planning – IP is 35 miles from New York City. While IP's location may not have been a critical issue when the licenses were issued thirty years ago, the NRC is sensitive to location issues in today's post-9/11 environment. Strictly speaking, the location of previously approved nuclear plants has not typically been a factor in NRC license extension decisions. However, the County is urging that the NRC formally change its regulations to include emergency evacuation as a relicensing factor. In reality, evacuations in the event of an emergency will be problematic without the active cooperation of the local towns and Westchester County. While there have been instances of the NRC approving Emergency Plans that lacked local support, we anticipate that Entergy will experience greater difficulties as a result of the high level of embedded mistrust about plant safety by County residents.. Moreover, the relative proximity of IP to New York City adds an additional level of concern. There may be vocal opposition to NRC relicensing from New York City as well as from the other surrounding counties, *i.e.* Rockland, Putnam, and Dutchess.

- Environmental Impacts – IP will have to install a closed-cycle cooling system to operate beyond the terms of the existing licenses. The most prominent feature of the system will be cooling towers that must be sited to maximize air flow and dispersion. This presents a logistical challenge for Entergy – the bluffs above the units would be the ideal site, but natural draft cooling towers would create a plume of evaporated cooling water. This would be of particular concern during winter operations when icing conditions would be created on downwind structures and roads, possibly for several miles. Forced draft cooling towers are an alternative, but require more space and have higher operating expenses.

Financial Risk – To the extent that IP2&3 would have to be back-fitted involving lengthy programs to construct cooling towers and tie into the existing plants, that work may be required to be completed, or at least started, prior to the final decision on the license extension. This type of construction project requires significant planning and effort, and the potential risks of design, construction, cost, and schedule would add to Entergy's license extension risk. Therefore our analysis assumes that IP faces financial as well as technical risk in obtaining license extensions from the NRC. We have factored these risks into our analysis by estimating IP's value assuming no license extension (thereby avoiding the cooling conversion costs) and with license extension (with the associated CapEx).

Opportunities for Public Participation – Assuming that Entergy does apply for extensions to the existing licenses, the County and its residents will have opportunities to express their opinions through public hearings and comments. The County and residents could also question the adequacy, planning and implementation of IP's Emergency Plan. If the County or residents can demonstrate that they would be adversely affected by the extension, they could request a formal adjudicatory hearing before a three person licensing board.[47] Parties would be able to present witnesses at the formal hearing who could be questioned and cross-examined. The board would then establish a record with full findings of fact for the NRC to

[47] 10 CFR Part 2

make its license extension decision. However, having a formal hearing would not provide any party with new or expanded grounds for NRC to deny a license extension.

Zoning Variance – In addition to NRC approval of license extension, Entergy will likely require a zoning variance. IP is in the M-2 zoning classification which is noted as "Planned Industrial District" within the Village of Buchanan. Permitted uses in this zone include gas stations, auto repair shops, oil change facilities, and a gypsum board manufacturing plant. Uses by Special Permit of the Planning Board or Zoning Board of Appeals include sheet metal shops, lumber yards, masonry supply, welding, plumbing, heating and a/c businesses, and "peaceful use of atomic energy". Entergy received a variance for a support building at the IP site in 2002, a copy of which is provided as Attachment 4. The variance decision increases the height permitted in the zone from 35 feet (which is usual for industrial zones) to 59 feet, plus an additional 10 feet for a roof screen to conceal mechanical systems. Thus the construction of cooling towers, which could be as large as 300 feet in diameter and 550 feet in height, would require a new variance and provide an opportunity for County and residential opposition. However, state and local efforts to take safety-related decisions concerning nuclear facilities appear to be preempted by federal law.

3. REPLACEMENT GENERATION

3.1. INTRODUCTION

The New York State Reliability Council has adopted an electric reliability standard of one outage in ten years, a common standard used throughout the U.S. NYISO adopted a statewide installed reserve margin of 18% to achieve this reliability standard.[48] In addition, New York City and Long Island have locational capacity requirements that recognize transmission limitations into those areas. An analysis of the New York reserve margin (with IP2&3 in service) indicates that the State is expected to have sufficient generating resources through 2010, and that new generation capacity will be required starting by 2011. Much of this new capacity will be required in the downstate region where most of the demand growth is located, since there is not sufficient transmission capacity to deliver additional power from the western or northern parts of the state. *In every case we evaluated, except the unrealistic immediate retirement case, we assume that enough replacement capacity would be developed to maintain the State's 18% reserve margin target.*

Project developers are keenly tuned to market dynamics in New York. They would realize that retiring IP would cause market energy and capacity values to increase across the downstate region. These price signals would be important, given IP's size and location, to encourage the development of new generation and/or transmission projects that would replace the lost capacity. These new generation projects could include decentralized and renewable resource options. If the retirement of IP were announced in advance, developers would be able to calculate the economic feasibility of their projects and pursue those that make financial sense in time to maintain the state's reliability requirement. In addition, utilities in the downstate regions might offer long-term PPAs for new replacement generation. PPAs offer generators market certainty and reduce price risk, improving the opportunity for owners to obtain debt and equity financing in today's skittish financial markets.

The developers' ability to respond to market price signals and the utilities' interest in contracting for new generation are central to our analysis. We believe that developers would require a minimum of three-to-four years to plan, permit, and construct a gas-fired combined cycle project. Perhaps six months to a year could be shaved off the time for a simple cycle project.[49] The early project development work can often be accomplished at minimal cost, even if a formal retirement plan was not announced, in order for the developer to get a "head start" on competitors.[50] Such tasks encompass conceptual design, site control, preliminary

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[48] An 18% reserve margin requires that the installed generating capacity in New York at the time of the statewide peak demand must be at least 118% of that peak demand.

[49] Simple cycle plants are comprised of gas turbines and electric generators, are relatively inexpensive to construct, are relatively expensive to operate, and are well-suited to peaking duty. Combined cycle plants are more expensive to construct because they add heat recovery steam generators and steam turbines to improve plant efficiency. As a result they are better-suited for intermediate or base-load duty, and operate at higher capacity factors.

[50] Projects that have been proposed but are not being actively pursued described further on in this section, are consistent with this description.

fuel supply and power offtake arrangements, and initial permit applications. The remaining project development and construction time would be approximately three years for a combined cycle plant, and less for simple cycle. Thus we would recommend that any voluntary retirement be announced at least three-to-four years in advance, to give the market enough time to develop replacement capacity.[51] Acquisition by condemnation would take a number of years as well, again giving the market sufficient time to respond.

LAI has evaluated a broad list of generation and transmission alternatives to IP. Transmission alternatives within the state would also require generating capacity to maintain the state's reliability standard. Transmission alternatives that tie into neighboring markets could import firm energy (*i.e.* energy with capacity value) that would not require in-state generation. The cases that we considered are listed below. We note that the market generation responses imbedded in many of these cases could include a gas-fired power plant developed at the IP site.

- Base Case with Retirement in 2013/2015
- License Extension Case with Retirement in 2033/2035
- Retirement in 2005 without Market Response
- Planned Retirement with Market Generation Response
- Retirement with Market Transmission Response

3.2. Base Case with Retirement in 2013/2015

The existing NRC license expiration dates of 2013/15 define our Base Case scenario against which we evaluate other options. If Entergy announced an agreement to retire IP2&3 on those dates at least three, and preferably four years in advance, there would be more than enough time for project developers and downstate utilities to respond. LAI has postulated a mix of gas-fired simple cycle peaker units and combined cycle plants that would be developed in or close to Westchester. The mix was determined by evaluating the forecasted economics of these plant types at the time the capacity is required, and then adding the plant type that is most financially attractive, *i.e.* has the lowest net capacity revenue requirement.

3.3. License Extension Case with Retirement in 2033/35

If the NRC licenses for IP2&3 are successfully extended for twenty years, no replacement plants would be required to replace IP capacity. In this scenario, our forecast of market energy prices include IP2&3 in the supply mix, but at lower levels of output as described in the Plant Performance section. Of course, there would still need to be some gas-fired capacity additions to meet load growth and maintain the state's 18% reserve margin requirement.

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[51] The development of replacement generation on the IP site itself could help mitigate adverse economic impacts to the local governments and the local economy.

3.4. Retirement in 2005 without Market Response

LAI ran an extreme case in which IP would have been retired on January 1, 2005, without any market response in order to test the effects of the state having less than an 18% reserve margin.[52] We believe this case is unrealistic, since project developers would take full advantage of the economic opportunity created by IP's retirement. Shutdown without a market response would prevent the state from achieving its 18% installed capacity margin and reduce the reliability of the bulk power system.[53] Even if some type of immediate shutdown were mandated by an unprecedented State or federal government fiat, NYISO would likely implement some type of emergency capacity and energy replacement plan that would minimize the disruptions to the bulk power grid.[54]

3.5. Planned Retirement with Market Generation Response

The absolute earliest retirement scenario, given a two-to-three year acquisition process, would be January 1, 2008. Under our base case assumptions, New York is expected to have 900 MW of capacity in excess of the 18% reserve margin in 2008. Therefore if IP2&3 were to be retired by 2008, approximately 1,100 MW of replacement generation would be needed in that year. This replacement capacity could be located at the IP site if Entergy or another developer pursued a project there, or could be located elsewhere in the downstate region. While gas pipeline upgrades may be required to serve a particular project, large-scale electrical transmission improvements would not be necessary in light of the existing transmission infrastructure from IP to New York City and Long Island. While the County is not obligated to replace IP capacity in the event of a successful condemnation or voluntary retirement, it would be beneficial to encourage replacement generation at the IP site in order to help mitigate adverse economic impacts to local governments and the local economy. In response to NYISO's recent implementation of the installed capacity demand curve mechanism, market participants would be motivated to develop replacement capacity. Investors' unwillingness to rely on volatile market energy prices and weakness in the capital markets might require Con Edison or other downstate utilities to enter into a compensatory PPA to help attract equity and debt investors.

The NYISO has divided up the state into eleven zones for planning purposes. Zones A-E comprise the western region, Zone F around Albany is referred to as the Capital District,

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[52] This case is comparable with the GE / NERA Study prepared for Entergy in March 2002, *Electricity System Impacts of Nuclear Shutdown Alternatives,* in which the authors focused on reliability, energy price, and consumer expenditure impacts. The authors assumed that there would not be any market response or NYISO action, leading to dramatic but unrealistic conclusions of reduced reliability, higher energy prices, and higher electricity expenditures.

[53] Quantifying the reliability impact on ratepayers, *e.g.* in terms of Loss-of-Load expectations, was beyond the scope of this assignment.

[54] For example, ISO-NE and the local utility, Connecticut Light & Power, have recognized that the southwestern Connecticut region has insufficient generation and transmission infrastructure, and have issued "Gap" RFPs to locate generation within that region on a short-term basis to maintain local reliability until the planned 345 kV transmission projects are completed.

Zones G, H, and I include Greene, Ulster, Dutchess, Orange, Putnam, Rockland, and Westchester and are treated as one region in our simulation modeling, Zone J is New York City, and Zone K is Long Island. Over the past few years, many plants have been constructed in New York City and on Long Island. Other projects that have been proposed in Zones G, H, and I but have not been developed are as follows:

- Wawayanda – This is a 540 MW gas-fired combined cycle plant that was proposed by Calpine to be located in Orange County, *i.e.* Zone G. Wawayanda was designed to utilize two GE 7FB gas turbines, heat recovery steam generators, and a steam turbine, with dry cooling towers to minimize water consumption. Calpine submitted an Article X application to the NYPSC which certified the project on October 22, 2002. Wawayanda was to be connected at new substation on NYPA's Marcy-South 345 kV line and was to receive gas via a 20 mile lateral to Tennessee Gas line in New Jersey. Construction has not yet commenced.

- Bowline – The 750 MW Bowline gas-fired combined cycle project was proposed at the existing Bowline plant (*i.e.* two 600 MW gas/oil units) by the plant owner, Mirant. The project, located in Rockland County, *i.e.* Zone G, received Article X certification on March 26, 2002, but construction was halted by Mirant's bankruptcy. Bowline was designed to utilize three GE 7FA gas turbines, heat recovery steam generators, and a steam turbine, with hybrid cooling towers. The project was to be connected via upgrades on the existing transmission right-of-way, and was to receive gas via a new 4.2 mile lateral to Columbia.

- Torne Valley – The 501 MW Torne Valley gas-fired simple cycle project was proposed by Sithe and was to be located in Rockland County, *i.e.* Zone G. The project was originally designed to be 827 MW combined cycle and was revised to 510 MW, utilizing three GE 7FB gas turbines. Torne Valley was to be connected to the Ramapo substation, but the Article X application was withdrawn in December 2001.

- Ramapo – The 1100 MW Ramapo gas-fired combined cycle project was proposed by American National Power and was to be located in Rockland County, *i.e.* Zone G. Ramapo was designed to utilize four ABB GT24 gas turbines and be connected to the Ramapo substation. American National Power submitted an Article X Application in January 2001, but withdrew the Application in September 2002.

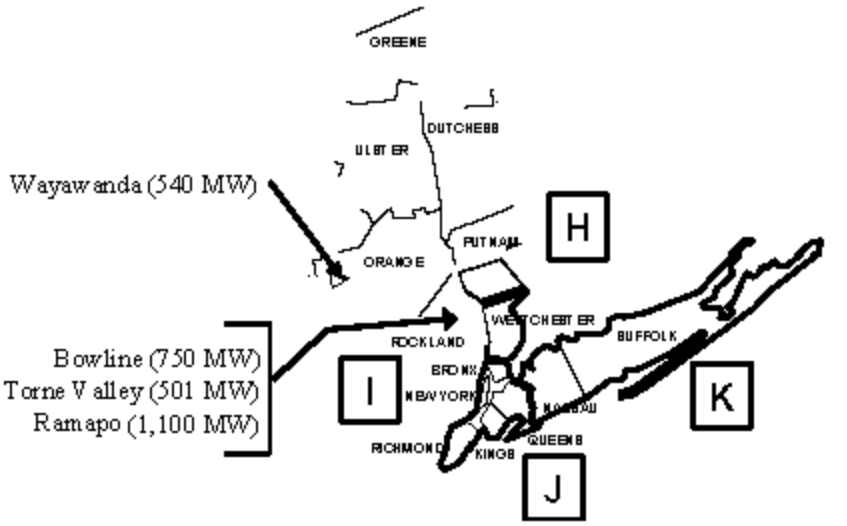
Power plants greater than 80 MW built in New York formerly required approval of the New York State Board on Electric Generation Siting and the Environment (commonly referred to as the Siting Board) under Public Service Law Article X.[55] The Siting Board consists of members of the NYPSC, the DEC, and other stakeholders. The Article X certification bundled all state reviews and approvals, including air permits, siting, and water use / discharge. Although the Siting Board encouraged conformance with local regulations, Article X obviated the need to obtain local permits. Upon Article X certification, virtually all of the

[55] Projects less than 80 MW had to go through the State Environmental Quality Review process.

key development ingredients (except NYISO-jurisdictional matters) such as plant design, size, site, fuel supply, water supply, transmission connection, and emissions control, had to be in place. Article X certification was seen as one of the last steps in project development, after which the developer could execute construction contracts and other agreements.

Upon the expiration of Article X on December 31, 2002, the siting and environmental review responsibility for power plants greater than 80 MW reverted to the State Environmental Quality Review (SEQR) process. Unlike Article X, under SEQR the project developer must obtain all local permits, in addition to state and federal environmental permits. Any state agency with some approval authority for the project can be designated as the Lead Agency under SECR. Typically, DEC serves as lead agency, but public power authorities, such as NYPA, or state funding agencies can also be the Lead Agency responsible for the environmental review if they are involved in the project.

Figure 2 – Location of Replacement Generation by County and Zone

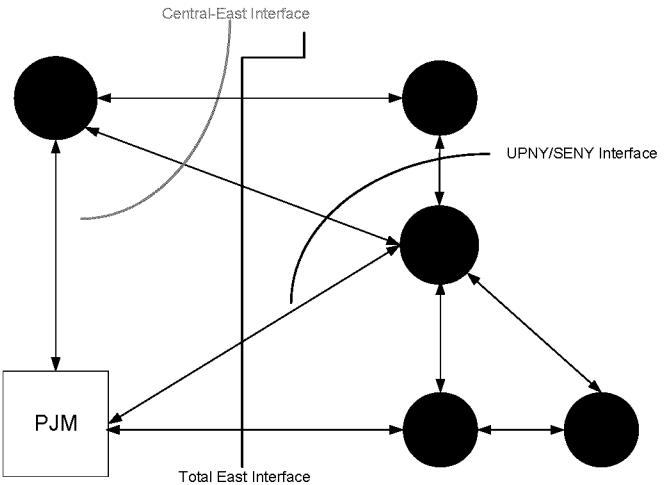


3.6. RETIREMENT WITH MARKET TRANSMISSION RESPONSE

LAI has identified four possible transmission alternatives to the retirement of IP2&3. In each case we take into account IP's locational advantage – it is in the downstate region where both customer demand and demand growth are concentrated. The state's bulk power transmission system generally transmits power from west-to-east (across the Central-East and Total East interfaces) through central New York and from north-to-south (across the UPNY-SENY interface) down the Hudson River valley. The existing transmission lines often are operated at full capacity, so any transmission schemes to deliver more power from the western or upstate regions to the downstate / southeastern region would have to reinforce or expand the transmission interfaces that limit power flows. Figure 3 below is a representation of the New

York Control Area transmission system with the major interfaces defined in-state and with the Pennsylvania-New Jersey-Maryland (PJM) market.

Figure 3 – New York Zones and Transmission Pathways



One of the four possible transmission alternatives involves the construction of a direct current (d/c) transmission line and the remaining three involve upgrades to the existing alternating current (a/c) network. In evaluating the three upgrade alternatives, LAI considered recent advances in conductor technology and their feasibility for the particular upgrades. Traditionally, upgrading a circuit requires replacing existing conductors with larger more heat-resistant ones, which usually requires reinforcements to existing towers or installing new towers, an expensive proposition. In this regard, LAI considered the use of new conductor designs that can increase the circuit capacity without needing to reinforce or replace towers.[56]

Retirement with Empire Connection Market Transmission Response

Several years ago, Conjunction LLC announced the development of the 140 mile Empire Connection Transmission project that would connect upstate New York, *i.e.* Zone F, the

[56] Among the new technologies LAI considered include the Aluminum Composite Conductor Reinforced cable and the Aluminum Conductor Composite Core cable. These conductors are designed to double the electrical transmission capacity of conventional conductors of the same diameter without reinforcing or replacing towers, making the new conductor designs economical in many situations. The Aluminum Composite Conductor Reinforced conductor was recently installed in its first 345 kV commercial application, while the Aluminum Conductor Composite Core cable has had some recent installations at 230 kV but none at the 345 kV level.

Capitol District around Albany, to the downstate grid, *i.e.* Zone J, New York City. The plan called for two physically separate d/c cable circuits to be buried underground along the existing Hudson River railroad right-of-way, with some portions mounted on poles above ground. Each of the ± 500 kV circuits would be controllable and able to transmit 1,000 MW for a total of 2,000 MW. Circuit 1 would interconnect from a new substation near the existing Leeds substation, along the Leeds/Gilboa 345 kV line, to Con Edison's Rainey 345 kV substation. Circuit 2 would interconnect from a new substation near the existing New Scotland substation, along the New Scotland/Alps 345 kV line, to Con Edison's West 49th Street 345 kV substation.

The project's Article VII Application to the NYPSC was originally filed on November 18, 2003. On August 5, 2004, Conjunction filed a supplement to the Application, which is under consideration by the NYPSC. The project's System Reliability Impact Study was approved by the NYISO on March 18, 2004. The study results showed that the performance of the New York bulk power system is not degraded by the project's interconnection. However, the project held an open season solicitation offering transmission capacity to market participants that was unsuccessful, rendering the Empire Connection project unlikely to be developed under current market conditions.

Empire Connection in and of itself would not provide replacement capacity for IP2&3. While it would provide a transmission pathway from the Capitol District to New York City, additional generation would have to be installed in Zone F to replace IP2&3 to maintain the statewide 18% reserve margin requirement. According to the Article VII filing, Empire Connection would cost about $750 million, equivalent to $375/kW for 2,000 MW, but detailed cost estimates were not provided. Based on the project's high cost, the inability to achieve certain development milestones, and the necessity of also adding new generation, Empire Connection is not a viable option in the 2008-2010 time frame.

LAI contemplated a modified Empire Connection project to take advantage of the 2,000 MW transmission pathway from Westchester to New York City that would be made available by retiring IP. This would reduce the project's cost by utilizing IP's existing terminal equipment at the Buchanan substation that would become available, and the cost of extending Empire Connection over the last few miles into Zone J would be avoided.[57] While this modification would reduce the project's capital cost, doing so would deprive the project owner, Conjunction, with an important revenue source – the ability to arbitrage energy price differentials between Zone F and Zone J. Therefore we have not pursued this modified Empire Connection project as a viable option.

Retirement with Upstate New York Market Transmission Response

A second transmission alternative would be to upgrade the existing 345 kV New Scotland-Leeds circuits and the 345 kV Leeds-Pleasant Valley circuits, and construct a new 345 kV

[57] A new Article VII filing would need to be made and a revised System Reliability Impact Study submitted for this modification because this alters the original configuration.

line from New Scotland to Pleasant Valley. This would increase the UPNY-SENY interface transfer capability (see Figure 3 above) by approximately 600 MW. As with other transmission alternatives, 600 MW of new generating capacity would have to be added in Zone F to take advantage of the increased transfer capability. The cost for upgrading the Leeds-Pleasant Valley circuits was estimated at $40 million plus $27 million to upgrade the New Scotland-Leeds circuits.[58] LAI estimated the cost for constructing a new 345 kV line from New Scotland to Pleasant Valley. The resulting total cost is approximately $177 million, equivalent to $295/kW. This cost would outweigh the savings of building a combined cycle plant in Zone F as opposed to Zones G, H, or I. Therefore LAI did not pursue this option for this assignment.

Retirement with Western New York Market Transmission Response

There have been a number of studies to increase the transmission interface limit across the Central-East interface to transmit more power from western New York. The most recent plan would be to convert the existing single 345 kV Marcy-New Scotland circuit to a double circuit and to rebuild the New Scotland station to a breaker-and-a-half design. This would increase the Central-East transfer capability by approximately 650 MW and increase the transmission capacity into Zone J by approximately 450 MW. We estimated the cost of this alternative at $143 million, equivalent to $220/kW. Even though this option is less expensive than the upstate New York option, the cost would still outweigh any savings of constructing a combined cycle plant in Zones A-E. Therefore LAI did not pursue this transmission option for this assignment.

Retirement with PJM via Ramapo Market Transmission Response

The fourth transmission alternative involves transmitting power from the PJM system into NYISO. The two systems are connected in a number of locations, including a 500 kV line from the PJM Branchburg substation to the NYISO Ramapo substation. PJM is approximately three times the size of NYISO, with a considerably higher percentage of coal and nuclear generation. LAI examined two options to increase the power flow to Buchanan: re-conductor the existing transmission paths from Ramapo to Buchanan, and construct a new dedicated (overhead or underground) transmission line from Ramapo to Buchanan. Either option would require extensive additional studies to satisfy reliability and environmental requirements, which are beyond the scope of this assessment.

The capacity of the Ramapo-Buchanan route could be increased significantly, conservatively estimated at 1,000 MW and perhaps as much as by 2,000 MW if both options are pursued. However, total power flows between eastern PJM and NYISO are governed by the Total East transfer capability, a simultaneous transfer limit that incorporates five interface locations and that takes into account single and multiple contingency events. Our investigation reveals that this alternative probably would not increase the Total East transfer capability significantly

[58] Cost provided in *Power Alert III, New York's Energy Future*, a report by the NYISO.

because of the simultaneous nature of the Total East limit. Therefore LAI did not pursue this transmission option for this assignment.

3.7. Entergy Gas-Fired Replacement Generation at IP Site

One generation replacement option would be for Entergy or another developer to build and operate a gas-fired simple cycle or combined cycle power plant at the IP site. The feasibility of this option is supported by Entergy's *Preliminary Scoping Statement* filed with the NYPSC on March 18, 2002 to construct a 330 MW simple cycle plant.[59] The plant was originally to be comprised of eight 45 MW aero-derivative gas turbines, later amended to two 165 MW GE 7FA industrial frame gas turbines.[60] The plant was to utilize a 5 acre parcel on the IP site outside of the "protected area" that houses the reactors. The plant would have tied into the Buchanan electric substation, less than 2,000 feet to the northeast. The principal components would have been the two gas turbines and generators in a main generator building, two 90 foot tall exhaust stacks, an electrical switchyard, a water demineralization system, and a control building.

NO_X emissions would have been controlled by using dry low NO_X combustors and through a selective catalytic reduction system. Natural gas for the plant would have been obtained from Algonquin, the interstate pipeline that traverses the IP property less than 1,000 feet away. While the existing Algonquin mainline may be adequate for a simple cycle plant that would operate in peaking mode during the summer season, we believe that substantial pipeline upgrades would be required to supply natural gas to a combined cycle plant throughout the winter heating season, November - March.

Entergy's Preliminary Scoping Statement indicated that the simple cycle project would have benefited the local community in a number of ways:

- The project would add to the local tax base.
- The project would improve utilization of the IP site.
- Construction would create 200-250 jobs during a one year period.
- Operation would require 3-4 full-time staff.
- The project would improve electric reliability, particularly during peak demand periods.

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[59] Case No. 02-F-0342.

[60] Aero-derivative gas turbines are similar to jet aircraft engines and are designed to start up and shut down quickly and frequently, ideal for peaking operation. Industrial frame gas turbines utilize similar technology on a larger scale and are more often utilized in a combined cycle arrangement, better suited for intermediate and base load operation. Aero-derivative gas turbines typically range from 5MW – 50MW, while industrial frame units typically range from 80 MW – 265 MW.

Site Suitability

Entergy abandoned the project and withdrew the *Preliminary Scoping Statement* prior to filing a more definitive Application for Article X approval. However, the IP site appears to be well-suited for replacement capacity, based on four key attributes – size, fuel supply, transmission connection, and water supply:

- Size – According to Entergy's *Preliminary Scoping Statement*, the IP site has land outside of the IP2&3 "protected area" that is vacant and used for temporary storage. The ISFSI under construction is not located on this vacant land. With careful planning, we believe that Entergy could utilize this land to site replacement generation, perhaps as much as 1,000 MW of combined cycle capacity.[61] However, if IP is converted to a closed-cycle cooling system, the cooling towers will probably use up most of the vacant land and preclude Entergy's ability to use the site for replacement generation.

- Fuel Supply – According to the *Preliminary Scoping Statement*, the Algonquin 26" and 30" gas pipelines traverse the IP site, and the gas interconnection would extend less than 1,000 feet. Entergy planned to obtain interruptible or seasonal secondary firm transportation on Algonquin. More recently, the Millennium pipeline project announced Phase 1 plans to construct a major gas pipeline from the Empire State Pipeline in Corning, New York to the Algonquin system in Ramapo, New York. Additional supplies from Western Canada, coupled with system reinforcements on the Algonquin mainline from Ramapo to Connecticut, would facilitate a gas-fired replacement plant on the IP site. Expensive upgrades on Algonquin would surely be required to provide firm year-round service to the site without denigrating the service rights of other Algonquin customers in New York and Connecticut.[62] The extent to which such upgrades could be reduced for "quasi-firm" service that allows for some delivery interruptions is unknown.

- Transmission Connection – The retirement of IP will provide a transmission pathway for 2,000 MW of on-site replacement capacity. Retiring IP would also free up terminal space at the Buchanan substation for any replacement capacity on the IP site. The Preliminary Scoping Statement suggests that the transmission lines would be less than 2,000 feet, a very short distance compared to other merchant project locations.

- Water – Peaking plants require relatively little water, and the Preliminary Scoping Statement stated that water would be required for inlet fogging (to improve hot weather performance) and turbine washing. Water was not anticipated for NO_x control. Entergy intended to use water from the Buchanan municipal system, rather

[61] The County will have to discuss site capacity with Entergy at the appropriate time.

[62] Quantifying pipeline service adequacy and upgrade costs were beyond the scope of this assignment. During the course of our analysis, no discussions were held with Algonquin, or its parent, Duke Energy, regarding gas delivery capacity to IP.

than the Hudson River. A large combined cycle plant might require more water, although the exact amount depends on the cooling technology utilized. We believe that the cooling technology adopted at the Athens plant, a wet/dry compromise that minimizes water consumption and plume formation, may be appropriate for the IP site.

Combined Cycle Replacement Generation

If IP was retired and cooling towers were not constructed, an on-site gas-fired combined cycle plant would be an appropriate replacement technology.[63] Since IP operates as a base-load resource, a combined cycle plant is better suited for base-load operation than the simple cycle plant proposed by Entergy. Both plant types are designed around gas turbine technology. In light of concerns regarding greenhouse gas emissions and the need for significant transportation infrastructure, it is doubtful that a coal-fired plant could be sited in Westchester County. An on-site combined cycle replacement plant would offer Entergy, the County, and the State a number of benefits:

- The site is already zoned for a power plant and has useful infrastructure in place. The Buchanan substation would allow up to 2,000 MW of replacement generation to be connected into the high voltage transmission system at virtually no cost to NYISO or Entergy. A replacement plant that would become operational at the time the IP units were retired would assure NYISO and State ratepayers of system reliability. Locating a site for a new power plant elsewhere in Westchester would be difficult and costly due to land costs, governmental considerations, and the need for the supporting infrastructure. Thus, the IP site has substantial value for replacement generation because zoning, infrastructure, and community acceptance all are favorable, conditions not easily duplicated elsewhere.

- Algonquin traverses the site and could deliver gas to the replacement plant. If Phase 1 of the Millennium project is completed in time and Algonquin expands its mainline, gas supplies should be available at IP throughout the non-heating season without significant facility additions. If the on-site replacement plant required firm year-round transportation service, Algonquin would likely require substantial and costly upgrades. However, if Entergy could obtain an air permit that would allow the plant to utilize distillate oil as a back-up fuel for up to 30 days per year, less costly upgrades might be sufficient to render non-firm service. Many plants have such permit conditions that allow the gas to be shifted to core loads, such as residential consumers who are entirely reliant on gas.[64] Back-up fuel oil capability that ensures uninterrupted winter

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[63] Evaluating the potential of other conventional and renewable power plant technologies was outside the scope of this assignment.

[64] For example, the Bowline 3 project listed on page 31 had an air permit that permitted fuel oil use with restrictions. The Wawayanda project had a gas-only air permit. SCS Astoria, a combined cycle project in New York City, can burn distillate fuel oil for 720 hours (30 days) per year. Many other plants that have recently commenced operation are also permitted to burn distillate fuel or some other oil product, with restrictions.

time operation would also be looked upon favorably by the NYISO.[65] Entergy would have to install above-ground storage tanks on-site to store some quantity of back-up fuel oil.

- The capital cost of a combined cycle plant is significant. Based on generic cost data, we estimate that a 1,000 MW (nominal rating) combined cycle plant would cost approximately $0.8 billion (2012 dollars), including all development, permitting, engineering, procurement, construction, and start-up costs.[66] Utilizing the IP site would reduce the capital cost somewhat.

- An on-site combined cycle plant would provide construction jobs for a period of time that we estimate at two-to-three years, longer than would be required for a simple cycle plant. While the permanent staffing level of the combine cycle plant would be less than for a nuclear facility, there would be continuing staff requirements to provide site security, maintain safety, and restore the former nuclear facility site.

- An on-site combined cycle plant would preserve some level of PILOT payments for the local communities, especially the Hendrick Hudson School District. While the level of PILOT would be subject to negotiations, we note that a report we conducted for NYISO last year indicated property taxes would average about $17.60/kW-yr in 2005. At this tax rate, property taxes (not necessarily as PILOT) for a 1,000 MW combined cycle plant, one-half of the IP capacity, would be $17.6 million in 2005, almost as much as IP's current PILOT.

Entergy actively pursued non-nuclear merchant power opportunities (*i.e.* non-utility power plants using fossil-fuel technologies such as a gas-fired plant at the IP site) up until two-to-three years ago. Deteriorating economics of merchant power projects caused Entergy to discontinue project development and either sell off plants or record charges due to value impairment for a sizeable portion of its domestic and international portfolio. Entergy also sold a number of gas turbines that had been ordered for new power plant projects to a special-purpose entity in 2001.

While Entergy's interest in developing a gas-fired simple cycle or combined cycle plant may have waned, an on-site replacement plant appears to have some advantages compared to other sites. Entergy could capture that value and thus benefit financially through a number of business arrangements. For example, Entergy could develop and own the on-site replacement plant, or could be a partner in which case it could contribute the site in lieu of cash, among other potential transaction structures.

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[65] Absent firm transportation on Algonquin, there may not be sufficient pipeline capacity during the heating season to provide adequate natural gas service once the 30 days of permitted oil use has been fully utilized.

[66] We assumed that the site could accommodate 1,000 MW of combined cycle capacity. While 2,000 MW may be possible at the IP site, such large plants at one site are very unusual. For example, the four merchant combined cycle plants described in section 3.5 range from 500 MW to 1,000 MW (nominal ratings).

3.8. Conversion of IP to Natural Gas

One of the options that LAI was asked to investigate was the conversion of the IP from a nuclear plant to a non-nuclear plant. A conversion would require installing new gas turbines and heat recovery steam generators to produce steam that would be utilized in the existing IP2&3 steam turbines and generators, *i.e.* a gas-fired combined cycle plant. Over fifteen years ago, one nuclear plant, then under construction, was converted to a gas-fired combined cycle plant, the Midland Cogeneration Project. The conversion of the Midland plant had unique features that render it irrelevant in the present context:

- The Midland nuclear plant was never completed and never had radioactive fuel on site.

- The Midland nuclear plant was owned by a utility, Consumers Power. Its conversion allowed Consumers Power to place a large portion of the nuclear expenditures for the abandoned nuclear plant into rate base. The business arrangement, sanctioned by the state utility commission, gave the utility a strong economic incentive to transfer as much of the expensive nuclear plant costs into the non-nuclear plant, regardless of technical merits.

- Combining new gas turbines with the existing steam turbines was not as efficient as a new combined cycle plant.

- The Midland combined cycle plant was located near many pipelines that had access to domestic and Canadian gas supplies. The IP site would have difficulty obtaining winter gas deliveries absent significant and expensive pipeline upgrades.

Another nuclear plant, Rancho Seco, was owned and operated by the Sacramento Municipal Utility District until it was retired in 1989. Rancho Seco was not converted to gas, but was replaced by conservation, cogeneration, and alternative energy sources through an aggressive program.

Other, more general reasons that we do not believe conversion of IP is feasible are as follows:

- The steam conditions exiting the heat recovery steam generators would not match the conditions required in the steam turbines, depressing total plant efficiency.

- Back-fitting new gas turbines and steam generators with existing steam turbines would not permit the overall combined cycle efficiency to be optimized.

- New combined cycle plants constructed under a turnkey contract typically have complete repair/replacement warranties and performance guaranties. Contractors cannot offer such warranties and guaranties for a converted plant.

- Utilizing the equipment would expose the new plant investors and lenders to nuclear plant-type risks (*ex.* soil contamination) that investors would ordinarily avoid.

3.9. Alternative Energy Sources

An evaluation of the potential of alternative energy sources to replace IP capacity was not part of the assignment given to LAI. Nevertheless, we are aware of certain state and federal initiatives to encourage alternative energy sources that may influence the County's strategy towards IP.

Last September the NYPSC adopted a Renewable Portfolio Standard requirement for utilities and other load-serving entities that requires them to increase their procurement of renewable energy to 24% of their total requirements by 2013. The NYPSC anticipates that voluntary purchases of renewable energy will increase the total to 25%. Currently, about 19% of the State's energy requirements are supplied by renewable sources, mostly hydroelectric in the western region. The NYPSC's order implements a program whereby the New York State Energy Research and Development Authority (NYSERDA) will subsidize developers of new renewable facilities, selected via auction, to increase the state's renewable portfolio. We expect the largest source of incremental renewable energy to be wind projects, but it is not certain how much could be developed in the downstate region that would help replace IP capacity.

The DOE has been directed by Congress to perform an assessment of alternatives to IP for meeting energy needs in New York. DOE was directed to use the National Research Council for this study. According to the Council's web site, a committee was established to identify and assess options for replacing IP energy, and then compare them to the continued operation of IP. The alternatives may include coal- or natural-gas-fired power generation, renewable-energy-based options, energy imports, and energy efficiency measures. In assessing the alternatives, the committee may consider such factors as economic costs and benefits, emissions, infrastructure barriers (*e.g.* fuel supply, compatibility with the transmission grid), health and safety, reliability of supply, and other factors. The committee will not recommend options or the future of IP. Rather, it will provide a menu of options with a sufficiently detailed description of the full impacts of choosing those options for policymakers to understand the implications of their potential decisions. The work is scheduled to be completed at the end of the year.

3.10. County / Cowpusa Alternatives

Westchester County and COWPUSA have a limited number of potential business strategies to encourage Entergy to shut down IP and construct replacement generation at the site. One strategy would be for the County to purchase unused land at the IP site that is in free release condition (described later on in this report) as a financial incentive. This land could then be leased to a developer for on-site replacement generation. Another strategy would be to expand COWPUSA's role to allow it to purchase wholesale power and sell retail power to Westchester residents. NYPA or Con Edison, which both have large retail customer bases, could better serve in this role. Purchasing wholesale power from Entergy under a PPA could encourage replacement capacity at the IP site or at another location.

Westchester County has encouraged cost-effective conservation, load management, and renewable energy sources and should continue to do so whether or not IP continues to

operate. Recommending specific alternative energy sources is outside of the scope of this assignment. However, there are many institutions active in this area as well as existing programs that could support Westchester's efforts:

- NYSERDA actively supports the development of conservation and load management programs that could be expanded throughout Westchester.

- NYISO has instituted market mechanisms to encourage load management, *i.e.* shifting or curtailing load that can be reliably called upon.

The merchant generation environment is highly competitive, demanding sophisticated energy bidding and fuel procurement strategies, efficient plant O&M practices, lean administration, and significant financial strength. We do not believe that COWPUSA should consider owning and operating replacement generation without a base of relevant experience. Many merchant plant owners that are not part of a large and diversified corporate structure are currently in financial distress.

We note that COWPUSA's ability to provide retail service in Westchester and compete against Con Edison is limited by two factors. First, the NYPSC's recent decision to differentiate MAC will lower Con Edison's retail rates in Westchester, taking a potential cost advantage away from COWPUSA. Previously MAC charges had the effect of increasing Con Edison's charges to Westchester customers (even though the underlying energy cost is lower than in New York City) while lowering Con Edison's charges to New York City customers. While the County is to be commended for its efforts in prompting NYPSC to phase out the imbalance, the MAC change results in lower Con Edison rates in Westchester, thus making it harder for COWPUSA to compete. Second, we investigated whether COWPUSA could avoid transmission charges by purchasing power directly from the on-site replacement plant and transmitting that power directly to the Westchester distribution system. However, doing so would require additional capital costs to design and construct the plant switchyard, and the plant's location in Buchanan would not allow COWPUSA to serve a large percentage of the County's potential load.

4. PLANT VALUATION

4.1. INTRODUCTION

LAI estimated the value of IP at various points in time and under different scenarios in order to guide the County regarding the potential acquisition of the plant as well as possible negotiations with Entergy to voluntarily shut down the plant. Compensation estimates using the Cost Approach, Comparable Sales Approach, and Capitalized Income or Earnings Approach are addressed in this section. This section also includes detailed discussions of LAI's forecast of plant revenues and expenses, as well as the discount rate appropriate for a merchant nuclear power plant, that are required for the Earnings Approach, the preferred valuation method for income-producing assets such as IP.

4.2. COST APPROACH

The Cost Approach involves a determination of value based upon the cost of duplicating IP, plus a consideration of any changes in standards and conditions if necessary.[67] Entergy acquired IP3 in November 2000 and IP2 in September 2001. These transactions are recent enough to utilize as a check against the Earnings Approach valuation.

IP3

IP3 was sold by NYPA to Entergy, along with the FitzPatrick station, in November 2000. Under the terms of the Purchase and Sale Agreement, Entergy agreed to a purchase price of $967 million allocated as follows: $636 million for the two plants plus $171 million for fuel and other inventory. This transaction was sufficiently recent to be considered in the valuation of IP3. In addition to the purchase prices in the Purchase and Sale Agreement, the parties executed a PPA, a Facilities Agreement, and a Value Sharing Agreement that convey value between the parties and should be considered in valuation. Each of these valuation components are discussed below.

Entergy is making purchase price payments over an eight year period following the closing date. According to the Purchase and Sale Agreement, the $637 million price for the plants is being paid as an initial payment of $50 million on the closing date and then seven annual installment payments of $83.715 million. Allocating the purchase prices among the plants can be accomplished based on plant size. Since IP3 was rated at 980 MW and FitzPatrick was rated at 825 MW, IP3 represented 54.3% of the combined plant capacities and, thus, is allocated $346 million for plant and $93 million for fuel.

At the time IP3 was sold the parties also executed a PPA under which NYPA agreed to purchase IP3's capacity, energy, and ancillary services through 2004 at a set price of $36/MWh. The parties had the option but did not extend the PPA beyond the initial term. LAI is not aware of any reason to believe that the PPA prices were set above or below then-

[67] Appraisers also refer to this approach as "Replacement Cost New" or "Reproduction Cost New".

prevailing market expectations about market energy prices; therefore no adjustment to the purchase price is required.

The Value Sharing Agreement ensures that NYPA will benefit from power sale revenues in the event that actual market energy prices exceeded specified target prices from 2005 to 2014. The target prices are set at $42.26/MWh in 2005 and rise gradually to $57.77/MWh in 2014. Forecasted energy prices applicable to IP3 are $59.04/MWh in 2005 to $68.04/MWh in 2014. The expected positive difference will be shared equally between Entergy and NYPA, thereby reducing IP3's valuation to Entergy through 2014. Based on our forecast of market energy prices, LAI estimates that NYPA will receive an average of $37.3 million per year under the Value Sharing Agreement.

The parties also executed a Facilities Agreement for Entergy to make additional payments to NYPA in the event Entergy acquired additional nuclear generating units in New York. The provision for Entergy's ownership of IP2 requires Entergy to pay NYPA $10 million annually, commencing in September 2003, the second anniversary of the date IP2 is acquired, and continuing to the earlier of December 31, 2015, the eleventh anniversary of the IP2 acquisition date, or the date when either IP2 or IP3 is retired. Assuming that IP2&3 are operated though the end of their respective NRC licenses, Entergy would make ten payments (2003-2012) of $10 million. Our valuation estimate includes payments made under both the Value Sharing Agreement and Facilities Agreement.

IP2

IP1&2 were sold by Con Edison to Entergy in September 2001. Under the Purchase and Sale Agreement, the purchase price was $502 million for the nuclear generating plants and associated facilities, plus approximately $107 million for fuel inventory.[68] The parties also executed a PPA under which Con Edison purchased IP2's output through 2004. LAI is not aware of any reason to believe that the PPA prices were set above or below then-prevailing market energy prices, which would require an adjustment to the purchase price. Since IP1 was shut down in 1974 and is in safe storage, the entire purchase price is allocated to IP2.

The PSA called for the purchase price to be paid in full at closing. There is only one provision of the PSA that may result in a significant financial transfer related to the sale of IP2 following the closing. The agreement stipulates that if decommissioning of IP occurs by any means other than decontamination (*e.g.,* by safe storage or entombment), then half of the amount by which the decommissioning funds exceed the decommissioning cost shall be paid to Con Ed. Unlike the sale of IP3, there are no other related agreements for sharing value with Con Edison after the closing.

A breakdown of IP's purchase prices is provided in Table 9, including the discounted value of the ten payments under the IP3 Facilities Agreement.

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[68] The sale also included IP1, three gas turbine units with a combined capacity of about 45 MW and the Toddville Training Center.

Table 9 – Indian Point Purchase Prices
($ millions)

	IP2	IP3
Power Plant	$502	$345
Fuel Inventory[69]	$107	$ 93
Facilities Agr't	$ 0	$ 87
Total	$609	$525

Cost Approach Considerations

In considering the changes in standards and conditions since Entergy acquired IP, there have been a number of changes in the power market over the past four years, as follows:

- Regulation – The New York wholesale power market has been deregulated since November 1999. There have not been any significant changes in federal nuclear power regulations since that time. Entergy acquired IP3 in November, 2000 and IP2 in September, 2001. Thus LAI believes that IP's Cost Approach value has not been materially affected by regulatory changes.

- Physical Depreciation – There may have been some physical wear and tear of the IP assets since the Entergy purchase, but LAI is not aware of any significant depreciation (*e.g.* major equipment failure) that would cause the original purchase price to not be a cost-based indicator of market value. Moreover, NRC regulations require nuclear plants be maintained to a very high standard, so that IP's cost-based market value has not been materially affected by physical depreciation.

- Functional Depreciation – The technology utilized at IP has not been made obsolete and does not prevent IP from providing energy and capacity into the market. IP's cost-based market value has not been materially affected by functional depreciation.

- Economic Depreciation – Economic depreciation includes changes in the value of the plant's output, which in this case is energy, capacity, and other ancillary services. Since Entergy purchased the IP assets, market energy prices in New York have increased about 25%, thus raising IP's cost-based market value. At the same time, IP has fewer operating years left under the NRC licenses. When they were purchased, IP2 had 12 years left to operate and IP3 had 15 years left. The remaining operating period under the existing NRC licenses is 9 years and 11 years for IP2 and IP3, respectively, a reduction of 26%. Thus the improvement in market energy prices is largely offset by the reduction in operating lives.

[69] Estimated book value of the nuclear fuel and fuel oil inventories at the time of closing.

Since the improvement in market energy prices is largely offset by the reduction in IP2&3 operating lives, there is no net impact of these adjustments. LAI inflated the original purchase prices by inflation, *i.e.* Gross Domestic Product Implicit Price Deflator, to a January 1, 2005 valuation date. The combined adjusted purchase price is $1.2 billion, broken down as shown in Table 10 below, a useful FMV indicator under the Cost Approach:

Table 10 – Cost-Based Valuation
($ millions, excluding fuel inventory, including adjustments)

	IP2	IP3
Purchase Date	September, 2001	November, 2000
Original Purchase Price	$609	$525
Quarters to Jan 1, 2005	13	17
Escalation Factor[70]	1.047	1.067
Adjusted Purchase Price	$638	$560

4.3. Comparable Sales Approach

Prior to the sale of the first IP unit, IP3, there were eight sales of equity interests in nuclear power plants in 1998 and 1999. All of these sales were at low prices when considered on a $/MW basis as sellers and regulatory commissions tended to view these nuclear assets as liabilities, and there were few qualified and interested buyers.

Beginning with the sale of IP3 and FitzPatrick in November 2000, prices increased significantly as buyers considered these plants as profitable enterprises once they were incorporated into a nuclear fleet with the prospect of improved performance. Capacity-weighted nuclear sales prices, expressed in beginning of year 2005 dollars, averaged about $24/kW from 1999 until just prior to the IP3 and FitzPatrick sale, and have since averaged over $500/kW. The value of nuclear plants selling into the competitive market was also enhanced by the rise in market energy prices, particularly in NYISO, New England (ISO-NE), and PJM. Given the dramatic shift in nuclear plant transaction values, LAI considered only those nuclear plant transactions that occurred since November 2000. Each transaction is briefly described below. All prices are in then-current dollars.

- Millstone 1, 2, & 3 – Northeast Utilities sold its 100% interest in units 1 and 2, and its 93.5% interest in unit 3 in March 2001 to Dominion Resources for $1.19 billion plus $105 million for fuel inventory.[71] The parties did not enter into a PPA. The selling price was allocated as shown below. Since Millstone 1 had already been shut down, we did not include the nominal $1 million price or capacity in our comparable sale analysis.

[70] Inflation in 2004, 2003, 2002 and 2001 was 1.2%, 1.3%, 1.6% and 1.8%, respectively. We assume that long-term inflation will be 3% beginning in 2005.

[71] Millstone 1 was subsequently shut down.

	Millstone 1	Millstone 2	Millstone 3
Plant	$1 million	$402 million	$790 million
Fuel	0	$42 million	$63 million

- Seabrook – Co-owners Northeast Utilities, United Illuminating, BayCorp, National Grid, NSTAR, and New Hampshire Electric Coop sold their combined 88.2% interest in late 2002 to FPL Group for $749.1 million plus $61.9 million for fuel and $25.6 million for parts. The parties did not enter into a PPA. The selling price was allocated as follows:

Plant	$749 million
Fuel	$ 62 million
Parts	$ 26 million

- Vermont Yankee – Vermont Yankee sold its 100% interest in July 2002 to Entergy for a total selling price of $180 million. The parties executed a ten year PPA that called for Entergy to sell 100% of the plant's output power to the prior owners. The selling price was allocated as follows:

Plant	$145 million
Fuel	$ 35 million

- Nine Mile Point 1&2 – Niagara Mohawk sold its 100% interest in Nine Mile Point 1, and NiMo, NYSEG, RG&E, and CHG&E sold their combined 82% interests in Nine Mile Point 2 in November 2001 to Constellation Energy Group for $675 million plus $134 million in interest charges and $87 million for fuel inventory. The parties executed a ten year PPA under which Constellation would sell approximately 90% of the plants' output. The selling price was allocated as follows:

Plant	$809 million
Fuel	$ 87 million

- Peach Bottom 2&3, Hope Creek, Salem 1&2 – Conectiv sold its 7.5% equity interest in Peach Bottom to Exelon in January 2001 for $5.2 million and its 5% equity interest in Hope Creek plus its 7.4% equity interest in Salem to PSEG in October 2001 for $17.3 million.[72] The fuel inventory was sold for an estimated $50 million. The selling price was allocated as follows:

Plant	$ 22 million
Fuel	$ 50 million

- Ginna – Rochester Gas & Electric (RG&E, part of Energy East Corporation) sold its 100% interest in the Robert E. Ginna plant to Constellation in June 2004 for $422.6

[72] Operational problems at the Peach Bottom units contributed to the low sales price.

million. The transaction also includes a ten year PPA under which Constellation is selling 90% of the plant's energy and capacity to RG&E. The $837/kW sale price is the highest price to date for a nuclear plant sale.

Plant	$ 423 million
Fuel	$ 22 million

- Kewaunee – Wisconsin Public Service Corporation and Wisconsin Power & Light have agreed to sell their combined 100% interest in the Kewaunee nuclear plant to Dominion Resources for $220 million. The sale was approved by the NRC and the FERC but was denied by the Wisconsin Public Service Commission.

The plant sizes and plant sales prices for these nuclear transactions have been escalated to Q1 2005 prices and are shown in Figure 4 below. The Peach Bottom/Hope Creek/Salem sale was excluded from the following figures, because the sales price was unduly influenced by several operational problems at Peach Bottom 2&3:

Figure 4 – Nuclear Plant Sales – Plant Size and Purchase Price

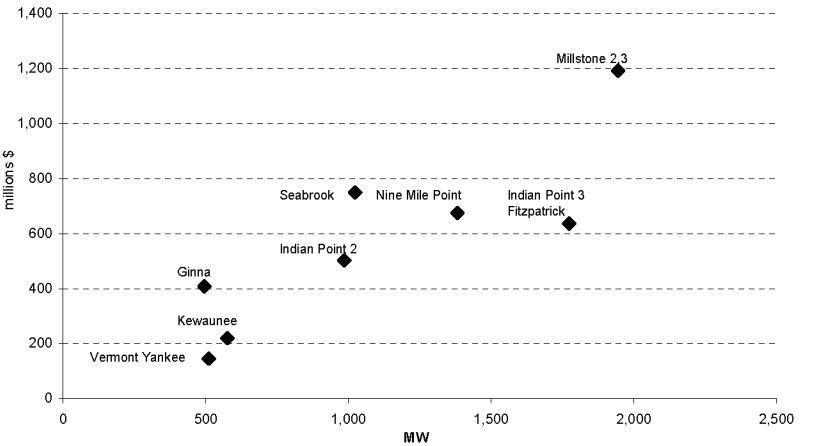
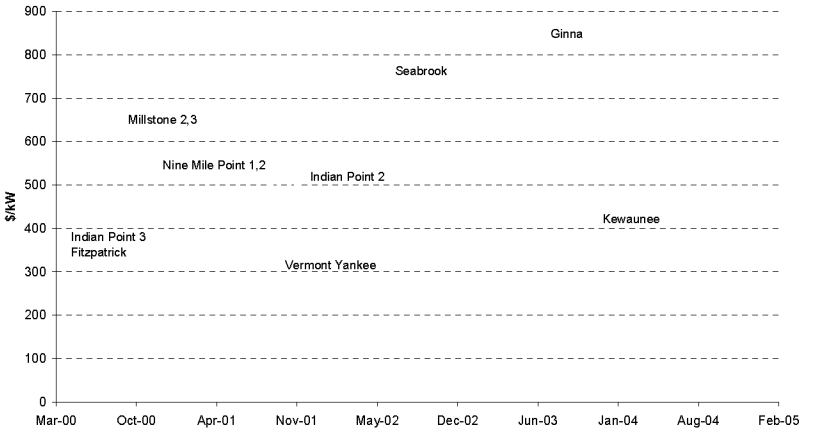


Figure 5 below indicates the nuclear plant sale prices per unit of capacity over time, beginning with the IP3 transaction:

Figure 5 – Nuclear Plant Sales – Transaction Date and Price



4.4. Earnings Approach

LAI believes that the Earnings Approach, also referred to as Capitalized Income Approach, provides the best basis for estimating the value of IP2&3. This approach is forward-looking and can account for the possible extension of the NRC license term. It is also the approach recommended and utilized by ORPS in its appraisal of IP. The Earnings Approach requires forecasting the revenues, operating expenses, net income, and net cash flow that Entergy would earn over the forecast horizon. The net cash flow is then discounted to a present value using a discount rate appropriate for the asset. LAI calculated IP values at various points in time assuming either that IP would be retired at the end of their current existing license periods in 2013/15, or alternatively at the end of twenty year license extensions in 2033/35.

4.5. Revenues

LAI forecasted the energy revenues for IP2&3 using the MarketSym chronological dispatch simulation model that simulates the hourly operation of the NYISO energy market. All generators submit bids to NYISO to provide energy on a day-ahead basis. The generators' energy bids typically are based on their variable operating costs, *e.g.* fuel, and may include a premium to recover fixed costs, *e.g.* labor, property taxes, capital cost recovery, as well. NYISO seeks to dispatch plants with the lowest bids possible, consistent with a safe and reliable system.[73] Under the current market rules, the highest bid accepted in any hour sets

[73] New York State is divided into 11 zones that may have differing market energy prices due to transmission constraints. A zone may have a relatively high market energy price if more expensive bids must be accepted to assure reliable energy supply in zones that have limited transmission import capacity. For example, (cont'd)

the market energy price paid to all generators operating in that hour. When system demand is low, the most expensive generator might be a coal-fired steam unit with low variable operating costs, therefore setting a low market energy price. When system demand is high, more expensive peaker plants are dispatched, setting a high market energy price. The MarketSym model takes into account the full range of variables that determine market energy prices.[74] These variables include:

- Load by zone based on historical hourly data and growing over time using NYISO forecasts.
- Supply based on the current mix and location of generators, known near-term supply additions and retirements, and forecasted long-term additions required to maintain the State's reliability requirement.
- The fuel type, efficiency (heat rate), availability, and other operational characteristics of each generator.
- Price forecasts for natural gas, distillate oil, residual oil, coal, uranium, and other fuel types.
- Transmission capacities and constraints within New York and with the surrounding markets of ISO-NE, PJM, Quebec, and Ontario

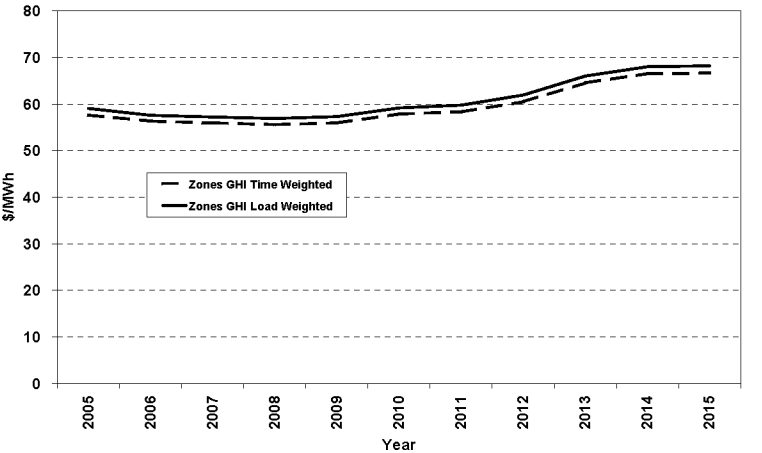
A nuclear plant such as IP has low variable operating costs and therefore operates mostly at full load whenever it is available, characteristic of base-load plants. Because IP operates as a base-load plant, it is "infra-marginal," meaning it is a price-taker, not a price-setter, in daily wholesale energy markets. The value of the energy is the cumulative value of the individual hourly market prices during each hour IP2&3 operate, multiplied by the net output delivered to NYISO. This approach implicitly values the contract prices in the PPAs that Entergy recently negotiated with Con Edison and NYPA at market prices.

A graph of LAI's forecast of average market energy prices for the years 2005-2015 for the Base Case in which IP is retired in 2013/15 is shown in Figure 6. These market energy prices are for the combined Zones G, H, and I (as defined by NYISO) that include Westchester and other counties to the north (as depicted in Figure 2). Market energy prices are relatively high by historical standards due to the high cost of gas and oil, the fuels used by generators that often set market energy prices during peak hours. The currently high energy prices have enhanced the bottom line for many base-load coal, uranium, or hydroelectric generators.

New York City (Zone J), and Long Island (Zone K), generally have much higher market energy prices than the rest of New York State. Our simulation modeling captures locational differences, and forecasts the appropriate market energy price for Westchester County.

[74] Our forecast of market energy prices do not incorporate potential second-order effects attributable to increased gas volatility throughout the winter if the gas-fired replacement generators do not have firm transportation rights. Generators are not required to have firm year-round transportation, and lacking such rights, we would expect more frequent pipeline congestion events.

Figure 6 – Base Case (Retirement in 2013/15) Forecast of Market Energy Prices



IP had PPAs to sell both capacity and energy to Con Edison and NYPA that expired on December 31, 2004. Both Con Edison and NYPA executed new PPAs with Entergy, and it is reasonable to assume that the PPA prices correspond to expected market energy prices. Buyers and sellers rationally set prices for multi-year bilateral contracts based on the prevailing outlook for wholesale power by location. Hence, buyers ordinarily do not pay more for contract energy than they could otherwise purchase in the competitive bulk power market. Generators likewise mark-to-market the value of energy, thereby setting price based on opportunity costs.[75] Thus LAI's forecast of market energy prices is the principal determinant of the Earnings Approach value of IP2&3.

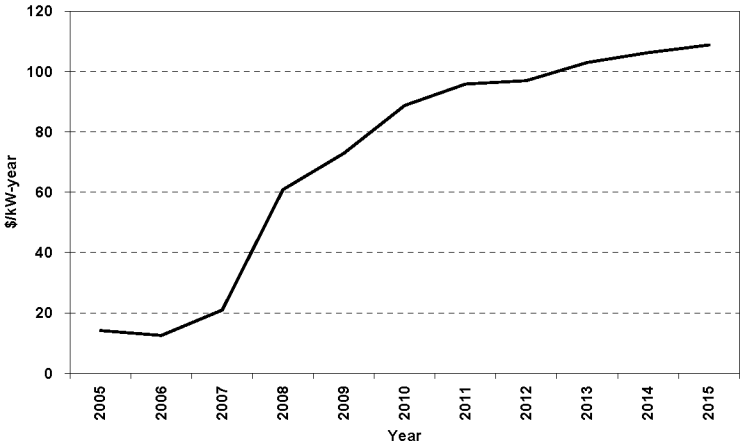
In addition to revenues derived from energy sales, generators in New York earn capacity revenues for being available for dispatch, regardless of the actual level of plant operation. Capacity prices are also location-based, reflecting the value of being located inside or outside of transmission-constrained zones. NYISO conducts auctions for capacity, matching bids from buyers with those from generators.[76] Whereas buyers may obtain part or all of their required capacity through PPAs, LAI believes that it is reasonable to assume that contractual

[75] While PPAs do reduce the volatility of market prices, this benefits both buyers and generators, so the effect is relatively neutral.

[76] NYISO also administers markets for ancillary services (*e.g.* spinning and non-spinning reserves), that are required from generators to assure the safe and reliable operation of the bulk power system. Revenues from such ancillary services are not material for IP.

capacity rates tend to follow market capacity rates. We forecast market capacity prices using proprietary in-house models that simulate NYISO's demand curve mechanism.

Figure 7 – Base Case (Retirement in 2013/15) Forecast of Market Capacity Prices



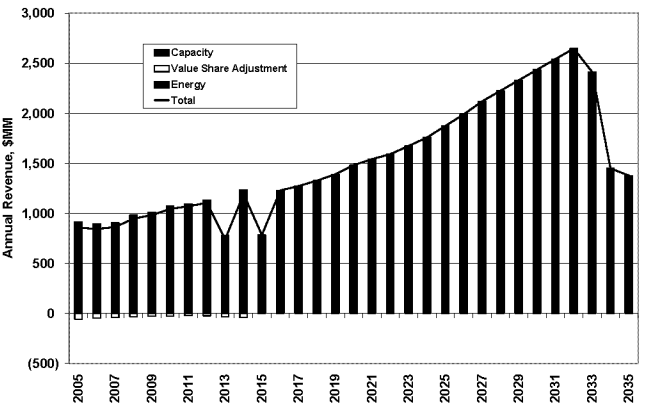
Although IP has strong transmission ties into New York City, market capacity rates are currently low for all generators outside of New York City and Long Island due to excess capacity above the State's 18% reserve margin target. These capacity rates are expected to rise as demand increases over time and the market "tightens up", as shown in Figure 7. Our expectation of timely and sufficient replacement generation would result in an 18% reserve margin in each year, and would leave market capacity prices unchanged. If there is any lag in the timing of replacement generation that leaves the State short of its 18% target, market capacity prices would rise, attracting investment but raising customer rates in the short-run until new generation restored the supply / demand balance.

Given our assumption of an 85% capacity factor, we forecast that IP will be entitled to roughly $100-$150 million of capacity revenues per year through the term of the existing operating licenses. Table 11 summarize IP's revenue outlook through the term of the existing operating licenses. Note that gross energy revenue is adjusted by the provisions of the Value Sharing Agreement applicable to IP3 generation.

Table 11 – Base Case (Retirement in 2013/15) Energy and Capacity Revenues
($ millions)

Year	Gross Energy Revenue	Value Sharing Adjustment	Capacity Revenue	Total
2005	$ 886.0	$ (59.1)	$ 29.2	$ 856.2
2006	$ 866.1	$ (49.0)	$ 25.8	$ 842.9
2007	$ 860.0	$ (41.4)	$ 43.2	$ 861.7
2008	$ 854.4	$ (33.8)	$ 125.6	$ 946.2
2009	$ 860.2	$ (28.8)	$ 150.5	$ 981.8
2010	$ 889.6	$ (29.6)	$ 183.1	$1,043.2
2011	$ 896.5	$ (24.4)	$ 197.7	$1,069.9
2012	$ 930.0	$ (25.7)	$ 200.1	$1,104.4
2013	$ 882.1	$ (37.6)	$ 186.3	$1,030.8
2014	$ 537.3	$ (43.7)	$ 109.4	$ 603.0
2015	$ 495.8	$ 0.0	$ 102.7	$ 598.5

Figure 8 – Life Extension Case Revenue Forecast w/ 20-year License Extension



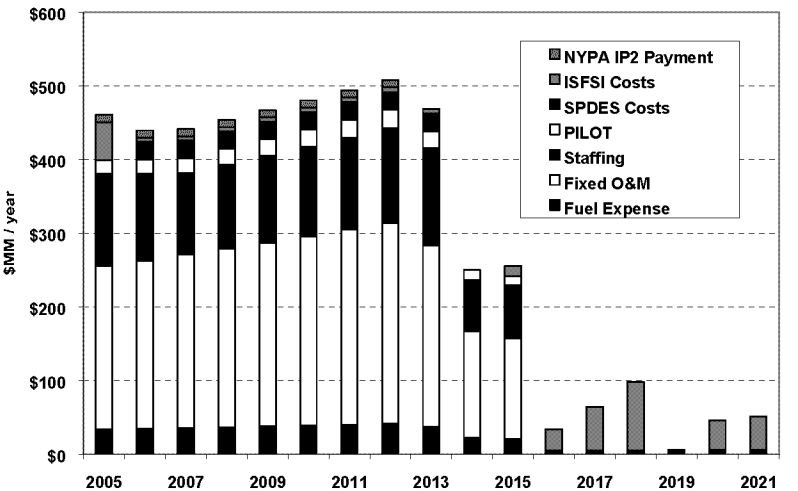
If Entergy is successful in extending the IP license terms for twenty years, IP's energy and capacity revenues are forecast to increase over time as shown in

Figure 8. Note that revenues drop off in 2013 and 2015 as the units are converted to a closed-cycle cooling system. Energy revenues appear to increase rapidly as inflation and real gas costs put upward pressure on market energy prices. In the last two years shown, revenues drop by one-half once IP2 is retired in 2033.

4.6. Operating Expenses

In order to forecast IP's expected operating expenses and CapEx, LAI relied principally on data from an NEI study prepared for Entergy, "Economic Benefits of Indian Point Energy Center" that was published in April 2004.[77] Entergy is not required to file as much data for IP, a non-utility merchant plant, than for a utility plant in rate base. We have supplemented this NEI data with relevant industry data and our own in-house data including that of other PWR nuclear plants. We are confident that our assumptions regarding operating expenses and CapEx are reasonable, and have documented the foundations for these assumptions in this section of our report. The total Base Case operating expenses are summarized in Figure 9 below.

Figure 9 – Estimated Base Case (Retirement in 2013/15) Operating Expenses



[77] Operating expenses are deductible for income tax purposes in the year incurred. CapEx is added to the asset base and then depreciated for income tax purposes over the useful life of the expenditure.

Non-Fuel Operating Expenses

IP operating expenses, excluding fuel and PILOT, can be divided into four key components – personnel, maintenance, administrative expenses, and taxes, which for 2002 totaled $453.8 million according to the NEI Study. If IP continues to operate beyond the current license term, operating expenses are projected to be much higher due to more frequent repairs and replacement of equipment, consistent with current industry experience.

Personnel – Labor is a large expense at IP. According to the NEI Study, there were 1,683 employees at IP and the Entergy Nuclear Northeast office in White Plains as of 2002.[78] Westchester's Planning Department lists IP employment at 1,550 as of 2001 and the current IP "Factsheet" (which may be out-of-date) lists 1,500 employees, which we assume excludes the White Plains office. An article in the *Westchester County Business Journal* indicates that total employment decreased to 1,355, plus 160 at the White Plains office, as of mid-2004.[79] We have assumed this latest employment figure.

Entergy has announced its intention to reduce IP's staff from 1,500 to between 1,000 and 1,100 to improve profitability.[80] We assume this reduction excludes the White Plains staff, and have assumed that IP employment will decline over the next three years, reaching a mid-point value of 1,050 as of 2007.

According to the NEI Study, IP personnel had average earnings of $95,000 in 2002.[81] Assuming average annual increases equivalent to the inflation rate, the average earnings in 2005 would be $100,312 as shown in the first line of Table 12 below.[82] We have assumed that average earnings will continue to increase at roughly the rate of inflation, and that plant operating staff receive higher compensation than security personnel. Total personnel expenses for the years 2005-2015 are listed in the second-to-last column of Table 12 below. We also include estimated decommissioning staff, although those costs can be recovered from the decommissioning funds and are therefore not a cost *per se*.

- Base Case Scenario without License Extension – If IP2 is retired at the end of the current NRC license term, operating personnel levels will begin to decline as each unit ceases operating while SNF and decommissioning personnel will increase. When IP3 is retired we estimate that SNF personnel will increase to 400 and site security staff

[78] Entergy Nuclear Northeast provides management and administrative services for Entergy's fleet of five non-utility nuclear plants.

[79] Westchester County Business Journal, April 26, 2004, "Industry group touts impact of indian point", by Alex Philippidis.

[80] Alex Philippidis. Westchester County Business Journal, September 2, 2002. *"Indian Pt. building designed for fewer jobs"*

[81] The actual data provided in the NEI Study indicates average earnings of $96,000; the discrepancy may be due to the fact that White Plains personnel have higher earnings than IP staff.

[82] We assume that pay raises in excess of inflation for existing employees will be offset by the lower starting salaries of new employees.

requirements will decrease slightly. SNF and decommissioning activities should be completed by 2025, at which time the site could be closed or sold.

- Entergy will be responsible for all of the operating, security, and SNF costs. The costs for decommissioning personnel, shown in the last column in Table 12, should be recoverable from the decommissioning funds, and are therefore not included as a cost in our valuation.[83] However, the decommissioning personnel costs are significant and are included in our consideration of local and State-wide economic impacts.

Table 12 – Estimated Personnel Levels and Expenses with 2013/15 Retirement

Year	Operating Staff	Security Personnel	SNF Personnel	Expenses (millions)	Decommissioning
2005	1,180	70	0	$ 125.2	0
2006	1,080	70	0	$ 118.5	0
2007	980	70	0	$ 111.2	0
2008	980	70	0	$ 114.6	0
2009	980	70	0	$ 118.0	20
2010	980	70	0	$ 121.5	60
2011	980	70	0	$ 125.2	100
2012	980	70	0	$ 128.9	160
2013	980	70	0	$ 132.8	240
2014	490	50	250	$ 103.0	340
2015	490	50	250	$ 106.1	420
2016	0	50	400	$ 61.3	480
2017	0	50	400	$ 63.2	500
2018	0	50	400	$ 65.0	500
2019	0	50	400	$ 67.0	500
2020	0	50	400	$ 69.0	500
2021	0	50	0	$ 5.6	500
2022	0	50	0	$ 5.8	500
2023	0	50	0	$ 6.0	500
2024	0	50	0	$ 6.2	500
2025	0	50	0	$ 6.3	500

- License Extension Scenario – If Entergy is successful in extending the NRC licenses, there will be a number of changes to the personnel assumptions and expenses listed in the table above. Operating personnel will be maintained at the 1,050 level as proposed by Entergy, SNF management will still be required as the wet storage pools are filled and SNF is loaded into dry storage casks, and decommissioning activities will be delayed until retirement in 2033/2035.

[83] Up to 4% of the Decommissioning Funds can be used for studies and other decommissioning preparations.

- Retirement in 2005 – In the unrealistic event that IP would have been retired on January 1, 2005, we expect that the entire personnel shift from operations to SNF and decommissioning functions will occur quickly, and that the duration of SNF and decommissioning will not change significantly.

- Retirement in 2008 – If IP were to be retired in 2008 we expect that the entire personnel shift from operating to SNF and decommissioning functions will occur gradually as in the Base Case, with the same duration of activities.

Maintenance Expense – According to the NEI report, total 2002 expenditures for IP and Entergy's administrative office in White Plains were $448.9 million. Ignoring personnel compensation of $161.2 million and fuel expenses of $30.2 million leaves total maintenance expenditures of $257.5 million. In order to divide these expenditures between IP and White Plains, we have assumed a 75% / 25% split for certain activity categories, as well as the fact that IP would require fewer administrative and overhead-type services than White Plains on a per-employee basis. The resulting expenditure estimates are shown in Table 13 below.

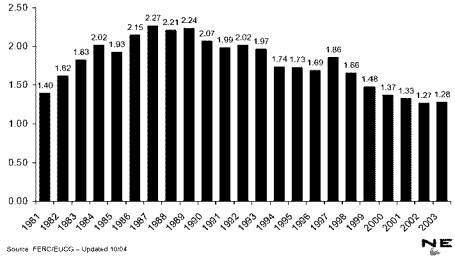
Table 13 – Estimated Breakdown of IP Maintenance Expenses[84]
(2002; $ millions)

Activity	NEI Study	IP	White Plains
Maintenance & Repair	$ 57.5	$ 57.5	-
Mgt and Consul Svcs	$ 35.4	$ 26.6	$ 8.8
Eng & Arch Services	$ 16.0	$ 16.0	-
Electric Utilities	$ 12.7	$ 9.5	$ 3.2
Fed'l Gov't Enterprises	$ 10.6	$ 8.0	$ 2.7
Computer & Data Proc	$ 10.4	$ 7.8	$ 2.6
Motors & Generators	$ 10.2	$ 10.2	-
Building Services	$ 9.7	$ 9.7	-
Insurance Agents	$ 8.9	-	$ 8.9
Other	$ 86.2	$ 64.6	$21.5
Total	$257.5	$209.8	$47.7

IP's maintenance expenses should increase with inflation over the next decade. However, if the IP operating licenses are extended, we estimate that maintenance expenses will increase an additional $10 million/year (2004 dollars) for each unit due to the added costs of maintaining the closed-cycle cooling system and more equipment requiring repair and replacement due to aging (as discussed below).

[84] Source: NEI Study

Figure 10 – Industry Average Non-Fuel O&M Costs (1981-2003)
(2003 cents per kWh)



LAI confirmed the reasonableness of our personnel and maintenance expense data tabulated above by comparing it to industry data reported by NEI. The average non-fuel O&M costs for all domestic nuclear plants has been declining over time and was reported to be as shown in Figure 10. In order to compare the 2003 industry average cost of 1.28¢/kWh to actual IP costs, we first assume an IP staff level of 1,050 ("right-sized" per Entergy's announced plans) at an average compensation of $96,235 (reported 2002 compensation plus one year of inflation). The resulting personnel cost is $101.0 million. Second, we add the IP maintenance expenditures of $209.8 from Table 13 above. Third, we divide the total non-fuel O&M expenditures by IP generation. According to NEI statistics, IP2 generated 8,375 GWh in 2003, and IP3 generated 7,607 GWh. The resulting O&M costs using IP data are provided in Table 14 below and appear to be higher than the nuclear industry plant average, even at the reduced staffing level. The higher operating expenditures may be explained by the higher cost of living in the area around IP, and the additional costs of keeping IP1 in SAFSTOR condition.

Table 14 – Estimated Non-Fuel O&M Expenditures
(2002 $ millions except as noted)

Personnel	$101.0
Maintenance	$209.8
Total	$310.8
Generation	13,982 GWh
Average Cost	2.22¢/kWh

License Renewal – The costs and schedule for preparing and pursuing a license renewal varies, depending on the status of the plant under consideration. According to a study

prepared by the EIA, the estimated cost to prepare a license extension application and for NRC review was $17.5 million in 1999.[85] These costs are in line with the Xcel Energy 2004 Resource Plan, which estimates $19 million for the relicensing costs associated with Prairie Island, a two unit Westinghouse PWR similar to IP. These estimates only include the costs associated with the development, preparation, submittal and subsequent NRC review of the application, and exclude any hardware upgrades at the site.[86] The overall schedule for a license extension decision from the NRC is approximately four years. That schedule includes an initial two year period for the development and submittal of the application, plus another two years for the NRC review and approval.

SPDES Escrow Payment – Under the terms of the draft State Pollution Discharge Elimination System (SPDES) permit, Entergy will be required to contribute $24 million per year into an escrow account from the time the final SPDES permit is issued to the time that construction on the cooling towers commences. Under the License Extension scenario, we anticipate that construction will take four years and will be completed in 2013. Thus Entergy would have to make escrow payments from 2006 through 2009. Under the Base Case scenario without license extension, Entergy would have to make escrow payments from 2006 though 2015. In the scenarios in which IP is retired in 2005 or 2008, we do not expect that Entergy would have to make further escrow payments.

Fuel Expenses

According to the NEI Study, IP purchased $30.2 million of uranium fuel in 2002 for one refueling. When IP's fuel expense is divided by IP generation for that same year, the resulting value is 0.19¢/kWh. In order to confirm the reasonableness of this expense we compared it to the 2003 industry average of 0.44¢/kWh as shown in Figure 11 below, provided by NEI. The U.S. nuclear fleet has plants that have refueling cycles that vary from as short as 12 months to as long as 24 months. Assuming an average of 18 months, the 0.44¢/kWh industry average should be adjusted to 0.33¢/kWh for plants, such as IP2&3, which are on a 24 month cycle. While IP's value is less than the adjusted industry average, it appears reasonable for a single refueling outage. In addition, IP's cost would be higher and closer to the industry average if the plant operated at an 85% capacity factor as we anticipate for the long-term.

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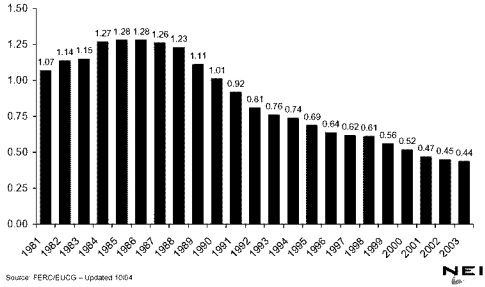
[85] Appendix E-3, Nuclear Power Plant Analysis of Annual Energy Outlook 1999, prepared by the EIA for the DOE.

[86] These costs do not include the cost to convert to closed-cycle cooling and other CapEx items discussed below.

Figure 11 – Industry Average Fuel Costs (1981-2003)
(2003 cents per kWh)



Capital Expenditures

Maintaining nuclear power plants requires significant CapEx to replace primary equipment components. In order to accurately estimate future CapEx requirements at IP, we have divided CapEx into the following principal changes (major modifications):

- Fuel Storage Building Gantry Crane
- Spent Fuel Pool Re-Racking or Dry Spent Fuel Storage
- Reactor Vessel Head Replacement
- Steam Generators
- Pressurizer Replacement and/or Repairs
- Closed-Cycle with Cooling Towers

If IP operates beyond 2013/15, we estimate that Entergy will spend over $1 billion, principally to convert the existing once-through cooling system to a hybrid cooling tower design. Other CapEx requirements are discussed below. In addition, we estimate that CapEx generally will increase $10 million/year for each unit over IP's remaining life, and maintenance expenses will also increase by $10 million/year for each unit, both due to plant aging. We calculate that license extension would be cost-effective in relation to the value of capacity and energy from the units over the anticipated twenty years of extended plant life. However, Entergy may be less inclined to pursue license extension if the CapEx requirement is higher than our estimate or if market power prices are lower than we forecasted. In either case, postulated compensation amounts to Entergy would be lower.

Fuel Storage Building Gantry Crane – On December 29, 2003 Entergy gave notice to the NRC of their plans to construct an ISFSI at IP to store SNF. Entergy is planning on using the Holtec International HI-STORM 100 Cask System with the HI-TRAC 100 spent fuel transfer cask, which requires a single-failure-proof gantry crane and hoist to be installed in both IP2&3. The existing 40-ton overhead cranes in IP2&3 are not single-failure-proof and do not have sufficient capacity to handle the Holtec HI-TRAC 100 spent fuel transfer cask. However, they will remain in place and will be utilized for other load handling activities in the FSB.

Per Entergy's June 16, 2004 submittal to the NRC, a new gantry crane with a design rated load capacity of 110 tons will be installed in the IP2 fuel storage building. The crane will be used to move dry cask storage equipment into and out of the spent fuel pool. The crane design and associated handling equipment must conform to:

- NUREG-0554, Single-Failure-Proof Cranes for Nuclear Power Plants
- NUREG-0612, Control of Heavy Loads at Nuclear Power Plants, for heavy load lifts over the spent fuel pit

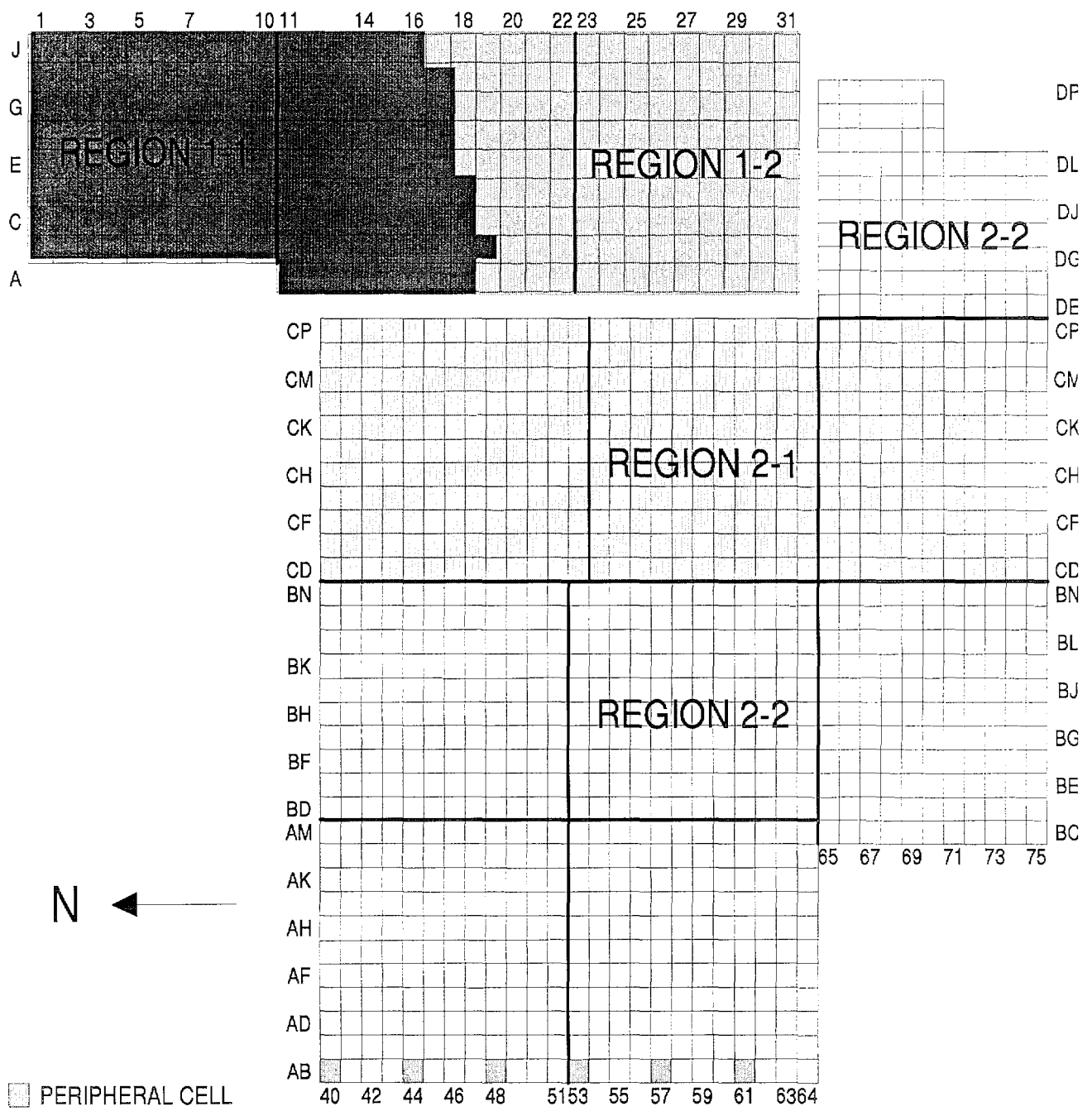
The estimated cost per plant installation is $7 million, which would equal approximately $14 million for both units.

Spent Fuel Pool Re-Racking or Dry Spent Fuel Storage – Nuclear plants typically replace a third of the fuel (approximately 65 fuel assemblies) at each refueling cycle. As with all domestic nuclear plants, SNF is placed in storage pools on site for several years following discharge where the SNF cools off. These storage pools are made more effective by adding boron, which absorbs neutrons from the SNF and allow more SNF to be stored in the pools. IP2&3 uses Boraflex, a metallic material that provides for the nonproductive absorption of neutrons and therefore permits SNF assemblies to be stored more densely.

IP2 had problems with Boraflex degradation as documented in a Licensee Event Report to the NRC in 2000. Because of Boraflex degradation, IP2 will not have full core offload capacity after 2006 and IP3 will not have full core offload capacity after 2009. The immediate cause of the degradation was dissolution of the boron from the Boraflex matrix. Boraflex, a neutron-absorbing material, consists of about 50% (by weight) boron carbide, and about 50% polymer matrix that contains the boron carbide. In the spent fuel storage pool, the Boraflex is exposed to the aqueous pool environment and high gamma radiation. Under these service conditions, the physical and chemical properties of Boraflex change, including shrinkage, gap formation, and Boraflex dissolution (the boron carbide dissolving into the water).

In the short term, this issue restricts the operational flexibility in IP's spent fuel pools since the SNF must to be stored in a "checkerboard" fuel distribution pattern in the racks. Fuel assemblies to be stored in the different defined regions of the spent fuel pool are identified or qualified based on burn-up, enrichment, and cooling times. A schematic diagram of the IP2 Spent Fuel Pool is provided below in Figure 12. The different regions denoted in the spent fuel pool schematic relate to the characteristics of the SNF that can be stored on those regions.

Figure 12 – Schematic Diagram of IP2 Spent Fuel Pool



IP2 needs a dry SNF storage management program in order to remain operational through the existing plant life. Re-racking is not an efficient option, and IP2 has already performed a re-racking in the 1990/91 timeframe. A dry storage program requires the following:

- Procure a SNF management solution/technology
- Design/construction of an ISFSI
- Implement a dry fuel storage loading campaign on-site

The technical aspects of a dry fuel storage management program are addressed in the Decommissioning and Spent Fuel Management section of this report. It is expected that Entergy will subcontract the work of establishing an ISFSI and loading the fuel into the dry casks. We estimate the total cost to be $70 million (all 2004 $) to design, license, and construct the ISFSI, $10 million to install rigging / ancillary equipment, and $40 million (*i.e.* 16 casks at $2.5 million/cask) to remove the SNF from wet storage, load in casks, and transport onto the ISFSI pad over the next ten years. We estimate that about $30 million has been spent prior to 2005 and is therefore not included in our analysis. A second, larger ISFSI will be required to accommodate additional SNF soon after the current NRC licenses expire.

The estimated CapEx for the larger ISFSI is $70 million (all 2004 $) to design, license, and install the pad in 2015-2017 (which represents a cost savings over the first ISFSI), plus $1.25 million/cask (again incorporating a cost savings compared to the first ISFSI) to remove the SNF and store an additional 91 casks in a major campaign in the 2018-2021 period assuming retirement at the end of the existing license terms.

Reactor Pressure Vessel Head Inspection, Repair and Replacement – The reactor pressure vessel (RPV) heads of PWRs have penetrations for control rod drive mechanisms and instrumentation systems. Nickel-based alloys (*e.g.* Alloy 600) were commonly used in the penetration nozzles and related welds. Primary coolant water and the operating conditions of PWR plants can cause cracking of these nickel-based alloys through a process called primary water stress corrosion cracking. The susceptibility of RPV head penetrations to corrosion cracking appears to be strongly linked to plant operating time and the temperature of the RPV head. Problems have therefore increased as plants have operated for longer periods of time. An example of such corrosion cracking found at the Davis-Besse plant is shown below.

Figure 13 – Example of Reactor Vessel Head Cracking

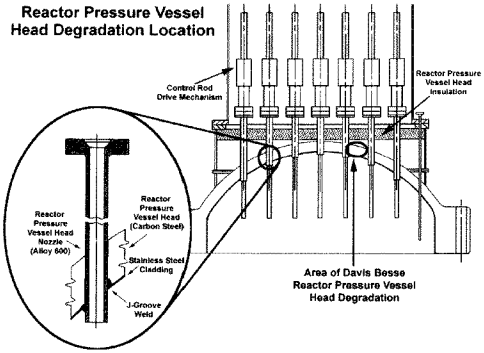


Photo courtesy of NRC

This issue is a concern for both IP units. IP3 must follow NRC inspection requirements for a moderate category plant, which requires RPV head inspections at least once over the course of every 2 refueling outages. The RPV head inspection frequency for IP2 is assumed to be the same as IP3. Both IP2&3 are operating on 24-month fuel cycles; therefore inspections would be performed at least once every 4 years. As of February 2004, 32 PWRs out of 69 in operation have or are proceeding with RPV head replacements. Thus RPV head replacement is likely at IP2&3. According to NEI, estimated inspection and repair costs are:

- $1.5 million per outage for the average RPV head inspections and stand-by repair capability.

- Repairs are estimated to cost approximately $1 million per nozzle. There are approximately 70 nozzles per RPV head.

Per recent industry experience, the costs for inspections and repair at other PWRs were:

- $5.5 million for NRC Mandated NDE Inspections per unit (Florida Power and Light Company).

- The cost of inspection and repair services at St. Lucie Unit 2 (Florida Power and Light Company) was approximately $11 million and lengthened the outage by 14 days.

- Approximately $7 million for RPV head inspections per unit at Prairie Island.

Based on this data, the industry estimate for RPV head replacements that would be applicable at IP2&3 are:

- NEI - $20 to $25 million

- Davis-Besse nuclear plant - $55 to $75 million

- Forbes Magazine[87] - $60 million

- General industry experience - $40 to $50 million

The costs to replace both IP2&3 RPV heads are estimated to range from $50 million (per NEI) to $150 million (per Davis-Besse). Given these data, and the significant number of PWR units that have or are proceeding with RPV head replacements, we estimate the cost at $100 million (2004 $) for both IP units. This CapEx might be required prior to their current license expiration, but we have made the reasonable assumption that this work would be conducted at the same time the cooling system is converted to a closed-cycle to minimize the plant outage time.

Steam Generators – All of the IP steam generators, in which heat produced in the reactor vessel is transferred to a secondary steam loops, have been replaced since the units originally became operational. The four steam generators in IP3 were replaced in 1989, and the four steam generators in IP2 were replaced in 2000 as a result of a generator tube rupture on February 15th of that year. The steam generators currently in service at IP2&3 should not need to be replaced again for the remainder of the current NRC license. If steam generators were required to be replaced prior to the current license termination date, it probably would not be economically prudent unless license extensions were being requested. If the NRC license is extended, the steam generators could require replacement again.

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[87] *U.S. Reactor Repairs Seen Topping $1 Billion.* Forbes Magazine. December 12, 2002

Pressurizer – Pressurizers are vessels that contain a mixture of steam and water for pressure control in the primary system. Operating experience, both domestic and foreign, has demonstrated that metals and welds (particularly Alloy 82/182/600) in PWR pressurizers are susceptible to primary water stress corrosion cracking (PWSCC).[88] Most recent leakage events were the result of axially-oriented PWSCC of the pressure boundary portion of pressurizer heater sleeves. Recent non-destructive examination results on heater sleeves have demonstrated that circumferentially-oriented PWSCC can occur in the non-pressure boundary portion of these components.

The NRC issued Bulletin 2004-01 on May 28, 2004 requiring all holders of operating licenses to evaluate their plants for this condition. On July 26, 2004 Entergy Nuclear Northeast responded that the pressurizers at IP2&3 do not contain Alloy 82/182/600 components. While no further action is required, IP2&3 will continue to monitor industry experience relative to cracking of these components and will enhance the applicable inspection programs in the future if warranted.[89]

Closed-Cycle with Cooling Towers – As mentioned previously, the DEC has issued a draft SPDES permit for IP. The draft permit effectively requires IP to replace its once-through cooling system that uses Hudson River water with a closed-cycle system utilizing cooling towers that will minimize environmental impacts. Closed-cycle cooling recirculates cooling water in a closed system; the only need for additional cooling water would be to make up water lost due to evaporation and water extracted from the closed system to flush out contaminants.

Entergy's analysis showed that the construction of hybrid cooling towers is generally feasible. Converting to a closed system is expected to require that each unit be out of service for nine months. Entergy may take advantage of this lengthy shut-down period to undertake some of the repairs / replacements / enhancements discussed above, or other CapEx, *e.g.* new steam turbines with improved efficiencies.

Entergy's projected capital cost to construct hybrid cooling towers for IP2&3 is approximately $740 million (2004 $), with additional O&M expenses of $145 million projected over the life of the plant (assuming each unit receives a 20-year life extension). We interpret this expense estimate to include the reduction in plant output as well as the additional O&M expenses for the cooling towers. As explained in Attachment 1, we estimate that output

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[88] Extensive operational experience with PWSCC in Alloy 82/182/600 materials used in the fabrication of pressurizer penetrations and steam space piping connections is not surprising. The initiation and growth of PWSCC flaws is known to be strongly dependent on the temperature of the primary system water to which the Alloy 82/182/600 materials are exposed and the length of the exposure. At the pressurizer, the reactor coolant system environment operates at a temperature of about 650°F (343°C), so PWSCC should be expected to occur in these materials and an effective degradation management program is warranted.

[89] A similar example occurred recently at San Onofre Unit 3, where cracks were discovered in the water heaters attached to the pressurizers during a scheduled refueling outage. Replacing the heaters was expected to extend the outage from just under 2 months to 3½ months, at an estimated cost of close to $7 million excluding the cost of replacement energy. At some point the steam generators will need to be replaced as well, at an estimated cost of $600 million.

would be reduced by 3%-5% due to pumping requirements and poorer condenser performance.

The estimated cost of the cooling towers may be a conservative value because IP will be required to have an emergency service cooling water system. In case of a failure in the cooling tower system, IP2&3 will need an alternative source of cooling water, referred to as an "Ultimate Heat Sink". Entergy may be able to use the existing Hudson River intake structure for this purpose, or may need to design and construct some other water source to address emergency conditions. We do not know if this additional cost will be significant and if it is included in Entergy's $740 million estimate.

In spite of the considerable CapEx to convert to cooling towers, LAI believes this will be cost-effective for Entergy because of the high market values for energy and capacity from IP2&3 over the anticipated twenty year extended plant life. However, if the CapEx requirement is higher than our $1 billion estimate, if the NRC approval is for less than twenty years, or if power prices retreat from the high values we forecast, Entergy may be less inclined to pursue license extension.

4.7. Discount Rate

In order to estimate the present value of prospective IP earnings it is necessary to discount future IP after-tax unleveraged net cash flows to a financially equivalent lump sum as of a defined valuation date. We have used discount rates that reflect the after-tax weighted average cost of capital (WACC) for a merchant nuclear power plant owner/operator. The discount rate is tantamount to the "hurdle rate" or threshold internal rate of return (IRR) that a company would find acceptable in committing discretionary capital to a nuclear plant, whose revenues are market-based. A WACC may consist of both equity and debt components in proportion to the capital structure of the investment. The required return on equity (ROE) and the cost of debt (adjusted for tax-deductibility) comprise the WACC, provided that both the ROE and debt interest rate fully reflect the risks of a merchant nuclear plant rather than the lower risks of an integrated energy company such as Entergy.[90]

Discount Rates and Risk – Nuclear plants are considered to be risky relative to other power generation technologies (as explained below). Merchant plants, such as IP, have additional risk compared to utility plants that have the assurance of recovering operating and capital costs through rates. LAI reviewed two documents published by Standard & Poor's (S&P), a major rating agency that provides information to financial investors and institutions. These documents, summarized below, describe the unique risks faced by owners of nuclear power plants. Entergy itself recognizes the unique risks of merchant nuclear plants and IP in particular. In its 2003 Annual Report, under the section titled "Management's Financial Discussion and Analysis" Entergy addressed the risks of owning and operating utility and non-utility nuclear plants. After one paragraph that briefly describes the various nuclear risks,

[90] The discount rate for the County of Westchester was assumed to be 4.0%, roughly equivalent to the estimated cost of GO tax-exempt debt as described on page 21.

Entergy devoted the remaining four paragraphs to safety-related issues surrounding IP; no other individual plant was mentioned.

S&P issued a report in 2003, *Time for a New Start for U.S. Nuclear Energy?* that addressed the future of nuclear power in light of then-current federal Energy Bill legislation designed to support nuclear investment. The S&P Report, provided as Attachment 5, highlighted the unique risks that investors face, divided into four categories:

- Pre-construction risks of cost growth, permitting delays, public opposition, and scope changes.
- Construction risks of cost growth, public opposition, regulatory changes, scope changes, construction delays, procurement delays, finance delays, and permitting / licensing delays.
- Operating risks of public opposition, regulatory changes, permitting / licensing delays, latent technical defects, market risk, fuel disposal, "mishap" repair costs, forced outages, and replacement power obligations.
- Decommissioning risks of regulatory changes, permitting changes, public opposition, disposal costs, and land reclamation costs.

While not all of these risks apply to IP, even nuclear plants beyond the permitting and construction stage expose owners to significant risks. The S&P Report states that:

> "…an electric utility with a nuclear plant exposure has weaker credit than one without and can expect to pay more on the margin for credit. Federal support of construction costs will do little to change that reality. Therefore, were a utility to embark on a new or expanded nuclear endeavor, Standard & Poor's would likely revisit its rating on the utility."

IP has the additional risk of being a merchant plant and not entitled to rate base treatment.[91] The S&P Report states that:

> "Clearly buying and selling electricity in a competitive environment comes with its risks, both market and political….These events (popularly referred to as the California "meltdown"), combined with the credit crunch that has hit many other utilities and energy merchants, have understandably moved public utility commissioners and capital providers into more risk-adverse postures. Absent these problems, nuclear power would still be challenged to attract new capital; in this environment, however, the task is all the more difficult."

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[91] The S&P Report makes the point that not even rate-base treatment protects investors. For example, the $400 million estimated cost to repair the Davis-Besse plant, not including replacement power, is unrecoverable from ratepayers, leaving shareholders to shoulder the cost.

Although S&P did not quantify a risk premium or minimum IRR, the Report concluded:

> "Investors, particularly lenders who rarely see any upside potential in cutting-edge technology investments, including energy, will likely find the potential downside credit risk on an advanced, nuclear power plant too much to bear unless a third party can cover some of the risks. An Energy Bill that covers advanced design nuclear plant construction risk may go a long way toward allaying those concerns, but if operational and decommissioning risks remain uncovered, look for lenders to sit this opportunity out."

In September 2004 S&P published a Commentary, *Evaluating Risks Associated with Unregulated Nuclear Power Generation*, provided as Attachment 6, which focused on the various risks faced by owners of merchant nuclear power plants:

- Environmental and safety compliance risks
- Risks associated with the storage of spent nuclear fuel
- Decommissioning risk
- Operational performance

While the companies that own and operate these plants have been successful, S&P states that "some element of event risk will always remain with this business strategy, which could ultimately impinge on credit quality." S&P explains:

> "In Standard & Poor's view, these nonregulated nuclear operations have higher risk than those plants that reside in a regulated utility business. Mostly, nonregulated plants lack the safety net afforded to those plants that are part of a regulated utility. The absence of this protection presents uncertainty regarding the ability to recover certain costs. Also, decommissioning risk is greater because underfunding cannot be recovered through the regulatory process."

Together, these two S&P documents demonstrate that merchant nuclear plants are viewed as much riskier than non-nuclear or utility-owned power plants.

Discount Rate Values – LAI researched available public sources of discount rates appropriate for merchant nuclear power plants as summarized below.[92] In our judgment, a 14%-20% discount rate is a reasonable range for our valuation analysis based on the following sources:

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[92] The FERC used to prepare benchmark returns on equity to establish a common basis for rate-setting purposes that would have been useful for our purposes, but no longer does so. FERC does not set rates for merchant plants.

- Public Utilities Fortnightly – supports a 15% discount rate
- Conference Paper on New Nuclear Plants – supports a 20% equity hurdle rate
- State Regulatory Decisions – supports a 14%-22% discount rate
- LAI Experience – supports a 14%-20% discount rate
- Bodington & Company Study – supports a 18.5% discount rate

Public Utilities Fortnightly – Triggering Nuclear Development

An article in the May 2004 issue of *Public Utilities Fortnightly* by Geoffrey Rothwell, Associate Director of the Public Policy Program and a senior lecturer at Stanford University, addressed how generating companies should evaluate the risks of investing in new nuclear power plants.[93] In his analysis Dr. Rothwell derived a 12% risk-adjusted real discount rate for nuclear power plant net revenues using a real options approach to estimate the risk premium above the real cost of capital. Dr. Rothwell's approach is based on estimates of specific sources of variability in nuclear power plant net revenues electric energy prices – energy prices, output, and operating costs. While this approach was applied to a potential new nuclear power plant investment, it could be applied to the valuation of an existing nuclear generation asset as well, since the uncertainty variables modeled by Rothwell would have identical or similar distributions for either a new plant or an existing plant.

A real risk-adjusted discount rate of 12% would be equivalent to a nominal discount rate of about 15%, assuming the 3% general inflation rate used herein.

Conference Paper – The Business Case for Building a New Nuclear Plant in the U.S.

J. Redding of GE Nuclear Energy, C. Muench of Black & Veatch, and R. Graber of Energy Path presented a paper at the 2003 International Conference on Advances in Nuclear Power Plants on the economics of new nuclear power plants in the U.S.[94] The three authors evaluated the economics, risks, and investment issues associated with building a new merchant nuclear power plant. The authors recognized that nuclear power plants are more risky than other technologies, and state that "Most CEOs and business development managers with whom we have discussed this issue talk in terms of 20% return on equity (versus 16% for combined cycle)." The authors blend this ROE with debt in a 50/50 ratio to obtain a 12% discount rate, implying an 8% debt interest rate. However, the authors do not indicate whether this interest rate is appropriate for a merchant nuclear plant. LAI believes that the interest rate is reflective of an integrated energy company, thus benefiting from other business

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[93] Rothwell, G.S., *Triggering Nuclear Development, Public Utilities Fortnightly*, May 2004, pp. 46-51, provided as Attachment 7. Dr. Rothwell also prepared *What Construction Cost Might Trigger New Nuclear Power Plant Orders?* SEIPR Discussion Paper No. 03-19, Stanford Institute for Economic Policy Research, Stanford University, Stanford, CA, March 2004.

[94] Proceedings of ICAPP '03, Cordoba, Spain, May 4-7, 2003, Paper 3188, provided as Attachment 8.

activities that diversify the company's risks. The cost of debt for merchant nuclear plants would likely be much higher. Moreover, it is not certain that lenders would provide non-recourse debt to a company entirely invested in merchant nuclear power.

State Regulatory Decisions

LAI researched the regulatory history of the nuclear plant sales listed in the Plant Valuation section of this report and found only one document in which a state commission utilized a discount rate that reflects the risks of a merchant nuclear plant in a deregulated competitive generation market. The Connecticut Department of Public Utility Control (DPUC) issued a decision in Docket No. 99-02-05 regarding CL&P's Application to recover stranded costs associated with the sale of its equity interests in Millstone 2 (81% of 870 MW), Millstone 3 (53% of 1154 MW), and Seabrook (4% of 1150 MW). In its introduction to the July 7, 1999 decision, DPUC summarizes the purpose and the need to prepare a valuation of Millstone:

> "Section 8 of Public Act 98-28 requires each electric company to submit an application for recovery of stranded costs that may be collected through the Competitive Transition Assessment (CTA) commencing on January 1, 2000..... This proceeding sought to quantify the potential stranded costs by determining the projected market valuations of The Connecticut Light and Power's (CL&P) various generation assets and power contracts. Critical to this process is the establishment of a market price forecast (MPF) for both energy and capacity from which the Department can then estimate the amount of CL&P's projected costs that are above market, and, therefore, stranded. The MPF is used in this Decision to estimate 1) the stranded costs associated with the purchased power contracts either retained by the Distribution Company or bought out; 2) the minimum bids for the nuclear units; 3) an estimate of nuclear stranded costs over the remainder of the nuclear plants' useful life, and, 4) an estimate of nuclear cost recovery from January 1, 2000, until the nuclear assets are sold."

There were two expert witnesses who utilized discount rates in their calculation of market valuations. Both witnesses agreed that the market for nuclear power plants (at that time) was new and had few precedents upon which to base a conclusion. CL&P's witness, Mr. O'Flynn, recommended a 20% discount rate based on his experience in transacting nuclear power plants. Mr. O'Flynn testified that:

- Merchant fossil power plants had return on equity requirements of 12%-16%.
- Nuclear plants are riskier due to complexity and uncertainty of NRC approval, unforeseen decommissioning costs, and uncertainty of planned outages.
- A 20% discount rate is appropriate for nuclear plants.

The Office of Consumer Council witness, Mr. Rothschild, utilized a 9.84% discount rate based on the capital structure of a BBB-rated generation-only utility, reflecting a 7.19% debt

rate and an equity premium of 0.49% to 0.87% above the return granted a distribution-only utility.[95]

The DPUC considered both discount rate estimates and concluded "that a 14% discount rate is appropriate for a future sale on the nuclear plants by 2004":

> "While the Department concurs with the Company that the risk of nuclear power exceeds that of fossil generating plants, the record also supports the use of a discount rate less than the 20% rate proffered by O'Flynn, which is inflated by an assumed 11% - 12% benchmark ROE for regulated utilities. Moreover, the Department concludes that by 2004, the high discount rate recommended by O'Flynn would likely drop as more sales are transacted, as the merchant nuclear plant market matures, and as buyers add successive plants to their portfolios. Although no particular capital structure is implied, the 14% discount rate allows for the possibility that a portion of the value of a nuclear plant asset could be purchased with debt financing."

Table 15 – Market Values of CL&P's Nuclear Assets
($/kW)

Discount Rate	Millstone 2	Millstone 3	Seabrook
20%	$ -11	$ 227	$ 179
17%	$ 6	$ 292	$ 236
14%	$ 35	$ 387	$ 323

Despite its conclusion that a 14% discount rate was appropriate, the DPUC selected estimated plant values that corresponded to higher discount rates. Assuming linear interpolation and extrapolation of the values in the table above, the DPUC effectively utilized discount rates of 15%-22% as shown below.[96] The average discount rate, weighted by CL&P's effective ownership shares in the three plants, was 18.3%.

- $25/kW for Millstone 2 – corresponds to 15%.
- $185/kW for Millstone 3 – corresponds to 22%.
- $185/kW for Seabrook – corresponds to 20%.

[95] LAI does not believe that Mr. Rothschild fully considered the risks of merchant nuclear power plants in determining the equity premium and resulting discount rate.

[96] The market values may not be linearly correlated to discount rates. However, for the purpose of this assignment, LAI believes that assuming a linear relationship is reasonable.

LAI Experience

The proposed discount rate range of 14% - 20% is consistent with LAI's experience. We have worked on a number of relevant plant valuation and investment matters in which the discount rates we used are consistent with the range in this assignment. In one case, LAI was retained by a utility investor that was considering purchasing an equity interest in a nuclear power plant that would be exposed to market risk. The purchaser conducted an evaluation of the plant's operating data and decided to pursue the purchase based upon estimated IRRs at the upper end of the range used in this assignment. As more accurate O&M data became available and the estimated IRR fell below the range used in this assignment, the investor withdrew its offer. LAI confirmed the reasonableness of the purchaser's decision to cancel the transaction.

Bodington & Company Report

LAI commissioned Bodington & Company, a firm specializing in energy industry investments, to review the literature and recent market transactions and to develop an independent estimate of the appropriate WACC for a merchant nuclear entity.[97] Bodington found that most recent nuclear transactions and merchant power asset transactions have not been "pure plays", that is, an entity with publicly traded securities engaged solely in the merchant generation business.

Bodington applied the Capital Asset Pricing Model (CAPM) to several publicly traded firms (*e.g.*, AES, Calpine, and Reliant) that are engaged primarily in merchant power generation to estimate a market-based cost of equity and found a range from 17.15% to 19.60%, built up from a risk-free return rate of 4.90%, a general market risk premium of 7.00%, and company Betas of 1.75 to 2.10. These companies have very high debt levels, reflective of a time when (fossil) merchant plants could be highly leveraged. Rather than use the current debt levels, Bodington imputed debt costs based on each company's S&P rating – all were in the B/C range, resulting in marginal debt cost of 12.0% pre-tax. Given that the selected firms are not "true plays", Bodington suggests that leverage should be decreased to 30%. Based on a Beta of 2.00, this approach yields a WACC of 15.39%.

As an independent approach, Bodington analyzed the sale of merchant assets from Duke Energy to KGen Partners in 2004. The resulting entity was financed with $425 million in cash equity and $50 million in a note to Duke at LIBOR plus 14.5%. The note establishes an upper range for merchant power debt cost at 16.95% and a lower bound on equity cost. Citing a typical risk premium of equity cost over debt of 6%, the cost of equity was estimated at 22.95%. With the leverage ratio of 11% implied in the transaction, the WACC was calculated at 21.54%.

Using both the CAPM and KGen approaches, Bodington concludes that a reasonable WACC for the envisioned IP transaction would be 18.5%.

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[97] The Bodington report is provided as Attachment 9.

Entergy's Non-Utility Nuclear Assets

LAI analyzed the financial statements of four integrated electric companies that have significant portfolios of merchant nuclear power plants: Entergy, Exelon, Constellation Energy, and Dominion Resources. Only Entergy provides separate financial data for their non-utility nuclear business that provides us with historical IRR and ROE data that is useful in calculating a discount rate appropriate for merchant nuclear power plants.

LAI reviewed Entergy's financial data provided in filings to the Securities and Exchange Commission (SEC) and in various documents for investors in order to estimate the actual ROE or IRR for their merchant nuclear power investments.[98] Entergy operates primarily through three business segments, U.S. Utility, Non-Utility Nuclear, and Energy Commodity Services, and provides useful data for each. The most recent key financial indicators for these business segments are provided in Table 16. The Non-Utility Nuclear segment owns and operates five nuclear power plants – Pilgrim, FitzPatrick, IP2, IP3, and Vermont Yankee – and is an important and very profitable part of Entergy's overall business activities. According to these indicators, the Non-Utility Nuclear business segment accounted for less than 15% of Entergy's total assets, but yields almost one-third of Entergy's net income.

Table 16 – 2003 Key Indicators of Entergy's Business Segments
($ millions)

	U.S. Utility	Non-Utility Nuclear *(and % of total)*		Energy Commodity	Entergy Consolidated
Operating Revenues	$ 7,585	$ 1,275	*13.9%*	$ 185	$ 9,195
Net Income	$ 493	$ 301	*31.7%*	$ 180	$ 950
Total Assets	$22,429	$ 4,171	*14.6%*	$ 2,077	$28,554
Shareholder's Equity	$ 5,448	$ 1,949	*22.4%*	$ 1,615	$ 8,704

Every year Entergy prepares an *Investors Guide and Statistical Report* designed to support investors understanding of Entergy's businesses. The report provides profitability measures for the Non-Utility Nuclear business segment over the years 2001 - 2003 that is summarized in Table 17 below.

[98] 2004 data was not available in time to be included in this report.

Table 17 – Reported Profitability of Non-Utility Nuclear Business Segment
(based on net income)

	2003	2002	2001	Average
Return on Invested Capital				
As Reported	12.7%	11.8%	10.0%	11.5%
Operational	8.6%	11.8%	10.0%	10.1%
Return on Equity				
As Reported	17.3%	16.4%	20.7%	18.1%
Operational	11.1%	16.4%	20.7%	16.1%

Return on Invested Capital (ROIC) is defined as net income plus after-tax interest expense divided by the average level of invested capital (equity plus long-term debt). ROE is defined as net income divided by the average level of common equity. The ROIC and ROE data differ due to interest expense and the amount of debt included in the business segment's capitalization. The amount of debt attributed to the Non-Utility Nuclear business segment has fallen from 48% as of year-end 2001 (hence the large difference between the ROIC and ROE data) to 24% as of year-end 2003 (resulting in a smaller difference). The reported profitability is presented on an "As Reported" basis per GAAP reporting requirements and on an "Operational" basis that excludes the impact of special items. Special items only affected the 2003 data, when an accounting change provided Entergy with a one-time increase in net income.[99]

While ROIC or ROE are single year measures of return, the fact that net income includes the effects of depreciation, amortization, and decommissioning accruals as expenses makes it an indicator of return over the life of the various investments included in the operating segment. Over the life of an investment, the average of annual ROIC or ROE measures should approximate the corresponding DCF internal rate of return. Of course, in the case of an ongoing, multi-asset concern, there are no clear beginning and ending points to test this hypothesis. Since Entergy's Non-Utility Nuclear business segment relies on parent company debt that does not reflect the specific risks of merchant nuclear plants, we believe that the ROE data is a more reliable indicator of WACC and supports our range of discount rates.

[99] According to Entergy's 2003 Annual Report, SFAS 143, *Accounting for Asset Retirement Obligations* required Entergy to (i) record the fair value of asset retirement obligations, *i.e.* nuclear plant decommissioning, (ii) measure the obligations assuming a third party performs the work, and (iii) discount future obligations using a credit-adjusted risk-free rate. The net effect for the Non-Utility Nuclear business segment was a one-time increase in net income of $155 million. Other non-operational items resulted in a combined adjustment to income of $104 million.

Table 18 – Estimated Profitability of Entergy Non-Utility Nuclear Business Segment
(based on cash flow; $ millions)

	2003	2002	2001	Average
Cash Flow Provided by Operations	$ 183	$ 282	$ 263	
Average Shareholders' Equity	$1,654	$1,165	$ 798	
Return on Equity – *high case*	11.0%	24.2%	33.0%	22.7%
Cash Flow Provided by Operations	$ 183	$ 282	$ 263	
Average Shareholders' Equity	$1,654	$1,165	$1,005	
Return on Equity – *low case*	11.0%	24.2%	26.2%	20.5%

Entergy's *Investors Guide and Statistical Report* provides performance data based on net income. However, the discount rate LAI intends to utilize will be applied to a forecast of IP cash flow. Therefore we have estimated similar financial performance measures based on the reported after-tax cash flow data provided in Entergy's 2003 Form 10-K. LAI divided the Non-Utility Nuclear business segment's cash flow provided by operations[100] by the average shareholder's equity (averaged between beginning-of-year and end-of-year) to estimate the cash flow-based profitability.[101] Over the period 2001-2003, Entergy's Non-Utility Nuclear business segment averaged about a 20.5%-22.7% ROE on an after-tax cash basis as illustrated in Table 18.[102] These measures of return based on cash flow are generally higher than the corresponding measures based on net income, because non-cash expenses such as depreciation are "added back" to obtain cash flow from operations.

It would be possible to derive a cash flow measure for return on invested capital by adding interest paid to cash flow from operations, before dividing by the average level of invested capital. This measure would have a similar relationship to its income-based counterpart. We believe that the ROE estimates shown above also support our range of reasonable discount rates.

4.8. Valuation / Compensation Results

Using the revenue and cost forecasts described above, LAI developed a *pro forma* cash flow model for IP. The cash flow model uses the forecasts of revenues and operating costs to calculate earnings before interest, taxes, depreciation, and amortization (EBITDA), then estimates the unleveraged after-tax net cash flow (Net Cash Flow) for an informed, willing buyer of the IP units as a going concern. The purchase price that results in a net present value

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[100] Cash flow provided by operating activities is essentially net income adjusted for non-cash items (depreciation, amortization, and decommissioning allowances and deferred taxes) included in income and for changes in working capital accounts. It does not include cash flows used in or provided by investing and financing activities.

[101] The SEC Form 10-Ks provided all of the data required to complete this calculation except for the shareholder's equity at the beginning of 2001.

[102] These ROE calculations are based on Entergy's book value of equity, while our derivation of discount rates is based on market values of equity.

of zero using the buyer's WACC as a discount rate is the FMV of the generating units. The development of EBITDA and the calculations for determining FMV are discussed in subsections below.

EBITDA

LAI estimated EBITDA for the original license term and for a license renewal period, based on the revenues and operating costs discussed above, as shown in Figure 14 and Figure 15, respectively. During the original license term EBITDA varies from $400 million to $600 million per year through 2012, and then drops off as the units are retired in 2013 and 2015. The values shown for 2016 and 2017 are typical of the years after shutdown, with negative EBITDA attributable to ongoing expenses for SNF management. If Entergy (or a hypothetical buyer) is successful in obtaining NRC license extensions and undertakes the CapEx for the cooling towers and other improvements, Entergy would begin investing capital as early as 2010. The negative EBITDA value in 2013 shown in Figure 15 reflects the CapEx spending and extended outage of IP2 prior to operation under the new license. The negative EBITDA in 2015 reflects the extended outage for IP3, partially offset by the operation of IP2.

Figure 14 – Original License Term EBITDA

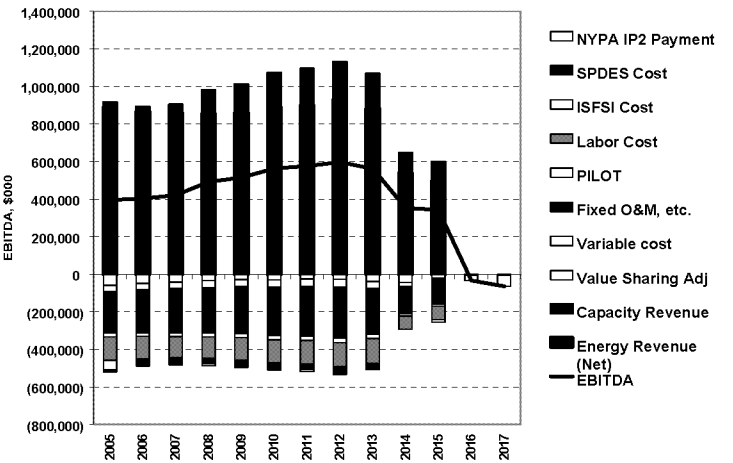
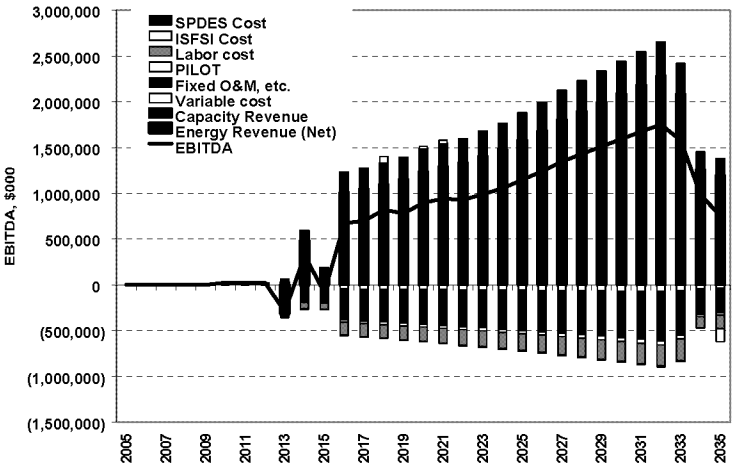


Figure 15 – License Renewal Term EBITDA



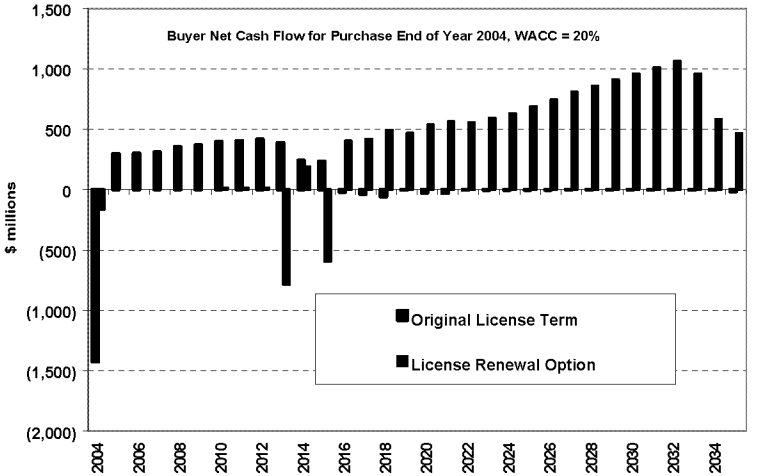
Net Cash Flow and FMV

We assume that a hypothetical third-party buyer of IP would depreciate the purchase price over the remaining reactor-months of the original license on a straight-line basis. If the buyer perceives a value in the option to relicense IP, that additional purchase cost would be amortized over the term of the renewed license along with the incremental CapEx required to obtain the license renewal, *e.g.*, NRC application, cooling towers, RPV heads. In this case, Net Cash Flow consists of purchase price and other CapEx as negative values, EBITDA as positive values, and sundry tax effects over the investment horizon. IP's FMV is simply the present value of those Net Cash Flows using the appropriate discount rate.[103]

Ownership of IP2&3 includes an implicit option to extend the IP licenses. To exercise the option, the owner would have to submit an application that may or may not be approved, and then, if the application is approved, the owner would have to make substantial CapEx investments in cooling towers and other equipment. A decision to proceed with license renewal would be based on the owner's perception of future revenues, expenses, and EBITDA relative to the CapEx required. If the present value of the Net Cash Flows associated with license renewal is positive, after adjusting for risk of NRC approval of the license extension application, we assume the owner would be inclined to proceed.

[103] The equations for calculation of Net Cash Flow and FMV are presented in greater detail in Attachment 10.

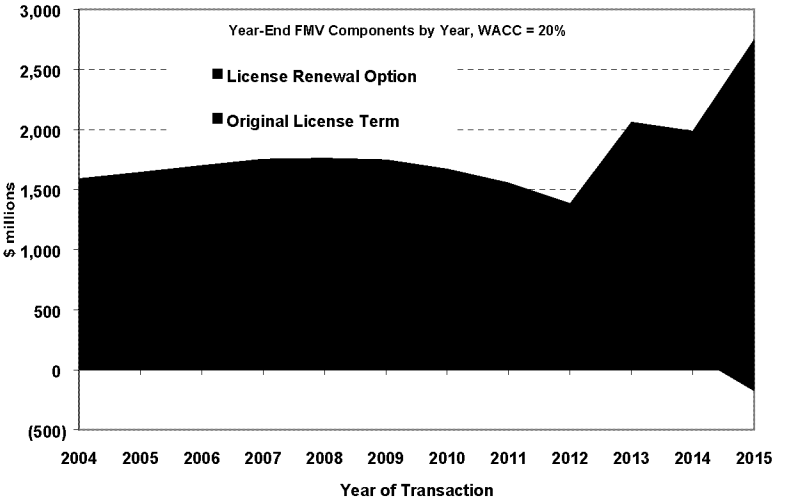
Figure 16 – Annual Net Cash Flow Forecast



Assuming a transaction date at the end of 2004 and certainty about license extension, the Net Cash Flows for IP2&3 using a discount rate of 20% are shown in Figure 16. The Net Cash Flows for the license renewal option include two types of negative cash flow – the purchase cost of the option in 2004 and the CapEx investments and loss of revenues in 2013/15.

This valuation approach can be applied in any year to the future cash flows to determine a FMV for a transaction in that year. Figure 17 shows FMV for transaction years from 2004 to 2015, again assuming a 20% discount rate and certain approval of license extension. Through 2015, the FMV of the original license period (shown in blue) declines gradually as the remaining years of operation decline. On the other hand, the future FMV of the license renewal option (shown in red) increases as the EBITDA from the extra twenty years of operation is discounted over fewer years. At the end of 2013 and 2015, the FMV of the renewal option increase dramatically, reflecting that CapEx is being spent for license renewal and becoming a sunk cost.

Figure 17 – IP2&3 FMV vs. Transaction Year



FMVs for selected transaction years under the acquisition through condemnation are summarized below in Table 19. While a 2005 transaction is unrealistic, it establishes a baseline to put the other years in perspective. Assuming a three year condemnation process and a retirement and payment date of January 1, 2008, we estimate IP's value, and hence the compensation due Entergy, at $1.8 - $2.7 billion, depending upon the discount rate.[104] As is shown in Table 19, waiting to commence the condemnation proceeding does not materially reduce IP's value.

[104] This is equivalent to $2.1 - $3.0 billion in 2005 dollars using the County's 4.0% discount rate.

Table 19 – Selected Case Valuations – Acquisition by Condemnation
($ millions)

Discount Rate	Transaction Date	1/1/2005	1/1/2008	1/1/2011	1/1/2016
20%	Original License Term	$1,426	$1,465	$1,177	$ (175)
	License Renewal Option	$ 165	$ 289	$ 495	$ 2,925
	Total	$1,591	$1,754	$1,671	$ 2,750
14%	Original License Term	$1,895	$1,831	$1,369	$ (211)
	License Renewal Option	$ 605	$ 913	$1,376	$ 4,410
	Total	$2,500	$2,744	$2,745	$ 4,199

January 1, 2011 would be about the latest date in which the acquisition FMV would avoid the CapEx of license renewal. Indeed, the FMV as of January 1, 2016 jumps dramatically, since the CapEx are incurred at that point. The FMV of the original license term is negative as of January 1, 2016 because the owner must incur SNF management costs after the units are shut down, with no offsetting revenue steam. FMV calculated at a 20% discount rate is significantly lower than FMV calculated at 14% in all instances.

Acquisition vs. Consensual Agreement

If IP were to be retired voluntarily, Entergy would lose the projected Net Cash Flows and would incur SNF and other expenses until decommissioning was complete, the SNF was removed, and the site sold or re-used. Our estimated compensation payments are summarized in Table 20 for retirements as of a number of dates, broken down into values for the original license terms and the license extension period. An agreement to voluntarily retire IP at the end of the original license term could be transacted at any time up to the point where heavy CapEx would be required, probably around the end of 2010, at which time its value would be $495 million to $1,376 million, depending on the discount rate.[105] If an agreement is reached earlier, the compensation payment could be considerably less reflecting Entergy's discount rate, as shown in Table 20. Given the disparity between Entergy's WACC / discount rate, and the County's low cost of debt, early payment of any compensation amount could lower the County's cost.[106] In addition, recognition of benefits to State residents, *e.g.* the health of Hudson River fisheries and improved homeland security, may provide a basis for the State to fund a share of any compensation payments to Entergy. Determination of just and reasonable compensation under eminent domain does not ordinarily consider tax impacts from the property owner recording a capital gain, so we did not try to estimate the tax consequences of compensation paid to Entergy.

[105] This is equivalent to $391 - $1,087 million in 2005 dollars using the County's 4.0% discount rate.

[106] The discount rate applied from the point of view of Entergy or a buyer interested in operating IP2&3 ranges from 14% to 20%, while the County's cost of long-term money is on the order of 4%.

Table 20 – Compensation for Voluntary Retirement Cases
($ millions)

WACC / Discount Rate	Retirement Date / Transaction Date	1/1/2005 / 1/1/2005	1/1/2008 / 1/1/2008	2013/15 / 1/1/2005	2013/15 / 1/1/2011
20%	Original license term	$1,489	$1,485	n/a	n/a
	License renewal option	$ 165	$ 289	$ 165	$ 495
	Total	$1,654	$1,774	$ 165	$ 495
14%	Original license term	$1,964	$1,854	n/a	n/a
	License renewal option	$ 605	$ 913	$ 605	$1,376
	Total	$2,569	$2,767	$ 605	$1,376

5. DECOMMISSIONING AND SPENT NUCLEAR FUEL

5.1. DECOMMISSIONING

Decommissioning is the removal of all radioactive materials from a nuclear plant site that are controlled under the NRC licenses. Decommissioning does not include the removal of SNF that the DOE is obligated to ship to Yucca Mountain, or other non-radioactive structures (*e.g.* cooling towers, water inlet facility or administrative offices and buildings) that Entergy would remove. When a nuclear site is decommissioned, the site and infrastructure are normally left in an industrial and environmentally safe condition, which could include exclusion fences and guard rails. Only after a license termination survey is performed, would a site be in "free release" condition, defined as a condition in which the most exposed person can receive no more than a low and acceptable dose of radiation from the site.

After the site is in free release condition, a nuclear plant site could be reused for another power plant, an industrial use, or some other purpose. The removal of any remaining non-radiological structures could be accomplished by a commercial razing company without any radiological considerations. Alternatively, a portion of the site that is isolated from the rest of the site and is in a free release condition could be reused.

The NRC defines decommissioning as one of three alternatives:

- DECON – The equipment, structures, and radioactive portions of the facility are removed or decontaminated to a level that permits free release and termination of the NRC license immediately or soon after the facility closes.

- SAFSTOR – A nuclear facility is maintained and monitored in a condition that allows the radioactivity to decay so that it can eventually be dismantled and removed; often considered as delayed DECON.

- ENTOMB – Radioactive contaminants are encased in a structurally sound material (*e.g.* concrete) and appropriately maintained and monitored until the radioactivity decays to a level permitting free release.

5.2. INDIAN POINT DECOMMISSIONING

The IP decommissioning effort will involve all three units with a goal of achieving a free release condition of the site. IP1 has been in SAFSTOR in which the components required to maintain the spent fuel storage pool are still in place. SNF is still in the IP1 spent fuel storage pool, but could be moved to dry storage (*i.e.* ISFSI) at any time because it has cooled sufficiently. IP1 will be decommissioned once the NRC approves Entergy's decommissioning plan for IP1&2 and the start date defined. IP2&3 are expected to remain in operation at least through the term of their current NRC licenses. The general sequence of the decommissioning work tasks should be very similar for each of the IP units. The basic differences would be staggered start dates and the lower quantity of Greater Than Class C

(GTCC) radioactive waste at IP1 because a majority of the waste has decayed to within the regulatory requirements defined for low-level (*i.e.* Class A, B, or C) radioactive waste.

Although the current IP decommissioning cost estimates and funding are based on two separate decommissioning projects (*i.e.* one for IP1&2 and one for IP3), a single, comprehensive project would achieve significant economies of scale.[107] A single decommissioning project could utilize shared systems and equipment, as well as cleared space on the site necessary to support decommissioning operations, as depicted on the attached schedule. For example, if IP2&3 were retired on their current license expiration dates, IP1 could be decommissioned first while SNF from IP2&3 are cooling, then IP2 could be decommissioned, and lastly IP3. Having two separate decommissioning projects would add substantially to the costs as a result of duplicating the systems / equipment and the large number of Entergy and contractor personnel. Two separate decommissioning projects would also prevent the decommissioning teams from applying the initial tooling, procedures, and lessons learned to subsequent decommissioning efforts.

Entergy has stated that IP1&2 decommissioning will commence immediately after IP3 ceases operation at the end of its license term. Entergy believes that initiating decommissioning at the end of the last license to expire will be the preferred approach. Under the existing licenses, the earliest date that this would occur is in December 2015, the end of the current IP3 license. Therefore we have assumed that some preliminary planning would be productive, for IP1, in particular, and the entire IP site would be decommissioned as expeditiously as practical after IP3 retires.

A decommissioning plan typically takes two years to develop. The NRC permits the use of a small part of the decommissioning fund to cover the costs for such planning. The plan would then be submitted to the NRC for review and approval to ensure that the activities and approach for decommissioning are technically reasonable and fiscally prudent. The NRC process can take another two years, during which time the plant owner could undertake additional planning and preparation. Therefore any decommissioning plan would likely be submitted to the NRC at least two years before the intended retirement date to allow decommissioning to start immediately after the plant ceases operations.

Since SNF needs a minimum five year wet cooling period after discharge from the reactor, the systems, components, and structures needed to ensure the safe operation of the storage pools need to be maintained while decommissioning is underway. For example, the decommissioning efforts would commence in the containment building (including reactor vessel and large component removal), the balance of plant systems, other structures, and the Auxiliary Building. The GTCC components would be removed, reduced in size (as required), and placed into high-level radioactive waste containers stored on site at or near the ISFSI. After the five year cooling time has been satisfied, the SNF can be loaded into a dry cask

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[107] Entergy has stated that the individual IP1&2 plants decommissioning budget estimates reflect project economies of scale attributable to a single optimized decommissioning plan per correspondence between Entergy and the NRC. In a single decommissioning project for all the IP units, the savings could amount to several hundred million dollars.

storage system, and any remaining GTCC from the spent fuel storage pools would be loaded into waste containers for storage. The GTCC waste may ultimately be accepted at Yucca Mountain or some other repository not currently identified. Lastly, all of the contaminated buildings and their foundations would be removed, and a decommissioning survey would be performed to document that the site can be free released and the NRC licenses terminated.

5.3. Decommissioning Funding

The prospective funding of nuclear power plant decommissioning was, and still is, a major accomplishment for the US electric utility industry. Under the NRC's Decommissioning Rule, utility owners were required to prepare a summary site-specific plan for each plant, a cost estimate, and an estimated schedule, and then collect a surcharge from all ratepayers to establish a fund dedicated solely to decommissioning that plant.[108] The surcharge was calculated to provide sufficient decommissioning funds, based on the expected retirement date, electrical production, investment return, and other variables. The funds could only be invested in high-grade securities.

Funding the decommissioning of IP involves two significant questions. First, is the basis for projecting the decommissioning costs valid given the NRC approach to funding, recent industry experience, and research? Second, is there sufficient money available in the IP1&2 and IP3 decommissioning funds to cover the entire decommissioning cost? For the purposes of this report, it is appropriate to explain how the decommissioning of US power reactors was planned, funded, and, ultimately, how the funding is administered.

Industry Funding History – The regulatory requirements for decommissioning funding were established in the 1970s.[109] This was a time when many of the original demonstration power reactors were going out of service and the magnitude of decommissioning even those small plants became obvious. A set of standard decommissioning models was developed by industry and the Atomic Energy Commission (now the NRC) that represented or bracketed almost all of the (then) new and larger plants like IP. These models were satisfactory from the standpoint of assessing the typical design of reactors in terms of commonality and gross economic assumptions, but did not consider specific plant and site characteristics such as:

- Local labor cost, jurisdictions, and productivity
- Waste transport costs to disposal sites and disposal fees
- Volumes of concrete, pipe, steel, and other materials
- Differences in time-dependent costs and expenditures
- Manning requirements during decommissioning

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[108] 10CFR Part 50.75 Reporting and Recordkeeping for Decommissioning Planning.

[109] Decommissioning planning requirements are addressed under 10 CFR Part 50 for the IP reactors.

- SNF management requirements not recoverable from the decommissioning fund
- Variations in decommissioning fund investment returns

There was also wide diversity of industry opinion as to how such a large and complex project that had never been attempted before, even when only considering the radioactive portion of a massive physical plant like IP2&3, might be managed and accomplished, as well as how long it would take to complete the project. The NRC established a "Decommissioning Rule" to set decommissioning fund collection rates, which was modified extensively during the period from the late 1970s until the mid-1990s to assure that it met the intent more effectively. In the meantime, the collections continued and the decommissioning plans were updated every two-to-five years on a case-by-case basis to reflect changes in the cost estimates, including labor, waste management, plant physical changes, general management, support services, etc.

Many of the decommissioning costs escalated at faster-than-expected rates prior to when the first large nuclear plants commenced decommissioning in the early 1990s. The owners of the IP units at that time, Con Edison and the Power Authority of the State of New York (PASNY, as NYPA was then known), began to collect decommissioning funds based on periodically updated engineering estimates. These funds were controlled and administered by the plant owners, but were the property of the ratepayers from the service areas of each plant. The NRC oversaw the general condition of the funds and their growth.

In the early 1990s, the NRC recognized the value in investing the funds and permitted the industry to do so with significant restrictions. Virtually all utilities used competent fund management professionals to administer these investments. Most of the funds benefited substantially, and the decommissioning funding estimates, when adjusted for the investment results, reduced the amounts ratepayers had to contribute.

There is now a small and growing industry in nuclear plant decommissioning services that can be considered an extension of plant O&M, similar to many outside technical services required for reactor head, steam generator replacements, and other back-fit programs. The commercial knowledge base includes many commercial and DOE facilities that are in the process of or have been decommissioned. Over the past thirteen years, all of the small commercial production power reactors and a significant number of the largest reactors have been shut down, have addressed SNF issues, and/or have gone through decommissioning. Many of the smallest research and demonstration plants, ranging in capacity from 4 to 50 MW, have also been shut down.

The following is a list of large commercial plants that are in the process, or have completed, decommissioning.[110] The owners of these plants have collectively spent approximately $3 billion over the past thirteen years in plant decommissioning.

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[110] NUREG-1350, Volume 16, USNRC Information Digest 2004 – 2005 Edition, July 2004 and USNRC Fact Sheet: *Decommissioning Nuclear Power Plants*, January 2004.

Table 21 – Decommissioned Commercial Nuclear Plants[111]

Nuclear Plant	Size (MW_{th})	Operations		Decommissioning		Status
		Started	Shutdown	Started	Completed	
Shoreham	2,436	1989	1989	1992	1995	Complete
Fort St. Vrain	842	1973	1989	1990	1997	Complete
Big Rock Point	240	1964	1997	1997	Ongoing	DECON
Dresden Unit 1	700	1960	1978	1998	Ongoing	SAFSTOR
Connecticut Yankee	1,825	1974	1996	1997	Ongoing	DECON
Humboldt Bay Unit 3	200	1962	1976	1988	Ongoing	SAFSTOR
Indian Point 1	615	1962	1974	1996	Ongoing	SAFSTOR
Fermi 1	200	1963	1972	1998	Ongoing	SAFSTOR
LaCrosse	165	1969	1987	1991	Ongoing	SAFSTOR
Maine Yankee	2,700	1973	1996	1997	Ongoing	DECON
Millstone Unit 1	2,011	1970	1995	1999	Ongoing	DECON
Peach Bottom Unit 1	115	1966	1974	1998	Ongoing	SAFSTOR
Rancho Seco	2,772	1974	1989	1999	Ongoing	DECON
San Onofre Unit 1	1,347	1967	1992	1999	Ongoing	DECON
Three Mile Island 2	2772	1978	1979	1993	Ongoing	SAFSTOR
Trojan Nuclear Plant	3,411	1975	1992	1996	Ongoing	DECON
Yankee Rowe	600	1963	1991	1995	Ongoing	DECON
Zion Units 1 and 2	3,250	1973	1998	1998	Ongoing	SAFSTOR

Representatives from several of these plants have indicated that their decommissioning funds were adequate to cover their expected costs. Thus we are confident that the basis for projecting IP's decommissioning costs appear valid using the NRC's requirements and past project performance.

IP Decommissioning Funds – When the IP plants were purchased by Entergy, two different financial arrangements were put in place. In the case of IP1&2, Entergy took over the funds from Con Edison "as-is" and stopped collecting additional funds from ratepayers while the fund continued to accrue interest. In 2003, Entergy made a one time $50 million contribution to the IP1&2 decommissioning fund because it was determined to be deficient by GAO studies commissioned by Congress. For IP3, NYPA retained the decommissioning fund and the fund management, but reserved the right to direct Entergy to decommission the plant in the future provided it made sufficient funds available to complete the decommissioning. This arrangement would allow NYPA to be involved in a meaningful way in any negotiations for a consensual agreement. Entergy would be responsible for SNF management and removal of non-radioactive structures in either case.

[111] The sizes of these plants are provided in terms of thermal MW. IP 1, 2 and 3 are 615, 3114.4, and 3067.4 MW_{th} respectively.

5.4. CURRENT CHALLENGES

While there are several decommissioning projects that are expected to finish soon, a number of new and impending challenges have developed:

Radioactive Waste Disposal – There are a limited and shrinking number of licensed waste disposal sites in the U.S. The last disposal site for Class A, B and C radioactive waste is in Barnwell, South Carolina, and is scheduled to close in June of 2008 for all but three states – New Jersey, South Carolina, and Connecticut. This will require owners, including Entergy, to make alternative arrangements to store waste either on-site or off-site at newly licensed storage facilities. All storage states have specified time limits for storage, charge for the service, and have reciprocal agreements with the shipping state governments that permit the receiving state to ship the waste back to the sending state. Other less radioactive low-level radioactive waste can be sent to one or more disposal sites that do not appear to be in imminent danger of closing to commercial customers. Currently there is no licensed disposal site for GTCC waste from IP.

Reactor Vessel Disposition – The RPV of a typical US power reactor is an over-sized (making transportation difficult), heavy (*i.e.* 600 to 1,200 tons), and highly radioactive steel vessel that typically must be eventually removed from a nuclear site. With few exceptions, the RPVs from smaller plants have been transported by barge, rail, and heavy haul off-road trailers to the Barnwell disposal site. At this time and for the foreseeable future, decommissioning plant owners will have to make other arrangements for RPVs and other non-fuel internal core GTCC waste. Due to the Barnwell site requirements concerning the inventory of radioactive materials and a planned June of 2008 closure, the IP RPVs (as well as other GTCC waste) may be "orphaned", in which case the only available option would be to store them in shielded canisters on site. Portions of the RPV that contain less radioactive components may be cut up and shipped to Envirocare of Utah.[112]

Residual Plant Condition – Over the past fifteen years, the nuclear industry and regulators have not settled on what constitutes completion of decommissioning from a residual site radiological condition standpoint. Some believe that the "last atom" rule applies and the licensee/owner has to remove every atom of man-made radioactive materials, and then prove that the last atom has indeed been removed. In essence, this standard would have the licensee return the site to below the background radiation levels on an isotope-specific basis. Others argue for a fixed limit (*i.e.* a pre-determined amount of activity above background) on radiation dose that permitted some quantity of radioactive materials to remain at a de-licensed site, but set a high standard with respect to the resulting maximum annual dose to any exposed individual. To put this into perspective, the maximum dose would be less than the difference in annual exposure between a person between living in Denver and a person living at sea level. The person living in Denver receives more natural radiation due to the differences in

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[112] These options are not new or untried. The RPV from San Onofre Unit 1, owned by Southern California Edison Company, has been prepared for long-term on site storage. The RPV from Rancho Seco, owned by the Sacramento Municipal Utilities District, will be cut up for disassembly and segregated such that selected pieces will be stored on site while other pieces will be shipped to Envirocare of Utah over the next two years.

levels of cosmic radiation at sea level and at 5,000 feet, and the composition of the earth itself.

5.5. Decommissioning Funding Status of IP

The decommissioning funds for the IP units are shown in Table 22 below. As explained earlier, current plans call for IP1&2 to be decommissioned in one program and IP3 separately, but there would be substantial savings if all three plants were decommissioned in one integrated project. LAI evaluated the adequacy of the IP decommissioning funds by reviewing data on the size of the funds and the estimated cost at the license expiration date, and reviewing a study released by the GAO on this issue.

Table 22 – Decommissioning Cost and Fund Status[113]
($ millions)

Plant	Fund Size (2002)	Estimated Decom'g Cost (2002)	License Expiration Date	Est'd Fund At License Expiration	Est'd Cost At License Expiration
Indian Point 1	$193.46	$297.8	12/2016	$383.03	$450.45
Indian Point 2	$232.03	$355.11	12/2016	$459.40	$537.13
Indian Point 3	$336	$353.70	12/2018	$733.45	$567.58
VT Yankee	$315.85	$395.97	12/2015	$595.57	$581.49
Pilgrim	$455.91	$408.16	12/2015	$859.68	$599.40
FitzPatrick	$367	$424.36	12/2017	$762.97	$661.15
Palisades	$425	$337.93		-	
Point Beach 1	$270.2	$303.88		-	-
Point Beach 2	$277.6	$303.88		-	-
Kewaunee	$527.8	$307.2		-	-
Prairie Island 1	$232.9	$307		-	-
Prairie Island 2	$244.6	$307		-	-
Monticello	$296.3	$395.3		-	-

Fund Data – Comparisons were made between the size of the IP decommissioning funds and the estimated decommissioning costs, as of 2002 (the last date for which fund status data reported to the NRC is available) and as of the expected license expiration date. The data for IP and for several other plants are shown in Table 22 below. These data indicate that as stand-alone projects, the decommissioning funds for IP1&2 would not be sufficient.[114] However, IP1&2 will be decommissioned together, reducing costs, so that we anticipate that

[113] Decommissioning funding amounts from NRC as submitted by plant owners per 10CFR50.75

[114] In November 2000, Con Edison entered into an agreement with Entergy for the sale of IP1&2. The agreement provided for a transfer of $430 million for which Entergy would assume full responsibility for decommissioning of both units. Entergy established a $50 million trust at closing to ensure that sufficient funds were available.

the IP1&2 funds should be close to adequate. In 2003 Entergy made a $50 million contribution to the IP1&2 fund, which is not included in the amounts shown in Table 22.

If a single IP decommissioning project is undertaken, as we anticipate, the costs would be reduced even further and the existing funds should be adequate to cover all decommissioning costs. The IP funds will be closely monitored over the remaining years of plant life, even though ratepayers do not contribute to the funds, to determine if Entergy must make additional payments into the funds. Table 22 above denotes the status of several nuclear power plant decommission funds, including IP, at the end of years specified in the table.

GAO Report – The GAO issued a report in October 2003 that addressed the adequacy of the decommissioning funds and the NRC's oversight of the funding. The Report, GAO-04-32, *Nuclear Regulation* (provided as Attachment 11) found that decommissioning funding had improved in general since the GAO's last review of the fund balances as of 1997. As illustrated in Table 23 below, the GAO Report found that IP1 was under-funded, and that IP2&3 were over-funded. The GAO Report also found that recent, *i.e.* 1999 and 2000, contributions for IP1 were inadequate while contributions for IP2&3 were more than adequate.

Since IP1&2 will be decommissioned together, we believe that, based upon present knowledge and circumstances, the combined funds for IP1&2 should be adequate, particularly when Entergy's 2003 $50 million contribution is considered. The decommissioning fund for IP3 should be more than adequate, and if all the IP units are decommissioned in a single integrated program then we are confident that the funds will be adequate, based upon present knowledge and circumstances.

Table 23 – GAO Analysis of Decommissioning Funds

Unit	Adequacy of Fund	Adequacy of Recent Contributions
IP1	– – –	– – –
IP2	+	+ + + +
IP3	+ + +	+ + + +

– – – means that fund balance / recent contribution is 51-100% less than benchmark
\+ means that fund balance / recent contribution is 0-25% more than benchmark
\+ + + means that fund balance / recent contribution is 51-100% more than benchmark
\+ + + + means that fund balance / recent contribution is 101% or more than benchmark

Decommissioning Surplus – We have considered the question of what party could keep any funds remaining after decommissioning is complete. We do not have sufficient information to answer this question. Moreover, SNF could be in dry storage on-site for many years after IP ceases operation, and the GTCC waste may need to be stored on-site even longer, making the issue of keeping any surplus funds somewhat moot.

5.6. Spent Nuclear Fuel Management

SNF is fuel that has been in any of the IP reactors while in operation. SNF is a cornerstone issue related to IP's value and to potential liabilities associated with its retirement and disposition. SNF is equally important as an issue related to ongoing operations past 2006 for IP2 and 2008 for IP3. In these years, each unit will run out of storage space in the existing wet storage pools. To mitigate this problem, the older and cooler SNF in their inventories will have to be moved to dry storage.

SNF at IP can be located in one of three areas on the site: (i) in the reactors at IP2&3, (ii) in the wet storage pools at each IP unit, and (iii) in dry storage in an ISFSI. When each of the IP2&3 reactors are refueled every 2 years (*i.e.* one refueling per year), approximately one-third of the core is removed and stored in that reactor's spent fuel storage pool. If either reactor were permanently closed, Entergy would have to immediately remove all of the fuel in the reactor and place it in wet storage to cool down for at least five years. The NRC requires all nuclear plants to have this "full core off-load" capability. In order to meet that requirement, Entergy is installing an ISFSI that should be ready to begin storing SNF in specially-designed dry casks next year.

The ISFSI is located on the site in the lower area adjacent to IP3 and is designed to store SNF from IP2. Entergy may need to store SNF from IP1&3 on the ISFSI in future years. The ISFSI should be adequate until the current IP2&3 license expiration dates, and will satisfy the NRC requirement for full core off-load capability at both units. This capability will not be necessary after the reactors have been defueled and shut down for the last time.

The prevailing understanding among nuclear plant owners is that the DOE is responsible for removing SNF from plant sites and shipping it to permanent storage in the Yucca Mountain Project, located on federal land about 100 miles northwest of Las Vegas in Southern Nevada. Yucca Mountain is supposed to be available on or before 2010, but its schedule remains problematic. Even if Yucca Mountain was completed on time, IP would not be able to ship the entire SNF inventory currently on site to Yucca Mountain before about 2020 given the nation's large and growing inventory of SNF as well as Yucca Mountain's limited ability to accept SNF at any one time due to logistics and transportation availability. Therefore, in any consideration of long-term IP operation and decommissioning plans, public perception/acceptance, and site security, SNF management is an expensive and pertinent issue.

Nuclear Fuel

The basic unit of nuclear fuel used at IP is called a fuel assembly, which consists of a group of hollow sealed rods that contain uranium oxide fuel pellets. Each rod is approximately 12 feet in length, and each assembly contains 204 rods in a firmly fixed array. There are 193 fuel assemblies that make up a full core in each reactor vessel. The management of new fuel at IP2/3 is almost totally a security issue, not a radiation or thermal issue. New fuel can be safely handled in close proximity to personnel, and cooling of the fuel is not an issue since new fuel does not generate any significant heat. If new fuel were on the site at the time of final shutdown, it would be transferred to another facility or sold to another user.

The management of SNF that has been used in a reactor is another matter. As the fuel is irradiated it becomes radioactive, requiring cooling and personnel shielding. The nuclear fuel used at the Shoreham plant on Long Island is a good example. While this fuel was irradiated for only approximately 3 effective reactor full-power days, it had to be shipped by shielded cask, just like high burn-up fuel (*e.g.* fuel that has been in the reactor for hundreds of full-power days).[115] The cost of shipping the Shoreham SNF to another user was in excess of $100 million.

IP2&3 discharge approximately one-third of the fuel assemblies every 24 month cycle. This long cycle creates a high burn-up fuel that has been used as much as the license permits. The SNF produces too much heat and radiation to be stored dry and must be cooled under water for five years at a minimum before it can be moved to dry storage. There is already a large quantity of SNF at IP, some fresh from the reactors and some dating back to the 1960s. As is the case with all other nuclear power plants in the U.S., there is no other site to which the SNF from IP may be moved at this time.

Storage Pools

After nuclear fuel has been in an operating reactor for a few years (the typical total residence time is about 3 cycles or 6 years), it is no longer useful. The SNF is transferred from the reactor to the storage pool via a water-filled pipe. SNF is highly radioactive, and at least five years of cooling in a storage pool is required before it can be moved to an ISFSI. Cooling systems must run constantly to dissipate the heat from the storage pool to an "ultimate heat sink" (*i.e.* the Hudson River for IP) via multiple heat exchangers. Radiation monitors and isolation systems are used to minimize the potential for the river to be radioactively contaminated.

SNF in storage pools is monitored and safeguarded against any loss of heat removal capability. Such a condition could cause the temperature of the storage pool to boil and/or accelerate the evaporation of the water shielding and protection equipment. However, the rate of heat released from the SNF decreases over time and reaches a point where the maximum temperature to which the water would rise in the event of a prolonged interruption of the heat removal system is acceptable and safe. The operator could then request a change in the plant operating requirements to lessen or even remove the license requirement for spent fuel pool cooling systems operability. If operations continue after 2013/2015, it is unknown how the ultimate heat sink will be designed into the new cooling towers system.

Independent Spent Fuel Storage Installation

The NRC requires nuclear plants to be able to store the full amount of SNF outside the reactor vessel, necessitating sufficient space in the wet storage pools. The year in which any plant will lose its full core off-load capacity is tracked and well known. IP2 is expected to lose full core off-load capacity in 2006, and IP3 will lose full core off-load capacity in 2009. To

[115] An effective full-power day is a measurement of use that denotes one full day at 100% power.

address this problem, Entergy has received NRC approval and is constructing an ISFSI on site for IP2. The ISFSI permit may well be extended to store SNF from IP3 as well.

While the DOE has plans to begin receiving SNF at the Yucca Mountain Repository in 2010, it is unlikely that this schedule will be met. The following projections reflect the conditions and events if Yucca Mountain is not operational by then:

- Sixty of the nation's nuclear plants will lose full core off-load capacity by 2008; virtually all of these owners are well into the process of addressing this issue, including dry storage in an ISFSI.

- Of the fifteen permanently shutdown reactors, twelve plan to install dry storage facilities.

- Of the 104 reactors that are currently operating, eleven have pool storage capacity that extends to the end of original license life and will not require dry storage. Some of these plants would be candidates for wet pool re-racking that extends their storage capacity.

- With license extension, all of the operating plants will require dry storage to continue to operate if Yucca Mountain is not open and receiving fuel by 2010.

IP has a substantial inventory of SNF, estimated to be up to 1600 assemblies per unit for IP2&3, equivalent to 100 storage canisters. In addition, IP1 contains 8 canisters worth of fuel. An ISFSI will not only maintain IP's full core offload capacity, but will ultimately allow IP to be decommissioned in an optimized site-wide program. The ISFSI is being constructed inside of the controlled portion of the IP site in a protected area.

Dry storage in an ISFSI involves taking the SNF from the wet pools in a canister, while shielded in a lead and steel transfer cask, to a location where the canister is welded shut. Each canister is a stainless steel cylinder approximately 12' high by 5' in diameter, which may contain up to 32 fuel assemblies. Each canister is then inserted into a shielded (approximately 3'-4' of concrete equivalent) storage silo, or overpack, approximately 20' high and 12' in diameter. IP2&3 produces a little over 64 assemblies, equivalent to approximately two canisters, of SNF per annual refueling cycle. The canisters would be transferred to the storage pools while an equal amount of older and less radioactive SNF would be transferred from the pools to the ISFSI. The IP site may or may not be able to be to store more fuel, wet or dry, on a continuing basis if their operating licenses are extended an additional twenty years and Yucca Mountain is delayed. There is sufficient capacity using both wet and/or dry storage to contain the SNF inventory through the off load of the last two cores in 2013 and 2015 under the original IP2&3 licenses, on the site, but the additional SNF generated over another twenty years would tax the sites' storage capacity.

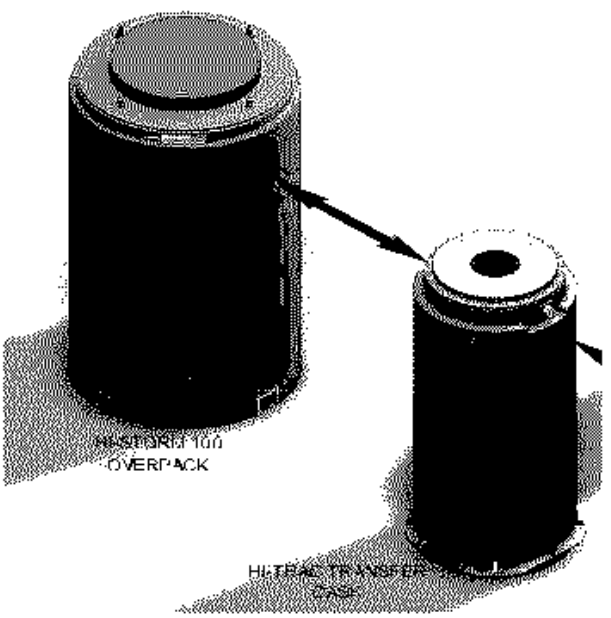
Entergy expects to load the first 192 SNF assemblies, requiring six casks and storage canisters, from the storage pools into the ISFSI in late 2005. Thereafter, IP will require about two canisters of SNF annually. If all of the SNF used at IP were to be stored at the on-site ISFSI, we estimate that approximately 108 storage containers will be required though the end

of the current license terms. This wet stored fuel inventory can, in theory, be kept in the pools until the DOE takes the fuel to the repository at Yucca Mountain. Assuming Yucca Mountain is opened on schedule in 2010 and IP is retired in 2013/15, we estimate that the SNF will not be totally removed from the site until the year 2024.

Once the current NRC licenses reach their 2013/15 expiration dates, we estimate that Entergy will require a second ISFSI to store the additional SNF that would be generated. The second ISFSI would be much larger and would likely be designed to begin accepting SNF from the wet storage pools about five years after IP2 retires, in 2018. At that point we estimate that Entergy could mount a much more intensive container construction and storage program and reduce the unit costs significantly, as described in the Valuation – Operating Expenses section of this report. If IP were to continue operating under an extended license, there may be some question whether the site can accommodate both ISFSIs as well as the cooling towers required for a closed-cycle system. In addition, keeping all of the necessary plant O&M staffs, systems and services, and infrastructure in place to protect and cool the fuel in wet storage and the ISFSIs is expensive, especially when the plants are not producing power.

Dry Storage Technology

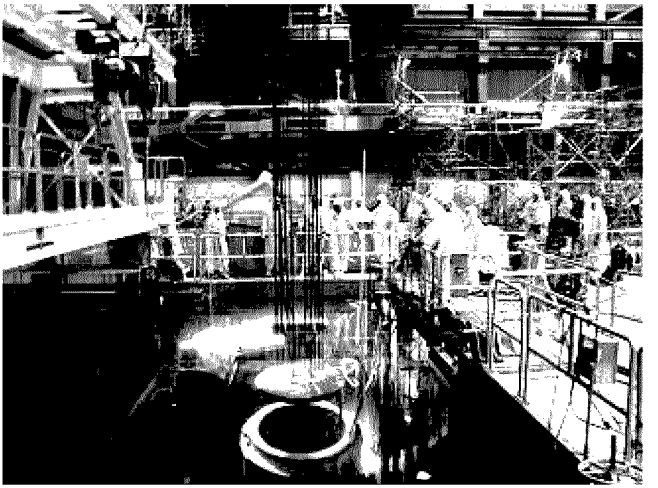
Figure 18 – Holtec HI-STORM Storage System



Entergy has chosen to utilize the Holtec HI-STORM Storage System for dry storage at IP. The technology has been thoroughly analyzed with respect to all hazards and accidents and is an accepted method of medium-term storage in the nuclear industry. The casks and other materials are inspected in accordance with NRC licensing requirements. From an overall safety standpoint, dry storage is generally acknowledged to be safer than wet storage. However, any form of SNF storage must meet specific NRC security and other physical

safeguards for the systems, structures, and components necessary to maintain the fuel in an acceptable condition.[116]

Figure 19 – Dry Runs at the FitzPatrick Plant Prior to Actual Loading



[116] Quality Assurance associated with SNF management is continuous and contiguous between 10 CFR part 50 (*i.e.* the reactor and operations) and 10 CFR Part 72/71 (*i.e.* SNF storage and off-site transportation) licenses. Quality Assurance requirements are pervasive and depend upon the condition of the fuel and reactor.

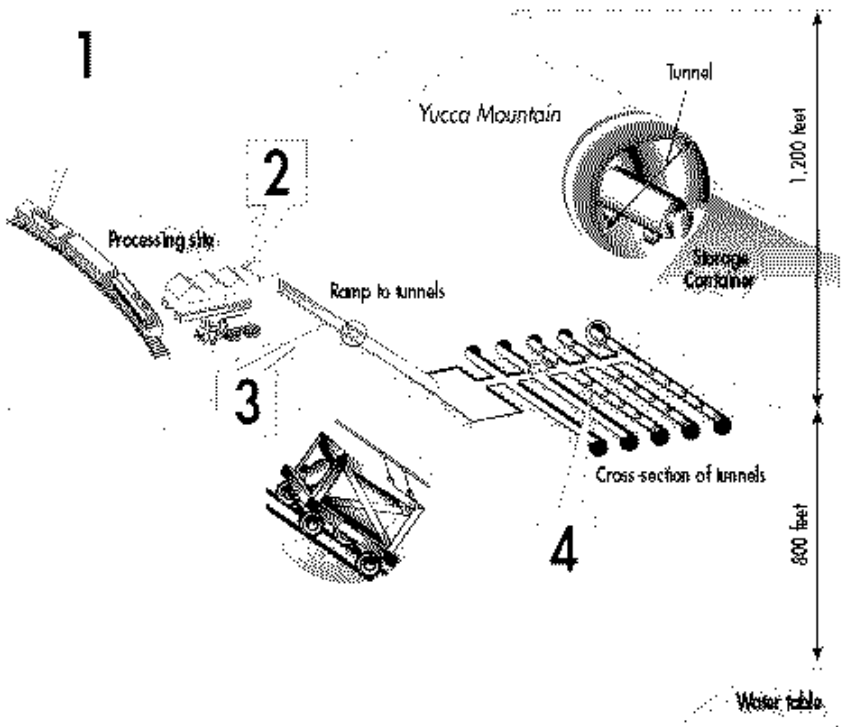
Figure 20 – Compact Spacing of HI-STORMs at the FitzPatrick ISFSI

The Holtec system, pictured on the previous page, allows fuel canisters to be stored or shipped. Photographs of the HI-STORM system were taken during dry runs at the J.A. FitzPatrick plant; the IP canisters should be approximately the same size.

Yucca Mountain

Storing SNF in an ISFSI is not viewed as a permanent solution. The current SNF policy in the U.S. is long-term disposal at the Yucca Mountain national repository. Yucca Mountain will not be open in time to accept SNF from IP2&3 before those units reach full core off-load capacity with their respective fuel storage pools, which is why an ISFSI is critical. The DOE is preparing a license application for Yucca Mountain that is due to be filed with the NRC in 2005. If the application is approved and a license granted (estimated to take 2-3 years), construction could commence in 2008 and Yucca Mountain could begin to accept SNF by 2010.

Figure 21 – Yucca Mountain



In Figure 21 we show a simplified schematic of Yucca Mountain. The numbers in the schematic are as follows:

1. Canisters of waste, sealed in special casks, are shipped to the site by truck or train.

2. Shipping casks are removed, and the inner tube with the waste is placed in a steel, multilayered storage container.

3. An automated system sends storage containers underground through the main tunnel to the side tunnels, or "drifts".

4. Containers are stored along the drifts, on their side.

The Yucca Mountain schedule has been delayed in the past, and the 2010 date is problematic. A number of licensing activities must be completed before facility construction can start, and there is a high probability of litigation delaying the final use of the site. Even if Yucca Mountain can accept SNF by 2010, it is unlikely it will accept sufficient quantities quickly

enough to avoid decommissioning delays stemming from SNF storage at IP.[117] The decommissioning problems would be a result of not being able to decommission the whole site due to stored SNF at the ISFSI.

The schedule to deliver SNF to Yucca Mountain is a key consideration. While the DOE may schedule shipments somewhat preferentially to minimize the need for capital investments in new ISFSIs, decommissioned or permanently retired plants may not be prioritized and therefore lose their nominal priorities. The currently projected shipping and receipt capacity at Yucca Mountain is about 1.25 casks per day. Since there are roughly 115 nuclear power reactors in the U.S. at which SNF is stored, Yucca Mountain will be able to accept about 3 shipments from each reactor per year. Even with no license extension, each of the IP2&3 units would have an inventory of 3200 SNF assemblies at retirement, and it would take about ten years to ship all the fuel to Yucca Mountain.

Radioactive Waste

Dry storage of all of the SNF on the site would facilitate the timely and efficient decommissioning of the IP units. GTCC waste from the reactor vessels, such as highly radioactive, non-fissile metal parts, must be removed and stored in high level radioactive waste containers. Currently there is no repository for GTCC waste in the U.S. The normal method of managing GTCC waste is to remove it at decommissioning and store it in standard ISFSI-size canisters at the ISFSI or elsewhere on the site. Mixing of GTCC waste with SNF is not allowed, other than integral non-fuel parts of the fuel assemblies. While the initial license application for Yucca Mountain did not include GTCC waste, an amendment may be able to extend the license administratively to accept GTCC waste. Otherwise, the GTCC waste could be "orphaned" with no licensed federal or state owned repository available. A large reactor such as each IP unit typically contains the equivalent of two-to-three waste canisters of GTCC.

117 A private fuel storage interim storage facility is being developed in Utah, but is unlikely to open in time to be of value to IP in terms of fuel management strategy. The private facility is not a DOE facility or final storage / disposal facility, and the responsibility for the SNF remains with the then current licensee (at the time) during transport in, storage, and transport out.

6. ECONOMIC AND RATE IMPACTS

6.1. ECONOMIC IMPACTS

LAI estimated the economic and rate impacts of retiring IP. We calculated the dollar value of these impacts on Westchester County and on New York State as a whole. In addition, LAI utilized economic "multipliers" to estimate how direct economic impacts have broader, secondary impacts on the County and the State. Consistent with our scope of work, we did not quantify any public safety and homeland security benefits from retiring IP. The key economic drivers that would give rise to the impacts that we did quantify include the following:

- Property taxes (*i.e.* PILOT) and property values
- Employment and employee compensation
- Payroll and corporate income taxes
- Local spending and sales taxes
- Market electricity prices
- Local community support
- County emergency planning
- Fisheries impacts
- Air emission impacts

One of the principal sources LAI used to estimate the economic impacts was the NEI Study that examined the economic, fiscal, and community benefits provided by IP. Entergy provided valuable employment, operating expense, and tax payment data to NEI, much of which is not otherwise available to the public. LAI used some of this IP data, provided it could be verified or that it appeared reasonable.

LAI included mitigating measures for each of these individual impacts where appropriate. For example, retiring IP would result in a significant reduction in operating staff, but many other engineering and construction jobs would be created for decommissioning and SNF management.

6.2. ECONOMIC MULTIPLIERS

In gauging the economic impacts of retiring IP2&3, it is necessary to estimate the direct effects as well as the indirect, or secondary, effects of retirement. For example, retiring IP2&3 would result in job loss. The direct effect would be the lost salaries for workers who lose their jobs, and the indirect effect would be the impact of reduced spending by those

workers in the community. Another example would be reduced local spending on goods and services by Entergy. The direct effect would be the loss of sales at local suppliers, and the indirect effect would be the reduced spending of those suppliers due to their reduced sales.

Economic multipliers are quantitative factors designed to provide a measure of the secondary economic impacts from changes in employment, income, and other variables. LAI utilized economic multipliers to reflect changes in compensation, employment and local spending. We did not utilize economic multipliers for changes in IP generation because it would be replaced by output from other power plants.

A wide range of economic multipliers can be found in publicly available economic analyses and reports. The wide disparity found among the economic literature can be traced back to the range of uncertainty and the vagueness of the analysis. Nonetheless, we endeavored to find appropriate multipliers that reasonably estimate the indirect impacts associated with various lost sources of funds. According to Cornell University, economic multipliers for the transport and utilities industries in New York are 1.31 for income and 1.48 for employment.[118] Another study evaluating DOE spending concluded that economic multipliers tend to be in the range of 1.5 to 2.0.[119] The NEI study, sponsored by Entergy, utilized multipliers for plant output and local employment on the County, state and country. NEI used a local multiplier of 1.17 and a state-wide multiplier of 1.25 for plant output, and a local multiplier of 1.35 and a state-wide multiplier of 1.45 for labor income. According to DOE, utility services generally produce an economic multiplier of 1.66 for the local economy.

For purposes of this analysis, LAI applied economic multipliers of 1.5 for the County and 1.75 for the State. We find these values are reasonable and near the mid-point of the values from reputable sources in the public domain. We note the inexact nature of economic multipliers, and caution that these values should not be taken as definitive.

6.3. Property Taxes and Property Values

At the time the IP assets were purchased, Entergy executed two agreements with the Town of Cortlandt, the Hendrick Hudson School District, and the County of Westchester to establish PILOT schedules for IP2&3. Both PILOT agreements are dated as of January 1, 2002, and establish PILOT schedules through 2014.[120] As shown in Table 24, PILOT payments are made to four government bodies and total $18.8 million in 2005, rising over time to $26.8 million in 2014.[121] The Hendrick Hudson School District receives over 80% of the payment, which currently amounts to 34.4% of the approved 2004/05 budget for the School District. In 2005/06, the School District will receive $15.2 million. IF IP were to retire, it is not known

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[118] Jack, K., N. Bills and R. Boisvert. *Economic Multipliers and the New York State Economy*. New York Department of Agricultural, Resource, and Managerial Economics. December 1996.

[119] Dumas, L.J. *Economic Multipliers and the Economic Impact of DOE Spending in New Mexico,* University of Texas at Dallas. March 2003.

[120] Year refers to tax year, *i.e.* June 1 of the reference year to May 31 of the following year.

[121] The NEI Study referred to PILOT payments of $25.3 million in 2002 which appears to be inconsistent with the PILOT agreement. PILOT payments prior to 2005 are not relevant for the purposes of the assignment.

how the School District would replace these PILOT funds other than through higher property taxes. The School District includes the schools in the municipalities of Buchanan, Verplanck, Crugers, Montrose, and parts of Cortlandt Manor, Croton, and the City of Peekskill.

Table 24 – Combined IP2&3 PILOT Schedule
($ thousands)

Year	Town of Cortlandt	Verplanck Fire District	Westchester County	Hendrick Hudson School District	Totals
2005	$616	$286	$2,762	$15,170	$18,834
2006	$589	$273	$2,691	$15,377	$18,930
2007	$600	$279	$2,745	$16,315	$19,939
2008	$600	$279	$2,800	$17,311	$20,990
2009	$613	$284	$2,856	$18,367	$22,120
2010	$613	$284	$2,913	$19,330	$23,140
2011	$613	$284	$2,971	$20,122	$23,990
2012	$624	$290	$3,030	$20,946	$24,890
2013	$624	$290	$3,091	$21,805	$25,810
2014	$624	$290	$3,153	$22,701	$26,768

Of critical importance, the PILOT Agreements are effective as long as IP2&3 remain licensed nuclear facilities. The PILOT amounts would not be affected by any improvements or capital expenditures that increase the capacity of the units or result in (i) construction of new buildings, (ii) addition to the foundation of an existing building, or (iii) expansion of an existing building. Past and future increases in the capacity of the units are presumably considered to be "recalibrations or power uprates" and do not trigger increased PILOT payments.

ISFSI – The establishment of an ISFSI at the IP site is not specifically addressed but is not expected to affect PILOT payments. An ISFSI would not result in triggering the above provisions (i) - (iii). Furthermore, this question was raised by the County during final negotiations on the PILOT Agreements. At the time, it was noted that dry casks would be considered personal property and the tax effects would be *de minimus*.

PILOT Payments at Retirement – The terms of the PILOT Agreements expire at the end of the 2014 Tax Year, "unless the Plant ceases to constitute a Nuclear Facility", defined as "a nuclear power electric generating facility with an operating license to generate power…" If IP is retired prior to the end of the NRC licenses it would probably have to retain its operating license (as long as radioactive materials remained on-site) but Entergy might argue that it is no longer obligated to continue making PILOT payments, thereby jeopardizing future payments.[122] Even if the PILOT Agreements were to expire, there may be modest property

[122] Resolving this issue may require negotiations or legal interpretation of language in the PILOT Agreements.

tax obligations based on the remaining assets. We have not tried to estimate these property taxes for this assignment.

If IP were retired at the end of the existing NRC licenses, Entergy (or IP's then-current owner) would be liable for property taxes at then-current rates. However, the value of the units would be severely diminished since they would cease generating revenues. We believe it is unlikely that the ISFSI and decommissioned units would have more than *de minimus* value for any possible purchaser. Therefore, upon retirement, regardless of the cause, property taxes might well decline to a negligible level.

License Extension – The terms of the PILOT Agreements provide that property taxes would be made pursuant to then-current law at expiration. Alternatively, Entergy could negotiate new PILOT Agreements for the period commencing with the license extensions. Therefore, LAI assumed that PILOT payments would continue and increase at the long-term general inflation rate of 3% if IP2&3 continued to operate under NRC license extensions.

Replacement Generation at IP Site – Constructing replacement generation at the IP site would not be covered under these PILOT Agreements. We anticipate that a new PILOT agreement would be negotiated for any on-site replacement generation; we cannot speculate what the level of PILOT would be. However, it is possible that even a 1,000 MW plant could provide PILOT revenues close to those negotiated for IP, as discussed in section 3 of this report.

Table 25 – Direct and Total Economic Impact of Lost PILOT
($ thousands; assumes no on-site replacement generation)

Year	Direct Impacts	Total County Impact	Total State Impact
2005	$18,834	$28,251	$32,960
2006	$18,930	$28,395	$33,128
2007	$19,939	$29,908	$34,893
2008	$20,990	$31,485	$36,733
2009	$22,120	$33,180	$38,710
2010	$23,140	$34,710	$40,495
2011	$23,990	$35,985	$41,983
2012	$24,890	$37,335	$43,558
2013	$25,810	$38,715	$45,168
2014	$26,768	$40,152	$46,844

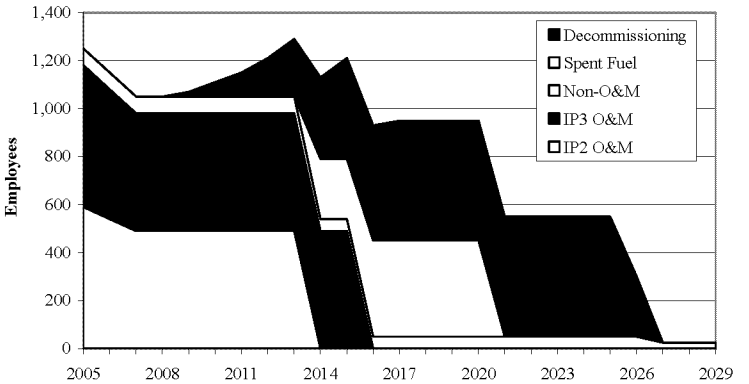
Nearby Residents – If IP were retired and not replaced it is likely that property values for homeowners would increase even if the IP site stores SNF. However, that impact might be offset by higher property tax rates to compensate for the decrease in PILOT payments, and the corresponding tax rate increase for other taxpayers. In any event, such impacts would be relatively confined to Buchanan. LAI did not speculate as to the net effect of local property values for the purpose of this assignment.

Indirect Impacts – The total direct and indirect impacts on the County and State economy are shown in Table 25 above, including local and state multipliers of 1.5 and 1.75, respectively, assuming no on-site replacement generation.

6.4. Employment and Employee Compensation

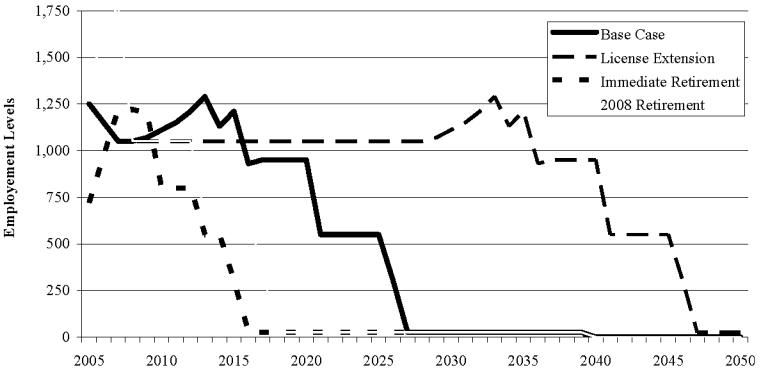
As explained earlier in this report, Entergy plans to reduce IP employment from about 1,350 in 2004 to between 1,000 and 1,100 over the next few years; we assumed the mid-point value of 1,050 employees by 2007. According to the NEI Study, about 18% of these employees reside in Westchester. Retiring IP will not mean the immediate loss of these jobs. Once IP ceases operating there will need to be staff to commence decommissioning activities, move SNF and other radioactive waste into dry storage, monitor the SNF, and provide site security. Therefore the impact of job loss will be mitigated over time. For example, if IP2&3 are retired at the end of their existing license terms, we estimate that employment could be as depicted in Figure 22. Thus the economic impact from employment will not affect Westchester for about five years, and will not be fully realized for another five years: Moreover, the loss of employment would be further offset if a replacement plant is constructed, which would produce additional construction and plant operating jobs.

Figure 22 – Base Case (Retirement in 2013/15) IP Employment



Note that employees dedicated to decommissioning and SNF management ramp up as operation and management of IP2&3 decline. In the Base Case where IP retires in 2013/15, 950 employees remain on sight until 2020, and then 550 until 2025. We assume that security personnel, shown as Non-O&M employees, remain until SNF is completely removed from the site. If IP was retired immediately, employment would increase in the short-term and then taper off as SNF was put into dry storage and decommissioning was completed. If the IP licenses were extended, we expect that personnel would remain level at 1,050 for a long time, except for periodic SNF activities. A comparison of employee levels across the four scenarios is provided in Figure 23:

Figure 23 – IP2&3 Employment Comparison of Retirement Scenarios



We distinguished between professional services (*i.e.*, O&M, SNF management, and decommissioning) and other services (primarily security) in estimating compensation levels. We estimate professional services employees have a total compensation of about $102,000 in 2005 and non-O&M employees have a lower total compensation, about $70,000. We assume both compensation levels increase at the inflation rate of 3%.

To calculate direct and indirect impacts to the County and the State we applied the 1.5 and 1.75 multipliers, respectively. These values are provided in Total Economic Impact, Table 30 and Table 31. For purpose of this analysis, we assume employment at Entergy's White Plains office remains at current levels regardless of future IP operation. Entergy also operate the FitzPatrick nuclear facility in New York as well as the Pilgrim and Vermont Yankee facilities in New England. We assume that White Plains employees will continue to be necessary to assist these and other facilities (*e.g.*, providing marketing services, ISO interaction and representation).

6.5. Payroll and Corporate Income Taxes

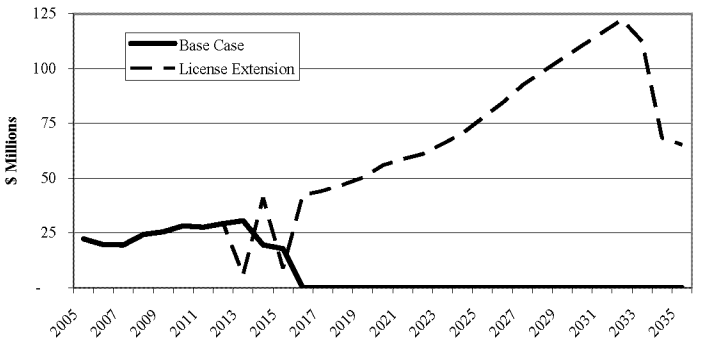
According to the NEI Study, Entergy paid payroll taxes of close to $10 million in 2002 for employees at IP and the White Plains office. However, NEI estimated that 99% of those payroll taxes went to the Federal government. The small amount of payroll taxes paid to New York State and local government entities were therefore ignored for this assignment.

The NEI Study did not include corporate income tax impacts. IP is owned by wholly-owned LLC subsidiaries of Entergy. New York State imposes a 7.5% franchise tax on net income, and treats LLCs as a corporation for tax purposes if it is treated as a corporation for federal income tax purposes. Based on information contained in Entergy's 2003 SEC Form 10K, it appears that Entergy's non-utility nuclear business segment pays federal income taxes.

Therefore we assume that the Entergy LLCs that hold the IP ownership interests pay state franchise taxes.

LAI estimated Entergy's payment of corporate income taxes based on our estimate of IP net income. This franchise tax is currently estimated to be $22.3 million, and is expected to terminate upon IP2&3 retirement. Figure 24 depicts the projected income tax payable to the State for the Base and License Extension cases. The values depicted in the Figure 24 escalate rapidly due to the forecasted rise in market energy prices as discussed earlier in this report. Changes in income taxes were then adjusted for economic multipliers for the State, and 5% of this value was then applied to the County based on the percentage of State population. On-site replacement generation would help mitigate any loss of tax revenues.

Figure 24 – New York Income Tax
($ millions)



6.6. Local Spending on Goods and Services

According to the NEI Study, IP (including the White Plains office) purchased $16.8 million worth of goods and services in Westchester County and the four nearby counties of Orange, Rockland, Putnam, and Dutchess in 2002. These purchases include services to buildings (*e.g.* janitorial services, landscaping, pest control, and plumbing), water supply and sewer services (presumably made to the local water district), and a wide variety of business services and equipment. Since most of these purchases related to IP, we did not try to subtract out purchases by the White Plains office. These purchases in the five county area represent about 30% of the combined IP & White Plains spending in New York. Applying the 7.5% sales and use tax in Westchester, these purchases provided an additional $1.3 million in County tax revenues. As noted previously, this loss of local spending would be offset by construction and operation of replacement generation on site.

According to the NEI Study, goods and services purchased in New York State totaled $54.9 million in 2002. The largest cost category was payments made to NYISO, principally for transmission services, followed by the purchase of motors and generators. Services to

buildings and other business services and equipment complete the list. Purchases of goods and services outside of New York State (*e.g.* specialized maintenance & repair and nuclear consulting services) were significant but were outside the scope of this assignment. LAI has no reason to doubt the purchase figures provided in the NEI Study. The local spending values provided in the NEI Study for 2002 are as follows:

Table 26 – Entergy Local Spending in 2002
($ millions)

	Local Spending on Goods & Services	Adjusted for Multiplier Effect
Westchester County	$ 11.1	$ 16.7
Nearby Counties	$ 5.7	$ 8.6
Five County Area	$ 16.8	$ 25.2
Other NYS[123]	$ 38.1	$ 70.8
New York State	$ 54.9	$ 96.1

To forecast direct expenditures in the local and State economies, we assumed that 2002 values would increase at the rate of inflation as long as IP was in operation. For all four scenarios assessed, we assumed that on the first year of decommissioning, non-employment expenditures would decline to 50% of the prior year. Expenditures were then adjusted year-to-year based on the level of employee compensation, which is tied primarily to the decommissioning schedule. If IP were to be retired, some of this spending would not be required. However, a fair amount would be required to support decommissioning and SNF activities.

6.7. Market Electricity Prices

Retiring IP prior to 2013/15 will increase market energy prices as IP output is replaced by other generators with higher operating costs. LAI estimated the impact on market energy prices using the MarketSym chronological dispatch simulation model.[124] However, a significant portion of utility energy requirements is purchased under long-term bilateral contracts, *i.e.* PPAs, so that ratepayers would not be fully exposed to those higher market energy prices in the short term. In addition, NYPA owns significant generation assets, *i.e.* approximately 6,500 MW, throughout New York, and sells much of the energy under cost-based rates that do not reflect market forces.

According to its 2004 10-K filing, Con Edison has capacity and energy purchase obligations of $1.36 billion in 2005, equivalent to 44% of its 2004 total power purchases.[125] In addition,

[123] "Other NYS" impact was calculated as the difference between the New York State total and the total for the five county area.

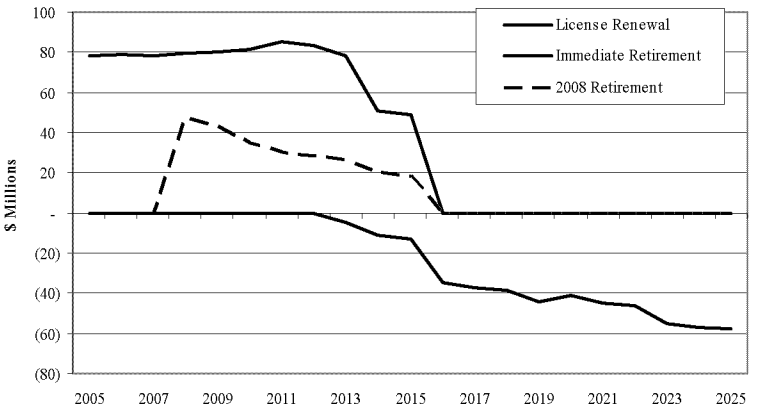
[124] MarketSym was previously described in section 4.5.

[125] Con Edison's purchase obligations decline only slightly over the following four years and average $1,194 million over the entire five year period. 70% of Con Edison's purchase obligations remain after five years.

Con Edison generates about 5% of its requirements from its own resources. Therefore Con Edison's ratepayers would be roughly 50% hedged against higher short-term market energy prices if IP were retired early. For the State as a whole, we assumed that electricity rates would be affected 50% by changes in short-term market energy prices.[126]

Figure 25 below indicates the expected increase in total electric charges for the County against the Base Case. The impact on the County was calculated as Westchester's 45% share (based on energy consumption) of the total change in electricity costs (including both energy and capacity components) for the combined Zones GHI that LAI modeled as a single region. We then applied the local economic multiplier of 1.5 to estimate the direct and indirect impacts of higher local electricity prices.

Figure 25 – Change in County Electricity Costs by Scenario
($ millions)

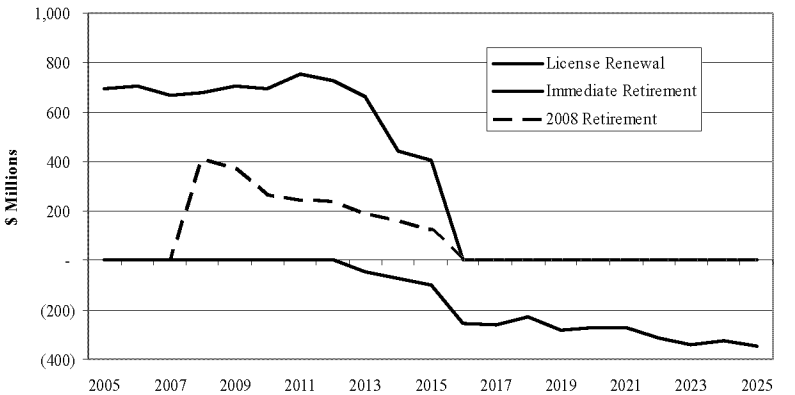


In the unrealistic case in which IP was retired immediately without replacement generation, local electricity costs would increase dramatically, about double the initial impact of an orderly retirement in 2008. (This is an unrealistic case is included only for comparison purposes). On the other hand, if the IP licenses were extended, electricity costs would actually be lower than if IP retired in 2013/15. LAI calculated the impact of these higher electricity costs on typical residential rates, as described at the end of this section.

[126] As discussed earlier, our scope of work did not include quantifying the potential secondary impact of increased gas price volatility on market energy prices. Or scope also did not include estimating the rate impact from any increased operations of gas- and oil-fired resources on Long Island.

The change in electricity costs under the three alternative scenarios against the Base Case is depicted in Figure 26, below. The total direct and indirect impact on the State economy equals 175% of the values depicted in Figure 26, based on the state economic multiplier 1.75. While the pattern of higher electricity costs is similar, the state-wide impact is much greater than the County impact. Over the eight year period of time, *i.e.* 2008 – 2015, that IP's output would be replaced by other generators, ratepayers state-wide would face an average energy price increase of about $250 million (1.6%) per year. This value assumes that ratepayers throughout New York are only exposed to only 50% of the higher market energy prices because of utility PPAs.

Figure 26 – Change in State Electricity Costs by Scenario
($ millions)



6.8. Local Community Support

In addition to the purchase of goods and services, Entergy supports local communities in Westchester through monetary contributions and employee volunteer efforts. According to the NEI Study, Entergy contributions totaled $0.3 million in 2002 and $1.2 million in 2003 for educational programs, health and public safety programs, environmental protection, and other endeavors. LAI has no reason to doubt the accuracy of these figures. Not knowing Entergy's current level of contributions, we believe that it is reasonable to assume that 2005 monetary contributions would be $0.8 million, slightly above the 2002 / 2003 average.

LAI believes that it is reasonable to assume that Entergy would continue to make some level of support during any decommissioning period, and even afterwards while SNF remains on site. Under our Base Case scenario in which there would be 2,000 MW of replacement power in combined Zone GHI but not in Westchester, we assume that Entergy contributions to the local community would increase at inflation through the existing NRC license term, and contributions would be reduced by one-half while there was decommissioning or SNF activity

at IP. It is reasonable to assume that a developer of on-site replacement generator would also find ways to support the local community.

6.9. County Emergency Planning

Westchester County maintains a $5.36 million annual budget for emergency services. As of 2002, about $4.62 million of County emergency expenses was directly attributable to operation of IP. If IP2&3 were closed, however, this value (escalated for inflation) could not be immediately avoided. County emergency services will be required for at least the ten-year decommissioning period, and possibly longer if the SNF and GTCC waste are stored on-site in dry casks. We presume that the County (as well as the individual municipalities) will not be able to materially reduce their emergency planning budgets until after the SNF is completely removed from the site, which we estimate to be 2024 in our Base Case scenario.

To the extent the emergency services budget could be modestly reduced due to the fact that IP2&3 are no longer operating, the net savings impact to Westchester residents is likely to be small. Each of the nuclear facilities in the state currently pays $550,000 into a fund to assist communities near nuclear plants with the incremental cost of emergency services. Westchester County currently receives $412,000 from the fund, operated by the State Disaster Preparedness Commission. This value would likely decline as the facility operation terminates, and in particular, once the there is no need for emergency services.

Accordingly, the net County emergency budget cost associated with the various cases emergency services due to closure of IP2&3 is expected to remain approximately $4.21 million (*i.e.*, $4.62 million the County spends less the $0.41 million received from the State Disaster Preparedness Commission). For purposes of this analysis we inflated the County's cost of emergency services as well as the County's allocation of funds from the State Disaster Preparedness Commission.

6.10. Fishery Impacts

IP utilizes a once-through cooling system that withdraws up to 2.5 billion gallons of water per day through three intake structures located on the shoreline of the Hudson River.[127] The intake structures utilize screens and a fish handling and return system to minimize fish mortality. The cooling water absorbs heat from the plant condensers and is discharged back into the Hudson through diffuser ports downstream of the intake structures.

IP's withdrawal of cooling water from the Hudson was originally approved under a National Pollutant Discharge Elimination System (NPDES) permit issued by the EPA. After the U.S. Clean Water Act was enacted in 1972, the EPA authorized the DEC to administer the NPDES program. Discussions and disagreements among numerous stakeholders about water resource issues led to the Hudson River Settlement Agreement in 1981 under which these issues would be researched over a ten year period. In 1982 the DEC issued a SPDES permit to IP2&3. This permit had a five year duration, was renewed in 1987, and expired in 1992.

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[127] IP1 is not operational but still draws cooling water from the Hudson River.

Over the next ten years the DEC unsuccessfully sought to negotiate new permit conditions with IP (and with Danskammer, another plant on the Hudson River). At the time the Hudson River Settlement Agreement expired in 1982, certain stakeholders filed a lawsuit that led to a Consent Order the following year. Under the Consent Order the parties agreed to implement certain mitigation measures contained in the Agreement. The Consent Order was extended a number of times through 1998. In December 1999 Entergy filed a Draft Environmental Impact Statement to DEC which formed the basis for a Final Environmental Impact Statement (FEIS) that was issued in June 2003.[128]

The FEIS provides the basis for DEC to determine whether to renew the SPDES permit that allows once-through cooling. Among its findings, the FEIS focused on fish entrainment and mortality, and estimated that IP is responsible for 1.2 billion instances of entrainment annually, of which at least 900 million fish die. The DEC issued a draft SPDES permit #NY-0004472 under which Entergy will be required to implement a closed-cycle cooling system that would eliminate water extraction from the Hudson River. The draft SPDES permit requires that Entergy submit a pre-design engineering report on the cooling system within one year of final issuance, and a detailed engineering plan within a second year. At this point in time it is expected that the SPDES permit will not be finalized until late 2005-mid 2006.

Entergy will be required to construct the closed-cycle cooling system if Entergy applies to extend its operating licenses, and the NRC approves the license extensions and determines that the closed-cycle cooling is feasible and safe. Entergy will be required to contribute $24 million per year into an escrow account to benefit the Hudson River from the time the final SPDES permit is issued up to the time that construction commences.[129]

The FEIS quantified fish mortality by species, and LAI applied industry-accepted replacement values for those fish from *Investigation and Monetary Values of Fish and Freshwater Mussel Kills*.[130] The net result is that IP, as it is currently configured, is estimated to harm the Hudson River fisheries by $119.2 - $499.5 million per year (2005 dollars), with a midpoint value of $309.4 million, as calculated in the table below. If IP was granted life extension and a closed-cycle cooling system were constructed, no Hudson River water would be required thereafter (except perhaps under emergency conditions for SNF cooling). If IP were retired, the amount of cooling water from the Hudson River would decline but would not cease entirely, since some Hudson River water might still be required for SNF storage pool cooling. In this case, there would still be some fish mortality; we assumed 10%, and used the midpoint value of $309.4 million to estimate a cost of $30.9 million per year until the SNF was removed from the storage pools. Since recreational fisherman and other State residents would

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[128] The FEIS covers three power plants that utilize Hudson River water: IP, Roseton 1&2, and Bowline 1&2.

[129] The annual escrow contribution was based on an estimated construction cost of $740 million, identical to the cost estimate LAI used in our financial analysis.

[130] R.I. Southwick and A.J. Loftus. American Fisheries Society, Special Publication 30, 2003. According to the preface, "the predecessors of this publication have been adopted as the legal basis for fines or restitution in more than half the states and have been upheld in numerous legal challenges."

enjoy the benefits of healthier Hudson River fisheries, there may be an opportunity for the State to help compensate Entergy for the early retirement of IP.

Table 27 – Fish Mortality and Valuation[131]
(millions unless noted otherwise)

Species	Mortality	Min Value	Max Value
American Shad	10.64	$ 0.17 per fish	$ 1.42 per fish
Bay Anchovy	326.67	$ 0.09 per fish	$ 0.09 per fish
River Herring	371.67	$ 0.17 per fish	$ 0.81 per fish
Striped Bass	46.50	$ 0.05 per fish	$ 2.13 per fish
White Perch	138.66	$ 0.09 per fish	$ 0.09 per fish
Atlantic Tomcod	n/a	n/a	n/a
Sub-totals	894.14	$ 109.2	$ 457.1
Inflation to 2005		* 1.09	* 1.09
Range of Impacts		$ 119.3	$ 499.5
Midpoint		$ 309.4	
90% Reduction		($278.5)	
Impact if Retirement w/o Cooling Towers (for five years)		$30.9	

The allocation of the direct and indirect economic impacts is difficult to determine. Because the value of the fisheries are along the entire Hudson River watershed, we placed most (90%) of the value elsewhere in New York State and only a modest amount (10%) in the County. We then applied the respective multipliers to determine the direct and indirect impacts on the representative locales, as seen in the following table:

Table 28 – Fish Mortality Valuation – Allocation to County and State
($ millions)

	Direct Impact	Adjusted for Multiplier Effect
County	$ 30.9	$ 46.4
Other State	$ 278.5	$ 487.4
Total NY State	$ 309.4	$ 533.7

These values were projected to grow at the rate of inflation as long as IP is in operation. River water might still be used as make-up water lost to evaporation from the cooling towers and for flushing out contaminants. Although the closed-cycle cooling system would no longer expel hot water into the Hudson River, we made no further adjustment due to our

[131] Sources: FEIS and American Fisheries Society

understanding that the overwhelming majority of fish mortality is due to entrainment. However, the introduction of hybrid cooling towers at IP may create new concerns and issues for people living near IP. Quantifying these concerns and issues, listed below, cannot be accomplished until the closed-cycle design is prepared and published.

- Water evaporation exiting the hybrid cooling towers may change the normal moisture composition of the surrounding areas.

- Late fall and winter operations of the hybrid cooling towers may increase precipitation in the form of snow, sleet, or ice to the down-wind area, thereby affecting road conditions and traffic safety.

6.11. Air Emissions

If IP is retired, many units (and not just the replacement generation) will be dispatched more hours in each year to make up the energy that IP would have produced. The MarketSym dispatch simulation model that we used can estimate, on an indicative basis, the resulting impact on regional air emissions.[132] The two key air emissions that we considered are NO_X and SO_2.[133]

- NO_X is generated by many types of power plants, including gas-fired simple and combined cycle plants, and is controlled using selective catalytic reduction and similar systems. Cars, trucks, and other motor vehicles are the largest source of NO_X emissions in New York. According to the EPA Office of Air and Radiation, power plants were responsible for 12.6% of New York's NO_X emissions in 1999, the last year for which EPA has complete data.

- SO_2 is generated by oil and coal combustion and is controlled by flue gas desulfurization (also referred to as scrubbers) or other systems. According to the EPA, power plants were responsible for 52.8% of New York's SO_2 emissions.

LAI roughly estimated air emissions in New York during two specific years, 2009 and 2016, to measure the impact of retiring IP. When IP is retired, we project an increase from New York power plants of approximately 4.0% - 4.3% in NO_X emissions and 2.6% - 2.7% in SO_2 emissions, as expressed in Table 29. These projections should be viewed as indicative estimates only; reliable estimates would require us to verify the emission rates for all of the individual plants that would operate at higher capacity factors and emission control upgrades that may be planned or required in the future and that have not been factored into our analysis. Reliable estimates of state-wide projections would also require us to project the changing mix and contribution of other emission sources that were outside our scope of work.

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[132] A detailed estimate of air quality impacts is beyond the scope of this assignment.

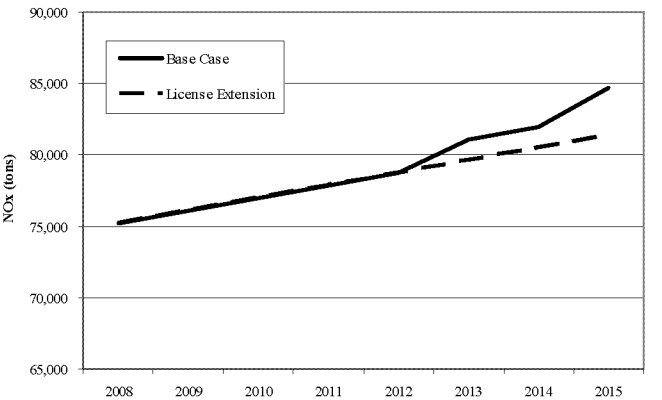
[133] We did not assess changes in CO2, mercury, volatile organic compounds, or other relevant air pollutants which are also likely to change if IP retired, which should not be construed as an indication that the impacts or estimated value is negligible.

Table 29 – Indicative New York State Air Emissions Impacts

Retirement Dates	Emission	Emissions with IP	Emissions w/o IP	Net Power Plant Increase	Net State-Wide Increase
2009 vs. 2013/15	NO_X	76.1 ktons	79.4 ktons	+3.3 ktons *+4.3%*	*+0.5%*
	SO_2	250.8 ktons	257.6 ktons	+6.8 ktons *+2.7%*	*+1.4%*
2016 vs. License Extension	NO_X	82.3 ktons	85.6 ktons	+3.3 ktons *+4.0%*	*+0.5%*
	SO_2	268.5 ktons	275.6 ktons	+7.0 ktons *+2.6%*	*+1.4%*

We made adjustments to the projected emission values to account for the staggered termination of IP2&3. In Figure 27, we show the projected increase in NOx emissions when IP2&3 are removed from service in 2013 and 2015 respectively. The pattern for SO_2 emissions would be similar.

Figure 27 – NO_X Emissions Under Base Case and License Extension Scenarios



We multiplied the change in emissions under each scenario as measured against the Base Case by an estimate of emission allowance values. Absent a proven method of estimating the economic costs of emissions, we applied a projection of emission allowances that are traded among regional entities to comply with Clean Air Act standards as set by the EPA as a proxy

for actual emission costs.[134] We recognize that, for a variety of reasons, emission allowance values do not adequately represent the human health and environmental costs associated with air pollution. Nonetheless, we believe that the emission allowance values represent, to a certain extent, the willingness of society to mitigate such emissions. SO_2 values range from roughly $215/ton to $480/ton over the forecast duration; NO_X emission allowances range from $1,200/ton to $3,000/ton. Allowance values do not necessarily rise along the general inflation rate, but more to our projection of the supply/demand balance for these financial derivatives.

Once the total emission costs were calculated, we estimated the impact on the County and the State. We assumed that all of the increased emissions impact the State, and 5% impacts the County, based on the proportion of the County population to the State population.[135]

6.12. Total Economic Impact

The total direct and indirect electric market and economic impacts to the County and State are shown in the following tables. Both tables compare the three non-Base Case scenarios against the Base Case assumption of retirement in 2013/15. These values reflect the allocation of costs to the County and State as a whole, and also the respective local and State economic multipliers. To simplify the information presented, we present annual data for three relevant years. Note that Corporate Income Tax is applied only at the State level, and that these impacts do not reflect any compensation paid to Entergy. These impacts assume no replacement generation is developed at the IP site. These impacts do not include any benefit in improvements in public safety or homeland security.

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[134] Extensive research on the economic impact of air emissions has been conducted by a wide range of government and non-government economists. The estimation techniques and values determined are diverse. A number of government agencies that regulate electric utilities have applied, at one time, damage estimates based on the cost to control pollution. See *Electricity Generation and Environmental Externalities: Case Studies,* US. DOE, September 1995. Our approach, *i.e.*, quantifying the impact of air pollution based on allowance values, is consistent with methodologies used by the state public utility commissions in Massachusetts, Wisconsin, and California.

[135] We recognize that not all emissions will fall in the State; a fair amount will fall outside State boundaries. Most assessments of emission outfall indicate the plumes generally travel from southwest to northeast.

Table 30 – Total Economic Impact to County by Scenario for Selected Years
($ millions; impacts relative to 2013/15 retirement; assumes no replacement generation)

	License Extension			Immediate Retirement			2008 Retirement		
	2005	2010	2016	2005	2010	2016	2005	2010	2016
PILOT	-	-	42.6	(28.3)	(34.7)	-	-	(34.7)	-
Employee Compensation	-	(1.7)	3.7	(0.8)	2.6	(20.7)	2.4	(1.5)	(9.2)
Corp. Income Tax	-	0.1	3.1	(1.3)	(2.1)	-	-	(2.1)	-
Higher Elec. Prices	-	-	104.8	(117.0)	(122.7)	-	-	(104.8)	-
Local Spending	-	-	12.6	(9.1)	(10.6)	(9.6)	-	(10.5)	(4.9)
Local Communtiy Support	-	-	0.8	(0.6)	(0.7)	-	-	(0.7)	(0.0)
County Emergency Planning	-	-	-	-	-	8.3	-	-	-
Fishery Impacts	-	-	6.4	41.8	53.8	6.4	-	48.4	6.4
Air Emissions	-	-	0.5	(1.4)	(0.7)	-	-	(0.5)	-
Total	-	(1.5)	174.5	(116.8)	(115.1)	(15.6)	2.4	(106.5)	(7.7)

The electric rate and economic impacts on the County are discussed below. In all retirement scenarios the economic impacts are offset, in part, by the improved health of the Hudson River fisheries, of which we assumed 10% would benefit County residents. We did not assume any on-site replacement generation:

- If IP were retired immediately, there would be relatively large short-term impacts, mostly due to higher electricity prices since this unrealistic scenario does not contemplate sufficient replacement capacity. By 2016 decommissioning and SNF activities would be completed, and the County would feel the loss of IP employment and local spending.

- If IP were to be retired in 2008, the short-term impacts would include loss of PILOT and somewhat higher electricity prices, even with sufficient replacement capacity. The loss of employee compensation and local spending would be felt sooner than in the Base Case.

- If the IP licenses were extended, the County would benefit from continued PILOT, employee compensation, and local spending, as well as from lower electricity prices. If IP were to utilize Hudson River for make-up water for the closed-cycle cooling system, there would be some economic cost to County residents from fish mortality.

Table 31 – Total Economic Impact to State by Scenario for Selected Years
($ millions; impacts relative to 2013/15 retirement; assumes no replacement generation)

	License Extension			Immediate Retirement			2008 Retirement		
	2005	2010	2016	2005	2010	2016	2005	2010	2016
PILOT	-	-	49.7	(33.0)	(40.5)	-	-	(40.5)	-
Employee Compensation	-	(12.8)	29.1	(6.2)	20.6	(161.0)	18.5	(11.5)	(71.6)
Corp. Income Tax	-	3.1	73.0	(34.6)	(49.3)	-	-	(49.3)	-
Higher Elec. Prices	-	-	445.7	(1,214.1)	(1,218.1)	-	-	(467.0)	-
State Spending	-	-	94.4	(52.5)	(61.4)	(33.6)	-	(60.9)	(6.3)
Local Communtiy Support	-	-	1.0	(0.7)	(0.8)	-	-	(0.8)	(0.0)
County Emergency Planning	-	-	-	-	-	5.8	-	-	-
Fishery Impacts	-	-	67.5	487.3	627.7	67.5	-	571.2	67.5
Air Emissions	-	-	10.9	(33.8)	(16.0)	-	-	(12.8)	-
Total	-	(9.7)	771.2	(887.6)	(737.9)	(121.3)	18.5	(71.5)	(10.5)

The electric rate and economic impacts on the State (including Westchester) are discussed below. In every retirement scenario, the improved health of the Hudson River fisheries, of which we assumed 90% would benefit State residents, would be significant and would offset economic impacts. We did not assume any on-site replacement generation:

- In the unrealistic scenario in which IP was retired immediately without sufficient replacement capacity, there would a large cost to ratepayers south of the Capital District. By 2016 decommissioning and SNF activities would be completed, and the State would feel the loss of IP employment and local spending.

- If IP were to be retired in 2008, the short-term impacts would include loss of PILOT and somewhat higher energy prices, even with sufficient replacement capacity. The loss of employee compensation and local spending would occur over time, and could be mitigated in part by on-site replacement generation.

- If the IP licenses were extended, the State would benefit from continued PILOT, employee compensation, and local spending, as well as from lower electric energy prices. If IP were to utilize Hudson River for make-up water for the closed-cycle cooling system, there would be some economic cost to State residents as fishery impacts.

As is shown by comparing the two tables, the State would bear much greater economic impacts from the retirement of IP, because the largest single impact would be higher market energy prices, most of which is absorbed outside of the County. The higher economic multiplier also means that State bears a higher burden with respect to the indirect effects of lower PILOT, employee compensation, local spending, etc. Non-County residents would, however, benefit the most from the improved health of Hudson River fisheries.

In the following figures, we show the year-to-year trend of benefits and costs of all four scenarios at the County and State level. The graphs show the total benefits and costs of the specific scenarios, not the relative benefits and costs against the base case assumption of 2013/15 retirement and no on-site replacement generation.

Figure 28 – Total Economic Impact to the County by Scenario
($ millions)

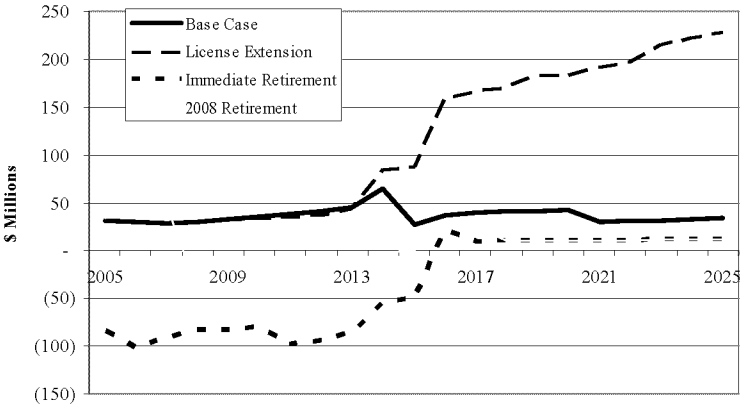
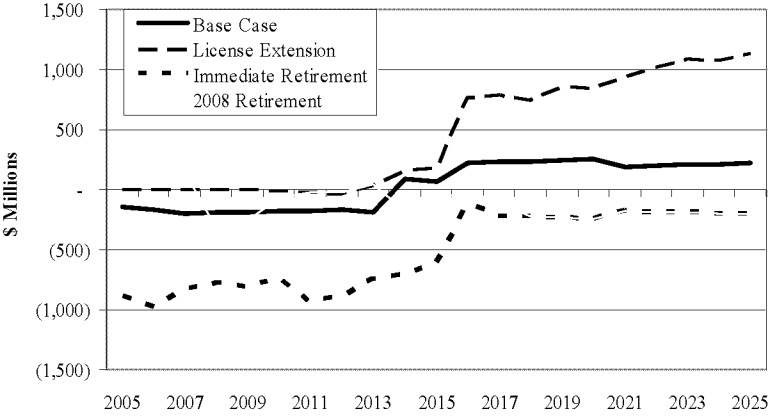


Figure 29 – Total Economic Impact to the State by Scenario
($ millions)



6.13. Total Costs and Rate / Economic Impacts

LAI has calculated the total direct and indirect costs and rate / economic impacts to the County and other stakeholders, assuming no on-site replacement generation, by combining the direct costs and impacts of (i) estimated compensation due Entergy, (ii) electric rate impacts, and (iii) economic impacts, as well as the indirect impacts using economic multipliers. Under the acquisition option in which the County or the State would commence condemnation proceedings immediately, and would complete the acquisition and shut down IP on January 1, 2008, we estimate the compensation due Entergy at $1.75 - $2.74 billion, plus $241 million for SNF management, expressed in present value terms as of January 1, 2008. This cost could be shared among the County, State, NYPA, and other stakeholders such as Con Edison, New York City, etc. When indirect impacts are included using a 1.75 multiplier, the total cost to the stakeholders increases to $2.99 - $4.48 billion, as seen in Table 33 and Table 34.

Table 32 – Direct and Total Costs – 2008 Acquisition by Condemnation
(2008 $ millions; impacts relative to 2013/15 retirement; no replacement generation)

Costs Shared by Stakeholders	Direct Cost	Direct and Indirect
Entergy Compensation	$1,754 – $2,744	$2,631 - $4,116
Spent Nuclear Fuel	$ 241	$ 362
Total	$1,995 – $2,985	$2,993 – $4,478

If IP is acquired through a condemnation proceeding, the County would bear a large proportion of the economic impacts due to lost PILOT, reduced employment, etc. The present value of the economic impacts on the County as of 2008 is $116 million; the figure would be over $330 million if not for assigning 10% of the value for the improved health of the Hudson River fisheries. When including the impact of the electricity market prices, the total direct impact increases to $214 million ($434 million excluding the fisheries).

To account for indirect effects on the County, we employed a County-specific multiplier of 1.5x. The present value of the direct and indirect impacts on the County is $320 million, excluding any share of compensation paid to Entergy.

Table 33 – Direct and Total County Impacts – 2008 Acquisition by Condemnation
(2008 $ millions; impacts relative to 2013/15 retirement; no replacement generation)

Rate / Economic Impacts on County	Direct	Direct and Indirect
Electric Market Impact	$ 216	$ 324
Economic Impacts (benefits in parenthesis)		
Property Taxes	$ 143	$ 215
Employment	$ 123	$ 185
Local Spending	$ 89	$ 134
Community Support	$ 6	$ 9
County Emergency Planning	($ 35)	($ 53)
Corporate Income Tax	$ 8	$ 12
Hudson River Fisheries	($ 220)	($ 330)
Air Emissions	$ 2	$ 3
Sub-Total	$ 116	$ 174
Totals	$ 332	$ 498

While the rest of the State would bear some of the same types of economic and rate impacts of retiring IP, it would receive the lion's share of the improved fisheries health benefit. Higher electricity prices would also impact the State, raising the total cost estimate.

Table 34 – Direct & Total State Impacts – 2008 Acquisition by Condemnation
(2008 $ millions; impacts relative to 2013/15 retirement; no replacement generation)

Rate / Economic Impacts on State	Direct	Direct and Indirect
Electric Market Impact	$ 1,742	$ 3,048
Economic Impacts (benefits in parenthesis)		
Property Taxes	$ 143	$ 250
Employment	$ 820	$ 1,435
Local Spending	$ 341	$ 597
Community Support	$ 6	$ 11
County Emergency Planning	($ 35)	($ 61)
Corporate Income Tax	$ 167	$ 292
Hudson River Fisheries	($ 2,198)	($ 3,847)
Air Emissions	$ 41	$ 72
Sub-Total	($ 715)	($ 1,251)
Totals	$ 1,027	$ 1,798

A voluntary retirement through a consensual agreement with Entergy would allow the County to avoid the costs and risks of an acquisition, keep in place Entergy's operation and management resources, provide Westchester with significant flexibility to arrange a compensation package that could include on-site replacement generation, and allow the State and other stakeholders to participate in the negotiations. We have assumed that the County

would enter into a consensual agreement to retire IP at the end of the existing license terms with Entergy and other stakeholders by January 1, 2011. In this option, the only cost the County would incur is its share of compensation due Entergy, since all of the electric market and economic impacts would be identical to our base case assumption of IP retirement in 2013/15. In effect, the County and other stakeholders would be buying out Entergy's option to extend IP's licenses. We estimate compensation due Entergy at $0.49 - $1.38 billion in present value terms as of January 1, 2011, much less expensive than the acquisition option.[136] As before, the compensation range is due to the uncertainty of an appropriate discount rate. When indirect impacts are included, the value rises to $0.87 - $2.42 billion.

Table 35 – Total Direct and Indirect County Costs – 2013/15 Voluntary Retirement
(2008 $ millions; impacts relative to 2013/15 retirement; no replacement generation)

Costs Shared by Stakeholders	Direct Cost	Direct and Indirect
Entergy Compensation	$495 - $1,376	$866 - $2,415
SNF Costs	-	-
Total	$495 - $1,376	$866 - $2,415

6.14. Rate Impacts

The impact of IP retirement on market energy prices, discussed earlier, can be translated into impacts that would be felt by residential ratepayers. A typical household in Westchester paid approximately $84.60 per month last summer and $90.59 last winter, or $1,051 per year, based on the Con Edison's 2004 retail rates. Con Edison resets its rates every six months to include necessary modifications to the market supply (*i.e.*, energy and capacity) and market adjustment charges. The principal components of each bill for the current winter and the past summer are depicted in the table below based on a typical household usage of 500 kWh/month.[137]

[136] In 2005 dollars, the cost is equivalent to $0.4 - $1.2 billion for the County, assuming a 4.0% discount rate.

[137] Source: NYPSC utility bill data. NYPSC uses 500 kWh/month as a standard average consumption value; actual average consumption may be materially higher in Westchester.

Table 36 – 2004 Monthly Con Edison Westchester Electric Bills
(based on 500 kWh/month)

Component	Summer '04	Winter '04-'05
Delivery Charge	$ 9.71	$ 9.71
Distribution Charge	$22.16	$19.97
Transmission Charge	$ 3.92	$ 3.62
System Benefits Charge	$ 0.80	$ 0.80
Taxes	$ 2.61	$ 2.56
Market Supply	$30.99	$34.98
Monthly Adjustment Charge	$20.40	$12.96
Total	$90.59	$84.60

Only one component of the residential bill would be affected by the retirement of IP: Market Supply, which combines the cost of both energy and capacity procured by Con Edison on behalf of its customers. In the past, MAC would also have been impacted by IP retirement, but is currently being phased out as discussed below.

Monthly Adjustment Charge

Prior to the development of competitive electric markets in New York, the NYPSC investigated but, at that time, found no substantial cost differences to warrant charging Con Edison's Westchester customers (Zones H&I) a different rate than Con Edison's New York City customers (Zone J).[138] In 2000, Con Edison unbundled its services and instituted a MAC to recover its stranded generation costs in a manner that equalized Con Edison's customer rates across Zones H (*i.e.* Westchester County) and J (*i.e.* New York City).[139] Since underlying electricity costs were higher in New York City, Westchester customers were burdened with a higher MAC to equalize Con Edison's rates between the two service areas. In fact, according to testimony filed by the County, Westchester ratepayers were paying over one-half of Con Edison's stranded costs but only account for 12% of Con Edison's total electricity consumption.

In December, 1999, the NYISO took control of the electricity markets and began its bid-based pricing mechanisms. Shortly thereafter, it became clear that the underlying costs for electricity products (*i.e.* energy and capacity) were significantly different among the NYISO zones. As the NYPSC implemented Con Edison's proposed MAC, Westchester raised concerns of unfair cost allocation. Although the NYPSC allowed Con Edison's MAC mechanism, it decided to examine Westchester's concerns about this issue and initiated a

[138] Case 28157, Consolidated Edison Company of New York, Inc. – Order Determining That a Geographical Classification of Customers is Unnecessary, 22 NYPSC 1428 (1982).

[139] Case 96-E-0897, Consolidated Edison Company of New York, Inc. – Rate Restructuring Proceeding, Order Concerning Retail Access Implementation Plan – Phase 3 (2/28/2000).

proceeding.[140] The NYPSC staff submitted a proposal to establish equal MAC rates over a three year phase-in period that would lower rates in Westchester and raise them in New York City. The case continued contentiously over the next two years. In its Order Adopting Staff Proposal, the NYPSC noted that the case presented a unique situation "where the utility company straddles two ISO zones that have substantially different commodity costs." In November 2003, the NYPSC decided to equalize the MAC over the three-year period, which would cause Con Edison's full service rates in Westchester to become lower than rates for New York City, thereby furthering economic efficiency goals.[141] Although New York City filed a Petition for Rehearing, the NYPSC denied the Petition in April 2004. Thus LAI expects that Con Edison rates for Westchester ratepayers will be lower than for Con Edison ratepayers in New York City starting this year.[142] While achieving a change in the MAC was a substantial victory for Westchester County and succeeded in lowering retail energy prices in the County, the MAC change also eliminates some ability for COWPUSA to compete against Con Edison in the retail service market.

Energy Price Forecast

LAI prepared a Base Case forecast of market energy prices assuming that IP's operating licenses would not be renewed, as well as forecasts for the alternative scenarios in which IP is retired immediately, retired in 2008, and the licenses are extended for twenty years. In general, we project electricity bills to increase rapidly in all cases. This is due in large part to the natural effects of inflation (set at 3% in our financial models), as well as the expected increase in real fuel commodity costs, particularly natural gas, that sets the market energy price during many on-peak hours of the year. Since the NYISO sets the market price for energy based on the cost of the last, or "marginal," unit to meet demand, hours when the marginal unit is a gas-fired facility will raise market energy prices for all generators.[143]

Over time, this effect will increase due to the additional use of gas in power plants and load growth in the region. As load increases, particularly during off-peak hours, natural gas is likely to set the market price in an increasing number of hours. Currently, lower cost coal and hydro units set the price for many of the off-peak (night-time and weekend) hours of the year. But because these resources are not growing in size, regardless of Westchester's actions related to IP, increases in off-peak load require higher cost units such as natural gas-fired facilities to increasingly operate and thus set the market price.[144] Under this system, more expensive units would be dispatched more frequently, including the gas-fired combined cycle

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[140] Case 00-E-1208, Consolidated Edison Company of New York, Inc. – Electric Rates, Order Instituting Proceeding (7/20/2000).

[141] Case 00-E-1208, Consolidated Edison Company of New York, Inc. – Electric Rates, Order Adopting Staff Proposal (11/25/2003).

[142] The MAC is reset and trued up every six months, but not simultaneously. For purposes of our analysis, we assumed the MAC is eliminated on January 1, 2005.

[143] In the short-run, utilities can hedge against market energy prices by executing PPAs with generators.

[144] Increased reliance on gas-fired generation may expose New York ratepayers to increased price volatility as periodic gas price spikes during the winter months directly affect market energy prices. Our gas price forecast incorporates average expected gas prices and does not focus on short-term price volatility.

units that we expect would replace IP. The following table describes changes to regional spot market energy prices that LAI forecasted using MarketSym if IP is retired immediately in 2005, in 2008, or has its licenses extended.[145] Values represent percentage changes against the Base Case of IP retirement in 2013/15.

Table 37 – Average Change in Market Energy Prices

Region	NYISO Zone(s)	2005 Retirement	2008 Retirement	License Extension
Westchester County	GHI	11.3%	8.4%	-7.5%
New York City	J	4.5%	3.8%	-2.9%
Albany	F	7.6%	6.5%	-3.7%
Western NY	A-E	0.1%	0.6%	-0.2%
Long Island	K	4.3%	3.9%	-3.1%

- If IP is retired immediately and replacement generation is not installed, an unrealistic scenario, market energy prices in Westchester are projected to increase by 11.3% on average through 2015.

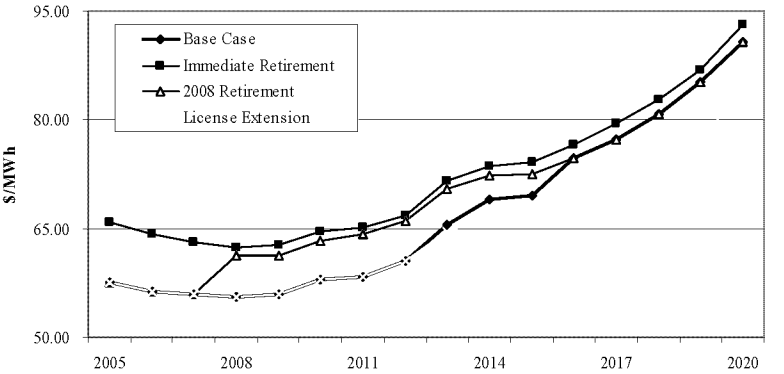
- If IP is retired in 2008 and developers have sufficient notice to install replacement generation, market energy prices in Westchester are projected to increase by 8.4% on average through 2015. Market energy prices in New York City are projected to increase by 3.8% on average. Unlike the Immediate Retirement scenario, the 2008 Retirement scenario allows for a reasonably orderly market-based transition. In this scenario, we presume three years represents adequate time for developers to build new replacement generation so that the IP2&3 shutdown does not result in a shortage in generating capacity.

- If the IP licenses are extended so that 2,000 MW of replacement generation is not required, market energy prices in Westchester are projected to *decrease* 7.5% on average from 2013 through the term of the license extension.

Average market energy prices for the County and surrounding regions are depicted in Figure 30. These values are considered "time-weighted" or averaged across all hours of the year.

[145] Importantly, as referenced above, not all energy procured is indexed to market prices. We estimate that approximately 50% of the energy consumed in New York State is under long-term or cost-based agreements that will not be impacted by IP's retirement.

Figure 30 – Forecast of Market Energy Prices in Westchester



Ratepayer Impacts

LAI forecasted the expected impacts on with residential customer electricity bills. As described earlier, ratepayers would only be exposed to changes in market energy prices for the share of their utility's supply not purchased through long-term PPAs. We have estimated that Con Edison ratepayers in Westchester and in New York City would be 50% affected by higher market energy prices. The results can be summarized as follows:

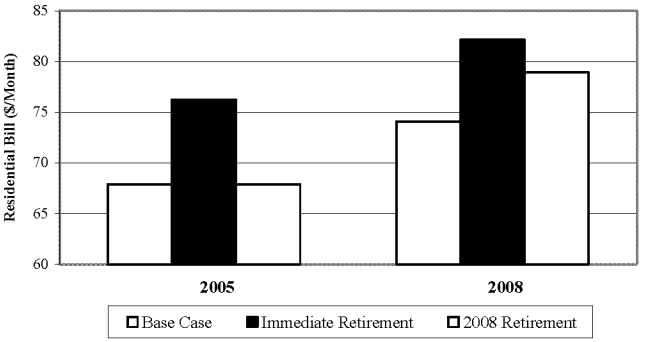
- In the unrealistic case that IP is retired immediately and replacement generation is not installed, the typical residential ratepayer will pay $4.20/month more in that year, and $3.76/month on average through 2015.

- If IP is retired in 2008, the typical residential ratepayer will pay $2.42/month more in electricity charges in that year, and $1.55/month more on average in electricity charges though 2015.

- If the IP licenses are extended so that 2,000 MW of replacement generation is not required, the typical residential ratepayer will pay $1.65/month *less* for electricity charges in the first full year to be impacted by the license extension, 2016, and approximately $2.05/month on average from 2013 through the duration of the license extension period.

In the following figure, we show total bills for years 2005 and 2008 for the Base Case in which IP is retired in 2013/15, Immediate Retirement, and 2008 Retirement scenarios.

Figure 31 – Comparison of Residential Bills by Scenario: 2005, 2008



Residential bills under the License Renewal scenario are identical to the Base Case without license renewal for the years 2005 and 2008 and were not included in Figure 31. License renewal does affect long-term prices, as shown in the following figure with typical bills under all four cases through 2018.

Figure 32 – Long-Term Trends of Monthly Bills by Scenario

ATTACHMENTS:

1. PERFORMANCE EFFECTS OF COOLING TOWERS
2. NEW YORK EMINENT DOMAIN PROCESS TIMELINE
3. CHAPTER 875 OF THE WESTCHESTER COUNTY CHARTER
4. ENTERGY ZONING VARIANCE
5. TIME FOR A NEW START FOR U.S. NUCLEAR ENERGY?
6. EVALUATING RISKS ASSOCIATED WITH UNREGULATED NUCLEAR POWER GENERATION
7. TRIGGERING NUCLEAR DEVELOPMENT
8. THE BUSINESS CASE FOR BUILDING A NEW NUCLEAR PLANT IN THE U.S.
9. REPORT OF BODINGTON & COMPANY REGARDING DISCOUNT RATE
10. FAIR MARKET VALUE CALCULATIONS
11. GAO REPORT: NUCLEAR REGULATION (EXCERPT)

Attachment 1

PERFORMANCE EFFECTS OF COOLING TOWER BACKFITS

The most significant modification to IP2&3 as part of the relicensing process, in terms of performance as well as cost, is likely to be the replacement of the once-through circulating water system with closed-loop cooling towers. This modification will reduce the net output of each unit by about 3% to 5% due to a combination of increased auxiliary power requirements and reduced steam cycle thermal efficiency.

Heat Rejection Requirements

All thermal power plants receive heat energy from a high temperature source and reject heat energy to a lower temperature sink. Generally, the greater the difference between source and sink temperature, the more work (*i.e.* electric energy) can be extracted and the higher the thermal efficiency of the thermal cycle will be.[1] The amount of heat that must be rejected is proportional to (1 – thermal efficiency) of the cycle.[2] At a 33.3% thermal efficiency, then, the roughly 3,000 MW of thermal energy from each reactor results in 1,000 MW of electric generation and 2,000 MW thermal (approximately 6,800 MMBtu/h) of condenser heat rejection.

The condensers are very large heat exchangers, consisting of a shell into which the steam turbines exhaust the spent steam, and which is traversed by thousands of tubes carrying cooling water. As the steam contacts the tubes, it is condensed, and the heat released by condensation is conducted through the tube walls and carried off by the cooling water. Condensate accumulates at the bottom of the shell and is pumped back through the cycle.

The temperature at which condensation occurs is determined by the amount and condition of the steam entering the condenser (*i.e.* the duty), the amount of surface area supplied by the tubes, the heat transfer coefficient determined by the material and wall thickness of the tubes, their cleanliness, and the velocity of the water flowing through them, and the total flow and the inlet temperature of the cooling water. For a given duty and surface area, the temperature will be higher as water flow decreases and/or inlet water temperature increases. A higher condensing temperature means a higher condenser pressure and a less efficient thermal cycle.[3]

Existing Indian Point Heat Rejection Design

IP2&3 were designed to use the Hudson River as their "sink" to dissipate the cycle heat. Pumps push large volumes of water (estimated at 840,000 gallons per minute for each unit

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[1] This comes from the Second Law of Thermodynamics, which requires that entropy of a system increase. For work to be created from thermal energy, energy must flow "down hill" to a lower temperature, an irreversible process.

[2] From the First Law of Thermodynamics, total energy is conserved.

[3] The saturation temperature (boiling or condensing temperature) of water is a function of pressure. At atmospheric temperature, water boils or steam condenses at 212 °F. At a vacuum of 28 inches of mercury (about 1 psi absolute), steam condenses at 101 °F.

from the river, through the condensers, and back to the river heated by about 17 °F. Steam flowing through the plant's turbines exhausts into the condensers at pressures as low as 1 psi absolute, or a vacuum of about 28 inches of mercury. Inlet water temperatures from the Hudson River presumably range from close to 32 °F in the winter to about 75 °F in the summer, with minimal fluctuations during a typical day.

The circulating water pumps are designed to handle a large flow at relatively low "head" or pressure differential. Since the water is discharged at river level, there is no significant net elevation head to overcome, so the pumps need only overcome friction losses. This results in relatively low power requirements for the pumps.

Cooling Tower Backfit Design Options

If a conversion to closed-loop cooling is required as part of the relicensing process for IP 2 & 3, the owner will have several design decisions to make:

- Location of the cooling towers
- The type of cooling tower
  - Natural draft or mechanical draft
  - Cross flow or counter flow
  - Wet (evaporative) only, or hybrid wet/dry
- Condenser modifications
  - Maintain current flow (and temperature rise) or decrease flow (increase rise)
  - Maintain current condenser envelope or replace with optimized design (longer tubes, different materials)
- Hydraulic design
  - Hot- or cold-side pumping
  - High water pressure operation or hydraulic recovery turbine

The crowded nature of the IP site at the main plant grade will probably preclude locating cooling towers at close to the same elevation as the condensers. One option that has been considered is locating them on a bluff about 100 feet above the main plant grade. The retrofitted circulating water system would have to allow for the head to the bluff level plus about 50 feet to the top of the tower fill.

Several nuclear power plants in the Northeast use natural draft cooling towers with their large (400 to 500 ft high) hyperbolic concrete stack shells. While more capital intensive than mechanical draft towers, they eliminate the parasitic load and noise of cooling tower fans, and the higher discharge elevations reduce fogging and icing problems. On the other hand, they have high visual impact and require a long construction period. Cross-flow and counter-flow designs are available in both natural and mechanical draft, and they offer trade-offs in pumping head, land requirements, control under extreme cold conditions, and fill design. Hybrid wet/dry cooling towers have seen limited applications for plume control and water conservation.

It may be possible to design a closed loop system around the existing condenser, but several concerns make this an unlikely choice. First, the condenser is designed for relatively low maximum inlet temperature, high circulating water flow (and correspondingly low temperature rise), and low water-side pressures. Maintaining the low temperature rise will result in a relatively expensive cooling tower and require high pumping power. If circulating water pumps are placed on the cold-water side of the condenser (normal practice), then the pressure on the water boxes and tubesheets will be significantly higher than in the once-through arrangement. If the pumps are placed on the hot-water side, pressure might still be an issue if the cooling tower is located on the bluff instead of at plant grade. To the extent possible within turbine building constraints, a new condenser with optimized dimensions might be more economical. It would probably have a longer effective tube length, achieved by pushing out the water boxes and circulating water piping or creating multiple passes. This would allow for lower circulating water flows and a higher temperature rise. Tubes might be of different material and diameter to optimize available space and minimize performance impacts.

In conjunction with condenser reconfiguration, the entire circulating water piping system will require reconfiguration. As indicated previously, the circulating water pumps might be on either side of the condenser. With a high elevation for the cooling tower relative to the condenser, some form of hydraulic recovery turbine may be appropriate to recover potential energy in water flowing down from the cooling tower basin to a plant level reservoir.

Cooling Tower Performance

All evaporative cooling towers are limited by an approach to the ambient wet bulb temperature.[4] If a tower is designed to cool a specific water flow rate from 112 °F to 95 °F when the wet bulb temperature is 80 °F, it is said to have a design approach of 15 °F (= 95° – 80°) and a range of 17 °F (=112° – 95°). Cooling tower range is equal to condenser rise. At the same duty (flow and range) this tower will have a somewhat higher approach at a lower wet bulb, so water temperature does not drop degree for degree with wet bulb. If range (duty with constant flow) is decreased, the approach will be lower at a given wet bulb temperature. This design condition is relatively severe. Achieving the same approach with less flow and a higher range (same duty) would require less cooling tower capacity.

While Hudson River temperature is quite stable day to day and follows a relatively predicable seasonal pattern, the temperature of water from a cooling tower will vary significantly with ambient conditions. The temperature of river water approaches seasonal average wet bulb temperature quite closely. Cooling tower water approaches hourly wet bulb with a significant differential.

Plant Performance Effects

[4] Wet bulb temperature is an indication of the amount of moisture in air at a given "dry bulb" temperature. At 100% relative humidity, the wet bulb temperature equals the dry bulb temperature. At low relative humidity and high dry bulb temperature, wet bulb temperature is significantly less than dry bulb temperature. Wet bulb temperature can be measured by covering the bulb of a thermometer with a water-soaked wick and spinning the thermometer through the air.

Regardless of which design options might be chosen, retrofitting to closed-loop cooling will result in a loss of net output from IP 2 & 3, particularly in the summer when wet-bulb temperatures are high. The loss of net output will consist of two components – reduced gross generation and increased auxiliary power load. For a natural draft tower, the auxiliary power would be almost entirely for pumping circulating water. With a mechanical draft tower, there would also be fan power to consider.

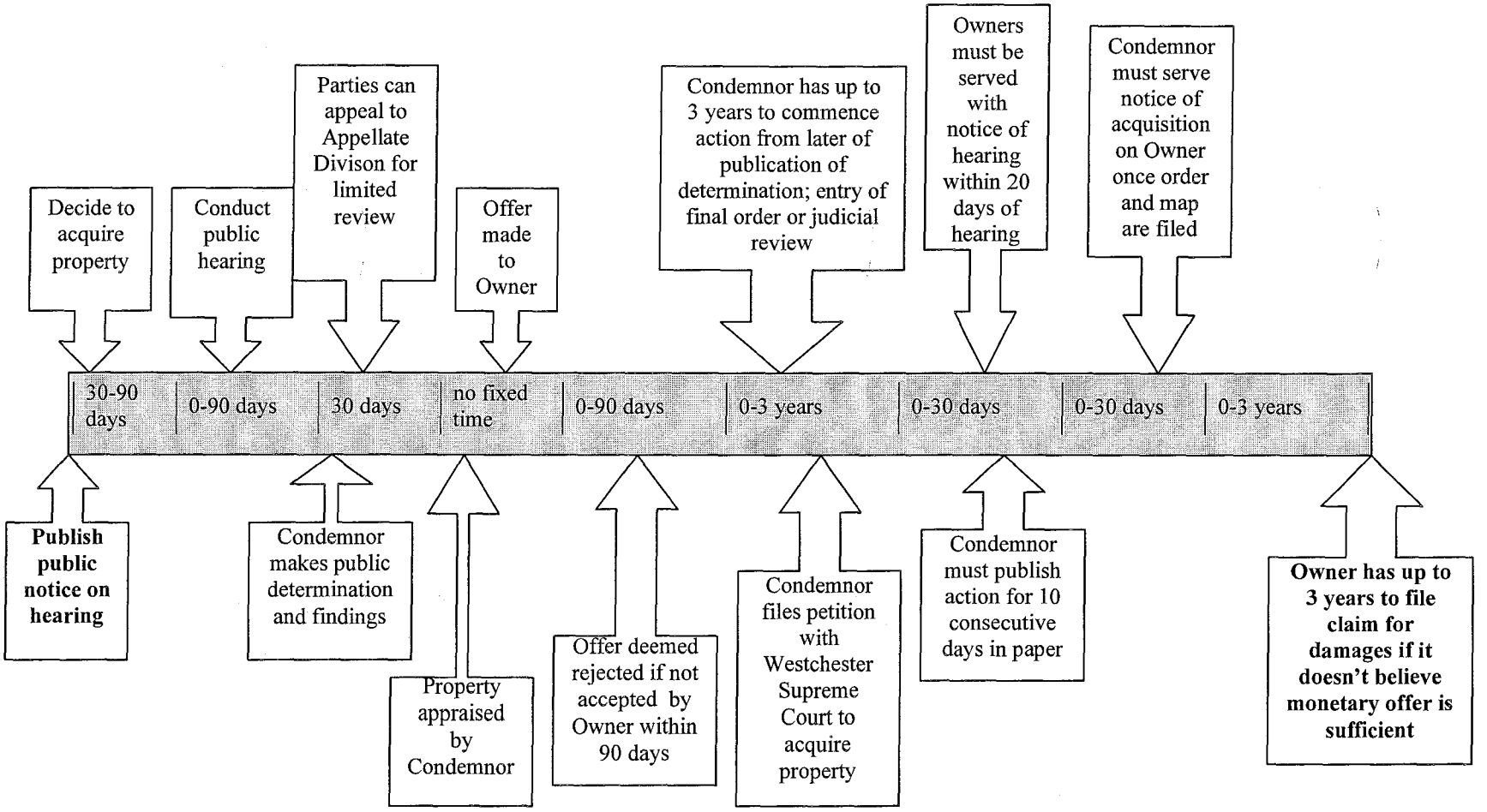
On a peak summer day, condenser inlet water temperature would increase by at least 10 °F, (*i.e.* the approach of the cooling tower). If the condenser rise is maintained at 17 °F, then condenser outlet temperature would increase by 10 °F and condensing temperature would increase by roughly the same amount. This could have a 1% or greater impact on generation, depending on turbine design parameters. If rise is increased (circulating water flow decreased) to control the size and cost of the cooling tower and reduce pumping requirements, there would be a larger increase in condensing temperature, unless surface area and/or heat transfer rates are increased.

Pumping power will increase substantially if flow is maintained at current levels. With up to 100 feet of additional head, power requirements would increase by up to 25 MW per unit, or 2.5% of output.[5] Based on these estimates and on earlier IP studies, net electric output from the facility might be reduced by at least 3% to perhaps as much as 5%.

[5] Pump kW = [Flow (gpm) x Head (ft)] / 3960 / Pump efficiency / Motor efficiency * 0.746
Assume that pump efficiency is 75% and motor efficiency is 95%.

Attachment 2

New York Eminent Domain Process



Attachment 3

Chapter 875

PUBLIC UTILITY SERVICE AGENCY

Sec. 875.01. Legislative findings and declaration of purpose.

It is hereby found and declared:

(1) The County of Westchester has been concerned for some time with the high cost of electric power in the Con Edison Service Area of the county and the effect of such costs on the economic growth and well-being of the county.

(2) It is essential for the county to take the necessary steps to obtain and maintain an adequate and reliable supply of less expensive electric power.

(3) By referendum held on March 30, 1982, the voters of the county overwhelmingly approved a proposition authorizing the county to establish a Public Utility Service Agency to construct, lease, purchase, own, acquire, use and/or operate a public electric utility service.

(4) The creation of a County Public Utility Service Agency will enable the county to contract for or otherwise purchase or acquire lower cost electric energy in the form of hydroelectric power and other economical forms of electricity from the State of New York or from any state agency, municipal, public or private corporation.

(L.L. No. 11-1982, § 1)

Sec. 875.11. Definitions.

As used or referred to in this chapter, unless a different meaning clearly appears from the context:

Agency shall mean the County of Westchester Public Utility Service Agency created by section 875.21 of this chapter.

Chairman shall mean the Chairman of the County of Westchester Public Utility Service Agency.

Commissioner of Finance shall mean the Commissioner of Finance of Westchester County.

Con Edison shall mean the Consolidated Edison Company of New York, Inc.

Con Edison Service Area of the county shall mean that territory within Westchester County where the Consolidated Edison Company of New York, Inc. now or hereafter is franchised to furnish electrical utility service.

County shall mean the County of Westchester.

County Board shall mean the Board of Legislators of the County of Westchester as the said board now exists or may hereafter be constituted.

County Executive shall mean the Chief Executive and Administrative Officer of the County of Westchester.

Executive Director shall mean the Executive Director of the County of Westchester Public Utility Service Agency appointed pursuant to section 875.31 of this chapter.

Fiscal year shall mean the period beginning with the first day of January and ending with the 31st day of December in each year.

Public electric utility service shall mean any electric service authorized to be furnished by any public utility company pursuant to Article 4 of the Public Service Law and shall include works, structures, poles, lines, wires, conduits, mains, systems, waterpower and any and all other real and personal property used or necessary for, connected with or relating to the furnishing of such electric utility service.
(L.L. No. 11-1982, § 1)

Sec. 875.21. Agency created; commissioners.

(a) There is hereby created a County of Westchester Public Utility Service Agency. The agency shall consist of seven commissioners to be appointed by the County Executive with the confirmation of the County Board. Three of the commissioners shall be selected and appointed by the County Executive from a list of not less than four nor more than six persons recommended by the Chairman of the County Board. The Chairman of the agency shall be designated by the County Executive from amongst the seven commissioners. All commissioners shall be residents of the Con Edison Service Area of the county at the time of their appointment and during their term of office. To the extent practicable, the commissioners selected shall have experience in one or more of the following disciplines: public utility management, finance/accounting, law, engineering, labor, consumer affairs. At least four commissioners shall have expertise or qualifications in at least one of among the following disciplines: law, engineering, finance/accounting and public utility management.

(b) Commissioners of the agency shall be appointed for a term of four years except that, of those first appointed, three commissioners, including the Chairman, shall be appointed for a term of four years, two commissioners shall be appointed for a term of three years, and two commissioners shall be appointed for a term of two years. The County Executive shall designate the terms to be served by the initial commissioners, except that of the three commissioners appointed upon the recommendation of the Chairman of the County Board from a list of not less than four nor more than six, one shall serve a four-year term, one shall serve a three-year term, and one shall serve a two-year term.

(c) Vacancies shall be filled in the same manner as original appointments; provided, however, that in the event of a vacancy in a position originally filled upon the recommendation of the Chairman of the County Board, the appointment shall be made by the County Executive from a written list of not less than two nor more than three persons recommended by the Chairman of the County Board. Vacancies occurring by other than expiration of term shall be filled for the balance of the unexpired term; provided, however, that an appointment for a term shortened by reason of a predecessor's holding over after expiration of a term shall be for the balance of that term.

(d) The County Executive may suspend with the approval of the County Board and may remove any commissioner for inefficiency, neglect of duty, misconduct in office or any other reasons.

(e) Neither the Chairman nor any other commissioner shall receive a salary. Each commissioner, including the Chairman, shall be entitled to reimbursement of actual and necessary expenses incurred in the performance of that commissioner's official duties. A majority of the whole number of commissioners of the agency, which is four, shall constitute a quorum, and the transaction of any business or the exercise of any power of the agency requires four affirmative votes.
(L.L. No. 11-1982, § 1; amended by L.L. No. 13-1986)

Sec. 875.31. Powers and duties.

(a) General powers and duties. The agency, on behalf of the county, shall have the power to establish, construct, lease, purchase, own, acquire, use and/or operate a public electric utility service within and/or without the territorial limits of the county for the purpose of furnishing to the county or for compensation to inhabitants of the Con Edison Service Area of the county any

electric service similar to that furnished by any public utility company specified in Article 4 of the Public Service Law and to purchase electrical energy from the State of New York or from any state agency, or other municipal corporation, or from any private or public corporation or other sources.

(b) Specific powers and duties. In discharging its powers and duties, the agency:

(1) Shall have the authority to contract for or otherwise purchase or acquire low-cost hydroelectric power or such other economical forms of adequate and reliable electricity from the State of New York, any agency of the State of New York, any other municipal corporation, or any private or public corporation, or other sources, as shall be available for the Con Edison Service Area of the county.

(2) Shall have the authority to negotiate with Con Edison and/ or other utility companies for the use, by lease and/or by contract, of such portion of the appropriate distribution, substation and transmission facilities necessary to transmit to the county or for compensation to inhabitants of the county in the Con Edison Service Area of the county such quantities of power as may be acquired by the Agency; and/or to sell such power to Con Edison for resale to its customers inhabiting the Con Edison Service Area of the county. Contracts and/or leases entered into by the agency with electric utilities for distribution of power purchased by the agency shall include a provision that the net savings associated with such energy or on taxes shall be passed along to customers in the Con Edison Service Area of the county and shown separately on their bills as a credit.

(3) Shall have the authority to determine what, if any, additional facilities and incidental improvements would have to be constructed and/or purchased in connection with the use, by lease and/or contract, of the foregoing facilities, to project the estimated cost thereof, and to recommend that the County Board authorize the purchase or construction of such facilities or improvements, where the Agency determines that same would be desirable and in the interest of the county, provided that the agency shall not construct and/or purchase such facilities or improvements without the approval of the County Board.

(4) May appoint an Executive Director, who shall be a person experienced in electric utility operations, to be responsible for the administration and day-to-day operations of the Agency. The Executive Director, who shall not be a member of the Agency, shall hold office at the pleasure of the agency and shall be paid a salary to be fixed by the agency. The Agency shall be empowered to delegate any one or more of its operational and administrative functions or powers to the Executive Director; provided, however, that the agency shall delegate to the Executive Director such functions and powers, including without limitation, that of appointment, discipline and removal of employees, as are necessary for the Executive Director to discharge his responsibilities.

(5) Consistent with applicable law, shall have the authority to make and alter bylaws for its organization and internal management and to make rules and regulations governing the use of its property and facilities, which bylaws, rules and regulations shall be filed with the Clerk of the County Board.

(6) Shall have the authority to enter into contracts, leases and other instruments and to acquire, hold and dispose of real or personal property necessary and convenient to the exercise of its powers.

(7) Shall have the authority to appoint, fix the compensation of and, consistent with section 297.31 of the Laws of Westchester County, provide for the indemnification of such officers and employees as it may require for the performance of its duties and to retain or employ consultants or

advisors on a contract basis or otherwise for rendering professional or technical services and advice.

(8) Shall have the authority to arrange for temporary financing prior to the receipt of revenues sufficient to meet current costs or expenses by obtaining such advances from the Commissioner of Finance as may be authorized by the County Board. Loans obtained in this manner shall be repaid as soon as the agency shall possess a sufficient excess of cash over current obligations to permit such repayment.

(9) Shall have the authority to initiate and prosecute all inquiries, investigations, surveys, and studies which it may deem necessary or desirable for the effectuation of the powers and duties conferred upon it by this chapter.

(10) Shall have the authority to exercise such other powers granted under law that are necessary or convenient to carry out and effectuate the purposes and provisions of this chapter.

(11) Shall have the authority to study and recommend to the County Board the development of alternative energy sources for local needs or conservation purposes.

(c) Nothing herein should be construed as authorization for the county or the agency on behalf of the county to exercise any power of condemnation or to establish generation, distribution, and/or transmission facilities separate from the Con Edison generation, distribution, and/or transmission system in the Con Edison Service Area of the county.

(d) Those provisions of the Laws of Westchester County pertaining to the award and execution of contracts and leases shall apply to the agency; provided, however, that the agency, at a public meeting, is hereby empowered to adopt its own rules and regulations, consistent with law, regarding the award and execution of agency contracts and leases.

(e) All monies of the agency shall be managed and used by the agency for the purposes of the agency in accordance with sound financial procedures established by the agency. Monies of the agency shall be paid out on checks signed by the Chairman of the agency or such other officer or employee as the agency shall so authorize. The agency may in its discretion elect to utilize the fiscal services of the Commissioner of Finance, and in such event the Commissioner of Finance shall provide such fiscal services as are requested by the agency. Monies of the agency deposited with the Commissioner of Finance shall be subject to requisition by the Chairman of the agency or of such other officer or employee as the agency shall authorize to make such requisition. All monies of the agency deposited with the Commissioner of Finance shall be maintained in a separate bank account or accounts and, except for investment purposes, shall not be commingled with any other monies. All deposits of monies with the Commissioner of Finance shall, if required by the Commissioner of Finance or the agency, be secured by obligations of either the United States or the State of New York or its municipalities or a market value equal at all times to the amount of the deposits.

(f) The agency, within 90 days after the end of its fiscal year, shall annually submit to the County Executive and the County Board a complete and detailed report setting forth, in addition to the financial statements required by section 875.61 of this chapter, the operations and accomplishments of the agency during such year and its legislative recommendations in furtherance of the purposes of the agency.
(L.L. No. 11-1982, § 1)

Sec. 875.41. Method of operation; rate setting.

The method of operation of the rates, rentals and charges for public electric utility service and the procedure for their collection shall be fixed by the County Board in accordance with law. The agency shall recommend to the County Board the establishment of a system of consumer electric rates, the intent of which shall be to enable the public electric utility service to be self-liquidating, and shall impose and collect the rates established in a manner consistent with law.
(L.L. No. 11-1982, § 1)

Sec. 875.51. Payments in lieu of taxes.

With respect to any property the agency may acquire within the county from any private utility company, including Con Edison, the agency shall make payments in lieu of taxes to the appropriate municipalities or districts in an amount equal to the amount that would have been paid in real estate or franchise taxes had such private utility continued to own such property.
(L.L. No. 11-1982, § 1)

Sec. 875.61. Annual audit.

The agency shall maintain books of record and account with respect to its operations in accordance with generally accepted accounting principles consistently applied. Within 90 days after the end of the agency's fiscal year, the agency shall deliver to the County Executive and the County Board its financial statements at the end of such year and for the year then ended, prepared in accordance with generally accepted accounting principles and accompanied by the report thereon, by a firm of independent accountants of recognized national standing selected after consulting with the Commissioner of Finance and the County Budget Director by the agency, based upon an audit using generally accepted auditing standards.
(L.L. No. 11-1982, § 1)

Sec. 875.71. Termination.

The agency's existence shall continue until terminated by law; provided, however, that no such law shall take effect so long as the agency shall have obligations outstanding. The terms of the commissioners of the agency shall expire upon the enactment of a law terminating the agency's existence, and the County Board shall constitute the agency until the effective date of the agency's expiration. Upon termination of the existence of the agency, all its rights and properties shall pass to and be vested in the county. No law terminating the existence of the agency shall be enacted except upon an affirmative two-thirds vote of all the members of the County Board.
(L.L. No. 11-1982, § 1; amended by L.L. No. 13-1986)

Sec. 875.81. Separability.

If any section, subdivision, paragraph, sentence, clause or provision of this chapter shall be unconstitutional or be ineffective in whole or in part, to the extent that it is not unconstitutional or ineffective, it shall be valid and effective, and no other section, subdivision, paragraph, sentence, clause or provision shall on account thereof be deemed invalid or ineffective.
(L.L. No. 11-1982, § 1)

Attachment 4

VILLAGE OF BUCHANAN

ZONING BOARD OF APPEALS

Westchester County, New York

DECISION & ORDER

Petitioner(s): **Entergy Nuclear Northeast** File No.: **3-02-BZ**

Address: **295 Broadway, Buchanan, NY** Public Hearing Date(s): **5/8, 6/12, 7/10/02**

Property Location: **295 Broadway, Buchanan, NY 10511**
Tax Map Designation: Section: Block: Lot:
Present Zoning District: **M-2**

Nature of Petition:
[ ] Use Variance [X] Area Variance
[ ] Special Permit [ ] Interpretation [ ] Other
Describe Specific Request:

Area Variance with respect to maximum building height dimensions to allow for the proposed Generation Support Building on the above property.

The above referred to Petition, having been duly advertised in The Journal News, the official newspaper of the Village of Buchanan, and the matter having duly come to be heard before a duly convened meeting of the Board on the above dates, at the Municipal Building, 236 Tate Avenue, Buchanan, New York, and all of the facts, matters and evidence produced by the Petitioner(s), by Village officials and by interested parties having been duly heard, received and considered, and due deliberation having been had thereon, the following Decision and Order is hereby made by this Board:

The Zoning Board of Appeals has taken into consideration the benefit to the applicant if the variance is granted as weighed against the detriment to the health, safety and welfare of the neighborhood or community by such grant. In making such determination, the Board makes the following findings:

1. There is no undesirable change in the character of the neighborhood or a detriment to nearby properties created by the granting of the area variance;
2. The benefit sought by the applicant cannot be achieved by some method, feasible for the applicant to pursue, other than an area variance;
3. The requested area variance is not substantial;
4. The proposed variance will have no adverse effect or impact on the physical or environmental conditions in the neighborhood or district; and
5. The alleged difficulty is not self-created.

Applicant is GRANTED the following Area Variance:

1. A Variance in the maximum building height from 35 feet to 59 feet to allow for the proposed Generation Support Building on the above property, plus an additional 10' high roof screen is permitted to conceal roof mechanicals from ground view.

NOW, THEREFORE, the Petition herein is granted and it is further ordered that in all other respects Petitioner(s) comply with all of the rules, regulations and ordinances of the Village of Buchanan, the Building Department, the Village Engineer, and all other agencies having jurisdiction thereof.

Date Filed: **July 10, 2002**

Nicolas Zachary

NICOLAS ZACHARY
Chairman, Zoning Board of Appeals

Attachment 5

STANDARD & POOR'S CORPORATE RATINGS

ublication date: 04-Jun-2003Credit
Reprinted from RatingsDirect

Time for a New Start for U.S. Nuclear Energy?

nalyst: Peter Rigby, New York (1) 212-438-2085

Since its beginnings, commercial nuclear energy has offered the tantalizing promise of clean, reliable, secure, safe, and cheap energy for a modern world dependent upon electricity. No one did more than Lewis Strauss, chairman of the U.S. Atomic Energy Commission, to define expectations for the industry when he declared in 1954 that nuclear energy would one day be "too cheap to meter." But the record proved far different. Nuclear energy became the most expensive form of generating electricity and the most controversial following accidents at Three Mile Island and Chernobyl. And today's electricity industry's credit problems of too much debt and too many power plants will do little to invite new interest in an advanced design nuclear power plant. Yet energy bills circulating through the U.S. Senate and House of Representatives hope to change that perception and perhaps lower the credit risk sufficient enough to attract new capital. Will Washington, D.C.'s new energy initiatives lower the barriers to new nuclear construction? Many would like to think so, but it will be an uphill battle.

The House version of the Energy Bill modestly "...sets the stage for building new nuclear reactors by reauthorizing Price-Anderson...." Since 1957, the Price-Anderson Act has indemnified the private sector's liability if a major nuclear accident happens on the premise that no private insurance carriers could provide such coverage on commercial terms. Without Price-Anderson, it is difficult to envision how nuclear plants could operate commercially, now or in the future. The more ambitious Senate version of the Energy Bill seeks to jump-start new nuclear plants in the U.S. by providing measurable financial resources for new projects. According to the latest version of the Senate Energy Bill, the Secretary of Energy could provide financial assistance to supplement private sector financing if the proposed new nuclear plant contributes to energy security, fuel, or technology diversity or clean air attainment goals. The bill would limit financial assistance to 50% of the project costs with financial assistance being defined as a line of credit, secured loan, loan guarantee, purchase agreement, or some combination of these assistance plans.

Key Nuclear Energy Provisions to the Proposed Energy Bills

House Version (H.R. 6)

- Reauthorization of Price-Andersen Act
- Support Nuclear Energy Research

Senate Version (S. 14)

- Reauthorization of Price-Andersen Act
- Provide Financial Assistance to Finance Private Sector Nuclear Power Plants
- Support Research on Advanced Reactor Designs

In light of how well U.S. nuclear plants have generally been operating recently and with promising new technology on the horizon, nuclear energy would seem to have a future. Currently, about 20% of the nation's electricity comes from nuclear power plants (see chart below). The introduction of competition and deregulation in the U.S. has helped drive the nuclear fleet into achieving record availabilities and load factors, as independent owners have taken ownership from utilities that divested generation. Even utilities that did not divest their nuclear plants have experienced greatly improved performance across the board. Today's nuclear power plant operation and maintenance and fuel costs are remarkably low compared with many fossil fuel plants--as low as 1.68 cents per kWh according to the Nuclear Energy Institute. Although the high-profile accidents at Three Mile Island and Chernobyl greatly raised the threshold for safer operations, operating success stories may overstate what may be achievable with new designs. Nuclear operators in the U.S. have had a few decades to work out operational problems, and with original debt paid off, more cash resources have been dedicated to improving performance. Providers of new capital for advanced, nuclear energy will want some comfort that credit and operating risks are covered. But the industry's legacy of cost growth, technology problems, cumbersome political and regulatory oversight, and the newer risks brought about by competition and terrorism concerns may keep credit risk too high for even the Senate bill to overcome.

Historic Risks Will Persist

A nuclear power plant's life cycle exposes capital providers to four distinct periods of credit risk that history has shown will persist. These periods are pre-construction, construction, operations, and decommissioning (see chart below). The risks tend to be asymmetrical with an enormous downside bias against credit providers and little or no upside benefits. To attract new capital, future developers will have to demonstrate that the risks no longer exist or that the provisions of the Energy Bill can effectively mitigate the risks.

Nuclear Power Plant Life Cycle Risks

Design and Pre-Construction

- Cost Growth
- Permitting Delays
- Public Opposition
- Scope Change

Construction and Testing

- Cost Growth
- Public Opposition
- Regulatory Changes
- Scope Change
- Construction Delays
- Procurement Delays
- Finance Delays
- Permitting and Licensing Delays

Commercial Operations

- Public Opposition
- Regulatory Changes
- Permitting and Licensing Delays
- Latent Technical Defects
- Market Risk
- Fuel Disposal
- "Mishap" Repair Costs
- Forced Outages
- Replacement Power Obligations

De-commissioning

- Regulatory Changes
- Permitting Changes
- Public Opposition
- Disposal Costs
- Land Reclamation Costs

During a nuclear plant's pre-construction phase, lenders, as they do with other projects, face the risks of cost growth and delay. When nuclear engineers encountered technology problems during the planning stages in the 1960s and 1970s, solutions inevitably resulted in scope changes or re-designs, or both. A 1979 Rand Corp. study for the U.S. Dept. of Energy still serves as a warning to investors in new, untested nuclear technology. The study found that cost budget estimates grew on average 114% over first estimates and that final actual costs exceeded those estimates by 141%. Half of the plants in the study never reached commercial operations. An extreme example of delays and cost overruns, which remains fresh in investors' minds, is Long Island Lighting Co.'s Shoreham nuclear power station. Begun in 1965 at an initial cost estimate of $65 million-$75 million, Shoreham endured 20 years of construction delays and design changes due to legal battles, local opposition, regulatory and political intervention, and technical problems that pushed the final cost to almost $6 billion. In the end, a complete and fully licensed power plant never went operational, and ratepayers, investors, and taxpayers are still footing the bill. Another example is TXU Corp.'s 2,300 MW Comanche Peak Units 1 and 2, which took longer than any nuclear plant to build and saw costs mushroom to nearly $12 billion by the time full operations began in 1993.

That no new nuclear plant construction has begun in the U.S. for over 20 years suggests that a new one would be susceptible to cost growth risk, as engineers incorporate advances in control and power systems, fuel systems, safety and regulatory requirements (which could become more onerous during the years of design and construction), material sciences, and information technology. Even promising new designs, such as the

pebble bed reactor (PBR) design that Eskom Holdings Ltd. of South Africa plans to build soon, would likely risk design changes and attendant cost growth if built in the U.S. Cost growth and delay can also arise from design and scope changes due to the efforts of effective interveners, such as the anti-nuclear citizen activist groups that successfully delayed Shoreham and ultimately prevented it from going commercial.

History also suggests that the construction and start-up phases of new nuclear power will likely encounter problems that will result in increased costs and delays. Licensing delays, construction management problems, procurement holdups, troubles with new technologies and construction defects, among other problems extended construction beyond 10 years for some U.S. nuclear power plants. It would be overly heroic to assume that the first nuclear plant to be built in more than two decades would escape the industry's legacy of construction problems. For a debt-financed construction endeavor, likely to cost hundreds of millions of dollars (possibly into the billion dollar plus range), these problems, or even the possibility of such problems, will likely drive risk-averse lenders to demand a significant risk premium unless a third party assumes completion and delay risks. In the world of cost-of-service, rate-of-return environments, utilities could, and did, pass these costs on to ratepayers to a certain extent. The bankruptcies of El Paso Electric Co. and Public Service Company of New Hampshire in the 1980s, however, attest to the limits of ratepayers' capacity to absorb construction risk.

Today, no utility or independent power producer or their capital providers will want to take unmitigated construction risk, particularly if it is difficult to quantify. In addition, given the possibility that much of the construction risk of a new nuclear plant may lay outside of the engineering, procurement, and construction contractor's control, no contractor will want to risk its balance sheet to provide the fixed-price, date-certain, turnkey construction contracts that have given great certainty to the cost of today's new fossil-fueled power plants. Because of the long lead-time historically associated with nuclear power, securing 100% financing upfront, as the industry has become accustomed to, may be difficult. That could introduce financing risks if projects encounter problems during construction; delays in securing final financing would, among other problems, drive up capitalized interest costs during construction and ultimately the project's cost.

While U.S. nuclear power plants have operated without major mishap for over 20 years, unexpected costs during the operational phase of a nuclear plant can be substantial. And it is unclear whether and if proposed government programs will be able, or willing, to offset the risk of these costs. Still, today's operators have demonstrated that they can safely operate older nuclear power plants. Yet the potential that incidents, such as last year's wholly unanticipated corrosion problem at FirstEnergy Corp.'s Davis Besse 900 MW plant, are not unique, one-time affairs will keep credit risk high for nuclear plant owners. In addition, investors will remember that the Davis Besse repair costs of about $400 million, not including replacement power, are unrecoverable from ratepayers, leaving investors to shoulder the costs. Incidentally, had the outage occurred during a period of high power prices and tight supply,

as was the case two years ago, the cost to investors would have been much higher.

Decommissioning costs, which entail the considerable expense of tearing down a plant and safely disposing or storing the radioactive waste, remain uncertain at best given how few U.S. nuclear plants have undergone decommissioning. Progress toward creating a permanent disposal site for nuclear waste at the government's Yucca Mountain site in Nevada will help mitigate decommissioning risk, as well as spent fuel disposal costs. Again, it is not clear who will bear decommissioning costs, but if lenders foresee any lender liability risk, they will steer clear of new nuclear investments or require steep compensation. That, as a point aside, may be one of the reasons so many plants have been granted license extensions. Refurbishing a depreciated nuclear power plant costs far less than decommissioning one.

Finally, for many of the reasons described above and all else being equal, Standard & Poor's Ratings Services has found that an electric utility with a nuclear exposure has weaker credit than one without and can expect to pay more on the margin for credit. Federal support of construction costs will do little to change that reality. Therefore, were a utility to embark on a new or expanded nuclear endeavor, Standard & Poor's would likely revisit its rating on the utility.

Competition Introduces New Risks for Nuclear Energy

As electricity deregulation and industry reform have progressed, capital providers to the nuclear power sector face some of the same risks as capital providers to other power generation technologies. Again, if policymakers want to attract capital to the industry, lenders in particular will likely have to be convinced that at least some of the risks are covered or mitigated. The sheer size of most new nuclear investments suggests that downside risk for lenders could be considerable indeed.

Clearly, buying and selling electricity in a competitive environment comes with its risks, both market and political. The wake of California's electricity reform problems forced one utility into bankruptcy and brought another to the brink of bankruptcy. Independent power producers are resisting efforts by California and its Department of Water Resources to abrogate or renegotiate recently executed power sales agreements. These events, combined with the credit crunch that has hit many other utilities and energy merchants, have understandably moved public utility commissioners and capital providers into more risk-averse postures. Absent these problems, nuclear power would still be challenged to attract new capital; in this environment, however, the task is all the more difficult. Competition has dramatically shifted risks from ratepayers to lenders and other investors; that is not likely to change.

In a competitive wholesale power environment, nuclear plants would likely sell power as a base load generator behind hydroelectric and ahead of coal and gas. Capital costs would be higher than coal plants and much higher than natural gas plants, but marginal operating costs would be very low, as they are now. Nonetheless, an owner of a new nuclear plant would likely want a long-term--20 years or more--power

contract with a creditworthy utility to ensure that fixed and variable costs are covered in order to attract the massive amount of capital needed for construction. Alternatively, a utility that wants to add a new nuclear plant to its portfolio would need regulatory assurances from its public utility commission that the entire cost of the plant would be recoverable from its rate base. In the first instance, few utilities, or their regulators, want such long-term contract obligations, especially in an environment of excess generation that can be purchased on the cheap. That gas costs and clean-air compliance costs could be on the rise might offset some of those concerns. For some of the same reasons, public utility commissioners may not be so forthcoming with their authority to grant rate-based treatment of a new nuclear plant, especially in the pre-construction period if cost growth risk remains uncovered. For many commissioners, the all-in costs of alternative generation will likely seem more predictable and cheaper than a new nuclear plant.

The current backlash against regulatory reform and open markets in parts of the country could also put a new nuclear plant at risk. A large, new nuclear plant will typically need access to a large electrical network with a geographically dispersed customer group--the network that a well-structured regional transmission organization, as envisioned by FERC, could provide. However, if transmission access is limited or if states have chosen to maintain barriers to electricity trading and marketing, physical or otherwise, as many have, a new nuclear power plant may find itself operating within a much smaller system, a situation that could raise its credit risk, all else being equal. One obvious mitigant to this risk would be to build much smaller nuclear plants, such as the 100-MW modular PBR designs.

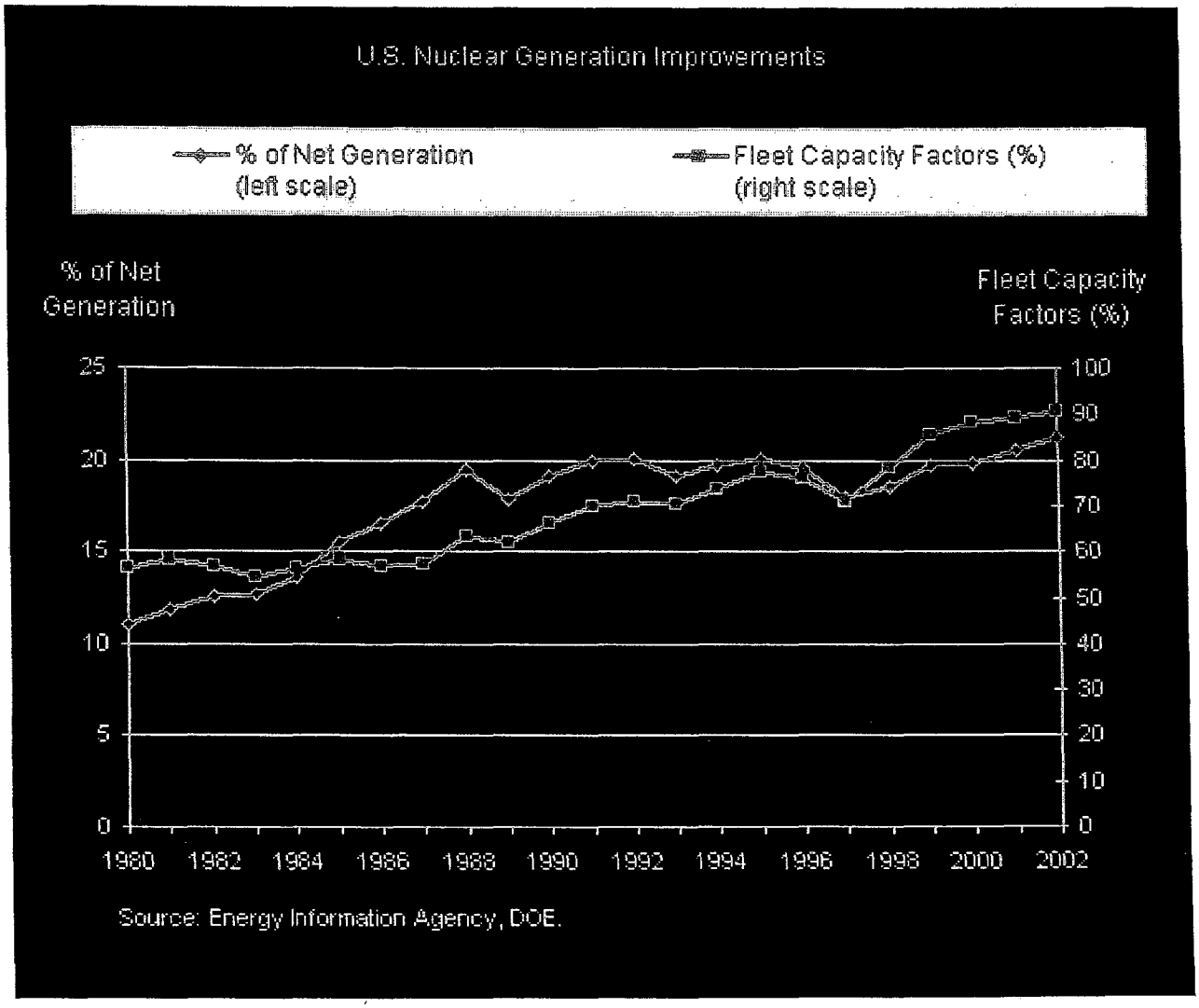
Whether a new nuclear plant is financed directly from the wallets of captive ratepayers or with long-term contracts, a large nuclear plant's size relative to its market raises outage-cost risk. A nuclear plant with a long-term power contract will likely contain provisions to provide replacement power, or the financial equivalent, if the plant becomes temporarily unavailable. Given nuclear power's vulnerability to rare, but extended forced outages, replacement power costs for 1,000-2,000 MW of base load power could be considerable, which would factor into credit risk. Similarly, a utility that owns a large nuclear station could find itself spending hundreds of millions of dollars to cover its short position while its station was down without assurances of recovery from ratepayers. Again, smaller PBRs would mitigate this risk.

Some of the preliminary provisions of the Senate Energy Bill contemplate some of these risks. A long-term power contract, for example, with the federal government that covers 50% of the plant's costs might mitigate some of concerns of operating in a competitive environment. Similarly, loan guarantees or lines of credit could also offset the costs. However, if gas- and coal-fired plants can be built for much less (e.g., 50% less) and the operational risk of extended nuclear plant outages remains uncovered, a government program could fall short of relieving investors' credit concerns. Moreover, as with any government subsidy program, lenders would invariably factor U.S. government counterparty risk in the form of subsidy re-authorization

uncertainty. Would the programs envisioned by the Senate bill last through the capital recovery period? Maybe. Maybe not.

A new risk for nuclear energy that has caught everyone's attention is terrorism. Because of the dangers that nuclear energy brings, security and insurance costs for nuclear facilities--new and old--are much higher than for fossil or renewable power plants. Therefore, in a competitive power environment, stakeholders in power generation may be reluctant to assume new risks that cost more to mitigate. Again, if a government subsidy can put security costs for new nuclear plants on an even playing field with conventional power generation, the industry could attract new capital. However, most new programs envisioned by Washington only address the construction risk.

As a note aside, some power generators and utilities may oppose efforts to support new U.S. nuclear generation capacity beyond existing subsidies, such as Price-Andersen, if they are heavily invested in coal and gas. New nuclear energy's low variable operating costs would likely displace existing coal-fired and gas-fired generation units in today's environment. It will do little, however, to displace oil-fired generation or lower U.S. oil imports because so little electricity, about 2% of the U.S. load, is actually generated by oil and much of that is for peak load, which nuclear energy would not serve anyway. But for stakeholders--investors, state politicians and regulators, lenders, customers--the risk that new nuclear generation could strand investment in conventional fossil-fuel-fired generation may be unacceptable unless the government provides financial compensation. And for a government trying to contain federal spending, those costs could be prohibitively expensive.



An Energy Bill Could Mitigate the Risks

To attract new capital to build the next generation of nuclear power plants in the U.S., developers will need to convince capital providers that the following risks are not materially greater than for fossil fuel power plants:

- The expense of cost growth, scope change, technology risk and start-up delay.
- The costs of unforeseen design problems that manifest themselves well after commercial operations begin.
- The costs resulting from the activities of effective interveners.
- The costs resulting from regulatory changes, including growth in oversight and compliance costs.
- The costs arising from forced outages in a competitive wholesale environment.
- The costs of replacing credit counterparties who are unwilling or unable to honor obligations or commitments upon which a nuclear plant's financing decisions were made.
- The added and uncertain expense of providing insurance and terrorism protection that nuclear plants need and that would disadvantage a nuclear plant operating in a competitive

wholesale market.

The versions of the Energy Bill circulating around Capitol Hill may indeed mitigate enough of the risks that would otherwise dissuade investors from financing new nuclear capacity. The key drivers will be not so much in the broad generalities of the authorizing legislation, but in the details of the enabling regulations promulgated by the Department of Energy. That could take some time to draft. However, the Senate mark-up of the bill appears to recognize the issues. Absent an affordable alternative, if Price-Anderson is not re-authorized, existing nuclear power plants could be forced to close because of the potential liability of an accident that could run into the billions of dollars. Beyond Price-Anderson, however, considerable government financial support will likely be needed to attract capital, given the perceived credit risks.

The proposed Energy Act's subtitle section, the "Nuclear Energy Finance Act of 2003," provides support for "advanced reactor designs" that covers reactors that enhance safety, efficiency, proliferation resistance, or waste reduction compared with existing commercial nuclear reactors in the U.S. In addition, financial support would consider "eligible costs" that would cover costs incurred by a project developer to develop and construct a nuclear plant, including costs arising from regulatory and licensing delays. Financial assistance may take the form of a loan guarantee of principal and interest, a power purchase agreement, or some combination of both.

The government's proposed support of new nuclear construction will come with limits. The objective is to cover the risks of new nuclear generation technology and construction until capital providers gain confidence that a new generation of nuclear power plants is commercially sustainable. The act would limit support to 50% of eligible project costs and to the first 8,400 MW of new nuclear generation. The 50% limit would certainly control the government's exposure, as well as mitigate the risks of moral hazard that a complete guarantee would invite. However, as the industry has learned, some of the costs that could undermine new nuclear power are not those of construction and design, but are the operational ones that could arise after government assistance has ended. In addition, given the risk of cost growth and the likely high capital costs of a new nuclear plant, a 50% level of financial assistance may not be enough to entice a developer comparing uncertain estimates of $1,500-$2,000 per kW capital cost of a new generation nuclear plant with more certain $500 per kW combined-cycle gas turbine or $1,000 per kW coal plant capital costs.

Whether or not the nuclear energy provisions of the Senate's version of the Energy Bill are good economic or energy policy is beyond the scope or intent of this article. New nuclear energy has compelling attributes, such as supporting energy diversity, replacing an aging U.S. nuclear fleet, offsetting rising natural gas prices, and reducing greenhouse gases and NOx, SOx, and particulate airborne pollutants. Once the capital costs are sunk, the variable operating costs can indeed be quite low. However, nuclear power tends to raise credit risk concerns during construction and well after construction. Investors, particularly lenders

who rarely see any upside potential in cutting-edge technology investments, including energy, will likely find the potential downside credit risk of an advanced, nuclear power plant too much to bear unless a third party can cover some of the risks. An Energy Bill that covers advanced design nuclear plant construction risk may go a long way toward allaying those concerns, but if operational and decommissioning risks remain uncovered, look for lenders to sit this opportunity out.

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Attachment 6

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Research:

Evaluating Risks Associated With Unregulated Nuclear Power Generation

Publication date: 09-Sep-2004
Credit Analyst: John Kennedy, New York (1) 212-438-7670

Competitive nuclear generation presents an added risk factor to a firm's business profile, given the inability to recover unexpected costs through a regulatory process. To date, those operating nonregulated generation have had success by mitigating risk through enhanced operating performance (higher capacity factors, shorter outage intervals), expertise in managing nuclear assets, and the ability to sufficiently fund decommissioning costs. Still, some element of event risk will always remain with this business strategy, which could ultimately impinge on credit quality.

In the late 1990s, several firms decided that nonregulated nuclear generation was their growth platform (see table). To date, those with nonregulated nuclear generation exposure have performed well, despite greater business risk related to fuel procurement and storage, asset concentration, and the potential need of replacement power. In Standard & Poor's view, these nonregulated nuclear operations have higher risk than those plants that reside in a regulated utility business. Mostly, nonregulated plants lack the safety net afforded to those plants that are part of a regulated utility. The absence of this protection presents uncertainty regarding the ability to recover certain costs. Also, decommissioning risk is greater because underfunding cannot be recovered through a regulatory process.

Top Nonregulated Nuclear Plant Owners	
Company	MW
Exelon Corp.	16,959
Dominion Resources Inc.	5,468
Entergy Corp.*	4,670
Constellation Energy Group Inc.	3,825
FirstEnergy Corp.	3,796
*Includes operating contract for the Cooper Plant.	

Some examples of the risks that these nonregulated nuclear operators may face include:

- Environmental and safety compliance risk;
- Risks associated with the storage of spent nuclear fuel;
- Decommissioning risk; and
- Operational performance.

Environmental and Safety Compliance Risk

Given the safety, health, and environmental concerns surrounding nuclear generation, compliance standards play an important role in credit quality for firms owning merchant nuclear generation for a number of reasons.

First and foremost, noncompliance can cause plants to shut down until certain standards are met. This prevents them from generating power and collecting revenue. Because these plants are nonregulated (not in rate base) an owner has no recourse for reimbursement of any lost revenue. Also, regulators such as the Nuclear Regulatory Commission (NRC) can influence outages and capital expenditures related to other oversight issues. Again, without the ability to recoup these costs through a regulatory

process, this could create an additional burden on merchant nuclear plants. Furthermore, repeated compliance problems, coupled with political pressures, could permanently close a plant or disallow a license renewal, leaving an owner with an unrecoverable stranded investment.

Spent-Fuel Storage

The question of where to store spent nuclear fuel is a key environmental issue. The Department of Energy is more than 10 years behind schedule in building a centralized repository. This creates a burden on nuclear plant owners as on-site storage capacity begins to dissipate.

Here again, the owners of nonregulated nuclear generation are responsible for paying for the process. For the most part, rates that a generator would charge incorporate storage costs. However, these owners could incur unexpected capital outlays and have no recourse for recovery. Some of these concerns are being mitigated by recent government actions. A recent settlement with Exelon Corp. will give the company $80 million for incurred storage costs, and it is likely that other firms will receive similar compensation.

Decommissioning Risk

A higher level of risk for nonrate-based nuclear plants arises in part from the uncertainty regarding a firm's ability to fund the requisite decommissioning costs. Given that decommissioning is a legal obligation for a nuclear plant operator, any funding shortfall would create a financial obligation on that firm's behalf. Unlike many of their peers who own nuclear plants in rate base, owners of nuclear power plants not in rate base neither collect decommissioning costs in rates, nor do they have recourse to the local regulator for relief. Therefore, the funding responsibility falls squarely on the owners of nonrate-based nuclear plants. Standard & Poor's views this obligation to be debt-like, similar to underfunded pension benefit obligations, and may incorporate any shortfall into computing credit metrics.

Operational Performance Risk

Given the competitive nature of nonregulated plants, Standard & Poor's considers operating efficiency as an important factor in credit quality. Generally, the incentive to purchase nonregulated nuclear power plants is the ability to produce power at costs lower than coal- or gas-fired counterparts. Also, many sale prices incorporate a purchaser's ability to increase operating margins through efficiency and cost savings. To generate the expected return on investment commensurate with the associated risk, new owners need expertise in budgeting and cost containment, operating know-how, and experienced personnel.

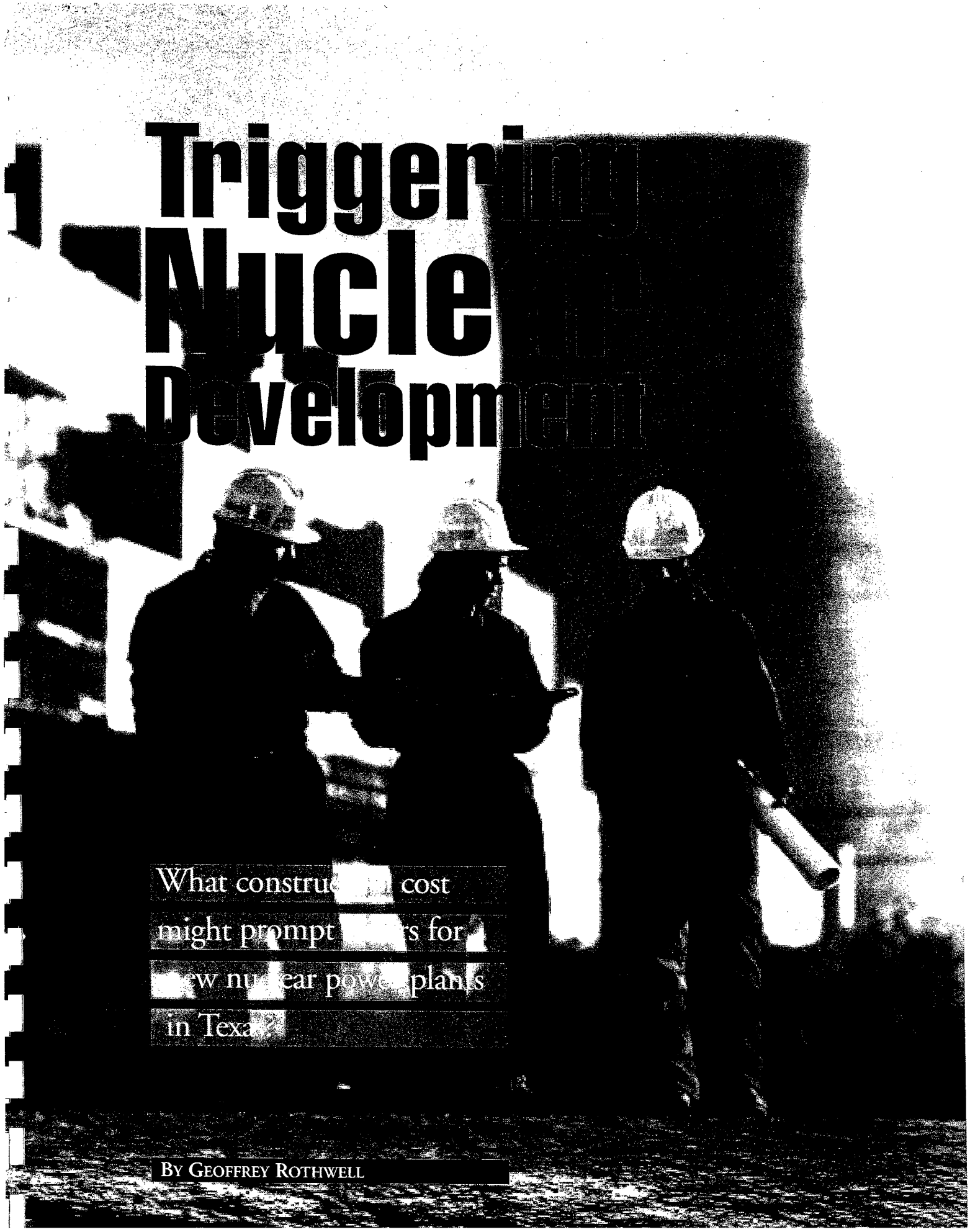
Unplanned or prolonged maintenance outages that reduce capacity factors and unexpected repair costs can be hurdles to achieving an appropriate operating margin. Again, the lack of a regulatory safety net deprives new owners of the ability to recover all or some of these unexpected capital expenditures. Furthermore, unplanned outages could create an obligation to provide replacement power, which could be at a higher (and unrecoverable) cost.

Summary

Standard & Poor's will closely monitor the issues surrounding a firm's ability to manage these issues, and continue to assess the need for adjusting financials in light of any obligations arising for these types of concerns.

Attachment 7

Triggering Nuclear Development



What construction cost might prompt utilities for new nuclear power plants in Texas?

By Geoffrey Rothwell

Electricity generation deregulation has opened U.S. wholesale electricity markets to unregulated power producers. In this uncertain environment, how should a generating company evaluate the risk of investing in new capacity?[1]

Building upon the calculations in the sidebar (*see p. 51*) we can calculate the price trigger for new nuclear power capacity by considering the option of building an advanced boiling water reactor (ABWR) in Texas coming into commercial operation in 2010.[2] This article: (1) provides a technique for estimating the mean and variance of net revenues from the power plant; (2) calculates the variance of net revenues; (3) determines a price trigger, or K*, that might trigger new orders for the current generation of nuclear power plants; and (4) discusses how to mitigate net revenue uncertainties in the form of controlling price risk, output risk, and cost risk.

ABWR Construction, Investment, Price, Output, and Cost

As an application of the real options approach to evaluating new nuclear power plants, public data is available to estimate construction cost, electricity prices, megawatt-hours generated, and operating costs for an ABWR in Texas. First, Table 1 (*see p. 50*) presents the average construction capital cost of a dual-unit ABWR built in the United States.[3] The following summarizes the reactor supplier's statement regarding Table 1:

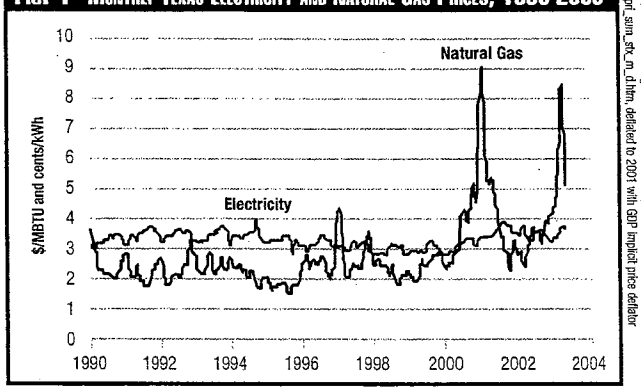
"The ABWR plant can be constructed in just four years for US$1,600/kWe and suppliers are willing to undertake a project on a fixed price, fixed schedule basis. As a result, the ABWR nuclear plant has proven itself in Japan and Chinese Taipei to be economically competitive with other power generation options and estimates indicate that it can be economic in other countries as well."

Let the construction cost (K) of the ABWR be $1,600/kWe (including financing charges) for a dual-unit 2,800-MW (gross) capacity plant (with 2,700 MW net). The plant could generate 23.65 M MWh each year at full capacity. The total investment, *I*, would be about $4,500 million (M).

Second, to forecast electricity prices over the life of the plant, consider energy sold in the Texas electricity market. The Texas market is unique in the U.S. because of its separation from the rest of the country into its own reliability region, known as ERCOT, the Electric Reliability Council of Texas. (Although all of ERCOT is in Texas, not all of Texas is in ERCOT.) Figure 1 shows Texas monthly electricity prices and natural gas prices from 1990 to 2003. Since the price spikes in 2000, the price of electricity (for example, "Type B Electric Energy" in ERCOT) has been higher and is likely to remain higher for the foreseeable future.

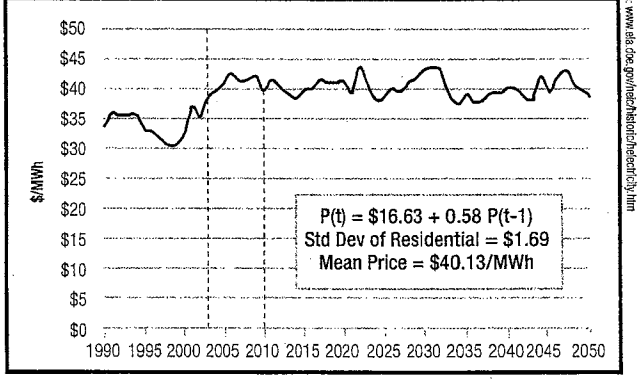
Figure 2 presents prices from 1990 to 2003 and simulated

Fig. 1 Monthly Texas Electricity and Natural Gas Prices, 1990-2003



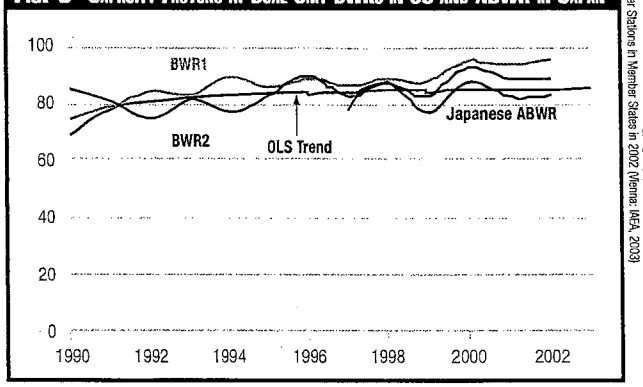
Source: www.eia.doe.gov/neic/historic/hetechfdly.htm and www.eia.doe.gov/oiaf/aeo/aeo_pri_sum_stk_m_d.htm, deflated to 2001 with GDP implicit price deflator

Fig. 2 A Simulation of Annual Competitive Market Prices in ERCOT



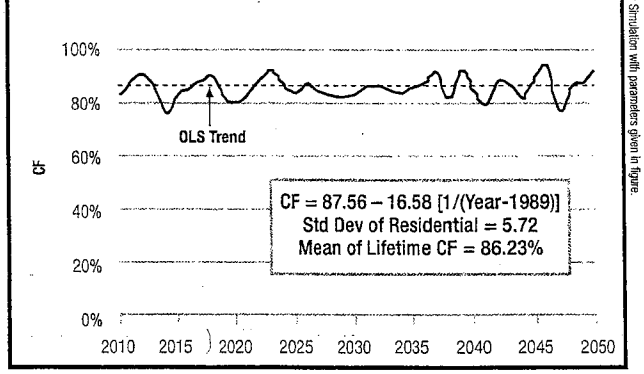
Source: www.eia.doe.gov/neic/historic/hetechfdly.htm

Fig. 3 Capacity Factors at Dual-Unit BWRs in US and ABWR in Japan



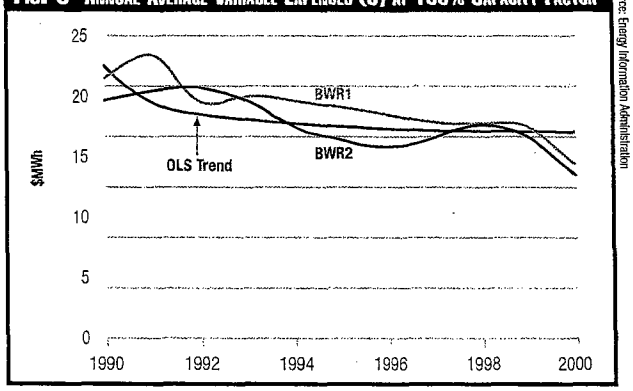
Source: International Atomic Energy Agency (2003). Operating Experience With Nuclear Power Stations in Member States in 2002 (Vienna: IAEA, 2003)

Fig. 4 A Simulation of Capacity Factor for a Dual-Unit ABWR



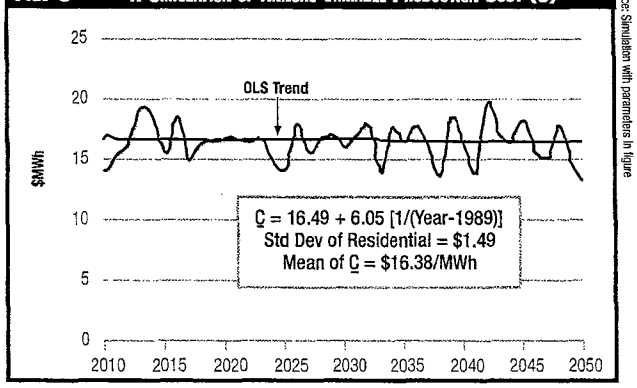
Source: Simulation with parameters given in figure.

Fig. 5 Annual Average Variable Expenses (C) at 100% Capacity Factor



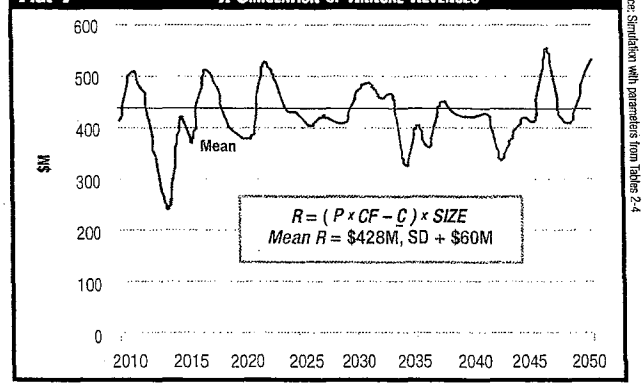
Source: Energy Information Administration

Fig. 6 A Simulation of Annual Variable Production Cost (C)



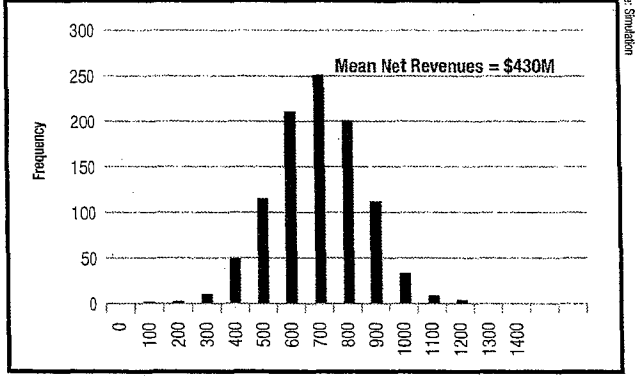
Source: Simulation with parameters in figure

Fig. 7 A Simulation of Annual Revenues



Source: Simulation with parameters from Tables 2-4

Fig. 8 1,000 Simulations of Net Present Value



Source: Simulation

prices from 2004 to 2050. These simulated prices represent one of 1,000 Monte Carlo trials. In these trials, average price follows the parameters given in Figure 2. For each year there is a random draw from a normal distribution that adds variance to electricity prices. (The standard deviation of this normal distribution is $1.69.) In the particular simulation presented in Figure 2 the mean electricity price was $40.13 and the standard deviation was $1.62.

Third, during the 1980s and 1990s, capacity factors at U.S. nuclear power units improved dramatically. Figure 3 presents capacity factors from 1990 to 2002 at: (1) dual-unit BWRs in the U.S. that came into commercial operation after 1982; and (2) the Japanese ABWR that came into full commercial operation in 1997. Data for General Electric BWRs larger than 1,100 MW are used to simulate capacity factors at ABWRs operating in the United States. Ordinary Least Squares parameters were estimated with this sample of capacity factors. The estimated trend line is identified in Figure 3. Assuming ABWRs follow the same trend, the expected lifetime capacity factor would be about 86 percent. Using estimated parameters, a Monte Carlo simulation of capacity factors for a dual-unit ABWR is presented in Figure 4. (This is from the same simulation as in Figure 2.)

Fourth, Figure 5 presents *C* (operating cost at full capacity) for dual-unit BWRs in commercial operation in the United States after 1982 for the years 1990 to 2000 (inflated to mid-2001 dollars). Assuming ABWRs follow the same trend, Figure 6 presents a Monte Carlo simulation of variable expenses. In this simulation, the mean *C* is $16.38, with a standard deviation of $1.58. To summarize, expected net revenues might be (R is at the mean of the 1,000 Monte Carlo trials):

$$R = (\$40.13/\text{MWh} \cdot 86\%) - \$16.38/\text{MWh}) \cdot 23.65\text{M MWh/year} = \$430\text{M/year}.$$

The Value of a Dual-Unit ABWR in Texas

With a real discount rate of 7 percent, the capital recovery factor (δ) is 0.0772 for 40 years. The NPV in 2010 (assuming both units are completed in 2010) is

$$\text{NPV} = (R/\delta) - I = (\$430\text{M}/0.0772) - \$4{,}500\text{M} = \$1{,}100\text{ M}.$$

The NPV is positive, so the investor-generator would build the ABWR under traditional investment criteria.

However, net revenues are uncertain. Simulations of the electricity prices, generation output, and input costs can be combined to determine the probability distribution of net revenues. Figure 7 presents a simulation of revenues for »

A Real-Options Approach

By Geoffrey Rothwell

Under standard investment criteria, the investor-generator would invest in new power capacity if the Net Present Value (NPV) of the project were positive. Net Present Value equals the discounted value of (1) the power plant's net revenues (R) per year (in millions of dollars) minus (2) total construction cost (I) including financing costs (e.g., interest during construction):

$$NPV = R/\delta - I > 0 \Rightarrow R > \delta \cdot I,$$

where δ is the capital recovery factor.[1] Under NPV investment criteria, the generator invests if net revenues are greater than the levelized cost of construction: $R > \delta \cdot I$. Let R^* be the "net revenue trigger value," such that if expected present value of net revenues is greater than R^*, the investor would order new power capacity. Under NPV analysis, $R^* = \delta \cdot I$. If net revenue is less than R^*, the investor-generator waits (does not invest).

Net revenues are

$$R = (P \cdot CF - \underline{C}) \cdot MWYEAR,$$

where (1) P is the market price of electricity in dollars per MWh (megawatt-hours),

(2) CF is the capacity factor equal to total electricity generated per year divided by the maximum dependable capacity per year,

(3) $\underline{C}$ is average production cost at full capacity (*i.e.*, total production cost divided by maximum output), and

(4) MWYEAR is the maximum dependable capacity (in megawatt-hours) per year.

For example, if P = \$40 per MWh, CF = 90%, and $\underline{C}$ = \$16/MWh, with $MWYEAR$ = 22M (million) MWh/year, then $R_t = [(\$40 \cdot 90\%) - \$16] \cdot 22M = \$440M/year$. With a real cost of capital of 7% (the nominal cost is closer to 10%), the capital recovery factor (δ) is 0.0772 over a 40-year life, and the NPV of annual net revenues (R/δ) is \$5,700M (ignoring taxes).[2]

Discounted net revenues can be calculated, but each of the three variables (P, CF, and C) is uncertain, because future electricity prices, generation output, and operating costs are unknown. Therefore, net revenues are uncertain and the NPV is uncertain. The traditional NPV analysis does not have a consensus method for evaluating NPV probability distributions.[3]

Real Options Analysis of Nuke Investment

Traditional NPV analysis assumes that all uncertainty is reflected in the risk premium associated with the cost of capital. How is this risk premium determined? The "real options" approach provides one answer, based on an evaluation of the probability distribution of net revenues.

Two assumptions must be made to evaluate this probability distribution with the real options approach. First, assume that percentage changes in net revenue follow a proportional Brownian motion with a normal distribution. Second, assume that uncertain net revenues are perfectly correlated with a portfolio of tradable assets (both real and financial).[4]

Under these assumptions the net revenue trigger value, R^*, is

$$R^* = (1/\phi) \cdot \delta \cdot I^*,$$

where ϕ represents an investor's discount of the NPV of uncertain net revenues.[5] From Equation (3), the trigger value for total construction cost, I^*, can be found:

$$I^* = (\delta/\phi) R^*$$

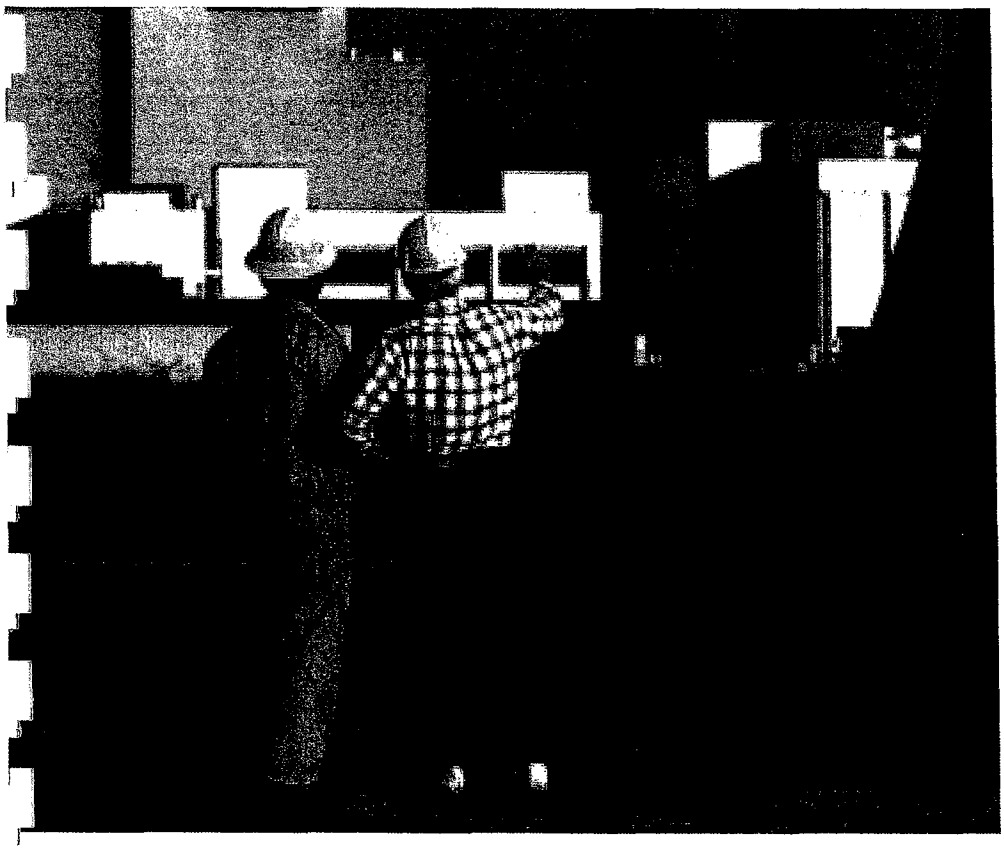
Finally, let K^* be the construction cost per kilowatt at I^*. For a plant of W kilowatts-electric, $K^* = I^*/W$. To summarize:

$$K^* = (\phi/\delta) \cdot (P \cdot CF - \underline{C}) \cdot (MWYEAR/W)$$
$$= (\phi/\delta) \cdot (P \cdot CF - \underline{C}) \cdot 8.760,$$

where the final term is equal to the number of hours in a year divided by 1,000 (the number of kilowatts in a megawatt). What is the value of K^* (the total construction cost per kWe) that might trigger new power plant orders? In the text (assuming $\phi = 1$), if K^* = \$1,980 kWe, investors would be indifferent between ordering new plants and waiting for new information.

Endnotes:

1. The capital recovery factor, δ, is equal to $[e^{rT}(er - 1)]/(e^{rT} - 1)$, where r is the generator's cost of capital and T is the economic life of the plant (ignoring tax effects, see next).
2. Neglecting income taxes is not likely to influence the primary conclusions of this paper under competitive market conditions, low corporate income tax rates, and the use of accelerated depreciation. However, the error will increase with increases in the cost of capital.
3. Consider Robert Brealey and Stewart Myers, *Principles of Corporate Finance* (2000, Irwin/McGraw-Hill); p. 275): "Finally, it is very difficult to interpret a distribution of NPVs. Since the risk-free rate is not the opportunity cost of capital, there is no economic rationale for the discounting process. Because the whole edifice is arbitrary, managers can only be told to stare at the distribution until inspiration dawns. No one can tell them how to decide or what to do if inspiration never dawns." Hopefully, this analysis will provide some inspiration for identifying sources of risk and how to mitigate them. It also provides a method for calculating the risk premium.
4. Avinash Dixit and Robert Pindyck, *Investment Under Uncertainty* (1994, Princeton University Press): pp. 65 and 148.
5. Here, ϕ equals $[(\gamma - 1)/\gamma]$ where $\gamma = 1/2 \cdot \{1 + [1 + (8\delta/\sigma^2)]^{1/2}\}$, see Rothwell (2004, Appendix. 2). This formula for γ assumes that financial markets price risk consistently across assets, including assets in a portfolio that is perfectly correlated with ("spans") net revenues for new power plants.



Mitigating the Risks of Nuclear Investment

Three risks were considered: price risk, output (capacity factor) risk, and cost risk. This section examines the sensitivity of the trigger K^* to mitigating each of these risks and what nuclear power plant owner-operators might be willing to pay for real and financial assets to mitigate each of these risks.

To examine the sensitivity of K^*, each risk can be suppressed in the Monte Carlo simulation. For example, if the owner-operator could contract with a buyer to guarantee the price of all output at $40/MWh (real) for 40 years, the standard deviation of the price could be reduced to zero and the trigger price (K^*) would rise. Each of the three risks can be held to zero; two of the three can be held to zero; or all three can be held to zero.

each year from 2010 to 2050, based on the particular simulation in Figures 2, 4, and 6. Figure 8 presents a histogram of 1,000 simulations of NPV. Average NPV is $740M with a standard deviation of $160M. Underlying this NPV are average net revenues of $430M per year. How might an investor-generator evaluate this probability distribution for NPV?

Following the real options analysis, the variance of percentage changes in net revenues was 4.2 percent in the 1,000 simulations represented in Figure 8. With a variance of 4.2 percent, $\phi = 60\%$.[4] So,

$$I^* = (\phi/\delta)\, R^* = (60\% / 0.0772)\ \$430\text{M} = \$3{,}340\text{M and}$$

$$K^* = (\$3{,}340\text{M} / 2{,}800\text{MW}) \cdot (1{,}000\ \text{MW/kWe}) = \$1{,}200/\text{kWe}.$$

Alternatively, the capital recovery factor could be adjusted to reflect the uncertainty in NPV, i.e., $(\delta/\phi) = 0.1287$, inferring a real discount rate of 12 percent, or a risk premium of 5 percent. (A 12 percent cost of capital yields a 12.87 percent capital recovery factor for a 40-year life.) This represents a decrease of about 25 percent from construction cost in Table 1. Therefore, if investors implicitly discount nuclear power because of these uncertainties, new nuclear power deployment requires lower construction cost.

As a benchmark, with the assumptions and simulations described in this paper, holding most revenue-related risk to zero, the nuclear power plant supplier could sell new nuclear power plants on a fixed-construction cost basis for a breakeven price of $1,980/kWe including IDC (*see Table 2, p. 51*). Controlling output and cost risk, price risk alone reduces K^* by $200/kWe. Controlling output and price risk, cost risk alone reduces K^* by $320/kWe. Controlling both price and cost risk, output risk alone reduces K^* by $380/kWe.

TABLE 1 AVERAGE CAPITAL COST OF A DUAL-UNIT ABWR BUILT IN THE U.S.

Direct costs (per 1,400-MW unit)	
Structures and improvements	$400
Reactor plant	$500
Turbine plant	$250
Electrical plant	$150
Miscellaneous plant (e.g., cooling)	$100
Total direct costs (per unit)	**$1,400**
Total indirect costs (per unit)	**$400**
Base (Overnight) Construction Cost	$1,800
Contingency (per unit)	$165
DC at 7% (4-year lead time per unit)	$275
Total Cost (per 1,400-MW unit)	**$2,240**
Total Cost (for two units, 2,800 MW)=*I*	**$4,480**
Plant Cost per kW (gross)=*K*	**$1,600**

(in millions of 2001 dollars)

Source: Based on Nuclear Energy Agency (2000, p. 99)

Further, controlling output risk, price plus cost risk together reduce K^* by $500/kWe. (Because of the slight correlation between price risk and cost risk in the simulations, there is an economy of risk reduction, compared to controlling price and cost risk separately for the equivalent of $520/kWe.) The influence of each pair of risks on K^* can be calculated (see Table 2). Finally, to trigger sales with no risk mitigation (output, price, or cost risk), K^* is about $780/kWe lower than the benchmark, *i.e.*, $1,200/kWe (as found above).

These values for mitigating risk give an opportunity to consider bargaining among nuclear power industry participants to share risk and returns from new nuclear power plants. For example, the owner-operator might be willing to reduce the price of firm power below the expected spot market price to encourage very long-term contracts. According to the assumptions here, the owner-operator might be willing to pay up to the equivalent of $200/kWe to eliminate price risk. (This is a price per megawatt-hour difference of about 10 percent, holding all else equal.)

Under electric utility rate-of-return regulation, price risk was reduced by giving electric utilities price increases to cover increases in reasonable costs of operation and capital. In deregulated markets, price risk is shared between the owner-operator and the electricity consumer. Further research should determine the willingness-to-pay of electricity consumers for firm power under very long-term contracts.

A related question concerns output risk (because risk-mitigating measures to control price risk require the delivery of firm power). The owner-operator must backup committed output with either: (1) financial instruments or contracts for purchases on the spot market; or (2) physical assets, such as natural gas peaking units. The owner-operator should be willing to pay up to $500/kWe to eliminate both output and price risk. Future research should consider alternative real asset and financial portfolios to best mitigate these two forms of risk simultaneously for new nuclear power plants.

The remaining risk to the investor is cost risk, which could be eliminated through contracting. For example, nuclear fuel (which has an asset life of decades) could be leased at a fixed price for a finite period and returned to the lessor. Also, an operations management company could operate the plant under contract. But the transaction cost of monitoring an operating contract is likely to be prohibitive. Therefore, cost risk should be assigned to the party best able to mitigate cost risk on a day-to-day basis—the owner-operator. Future research should consider how much cost risk can be mitigated and how much equity in the project might be required of the owner-operator to create optimal incentives to deliver cheap, reliable, and safe electricity.

TABLE 2 DECOMPOSITION OF REVENUE VARIANCE

Source of Variance	σ^2	I	"Price" of Control
Almost none	0.0001	$1,980/kW	$0
Price	0.009	$1,780/kW	$200/kW
Cost	0.014	$1,660/kW	$320/kW
Output	0.017	$1,600/kW	$380/kW
Price + Cost	0.024	$1,480/kW	$500/kW
Price + Output	0.026	$1,450/kW	$530/kW
Cost + Output	0.032	$1,360/kW	$620/kW
P + Cost + Output	0.042	$1,200/kW	$780/kW

Note: There are differences due to rounding.

Calculations based on the Real Options Approach

Three risks influence annual net revenues (revenues before payments on construction expenditures) from operating nuclear plants: output risk, price risk, and cost risk. Currently operating nuclear power plants were built under rate-of-return regulation. Future nuclear power plants likely will be built in deregulated environments. These environments put competitive pressure on nuclear power plant suppliers to lower new nuclear power plant construction cost and to develop a new business model for new plants. Future research should examine risk-mitigating components of this new business model. Until a new business model is created and implemented, it is unlikely that there will be new orders for nuclear power plants in Texas (or anywhere in the United States).

Geoffrey Rothwell is senior lecturer in the Department of Economics and the associate director of the Public Policy Program, Stanford University. He is also working for the U.S. Department of Energy on the economics of new nuclear power. However, the analysis here is independent research. Contact him at rothwell@stanford.edu.

Endnotes

1. A more detailed explanation of the techniques used here can be found in Geoffrey Rothwell, "What Construction Cost Might Trigger New Nuclear Power Plant Orders?" (March 2004) at *http://siepr.stanford.edu/papers*. On deregulated electricity markets, see Geoffrey Rothwell and Tomas Gomez, *Electricity Economics: Regulation and Deregulation* (2003, IEEE Press with John Wiley).
2. Two ABWRs have been operating in Japan since 1997 and four units are under construction in Japan and Chinese Taipei. The ABWR has been certified by the U.S. Nuclear Regulatory Commission for construction in the United States.
3. See Nuclear Energy Agency. *Reduction of Capital Costs in Nuclear Power Plants* (2000, Paris: OECD): pp. 96-99. In their 2003 edition Brealey and Myers dropped their discussion of "Misusing Simulations" (part of which is quoted here) and added a new section, "Real Options and Decision Trees."
4. Here $\gamma = 1/2 \cdot \{1+[1+(8 \cdot 0.077/0.042)]^{1/2}\} = 2.5$ and $\phi = (\gamma - 1)/\gamma = 0.60$

Attachment 8

Proceedings of ICAPP '03
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Paper 3188

The Business Case for Building a New Nuclear Plant in the U.S.

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Abstract – *Sustained economic performance by a nuclear plant generates a significant amount of cash for its owner. This cash becomes available for other investments including additional power generating assets. What better investment can a successful nuclear utility make than in a new nuclear plant? Of course, one must make the corresponding business case. A pro forma is developed and this provides a forecast of revenue, costs, the resulting cash flow, and, more importantly, the positive effect on the value of the owner's company as reflected in its stock price. The capital cost of the plant represents not only the single biggest cost but also a significant outflow of cash. Central to establishing the business justification then is the capital cost and how the resulting pro forma compares with that of other investments.*

I. INTRODUCTION

The ability to operate a nuclear plant safely year-in and year-out with a capacity factor of 90% is certainly a pre-requisite for moving ahead with a new plant. So is the ability to consistently maintain production costs at or near 1.0 cent per kwhr. The performances of many U.S. nuclear power plants already fall into this category of excellence, demonstrating that U.S. nuclear utilities have the management skills to safely and profitably operate nuclear plants.

Sustained economic performance by a nuclear plant generates a significant amount of cash for its owner. This cash becomes available for other investments including additional power generating assets. What better investment can a successful nuclear utility make than in a new nuclear plant?

II. REGULATION OR DEREGULATION?

The obvious answer is that a utility has several potentially attractive options including additional combined cycle plants, advanced clean coal plants and a range of renewable technologies. Indeed, some states have adopted Renewable Portfolio Standards that mandate the build-out of renewable plants. (California, for example, recently adopted a RPS that requires utilities to increase their total amount of eligible renewable resources by at least one percent per year, until 20 percent of its retail sales are procured from renewables. If only nuclear plants were considered an eligible renewable resource...)

Because these options are to varying degrees attractive and because a nuclear plant has not been ordered in the U.S in nearly three decades, the CEO and Board of Directors are going to look long and hard at the nuclear option. To get their approval to build a new nuclear plant means that someone must make an unassailable business case for it.

It is commonly assumed that a new nuclear plant will be a merchant plant built by a utility or consortium of utilities in a state whose wholesale electricity market has been de-regulated. We don't think this is necessarily the case. Because of the unfortunate experience with deregulation in California, many states have put a halt to or slowed down their own deregulation plans. So it is conceivable that the next nuclear plant in the U.S., the one that will break the logjam so to speak, will be built by a regulated utility with the approval and perhaps the encouragement of its Public Utilities Commission.

In fact, there are many advantages to building a nuclear plant in a regulated environment, that is, on a cost-of-service basis. The utility has a higher degree of assurance that it will recover its costs and earn an 11 to 12% return on those costs. If the plant suppliers provide the utility with firm priced contracts for the plant's construction, it would seem almost a certainty that these costs will be deemed prudent by the PUC. There is, in other words, significantly less risk to the utility. (Utilities building a $2B merchant plant nuclear plant could be putting themselves in a situation often described as "betting the company.")

Currently, there is no straightforward market mechanism for capturing the value of new nuclear capacity in terms of fuel diversity and reducing pollutants. However, policy makers at the state level could and, in our opinion, should take these issues into consideration when planning new capacity. Thus state decision makers might very well decide that their utilities are "long" on natural gas capacity and direct them to build new nuclear in order to diversify their generating portfolio and reduce CO2 emissions.

Of course, many policy makers and PUCs at the state level have biases against nuclear power and it would be difficult, to say the least, to surmount the ideological and political hurdles that stand in the way of getting approval for new nuclear capacity. Although public support is always important, let's face it, a non-regulated utility or a developer can build a merchant nuclear plant without it (we are assuming, of course, that the plant is licensed and complies with all safety and environmental requirements.)

It is able to do so because it takes on the risk that is otherwise borne by the ratepayers. As we have written elsewhere [(1)], that risk is extensive and must be carefully managed. As we all know, more risk must be offset by a higher return on investment. Most CEOs and business development managers with whom we have discussed this issue talk in terms of 20% return on equity (vs. 16% for combined cycle.) This translates into a 12% weighted cost of capital, otherwise known as the discount rate.

So, the question to which we will now turn is this: can a nuclear plant be built as a merchant plant and achieve financial success where we will measure such success as achieving at least a 12% Internal Rate of Return. This is equivalent to a zero Net Present Value. If this is achieved, the minimal expectations of the owner will be met. We say minimal because it is in line with the company's other business returns but it does not exceed them and thereby increase the value of the company.

III. IF A NUCLEAR PLANT WAS ORDERED TODAY

In order to answer that question, a project *pro forma* has been developed. Since the *pro forma* is in the form of a spreadsheet, it can be used to determine the 2 or 3 key elements upon which the success or failure of the project depends by performing several "what if" cases.

So let's begin by assuming that a nuclear plant is ordered today. Imagine a newspaper report along the lines of that in Figure 1. The cost is reported to be $1445/kw and that this will be shared by more than one utility (it isn't clear if GE is to be an investor, but this could be read into the announcement.) The most telltale part of the report is that investors were lukewarm about the news. Why might that be?

First Nuclear Plant in U.S. Ordered
Reuters
May 4, 2003

SAN JOSE, CA (Reuters) — GE, Black& Veatch, and a consortium of utilities announced today that they have signed an agreement to proceed with the construction of an ABWR nuclear power plant. Stock prices of all companies remained unchanged as investors reacted with caution to the announcement. The plant, estimated to cost $1445/kw, will be built in California and sell into that state's wholesale markets. An excited Gov. Gray Davis told reporters...

(continued on back page)

Figure 1: A purely fictitious newspaper report.

Since investors and analysts are pretty smart people, they know that this project will not create additional value for the firm. They base this upon an analysis, using the data in Table 1 that indicates the net present value of this project is zero.

Table 1:

Capital cost	$1445/kw (overnight value)
Fuel cost	$0.50 cents per kwhr
O&M cost	$0.60 cents per kwhr
Equity	50%
Discount rate	12% (the weighted cost of capital)
Gas prices	$4.00/MBTU for 40 years

To say the same thing in a different way, the Internal Rate of Return (IRR) for this project is 12.0%. Since the discount rate or weighted cost of capital for the utility is also 12.0%, no value is created or destroyed.

We are assuming that natural gas prices determine the cost of electricity in the marketplace since combined

cycle plants have been "on the margin" more than half the time in most major markets and in some markets 80% of the time or more. A gas price of $4 per MBTU translates into electricity prices of about $50/MWhr when the average heat rate for the system is 8000 MBTU/kwhr.

Some discussion of the capital cost used here is in order. GE and B&V spent a good deal of time and effort in 2002 in the performance of a bottoms-up estimate of the capital cost of the ABWR. This estimate was based upon the quantities and vendor costs that were compiled in the POWRTRAK ™ database during the delivery of the Lungmen ABWRs in Taiwan. GE and B&V's scope on this project was the Nuclear Island and so the accuracy of this portion of the plant is quite high Labor costs and productivity figures were taken from B&V's proprietary database for U.S. power plant projects. The Turbine Island costs are based upon a new turbine-generator design that GE and B&V are developing and is an estimate as opposed to an actual cost. The radwaste building and yard area are included in the scope of the estimate.

The cost figure of $1445/kw includes everything except inflation and financing (both of which are, of course, included in the financial analysis used to determine the IRR.) It includes the EPC (Engineering, Procure, and Construct) cost, supplier's profits, the owner's cost, licensing and development costs, and a contingency. Even the cost of engineering the new turbine-generator and turbine island is included. It is as solid a number as one can get and the team of GE and B&V stand behind it.

It is important to note that this is an estimate for a single unit. The GE plan to commercialize the ABWR in the U.S. does not rely upon the simultaneous construction of 6 or 8 ABWR units.

IV. MAKING NUCLEAR A BETTER INVESTMENT

We need to get investors more excited about a new nuclear project and we do that by improving the IRR. It is also important to reduce the negative cash flows during the construction period since these would dilute the utility's overall earnings and diminish the value of the utility as an investment. This is not a good career path for those responsible for managing the utility.

IVA. The Obvious Ways

Reducing the capital cost of the plant is an obvious way to improve the financial attractiveness of the plant. In fact, reducing the capital cost from $1445/kw to $1300/kw increases the IRR by a full percentage point. With this in mind, the GE engineering team has identified a number of design changes that would reduce capital cost by about this amount and is currently evaluating these for implementation into the ABWR and ESBWR designs.

If two units were built at the same site and a year apart, then the capital cost of the second ABWR unit would be $1180/kw. This is a cost reduction of 18% or $240/kw. The IRR for a two-unit project would therefore be larger, in fact, a full percentage point higher.

Another obvious thing to do is sell the output of the plant at a higher price. This is not as facetious as it may seem on the surface. The location of the plant site has a significant influence on the price it receives for its electricity. Power pools such as PJM use locational marginal pricing (LMP) and others such as California use zonal pricing. Those interested in such things can find hourly spot prices for PJM at http://www.pjm.com/). The prices vary significantly by node or zone. For example, the PJM website indicates that the spot price on January 21, 2003 at Deer Creek 1 is $39.40 MWhr and is $60.70 per MWHR at Seneca.

If two units were built on the same site and a year apart, then the capital cost of the second ABWR unit would be $1180/kw, a savings of 18% or $240/kw compared to the cost of a single unit.

Wholesale prices are difficult to project since these are determined by the cost of natural gas, how many new plants are brought on line, and the demand. Nodal prices are even more difficult to predict over the long term since load centers and the grid itself change over time. No one can safely predict what electricity prices will be six years from now when the nuclear plant goes into commercial operation.

It would be wise therefore to sell most of the plant's output through long term bi-lateral contracts. Since the cost of producing nuclear electricity is stable and predictable over time, it is possible to offer industrial customers fixed prices for electricity (the energy as opposed to the T&D portion). Given the volatility of gas prices and the subsequent up-and-down of wholesale prices, industrial customers will find this attractive. Indeed when TVO, a Finnish utility, announced its decision to build a new nuclear plant,

they were contacted by over 50 industrial consumers interested in purchasing some portion of the output of the plant at a fixed rate. A nice mix would be to have 90% of the nuclear plant's output under long-term contract and the remaining 10% available to be sold in the spot market in order to take advantage of the periodic price spikes that do occur. The significance of selling most of the plant's output on a long-term basis, particularly if that means 10-year strips or longer, is that the risk associated with the utility's generating portfolio is reduced. Moreover, if industrial consumers are offered an attractive long-term contract in exchange for some commitment *in advance* of project start, as was the case with TVO, then the risk associated with the project is significantly reduced.

IV.B. Accelerated Depreciation

Because a nuclear project is capital intensive, accelerated depreciation of the plant's asset value will reduce the amount of income tax owed and thereby increase cash flows. The latter directly increases the IRR. If the accounting rules permitted 7-year MACRS (Modified Accelerated Cost Recovery) instead of the usual 40 year, straight-line depreciation, the IRR would increase by 0.65%.

There is justification for this change. MACRS is allowed for renewable energy projects as a way to encourage its use. Wind energy projects, for example, are eligible for 5-year MACRS. For the same reason--to encourage the use of an important source of energy--we would like to see legislation that would permit MACRS to be used for new nuclear capacity, new plants as well as power uprates.

Better technology and lower costs, MACRS and a Production Tax Credit have succeeded in bringing about a proliferation of new wind projects in recent years. This strikes us as a good blueprint to follow when it comes to new nuclear plants.

IV.C. Production Tax Credit

Since we brought up the Production Tax Credit for wind energy projects, let us propose that there be a PTC for nuclear plants as well. This would be in recognition of the fact that increases in output from current nuclear plants account for 2/3 of all emission free generation in the U.S. in recent years. Sound environmental policy must recognize the value of nuclear plants in terms of reducing NOx, SOx and CO2. There is no way, for example, for the U.S. to comply with the intent of the Kyoto treaty without the expanded use of nuclear power plants to meet future increases in demand.

It makes policy sense to encourage the construction and use of new nuclear plants by providing owner's with a Production Tax Credit (PTC), in the same way that owner's of wind energy facilities are given a 1.8 cents per kwhr PTC. A nuclear PTC of just 0.5 cents per kwhr for 10 years—just 1/3 the value of the wind PTC--would be sufficient to increase the IRR by 0.9%.

IV.D. Investment Tax Credit

Past economic stimulus packages created by Congress have contained provisions for tax credits given to capital investments that create jobs and improve the economy. An investment tax credit (ITC) on capital expenditures (equity portion only) made during the construction of the plant would have dual effect of increasing the project returns and mitigating the impact of negative cash flow during this time. A 10% ITC would increase the IRR by 0.45% and reduce the negative cash flow by nearly $50M during the peak year of construction.

IV.E. Leverage

Not so long ago, developers were building merchant power plants with highly leveraged project financing, that is, with debt of about 80%. As a result of the Enron debacle and the downturn of the wholesale market, lenders are wary and require substantially more equity from developers. For our analysis we used 50% debt and 50% equity in keeping with the current realities and the higher risk associated with nuclear construction.

It may be possible to reduce the equity requirements by demonstrating to lenders that risks are properly managed. We have written extensively on this subject (Reference 1) and believe that selection of a well-managed engineering and construction team that has experience building advanced plants assures investors that capital cost projections will not be exceeded and that the plant will be free of technical problems. GE and B&V bring this kind of experience to a project by virtue of having built two ABWRs in Japan and two more in Taiwan.

Let's say this kind of experience and risk management is worth a 5% reduction in equity requirements so that the debt to equity ratio is now 55-45. The discount rate would fall and the NPV would increase by an amount equivalent to 0.5% rise in IRR.

Table 2 summarizes all of these changes:

Table 2: Our Game Plan	IRR
Base case	12.00%
Reduce capital costs	+1.00
Accelerated depreciation	+0.65
Production tax credit	+0.90
Investment tax credit	+0.45
Risk management	+0.5%
	15.50%

These numbers should be sufficient to get investors and analysts excited about owning stock in this utility.
In light of the Bush administration's stated goal of having a new nuclear plant in commercial operation by 2010, we think those changes that require legislative or regulatory approvals are politically achievable. With these changes, owners and suppliers can clear the final economic hurdle standing in the way of a new U.S. nuclear plant. We look forward to seeing the following report in our newspapers:

First Nuclear Plant in U.S. Ordered
Reuters
May 4, 2003

SAN JOSE, CA (Reuters) — GE, Black & Veatch, and a consortium of utilities announced today that they have signed an agreement to proceed with the construction of an ABWR nuclear power plant. Stock prices of all companies climbed in heavy trading as investors reacted positively to the announcement.

This action by GE and utilities follows enactment last week of the Energy Policy Act of 2003. A key element of this legislation is the use of tax credits and accounting changes to stimulate the construction of new, advanced nuclear plants.

The ABWR plant, estimated to cost $1300/kw, will be built in California and sell into that state's wholesale markets. An excited Gov. Gray Davis told reporters "This solves all of our problems....

(continued on back page)

Figure 2: Another purely fictitious newspaper report but one that we would love to see.

V. WHAT ABOUT GAS PRICES?

As far as gas prices are concerned, we are likely to enter uncharted waters in the very near future, and this will accrue to the benefit of the ABWR. The dramatic decline in gas drilling productivity over the last three years, and over 200,000 MW of new natural gas power plants in the next two years could quite possibly be the start of a long term increase in gas prices. In the short term, aggravated by a colder-than-expected winter in the East, short-term prices could easily exceed the nearly $8.70/mmbtu gas experienced in January 2001. The California Energy Commission forecasts that gas prices in California will be between $4 and $4.50 per MBTU for the next five years, climbing to $5 per MBTU by the end of this decade. (Reference 2)

As gas is increasingly on the margin even current nuclear owners will benefit. A $1 per MBTU increase in gas prices would increase the IRR determined in this analyses by 2.5 percentage points, equivalent to about a $300/kw reduction in overnight costs.
Merchant companies like Calpine are certainly concerned about gas price uncertainty and the possibility of a sustained increase in prices. They can and do protect themselves by hedging and by purchasing their own supply of gas. However, these are limited means of coping and gas price increases can have unfavorable consequences as the article reproduced below clearly indicates. Most merchant companies do not, however, diversify (except for a bit of renewables) because their business model calls for focusing on one technology that in the case of Calpine is advanced combined cycle.

Integrated utilities, many of which are still subject to regulation, do diversify and in fact know what mix of capacity (baseload, intermediate, peaking) and fuel (gas, coal, nuclear, renewable) is optimal for their business conditions. A representative mix is 60% baseload, 20% intermediate, and 20% peaking although certainly not all utilities follow this recipe.

Technologies that use gas are not suitable for baseload purposes on a sustained basis not only for technical reasons but because they have trouble competing with existing coal and nuclear plants which get dispatched first. During the recent "boom" years utilities ordered or built significant amounts of new gas fired plants to the point that the actual mix strayed pretty far from the desired mix. It was for exactly this reason that many utilities began considering their baseload options

Calpine's Profit Falls 50% As Its Fuel Costs Skyrocket
DOW JONES NEWSWIRES
November 5, 2002

SAN JOSE -- Calpine Corp.'s net slumped 50% in the third-quarter net income amid higher costs for fuel and for project under development as well as a decline in prices.

The energy concern on Tuesday posted net income of $161.3 million, or 36 cents a share, down from 320.8 million, or 88 cents a share, a year earlier.

The latest results included a gain of $12.9 million, or three cents a share, from the sale of discontinued operations. The company also booked charges totaling five cents a share, including severance and other costs, deferred project-cost write-offs and a loss on the sale of turbines.

Excluding these items, the company said it posted recurring earnings of $170.9 million, or 38 cents a share, below its August guidance for earnings between 40 cents and 55 cents a share. Revenue, meanwhile, slipped 1% to $2.5 billion from $2.52 billion.

Fuel expenses jumped 60% to $525.5 million, and project development costs more than quadrupled to $23.9 million.

including clean coal and nuclear. The sense of urgency diminished as soon as we entered the current "bust" years but new baseload capacity, including nuclear capacity, is still being actively considered.

Better technology and lower costs, a short MACRS and a Production Tax Credit have succeeded in bringing about a proliferation of new wind projects in recent years. This strikes us as a good blueprint to follow when it comes to new nuclear plants.

There are signs already that a recovery is anticipated. Consider this revealing report from the February 3, 2003 edition of Power Week:

"PacifiCorp said last week it will need more than 4,000 MW of additional generation capacity by 2014 to meet a projected load growth rate of about 2% per year across its six state service area. Including long-term power purchases and new capacity additions, PacifiCorp's energy resource portfolio would increase about 40% over current levels, according to the company's 162-page Integrated Resource Plan 2003 submitted state regulatory commissions The plan takes into account retirement of aging plants and supply contracts.

The plan calls for diversification resources, including wind, geothermal, gas, coal and demand-side management. PacifiCorp said it thoroughly analyzed energy resource options various scenarios that accounted for possible changes in weather, electricity use, fluctuations in fuel costs, plant performance and other considerations.

The result is a plan for 2,100 MW new baseload capacity, 1,200 MW of peaking generation, 700 MW load shaping contracts and other resources, 1,400 MW of renewable energy, and up to 450 average MW load to be avoided through demand-side management programs."

To reinforce the points made in this paper, we note that:

- the Plan calls for resource diversification
- half of the additional capacity is new baseload.

We think that the best way to meet these two needs is the addition of new nuclear capacity.

VI. SUMMARY

There is an important role for nuclear power to play in meeting the needs of U.S. utilities whether in a regulated setting or in deregulated markets. The risks associated with building the first few nuclear plants in a deregulated market will require higher than normal returns. We have advanced several proposals that would make investing in a new nuclear power plant more financially attractive. These would hasten the introduction of advanced nuclear technology in the U.S., something we feel is desirable on many levels. ❐

VII. REFERENCES

1. J.R. Redding, *Cost, Schedule and Risk Management: The Building Blocks of a U.S. Nuclear Project*, Proceedings of PowerGen International Conference, Orlando Florida, December, 2002.

2. California Energy Commission, "Comparative Cost of California Central Station Electricity Generation Technologies", Staff Draft Report, February 13, 2003. Available on the Internet at http://www.energy.ca.gov/energypolicy/documents/2003-02-25+26_workshop/2003-02-11_100-03-001SD.PDF

Attachment 9

BODINGTON & COMPANY

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December 17, 2004

Mr. Seth Parker
Principal
Levitan & Associates, Inc.
100 Summer St. #3200
Boston, MA 02110

Re: **Discount Rate for Valuation of Indian Point**

Dear Mr. Parker:

In this memorandum we present the basis for a discount rate to calculate the value of Indian Point. Indian Point is a nuclear power plant that is not utility rate-based property and is therefore exposed to merchant risks.

In sum, there are no "pure play" merchant transactions or existing literature from which to draw a discount rate. Accordingly, we considered business and financial risks, and then employed the capital asset pricing model ("CAPM") and data on KGen's recent acquisition of gas-fired merchant projects to make two independent estimates of a valuation discount rate appropriate for Indian Point. The data and methods corroborate each other and together support a discount rate of approximately 18.5%.

Please note that this work reflects an initial review of literature and data. More detailed reviews and analyses may be necessary to support thorough explanations and testimony in the future.

First, the value of Indian Point may be estimated using several different measures of income and each measure of income has its own appropriate discount rate. For this evaluation, we have estimated the rate to be applied to debt-free after-tax net cash flow ("ATNCF").

- For valuation of un-levered ATNCF, the appropriate discount rate is the weighted average cost of capital ("WACC") for a potential buyer of Indian Point.[1]
- Debt-free ATNCF is a measure of net cash flow including income tax benefits and costs but excluding all considerations of potential debt financing.
- Tax rates assumed are a 35.0% maximum marginal Federal rate and an 8.5% maximum marginal New York State rate, for a combined rate of 40.5%.[2]
- Valuation date is January 1, 2005.

I. Review of Transactions and Literature

A detailed review of power project transactions and related discount rate literature is beyond the scope of this Exhibit. Subject to that qualification, examples of project sales and published comments concerning related discount rates are addressed below.

[1] Note that WACC is not the same thing as internal rate of return ("IRR"). WACC is the expected cost of capital, IRR is a measure of expected or actual return on capital. In capital budgeting theory, IRR should exceed WACC for a prudent investment.
[2] 0.35*(1-0.085)+0.085=0.4053

Drawing from a log of sales of power projects during the last several years, the following tables presents examples of both nuclear and non-nuclear merchant project transactions.

Examples of Recent Nuclear and Merchant Project Sales

Buyer	Seller	Project	Year
Nuclear Projects			
Entergy	Yankee owners	Yankee	2002
Exelon	British Energy	Clinton, TMI1, Oyster Creek	2003
FPL Energy	Seabrook owners	Seabrook	2002
Texas Genco et al	AEP	South Texas	2004
Non-Nuclear Merchants			
Brascan	Reliant	Orion Portfolio	2004
Calpine	NRG Bank Group	Brazos Valley	2004
Centric PLC	FPL / El Paso	Bastrop	2004
KGen	Duke	SE Portfolio	2004

In addition to the nuclear transactions noted above, Dominion agreed to purchase the Kewaunee facility in Wisconsin during late 2003. The Wisconsin Public Service Commission recently rejected an application for a change in ownership. While this and the transactions noted above do show that there is a market for nuclear and merchant facilities, none of the buyers is a stand-alone or "pure play" nuclear merchant entity with its own publicly-traded securities. Accordingly, none of the deals done to date provide a direct observation of WACC for the buyer of a nuclear merchant.

Discount rates for nuclear generation have been addressed in several recent publications.

- Standard & Poors ("S&P"): In "Time for a New Start for U.S. Nuclear Energy?" and "Evaluating Risks Associated with Nuclear Power Generation" S&P reviewed many issues concerning nuclear power but did not estimate WACC.
- Geoffrey Rothwell: "Triggering Nuclear Development" presents a real options approach to estimating a discounting rate and more information on the methodology appears in "What Construction Cost Might Trigger New Nuclear Power Plant Orders?"[3] Rothwell focuses on the cost uncertainties associated with nuclear generation and calculates a real discount rate of 12% for nuclear generation using a real options approach. He applies this rate to "net revenue", a measure he defines as pre-tax operating income. These papers are primarily silent on the incremental risks associated with merchant operations. Accordingly, this rate is not a WACC for application to Indian Point's merchant ATNCF. In addition, real discount rates cannot be easily adjusted for application to nominal ATNCF because depreciation is fixed at a point in time and then affects income taxes for many years in the future regardless of inflation.
- Messrs Redding, Muench and Graber: These authors with GE Nuclear Energy, Black & Veatch and Energy Path presented "The Business Case for Building a New Nuclear Plant in the U.S." during 2003 in Spain.[4] They describe a 12% IRR as a minimum expectation and do address income taxes, financing and merchant risks. They also cite discussions with CEOs to support the assertion that investors expect a 20% return on equity for nuclear and 16% for natural-gas-fired combined cycle

[3] Rothwell, Geoffrey, "Triggering Nuclear Development", Public Utilities Fortnightly, May 2004, pp 47-51, see page 50. Rothwell, Geoffrey, "What Construction Cost Might Trigger New Nuclear Power Plant Orders?", Stanford Institute For Economic Policy Research, March 31 2004, 26 pages, see page 6 and the appendix definition of net revenue.

[4] Proceedings of ICAPP 03', Cordoba, Spain, May 4-7 2003, Paper 3188, see page 2.

investments, a nuclear risk-premium of 4%. However, the basis for 12% is not presented in detail and several of their calculations appear contrary to accepted financial theory.

Finally, Entergy purchased Fitzpatrick and Indian Point Unit 3 from the New York Power Authority in November 2000 and Indian Point Unit 2 from Consolidated Edison in September 2001. Entergy publishes some business-segment-specific data and does provide selected information on these projects and its nuclear business unit.[5] According to these data, the nuclear unit's return on average invested capital has been 8.5% to 12.2%, return on common equity has been 16.4% to 27%. The capital structure has been 23.5% to 45%, averaging approximately 30%, debt. Entergy holds a Note to the New York Power Authority relating to the purchase of Fitzpatrick and Indian Point. Entergy's forecast of interest payments on this Note implies an interest rate between 6% and 7%. While this cost of capital data does concern the subject property, the data are not reflective of terms for a merchant nuclear project as of January 2005. Those terms and financial performance instead reflect what are now embedded costs and a seller-financing Note negotiated between Entergy and a seller during 2000.

II. CAPM-Based Estimate of WACC

We first employ the CAPM to estimate the cost of equity and then combine that with an estimate of the cost of debt and a reasonable capital structure to calculate WACC. CAPM requires estimates of the risk free return, beta, and the equity risk premium.

- We selected companies that have substantial merchant power generation business units and obtained the most recent Value Line and S&P data on these companies. All the data are dated during December or Fall 2004.
- Risk-free return is the yield on 20 year Treasuries as of early December 2004.
- Beta is estimated by and taken from the most recent Value Line analysis of each company.
- Market risk premium is 7.0% and taken from recent Ibbottsen Associates publications. This represents an average of the full-period income and total asset returns estimated by Ibbottsen.
- Actual current cost of debt does not reflect the current marginal cost of debt capital because it may include existing fixed rate debt. Accordingly, we obtained the S&P rating for each company's debt and have employed the current market-based yield for each rating. Reuters publishes yield spreads for issues of different quality.
- Capital structures are also based on data published by Value Line and S&P.

[5] www.entergy.com/Investor/Financial/assual.asp See 2002 Investor Guide, pages 49-51.

CALCULATION OF WACC

	Material Merchant Exposure					Nuclear	
Company	AES	Calpine	Duke	FPL Group	Reliant	Dominion	Entergy
COST OF EQUITY							
CS symbol	AES	CPN	DUK	FPL	RRI	D	ETR
Risk free rate	4.90	4.90			4.90		
Beta	1.85	2.10			1.75		
Market risk premium	7.00	7.00			7.00		
CAPM result	17.85	19.60			17.15		
COST OF DEBT							
S&P Rating, range	B+/CCC	B/CCC			B+/B-		
Marginal cost of B/C debt	12.00	12.00			12.00		
WACC							
Combined tax rate	40	40			40		
Capital Structure							
Common Equity	8	2	40	44	51	40	53
Preferred Equity							2
Debt	92	98	60	56	49	60	45
Result	8.03	7.50			12.23		

Several facts must guide interpretation of the data above.

- None of the companies are "pure play" merchants. While DUK, FPL, D and ETR do have merchant exposure they also have substantial regulated assets and thus we omit their cost of capital data from the table above. AES, CPN and RRI have more merchant exposure but do also own contracted assets.
- The high leverage of AES and CPN is an artifact of the late 1990s and early 2000s when debt financing was more available for merchant projects and equity valuations were high. Little debt, at any price, is now available for merchant financings. The figures represent the so-called "embedded" capital structure not the marginal structure required to finance a new merchant acquisition.

Accordingly, the data above do support a beta of approximately 2.00 and a corresponding cost of equity of approximately 19%. They also show that the cost of debt should be consistent with current yields on sub-investment-grade B and C rated issues. The estimated average current yield on B/C-rated debt is approximately 12%. Further, the likely capital structure involves less than 50% debt. Entergy's nuclear unit capital structure implies that reasonable leverage is less than 30%.

III. KGen Cost of Capital

Duke Energy sold a portfolio of merchant projects to KGen Partners during 2004, and several aspects of the financing provide valuable information on the potential cost of capital for a buyer of Indian Point.

Duke Energy North America ("DENA") developed numerous merchant projects and had a portfolio of eight projects in four states located within the in the Southeast Electric Reliability Council ("SERC"). As DENA's heavy investment in merchant generation failed to yield current earnings, asset sales began. Lackluster bids forced Duke to write down the value of the plants three times and the portfolio was ultimately sold to KGen Partners ("KGgen"). KGen is owned by MatlinPatterson and the firm previously purchased interests in NRG.

Duke's southeast merchant portfolio included three combined cycle projects and five peakers. Combined cycle projects accounted for 2,360 MW of the 5,280 MW total, all are natural-gas fired, all went into service during 2002, and after a multiple round auction the acquisition closed on August 5 2004 with KGen.

The transaction had three key components; cash, a high-yield note and a power purchase agreement. Total cash was $425 MM. Regarding the high-yield note, Duke holds a $50 MM receivable from KGen. This note bears interest at LIBOR +14.5% and is secured by a fourth lien on KGen's owner. Interest compounds quarterly and both interest and principal are due in a balloon payment after 7.5 years. Finally, the transaction included a seven-year power sales agreement between KGen and Georgia Power concerning the Murray combined cycle facility. Duke also operates this project under a long-term operations and maintenance agreement.

The terms for the high-yield note establish a lower bound on the cost of equity, an upper bound on the cost of debt and also show an example of capital structure.

- As of mid-December 2004 LIBOR is approximately 2.45% hence the full rate of KGen's note is approximately 16.95%.
- That rate is a lower bound on the cost of equity. Based on Ibbottson, Brigham & Houston, business risks and financial risks, a reasonable equity risk premium over the debt rate is approximately 6%.

CALCULATION OF WACC

Company	KGen
COST OF EQUITY	
Sub debt rate	16.95
Premium	6.00
Result	22.95
COST OF DEBT	
S&P Rating, range	Unrated
KGen High Yield Note	16.95
WACC	
Combined tax rate	40.00
Capital Structure	
Equity	89
Debt	11
Result	21.54

IV. WACC for Indian Point

Building on the CAPM and KGen estimates of WACC presented above, in this Section IV we now estimate a reasonable discount rate for valuing Indian Point's potential un-levered ATNCF.

- KGen data were presented above and are repeated below.
- The market-traded companies with substantial merchant exposure noted above included AES, CPN and RRI. Cost of equity and debt data based on these companies appears below. Regarding capital structure, all three have more embedded leverage than appears realistic in today's markets. The 70:30 ratio below is both lower than embedded leverage and based on the actual leverage for Indian Point shown in Entergy's financial statements.

CALCULATION OF WACC

Company	KGen	Market-Traded Merchants	Indian Point Estimate
COST OF EQUITY			
Sub deat rate	16.95		
Preumium	6.00		
Risk free rate		4.90	
Beta		2.00	
Market risk premium		7.00	
Result	22.95	18.90	20.93
COST OF DEBT			
S&P Rating, range	unrated	B/C	B/C
Yield	16.95	12.00	14.48
WACC			
Combined tax rate	40.00	40.00	40.00
Capital Structure			
Common Equity	89	70	80
Debt	11	30	20
Result	21.54	15.39	18.48

The 18.5% WACC for Indian Point calculated above is based on an average of KGen and the Market-Traded Merchants. While many issues are important and many variations could be considered, this result is broadly consistent with market data.

- A cost of equity of approximately 21% is similar to Messrs Redding, Muench and Graber findings about investors expecting a 20% return on equity. This cost of equity is also implied by a beta of approximately 2.40, and such a beta is consistent current perceptions of the material non-diversifiable risks associated with merchant and nuclear operations.
- A 15% cost of debt is and should be both above the cost of more-secure issues and below the cost of KGen's subordinated note secured by only a fourth lien.
- The spread between 21% and 15%, approximately 6%, is consistent with the spreads found by Ibbottson and Brigham & Houston for the difference between the costs of equity and debt.
- An 80:20 capital structure is consistent with both difficult financing conditions for merchant projects and Indian Point's marginal costs and location in a market less troubled than SERC.

Attachment 10

Formula for Fair Market Value

Basic Equation

Fair market value (FMV) of a business is derived from the unleveraged after-tax net cash flow ($ATNCF_u$) that a willing, informed buyer would expect from its purchase. $ATNCF_u$ is a string of cash flows consisting of the purchase price as a negative (outward) cash flow, earnings before interest, taxes, depreciation, and amortization (EBITDA) less associated income taxes, and the tax shield provided by depreciation of the purchase price over the life of the business. FMV is the purchase price that makes the present value of the $ATNCF_u$ stream zero when discounted at the appropriate weighted average cost of capital (WACC):

$$0 = PV(ATNCF_u) = -FMV + PV(EBITDA)*(1-TR) + PV(Dep\ of\ FMV)*TR$$

TR = Effective income tax rate
PV( ) = Present value of a string of cash flows at discount rate of WACC
Dep of FMV = String of annual depreciation charges on FMV as a purchase cost

The equation above requires iteration on an estimate of FMV. The iteration can be avoided in this instance by using a depreciation factor in each year (the ratio of the depreciation charge to the amount being depreciated) in the present value term, and rearranging:

$$FMV = PV(EBITDA) * (1 - TR) / \{ 1 - TR * PV(DepFac) \}$$

FMV of License Renewal Option

Ownership of IP 2&3 carries with it an implicit option to re-license the units for operation beyond their current license expiry dates. To exercise the option, the owner must make substantial capital investments. A decision to proceed with license renewal would be based on the owner's perception of future revenues and expenses (EBITDA) relative to the investment required. If the present value of the $ATNCF_u$ associated with license renewal is positive, the owner would be inclined to proceed. A positive present value would increase the price a buyer might be willing to pay for the facility, after adjusting for the perceived probability of renewal application approval and the tax treatment of the amortization of any premium paid for the option.

$$V_{total} = \text{Original License Term FMV} + \text{License Renewal Option FMV}$$

$$= V_{OLT} + V_{LRO}$$

$$V_{OLT} = PV(EBITDA_{OLT}) * (1 - TR) / \{ 1 - TR * PV(DepFac_{OLT}) \}$$

$$V_{LRO} = P_{approval} * [\ PV(EBITDA_{LRO}) * (1 - TR) - PV(CapEx_{LRO}) * \{1 - TR * PV(DepFac_{LRO})\}\ ] / \{1 - TR * PV(DepFac_{LRO})\}$$

$EBITDA_{OLT}$ = EBITDA for original license term

$DepFac_{OLT}$ = depreciation factor for V_{OLT}

$P_{approval}$ = probability of approval of renewal application

$EBITDA_{LRO}$ = EBITDA for license renewal period

$CapEx_{LRO}$ = capital expenditure to achieve renewal

$DebFac_{LRO}$ = depreciation factor series for V_{LRO} and $CapEx_{LRO}$

Attachment 11

United States General Accounting Office

GAO

Report to the Honorable Edward J. Markey, House of Representatives

October 2003

NUCLEAR REGULATION

NRC Needs More Effective Analysis to Ensure Accumulation of Funds to Decommission Nuclear Power Plants

GAO

Accountability * Integrity * Reliability

GAO-04-32

October 2003

NUCLEAR REGULATION

NRC Needs More Effective Analysis to Ensure Accumulation of Funds to Decommission Nuclear Power Plants

GAO
Accountability·Integrity·Reliability
Highlights

Highlights of GAO-04-32, a report to the Honorable Edward J. Markey, House of Representatives

Why GAO Did This Study

Following the shutdown of a nuclear power plant a significant radioactive waste hazard remains until the waste is removed and the plant site decommissioned. In 1999, GAO reported that the combined value of the owners' decommissioning funds was insufficient to ensure enough funds would be available for decommissioning. GAO was asked to update its 1999 report and to evaluate the Nuclear Regulatory Commission's (NRC) analysis of the owners' funds and its process for acting on reports that show insufficient funds.

What GAO Recommends

NRC should (1) develop an effective method for determining whether owners are accumulating decommissioning funds at sufficient rates and (2) establish criteria for taking action when it is determined that an owner is not accumulating sufficient funds. NRC disagreed with these recommendations suggesting that its method is effective and that it is better to deal with unacceptable levels of financial assurance on a case-by-case basis. GAO continues to believe that limitations in NRC's method reduce its effectiveness and without criteria, NRC might not be able to ensure owners are accumulating decommissioning funds at sufficient rates.

www.gao.gov/cgi-bin/getrpt?GAO-04-32.

To view the full product, including the scope and methodology, click on the link above. For more information, contact Jim Wells, at (202) 512-6877 or WellsJ@gao.gov.

What GAO Found

Although the collective status of the owners' decommissioning fund accounts has improved considerably since GAO's last report, some individual owners are not on track to accumulate sufficient funds for decommissioning. Based on our analysis and most likely economic assumptions, the combined value of the nuclear power plant owners' decommissioning fund accounts in 2000—about $26.9 billion—was about 47 percent greater than needed at that point to ensure that sufficient funds will be available to cover the approximately $33 billion in estimated decommissioning costs when the plants are permanently shutdown. This value contrasts with GAO's prior finding that 1997 account balances were collectively 3 percent below what was needed. However, overall industry results can be misleading. Because funds are generally not transferable from funds that have more than sufficient reserves to those with insufficient reserves, each individual owner must ensure that enough funds are available for decommissioning its particular plants. We found that 33 owners with ownership interests in a total of 42 plants had accumulated fewer funds than needed through 2000 to be on track to pay for eventual decommissioning. In addition, 20 owners with ownership interests in a total of 31 plants recently contributed less to their trust funds than we estimate they needed to put them on track to meet their decommissioning obligations.

NRC's analysis of the owners' 2001 biennial reports was not effective in identifying owners that might not be accumulating sufficient funds to cover their eventual decommissioning costs. In reviewing the 2001 reports, NRC reported that all owners appeared to be on track to have sufficient funds for decommissioning. In reaching this conclusion, NRC relied on the owners' future plans for fully funding their decommissioning obligations. However, based on the owners' recent actual contributions, and using a different method, GAO found that several owners could be at risk of not meeting their financial obligations for decommissioning when these plants stop operating. In addition, for plants with more than one owner, NRC did not separately assess the status of each co-owner's trust funds against each co-owner's contractual obligation to fund decommissioning. Instead, NRC assessed whether the combined value of the trust funds for the plant as a whole was reasonable. Such an assessment for determining whether owners are accumulating sufficient funds can produce misleading results because owners with more than sufficient funds can appear to balance out owners with less than sufficient funds even, though funds are generally not transferable among owners. Moreover, NRC has not established criteria for taking action if it determines that an owner is not accumulating sufficient funds.

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Abbreviations

FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
NRC	Nuclear Regulatory Commission
SAFSTOR	Safe Storage

Abbreviations

FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
NRC	Nuclear Regulatory Commission
SAFSTOR	Safe Storage

GAO
Accountability * Integrity * Reliability
United States General Accounting Office
Washington, D.C. 20548

October 30, 2003

The Honorable Edward J. Markey
House of Representatives

Dear Mr. Markey:

Following the retirement of a nuclear power plant and removal of the plant's spent or used fuel, a significant radioactive waste hazard remains until the waste is removed and disposed of, and the plant site decommissioned.[1] Decommissioning of existing plants is expected to cost nuclear power plant owners about $33 billion dollars.[2] The Nuclear Regulatory Commission (NRC), which licenses nuclear power plants, requires plant owners to submit biennial reports on decommissioning funding that, among other things, provide financial assurance that enough funding will be available when the power plants are retired.

In 1999, we reported that the combined value of the owners' decommissioning trust fund accounts (as of the end of 1997) was 3 percent less than needed to ensure that enough funds would be available when the plants are retired.[3] In addition, we found that NRC had not established criteria for responding to unacceptable levels of financial assurance. In December 2001, we reported that transfers of plant licenses among companies stemming from economic deregulation and the restructuring of the electricity industry had, in many cases, increased assurances that new plant owners would have sufficient decommissioning funds when their plants are retired.[4] Nevertheless, in some instances, NRC's evaluation of the adequacy of funding arrangements was not rigorous enough to ensure that decommissioning funds would be adequate.

[1]Retirement means the permanent cessation of a plant's operation.

[2]Costs in 2000 present value dollars and are for decommissioning the plant site only and exclude costs for cleaning up nonradiological hazards and storing spent fuel.

[3]U.S. General Accounting Office, *Nuclear Regulation: Better Oversight Needed to Ensure Accumulation of Funds to Decommission Nuclear Power Plants*, GAO/RCED-99-75 (Washington, D.C.: May 3, 1999).

[4]U.S. General Accounting Office, *Nuclear Regulation: NRC's Assurances of Decommissioning Funding during Utility Restructuring Could Be Improved*, GAO-02-48 (Washington, D.C.: Dec. 3, 2001).

In this context, you asked us to update our earlier findings on the adequacy of owners' decommissioning funds. Specifically, this report (1) assesses the extent to which nuclear plant owners are accumulating funds at sufficient rates to pay decommissioning costs when their plants' licenses expire and (2) evaluates NRC's analysis of the owners' 2001 biennial reports and its process for acting on reports that show unacceptable levels of financial assurance.

As part of our review, we collected data from the 2001 biennial reports on estimated decommissioning costs and actual decommissioning trust fund balances, generally as of December 31, 2000, for 122 nuclear power plants licensed by NRC. In addition, we surveyed the owners of the plants to determine how the trust fund balances were invested in 2000 and to identify the annual amounts that the owners had contributed to the trust funds in recent years. Eighty-two percent of the owners responded to our survey.[5] Using an approach similar to that used for our 1999 report,[6] we analyzed both the combined efforts of all owners to accumulate funds to decommission all of the nuclear plants and each individual owner's efforts to accumulate funds for decommissioning each of its plants. For our analysis, we estimated the most likely future values of key assumptions, such as decommissioning costs, earnings on the decommissioning funds' assets, and the operating life of each plant. To address the inherent uncertainty associated with forecasting outcomes many years into the future, we also analyzed the effect of using pessimistic and optimistic values for these key assumptions. To evaluate NRC's analysis of the biennial reports and its process for acting on reports that have not satisfied decommissioning funding assurance requirements, we reviewed NRC's guidelines and policies for analyzing these reports and interviewed NRC's officials about how they conducted their analysis. Appendix I provides more detail on the scope and methodology of our review.

Results in Brief

Although the collective status of the owners' decommissioning fund accounts has improved since our last report, some individual owners are not on track to accumulate sufficient funds for decommissioning. Using

[5]We administered the survey to 110 owners. Since then, the ownership of some plants has changed and as a result, the total number of owners has declined. Our analysis assesses 222 trust funds held by 99 owners.

[6]GAO/RCED-99-75.

our most likely economic assumptions, the combined value of the nuclear plant owners' trust funds in 2000—about $26.9 billion—was about 47 percent greater than needed at that point to ensure that sufficient funds will be available to cover the approximately $33 billion in estimated decommissioning costs when the plants are retired. This value contrasts with account balances that collectively were 3 percent below what was needed by the end of 1997. Overall industry results can be misleading, however. Because NRC does not allow owners to transfer funds from a trust fund with sufficient reserves to one without sufficient reserves, each individual owner must ensure that enough funds are available for decommissioning its particular plants. We found that 33 owners of all or parts of 42 different plants had accumulated less funds than we estimated they needed to have through 2000 to be on track to pay for eventual decommissioning. Under our most likely assumptions, these owners will have to increase the rates at which they accumulate funds to meet their future decommissioning obligations. Of the 33 owners, 26 provided contributions information for our survey. Of these 26 owners, only 8 appeared to be making up their shortfalls with recent increases in contributions to their trust funds.

NRC's analysis of the owners' 2001 biennial reports was not effective in identifying owners that might not be accumulating sufficient funds to cover their eventual decommissioning costs. In reviewing the 2001 reports, NRC reported that all owners appeared to be on track to have sufficient funds for decommissioning. In reaching this conclusion, NRC relied on the owners' future plans for fully funding their decommissioning obligations. However, based on the actual contributions the owners recently made to their trust funds, we found that several owners could risk not meeting their financial obligations for decommissioning when these plants are retired. In addition, for the plants with more than one owner, NRC did not separately assess the status of each co-owner's trust funds against the co-owner's contractual obligation to fund decommissioning. Instead, NRC assessed whether the combined value of the trust funds for each plant as a whole was reasonable. Such an assessment for determining whether owners are accumulating sufficient funds can produce misleading results because owners with more than sufficient funds can appear to balance out owners with less than sufficient funds, even though funds are generally not transferable among owners. Furthermore, NRC has not established criteria for responding to any unacceptable levels of financial assurance. Accordingly, we are recommending that NRC develop and use an effective method for determining whether owners are accumulating funds at

sufficient rates and establish criteria for responding to unacceptable levels of financial assurance.

Background

NRC's primary mission is to protect the public health and safety, and the environment, from the effects of radiation from nuclear plants, materials, and waste facilities. Because decommissioning a nuclear power plant is a safety issue, NRC has authority to ensure that owners are financially qualified to decommission these plants.

Of the 125 nuclear power plants that have been licensed to operate in the United States since 1959, 3 have been completely decommissioned. Of the remaining 122 plants, 104 currently have operating licenses (although 1 has not operated since 1985), 11 plants are in safe storage (SAFSTOR) awaiting active decommissioning,[7] and 7 plants are being decommissioned. At the time of our analysis, 43 plants were co-owned by different owners.

NRC regulations limit commercial nuclear power plant licenses to an initial 40 years of operation but also permit such licenses to be renewed for additional 20 years if NRC determines that the plant can be operated safely over the extended period. NRC has approved license renewals for 16 plants (as of August 20, 2003).

In 1988, NRC began requiring owners to (1) certify that sufficient financial resources would be available when needed to decommission their nuclear power plants and (2) require them to make specific financial provisions for decommissioning.[8] In 1998, NRC revised its rules to require plant owners to report to the NRC by March 31, 1999, and at least once every 2 years thereafter on the status of decommissioning funding for each plant or proportional share of a plant they own.[9] Under NRC requirements, the

[7]SAFSTOR involves placing the stabilized and defueled facility in storage for a time followed by final decontamination and dismantlement, and license termination.

[8]NRC licenses include all co-owners as co-licensees; in general, one owner is authorized to operate the facility while the others are authorized only to have an ownership interest. Co-owners generally divide costs and output from their power plants by using a contractually defined pro rata share standard.

[9]U.S. Nuclear Regulatory Commission, *Financial Assurance Requirements* (Sept. 22, 1998), 63 Fed. Reg. 50465.

owners can choose from one or more methods, including the following, to provide decommissioning financial assurance:

- prepayment of cash or liquid assets into an account segregated from the owner's assets and outside the owner's administrative control;
- establishment of an external sinking fund maintained through periodic deposit of funds into an account segregated from the owner's assets and outside the owner's administrative control;
- use of a surety method (i.e., surety bond, letter of credit, or line of credit payable to a decommissioning trust account), insurance, or other method that guarantees that decommissioning costs will be paid; and
- for federal licensees, a statement of intent that decommissioning funds will be supplied when necessary.

In September 1998, NRC amended its regulations to restrict the use of the external sinking fund method in deregulated electricity markets. Prior to this time, essentially all nuclear plant owners chose this method for accumulating decommissioning funds. However, under the amended regulations, owners may rely on periodic deposits only to the extent that those deposits are guaranteed through regulated rates charged to consumers.

In conjunction with its amended regulations, NRC issued internal guidance, describing the process for reviewing the adequacy of a prospective owner's financial qualifications to safely operate and maintain its plant(s) and the owner's proposed method(s) for ensuring the availability of funds to eventually decommission the plant(s).[10] The guidance outlines a method for evaluating the owner's financial plans for fully funding decommissioning costs. In addition, the guidance states that, except under certain conditions, the NRC reviewer should, when plants have multiple owners, separately evaluate each co-owner's funding schedule for meeting its share of the plant's decommissioning costs.[11]

[10]U.S. Nuclear Regulatory Commission, *Standard Review Plan on Power Reactor Licensee Financial Qualifications and Decommissioning Funding Assurance*, NUREG 1577, Rev. 1, March 1999.

[11]Under NRC's guidance, co-owners trust funds can be collectively evaluated when the lead licensee agrees to coordinate funding documentation and reporting for all the co-owners.

Despite Industry-wide Improvement, Some Owners of Nuclear Power Plants Are Not Accumulating Sufficient Decommissioning Funds

Using our most likely economic assumptions, the combined value of the nuclear power plant owners' decommissioning trust funds was about 47 percent higher at the end of 2000 than necessary to ensure accumulation of sufficient funds by the time the plants' licenses expire. This situation contrasts favorably with the findings in our 1999 report, which indicated that the industry was about 3 percent below where it needed to be at the end of 1997 to ensure that enough funds would be available. However, because owners are not allowed to transfer funds from a trust fund with sufficient reserves to one without sufficient reserves, overall industry sufficiency can be misleading. When we individually analyzed the owners' trust funds, we found that 33 owners for several different plants had not accumulated funds at a rate that would be sufficient for eventual decommissioning.

Collectively the Nuclear Power Industry Is on Pace to Accumulate More Than Sufficient Funds for Decommissioning

Through 2000, the owners of 122 operating and retired nuclear power plants collectively had accumulated about 47 percent more funds than would have been sufficient for eventually decommissioning, using our most likely economic assumptions. Specifically, the owners had accumulated about $26.9 billion—about $8.6 billion more than we estimate they needed at that point to ensure sufficient funds. This situation contrasts with the findings in our 1999 report, which indicated that the industry had accumulated about 3 percent less than the amount we estimated it should have accumulated by the end of 1997.

Using alternative economic assumptions changes these results. For example, under higher decommissioning costs and other more pessimistic assumptions, the analysis shows that the combined value of the owners' accounts would be only about 0.2 percent above the amount we estimate the industry should have collected by the end of 2000. (See app. II for our results using more optimistic assumptions.)

The collective improvement in the status of the owners' trust funds (under most likely assumptions) since our last report is due to three main factors. First, all or parts of the estimated decommissioning costs were prepaid for 15 plants when they were sold to new owners. For example, the seller prepaid $396 million when the Pilgrim 1 nuclear plant was sold in 1998 for the plant's scheduled decommissioning in 2012. Second, for 16 other plants, NRC approved 20-year license renewals, which will provide additional time for the owners to make contributions and for the earnings to accumulate on the decommissioning fund balances. Third, owners earned a higher rate of return on their trust fund accounts than we projected in our 1999 report. For example, the average return on the trust funds of owners who responded to our survey was about 8.5 percent[12] (after-tax nominal return) per year, from 1998 through 2000, instead of the approximately 6.25 percent per year we had assumed. The higher return was a result of the stronger than expected performance of financial markets in the late 1990s.[13] Since that time, however, the economy has slowed and financial markets—equities in particular—have generally performed poorly.

Several Owners Are Not Accumulating Sufficient Funds for Decommissioning Their Plants

In contrast to the encouraging industry-wide results, when we analyzed the owners' trust fund accounts individually, we found that several owners were not accumulating funds at rates that would be sufficient to pay for decommissioning if continued until their plants are retired. Each owner has a trust fund for each plant that it owns in whole or in part. For example, the Exelon Generation Company owns all or part of 20 different plants. For this analysis, we assessed the status of 222 trust funds for 122 plants owned in whole or part by 99 owners. As shown in table 1, using our most likely assumptions, 33 owners of all or parts of 42 different plants (50 trust funds) had accumulated less funds than needed through 2000 to be on track to pay for eventual decommissioning (see app. II for details).[14] Thirteen of these

[12]Based on 72 owners who provided after-tax rates of return for 1998, 1999, and 2000. These owners' trust funds accounted for about 71 percent of the total trust funds in 2000.

[13]For 2000 (the only year for which we have data on fund allocations), on average, owners allocated their funds rather evenly between equities and fixed income assets (see app. I for details). Investment plans such as pension funds that invested more heavily in equities may have earned a greater overall return during this period.

[14]Some owners whom we estimate are below the benchmark have a parent company guarantee or other method to support financial assurance obligations. However, we did not evaluate the adequacy of these provisions. See app. II, table 4.

plants were shut down before sufficient funds had been accumulated for decommissioning. Although the remaining 78 owners of all or parts of 93 plants (172 trust funds) had accumulated more funds than we estimate they needed to have at the end of 2000, funds are generally not transferable from owners who have more than sufficient reserves to other owners who have insufficient reserves. Under our most likely assumptions, the owners whom we estimate to be behind will have to increase the rates at which they accumulate funds to meet their eventual decommissioning financial obligations.

For our analysis, we compared the trust fund balance that individual owners had accumulated for each plant by the end of 2000 with a "benchmark" amount of funds that we estimate they should have accumulated by that date. In setting the benchmark, we assumed that the owners would contribute increasing (but constant present-value) amounts annually to cover eventual decommissioning costs.[15] For example, at the end of 2000, an owner's decommissioning fund for a plant that had operated one-half of a 40-year license period (begun in 1980) should contain one-half of the present value of the estimated cost to decommission the owner's share of that plant in 2020. Although this benchmark is not the only way an owner could accrue enough funds to pay future decommissioning costs, it provides both a common standard for comparisons among owners and, from an equity perspective among ratepayers in different years, a financially reasonable growing current-dollar funding stream over time. Appendix I describes our methodology in more detail.

[15]Our analysis simulates that the owners will increase their yearly future funding at the assumed after-tax rate of return on the investments of the funds, and that once in the fund, these yearly contributions will grow at this same rate. See appendix I for a discussion of our methodology.

Table 1: Status of Individual Owners' Trust Fund Balances through 2000, Compared with Benchmark Trust Fund Balances, under Most Likely Assumptions[a]

Status	Trust funds	Owners	Plants currently operating	Plants shut down
Above benchmark balance	172	78	88	5
Below benchmark balance	50	33	29	13
Total	**222**	[b]	[b]	[b]

Source: GAO analysis.

[a]Most likely assumptions include 20-year license renewals that have been approved by NRC for 16 plants as of August 20, 2003.

[b]Not applicable.

The status of each owner's fund balance at the end of 2000 is not, by itself, the only indicator of whether an owner will have enough funds for decommissioning. Whether the owner will accumulate the necessary funds also depends on the rate at which the owner contributes funds over the remaining operating life of the plant; by increasing their contribution rates, owners whose trust fund balances were below the benchmark level could still accumulate the needed funds. Consequently, for the owners who provided contributions information to us, we also analyzed whether their recent contribution rates would put them on track to meet their decommissioning obligations. For this second analysis, we compared the average of the amounts contributed in 1999 and 2000 (cost-adjusted to 2000) with a benchmark amount equivalent to the average yearly present value of the amounts the owners would have to accumulate each year over the remaining life of their share of the plants to have enough decommissioning funds.

As table 2 shows, 28 owners with ownership shares in 44 different plants (50 trust funds) contributed less than the amounts we estimate they will need to meet their decommissioning obligations, under our most likely assumptions.

Table 2: Status of Individual Owners' Recent Trust Fund Contributions, Compared with Benchmark Trust Fund Contributions, under Most Likely Assumptions[a]

Status	Trust funds	Owners	Plants currently operating	Plants shut down
Above benchmark contributions	122	58	76	5
Below benchmark contributions	50	28	34	10
Total	**172[b]**	[c]	[c]	[c]

Source: GAO analysis.

[a]Most likely assumptions include 20-year license renewals that have been approved by NRC for 16 plants as of August 20, 2003.

[b]Contributions not available for 50 other trust funds.

[c]Not applicable.

We compared the owners in table 1 with those in table 2 to see whether owners who are behind in balances were making up their shortfalls with recent increases in contributions. Of the 33 owners who we estimate had less than the benchmark balances through 2000, 26 owners of all or parts of 38 plants provided contributions information. Of these owners, only 8 owners of all or parts of 9 plants appeared to be making up their shortfalls with recent increases in contributions. By contrast, 20 owners with ownership interests in 31 plants recently contributed less to their trust funds than we estimate they needed to put them on track to meet their decommissioning obligations.[16]

These results would change under alternative economic assumptions. For example, if economic conditions improve to those assumed in our optimistic scenario, of the 20 owners who were below the benchmark under most likely assumptions on both balances and contributions, 12 owners would still be below the benchmark in both categories, even under optimistic assumptions.

However, if economic conditions worsen to those in our pessimistic scenario, 34 owners who were above the benchmark under most likely assumptions on either balances or contributions would be below either of

[16]Some of these owners were also making up their shortfalls on other plants.

these benchmarks under pessimistic assumptions. (See app. II for detailed results.)

NRC's Analysis Did Not Effectively Determine Whether Each Owner Was Accumulating Sufficient Decommissioning Funds

NRC's analysis of the 2001 biennial decommissioning status reports was not effective in identifying owners that might not be accumulating funds at sufficient rates to pay for decommissioning costs when their plants are permanently shut down. Although the NRC reported in 2001 that all owners appeared to be on track to have sufficient funds for decommissioning,[17] our analysis indicated that several owners might not be able to meet financial obligations for decommissioning. NRC's analysis was not effective for two reasons. First, NRC overly relied on the owners' future funding plans, or on rate-setting authority decisions, in concluding that the owners were on track to fully fund decommissioning. However, as discussed earlier, based on actual contributions the owners had recently made to their trust funds, several owners are at risk of not accumulating enough funds to pay for decommissioning. Second, for the plants with more than one owner, NRC did not separately assess the status of each co-owner's trust funds relative to the co-owner's contractual obligation to fund a certain portion of decommissioning. Instead, NRC combined funds on a plant-wide basis and assessed whether the combined trust funds would be sufficient for decommissioning. Such an assessment method can produce misleading results because the owners with more than sufficient trust funds can appear to balance out those with insufficient trust funds. Furthermore, if NRC had identified an owner with unacceptable levels of financial assurance, it would not have had an explicit basis for acting to remedy potential funding deficiencies because it has not established criteria for responding to unacceptable levels of financial assurances.

NRC officials said that their oversight of the owners' decommissioning funds is an evolving process and that they intend to learn from their review of prior biennial reports and make changes to improve their evaluation of the 2003 biennial reports. However, they also said that any specific changes they are considering are predecisional, and final decisions have not yet been made.

[17] *Summary of Decommissioning Trust Funding Status Reports For Power Reactors*, SECY-01-0197, Nuclear Regulatory Commission, November 5, 2001.

NRC's Review Relied on Owners' Future Plans for Making Contributions

According to NRC officials, in reviewing the 2001 biennial reports, they used a "straight-line" method to establish a screening criterion for assessing whether owners were accumulating decommissioning funds at sufficient rates. Specifically, NRC compared the amount of funds accumulated through 2000 (expressed as a percentage of the total estimated cost as of 2000 to decommission the plant) to the expended plant life (expressed as a percentage of the total number of years the plant will operate). Under this method, the owner of a plant that has operated for one-half of its operating life would be expected to have accumulated at least one-half of the plant's estimated decommissioning costs (that is, it would be collecting at or above the straight-line rate). NRC found that the owners of 64 out of 104 plants currently licensed to operate were collecting at the above a straight-line rate, and that the owners of the remaining 40 plants were collecting at the less than a straight-line rate.[18]

On a plant-wide basis, NRC then reviewed the owners' "amortization" schedules for making future payments to fully fund decommissioning. The schedules, required as part of the biennial reports, consist of the remaining funds that the owners expect to collect each year over the remaining operating life of the plants. In estimating the funds to be collected, the owners may factor in the earnings expected from their trust fund investments. To account for such earnings, NRC regulations allow an owner to increase its trust fund balance by up to 2 percent per year (net of estimated cost escalation), or higher, if approved by its regulatory rate-setting authority, such as a state public utility commission. Because these owners' amortization schedules identified sufficient future funds to enable them to reach the target funding levels, NRC concluded that all licensees appear to be on track to fund decommissioning when their plants are retired.

However, relying on amortization schedules is problematic, in part because the actual amounts the owners contribute to their funds in the future could differ (that is, worsen) from their planned amounts if economic conditions or other factors change. NRC officials said that owners are not required by regulation to report their recent actual contributions to the trust funds, and NRC does not directly monitor whether the owners' actual contributions match their planned contributions. Consequently, NRC relies on the owners' amortization schedules as reported in the biennial reports.

[18]One plant—Browns Ferry 1—has a license but is currently not operating.

Such reliance is also problematic because in developing their amortization schedules, the owners could use widely varying rates of return to project the earnings on their trust fund investments. For example, each of the three co-owners of the Duane Arnold Energy Center nuclear plant assumed a different rate, ranging from 2 to 7 percent (net of estimated cost escalation). Other factors being equal, the owners using the higher rates would need to collect fewer funds than the owner using the lower rate of return. While the return that each owner actually earns on its investments may be higher or lower than these rates, by relying on the owners' amortization schedules, NRC effectively used a different set of assumptions to evaluate the reasonableness of the trust funds accumulated by each owner. Consequently, NRC did not use a consistent "benchmark" in assessing the owners' trust funds. By contrast, we used historical trends and economic forecasts to develop assumptions about rates of earnings and other economic variables, applied the same assumptions in evaluating the adequacy of each owner's trust fund, and based expected future contributions on actual amounts contributed in recent years.

NRC's Analysis Focused on the Adequacy of Trust Funds on a Plant-by-Plant Basis

NRC's internal guidance for evaluating the biennial reports states that for plants having more than one owner, except in certain circumstances, each owner's amortization schedule should be separately assessed for its share of the plant's decommissioning costs.[19] For those plants that have co-owners, NRC used the total amount of funds accumulated for the plant as a whole in its analysis. However, as we demonstrated with our industry-wide analysis, such an assessment for determining whether owners are accumulating sufficient funds can produce misleading results because owners with more than sufficient funds can appear to balance out owners with less than sufficient funds, even though funds are generally not transferable among owners.

[19]Requirement is waived if lead owner has agreed to coordinate funding documentation and reporting for all co-owners. In such cases, the guidance does not require a separate evaluation of each co-owner's amortization schedule.

In explaining their approach, NRC officials said that the section of the guidance that calls for a separate evaluation of each owner's amortization schedule for its share of the plant is not compulsory. In addition, they said that they consider each owner's schedule to determine the total funds for the plant as a whole, but they believe that the same level of effort is not required for each individual trust fund balance unless there is a manifest reason to do so. They also stated that NRC's regulations do not prohibit each co-owner from being held responsible for decommissioning costs, even if these costs are more than the co-owner's individual ownership share. However, assessing the adequacy of decommissioning costs on a plant-wide basis is not consistent with the industry view, held by most plant owners, that each co-owner's responsibility should be limited to its pro rata share of decommissioning expenses and that NRC should not look to one owner to "bail out" another owner by imposing joint and several liability on all co-owners.[20] NRC has implicitly accepted this view and has incorporated it into policy to continue it. In a policy statement on deregulation,[21] NRC stated that it will not impose decommissioning costs on co-owners in a manner inconsistent with their agreed-upon shares,[22] except in highly unusual circumstances when required by public health and safety considerations and that it would not seek more than the pro rata shares from co-owners with *de minimis* ownership. Nevertheless, unless NRC separately evaluates each co-owner's trust fund, NRC might eventually need to look to require some owners to pay more than their share.

NRC Has Not Established Criteria for Responding to Unacceptable Levels of Financial Assurance

While the NRC has conducted two reviews of the owners' biennial reports to date, it has not established specific criteria for responding to any unacceptable levels of financial assurances that it finds in its reviews of the owners' biennial reports. As we noted in our 1999 report, without such criteria, NRC will not have a logical, coherent, and predictable plan of action if and when it encounters owners whose plants have inadequate financial assurance. NRC officials said that their oversight of the owners'

[20]Joint and several liability refers to the legal doctrine, which would allow holding all or any one of the co-owners financially responsible for the default of any co-owner.

[21]*Final Policy Statement on the Restructuring and Economic Deregulation of the Electric Utility Industry*, 62 Fed. Reg. 44071 (Aug. 19, 1997).

[22]Co-owners generally divide costs from their facilities using a contractually defined pro rata share.

decommissioning funds is an evolving process, and they are learning from their prior reviews. However, they also said that any specific changes they are considering are predecisional and final decisions have not yet been made.

The absence of any specific criteria for acting on owners' decommissioning financial reports contrasts with the agency's practices for overseeing safety activities at nuclear power plants. According to NRC, its safety assessment process allows it to integrate information relevant to licensee safety performance, make objective conclusions regarding the information, take actions based on these conclusions in a predictable manner, and effectively communicate these actions to the licensees and to the public. Its oversight approach uses criteria for identifying and responding to levels of concern for nuclear plant performance. In determining its regulatory response, NRC uses an "Action Matrix" that provides for a range of actions commensurate with the significance of inspection findings and performance indicators. If the findings indicate that a plant is operating in a way that has little or no impact on safety, then NRC implements only its baseline inspection program. However, if the findings indicate that a plant is operating in a way that implies a greater degree of safety significance, NRC performs additional inspections and initiates other actions commensurate with the significance of the safety issues. A similar approach in the area of financial assurance for decommissioning would appear to offer the same benefits of objectivity and predictability that NRC has established in its safety oversight.

Conclusions

Ensuring that nuclear power plant owners will have sufficient funds to clean up the radioactive waste hazard left behind when these plants are retired is essential for public health and safety. As our analysis identified, some owners may be at risk of not accumulating sufficient trust funds to pay for their share of decommissioning. NRC's analysis was not effective in identifying such owners because it relied too heavily on the owners' future funding plans without confirming that the plans were consistent with recent contributions. Moreover, it aggregated the owners' trust funds plant-wide instead of assessing whether each individual owner was on track to accumulate sufficient funds to pay for its share of decommissioning costs. In addition, NRC has not explained to the owners and the public what it intends to do if and when it determines an owner is not accumulating sufficient trust funds. Without a more effective method for evaluating owners' decommissioning trust funds, and without criteria for responding

to any unacceptable levels of financial assurance, NRC will not be able to effectively ensure that sufficient funds will be available when needed.

Recommendations for Executive Action

To ensure that owners are accumulating sufficient funds to decommission their nuclear power plants, we recommend that the Chairman, NRC, develop an effective method for determining whether owners are accumulating funds at sufficient rates to pay for decommissioning. For plants having more than one owner, this method should include separately evaluating whether each owner is accumulating funds at sufficient rates to pay for its share of decommissioning. We further recommend that the Chairman, NRC, establish criteria for taking action when NRC determines that an owner or co-owner is not accumulating decommissioning funds at a sufficient rate to pay for its share of the cost of decommissioning.

Agency Comments and Our Evaluation

We provided a draft of this report to NRC for its review and comment. NRC's written comments, which are reproduced in appendix III, expressed three main concerns regarding our report. First, NRC disagreed with our observation that its analyses of funding levels of the co-owners of a nuclear plant are inconsistent with its internal guidance. We revised the report to remove any inferences that NRC was not complying with its own guidance. While clarifying this point, we remained convinced that NRC needs to do more to develop an effective method for assessing the adequacy of nuclear power plant owner's trust funds for decommissioning. NRC's current practice is to combine the trust funds for all co-owners of a nuclear plant, then assess whether the combined value of the trust funds is sufficient. However, as our analysis indicates, NRC's practice of combining the trust funds of several owners for its assessment can produce misleading results because co-owners with more than sufficient funds can appear to balance out those with less than sufficient funds. As a practical matter, owners have a contractual agreement to pay their share of decommissioning costs, and owners generally cannot transfer funds from a trust fund with sufficient reserves to one without sufficient reserves. While NRC recognizes that private contractual arrangements among co-owners exist, the agency stated that it reserves the right, in highly unusual situations where adequate protection of public health and safety would be compromised if such action were not taken, to consider imposing joint and several liability on co-owners for decommissioning funding when one or more co-owners have defaulted. Nonetheless, we believe that NRC should take a proactive approach, rather than simply wait until one or more co-

owners default on their decommissioning payment expenses, to ensure that sufficient funds will be available for decommissioning and that the adequate protection of public health and safety is not compromised. Such an approach, we believe, would involve developing an effective method that, among other things, separately evaluates the adequacy of each co-owner's trust fund.

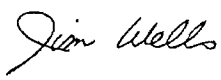
Second, NRC disagreed with our view that some owners are not on track to accumulate sufficient funds for decommissioning. NRC's position is that it has a method for assessing the reasonableness of the owners' trust funds and that our method has not been reviewed and accepted by NRC. While we recognize that NRC has neither reviewed nor accepted our method, our report identifies several limitations in NRC's method that raise doubts about whether the agency's method can effectively identify owners who might be at risk of not having sufficient funds for decommissioning. A particularly problematic aspect of this method is NRC's reliance on the owners' future funding plans to make up any shortfalls without verifying whether those plans are consistent with the owners' recent contributions. We found some owners' actual contributions in 2001 were much less than what they stated in their 2001 biennial reports to NRC that they planned to contribute. For example, one owner contributed about $1.5 million (or 39 percent) less than the amount they told NRC that they planned to contribute. In addition, based on our analysis using actual contributions the owners had recently made to their trust funds, we found that 28 owners with ownership shares in 44 different plants contributed less than the amounts we estimate they will need to make over the remaining operating life of their plants to meet their decommissioning obligations. Therefore, we continue to believe that some owners are not on track to accumulate sufficient funds to pay for decommissioning.

Finally, NRC disagreed with our view that it should establish criteria for responding to owners with unacceptable levels of financial assurance. NRC stated that its practice is to review the owners' plans on a case-by-case basis, engage in discussions with state regulators, and issue orders as necessary and appropriate. Since NRC has never identified an owner with unacceptable levels of financial assurance, it has never implemented this practice. We believe that NRC should take a more proactive approach to providing owners and the public with a more complete understanding of NRC's expectations of how it will hold owners who are not accumulating sufficient funds accountable. As stated in our draft report, this lack of criteria is in contrast to NRC's practices in overseeing safety issues at nuclear plants, where the NRC uses an "Action Matrix" that provides for a

range of actions commensurate with the significance of safety inspection findings and performance indicators. In the area of financial assurance, a similar approach could involve monitoring the trust fund deposits of those owners who NRC determines are accumulating insufficient funds to verify that the deposits are consistent with the owners' funding plans.

We conducted our review from June 2001 to September 2003 in accordance with generally accepted government auditing standards. Unless you publicly announce the contents of this report earlier, we plan no further distribution until 30 days from the report date. At that time, we will send copies of this report to the appropriate congressional committees; the Chairman, NRC; Director, Office of Management and Budget; and other interested parties. We will also make copies available to others upon request. In addition, this report will be available at no charge on the GAO Web site at http://www.gao.gov. If you or your staff have any questions, please call me at (202) 512-6877. Key contributors to this report are listed in appendix IV.

Sincerely yours,



Jim Wells
Director, Natural Resources
and Environment

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Plant name	Owner	Ownership share of plant (percent)	Baseline (most likely) scenario: Adequacy of trust fund balances as of end of 2000	Baseline (most likely) scenario: Adequacy of recent trust fund contributions[a]
Farley 2[c]	Alabama Power Co.	100	+ +	+ + + +
Fermi 1[d]	Detroit Edison Co.	100	_	_ _ _
Fermi 2	Detroit Edison Co.	100	+ + +	+ + + +
FitzPatrick	Entergy Nuclear Operations, Inc.	100	+ + +	+ + + +[e]
Fort Calhoun[h]	Omaha Public Power District	100	+	+ + + +
Ginna[h]	Rochester Gas & Electric Corp.	100	_	[g]
Grand Gulf 1	South Mississippi Electric Power	10	_ _	_ _ _
Grand Gulf 1	System Energy Resources, Inc.	90	+	+ + + +
Haddam Neck[d]	Connecticut Yankee Atomic Power Co.	100	+	+ + + +[e]
Harris 1	North Carolina Eastern Municipal	16.17	+	_
Harris 1	Progress Energy Carolinas, Inc.	83.83	+	+
Hatch 1[b]	City of Dalton (Georgia)	2.2	+ + + +	[e, g]
Hatch 1[b]	Georgia Power Co.	50.1	+ + +	+ + + +
Hatch 1[b]	Municipal Electric Authority of Georgia	17.7	+ + +	+ + + +
Hatch 1[b]	Oglethorpe Power Co.	30	+ + +	+ + + +
Hatch 2[b]	City of Dalton (Georgia)	2.2	+ + + +	[e, g]
Hatch 2[b]	Georgia Power Co.	50.1	+ + + +	+ + + +
Hatch 2[b]	Municipal Electric Authority of Georgia	17.7	+ + + +	+ + + +
Hatch 2[b]	Oglethorpe Power Co.	30	+ + +	+ +
Hope Creek 1	PSEG Nuclear, LLC	100	+ + + +[i]	[g]
Humboldt Bay 3[d]	Pacific Gas & Electric Co.	100	+	+ + + +[e]
Indian Point 1[d, f]	Entergy Nuclear Operations, Inc.	100	_ _ _[i]	_ _ _[i]
Indian Point 2	Entergy Nuclear Operations, Inc.	100	+	+ + + +
Indian Point 3	Entergy Nuclear Operations, Inc.	100	+ + +	+ + + +[e]
Kewaunee	Wisconsin Power & Light	41	+ + + +	+ + + +[e]
Kewaunee	Wisconsin Public Service Corporation	59	+ + + +[i]	+ + + +[e, i]
LaCrosse[d, f]	Dairyland Power Cooperative	100	_	_ _ _
LaSalle County 1	Exelon Generation Co., LLC	100	+ + +	_
LaSalle County 2	Exelon Generation Co., LLC	100	+ + +	+ + +
Limerick 1[j]	Exelon Generation Co., LLC	100	_	_ _ _
Limerick 2[j]	Exelon Generation Co., LLC	100	_	_
Maine Yankee[d]	Maine Yankee Atomic Power Co.	100	_ _	_ _

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Plant name	Owner	Ownership share of plant (percent)	Baseline (most likely) scenario: Adequacy of trust fund balances as of end of 2000	Baseline (most likely) scenario: Adequacy of recent trust fund contributions[a]
Vogtle 2	Oglethorpe Power Co.	30	_	_ _ _
Waterford 3	Entergy Louisiana, Inc.	100	_	+
Watts Bar 1	Tennessee Valley Authority	100	+ + + +	_ _ _
Wolf Creek 1	Kansas City Power & Light Co.	47	+	_
Wolf Creek 1	Kansas Electric Power Cooperative	6	_ _	_ _ _
Wolf Creek 1	Kansas Gas & Electric Co.	47	+	+
Yankee Rowe[d]	Yankee Atomic Electric Co.	100	_	+ + + +
Zion 1[d]	Exelon Generation Co., LLC	100	_ _	_ _ _
Zion 2[d]	Exelon Generation Co., LLC	100	_ _ _	_ _ _

Legend

+ means that fund balance/recent contributions were 0 to 25 percent more than benchmark.

++ means that fund balance/recent contributions were 26 to 50 percent more than benchmark.

+++ means that fund balance/recent contributions were 51 to 100 percent more than benchmark.

++++ means that fund balance/recent contributions were 101 percent or more than benchmark.

_ means that fund balance/recent contributions were 0.1 to 25 percent less than benchmark.

_ _ means that fund balance/recent contributions were 26 to 50 percent less than benchmark.

_ _ _ means that fund balance/recent contributions were 51 to 100 percent less than benchmark.

Source: GAO analysis.

[a]Adequacy of recent contributions is based on responses to our survey. The percentages are more, or less, than the benchmark, meaning the owner has contributed more, or less, on average for 1999 and 2000 (cost adjusted to 2000) than the annual average of the present value amounts required in each subsequent year until its plant is retired.

[b]Plant's operating license extended for 20 years.

[c]Plants whose owners are expected to apply for 20-year license renewals by December 2003.

[d]Plant has permanently shut down.

[e]Trust fund balance exceeds present value of estimated decommissioning costs.

[f]Owner has, as of March 31, 2003, an additional method to support financial assurance obligations (e.g., parent company guarantee, statement of intent).

[g]Contributions data are not available.

[h]Plants whose owners have applied for 20-year license renewals, as of August 20, 2003.

[i]Includes balances and/or contributions from a previous owner's biennial report and/or responses to our survey.

[j]Owner had, as of March 31, 2001, an additional method to support financial assurance obligations (e.g., parent company guarantee, statement of intent).

[k]Liability is for decommissioning share and not ownership share.