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Before the
UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the matter of
Power Authority of the State of New York
Application for transfers of Part 50 licenses
for James A. FitzPatrick Nuclear Power Plant — Docket No. 50-333
to Entergy FitzPatrick, LLC, and Entergy Nuclear Operations, Inc.
and for Indian Point Unit 3 Nuclear Power Plant — Docket No. 50-286
to Entergy Indian Point 3, LLC, and Entergy Nuclear Operations, Inc.

CITIZENS AWARENESS NETWORK'S REQUEST FOR HEARING AND PETITION TO INTERVENE IN THE LICENSE TRANSFERS FOR JAMES A. FITZPATRICK AND INDIAN POINT UNIT 3 NUCLEAR POWER PLANTS AND REQUEST FOR SUBPART G HEARING DUE TO SPECIAL CIRCUMSTANCES

Citizens Awareness Network, Inc. [CAN], pursuant to 10 CFR §§ 2.1306, 2.1308, and, see below, § 2.1329(b), hereby requests that the United States Nuclear Regulatory Commission conduct a hearing on the pending application to transfer the operating licenses for James A. FitzPatrick Nuclear Power Plant ["FitzPatrick" or "JAF"] and Indian Point Unit 3 Nuclear Power Plant ["IP3"] from the Power Authority of the State of New York ["NYPA"] to Entergy Nuclear Operations, Inc. [ENO], Entergy Nuclear FitzPatrick, LLC (in the case of FitzPatrick) [ENF], and Entergy Nuclear Indian Point 3 (in the case of IP3) [ENIP], and petitions to intervene in such hearing. In support of these requests, CAN has provided the attached declarations of Jean Chambers, a representative member of CAN and local resident near FitzPatrick, Exhibit 1; Marilyn Elie, a representative member of CAN and local resident near Indian Point 3, Exhibit 2; and expert opinions in the declaration of David Lochbaum, Union of Concerned Scientists, Exhibit 3 (with attachment 'A'), attached hereto, and further sets forth as follows:

Motion to Stay Proceeding and/or Decision on Application for License Transfer

Template = SECY-037 SECY-02

CAN requests that the Commission stay the instant proceeding (and/or decision) until the uncertainties on (1) the taxation status and disposition of the Master Decommissioning Trust ["Decommissioning Trust," or "decommissioning funds"] and (2) New York State Department of Environmental Conservation permitting requirements for FitzPatrick and Indian Point 3 are resolved. As set forth herein, the taxation status of the Decommissioning Trust is central both to the ultimate disposition of the funds, the ability of Entergy to provide adequate assurance of the future safe operation of FitzPatrick and IP3, and the ultimate fate of the facilities in question. These uncertainties must be resolved in order for the NRC to be able to make a rational decision on whether the proposed transfer of operating licenses for FitzPatrick and IP3 is consistent with the requirement to protect the public health and safety.

The decommissioning arrangements set forth in the sale agreement and license transfer applications rely on a system of determining responsibility for decommissioning and site remediation that is unprecedented, dubious in its assurances, and lacks clear accountability in its scope. It is occasioned by uncertainties and unresolved questions regarding the tax status of the decommissioning fund, and is structured to effectively postpone the need to make a decision about whether the fund should be transferred to Entergy. The tax uncertainties are, as CAN understands it, at least twofold: on the one hand, whether NYPA will be legally allowed to retain the fund without facing capital gains tax; and on the other hand, whether Entergy would be allowed to acquire the fund without paying capital gains tax. The sales agreement is structured such that Entergy need not be concerned with paying capital gains in the near term, and it provides for the scenario in which it is determined that NYPA must pay tax on the fund. However, it is unclear which party will assume responsibility and how it will justify financial security should it turn out that the fund is taxable for both parties. Such a scenario affects not only the fate of the fund; it presents the potential for a legal quagmire subject to extensive litigation, leaving the public health and safety in a regulatory limbo previously uncontemplated. The fact that NYPA and Entergy have not included Exhibits O-1 (Decommissioning Agreement (FtizPatrick)), O-2 (Decommissioning Agreement (Indian Point 3)), or P (Decommissioning Trust Amendment) from the "Purchase and Sale Agreement" in Enclosure 4 of the applications only contributes to these uncertainties and make it impossible for the public to understand the consequences of the license transfer.

Furthermore, the possibility that Entergy, five or ten years down the line, may suddenly be responsible for hundreds of millions of dollars in capital gains tax has implications for Entergy's nuclear operations, and the fate of the facilities. It is unclear from the publicly available documents whether Entergy would be allowed to access funds from the $50 million Letter of Credit Agreement and/or the $40 million Working Capital Credit Line for tax-related expenses. Whatever the case, the monetary requirement would far exceed the sum of Entergy's financial commitments to support FitzPatrick and Indian Point 3, and it is otherwise unclear whether Entergy has the financial wherewithal to pay the capital gains tax (a sum that far exceeds what Entergy has offered as the "Initial Consideration" ($50 million) for FitzPatrick and IP3).

The Internal Revenue Service's initial rulings on Entergy's and AmerGen's private letter ruling requests to relieve the companies from the tax consequences of acquiring the decommissioning trust funds of Pilgrim and Three Mile Island-1, respectively, brings this scenario into sharp relief. The IRS plainly stated that the decisions could not be used as a precedent.[1] Significantly, in both cases, the IRS ruling disallowed transfer of non-qualified funds as tax exempt. Exercise of the IRS's discretion, rather than an interpretation of its regulations, formed the basis of both rulings--hence, such discretion may or may not be exercised in future cases.

The sale could proceed despite an unfavorable IRS ruling. However, the amount of capital required to secure these buyouts could easily compromise Entergy's financial security. This situation thus raises questions about Entergy's ability to own, operate and decommission FitzPatrick and Indian Point 3 -- in addition to the fleet of nuclear power stations it plans to have and operate.[2] Given that Entergy currently plans to amass up to 16 nuclear generating stations, the tax consequences at issue are substantial[3] and must be analyzed, considered, and understood within the context of Entergy's entire scheme in order for the NRC to make any rational decision on the appropriateness of what Entergy puts forward as but another "isolated" license transfer application. It therefore makes no sense to proceed with the transfer until the questions related to the allocation of responsibility for decommissioning and the tax status for the decommissioning funds are resolved.

In the license transfer applications, NYPA and Entergy acknowledge that the closing of the Purchase and Sale Agreement is contingent upon approval from the Federal Energy Regulatory Commission [FERC] and the New York State Department of Environmental Conservation [NYSDEC, or DEC]. It would make sense for the NRC to stay the license transfer

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[1] Internal Revenue Service Letter Rulings 1999 TNT 210-36 *Qualified Nuclear Decommissioning Funds Won't Recognize Gain*, Doc 1999-34921, LTR 199943041 (July 21 1999). Exhibit 9, attached hereto.

[2] Airozo, Dave, *Decommissioning Trust Funds Lure Potential Nuclear Plant Buyers* 40 NUCLEONICS WEEK at 1 (March 18, 1999).

proceeding pending all other regulatory reviews, since the other proceedings may result in changes to agreements between NYPA and Entergy which could affect Entergy's financial ability to ensure the safe operation and decommissioning of the facilities. For instance, the FERC proceeding could result in the restructuring of the Power Purchase Agreement [PPA] between NYPA and Entergy, which is central to Entergy's ability to generate sufficient revenues to pay operating costs of FitzPatrick and IP3. Entergy has presumably agreed to the PPA so as to ensure sufficient operating revenues to keep the reactors open; however, should FERC rule that the PPA is not in the interest of ratepayers, it may require NYPA and Entergy to lower the rates agreed to in the PPA, cutting into Entergy's operating revenues. Since one of the central questions in the NRC review of license transfers, particularly when the applicant is not a public utility (as ENF and ENIP are), is the applicant's ability to offer sufficient financial assurance that maintenance, operating, outage and decommissioning costs can be provided for in a manner that protects the public health and safety. Hence, the NRC has two choices: either the FERC and NRC proceedings should be joined so that these issues can be analyzed together; or the NRC must wait until the financial uncertainties are resolved.

Similarly, the DEC review could have an effect on the outcome of the transaction by requiring the owner of Indian Point 3 to make modifications to the facility to minimize the environmental impact of continued operation. This possibility has been made immediate by the DEC's response to Consolidated Edison's [ConEd] Modification Draft Environmental Impact Statement [DEIS] regarding the Hudson River Settlement Agreement State Pollutant Discharge Elimination [SPDES] permit for Indian Point Unit 2 [IP2]. On June 27, 2000, the NYSDEC

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[3] British Energy website: www.ukbusinesspark.co.uk.bry44970.htm, at British Energy, UK Activity Report 2000; *see also Changing the Structure: PECO, Brits Create AmerGen, Go Fishing for US Nukes*, ELECTRICITY JOURNAL (November 1997).

presented Consolidated Edison with 186 comments on the DEIS, challenging much of ConEd's analysis. *See* Letter from Mr. Richard Benas, NYSDEC, to Dr. John Young, Consolidated Edison Co. of New York, June 27, 2000. DEC's concerns, which primarily have to do with the impact of Indian Point Units 2&3 on the Hudson River, in terms of the effects of both water intake and thermal discharges on critical wildlife populations. One of the potential solutions that DEC is asking ConEd to consider is the possibility of redesigning the coolant system at IP2 to include use of a coolant tower, to minimize both water intake and thermal discharges.[4] The DEC's comments acknowledge that IP2 and IP3 are virtually indistinguishable in this regard, since the reactors are of the same design and occupy the same site. However, should the DEC rule that extensive modifications to IP3 are necessary, it could impact Entergy's operating revenues, or indeed the fate of the proposed sale. In either case, the NRC's ruling on license would be moot: either Entergy's financial assurances need to be reevaluated; or the Commission and NRC staff have wasted their time reviewing applications that are irrelevant.

CAN, thus, requests the NRC to deny or defer Entergy's application until such time as the uncertainties described above are thoroughly and transparently resolved and Entergy and NYPA's financial responsibilities are clarified. In support of this request, CAN notes, pursuant to subpart M, that the questions arising from the fate of the decommissioning fund so overshadow the question of Entergy's ability to support the operation of FitzPatrick and IP3 as to make a reasonable decision on other matters impossible. In the alternative, CAN requests that the decommissioning issues be addressed through a subpart G hearing, as set forth below by motion, due to the "special circumstances relating to the subject of the hearing" per §2.1329(b):

[4] Benas, Richard, "Letter to Consolidated Edison on Hudson River Settlement Agreement SPDES Modification DEIS" (June 27, 2000), in particular comments 145, 161, and 185. Exhibit 4, attached hereto.

the unprecedented structure and terms of the agreement; the uncertainties pertaining thereto, unpremeditated in the Atomic Energy Act or the NRC's existing rules and regulations on decommissioning and license transfers; and the national security and public health and safety concerns resulting therefrom.

Request for Joint Hearing on the Applications and Petition to Intervene

Should the Commission reject the motion for denial or postponement of the applications, CAN requests a joint hearing and petition to intervene on the applications to transfer operating licenses on FitzPatrick and IP3 from NYPA to ENF, ENIP, and ENO. FitzPatrick and IP3 carry separate licenses and there are specific issues related to Entergy's ability to operate each of the reactors in a manner that ensures the public health and safety, as set forth herein. However, there are overarching concerns deriving from the simultaneous transfer of both reactors and the arrangements made by NYPA and Entergy. The proposed sale of FitzPatrick and IP3 was negotiated as a joint transfer of both facilities: Entergy's business plan for operating FitzPatrick and IP3 and the arrangements set forth in the sale agreement closely intertwine the finances, day-to-day operations, and decommissioning of the reactors. There are also many unresolved questions on these points, described in the contentions set forth herein, due to information redacted from the publicly available documents and the apparent incompleteness of the applications on matters related to costs and revenues of continued operation and decommissioning.

Furthermore, the proposed agreement between NYPA and Entergy for the sale of FitzPatrick and Indian Point Unit 3 is unique from previous sales of nuclear generating stations. Significantly, arrangements pertaining to the consideration, operating revenues, and decommissioning are unprecedented and warrant thorough scrutiny and regulatory review.

Nuclear utilities and the New York State Department of Public Service have touted the deal for FitzPatrick and Indian Point 3 as demonstrating a "maturation" in the market for nuclear facilities. However, there are many other factors shaping the agreement between NYPA and Entergy, including: NYPA is an unregulated New York State agency with limited oversight from the state agencies responsible for ensuring the public interest is protected in the electric utility industry (and now restructuring); Entergy's increasing debt load through its expanding operations in the US and internationally, and complications thereto; liability for spent fuel storage at FitzPatrick; the abnormally large size of the FitzPatrick/IP3 decommissioning trust fund, from which Entergy hopes to profit; and increased skepticism by the public and government officials and agencies over the propriety of other nuclear station transfers. CAN contends that the agreement made by NYPA and Entergy is structured to exploit fiscal opportunities, mitigate fiscal liabilities, and create loopholes to escape other liabilities (particularly those related to nuclear safety, worker compensation, decommissioning, and site clean-up). Thus, the proposed transfer of FitzPatrick and Indian Point 3 is a radical departure from the conventional structure of commercial reactor ownership. The uncertainties it presents in terms of financial accountability, worker protection, and ultimately the public health and safety warrant a thorough review by the Commission with the full participation of the public. A public hearing is further warranted because the proposed agreement is the first of its kind and may set precedent for future sales of nuclear reactors.

Significantly, the proposed sale has thus far received no formal review by any state or federal agency. The application for transfer of the operating licenses is the first and potentially only forum in which the sale will be thoroughly analyzed to determine whether it assures adequate funding and legal and fiscal accountability to protect the public health and safety.

Subsequent reviews by the Federal Energy Regulatory Commission and the New York State Department of Environmental Conservation will necessarily be more narrow in their focus. It is therefore incumbent upon the Nuclear Regulatory Commission — according to its mandate under the Atomic Energy Act as the federal agency ultimately responsible for ensuring the public health and safety — to conduct a comprehensive review of the proposal to transfer FitzPatrick and Indian Point 3.

Wherefore, CAN requests a joint hearing to review the license transfer applications for the James A. FitzPatrick and Indian Point 3 and petitions for intervention status in the proceeding.

Motion to Hold Subpart G Hearing Due to Special Circumstances

CAN also requests the Commission, pursuant to 10 C.F.R. §2.1329(b), due to the "special circumstances concerning the subject of the hearing" to hold a substantive subpart G hearing, or, in the alternative, a substantive subpart M hearing at the preliminary stage with the possibility of converting to a subpart G hearing if necessary. CAN contends that, due to the issues and justifications set forth herein below, the application of subpart M, particularly in cross examination and discovery, would not serve the purposes for which the rule was intended — full and fair hearing on license transfer on an expedited basis. CAN contends that upon careful examination of the materials provided herein below and attached hereto, the Commission will have an adequate basis to determine that the matters in this license transfer are not strictly "financial in nature" as contemplated in the promulgation of Subpart M. In this regard, the Commission's ruling in *Niagara Mohawk Power Corporation, New York State Electric & Gas Corporation, and AmerGen Energy Company, LLC* (Nine Mile Point, Units 1 & 2), CLI-99-30, 199 NRC LEXIS 115 at *18-19 (December 22, 1999), is distinguishable from the instant case.

In this case, given the issues raised herein below, public and occupational health and safety are at issue, not merely administrative determinations concerning the paper transfer of a the license and conforming of technical specifications to reflect such a mere paper change. CAN contends that the Commission will completely abdicate its responsibility to protect public health and safety of workers and the public and also abdicate, thereby, its duty to safeguard the national interest, under the Atomic Energy Act, §§ 105, 184, 189a, if it permits the license transfer at issue to go forward as a purely "administrative" determination without considering the extensive substantive issues surrounding this particular transaction. Such issues will only receive adequate attention in the context of a full adjudicatory hearing process with the right to call for evidence, present evidence, and cross examine evidence.

In support of this motion, as set forth herein, CAN has obtained information on Entergy's 1996 due diligence inspection of FitzPatrick and Indian Point 3 that, together with consistent NRC inspection findings from Fall 1998 to the present, raises questions about the ability of Entergy to assure the continued safe operation of NYPA's nuclear facilities. These questions must be resolved prior to transfer of the operating licenses. In 1996, Entergy decided not to purchase FitzPatrick and IP3 based on due diligence findings that the material condition, management and organizational structure, operator training, budgeting, and work culture did not provide adequate assurance of safety.[5] It is unclear how or why Entergy's evaluation of the facilicities has changed since NYPA's operation and the material condition of the facilities has remained substantially the same in the intervening period. Furthermore, Entergy has not provided adequate financial assurance that it will be able to support large capital improvements to the facilities or make the kind of operational and personnel improvements that may be needed at FitzPatrick and IP3. Significantly, it is unclear how Entergy's proposed operational and organizational structure differs substantially from what the 1996 due diligence evaluation identified as core problems with NYPA's organizational and management structure, particularly in terms of corporate control of site management and the lack of "site ownership" by on-site personnel responsible for operating and maintaining the reactors safely. Furthermore, it is impossible to resolve these issues without an official hearing process due to the nature and extent of material redacted from the license transfer applications. For the above-stated reasons, and because the consistency of the 1996 Entergy due diligence findings with recent findings at FitzPatrick and Indian Point 3 create a "special circumstance relating to the subject of the hearing," the scope of the rules set forth under subpart M is inadequate to govern the review of the license transfer applications. Therefore, pursuant to §2.1329(b), CAN requests that the Commission hold a substantive subpart G hearing on the applications.

In the alternative, CAN would be willing to accept a joint hearing on the transfer of FitzPatrick and IP3 with the New York State Department of Environmental Conservation and the Federal Energy Regulatory Commission, held in New York State. Such a hearing would have several advantages for CAN, NYPA, and Entergy, as well as the NRC: timely resolution of the various regulatory approvals required by the applicants to complete the proposal to transfer of FitzPatrick and IP3; easement of the burden to all parties resulting from the need to engage in three separate fora to review the proposed transaction; the ability to address related issues affecting the transfer, the future operation of FitzPatrick and IP3, and the environmental and public health and safety impacts of the proposed sale.

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[5] Entergy, Inc., Summary of the Entergy Due Diligence Process (November 1996). Exhibit 5, attached hereto.

In support of the above motions and requests, CAN further sets forth herein below as follows:

I. INTRODUCTION: PRELIMINARY ISSUES AND ARGUMENTS.

The nuclear industry in the US presently faces a transformation which will radically reorganize the financial and management structure of the nuclear power industry and have a resultant direct impact upon occupational and public health and safety. Two giant commercial combines, one a global power corporation and the other a multinational conglomerate, are rapidly purchasing the United States reactor inventory, beginning with the aging and embrittled fleet of nuclear generating stations in the Northeast, in a piecemeal fashion, region by region. Four other global power companies stand poised to begin purchasing reactors, likely depending on the outcome of these trial cases in the Northeast. AmerGen has now acquired Three Mile Island and Clinton, has submitted license transfers on Oyster Creek, was bidding on Nine-Mile Point 1 and 2, and intends to bid on the Millstone complex.[6] Entergy already owned five reactors in the South, has aquired Pilgrim, and now stands to acquire FitzPatrick and Indian Point 3. The proposed sale of FitzPatrick and Indian Point 3 would be the first multi-unit transfer in the nuclear industry attempt at restructuring. It would be the largest transfer of public assets in New York State history. State regulatory authorities with limited powers are overwhelmed by the task of determining the dubious fiscal propriety of such transactions.

This revolution in ownership of nuclear power capacity originated as a crisis of the competitive market brought about by utility deregulation. Initially, this process was intended to end monopoly control of electricity production and sales and reduce costs to consumers through

[6] Associated Press, Facts About The Companies (June 25, 1999); see also Hencke, Dave, Decommissioning Trust Funds Lure Potential Nuclear Plant Buyers 40 NUCLEONICS WEEK at 1 (Mar. 18, 1999). Exhibits 3 and 4, attached hereto.

the aegis of market competition. Thus far, nuclear power has required massive public subsidy in order to survive in regulated markets. The public now faces a potentially massive debt due to the investment in "power too cheap to meter."

This debt burden will be comprised of shortfalls in decommissioning funds and billions of dollars in stranded costs from bad investments in a technology which the nuclear industry did not deliver as promised (i.e., safe and clean "power too cheap to meter").[7] State authorities facing the prospect of being forced to manage the clean up of contaminated reactor sites have been willing to agree to any offer which might relieve the state of financial liability for future site remediation under decommissioning. These agreements include a 12-year, above market rate power contract in Vermont Yankee's case, the purchase of nuclear stations at 10 cents on a dollar in Pennsylvania (Three Mile Island) and New Jersey (Oyster Creek), and ratepayer responsibility for the stranded debts of nuclear utilities as in Pennsylvania, Illinois, Massachusetts and Connecticut.[8]

The procedure in this instant case, which the applicant and the NRC have characterized as a simple license transfer application with no health and safety implications, is but part of the rapidly accelerating consolidation of nuclear power ownership. By choosing to abdicate its antitrust authority under the Atomic Energy Act, the NRC would be permitting a *de facto* revolution, a rapid consolidation in nuclear power ownership through premature acceptance of this and other Entergy applications and the accelerated hearing schedules they seek to impose.[9]

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[7] *Id.*

[8] *See generally*, Petition of Vermont Yankee Nuclear Power Corporation and Prefiled Testimony, Vermont Department of Public Service, Docket No. 6300 (November 22, 1999); *see also* Herbert, Josef, *Nuclear Plants Sell At Bargain Basement Prices*, JOURNAL OF COMMERCE at 11-A (Mar. 17, 1999). VY petition not attached. Josef article attached hereto as Exhibit 5.

[9] Salpukas, Agis, *A Small Circle of Companies Seeks Control of Reactors*, NEW YORK TIMES, at C-1 (March 6, 1999).

The unique and unprecedented events which are now before the Commission and other federal agencies require changes in the regulations governing these emerging entities, and the enforcement practices and scrutiny of the applications which will allow this rapid consolidation to go forward. As such, the Commission has a solid basis for delaying or suspending the instant proceeding to permit the kind of time it takes for the careful scrutiny and deliberation over such applications as is appropriate under the unprecedented nature of the transformation now taking place.

Given the very real potential consequences to the human and natural environmental which would flow from approval of this segmented sequence of license transfers -- leading to an unsupportable aggregation of holdings, with management bent on maximizing profit to survive, as detailed in issues herein below, -- the Commission should regard the request as part of its decisionmaking process concerning a major federal action affecting the quality of the human and natural environment, and deny that request. The Commission should also conduct an Environmental Impact Study, pursuant to the requirements of the National Environmental Policy Act [NEPA], on the potential effects of massive consolidation of nuclear power facility ownership, with particular attention to foreign ownership [anti-trust concerns] in that picture. NEPA, 42 U.S.C. §§4321, *et seq.*; AEA, 42 U.S.C. §2133. Since having reached the agreement with NYPA in March, Entergy has public announced its interest in acquiring every other nuclear station in the Northeast, including Nine Mile Point 1&2, Millstone 2&3, Seabrook, and even the troubled Indian Point 2 reactor; it can also be assumed that Entergy would be interested in Ginna Station should Rochester Gas & Electric decide to divest, as well as Vermont Yankee should the sale to AmerGen fall through. Thus, Entergy's strategy would plainly establish a regional monopoly in nuclear generation, fully 20% of the New York/New England electric generation capcacity. Entergy's purchase of NYPA's facilities strategically positions the company to acquire Nine Mile Point and Indian Point 2, through the promise of consolidating operations at New York's multiple-unit sites. While it may be argued that such consolidation poses an economic advantage to the potential new operator and simplifies the operation and decommissioning of these multiple-unit sites, it inversely poses anti-trust problems that could adversely affect the public health and safety, as well as national security in the nation's most densely populated region.

A thorough understanding of the terms of all agreements and internal projections and plans for reactor operation and financing is necessary for assessing the impacts of this license transfer on health and safety issues. Therefore, the priority (practice) of holding any information regarding finances of potential licensees as proprietary reasonably should be set aside in favor of the imposition of a higher standard for information to achieve proprietary status in order to satisfy the public interest. The financial condition of licensees has always been subject to NRC standards, and the NRC has recognized such information as relevant to issues of public health and safety. ENIP, ENF, ENO and their parent companies support the withholding of information in order to limit public access to information. CAN contends that this information is relevant and in the public interest, and that permitting the applicant to withhold it undermines the public's ability to participate in the proceeding.[10]

Any argument Entergy may make that the issues contained in its petition should not be fully examined in order to expedite approval of the license transfer must be denied lest the NRC abdicate its responsibilities under the Atomic Energy Act.[11]

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[10] Hencke, David, *Nuclear Industry's Plea For Secrecy*, THE GUARDIAN at 7 (July 8, 1999).

[11] The Atomic Energy Act of 1954, as amended [AEA], provides in pertinent part that:

Transfer of the FitzPatrick and IP3 licenses, in the context of the recent historic effects of deregulation, coupled with Entergy's intention to acquire an extremely large "fleet" of nuclear reactors, greatly accelerates the on-going transformation of the entire financial basis of the nuclear power industry in the United States.[12] This alone should be sufficient to trigger heightened NRC scrutiny of these transactions.

Entergy has already received license amendments to transfer the Pilgrim Nuclear Station, is presently applying for license transfers on two more nuclear stations, and clearly plans to continue on this course. The NRC has a clear responsibility to take a broader view of the impact of not only amendments to FitzPatrick's and Indian Point 3's operating licenses, but the total impact of multiple license transfers to a single holding company during a period which Commissioner Edward McGaffigan characterizes as a "dynamic time for the nuclear industry,"[13] and one in which the agency has publicly committed itself to alleviating the regulatory burdens on the industry in order to strengthen the competitiveness of nuclear power (a commitment with a dubious relationship to the Commission's statutory charge, post-AEC, in contradistinction to that of the Department of Energy). The NRC is in fact aware of the regulatory implications of reactor ownership, the complex relationships between ownership and operation, and "changes in organizational structure that may affect nuclear plant ownerhsip," as described in the March,

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> [N]o license granted hereunder * * * shall be transferred, assigned, or in any manner disposed of, either voluntarily or involuntarily, directly or indirectly, through transfer of control of any license to any person, <u>unless the Commission shall, after securing full information, find that the transfer is in accordance with the provisions of this Act</u>, and shall give its consent in writing.

AEA § 184, 42 U.S.C. §2234 (emphasis added); *see also* 10 CFR §§30.34 (b), 40.46, 50.80, 72.50.

[12] Moore, Matt, *5 Wanted: Nuclear Reactors, Serious Inquiries Only*, ASSOCIATED PRESS (April 2, 2000).

[13] Smith, Rebecca, *Power Industry Changing in the Face of Deregulation*, THE WALL STREET JOURNAL (October 28, 1999).

2000 report *"Owners of Nuclear Power Plants"* R.L. Reid and V.S. White, Oak Ridge National Laboratory, Prepared for Division of Reactor Program Management, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission. It is in the best interests of the NRC, as well as the public health and safety, to fully investigate the ramifications of the industry's restructuring strategies as they are evolving, rather than have to go back at a later date evaluate and revise regulations and license requirements similarly to the NRC's and industry's efforts post-Three Mile Island-2.

The ongoing process of deregulation of the electric power industry and resulting changes in the ownership of generating stations has outpaced the NRC's ability (and other agencies) to effectively react and regulate. The vacuum of state and federal regulations guiding this new direction in the industry necessitates that the NRC take special care to consider the unfolding ramifications of permitting a rapid proliferation of license transfers and mergers. Given the ever-mounting costs of decommissioning and the effects of a single, massive failure by one large company holding dozens of facilities, the financial consequences could easily outstrip the Savings and Loan scandal. Were that not enough to inspire the NRC to exercise greater care, the potential negative implications for the health and safety of workers and the public are disquieting, to say the least. Certainly, one would hope, this is disquieting enough to warn the Commission against continuing the course of hasty approval it has thus far sponsored.

Of even greater concern for the impact on occupational and public health and safety, the transfers and mergers at issue are taking place concurrently with the introduction of the NRC's Revised Reactor Oversight Process and a shift towards so-called "risk-based" regulations. This comes in response to NRC funding cutbacks. The number of resident inspectors at many of the stations whose licenses may be transferred will be reduced, lessening NRC oversight and direct, on-site support of the new owners, thus permitting an increased risk to occupational and public health and safety. For Entergy to take on a rapidly expanding fleet of aging reactors at this point, and instituting new and experimental operations and management models to meet the demands of an unregulated market, makes an already complicated situation even more complex, and leaves the public increasingly vulnerable to the consequences of nuclear mishaps. The ability of the NRC to regulate effectively -- while both regulator and licensees are undergoing radical and unprecedented changes in their organizational structures and operational procedures -- warrants great caution and generous reliance on the system of checks and balances between the NRC, licensees, and the public established by the Atomic Energy Act to ensure national security and protect the public health and safety.

II. ADDITIONAL ISSUES AND STANDING CONSIDERATIONS[14]

1.A The Application For License Transfer Should Be Denied Because The Application Does Not Provide Sufficient Assurance Of Adequate Funding For The Eventual And Actual Costs Of Decommissioning FitzPatrick and Indian Point 3.

The present cost estimates for decommissioning FitzPatrick and Indian Point 3 do not reflect the costs required to meet Nuclear Regulatory Commission regulations for site remediation standards.

Until the proposed transfer, the Power Authority of the State of New York has been able to charge ratepayers for the cost of capitalizing the decommissioning trust fund, which, through amortization, would generate adequate funds to assure final site clean-up. Entergy's Purchase Agreement with NYPA, and the license amendment application at hand,[15] state that Entergy will be responsible for adequate funding to clean up the sites (above and beyond the balance in the

[14] CAN notes that subpart M of 10 CFR Part 2 refers to "issues" rather than "contentions." Keeping with Commission practice, CAN takes the terms as equivalent.

decommissioning trust fund) without the guarantee of continuing ratepayer subsidies or payments. *See* NYPA Application and enclosures. There is strong reason to believe that the decommissioning cost estimates for FitzPatrick and IP3 are inadequate, and therefore the possibility of a shortfall in decommissioning funding can be anticipated. In that case, the application does not provide an adequate assurance of the ability to accomplish decommissioning and final site clean-up.

In this regard, among other sources, CAN relies on studies of the General Accounting Office (GAO). The GAO found that 36 of 76 nuclear plant licensees had not accumulated sufficient funds as of 1997 to cover future decommissioning costs as estimated under current regulation.[16] GAO expressed concern that evolving competition in the electric industry would exacerbate the problem, and, significantly in this matter, that NRC lacks thresholds for acceptable levels of financial assurances or a mechanism for responding to the risks caused by unacceptable levels of funding. The GAO also concluded that there is no logical, coherent, and predictable oversight of NRC licensees' financial assurance for decommissioning nuclear power facilities.[17] GAO suggests that NRC clarify: (1) the objectives, scope, and methodology of reviews of licensees' financial reports; (2) thresholds for identifying acceptable, questionable, and unacceptable financial assurances; and (3) criteria for actions to be taken based on the results of these reviews.[18] Until recently, it was accepted that there would be large shortfalls in meeting the clean-up costs at nuclear generating stations. Until recently, however, the nuclear industry has always had the option of petitioning for financial relief through

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[15] Filed with VY and AmerGen's above referenced letter to Samuel Collins (January 6,2000).

[16] GAO, *Nuclear Regulation: Better Oversight Needed to Ensure Accumulation of Funds To Decommission Nuclear Power Plants* (May 1999).

[17] Foster Electric Report (No. 165), *GAO Report Questions Adequacy of the Funding Mechanisms for Nuclear Plant Decommissioning* at 28 (May 19, 1999).

increased charges to ratepayers. This option disappears in a "deregulated" market, particularly where stranded costs are apportioned in the restructuring agreement.

Furthermore, the Decommissioning Cost Estimates, Purchase and Sale Agreement, and License Transfer Applications contain no provision for off-site remediation, a potentially expensive project within decommissioning. Both reactors have a documented record of having released hazardous material off-site (both radiological and non-), in quantities that require remediation if the public health and safety is to be protected as a consequence of the operation of FitzPatrick and Indian Point 3, and the eventual termination of the operating licenses in question. These include both accidental releases, such as the rupture of underground piping (June 1994),[19] inadvertent primary coolant water draindown (July, 1994 and October, 1994), and undercalculated radiological release data (1980-1993),[20] all at IP3; or the deliberate disposition of radiological material off-site, such as the well-documented practice at FitzPatrick during the years 1989-1993 of illegally transporting sludge containing Mn-54, Co-60, Zn-65, and Cs-137 to a municipal sewage treatment facility.[21] While there is likewise no provision determining responsibility for off-site remediation in the Purchase and Sale Agreement, CAN argues that this is an ommission, whether deliberate or accidental, that must be accounted for in the NRC's review of the license transfer applications, and must be resolved as a requisite for approval. Consequently, it must be ascertained whether the existing decommissioning cost estimates are accurate, and whether (based on that evaluation) the decommissioning funds as

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[18] *Id.*.

[19] Fromm, Catherine, *"Indian Point 3 pipe break leaks toxins into river,"* GANNETT SUBURBAN NEWSPAPERS, (June 29, 1994). Exhibit 6, attached hereto.

[20] Talbot, David, *"Mildly Radioactive gas release found,"* GANNETT SUBURBAN NEWSPAPERS, (October 23, 1993). Exhibit 7, attached hereto.

[21] Molloy, Andy, *Treasures In The Landfill*, SYRACUSE PEACE NEWSLETTER (April, 1994). Exhibit 8, attached hereto.

presently constituted will be adequate, or there are adequate financial assurances that increased costs can be provided for.

In this case, Entergy's averment that it intends to make a profit on decommissioning trust funds and return that profit to its shareholders is, to put it mildly, an exercise in faulty logic, unfounded, and unsupported. For Entergy to make a profit on decommissioning, it would require that they cut corners and risk the health and safety. A key part of this strategy is Entergy's plan to build new power plants on the decommissioning sites, thereby limiting the scope of remediation they would be required to accomplish.[22] This dangerous, controversial, and unprecedented practice is still of questionable legality. Entergy's willingness to rely on speculation warrants further investigation of its decommissioning plans through a subpart G hearing.

Entergy's expectation that decommissioning costs will decrease below currently estimated levels contradicts industry experience and the historical record. Entergy's own record in decommissioning thus far is minimal and fraught with problems, having led to the bankruptcy of Entergy's major contractor at Maine Yankee. Assurances that Entergy will have acquired enough decommissioning experience by the time FitzPatrick and IP3 begin clean-up and remediation are based on mere speculation. Entergy will only have managed decommissioning at two reactors (Maine Yankee and Millstone 1). Significantly, Entergy will also have to begin decommissioning 3 of its own reactors (Pilgrim, 2012; FitzPatrick, 2014, and IP3, 2015) within three years of each other; if Entergy's acquisition strategy is even modestly successful, the company will have to begin decommissioning up to 4 other reactors within the same time frame (Nine Mile 1, 2009; Ginna, 2009; IP2, 2013; Millstone 2, 2015). The assumption that Entergy

[22] Entergy, *Annual Report 1999* (March 2000) at page 23.

will be able to reduce decommissioning costs by devising an experimental and as-yet undeveloped strategy for decommissioning, utilizing a rotating work schedule at simultaneously decommissioning facilities, is not enough to base a decision on adequate financial assurance. At best, these matters warrant investigation and evaluation through the requested subpart G hearing process.

Entergy's averred plans also raise the specter of the harms decried in David Lochbaum's Declaration at ¶9 and supported, in part, by his attached Exhibit 'B' UCS report on Overtime and Staffing Problems in the Commercial Nuclear Power Industry (March 1999).[23] The safety issues, supported by the Lochbaum Declaration, could harm CAN's representative members Jean Chambers and Marilyn Elie. Not only could they suffer property damage due to increased electrical rates, but the radiation dangers of inadequate clean-up or cost-cutting impacts upon workers leading to unplanned and dangerous releases of radiation, would harm their health and safety and harm their ability to enjoy the natural environment around them, and, in particular, utilize the FitzPatrick and Indian Point sites after final site release. If the NRC holds the requested hearing, CAN will have an opportunity to present evidence to the Commission (or ASLB panel) which could lead to conditions being placed upon the license transfer that would avoid the harm to CAN (and its representative member). Conditions controlling hours, overtime, and establishing proper parameters for the handling and accumulating of adequate decommissioning funds would cure the harms to CAN and its representative member. This satisfies the requirement of 10 CFR §§ 2.1306 , 2.1308 for an admissible interest and standing, and this issue should be taken up for hearing. It also involves more than mere financial matters and, thus, implicates a more detailed hearing process than is

[23] See also Docket No. 50-271, *Citizen Awareness Network, Inc.'s, Request for Hearing.*

provided under 10 C.F.R. Subpart M. Therefore, the NRC should, pursuant to 10 C.F.R. § 2.1329(b), upon need to resolve such special issues not properly within a simple license transfer, conduct a 10 CFR Subpart G proceeding.

1.B The Applications should be denied because the License Transfer Applications, and the Purchase and Sale Agreement upon which they are based, make no provision for determining responsibility for off-site remediation under the decommissioning of FitzPatrick and Indian Point 3.

At § 2.4(b) of the Purchase and Sale Agreement, Entergy and NYPA agree that Entergy will not assume responsibility for off-site remediation of "environmental liabilities" resulting from NYPA's operation of FitzPatrick and Indian Point 3:

> 2.4. Liabilities Not Assumed: Notwithstanding any provision hereof to the contrary, Buyers [ENF and ENIP] shall not assume, pay or perform any Liabilities of Seller [NYPA] that are not expressly identified in Section 2.3 as an Assumed Liability, including, without limitation, the following excluded liabilities (the "Excluded Liabilities"): ...
>
> (b) any Liabilities, including without limitation any Environmental Liabilities, relating to the off-Site disposal, storage, transportation, discharge, Release, recylcing, or the arrangement for such activities, by Seller, of Hazardous Substances that were generated at a Site, at any Offsite Hazardous Substance Facility or at another location that is not a Site (other than as a result of subsurface migration from a Site), where the initial disposal, storage, transportation, discharge, Release or recycling of such Hazardous Substances at such Offsite Hazardous Substance Facility occurred prior to the Closing.

This aspect of the agreement seems to imply that Entergy will not assume responsibility under decommissioning for remediating contamination resulting from NYPA's operation of FitzPatrick and Indian Point 3, insofar as that contamination has spread off-site. While it may be reasonable for Entergy not to be held legally liable for the previous operator's indiscretion, mishaps, or illegal actions, there is apparently no provision that will hold NYPA accountable for such remediation, either. The possibility that NYPA will be released from any responsibilities as a licensee, should the NRC approve the applications to transfer the operating licenses for

FitzPatrick and Indian Point 3, creates an ambiguity in the NRC's ability to regulate whole areas of decommissioning with respect to the facilities in question. These ambiguities must be resolved prior to transfer of the operating licenses. There are several possibile conditions that can be placed upon the transfer, or revisions that could be made to the Purchase and Sale Agreement and the applications, that would resolve the situation:

C. Through the EIS requested herein below at § II.1.C., establish an accurate and detailed study of contamination described by the terms of § 2.4(b) of the Purchase and Sale Agreement, which NYPA must remediate before the licenses can be transferred.

D. Or, as a second the alternative, if the license transfers are otherwise to be permitted, then NYPA should not simply be released of all licensee responsibility, but rather issued a "decommissioning" license until NYPA has completed those "environmental liabilities" not assumed by Entergy through the Purchase and Sale Agreement.

Should the NRC and the applicants choose either of the above options, the question of how to fund the remediation must be addressed, so as to protect the decommissioning fund from being prematurely depleted. NYPA's accountability for partial site remediation and cleanup should not unduly compromise the quantity of funds available to accomplish the complete decommissioning project after license expiration.

E. As a third and simpler alternative, since the present license transfer represents another unprecedented step in the process of industry restructuring, unpremeditated in the development of rules, regulations, and license requirements related to decommissioning, clause 2.4(b) should be disregarded insofar as

> decommissioning responsibilities are concerned and Entergy should be required to conduct a complete and thorough decommissioning without regard to whether the off-site contamination was caused by NYPA or Entergy. However, insofar as Entergy should not be held liable for NYPA's indiscretion, mishaps, or illegal actions, Entergy should be allowed to recover those costs from NYPA, should the actual costs of decommissioning exceed the amount in the Decommissioning Trust.

It should further be noted that this part of the agreement is inconsistent with other assumptions of liability by Entergy, implied or expressed in Purchase and Sale Agreement. For instance, Entergy is apparently accepting the material condition of the facilities "as is" at the time of Closing, with the implied risk that Entergy may incur unanticipated maintenance needs and costs as a result of NYPA's actions prior to Closing. Entergy is not disavowing responsibility for radiological material NYPA has buried on-site prior to 1980 (per U.S. General Accounting Office findings, as herein below), although such waste constitutes a potentially undocumented and expensive aspect of decommissioning. The only difference between the above examples and the liabilities described in 2.4(b) is the apparent lack of accountability for "off-site" liabilities contamination. However, the actual application of 2.4(b) in the actual process of decommissioning of FitzPatrick and IP3 is likely to be fraught with subjective judgment, and it is not consistent with protecting the public health and safety to leave these questions unresolved.

Thus, NRC action to address this matter unaccounted for in the license transfer proceeding and the Purchase and Sale Agreement – which is, in fact, central to the ultimate disposition of the sites and completion of decommissioning in a manner that protects the public health and safety -- could avoid harm to CAN and its representative members. Furtherrmore, if the NRC holds the requested hearing, CAN will have an opportunity to present evidence to the Commission (or ASLB panel) which could lead to conditions being placed upon the license transfer that would avoid the harm to CAN (and its representative members).

1.C The NRC must conduct an EIS to determine the level of contamination on and off the FitzPatrick and Indian Point 3 sites to fully determine the level of contamination at FitzPatrick and IP3, and, in turn, to establish the appropriate level of funding necessary for Entergy to meet NRC site release criteria.[24]

The General Accounting Office report found that before 1980, the NRC permitted licensee to bury radioactive waste at reactor (and other) sites. There was very limited documentation of such disposal, and few, if any, safeguards. GAO examined sites which were contaminated in excess of NRC guidelines. At these sites, it found lack of adequate information on buried waste, and groundwater contamination.[25] The licensees have not monitored such waste problems--nor did the NRC require them to do so. This is necessary, as pointed out in the observation underlying Mr. Lochbaum expert opinions, *see* Declaration of David Lochbaum, Exhibit 3, attached hereto, in order to ascertain the extent of contamination at FitzPatrick and IP3 (and other reactors), and set realistic funding requirements to meet final site remediation costs due to the nature, location, and extent of such contamination.

Decommissioning, at present, is experimental. The experience of workers and managers at nuclear reactor site has proven to be contrary to expectation at every nuclear station

[24] Finding that a license transfer may provide adequate protection of public health and safety under 42 U.S.C. §2232 does not preclude the need for further consideration under NEPA, 42 U.S.C. §§ 4321, *et seq. Limerick Ecology Action v. U.S. NRC*, 869 F2d 719 (3d Cir. 1989).
[25] GAO *NRC's Decommissioning Procedures and Criteria Need to Be Strengthened* GAO/RCED-89-119 (May 1989).

which has begun the decommissioning process. The NRC Staff has acknowledged as much, and is quoted in an article as stating that:

> [T]he Oyster Creek decommissioning process has national significance. Taking apart aging nuclear power plants will cost $15 billion during the next 10 years, according to industry estimates, and little planning has been done. 'We have gotten into this business a lot faster than we expected,' said Jack Roe, director of the NRC's reactor program management. [N]RC workers say they were surprised when nuclear plant operators suddenly announced they would not restart reactors because the reactors were no longer profitable.[26]

To date, at many reactors, given the level of subsurface and groundwater contamination that have been found, levels of contamination and the funding required for cleanup have far exceeded expectations. For example, at the Yankee Nuclear Power Station in Rowe, Massachusetts, one of the smallest commercial nuclear generating stations, decommissioning was initially estimated at $250 million for site clean-up to a "green field" condition. At present, cost estimates are $360 million for "decommissioning" alone, with extras, such as $40 million in site remediation and another $70 million to create the temporary storage for Rowe's 40 million curies of irradiated fuel, bringing the total cost to nearly $500 million. That means, without even having an approved License Termination Plan in place, the cost of cleaning up the tiny Rowe reactor is has already reached nearly 1/2 a billion dollars!

Despite the fact that costs have exceeded estimates in every decommissioning to date, Entergy claims that, with experience, the costs of decommissioning will decrease, as techniques are developed to effectively isolate, determine, and clean up contamination. Yet, at FitzPatrick and IP3, there may well not be time for Entergy to get that experience. The licenses at FitzPatrick and IP3 (as well as Pilgrim, and other potential Entergy reactors) expire within a

[26] Moore, Kirk, *Radioactive Rods Could Pose Risk at Oyster Creek*, THE ASBURY PARK PRESS (November 5, 1998).

short period of time of each other. Potentially, Entergy will experience a "crash course" in decommissioning. It will be forced to decommission several reactors simultaneously. Other companies' experiences in decommissioning reactors demonstrate, however, that both licensees and contractors lack the necessary skills to effectively and efficiently clean up nuclear sites within original cost estimates.[27]

Hence, Entergy's claims that it can handle the situation fly in the face of existing experience and should, therefore, be discounted.

Braggadocio aside, Entergy faces additional obstacles to successful decommissioning of the FitzPatrick and Indian Point 3 nuclear power stations. Until recently, cost overruns in decommissioning were guaranteed by the ability of utilities to return to Public Service regulatory boards for increases in ratepayer subsidies (i.e., increased electric rates). Entergy's power contract in the Purchase and Sale Agreement for FitzPatrick and Indian Point 3 does not provide this option. Given that Entergy's other acquisitions will be in various stages of decommissioning or nearing the ends of their operating licenses, the burden on Entergy Corporation to subsidize the shortfalls of ENF and ENIP, could be unduly great. Lack of funding, or an effort to decontaminate the site based on a low, under-funded budget, rather than one based on a commitment to fully decontaminate FitzPatrick and IP3, whatever the cost, poses health and safety risks to the public, and, in particular, CAN members. Declarations of Jean Chambers, Exhibit 1, and Marilyn Elie, Exhibit 2, attached hereto. Not only could CAN's representative members suffer property damage due to increased electrical rates in the event that, under emergency conditions, Entergy would be able to litigate to affect rate increases to try to

[27] *Compare* TLG decommissioning studies for the Yankee reactors in Maine, Connecticut, and Rowe, for example, which are in the NRC public document files, *with* final site clean-up costs

meet its shortfalls, but the radiation dangers of inadequate clean-up or cost-cutting impacts upon workers leading to unplanned and dangerous releases of radiation, would harm their health and safety and harm their ability to enjoy the natural environment around them, and, in particular, utilize the FitzPatrick and Indian Point sites after final site release.

If the NRC holds the requested hearing, CAN will have an opportunity to present evidence to the Commission (or ASLB panel) which could lead to conditions being placed upon the license transfer that would avoid the harm to CAN (and its representative members). Conditions controlling hours, overtime, and establishing proper parameters for the handling and accumulation of adequate decommissioning funds would cure the harms to CAN and its representative member. This satisfies the requirement of 10 CFR §§ 2.1306 , 2.1308 for an admissible interest and standing, and this issue should be taken up for hearing. It also involves more than mere financial matters and, thus, implicates a more detailed hearing process than is provided under 10 C.F.R. Subpart M. Therefore, the NRC should, pursuant to 10 C.F.R. § 2.1329(b), upon need to resolve such special issues not properly within a simple license transfer, conduct a 10 CFR Subpart G proceeding.

2. **Entergy Lacks the Ability to Manage a Fleet of Aging Reactors such as JAFNPP and IP3NPP--which lack will place CAN members at risk due to an accident at JAFNPP or IP3NPP.**

A. Through the acquisition of FitzPatrick and Indian Point 3, Entergy is creating a situation in which a single company will operate a fleet of latter-vintage reactors, all experiencing a pattern of aging-related degradation. Many of these reactors (FitzPatrick, Pilgrim, and potentially Nine Mile Point Unit 1) are older than any of Entergy's BWRs. Age-related degradation at FitzPatrick and these other reactors is further advanced than at any of the BWRs

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now projected for these same projects. Either the experience and technique are lacking or the currently operated by Entergy's public utility subsidiaries, significantly limiting the scope of Entergy's claimed experience in maintaining and operating reactors of this type. Although Entergy's Arkansas Nuclear One Unit 1 (ANO1) pressurized water reactor is just older than IP3NPP, Entergy's record at ANO1, and even younger PWRs such as Waterford 3, is spotty at best; Entergy's ability to manage an increasing number of reactors that are entering their twilight years may be stretched past the limit. The NRC must therefore take into consideration the effect of consolidating a large number of aging, mismanaged and otherwise troubled facilities under a single corporate umbrella, especially given the rigors of operating those facilities in a deregulated electricity market without the flexibility of returning to ratepayers to reimburse unexpected operating and maintenance costs. This situation is made critical, as set forth herein below, by inadequate financial assurance that Entergy will be able to support the continued operation of FitzPatrick and Indian Point 3 in a manner that guarantees the public and health safety.

<u>Aging Related Degradation and Leak Detection Problems at FitzPatrick and IP3</u>

The effects of reactor aging are "synergistic." Degradation of some key affected systems interactively affects degradation in other systems. This, in turn, vastly increases the need for specificity in overall system knowledge, and vigilance and timeliness in even the most routine maintenance. For example, workers at Nine-Mile Point Unit 1 [NMP-1] identified a long, through-wall crack in the reactor's Main Drain Line [MDL] only by visual inspection following a special hydrostatic test of reactor vessel pressure. The crack had not been detected during the previous operating cycle, or during the 2-month long refueling outage. They later determined that the crack was caused by deteriorated packing in Main Steam Isolation valves, which were

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estimates were much too low.

leaking water onto the MDL. For a number of years, plant personnel were aware that the packing was leaking. Yet it was not scheduled for replacement. Moreover, despite the risk-significance of a break in the MDL, the licensee's analysis did not anticipate the synergistic effect of the leaks on other systems. Workers at the same reactor over the past four years have had to do maintenance on several other systems and pieces of equipment, much of it at significant expense: emergency core coolant condensers (1997 & 1999); core shroud (1995,1997, & 1999); control rod stub tubes (1999).

NMP1 is only five years older than FitzPatrick. Workers and engineers throughout the industry understand that NMP1 is a bellwether for age-related degradation in all BWRs around the country. JAF has, in fact, followed the trend at Nine Mile Point-1, having installed tie-rods to provide lateral reinforcement to the horizontal welds and new emergency core coolant condensers within the last few years. Hence, a significant issue to consider in a license transfer of JAF is whether the new operator/owner will have both the technical and financial wherewithal, the "hands on" experience with aging BWR problems, to meet and address JAF's evolving special needs. If Entergy is to become the operator of FitzPatrick, the NRC must first be certain that Entergy is capable, in the years remaining on the license, of anticipating and meeting maintenance costs and experiences on the scale NMP-1 has already experienced. Failure to do so will likely result in an unsafe condition at FitzPatrick.

Entergy maintains that, through its acquisition strategy, it will be able to achieve more efficient operation. This, Entergy claims can be accomplished through consolidation of the workforce and maintenance activities. Such an approach, however, requires the careful and detailed advance planning of all activities, and tight coordination of the workforce rotation, relying on tightly planned maintenance schedules. This kind of scheduling, however, requires accurate foreknowledge of maintenance needs. One basis for such knowledge, going forward in the nuclear industry, is the NRC's "leak-before-break" methodology. For instance, under current regulations, a licensee must be able to identify a leak of no greater than 7 gallons/minute for a 3"-diameter pipe. Recent experience at aging reactors like FitzPatrick and Indian Point 2 belies the efficacy of this requirement. Leak detection equipment is not accurate enough to meet current standards, and even when increases are detected, the assurance of a regulatory limit too often means that a worsening trend is not heeded until it is too late.

FitzPatrick, in fact, represents an exceptional case in this regard, since it no longer meets the minimum standards set in NRC's leak-before-break policy. Through NRC Power Reactor Event Report Number 36489 (December 6, 1999) NYPA applied for an exception to "leak-before-break" at FitzPatrick upon finding that leak detection equipment could not detect leaks of 7 gallons/minute in 3"-diameter pipes outside containment. Instead, NYPA estimated that, for *most* pipes outside containment, detection equipment could identify a leak of 25 gallons/minute. And there were further exceptions: "For those areas which the system **cannot detect a 25-gpm leak**, the system is considered operable because **in some cases**, the actual pipe diameter is greater than 3 inches" (emphasis added). *See* NRC Deviation Event Report Number 36489. It is unclear why the NRC would accept NYPA's proposed exception to leak-before-break based on the rationale supplied in the event report, nor whether the revised standard supplied by NYPA provides reasonable assurance of safe operation. Nevertheless, there are apparently some cases in which the leak detection system at FitzPatrick must still be considered inoperable.

This situation is not limited to FitzPatrick. Last fall, NYPA had a similar situation occur at Indian Point 3. *See* Deviation Event Report Number 36313. All plant personnel within containment were forced to evacuate when an Unusual Event was declared and increased radiation levels were measured due to a leak in the loop-3 flow transmitter. The leak, which exceeded the 10gpm standard set for leak detection equipment within containment, went undetected until "workers heard the leak occur and saw steam issuing from a transmitter room." Thus, leak detection equipment did not perform up to the standards set by leak-before-break, and as at NMP1 with the MDL crack, it was direct observation by workers that was able to identify and the degradation and respond to the situation. However, the reliance on leak detection equipment, for which there is increasing evidence of it inadequacy, compromises occupational health and safety.

Hence, under an appropriate condition to transfer the license, Entergy should be required to modify inspections and leak detection equipment. In addition, Entergy should be required to institute programs to study the rate of crack propagation. This would allow personnel adequate time for planning and scheduling of maintenance activities, and to detect material condition problems before they result in large leaks that increase radiological exposure to workers. NRC, however, needs to oversee the development and implementation of systems and procedures necessary to provide objective review and ensure that the public health and safety is protected, not just add a license condition.

Entergy's application does not adequately address Entergy's lack of expertise or the steps it will take to ameliorate this condition to sufficiently protect the public health and safety. With a tightly packed schedule and a depleted workforce due to "profitability" cuts, Entergy will not have the flexibility to quickly react to surprises at two or more of its generating stations. For this reason alone the application for license transfer should be denied, a hearing commenced, or conditions should be imposed upon the license to require special additional training.[28]

This situation will increase the accident risk at FitzPatrick and Indian Point 3, a risk that would likely harm local residents and CAN's members. Declarations of Jean Chambers and Marilyn Elie, Exhibits 1 & 2, attached hereto. Not only could she suffer property damage due to increased electrical rates in the event that under emergency conditions, Entergy would be able to litigate to affect rate increases to try to meet its shortfalls, but the radiation dangers of inadequate clean-up or cost-cutting impacts upon workers leading to unplanned and dangerous releases of radiation, would harm their health and safety and harm their ability to enjoy the natural environment around her, and, in particular, utilize the FitzPatrick and Indian Point 3 sites after final site release.

<u>Final Safety Analysis Report</u>

In the license transfer applications, pursuant to 10 CFR 50.34, Entergy contends that the Final Safety Analysis Report, at both IP3 and FitzPatrick, "was updated to the Updated Final Safety Analysis Report in 1982 and has been subsequently updated in accordance with 10 CFR 50.71(e)."[29] [30] However, it is unclear whether Entergy has fully investigated this matter itself, since there is evidence that the UFSAR's at FitzPatrick and Indian Point 3 have not been kept fully up to date. Recent inspections at both reactors have revealed inaccuracies in the UFSAR's at both FitzPatrick and Indian Point 3:

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[28] *See* NRC Power Reactor Event Report Number 36489 (December 6,1999) (James A. FitzPatrick staff noted that the reactor's leak-detection equipment would not meet the 3"-line, 7-gallon/minute requirement, and submitted an exception, LER-36489, stating that the equipment could only be expected to satisfy a standard of 25 gallons/minute "in most areas" thus, shockingly, leaving open the question of whether leaks would be detectable at all in some areas and systems).
[29] Docket 50-286 at page 16.

1) JAF -- EA 99-235, § 1R03.2.b. (December 29, 1999): "During NYPA's review of the Final Safety Analysis Report in response to the Nuclear Regulatory Commission's 10 CFR 50.54f validation request, they failed to identify that the FSAR description for the operation of the HPCI injection isolation valve (23 MOV [motor-operated valve]-19) was incorrect. Specifically, the FSAR Section 7.4.3.2.5 describes that, 23 MOV-19 will remain open upon receipt of a turbine trip signal until closed by operator action in the control room. Contrary to this statement, 23 MOV-19 will close without operator action upon a turbine trip. (DER 99-2250)"
2) JAF -- EA 99-235, § 1R04.b. (December 29, 1999): "The FSAR, Section 7.10m describes the operation of the feedwater control system and states that three element control is the normal mode of operation. However, FitzPatrick has operated in the optional single element mode for approximately 15 years. ... [N]o engineering analysis was performed to evaluate this departure from the FSAR."
3) JAF -- EA 00-136, § 4OA2.b. (June 9, 2000): "Through discussions with members of the NYPA licensing department, the inspectors ascertained that NYPA did not report these findings because even though the RCIC system was designed to remove residual heat for certain events and is required by their technical specifications, the system was not credited to remove residual heat in the Final Safety Analysis Report safety analysis of the LOCA analysis. The inspectors noted however, that NYPA's position was contrary to the guidance provided in NUREG-1022, 'Event Reporting Guidelines 10 CFR 50.72 and 50.73,' Revision 2, which states, 'If the plant's fafety analysis considered RCIC as a system needed to remove residual heat (e.g., it is in the Technical Specifications) then its failure is reported under this criterion ...'"
4) IP3 -- NRC Inspection Report 05000268/2000-003, § 4OA2.1.b. (July7, 2000): "Post Accident Containment Venting (PACV) System: During the review of DER's 98-01097 and 99-00472 regarding the status of the PACV system operating procedure, the inspectors performed a system walkdown and identified several problems. The air signal to flow integrator FI-1249A, which was shown in FASR Figure 5.4-1, was not installed. Similarly, the integrator's flow counter was not installed. The inspectors also identified non-zero readings for other system instruments and questioned if the system instruments and prssure contol valves were periodially calibrated. The licensee determined that they were not periodically callibrated."

Based on the indications of inspection findings over the last year, the question of whether the UFSAR documentation at IP3 and FitzPatrick has been kept properly up to date, as required by 10 CFR 50.71(e). The instances of deviations noted above have not been identified as a result of any systematic effort to ensure that FitzPatrick and IP3's UFSAR's are in order, but rather the identifications have been made piecemeal as a result of NRC inspection efforts following safety-related system failures, or follow-up inspections on Deviation and Event Reports. Until a

[30] Docket 50-333 at page 15.

determination can be made as to whether the UFSAR's at FitzPatrick and IP3 are accurate and fully up-to-date, NYPA may be operating outside of its licenses and it would not be appropriate for the operating licenses to be transferred while the reactors are in an unanalyzed condition.

If the NRC holds the requested hearing, CAN will have an opportunity to present evidence to the Commission (or ASLB panel) which could lead to conditions being placed upon the license transfer that would avoid the harm to CAN (and its representative member). Conditions ensuring the proper monitoring and tracking of material condition issues and the full compliance of the Final Safety Analysis Reports with NRC licensing requirements would cure the harms to CAN and its representative members. This satisfies the requirement of 10 CFR §§ 2.1306, 2.1308 for an admissible interest and standing, and these issues should be taken up for hearing. It also involves more than mere financial matters and, thus, implicates a more detailed hearing process than is provided under 10 C.F.R. Subpart M. Therefore, the NRC should, pursuant to 10 C.F.R. § 2.1329(b), upon need to resolve such special issues not properly within a simple license transfer, conduct a 10 CFR Subpart G proceeding.

B. Entergy Nuclear FitzPatrick, LLC, and Entergy Nuclear Indian Point 3, LLC, are newly formed corporations. Furthermore, Entergy's non-utility nuclear operations rely on an unprecedented and unproven model for managing a fleet of nuclear stations. We must therefore look at Entergy's operating record and relevant examples from elsewhere in the nuclear industry to assess ENF's and ENIP's qualifications to own and operate FitzPatrick, Indian Point 3, and a fleet of nuclear generating stations. Entergy's record is not good enough to warrant license transfer without an in-depth investigation through a formal hearing process, and industry experience indicates that the conditions of operating in a deregulated market can be adverse to safety.

Entergy, in its applications for the license transfers of JAFNPP and IP3NPP, relies upon the experience and resources of its parent company, Entergy's public utility subsidiaries,[31] and its operations subsidiary Entergy Operations, Inc., to establish a track record as a nuclear reactor operator. The operating records of Entergy and its subsidiaries are, however, mixed at best, irrelevant in some regards, and alarming in many others. Significantly, ENF and ENIP must rely on these controversial histories because they have none of their own; in fact, ENF and ENIP's averment that they will be able to draw on Entergy's experience and expertise is merely another way of saying that they are utterly dependent upon it. Furthermore, the majority of ENF's and ENIP's corporate officers also hold positions in other Entergy companies or are Officers of Entergy Corporation, making it inevitable that Entergy's new acquisitions will inherit the company's record and operational style.

Much has been made of Entergy's "improved" operating record and efficiency during maintenance outages at facilities such as River Bend and Arkansas Nuclear One. This emphasis avoids discussing Entergy's history of violations and insufficient attention to maintenance and worker training. The Nuclear Regulatory Commission took enforcement action against Entergy 17 times for violations between 1996 and 1999,[32] sometimes for problems that dated back 10 years or more.[33] Since 1999, Entergy has three more violations pending at ANO Unit 1, Grand Gulf, and Waterford Unit 3, for issues safety related problems with maintenance and operator training. Recent inspections reveal ongoing problems at all of Entergy's facilities

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[31] Entergy Arkansas, Inc., Entergy Gulf States, Inc., Entergy Louisiana, Inc., and System Energy Resources, Inc.

[32] Office of Enforcement, U. S. Nuclear Regulatory Commission, *"Escalated Enforcement Actions Issued Since March 1996 for Reactor Licensees"* (June 22, 2000) at http://www.nrc.gov/OE/rpr/rx.htm

in areas such as "plant operations, the quality of maintenance activities, and the condition of plant material and equipment,"[34] "effective implementation of programs within the reactor safety strategic performance area,"[35] quality of engineering products,[36] "control and implementation of surveillance testing,"[37] "engineering staff efforts were not always effective in preventing and resolving degraded conditions of some balance of plant equipment."[38] The number of violations against Entergy rates among the highest of US operators, and it appears that the improved capacity factors at Entergy facilities are shadowed by questionable maintenance practices and inadequate procedures, work performance, and operator training. This record does not justify the special privelege of becoming one of a few companies entrusted with consolidating the ownership and operation of the nation's nuclear stations, for which Entergy is asking the Commission through the Pilgrim, FitzPatrick, and IP3 license transfer applications.

Moreover, Entergy's problems at its nuclear facilities are not unique. Entergy has an established record in its transmission and delivery businesses of marginalizing safe operation for the sake of profit through chronically postponing maintenance and reducing the skilled workforce to levels that compromise worker and public health and safety. In 1998, the State of Texas Public Utility Commission (TPUC) fined Entergy Gulf States, Inc., $9 million and

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[33] *See* EA 96-025, Docket No. 50-382, *"NOTICE OF VIOLATION AND PROPOSED IMPOSITION OF CIVIL PENALTY - $50,000 (NRC Inspection Report No. 50-382/95-23)"* (March 28, 1996)

[34] U.S.N.R.C, *"PLANT PERFORMANCE REVIEW - WATERFORD STEAM ELECTRIC STATION, UNIT 3"* (March 31, 2000). See *also "PLANT PERFORMANCE REVIEW - GRAND GULF NUCLEAR STATION"* (March 31, 2000) and the associated notice of violation (Docket No. 50-416, EA 99-305) for similar problems with material conditions and maintenance at Grand Gulf

[35] Ibid.

[36] U.S.N.R.C., *"PLANT PERFORMANCE REVIEW - RIVER BEND STATION"* (MARCH 31, 2000)

[37] Ibid.

penalized the company with a rate reduction for "lack of effective and prudent maintenance policies, uneven spending in the area of operations and maintenance (O&M), cuts in experience personnel, and consequent deterioration in the quality of service."[39] Among the problems that the TPUC cited were Entergy's negligence in routine inspections and preventative maintenance of the transmission system, and the inability to handle emergency situations due to the reduced workforce.[40] The TPUC also cited problems with lack of clear accountability and lines of communication between Entergy and its holding company subsidiaries, the company's willingness to sacrifice service to certain customers more than others, and the Entergy's practice of maintaining "a list of 'politically sensitive' accounts, which suggests that some customers may receive preferential treatment."

The TPUC findings are consistent with more recent findings by the Council of the City New Orleans (July, 1998) and reports and testimony following the July 23, 1999 episode of rolling blackouts that affected 555,680 Entergy customers in a four-state area. Entergy has an established record of cutting corners on operations and maintenance in nearly every aspect of its business, from transmission and delivery, to customer service, to generation. Furthermore, the consistency of this record across Entergy's subsidiaries and areas of operations -- and the TPUC's findings on the relationships, chain of command, and lines of communication between the subsidiaries and the parent corporation – implicate the policies and directives. The willingness to sacrifice worker and public health and safety while "the company has available

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[38] U.S.N.R.C., *"PLANT PERFORMANCE REVIEW - PILGRIM NUCLEAR POWER STATION"* (March 31, 2000)

[39] Public Utility Commission of Texas, PUC Docket No. 18249, *Entergy Gulf States, Inc., Service Quality Issues* (February, 1998).

[40] Ibid.

funds that should be sufficient to provide higher-quality service,"[41] questions about discrimination against certain demographics of customers in deference to "politically sensitive" accounts,[42] and evidence of public misrepresentation during times of emergency[43] implicate the character of Entergy Corporation. Character of the licensee is an appropriate issue in a proceeding to transfer a license. *Georgia Power Co*,. 38 NRC 25 (1993, CLI); *Metropolitan Edison Co.*, 21 NRC 1118 (1985, CLI). Because of these concerns, and since the leadership of ENF and ENIP are also, for the most part, Officers and Executives of Entergy Corporation, the Commission must investigate these matters as they pertain to: (1) the need to reduce operating costs at FitzPatrick and Indian Point 3 and the company's plans for meeting that need; (2) Entergy's plans to decommission plants at or below the sum available in the decommissioning fund; (3) Entergy's ability to provide financial support to the operation of FitzPatrick and Indian Point 3 and support decommissioning cost overruns; and (4) Entergy's intention to amass a large of fleet of US nuclear stations, of which the instant case is one of the first steps.

Entergy's cost-cutting measures, while operating an increasing fleet of aging reactors in a deregulated energy market, have dire implications for the public health and safety and could cause harm to CAN's representative members. See Declarations of Jean Chambers and Marilyn Elie, Exhibits 1 and 2, attached hereto. They could suffer property damage due to increased electrical rates in the event that under emergency conditions, Entergy would be able to litigate to affect rate increases to try to meet its shortfalls due to incomplete clean-up and no post-Price Anderson qualified insurance coverage, but the radiation dangers of inadequate clean-up, leading

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[41] Ibid.

[42] Ibid. See also, Groesch, Gary L., *"Report to New Orleans City Council for the Alliance for Affordable Energy"* (August 13, 1999). Exhibit 9, attached hereto.

[43] Ibid. See also Groesch, Gary L., *"Statement before the New Orleans City Council Utility Committee"* (August 12, 1999). Exhibit 9, attached hereto.

to dangerous radiation left on the sites, would harm their health and safety and harm their ability to enjoy the natural environment around them, and, in particular, utilize the FitzPatrick and Indian Point 3 sites after final site release.

C. Entergy's operation of FitzPatrick and Indian Point 3 through its non-utility subsidiaries will subject the operation of the nuclear stations to pressures to reduce cost that constitute an unanalyzed condition, adverse to safety, that must be reviewed and resolved prior to transferring the operating licenses.

It is commonly accepted that utility deregulation will require nuclear operators to be reduce operating costs in order for nuclear power to become competitive with other generation sources.. This will require reducing outage time, so that reactors operate at higher capacity factors, and reducing the size of the workforce. Entergy's license transfer applications describe the need for Entergy to operate FitzPatrick and IP3 each at an average 85% capacity. According to the unofficial figures available to the public through the media, this would be a substantial increase over the lifetime capacity factors FitzPatrick and IP3 have been able to achieve. Judging from the estimated operating revenues Entergy presents in the license transfer applications, ENF, ENIP and ENO will operate the reactors each at 90% capacity in non-refuelling years, and at 80% in refuelling years. Since these levels of performance have never been sustained for extended periods of time in FitzPatrick's and Indian Point 3's operating histories – and since the reactors are aging and becoming more embrittled – Entergy is gambling that they can improve performance and duplicate the experience at ANO and River Bend.

However, ANO and River Bend were much younger reactors when Entergy took them over, and were not suffering from the problems of aging-related degradation that FitzPatrick and IP3 suffer from. Furthermore, according to reports by IP3 workers published in the media, NYPA was only able to complete the refuelling outage at IP3 on the schedule Entergy will need to maintain by unnecessarily exposing the workforce to radiation. 188 workers were exposed during the outage, many of them while working in areas of the plant in which the air conditioning was broken. Rather than wait to repair the air conditioning, workers were asked to reduce their protective gear under pressure to complete the outage on schedule. Thus, the schedule was only maintained, in at least this one instance, by postponing maintenance on equipment and sacrificing the safety of the workers. The expectation that Entergy will be able to safely reduce maintenance and refuelling outage time, or safely postpone maintenance until it is convenient to schedule it, must be investigated through a hearing process with the opportunity for cross-examination.

Recent internal reports on Consolidated Edison's operation of Indian Point 2 should serve as a bellwether for the strategy of cost-cutting under utility deregulation. A recent *New York Times* article reports:

> Consolidated Edison decided in 1997 not to replace the steam generator that would cause an accident at a Westchester County nuclear reactor two and a half years later because the company was uncertain whether the move was a good financial bet in the deregulated market that was developing, according to an internal planning document. ...
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> In October 1997, Con Ed financial planners concluded that replacing the reactor's steam generators soon was the cheapest option for customers and shareholders. Their analysis noted that the generators were deteriorating -- a common occurrence in reactors -- limiting how much electricity they could produce. And if the generators were not replaced, they would have to be inspected more often, cutting the number of days the plant could run, according to the planners' document, which was provided to *The New York Times* by Edward A. Smeloff, a utility expert at Pace University Law School who has been critical of Con Ed's performance in running the reactor. But Con Ed's analysis also pointed out that its financial projections were highly sensitive to the price of electricity and that postponing a decision would give the company an opportunity to refine its estimates as the state made its transition to a deregulated electricity market. That transformation happened last November.
>
> In their analysis, the financial planners accepted a judgment -- which

> turned out to be wrong -- by Con Ed engineers that the existing steam generators were safe for continued use, although if kept in place they would need an extra inspection each year. ...[44]

Based on the NRC Augmented Inspection Team findings following the February 15, 2000 steam generator tube rupture at IP2, ConEd failed to do maintenance on a number of safety-significant systems: Isolation Valve Seal Water System, Condenser Vacuum Pump, and the Steam Jet Air Ejector steam supply pressure regulator, which "had never worked properly."[45] The inability of Entergy to recover unexpected or increased operating costs from ratepayers under deregulation and the Power Purchase Agreement – compounded by the need to maintain an 85% minimum capacity factor – will put Entergy under similar pressures that forced Consolidated Edison to postpone maintenance on IP2's steam generators, and presumably other systems as well. These findings plainly challenge the NRC's preliminary evaluations that the pressures of deregulated electricity markets do not present adverse or unanalyzed conditions for nuclear safety. In light of the findings at IP2, the Commission must analyze the transfer of commercial power reactors to non-utility operators with greater scrutiny to ensure that the proposed conditions, plans, strategy for operations are consistent with protecting the public and worker health and safety, beginning with the instant case.

In the license transfer applications Entergy assumes that it will retain the existing workforce. Entergy further avers that it will not begin downsizing until 2001, and that it will not do so by "firing" workers. Instead, Entergy has publicly described relying on a process it calls "natural attrition," or the retirement of the most experienced workers at FitzPatrick and Indian

[44] Wald, Matthew, *"Con Ed Put Off Plant Upgrade Over Rate Fear,"* NEW YORK TIMES (June 30, 2000).
[45] Report No. 05000247/2000-002, *Attachment 2 "IP2 Steam Generator Tube Leak (2/15/00) Sequence of Events and Organization Response Time Line"* (April 28, 2000).

Point 3, after which Entergy will presumably not hire replacements.[46] Thus, not only will the workforce at FitzPatrick and IP3 be reduced, potentially to levels adverse to safety, but the knowledge base of the facilities will gradually and silently erode through the attrition of the most experienced workers. Furthermore, there are reports that workers have already begun leaving FitzPatrick and Indian Point 3 at double the normal attrition rate, rather than wait to be laid off.[47] The impact on staffing levels, work loads, and morale must also be analyzed and reviewed, both in terms of the immediate condition and safety of Indian Point 3 and FitzPatrick, and for its implications for Entergy's application and plans to take over operation of the facilities.

The dangers of a reduced workforce, and the consequent excessive reliance on overtime and/or contractors has been established at British Energy's nuclear stations in the United Kingdom and Entergy's transmission and delivery business. BE's record has been made relevant in the US through its part-ownership of AmerGen, and AmerGen's reliance on BE for its operational and management experience and expertise. In the absence of an in-depth review of staffing level issues at US nuclear facilities, the NRC, the industry and the public can only rely on relevant experience in other countries or aspects of the industry where the conditions of market pressures and workforce reduction are more established.

BE has been repeatedly cited for its unsafe job cutting practices at nuclear stations in the UK and Scotland. In fact the Nuclear Installations Inspectorate ordered BE to halt its "job reduction" program until BE could demonstrate that the cutbacks would not jeopardize safety. It has yet to do so.[48] BE was repeatedly cited by the Inspectorate for its job slashing, which

[46] Public Meeting to Review the Proposed Sale, Scriba Town Fire Hall (February 24, 2000).
[47] Schneider, P.D., *"Nuke Workers Worried about Jobs, Safety,"* OSWEGO PALLADIUM TIMES (July 20, 2000). Exhibit 10, attached hereto.
[48] *Safety Watchdog Orders British Energy to Halt Job Reductions*, THE INDEPENDENT (London, U.K.) (January 28, 2000).

marginalized safety at its nuclear stations. The Inspectorate said that because of a lack of control over the retention of the key skill base and the intelligent customer requirement, they found that the Licensee's capability in some areas now resides in single experts and that this is not good practice in a company that operates 11 reactors and provides – 20% of the country's energy supply.[49] The Report illustrates another vulnerability, which is a shortage or lack of key expertise in irradiation embrittlement, and autenitic steel inspection, an essential department considering age-related deterioration at nuclear generating stations.[50]

BE's inability to effectively assess appropriate job cuts marginalizes safety at its nuclear generating stations. A loss of experienced workers or the extensive overwork of a smaller pool of worker has adverse effects upon safety. The UK Inspectorate Report team were of the opinion that a "long hours culture" exits within the Licensee [BE--AmerGen's 50% parent], especially in areas where work pressures are high. The team believed that the data it collected are indicative that BE too extensively reduced resource levels in a variety of areas and this is not good for nuclear safety.[51] Although BE believed that job cutting entailed "trimming the fat" in the corporation, and that remaining staff could easily manage the workload (similarly to what AmerGen intends to do at VYNPS and other facilities), this proved to be a false assumption.

The Report found that key workers in many areas work long hours. Thus, it is not possible to recover from the situation quickly: the vulnerabilities are likely to persist for some years regardless of any counter measures that are introduced.[52]. In reactor systems branch audit, the Report states that:

[49] HSE, *Safety Management Audit*, *supra* note 31 at 11-12.
[50] *Id.* at 12.
[51] *Id.*, No. 69 at 14.
[52] *Id.*, No. 81 at 16-17.

> This branch exhibited many of the problems common to other areas within Engineering Division, notably: reductions in staff not being matched by reductions in workload: significant levels of overtime working (up to 25% in excess of standard hours with higher short term peaks) and under reporting of overtime; a general view among the staff that specialists are no longer valued within BEGL…and an increasing reliance upon contractors to provide technical support.[53]

BE did not have the systems in place to evaluate either job cutting or the effects such cuts could have in terms of overwork on the remaining workforce and, hence, job performance and safety. For example, loss of staff and excessive overtime work of remaining employees in the "Assessment Branch" created a situation in which the employees had such heavy work loads that the Branch was "unable to undertake the full range of activities which we expect to find, and which they would wish to discharge -- for example, to follow up on the implementation of modifications at the stations, to investigate root causes of rejected or poor quality cases, or to undertake a more comprehensive review on a same of safety cases."[54]

If these "forced" overtime practices are allowed to be used at FitzPatrick or Indian Point 3 (or other Entergy reactors), dangerous results will surely follow. *See generally*, Declaration of David Lochbaum, ¶9 (a), Exhibit 3 and attachment to same, Exhibit 'B', a report on overtime and its effects in the nuclear industry. As Mr. Lochbaum indicated, this situation makes an accident more likely to occur at Vermont Yankee. Declaration of David Lochbaum at ¶9(a). Thus, CAN's members may be harmed under such conditions. Declarations of Jean Chambers and Marilyn Elie, Exhibits 1 and 2, attached hereto. Failure to address this issue would be a harm in itself to persons such as CAN's representative members who want to be able to enjoy the natural environment in the area now occupied by FitzPatrick and Indian Point 3. To be unable to freely hike and recreate there for fear of both contamination and an inability to obtain any recovery for

[53] *Id.* at 29.

radioactive contamination due to such activities is a genuine harm. See Declarations of Jean Chambers and Marilyn Elie, Exhibits 1 and 2, attached hereto. The NRC's failure to order full hearing on this issue places local residents and CAN members at risk. Declarations of Jean Chambers and Marilyn Elie, Exhibits 1 and 2, attached hereto. They could suffer property damage due to increased electrical rates in the event that under emergency conditions, Entergy would be able to litigate to affect rate increases to try to meet its shortfalls due to incomplete clean-up and no post-Price Anderson qualified insurance coverage, but the radiation dangers of inadequate clean-up, leading to dangerous radiation left on the sites, would harm their health and safety and harm their ability to enjoy the natural environment around them, and, in particular, utilize the FitzPatrick and Indian Point 3 sites after final site release.

If the NRC holds the requested hearing, CAN will have an opportunity to present evidence to the Commission (or ASLB panel) which could lead to conditions being placed upon the license transfer that would avoid the harm to CAN (and its representative member). Conditions controlling hours, overtime, and establishing proper parameters for the handling and accumulating of adequate decommissioning funds would cure the harms to CAN and its representative members. This satisfies the requirement of 10 CFR §§ 2.1306, 2.1308 for an admissible interest and standing, and this issue should be taken up for hearing. It also involves more than mere financial matters and, thus, implicates a more detailed hearing process than is provided under 10 C.F.R. Subpart M. Therefore, the NRC should, pursuant to 10 C.F.R. § 2.1329(b), upon need to resolve such special issues not properly within a simple license transfer, conduct a 10 CFR Subpart G proceeding.

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[54] *Id.* at 38.

3. Given the historical problems at the FitzPatrick and Indian Point Unit 3 nuclear generating stations, CAN believes that an Environmental Impact Study is warranted before license transfer application is approved to protect the health and safety of the workers and the public.

FitzPatrick and Indian Point 3, like other Northeast reactors, have experienced serious problems with the accuracy of their Final Safety Analysis Reports, and compliance with design bases and technical specifications. As of August, 1999, Indian Point 3 was rated in the bottom quintile of US nuclear stations for design basis documentation compliance. FitzPatrick has had chronic failures of its emergency core cooling systems; personnel errors have compounded these failures, complicating, and even initiating in some cases, emergency shutdowns. Indian Point 3 has documented problems with inadequate cable separation and other electrical equipment standards. Both reactors have an acknowledged inability to satisfy leak-before-break detection standards for mitigating the safety risks of aging-related embrittlement.

Many of the underlying operational and performance problems still plaguing FitzPatrick and Indian Point 3 were identified by Entergy in 1996, during its due diligence review of FitzPatrick and Indian Point 3. At the time, Entergy was considering entering into an agreement with NYPA to operate the reactors. Entergy conducted a due diligence investigation based on industry and Institute for Nuclear Power Operations standards. The findings included problems at both FitzPatrick and Indian Point 3: safety culture; ability to set priorities appropriately; plant technology and material condition; inadequate maintenance and outage planning.[55] One of the most significant problem areas with the "organizational structure and accountabilities" of NYPA's nuclear operations:

- No site Vice President
- No real focal point for site accountability

[55] Entergy, *"Summary of the 1996 Entergy Due Diligence Process,"* (November, 1996). Exhibit 5, attached hereto.

- Key functions have off-site or out-of-nuclear reporting
- Key projects are managed by corporate, rather than plant, project managers
- Corporate engineering control of programs compounds problems with on-site engineering groups[56]

One of the most striking results of these conditions in a "operations not clearly 'owning' the plant and driving the processes." Based on the findings, Entergy decided not to enter into the agreement with NYPA in 1996.

Since FitzPatrick and Indian Point 3 still exhibit many of the problems described, and even predicted, in Entergy's 1996 investigation, it is unclear why Entergy's evaluation of FitzPatrick and Indian Point 3 has changed. In 1996, Entergy was only considering an agreement to become the licensed operator under contract from NYPA, which involves significantly less liability than actually assuming ownership of two aging nuclear generating stations. These matters warrant a thorough public review and analysis by the NRC to understand Entergy's rationale for purchasing FitzPatrick and Indian Point 3: whether that reflects a change in safety standards or a different "cost-benefit analysis" wherein the priority of safety relative to Entergy's ability to profit through the deal has changed. Furthermore, the NRC must review the safety impact of Entergy's proposed operating agreements and the limited liability ownership structure, which shields Entergy Corporation from financial liability for safety problems at FitzPatrick and Indian Point 3.

The corporate structure of ownership and operations Entergy has proposed for the acquisition of FitzPatrick and Indian Point 3 is directly affected by these questions, and affects Entergy's ability to provide adequate assurance for the safe operation of FitzPatrick and Indian Point. There are numerous aspects of these arrangements that are unclear, due to the nature and extent material redacted from the publicly available documents, and it is impossible for the public be assured that the Entergy's applications will protect the public health and safety. For instance, the Entergy Nuclear Investment Companies #1 and #2 [the Investment Companies, or IC's], shown in Enclosure 6 of both applications, are described nowhere else in the publicly available documents. It is unclear what their role will be relative to ENF and ENIP, respectively, nor what the "criss-crossing" lines of relationship indicate for their legal, financial, and operational roles. Furthermore, the possibility that the IC's will have some sort of fiscal decision-making authority over the availability of funds to ENF and ENIP portends the same problems of corporate control over operations, and lack of "site ownership" by operations personnel, that Entergy criticized in NYPA four years ago. The overlapping responsibilities of ENF and ENIP's corporate officers with Entergy Corporation and other Entergy companies and subsidiaries portends a crisis of accountability and the ability of site personnel to have authority with regard to safety concerns.

The NRC's failure to order full hearing on this issue places local residents and CAN members at risk. Declarations of Jean Chambers and Marilyn Elie, Exhibits 1 and 2, attached hereto. They could suffer property damage due to increased electrical rates in the event that under emergency conditions, Entergy would be able to litigate to affect rate increases to try to meet its shortfalls due to incomplete clean-up and no post-Price Anderson qualified insurance coverage, but the radiation dangers of inadequate clean-up, leading to dangerous radiation left on the sites, would harm their health and safety and harm their ability to enjoy the natural environment around them, and, in particular, utilize the FitzPatrick and Indian Point 3 sites after final site release.

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[56] Ibid.

If the NRC holds the requested hearing, CAN will have an opportunity to present evidence to the Commission (or ASLB panel) which could lead to conditions being placed upon the license transfer that would avoid the harm to CAN (and its representative member). Conditions controlling hours, overtime, and establishing proper parameters for the handling and accumulating of adequate decommissioning funds would cure the harms to CAN and its representative members. This satisfies the requirement of 10 CFR §§ 2.1306, 2.1308 for an admissible interest and standing, and this issue should be taken up for hearing. It also involves more than mere financial matters and, thus, implicates a more detailed hearing process than is provided under 10 C.F.R. Subpart M. Therefore, the NRC should, pursuant to 10 C.F.R. § 2.1329(b), upon need to resolve such special issues not properly within a simple license transfer, conduct a 10 CFR Subpart G proceeding.

4. Given the historical problems in NRC Region I, CAN contends that an independent evaluation of the James A. FitzPatrick and Indian Point Unit 3 nuclear power plants is required before any license transfer applications can proceed.

CAN has documented NRC Region I's abdication of regulatory oversight. The NRC is well aware of the historic, systemic mismanagement at nuclear generating stations in the Northeast. The Millstone debacle has raised serious concerns in communities surrounding these nuclear generating stations over the ability of the NRC to protect the health and safety of both workers and ordinary people who have little power to control the actions of large corporations and conglomerates such as Entergy.

Since 1996, CAN has petitioned the NRC to investigate NRC Region I in order to understand the root causes for the NRC's miserable regulatory failures in its oversight of the Millstone complex, Connecticut Yankee, Vermont Yankee, Maine Yankee, Pilgrim, and Yankee

Rowe.[57] In fact, portions of the key petition are *still* pending. The NRC has yet to determine the root causes of chronic, systemic mismanagement, and the deficiencies in the NRC regulatory oversight in Region I, which allowed (and continue to allow) deficiencies to exist at nuclear generating stations, appears intact. A proper analysis of this lapse in oversight would have increased public confidence in the NRC's regulatory abilities, and, more important, allowed the NRC to implement effective solutions to the problems. CAN has zero confidence that the NRC's current risk-based regulatory approach will do anything positive about the Region I deficits. In fact, such an approach will only further confound the apparent regulatory anarchy in Region I.

Public Citizen issued a report on NRC oversight which reaches a similar conclusion to CAN's concerning endemic problems. The Public Citizen report concludes that the frequency and quantity of design basis documentation problems it reviewed could only occur (and persist) in the absence of effective NRC regulation and oversight.[58]

Until the staff deficiency in Region I is resolved, CAN contends that, in order to protect the health and safety of the workers and the public who will likely be harmed if the FitzPatrick and Indian Point 3 licenses are transferred to an overburdened company with a poor performance history, the NRC must commission an independent analysis to determine the actual condition of FitzPatrick and Indian Point 3. The license transfers should be denied until the NRC has completed and reviewed a detailed analysis of the reactors. Such an analysis will serve the dual role of informing Entergy of the nature and extent of any and all systemic problems at

[57] *See, e.g.*, Citizens Awareness Network, *Petition For Enforcement, Pursuant To 10CFR 2.206 To Revoke Northeast Utilities Operating Licenses for the Connecticut Nuclear Power Stations Due To Chronic, Systemic Mismanagement Resulting in Significant Violations of NRC Safety Regulations, and To Investigate the NRC's Staff's Responsibility For Not Dealing With This Problem For Over A Decade* at 1-6, 18-22 (November 25, 1996)

FitzPatrick and IP3. It will also preserve "institutional" memory concerning spills, contamination, and other decommissioning and site clean-up related matters. As the new owner will be shifting personnel, without such an intensive study now, information crucial to effective site remediation will be lost. *See* Declaration of David Lochbaum at ¶9(c), Exhibit 3, attached hereto. Unlike Maine Yankee, which Mr. Lochbaum used as an example of the process that should be undertaken at VYNPS, VYNPS would have a new owner and undergo personnel changes. Steps, as Mr. Lochbaum pointed out, for sound reasons of public health and safety, should be taken to preserve this information intact. *Id.* FitzPatrick's and Indian Point 3's operational histories are comparable to, if not worse than, Vermont Yankee's and the review of license transfer applications would benefit from the same degree of assessment and analysis.

Failure to order such an analysis prior to sale places CAN members in the neighborhood at risk. Declarations of Jean Chambers and Marilyn Elie, Exhibits 1 and 2, attached hereto. They could suffer property damage due to increased electrical rates in the event that under emergency conditions, Entergy would be able to litigate to affect rate increases to try to meet its shortfalls due to incomplete clean-up and no post-Price Anderson qualified insurance coverage, but the radiation dangers of inadequate clean-up, leading to dangerous radiation left on the sites, would harm their health and safety and harm their ability to enjoy the natural environment around them, and, in particular, utilize the FitzPatrick and Indian Point 3 sites after final site release.

If the NRC holds the requested hearing, CAN will have an opportunity to present evidence to the Commission (or ASLB panel) which could lead to conditions being placed upon

[58] Riccio, James P., *Amnesty Irrational: How the Nuclear Regulatory Commission Fails to Hold Nuclear Reactors Accountable for Violations of Its Own Safety Regulations*, Public Citizen (August, 1999).

the license transfers that would avoid the harm to CAN (and its representative members). Conditions controlling hours, overtime, and establishing proper parameters for the handling and accumulating of adequate decommissioning funds, and preserving institutional memory within the context of a broad-based independent review of the entire FitzPatrick and Indian Point 3 facilities would cure the harms to CAN and its representative members. This satisfies the requirements of 10 CFR §§ 2.1306 , 2.1308 for an admissible interest and standing, and this issue should be taken up for hearing. It also involves more than mere financial matters and, thus, implicates a more detailed hearing process than is provided under 10 C.F.R. Subpart M. It needs the intensive investigatory power which cross examination of evidence and witnesses provides. Therefore, the NRC should, pursuant to 10 C.F.R. § 2.1329(b), upon need to resolve such special issues not properly within a simple license transfer, conduct a 10 CFR Subpart G proceeding.

5. CAN contends that the license transfer should be denied until ENF and ENIP and their parent corporation establish baseline funding that is clearly defined and substantially increased over current levels to address the dangers to public health and safety inherent in permitting the controversial and risky endeavor in which they are engaged.

Entergy is only committing a total of $90 million to insure ENF's and ENIP's ownership of FitzPatrick and Indian Point 3. This is less than half what AmerGen's parent companies have committed to support AmerGen's acquisitions. Entergy must be required to commit more funding to support its new acquisitions. Furthermore, the conditions and arrangements of Entergy's financial commitments to ENF and ENIP are uncertain. The publicly available documents do not explain, for instance, whether the $50 million Letter of Credit from Entergy Global Investments, Inc., is to support <u>all</u> of Entergy's nuclear acquisitions, including Pilgrim at this point, and potentially a half-dozen other nuclear stations in the Northeast. It is also not clear whether those funds are immediately available to ENF and ENIP upon their assumption of operation of the facilities, or whether it is contingent upon the initial $50 million Letter of Credit from Entergy Corporation being repaid. Entergy's ability to live up to commitments made under the Purchase and Sale Agreement and the license transfer applications make stringent demands to generate revenues through continued operation. Since FitzPatrick and IP3 have never been able to meet such standards for the sustained periods Entergy is projecting, and because maintenance outage costs for two reactors can easily exceed the $90 million available to FitzPatrick and IP3, there must be adequate assurance that fate of the facilities will not compromise worker and public health and safety. This would also reduce the pressure on ENF, ENIP and ENO to put off and/or rush maintenance outages out of economic necessity, since more financial support would be likely to be available. The NRC must hold a full hearing and thorough public review to investigate these matters and determine an adequate level of financial assurance and clear and transparent arrangements that do not undermine the safe operation of FitzPatrick and Indian Point 3.

The NRC's failure to order full hearing on this issue places local residents and CAN members at risk. Declarations of Jean Chambers and Marilyn Elie, Exhibits 1 and 2, attached hereto. They could suffer property damage due to increased electrical rates in the event that under emergency conditions, Entergy would be able to litigate to affect rate increases to try to meet its shortfalls due to incomplete clean-up and no post-Price Anderson qualified insurance coverage, but the radiation dangers of inadequate clean-up, leading to dangerous radiation left on the sites, would harm their health and safety and harm their ability to enjoy the natural environment around them, and, in particular, utilize the FitzPatrick and Indian Point 3 sites after final site release.

If the NRC holds the requested hearing, CAN will have an opportunity to present evidence to the Commission (or ASLB panel) which could lead to conditions being placed upon the license transfer that would avoid the harm to CAN (and its representative member). Conditions controlling hours, overtime, and establishing proper parameters for the handling and accumulating of adequate decommissioning funds would cure the harms to CAN and its representative members. This satisfies the requirement of 10 CFR §§ 2.1306, 2.1308 for an admissible interest and standing, and this issue should be taken up for hearing. It also involves more than mere financial matters and, thus, implicates a more detailed hearing process than is provided under 10 C.F.R. Subpart M. Therefore, the NRC should, pursuant to 10 C.F.R. § 2.1329(b), upon need to resolve such special issues not properly within a simple license transfer, conduct a 10 CFR Subpart G proceeding.

6. **NRC has not adequately examined the implications of Entergy's commitment to establish a fleet of nuclear power stations in the US in light of the serious anti-trust implications of such a fleet in the hands of what is, essentially, a single company. These implications include, but are not limited to: (a) regional, and even national, energy dependence on a single supplier, a matter potentially adverse to the national interest and national security, and (b) health and safety issues for workers and persons living in proximity to FitzPatrick, Indian Point 3, or any of the facilities in the event that the single corporate holder is unable to maintain the necessary capital flow for operations, maintenance, repairs, and/or decommissioning.**

Entergy has committed to acquiring up to 9 nuclear stations in the Northeast.[59] It is planning to acquire nuclear stations in the Midwest and on the West Coast.[60] Entergy has not demonstrated that it has the adequate funding to pursue its endeavors. Entergy owns 5 reactors

[59] Moore, Matt, *"5 Wanted: Nuclear Reactors, Serious Inquiries Only,"* ASSOCIATED PRESS (April 2, 2000).
[60] Ibid. *See also* Entergy Corporation, *"Annual Report 1999,"* (March 2000) at page 23.

in the South. If Entergy is even modestly successful, within two years it could control approximately 20% or more of the generating capacity in New York and New England, the US's most densely populated region; within a few more years, if Entergy is successful in its efforts to move into the Midwest and West Coast, the company could control 20-25% of the nuclear generating capacity in the US, on par with the AmerGen/Excelon combine.

In the license transfer applications, Entergy avers that the requirements under 10 CFR §50.33a are not applicable, by Commission determination that "the Atomic Energy Act of 1954 as amended does not require or authorize anti-trust reviews of post-operating license transfer applications." However, Entergy provides no citation substantiating this representation, and the activity of constructing nuclear facilities was clearly not what prompted the need for anti-trust review under §50.33a, for the conditions described in §50.33a(a)(1)-(3) have to do with the total generation capacity of the license applicant. The anti-trust consideration is not over how many power plants a single licensee can build, but rather over how much electric generation rests in the hands of a single owner -- thus the 1400 MW(e) standard, and not a specification about how many generating stations the applicant may construct. Although the instant case, and the process of nuclear industry restructuring, were unanticipated in the development of 10 CFR §50, the concern over consolidation of the electric generation supply in the hands of a single owner is clearly relevant and applicable, especially as regards nuclear generation. Therefore, the NRC has a Congressionally mandated oversight duty on antitrust matters in license transfer proceedings under Atomic Energy Act of 1946, as amended 1954, et seq [AEA]. §§105, 184; 42 USC §§ 2135(c), 2234, and related portions concerning the licensing of nuclear facilities and the NRC's oversight authorities for such licensees. The NRC, in the interests of public and occupational health and safety, must exercise this antitrust investigative power which Congress mandated in all licensing actions. The purpose of this express grant of authority and mandate for action in AEA § 105 and 184 and related portions of the Act, is to prevent any regulatory gap in the approval of a highly dangerous activity -- NRC licensee operations of nuclear powered electric generating facilities. Such NRC licensee operations endanger employees and persons living and working in nearby communities on a daily basis. They also endanger larger populations and the natural environment given the possibility of accidents which could contaminate rivers and drinking water sources, as well as land, air, people, crops, livestock, and domestic animals. They endanger CAN and its representative members. Plainly, such dangers are multiplied in the event an NRC nuclear licensee cannot meet its financial obligations due to financial shortfalls which could easily be triggered due to the effects of over-reaching in ownership of such facilities. This is a situation which must be investigated fully in the context of this license transfer application considering the issues set forth herein above.

In addition, given the age of many of the facilities now up for sale, financial problems could also occur due to multiple closures of facilities precipitated by accidents, repairs, enforcement actions, decommissioning, and various combinations of such events. Thus, to characterize an antitrust analysis as relating strictly to administrative matters and financial considerations is to fail to see the proverbial forest for the trees. The health and safety problems which may arise due to NRC permitted conglomeration of nuclear reactor holdings is not at all speculative, particularly in the context of: Entergy's current buying pattern; the behavior and ownership responsibilities of Entergy Corporation and its other subsidiaries; the historic problems of the reactors Entergy is acquiring and others owned by Entergy; and Entergy's commitment to obtaining regional, and even national, dominance in nuclear generation. In the event that incidents at its holdings trigger acute cash flow problems, due to the fact that multiple nuclear facilities are involved, the consequences could range from "mere" losses of power to large segments of the country during times when it is vital (e.g., winter cold conditions or hot summer months), to failure to prevent (or triggering) nuclear accidents, and releases of nuclear material and radiation from facilities (with the incident harm to persons and property on a massive scale).

Moreover, in a competitive environment, owners of a large number of nuclear facilities -- as Entergy wants to be and is on its way to becoming -- will likely try to cut costs in every available way to maximize their profits, including the kind of overtime practices described by CAN's expert, David Lochbaum and detailed in Exhibit 'B' to his Exhibit 3, attached hereto. These likely scenarios Mr. Lochbaum described pose genuine risks of harm to CAN and its members are applicable to Entergy and the instant case, as well as AmerGen and Vermont Yankee. Only under a full and formal adjudicatory process will the NRC acquire the kind of information necessary to place conditions on the license that will protect CAN and its members from harm.

Recently, in a yet to be completed rulemaking under which the NRC proposes to relinquish by interpretation the Congressionally mandated antitrust power it must exercise in granting licenses, the NRC has advanced the claim that a "lack of resources" to conduct antitrust evaluations at proposed licensed transfer is a reason to stop conducting such evaluations. Yet, considering such a resource allocation decision, nowhere in its cases or rulemaking does the NRC analyze the potential for harm faced by persons such as CAN's members, when failure to exercise that oversight at the license transfer stage leads to the need to exercise enforcement authority or supervise clean-up of a major accident due to violations of significant health and safety regulations at FitzPatrick or Indian Point 3 when they are owned under the umbrella of a single corporation with the burden of operating many, many nuclear facilities. In this way, the NRC's failure to conduct the kind of antitrust review Congress desired in a case like the one before it now is not only illegal, but endangers public and occupational health and safety, in particular, that of CAN and its members in New York. The NRC has not considered the costs and benefits of exercising the antitrust authority at license transfer stage in a case like this waiting to solve potential problems via inspection/enforcement. With an increased regulatory burden on the NRC's already shrunken and overworked inspection staffs, its will be difficult to offer adequate protection to persons, such as CAN's members, when owners, like Entergy, of multiple reactor facilities end up, under a cost-cutting attempt to maximize profits, with widespread health and safety violations at many different locations. Every locality, every reactor "community" -- like the ones CAN's New York members are in, will suffer the ill effects of the NRC failure to do the job Congress mandated it to do up front, at the licensing stage. Additional potentially serious, accident-triggering scenarios arise when one considers overtime patterns within the nuclear industry. *See*, Union of Concerned Scientists, Overtime and Staff Problems in the Commercial Nuclear Power Industry (March 1999), attached as Exhibit 'B' to Exhibit 3, Declaration of David Lochbaum, attached hereto.

Apparently, the NRC does not even have the resources necessary to follow out a simple risk assessment of the chains of events which plainly follow when a large-scale owner bent on maximizing profits takes either or both paths of increasing overtime coupled with staff-cutting, and/or firing qualified personnel and trades union members for replacement with lesser skilled and experienced contract labor. (Even when such contract labor is skilled and experienced, the skills and experience are not completely fungible--each nuclear facility, particularly the older ones which are now purchased on the cheap, having site-specific, particularistic configurations, problems, and out-of-usual design solutions.) The NRC has not done what Congress most clearly and plainly authorized and mandated in the Atomic Energy Act: evaluate the health and safety and national security consequences of actions in the process of nuclear licensing, production, operations, waste storage, and clean-up.

The NRC also fails to even evaluate, based upon any study of its own records in this regard, whether there are increased numbers of violations of NRC regulations among those facilities already owned in bulk by some licensees, the overtime and hiring practices of such licensees, and related matters. Failure to conduct the mandated antitrust evaluations prior to license transfer, as shown above, jeopardizes the human and natural environment. Thus, the NRC failure to conduct such antitrust evaluations during this period of rapid consolidation of nuclear reactor holdings under giant, partly foreign controlled mega-corporations, is, in itself, a major federal action affecting the quality of the human and natural environment. In this way, the NRC's failure to conduct an EIS of its decision to stop doing what Congress required under the AEA violates the National Environmental Policy Act, 42 U.S.C. §§4321, *et seq.*

The NRC states that "there will be no realistic gap in antitrust law enforcement if the NRC no longer performs antitrust reviews of post-operating license transfer applications." *Kansas Gas and Electric Company* (Wolf Creek Generating Station, Unit 1), CLI-99-19, 1999 NRC LEXIS 85 at *57, n22 (June 18, 1999). This conclusion, an historic about-face in the NRC's struggle to maintain regulatory hegemony over all matters nuclear, fails to consider that Congress <u>mandated</u> such reviews in operating licenses under its grant of discretion and authority to the NRC to ascertain that <u>any</u> nuclear related license which the NRC issues does not go to a foreign power or foreign dominated corporation, and is neither inimical to public and occupational health and safety nor national security. AEA § 184. This is not a strained interpretation. It is one that should be plain to anyone reading the statute as an entirety, instead of in a segmented way.

Furthermore, CAN's members' health and safety are jeopardized by the NRC's failure to conduct antitrust evaluations of the AmerGen license as no other agency which reviews this transaction is empowered to examine the antitrust implications of a licensing (or transfer of license) from the perspective of such an action's impact upon occupational and public health and safety and national security. Abdication of the AEA's Congressional charge to the NRC to conduct such antitrust evaluation and to make particular types of findings in granting (or transferring) of a license creates a dangerous gap in the regulatory scheme enacted under the Atomic Energy Act, §§105, 184, and related sections on licensing and issues related to licensing.

Congress, in the Atomic Energy Act, does not separate initial licensing and subsequent transfers in any way recognizing or characterizing the latter as deserving lesser attention from the NRC in antitrust matters. Nor, significantly, does the Atomic Energy Act or any other legislation lift from the NRC's shoulders the "burden" of making the requisite inquiries under AEA § 105 and 184. Furthermore, any silence on this difference, or lack of clarity which might be found in the statute, should be resolved using common sense and customary practice in language not the NRC's disinclination to deal with the issues or alleged lack of resources. It should also be resolved by reading the entire statute together as a whole, given the broad charge to the NRC to conduct its investigations for the purpose of assuring that public health and safety be protected and that the national interest be safeguarded in dealing with all aspects of the licensing of nuclear production, utilization, and waste disposal. If the NRC's alleged "lack of resources" were intended as a message from Congress, Congress would have, by legislation, tied resource allocation to specific acts or omission, and to changes laws governing NRC practices if it so desired. To date Congress has not done so. In fact, until Congress changes the law, Congress has, by law, directed the NRC to conduct such evaluations.

Unless and until the NRC conduct such antitrust evaluations considering occupational health and safety issues related to the development and licensing of nuclear conglomerates, as well as the national security implications of foreign domination of such corporations, no license transfer should be permitted in this matter. Only by providing a full adjudicatory process in this case will CAN's members receive the kind of assurance they deserve that they will be safe from harm under license transfers of the James A. FitzPatrick and Indian Point Unit 3 operating licenses to Entergy (or any other company). Failure to order such an analysis prior to sale places residents and CAN members in the neighborhood at risk. Declarations of Jean Chambers and Marilyn Elie, Exhibits 1 and 2, attached hereto.

They could suffer property damage due to increased electrical rates in the event that under emergency conditions, Entergy would be able to litigate to affect rate increases to try to meet its shortfalls due to incomplete clean-up and no post-Price Anderson qualified insurance coverage, but the radiation dangers of inadequate clean-up, leading to dangerous radiation left on the sites, would harm their health and safety and harm their ability to enjoy the natural environment around them, and, in particular, utilize the FitzPatrick and Indian Point 3 sites after final site release.

If the NRC holds the requested hearing, CAN will have an opportunity to present evidence to the Commission (or ASLB panel) which could lead to conditions being placed upon the license transfer that would avoid the harm to CAN (and its representative member). Conditions controlling hours, overtime, and establishing proper parameters for the handling and accumulating of adequate decommissioning funds, and preserving institutional memory within the context of a broad-based independent review of the entire VYNPS facility would cure the harms to CAN and its representative member. This satisfies the requirement of 10 CFR §§ 2.1306 , 2.1308 for an admissible interest and standing, and this issue should be taken up for hearing. It also involves more than mere financial matters and, thus, implicates a more detailed hearing process than is provided under 10 C.F.R. Subpart M. It needs the intensive investigatory power which cross examination of evidence and witnesses provides. Therefore, the NRC should, pursuant to 10 C.F.R. § 2.1329(b), upon need to resolve such special issues not properly within a simple license transfer, conduct a 10 CFR Subpart G proceeding.

7. **Entergy has committed to put up only $90 million to assure its non-utility nuclear subsidiaries have sufficient revenues to safely operate its fleet of reactors. The funds reasonably required to support an endeavor on the scale Entergy intends far exceed that amount. Given that: (a) many of Entergy's reactors will be in varying states of operation and decommissioning, (b) Price Anderson Act insurance does not cover decommissioning, and (c) decommissioning costs are always uncertain at best, it is plain that Entergy's generalized assurances are insufficient to permit license transfer.**

To adequately assess the implications of James A. FitzPatrick and Indian Point Unit 3 ownership within the context of Entergy's intended "portfolio" of nuclear generating companies, the NRC must conduct a full anti-trust review of the transactions, and obtain from Entergy a clear commitment to substantially increase funding, as requested in issue #6 above. In addition, however, a special account should be created to hold these reserve assets. This would create a degree of financial security sufficient to justify approval of such a risky venture. This is due to the lack of adequate insurance coverage under Price Anderson to cover complete cleanup. Declaration of David Lochbaum at ¶9(b), Exhibit 3, attached hereto. As Mr. Lochbaum stated:

> The license transfer may increase the potential for people not being compensated for illnesses or property damage caused by radiation released from the nuclear power plant sites. During the period of the operating license, the public is guaranteed under the Price-Anderson Act of 1957 and its amendments for compensation. The Price-Anderson liability coverage ends when the operating

> license is terminated even though radioactive material could remain at the site in harmful amounts. The change in ownership may make it more difficult for any person suffering loss caused by the release of radioactivity from the sites after license termination to receive compensation.

Id. Entergy has provided no assurances to the NRC concerning its financial abilities to cover contingencies outside Price Anderson insurance coverage as Mr. Lochbaum described it above. Given that CAN's members want to be able to freely enjoy the coasts of Lake Ontario and the Hudson River where FitzPatrick and Indian Point 3 now lie, the inability to compensate persons harmed from an incomplete cleanup is a genuine concern. The NRC should not allow the license transfer in this case without a full adjudicatory hearing on this issue in order to determine how Entergy would deal with the indemnification and compensation issues. Moreover, failure to address this issue would be a harm in itself to persons such as CAN's representative members who want to be able to enjoy the natural environment in the area now occupied by FitzPatrick and Indian Point 3. To be unable to freely hike and recreate there for fear of both contamination and an inability to obtain any recovery for radioactive contamination due to such activities is a genuine harm. See Declarations of Jean Chambers and Marilyn Elie, Exhibits 1 and 2, attached hereto. The NRC's failure to order full hearing on this issue places local residents and CAN members at risk. Declarations of Jean Chambers and Marilyn Elie, Exhibits 1 and 2, attached hereto.

They could suffer property damage due to increased electrical rates in the event that under emergency conditions, Entergy would be able to litigate to affect rate increases to try to meet its shortfalls due to incomplete clean-up and no post-Price Anderson qualified insurance coverage, but the radiation dangers of inadequate clean-up, leading to dangerous radiation left on the sites, would harm their health and safety and harm their ability to enjoy the natural environment around them, and, in particular, utilize the FitzPatrick and Indian Point 3 sites after final site release.

If the NRC holds the requested hearing, CAN will have an opportunity to present evidence to the Commission (or ASLB panel) which could lead to conditions being placed upon the license transfer that would avoid the harm to CAN (and its representative members). Conditions controlling hours, overtime, and establishing proper parameters for the handling and accumulation of adequate decommissioning funds, and preserving institutional memory within the context of a broad-based independent review of the entire FitzPatrick and Indian Point 3 facilities, analyzing the antitrust implications of the sale, conducting an environmental study of the sites, and dealing with this indemnification issue would cure the harms to CAN and its representative member.

As such, this issue, along with all the others, satisfies the requirement of 10 CFR §§ 2.1306, 2.1308 for an admissible interest and standing, and this issue should be taken up for hearing. As the issues raised involve more than mere financial matters, a more detailed hearing process than is provided under 10 C.F.R. Subpart M is appropriate in this case. To resolve the matters CAN has raised requires the intensive investigatory power which only the proverbial engine of cross examination of evidence and witnesses can provide. Therefore, the NRC should, pursuant to 10 C.F.R. § 2.1329(b), upon need to resolve such special issues not properly within a simple license transfer, conduct a 10 CFR Subpart G proceeding.

CONCLUSION

For the reasons set forth above, CAN requests a full, substantive hearing on the license transfer request at issue, and the granting of the Petition to Intervene in such a hearing, and that its motions in this matter be granted.

DATED this ~~22~~ 31st day of ~~February~~ July, 2000.
(TEJ) (TLJ)

Respectfully submitted:

CITIZENS AWARENESS NETWORK, INC.

BY: Timothy L Judson
Timothy L. Judson, CAN

pro se for CAN

Citizens Awarness Network, Inc.
162 Cambridge St.
Syracuse, NY 13210
(315) 475-1203

State of New York
County of Onondaga

On 31st July, 2000 the above signed Timothy L. Judson appeared before me and affirmed that the above Declaration is true and correct and he signed it as his free act and deed.

Gerarda Russo, Notary

GERARDA RUSSO
Notary Public, State of New York
Qualified in Onon. Co. No. 01RU6031513
My Commission Expires Oct. 4, 2001

cc: Office of Secretary;
Service List

Exhibit 1

Declaration of Jean Chambers, Representative Member of Citizens Awareness Network, Inc.

July 31, 2000

The Secretary of the Commission
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001
ATTN: Rulemakings and Adjudications Staff

Docket No. 50-333 - In the Matter of Power Authority of the State of New York, Entergy Nuclear FitzPatrick, LLC, and Entergy Nuclear Operations, Inc. (James A. FitzPatrick Nuclear Power Plant)

Dear Sir/Madam:

Enclosed for filing is my declaration in support of the Citizens Awareness Network, Inc.'s, Request for Hearing and ,Petition for Leave to Intervene in the Consideration of Approval of Transfer of James A. FitzPatrick Nuclear Power Plant operating license to Entergy Nuclear FitzPatrick, LLC and Entergy Nuclear Operations, Inc., and supporting exhibits.

Sincerely,

Jean Chambers

Jean Chambers
Citizens Awareness Network, Inc.

cc: attached service list

Before the
UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the matter of
Docket No. 50-333
New York Power Authority
Application for transfer of Part 50 license
for James A. FitzPatrick Nuclear Power Plant
to Entergy Nuclear FitzPatrick, LLC,
and Entergy Nuclear Operations, Inc.

DECLARATION OF JEAN CHAMBERS IN SUPPORT OF CAN'S STANDING

I, Jean Chambers, state the following as true:

1. My name is Jean Chambers.

2. I reside at 149 E. 7TH St., Oswego, NY 13126.

3. I have lived in Oswego for five years.

4. The place where I live is approximately 6-1/2 miles from the James A. FitzPatrick Nuclear Power Station in Lycoming, New York.

5. I am also a citizen of Oswego County which purchases some of its power from James A. FitzPatrick and a New York State resident, which NYPA is supposed to serve by benefiting the economy of New York state.

6. I have concerns for my health and safety because I live so close to James A. FitzPatrick Nuclear Power Plant.

7. I am a member of the Citizens Awareness Network, Inc. {CAN}, and have authorized CAN to represent me in this matter.

8. I am aware of the issues that CAN is raising in this proceeding and agree with the concerns that CAN has, as I share those concerns.

9. I am concerned that whoever owns FitzPatrick has the experience and financial ability to completely clean up the site for release to the public when the useful life of the plant has ended. In this way, the license transfer matter has a direct bearing on the possibility of my being able to safely enjoy the natural environment in this area. I think that the NRC should conduct a full environmental assessment of the FitzPatrick facility to determine the extent of contamination there so that it can be sure that any new owner has

the financial means necessary to clean up the site. Also, given the history of lack of oversight in many other reactors in the New York area, I would like to see the NRC conduct an independent evaluation of the James A. FitzPatrick Nuclear Power Plant so that people living nearby, like me, would be certain that all of the problems with the reactor are known and documented before a new owner takes over.

10. I am also aware that Entergy is not assuming liability for off-site contamination caused by FitzPatrick during the time when New York Power Authority has owned and operated it. I am aware that James A. FitzPatrick and other reactors routinely release radioactive materials into the air and water, and that the spread of radiation does not stop at the edge of the FitzPatrick site. Someone has to be responsible for ensuring that these pollutants do not continue to affect the health and safety of me and other people living near FitzPatrick after it closes down, and I am concerned that the license transfer application by Entergy doesn't guarantee that. I am also aware that NYPA routinely shipped radioactive sludge from the James A. FitzPatrick Nuclear Power Plant to a municipal sewage facility in the Town of Minetto, Oswego County, which could affect the health of people living in the area. Since this was so common at FitzPatrick, there needs to be an Environmental Impact Study before the license can be transferred to Entergy. But more importantly, there has to be a guarantee that, whoever owns FitzPatrick, the pollution released off-site from FitzPatrick is eventually cleaned up.

11. I am also concerned about the problems which may arise if the license to operate FitzPatrick is transferred to a company lacking the resources and experience to operate many aging reactors at the same time. In particular, I am concerned about license transfer to a company such as Entergy which does not have experience dealing with an aging nuclear reactor like James A. FitzPatrick. In addition, I am concerned about what I have heard concerning the overtime practices and job-cutting which the would-be owner, Entergy, has engaged in with their transmission and delivery services and at other nuclear plants they operate or have purchased, such as the Pilgrim plant in Massachusetts. I think the NRC should fully investigate these charges before any license transfer is permitted so that persons like myself living near FitzPatrick will know that they will not be endangered by work practices that cut corners on safety for profit. Already, there is evidence that these conditions have compromised safety at Consolidated Edison's Indian Point 2 reactor, resulting in an emergency on August 31, 1999, and an accident on February 15, 2000. For this reason, I would like some assurance, which the NRC could provide by making this a condition for license transfer, that persons at FitzPatrick with experience will not lose their jobs, and that the new owner will not be allowed to fire a lot of experienced people and replace them with contract labor.

12. Many of my friends and I are concerned about the health and safety implications of FitzPatrick's planned dry-cask storage site. Not only are we worried about the well-known problems with making safe dry casks for storage, but we are also worried about the siting of the casks so near to populated areas and the coast of Lake Ontario, which opens up possibilities of harm to people if one or more casks were to tip over in a earthquake or be targeted by terrorists, or suffer any other damage. I think a full environmental impact study is needed to ensure the health and safety of the people,

especially since any radioactive emissions from the dry casks would be in addition to those already occurring from planned and unplanned shutdowns and startups. The NRC has a responsibility to the public to keep us informed about any new levels of potential hazard from these plants, especially since FitzPatrick is only one of three aging plants with nearly full storage facilities at Nine Mile Point.

13. Finally, I am also concerned about the way in which Entergy's intention to buy up many nuclear reactors could affect my health and safety. Unless the NRC looks into the potential affects of such a plan upon energy dependence in this area, we could end up stuck for years with a company that controls most of the electricity available to us. This could mean high prices, unsafe conditions at Indian Point in order to keep up profits to support other Entergy operations, and other practices that would cut costs on site--all of which is dangerous to persons living near FitzPatrick as I do. In my mind, the NRC is supposed to look at the national security and health and safety implications of any actions which could reasonably affect the ability of its licensees to safely operate their nuclear plants.

14. For the reasons I stated above, I believe the license transfer in this case should be open to dealing with the health and safety issues CAN is raising. I hope that the NRC will permit these issues to be discussed so that I and persons like me living near FitzPatrick may be assured any new owner will operate it as safely as possible.

I declare under penalty of perjury that the foregoing is true and correct.

DATED: Oswego, New York the 31st day of July, 2000.

Jean Chambers

Jean Chambers
149 E. 7th St.
Oswego, NY 13126
315-342-6169

STATE OF NEW YORK
COUNTY OF ~~OSWEGO:~~ Onondaga (GR)

On this 31st day of July, 2000, the above signed Jean Chambers appeared before me and affirmed that the above Declaration is true and correct and that she signed it as her free act and deed.

GERARDA RUSSO
Notary Public, State of New York
Qualified in Onon. Co. No. 01RU6031513
My Commission Expires Oct. 4, 20 01

Before me:

Gerarda Russo

Notary Public   My Commission Expires 10/4/01

CERTIFICATE OF SERVICE

I, Jean Chambers, on behalf of the Citizens Awareness Network, Inc., hereby certify that copies of my declaration in support of the Citizens Awareness Network's Request for Hearing and Petition to Intervene were served upon the persons listed below by e-mail and with a conforming copy deposited in the U.S. mail, first class, postage prepaid, this 31st day of July, 2000.

Jean Chambers

Jean Chambers

Secretary of the Commission
U.S. Nuclear Regulatory Commission
Attn: Rulemakings and Adjudications Staff
Washington, D.C. 20555-0001
secy@nrc.gov

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smg4@exchange.co.westchester.ny.us

Exhibit 2

Declaration of Marilyn Elie, Representative Member of Citizens Awareness Network, Inc.

Exhibit 3

Declaration of David Lochbaum, Union of Concerned Scientists

DECLARATION OF DAVID A. LOCHBAUM, NUCLEAR SAFETY ENGINEER, UNION OF CONCERNED SCIENTISTS, CONCERNING TECHNICAL ISSUES AND SAFETY MATTERS INVOLVED IN THE TRANSFER OF THE FITZPATRICK AND INDIAN POINT 3 OPERATING LICENSESTO ENTERGY

I, David A. Lochbaum, make the following declaration:

1. My name is David A. Lochbaum. I reside in the state of Maryland.

2. I am employed by the Union of Concerned Scientists as their nuclear safety engineer. I have been so employed since October 1996. The Union of Concerned Scientists, with offices located at 1707 H Street NW Suite 600, Washington, DC 20006-3919, is an independent nonprofit organization dedicated to advancing responsible public policies in areas where technology plays a critical role.

3. I have the following responsibilities at UCS: a) direct and coordinate nuclear safety program; b) monitor developments in nuclear industry to assess and respond to impact; c) serve as technical authority and spokesperson on nuclear issues; and d) initiate legal action to correct safety problems.

4. I have worked in the field of nuclear engineering since June 1979. I am a graduate of the University of Tennessee with a bachelor of science in nuclear engineering.

5. After receiving my nuclear engineering degree, I went to work for the Georgia Power Company as a junior engineer at their Edwin I. Hatch Nuclear Power Plant. I held various positions in the commercial nuclear power industry over the next 17 years prior to joining UCS. This experience is detailed in the resume attached hereto as Exhibit A.

6. I am the author of *Nuclear Waste Disposal Crisis* (Pennwell Books, Tulsa, January 1996) on the technical problems with spent fuel storage at reactor sites and numerous reports for UCS on nuclear safety issues.

7. At the request of Central New York Citizens Awareness Network, Inc., I have monitored the proposed transfer of the operating licenses for the James A. FitzPatrick and Indian Point 3 nuclear power plants. I have also examined and am familiar with, for the purposes of preparing this declaration, the applicable federal regulations contained in Title 10 of the Code of Federal Regulations. I have relied upon these documents in formulating my opinions as expressed in this declaration.

8. Having examined the relevant documents as mentioned above, it is my professional opinion that the proposed license transfer raises significant safety concerns for persons working at these nuclear plants and/or living within close proximity to the

facilities. It is also my professional opinion that these significant safety concerns have not been adequately considered.

9. It is my professional opinion that the following significant safety issues would be created by the operating license transfer for persons living in close proximity to the nuclear power plants and/or persons working there:

(a) The license transfers may increase the likelihood that workers at FitzPatrick and Indian Point 3 experience human performance degradation caused by fatigue. UCS issued a report on overtime and staffing issues last year (Exhibit B). Any new owner of these nuclear plants may be tempted to help recover the purchase costs by reducing the staffing levels for the plants. The remaining staff members may be forced to work longer hours, thus increasing the potential for fatigue and fatigue-induced errors. Increased likelihood of worker errors directly corresponds to increased risk as documented in UCS's report. The Nuclear Regulatory Commission (NRC) presently lacks regulations that protect the public from safety mistakes made by fatigued workers. There are no enforceable working hour limits. Thus, because these license transfers may reduce staffing levels and increase worker fatigue, they represent a potential nuclear safety threat.

(b) The license transfers may increase the potential for people not being compensated for illnesses or property damage caused by radiation released from the nuclear power plant sites. During the period of the operating license, the public is guaranteed under the Price-Anderson Act of 1957 and its amendments for such compensation. The Price-Anderson liability coverage ends when the operating license is terminated even though radioactive material could remain at the site in harmful amounts. The change in ownership may make it more difficult for any person suffering loss caused by the release of radioactivity from the sites after license termination to receive compensation.

(c) The license transfers may increase the likelihood that the nuclear plant sites are improperly decommissioned. Surveys of soil on the plant sites will be conducted primarily in locations where records show spills and run-offs have occurred. In past plant decommissionings, these sample locations were supplemented by the recollections of plant workers. The license transfers may inhibit the identification of these survey locations, and thus reduce the likelihood that contaminated spots will be remediated, if all records are not transferred to the new owner and if the "corporate memory" is not retained.

(d) The license transfers may decrease safety levels at the nuclear plants. In the past, safety problems identified by plant workers were corrected with the repair costs passed along to the customers via rate actions. In a deregulated electricity marketplace, any such repair costs are factored into the prices for electricity from the nuclear plants. If the repair costs make the nuclear plants' electricity uncompetitive, the plants will eventually close. Plant managers and workers understand this relationship and may feel restrained in identifying and correcting safety problems. A UCS report released last October (Exhibit C) documented more than a dozen nuclear power plants that had to be closed for longer than a year for safety repairs. In the deregulated electricity marketplace, such long outages will probably trigger permanent plant closure. Thus, there is incredible pressure to minimize the extent of safety problems found at any nuclear power plant. It is true that this pressure exists for the existing owner and any new owner of the FitzPatrick and Indian Point 3 plants, but the sale essentially places a tangible cap on the value of the plants. By analogy, consider someone who purchases a used car for $800. Shortly after acquiring this car, the new owner takes it to a repair shop due to loud, clanking noises coming from under the hood. The new owner will be tempted to live with a transmission problem rather than spend $1,400 for the parts and labor necessary to fix it. The new owner accepts increased risk of trouble on the road. Likewise, the new owner of a nuclear plant will be tempted not to spend much money on correcting safety problems.

10. It is my professional opinion that the safety concerns addressed in paragraph 9 could be created by the transfer of the operating licenses for FitzPatrick and Indian Point 3. I am also of the professional opinion, and do so state here, that the risk to persons working at the plant and/or living in close proximity to the plants could be increased by the proposed license transfer, and the risks and potential are real, not highly speculative, and should be taken very seriously.

I declare under penalty of perjury that the foregoing is true and correct.

Executed July 31, 2000

David A. Lochbaum

David A. Lochbaum
Union of Concerned Scientists
1707 H Street NW, Suite 600
Washington, DC 20006-3919
(202) 223-6133
dlochbaum@ucsusa.org

Exhibit 3A

Resume of Mr. Lochbaum

Exhibit 3B

Union of Concerned Scientists Report on Worker Fatigue

Exhibit C

Union of Concerned Scientists

Exhibit 4

Letter from Mr. Richard Benas, New York State Department of Environmental Conservation, to Dr. John Young, Consolidated Edison Company of New York

New York State Department of Environmental Conservation
Division of Environmental Permits, Room 538
50 Wolf Road, Albany, New York 12233-1750
Phone: (518) 457-2224 • FAX: (518) 457-7759
Website: www.dec.state.ny.us

John P. Cahill
Commissioner

June 27, 2000

Dr. John Young
Consolidated Edison Company of New York, Inc.
4 Irving Place
New York, N.Y. 10003

Dear Dr. Young:

Attached are the comments of the New York State Department of Environmental Conservation (DEC) regarding the Hudson River Settlement Agreement State Pollutant Discharge Elimination (SPDES) Modification Draft Environmental Impact Statement, submitted to DEC on December 15, 1999.

Please provide written responses to DEC's comments as well as the attached written public comments by July 27, 2000. It will be appropriate to also respond at the same time to the public comments of the legislative hearings of June 8, 2000. Copies of the hearing transcripts may be obtained from Dalco Reporting at (914) 325-8778. You may prepare a single response for similar public comments; however, please list for each of these responses the names of all those who made the comment.

If you have any questions please contact me at (518) 457-5941.

Sincerely,

Richard Benas
Environmental Analyst 2
Division Of Environmental Permits

CC: HRSA Participants
HRSA Review Team

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Comments of the New York State Department of Environmental Conservation on the Hudson River Settlement Agreement State Pollutant Discharge Elimination Permit (SPDES) Modification Draft Environmental Impact Statement (DEIS)

1. Please provide the list of references reviewed for all aspects of Chapter V Environmental Setting of the DEIS.

2. Please provide support or appropriate citations for the statement on Pg V-1, 3rd paragraph, 1st sentence where it states "Few water bodies have been the subject of sampling and evaluation over a multiyear period.

3. Please explain the term "Division 05 for New York Climatological data" as stated on Pg V-6, Paragraph C, Long Term Variations. Please provide a citation for this data and term.

4. Please provide additional detail or a valid citation for the terms G4 or G5 in the Nature Conservancy's , ranking system as used on Pg V-7, Vegetation, 1st partial paragraph.

5. Please provide citations or data that support the conclusion found on the last sentence of Pg V-7, under the Vegetation Section where it states " ...conversion of forests to agricultural or urban uses can cause changes to the soil structure that will prevent development of the original community type for an extremely long time." Further, the paragraph does not mention industrial impacts on vegetation. Please describe the industrial impacts on the river basins vegetation and soil structure.

6. There is a typographical error on Pg V-7, Pg V-7, Section b, wetland and Aquatic Vegetation, on the 3rd line "fins" should be ferns.

7. Please explain the relevance of the 2nd paragraph on Pg V-9, regarding shipping channel dredging, to wetlands vegetation.

8. Please add appropriate text (similar in scope to the section labeled 'Wildlife' on Pg V-9 on aquatic resources (fish, crustaceans and invertebrates) of the Hudson River Estuary.

9. Please define the term "YBP" used in the first line of the 2nd full paragraph on Pg V-11.

10. The 2nd paragraph on Pg V-15 describes the increase in boating activities associated with the Hudson Valley, then raises concerns relative to crowding and aquatic safety, and finally concludes that recreational fishing is a popular activity in the lower Hudson Valley. Please provide additional details relative to Hudson River boating and fishing access; elaborate on the concerns expressed relative to crowding and aquatic safety; and finally, provide a detailed description of the estuary's recreational fishery, past and present.

11. Table V-6 on Pg V-25 is missing values for the Drainage area relative to Sparkill Creek, Moodna Creek, and Fishkill Creek. Please provide the missing information in order to complete the Table.

12. Please provide the citations which support the discussion of tidal flows or present the methods and materials utilized to measure tidal flow in the second full paragraph on Pg V-27.

13. The 3rd full paragraph on Pg V-28 seems to be incomplete, because there is no reference to data, figures or tables. Please clarify this paragraph. It appears that the paragraph should describe average annual temperature variations; if this is correct, please provide appropriate data, and then discuss in detail the strengths and weaknesses of the data.

14. Please present citations and data which demonstrate and support how salinity "may indirectly affect the distribution and well-being of biota ..." as stated under Salinity in the 3rd paragraph on Pg V-33.

15. Please explain in detail what concerns have been raised regarding the Chelsea Pumping Station along with citations for supporting those concerns as indicated in the first full sentence on Pg V-34.

16. There is only one citation for the whole introductory section under Toxics on pg V-40. Are the observations presented in the introductory paragraphs original work or are they a compendium of thoughts from a literature review? Please describe in detail the source or sources of information of this section of the DEIS. Further, without benefit of knowledge of the source of your information, the term trace contaminants requires a definition.

17. The discussion of PCB's under Organic Contaminants on Pg V44 - V-50 contains errors and illogically compares data from various years. The section goes beyond describing the history of the issue, and seems to present an editorial view of PCB contamination relative to current and future management decisions of Hudson River fishes especially striped bass. Please rewrite this section relative to PCB contamination found in the Hudson River sediment and fish tissue samples and delete any discussion of fishery management actions. Such management discussions are inappropriate for the environmental settings section. In describing the history of the issue describe in detail, include the use of PCB's by the electric generating industry. Please also provide a description of possible sources of contamination of the estuary.

18. The first paragraph on Pg V-51 under Health Advisories is not accurate. Please review current NY DOH health advisories and edit the paragraph accordingly.

19. The second paragraph on Pg V-53 under Dissolved Oxygen describes the process of oxygen production and use. The last, concluding sentence seems disconnected to the rest of the paragraph. Please review the intent of the paragraph and its concluding sentence. Then provide further descriptive material to the paragraph and concluding sentence so that the intent and meaning of the last sentence is clarified.

20. Please provide an analysis, including the methods and materials to be employed, of the individual population changes relative to impacts within the whole drainage basin as indicated on Pg V-56 in the 1st full paragraph under D. Biological Resources of the Estuary, 1. Hudson River Estuary Aquatic Ecosystem.

21. Please provide the citation or citations which support the conclusion on Pg V-56 under Hudson River Estuary Aquatic Ecosystem that the 24 year time period is "long enough for the effects of interactions among species (competition and predation) and perturbations generated by

other factors in the ecosystem to spread throughout the food webs in the ecosystem." Under the 3rd (last) sentence, the citation "Pimm", 1991 is not listed in the references Pg V-56. Please add this citation. Finally, please describe in detail the analysis employed to conduct this evaluation.

22. Please explain why the perturbations selected were chosen and other perturbations such as construction projects, power production, mining, deforestation, development, commercial shipping, maintenance dredging, among others where not considered in the 1st sentence of the 1st paragraph on Pg V-57 under Perturbations to the Hudson Ecosystem.

23. Please describe in detail how the construction and upgrading of the NYC treatment plants affected habitat availability as indicated in the 2nd paragraph on Pg V-57 under Habitat Availability. Was this a positive or negative impact? The second paragraph as written is a statement about treatment plants but does not tie into habitat.

24. Please clarify the section on Pg V-57 Habitat Availability which seems to conclude that the only two significant habitat events in the whole ecosystem affecting habitat availability are the discontinuation of the water chestnut control program and the upgrading of the NYC waste treatment plants. In clarifying this section please discuss all other impacts which may have positively or negatively affected habitat availability within the ecosystem and answer the question-how has development within the watershed affected the aquatic habitat?

25. The 1st paragraph under Competition on Pg V-58 does a good job of presenting citations for all statements accept the following: "In the Hudson River estuary, the foodweb directly links juvenile fish populations to the discharge of raw sewage." Please provide the documentation which supports this statement and then present a detailed discussion why we are not seeing a decline in juvenile fish production with improving water treatment facilities.

26. Please describe in detail how the construction and upgrading of the NYC treatment plants affected habitat availability on Pg V-58 under Competition. Please present a detailed discussion of the rationale that waste water improvements and zebra mussels were the only two topics necessary for a discussion relative to competition. Please examine and report on all aspects of interspecific competition that could affect this process relative to Hudson River aquatic species. Please examine the 24 years of data collected and present a detailed discussion of what interspecific interactions have occurred.

27. Please describe in detail the rationale for the conclusion that only the adult striped bass population increase had an affect on predation. Please present all empirical data that supports your assertion (food habits studies) on Pg V-59 under Predation Section.

28. Please present the proper citation and recognition for the data reported relative to the Spring Striped Bass by-catch index from the American shad gill net fishery on Pg V-59 under Predation.

29. With respect to the statement attributed to Pimm,1991on page V-59: "A change of this magnitude at the top of the foodweb should affect other fish populations within the Hudson River ecosystem." Did Pimm (1991) conduct an evaluation of the Hudson River estuary striped bass population in relation to predation or is this hypothetical statement? A citation for Pimm is not listed in the references section. Please provide the proper citation. Further, striped bass have been implicated as a chief predator in a number of areas, however, they are not the only predator population that has demonstrated a population increase during the period. The Double Crested

Cormorant population has demonstrated a large increase during the same period. Please examine the Cormorant population shifts in detail and describe how such shifts might affect other populations. Please also describe, in detail, the role of all predators within the Hudson River ecosystem and their potential interactions with striped bass and double crested cormorants and the affects on predation.

30. Please present the data that supports the line of demarcation between the brackish and freshwater portions of the river that occurs between RM 55 and 56. Section b. under Major Habitats on Pg V-60 presents this clear line of demarcation. The DEIS states that there are at least two major areas of the main stem of the Hudson, however, there are also seasonal variations relative to their occurrence. This paragraph recognizes daily and seasonal differences in reproduction and feeding behavior for individual species, but does not appear to recognize that the two major habitats described vary both daily and seasonally. Please present detailed information relative to the seasonal variations in magnitude of the two major habitats.

31. Please present citations which support the discussion on Pg V-60 paragraph (c) under Major Trophic Groups.

32. "Are must" should read "are most"in the last paragraph on Pg V-60.

33. Please present citations which support the discussion and the last sentence under the phytoplankton section on Pg V-61.

34. It states in the 1st paragraph under the phytoplankton section on Pg V-61, Rooted Aquatic Vegetation, that "owing to the high turbidity levels in the Hudson, rooted aquatic plants are found primarily in marginal nearshore areas and extending offshore less than 100 yards." This statement contradicts the discussion of wastewater treatment and zebra mussels. Please provide a detailed discussion that describes which predominates and what the trends might be in the future. Please present supporting citations or data. Please define "marginal nearshore areas." Finally, please clarify if rooted aquatic vegetation is a trophic group or a habitat. Please present the rationale for including this section as a trophic group.

35. Please describe in detail why a transition zone was chosen for zooplankton and not for the major habitats as discussed in the first full paragraph on Pg V-62 under Zooplankton. The description of the break in habitat for zooplankton differs from the break in Major Habitats described on pg V-60. The first description defines a clear break at RM 55-56, where as this section for zooplankton describes a transition zone (RM 40-68). Please support the choice with appropriate data or citations.

36. Please explore the possibility that water withdrawals for cooling might be a contributing factor for the observed decline in zooplankton as discussed in the last paragraph on Pg V-62. Please describe in detail any efforts to determine entrainment effects on zooplankton and the resultant survival for the Roseton, Bowline and Indian Point facilities. Further, please describe in detail what portion of the Hudson River total daily flow is used as once through cooling water as a component of the evaluation of entrainment on zooplankton.

37. Please present a citation or citations which support the statement that this group of organisms connects non-living matter to higher trophic levels as discussed in the first paragraph on Pg V-62 under the Section on Macroinvertibrates and Shellfish.

38. Please revise the section on Fish on page V-64 and V-65 to more accurately describe the species present in the estuary, along with a more detailed description of fish captured during 24 years of survey efforts.

39. Please describe in detail with appropriate data and citations the significance of the statement contained in the last sentence in the last paragraph on Pg V-64. Also in this section please reference the appropriate section of the DEIS which discusses Tomcod.

40. Please revise the discussion of striped bass in relation to the foodweb. Please present the food habitats data or citation that supports the contention that striped bass prey on juvenile Atlantic sturgeon as discussed in the 1st paragraph on Pg V-65. Please present a detailed discussion of the striped bass food habits by season and size for the Hudson River estuary and compare these data with information from other spawning estuaries. The revised paragraph should more accurately portray the foodweb associations relative to all life stages of striped bass found in the estuary.

41. Please present the citations or data which support the observations in the second paragraph on Pg V-65.

42. Please support your observations in the 3rd paragraph on Pg V-65 with data or citations. Please reconcile that gizzard shad and spottail shiners are captured down to the Region 3 area and shortnose sturgeon have been captured in New York Harbor.

43. Please change the 3rd paragraph on Pg V-65 to reflect that river herring and American shad are more properly classified as anadromous migrants.

44. Please provide a discussion of blue crabs in the setting section of the DEIS.

45. The 1st paragraph on Pg V-65under Other Vertebrate Wildlife concludes that "While this group has not been well studied as a whole, there does not appear to be any members that depend, exclusively, upon the Hudson River estuary for aquatic resources." While the word exclusively controls the meaning of the statement, the section fails to consider avian wildlife which utilize the estuary at various times of the year, such as American eagles, ospreys, and cormorants. These three species, in particular, prey on aquatic species. Please review the available literature relative to avian life in the estuary and revise this section to more accurately reflect its importance to them and describe any interactions in relation to tropic levels and predator prey relationships. Further, please describe in detail how the amphibians and mammals interact with the Hudson River trophic levels.

46. Please review and correct the statement on the 1st line on Pg V-66 under Life History and Abundance of Selected Species with the proper word or words. Should "assessed" be assessment?

47. Please provide the date for the citation in the last sentence of the 3rd full paragraph on Pg V-68.

48. Please describe what is meant by near shore waters as indicated in the1st full paragraph on Pg V-70. Please also support this description with appropriate data or citations.

49. Please present the data or citations which support the statement "that older striped bass tend to travel further north..." as stated in the 1st full paragraph on Pg V-70 under Striped Bass. With the large number of striped bass tagged during the winter striped bass mark-recapture program (SBMR) there must be information to support this observation. Please present a detailed description of the movements and migrations of striped bass based upon the SBMR program along with appropriate literature citations.

50. Please present the data or citations that supports the observation that ages 4 and older native adults move to spawning grounds as stated in the 1st full paragraph on Pg V-70 under Striped Bass. While it is true for males which mature at age 2, it is not true for females. Only a small fraction of the females are mature at age 4.

51. Please explain in detail, or make appropriate correction to the evaluation of YSL movements as indicated in the concluding sentence of the 3rd full paragraph on Pg V-70, where it states "The difference in distribution may mean that YSL migrate upriver using tidal currents, ...". This conclusion is not supported by figure V-33 which demonstrates a downstream distribution of YSL in relation to egg distribution.

52. Please review the observations relative to PYSL and juvenile distribution as indicated in the 1st full paragraph and 1st sentence on Pg V-71. It appears that PYSL are distributed from Yonkers to Saugerties, where as juveniles they are distributed from Yonkers to Albany. This observation is not reflected in the text. Please reevaluate your data and provide the corrected observations and analyses.

53. Please present a summary of the Hudson River striped bass tagging data which supports the general movements and migrations discussed as indicated in the last paragraph on Pg V-71.

54. The last paragraph on Pg V-73, regarding winter tagging of striped bass, states (assumes) that all 1+ Hudson River striped bass move into the winter trawl survey area. Please provide the data that supports this observation (assumption). Further, since a large number of age 1+ striped bass have been tagged since 1984, please present the distribution of age 2+ tag returns for the period applicable to the DEIS. Please discuss in detail how this affects the results of your population estimates.

55. Please present further discussion relative to any trends in production or other observations regarding striped bass production as measured from the juvenile life stage as indicated on Pg V-74 under the Young of Year (YOY) abundance paragraph. This paragraph does not seem to present a thorough discussion of the YOY indices. Is this the most appropriate life stage to use?

56. Please offer some observations as to why the correlations between YOY and age 1+ failed after 1990 as indicated on Pg V-74. Please support such observations with appropriate data analysis or citations.

<u>The following comments pertain to the Economic Valuation Section of the DEIS Appendix entitled "The pricing of Striped Bass Wholesale and Retail Mark-ups, Fall, 1997", Jon Conrad and Andrew M. Conrad, April 1999.</u>

57. General Comment: The results of the Economic Valuation presented in the Appendix reflect only one segment of a fishing year when abundance is high and prices are low, therefore biasing

the results low. There are several items chosen which further bias the survey to lower the mean prices.

This chapter of the Appendix discusses the commercial valuation for striped bass; there is no corresponding chapter which describes the recreational valuation for striped bass. Therefore, there is no foundation set for future calculations that attempt to assess the recreational value of striped bass.

58. The Appendix VI-5-A states on Pg 1: "This report presents the exvessel, wholesale, and retail prices for striped bass as observed from September through early December 1997." This short period of time represents less than 1/3 of the fishing season and is the period of lowest exvessel pricing and the highest potential availability of striped bass. New York's commercial striped bass season currently begins July 1 and runs through December 15 of each year. Highest exvessel prices are observed early in the season, up to $4.00 per pound when sold to local markets, and generally decreases during the season.

The Fulton Fish Market Wholesale Prices for striped bass for the period of July to December for New York caught striped bass are presented below:

July	August	September	October	November	December
$3.50	$3.08	$3.04	$2.60	$2.28	$2.50

The New York Wholesale Prices from the "Green Sheet" started high in July and declined through the period with a slight increase in early December. Note: the Fulton Fish Market prices paid to the fisherman are generally lower than that paid by local market places on Long Island. Based upon personal communication with fisherman these prices more accurately resemble the exvessel prices paid to local commercial fisherman than the wholesale price. A detailed survey of local commercial fisherman is required in order to verify this observation.

The DEIS is deficient because the survey period does not reflect the fishing year and therefore is incomplete; and the survey period presents a low bias in the pricing and should not be used for comparative purposes.

59. The last sentence of the 4th paragraph on Pg 1 concludes by stating "...section five summarizes our major conclusions and notes some limitations of the present study". A review of Section Five finds that no limitations are listed. Please provide a detailed discussion on the limitations of this study along with a detailed discussion of their affect on the analysis.

60. The comment in the 1st paragraph on Pg 1 under Section II Methods, relates to the survey methodology, sample size and timing of the survey.

The survey questionnaires were mailed on October 27, 1997 to 140 seafood harvesters, processors, wholesalers, retailers, and restaurants that were drawn from a list of seafood purveyors in New England and the Mid-Atlantic states. The survey instrument targeted establishments and fishermen after the prime season, when only about six weeks remained in a 24 week season, thus supporting the bias suggested in comment number 1. There is no summary of the distribution of the businesses surveyed, by state. The only summary of results suggests that the response rate was very poor. Of 140 surveys sent out, 53 (37.8%) were returned as undeliverable; thus making the effective sample size 87. Of the 87 surveys that were received only 33 (37.9%) were returned. In addition, there were 5 telephone interviews, and one E-mail response for a total of 39 responses. From this they obtained 8 exvessel prices, 23 wholesale prices, and 10 retail prices for a total of 41. The discrepancy of 41 responses from 39 surveys must be reconciled; and, more importantly there is no discussion nor recognition of the magnitude of the commercial fishery, the wholesale marketing of striped bass or the retail marketing of striped bass. In New York alone there are approximately 560 commercial license holders, 350 licensed dealers and hundreds of places that sell striped bass retail. This survey does not represent an accurate picture of the commercial pricing for striped bass as it stood during the 1997 fishing season.

70. The 1st full paragraph on Pg 2 states that supplemental data was obtained from the National Marine Fisheries Service (NMFS). However, no data is supplied and no temporal information presented other than to say that 56 wholesale price quotes were contained in the data. Please provide this missing data and compare it to the rest of the survey results.

71. The 1st paragraph under A. Prices on Pg 2 correctly states that exvessel prices fall within the range of Fall pricing but fail to factor in early season prices of up to $3.75, thus biasing their results low. There is an error in the calculation of the mean exvessel price, described in more detail in the Striped Bass Benefits Assessment review. The mathematical error is only observed when the exvessel price is presented in the next section. The authors show a range of exvessel prices of $2.00 to $9.00 per pound however, the mean is only $1.79. This is not possible and should be corrected.

72. Concerning paragraphs 2 and 3 of the Results on Pg 2, please explain why a "suspiciously" high wholesale value was dropped, thus lowering the mean value, but a "suspiciously" low retail value was retained thus lowering the mean value. These two actions further bias the results by lowering potential pricing factors. Not only is the survey sample size low but the results are further complicated by selectively removing or retaining data points.

73. Concerning paragraph 4 of Pg 2, which discusses Fulton Fish Market Wholesale Prices, it could not be verified that the results of this information, other than the ranges, were similar ($1.65 to $3.50) but not the same as presented in the DEIS ($1.50 to $3.75). DEC's calculations from the New York data for 1997 showed a mean wholesale price of $2.70 and a standard deviation similar to that presented. Please verify the results of the survey presented and provide all data and documentation that supports the text of this report.

74. The data reflected in the Unnumbered And Untitled Summary Table on Pg 3 does not match up accurately with data presented throughout the rest of the report. The table and report should reflect the full season fishery rather than just a small subset of the fishery when prices are at their lowest. Please provide a corrected assessment. Concerning the Conrad Study: I would go even further to say that the study is too limited to be included. NMFS data and exvessel prices should be used. Response rates below 50% are highly indicative of serious flaws.

75. The third sentence in the 1st full paragraph of Pg 4 of the Appendix states,"The current study was intended to provide an overall assessment, and therefore, does not provide information on specific regions, fisheries, and retail products." The study is deficient based upon the errors and omissions listed above. Also, there is no statistical analysis of the sample size against the estimated population in each category (exvessel, wholesale, and retail). Such an analysis is necessary to understand how decisions can be made from this small sample size.

76. Please explain, in detail, how the current study can be compared to the study by Norton, Smith and Strand. This comparison should examine sample sizes, methodology and results in detail. In addition, please explain and describe in detail the similarities or differences in marketing of striped bass between 1980 and 1997 in relation to the regulatory changes that have occurred during that time. For example, in 1980 there was an open market for striped bass, however, since 1997 all striped bass harvested have to be tagged and there are quota restrictions on the harvest. How do management decisions affect the marketing of striped bass and therefore the analysis presented here?

77. The 2nd paragraph on Pg 4 concludes that wholesale prices overlap almost completely with those presented by Norton, et.al. Please reconcile this conclusion given that the current study reflects, at best, a September to mid-December snap shot and the 1980 study reflects a full two year period. Please explain, in detail, how the comparison can be made. Likewise, for the Retail prices, the report concludes that the Retail price ranges are similar but that they vary broadly. The Appendix report should be modified by reporting the Retail prices for whole fish, gutted fish, and prepared fish and the fractions of the market they make up. Such details are critical to presenting an accurate picture of the Retail prices paid for striped bass and thus the average Retail prices to be utilized in further calculations regarding the economic valuation of Hudson River striped bass.

78. Please list the citation or explain the statement in the 3rd paragraph on Pg 4: "two and one-half the knife." The paragraph appears to be discussing the wholesale to retail mark-up but the supporting detail is deficient so one cannot be sure of the intent. Please provide sufficient detail that shows how this material supports the stated conclusions.

79. Please explain, in detail, what the differences are between the two survey methodologies and where the current study diverges from the 1980 study as indicated in the 4th paragraph on Pg 4. Present a detailed analysis of these differences, justifying the current studies methods, results, and conclusions.

80. The conclusions set forth on Pg 5 are not supported by the text of the report. A statement is provided that the average exvessel price per pound paid for striped bass between Delaware and Massachusetts for 1997 was $1.80 per pound. This is for a full year whereas the average price per pound calculated for this study was $1.79, which is for the Fall only. Please provide a detailed discussion of the two studies or present a stronger set of conclusions relative to the current study considering all the comments provided herein.

<u>The following comments relate to Appendix VI-5-B, Striped Bass Benefits Assessments:</u>

81. The Hilborn model is described in the 1st paragraph on Pg 1 as a model of sustainable harvest under a variety of power plant operating scenarios. In fact, the model uses a spawner-recruit relationship to describe the striped bass stock under a variety of power plant operating conditions and fishery management conditions. The sustainability of any harvest scenario is only as effective as the input parameters to the model and the management controls in place on either the power plants or the harvest, complicated by environmental conditions. Based upon the review of the proceeding section and the interpretation of the striped bass model results there are numerous questions regarding the economic valuation.

decrease in harvest for increasing rates of CMR, thus contradicting Table 2 in this report. Please correct Table 2 to reflect the consequences described in the Hilborn Report (Table 13) or provide the support for the values presented in Table 2.

87. The 2nd paragraph on Pg 2 indicates the commercial fish parameter is set at 0.5. The Appendix report should discuss in detail the rationale for choosing this parameter value and describe the consequences of alternative choices. As stated above, the parameter value set at 0.5 is too high given the current harvest patterns of the striped bass.

88. Please verify the math for Unit Price (u) in paragraph 3 on Pg 2. The document demonstrates a range in values from $2.00 to $9.00/lb exvessel price with an average of $1.79/lb. The average price has to be between the minimum and maximum value. Please recalculate this value and report the results, and verify all values used in the model and rerun the model with corrected values. Provide the results of all new model runs.

99. As indicated in the 4th paragraph on Pg 2 the Consumer Price Index (CPI) values are not reported, but referred to for the years 1913 to 1998 and the results were used to adjust the raw prices of striped bass. However, the formula utilizes only the values for 1979 and 1998. Please provide the details of this analysis, the supporting data and the rational for choices.

100. The first sentence in the 1st paragraph on Pg 3 provides a result that is not explained nor discussed. Please describe what this value represents? Further, the paragraph should present a discussion of the results for the marginal value of striped bass in relation to the discount rate also described in this paragraph.

101. Concerning the Results and Discussion on Pg 3 and based upon the above comments the results of this study, at best, represent a minimum value of the increase in sustainable harvest of striped bass. However, based upon the comments DEC has submitted it is not possible to verify the results, therefore the report must be corrected after further analysis that includes the corrections and details noted.

102. Please evaluate the economic value for striped bass using the mortality associated withe subject power plants employing the replacement value of PYSL and juveniles from AFS Special Publication 24. Compare these results with those presented in the DEIS and offer a rationale for not revising the DEIS using these new results.

<u>The following comments are based upon review of "The Value of Changes in Harvests of Hudson River Shad" within Appendix VI of the DEIS by Jon M. Conrad, undated.</u>

103. The assessment in the 1st paragraph of Pg 1 only recognizes the value of the commercial fishery. A substantial recreational fishery for American shad and Striped comments exists in the Hudson River and therefore the Appendix must consider a valuation of power plant impact for this component of the American shad fishery. Please provide a detailed analysis, including an update of the Connelly and Brown studies and using Shepard's 1976 study, of the recreational fishery for American shad and Striped bass in the Hudson River and the corresponding economic valuation. The analysis must present all models and data used in the valuation and the valuation must be compared with the commercial valuation.

82. The 1st line of paragraph of Pg 3 appears to have a typo - should "change" be charge?

83. The assumption stated in paragraph 3 on Pg 1 that an increase in population does not increase the costs to fishermen is unsubstantiated and should be verified. Conversely, the assumption that the value of the additional yield will remain constant through time may not be true and likewise should be verified. What evidence is there to suggest that these assumptions are true? If there is none, what are the consequences to this study? Please provide answers to these questions and factor them into the analysis in Appendix VI.

84. It is assumed in paragraph 4 of Pg 1 that the additional yield can be sustained indefinitely and that society has a time preference that discounts future value at an annual rate. Please provide the documentation that supports these two assumptions, that harvest can be sustained indefinitely and that society has a time preference that discounts future value.

85. In Table 1 on Pg 2 Parameter values are presented as follows:

u - Price/lb - these values reflecting the lower, mid and upper bound are not defined as exvessel, wholesale, retail or restaurant values. Therefore, no judgement can be made on their validity.

S - Share of harvest between commercial and recreational fishers. This value is set at 0.5 which is not true for the Hudson River nor the Coastal harvest. The Hudson River commercial fishery has been closed since 1975 due to PCB contamination and the Coastal harvest for striped bass is dominated by the recreational fishery. The correct proportions need to be ascertained and employed in this analysis.

W - (lbs/fish) The average weight chosen here reflects the mean weight for a gill net caught striped bass between 24 - 28 inches in total length. The model has to either recognize an age where the mean weight for the cohort can be identified from the literature or it has to identify a size range for the cohorts. In either case, the choice of mean weight will have to vary. Data is available from the literature with which to conduct this assessment and should be used.

λ - ($/fish) There is no documentation relative to these values. Please provide the source of these values. This is based upon a per fish basis, accordingly, please relate them to the current creel limits. In the American Fisheries Society, Special Publication 24 "Investigation and Valuation of fish Kills", 1992, the value of a salt water striped bass fishing trip for New York is set at $179.24 per day and for a fresh water striped bass fishing trip the value is set at $58.13 per day. These values reflect the willingness to pay for fishing at a creel limit of one, recognizing that the catch is usually far greater than the allowable creel or possession limit. In any event the values for a striped bass fishing trip represent a much greater value than the $3.00 to $29.00 range per fish parameter values in Table 1. Please provide the source of the information provided and validate the price per fish versus the AFS price per trip method.

86. Table 2, Parameter Values on Pg 2, seems to indicate that there will be an increase in striped bass population, and thus its harvest, with increasing CMR and F (Fishing Mortality) at a 28" minimum size limit. It may also be likely that increasing CMR would result in a greater kill of juvenile striped bass and thus a smaller striped bass population.

Table 2 suggests that there would be an increase in harvest across the board for increasing CMR and Instantaneous Fishing Mortality Rates. This is not supported by the Striped Bass model produced for this document (Hilborn, Table 13). Table 13 reflects an increase in harvest to about F 0.4 and then a decline in harvest after that for all CMR rates. Further, the table reflects a

104. Please verify that a final Deriso et. al. (1999) American shad population model was reported in the DEIS; if not, rerun all estimates using final model outputs.

105. As indicated in paragraph 1 of Pg 3 unlike the striped bass assessment which examined both CMR and fishing mortality (F), the American shad assessment examines only CMR. Explain why fishing mortality rates were not examined in the shad assessment. Please include fishing mortality rates in a reassessment of the valuation, providing complete details regarding this assessment and the sensitivity of the model to variations in fishing mortality.

106. As indicated in the 1st paragraph on Pg 4 the American shad assessment appears to utilize a different methodology than the striped bass assessment. Please describe in detail the two models and any differences in the two models. If the models are the same, please provide a detailed analysis of the impacts that fishing mortality (F) will have on the results.

107. In the 5th paragraph on Pg1 the Appendix states "...assumes steady-state environmental conditions, a change in the operation of Hudson River power plants that reduces fishing mortality will result in an increment to the harvest of American shad ..." Please describe whether this fishing mortality is CMR or harvest. Based upon comments in the Introduction, it seems that the DEIS is describing CMR, which has been translated to a fishing rate. If this is so, please describe in detail the methodology used in this calculation. This paragraph needs clarification. Please present a detailed summary of how the CMR values were translated to yield in weight. Please describe in detail the model employed to make these conversions along with appropriate citations.

108. The 2nd paragraph on Pg 1 under Modeling Methods discusses the Deriso et al (1999) model which presents "the increment of harvest", and "the incremental weight of yield each year per unit of power plant CMR." Please describe in detail the sensitivity of the economic model to these factors. Further, please describe in detail, how fishery management affects the economic models.

109. In the first sentence in the 2nd paragraph on Pg 1 it is assumed that Δw does not change (charge?) any additional costs to commercial fishers and that the value of the additional yield will remain constant through time. Please support this assumption with appropriate citations or data. Then describe in detail how sensitive the model is to the assumptions. This second part of the assumption relative to constant value is the most critical part of the assumption and requires a detailed description supporting the assumption. Please explain in detail why a survey, as was undertaken in the striped bass assessment, was not undertaken for the American shad assessment.

110. The last sentence of the 2nd paragraph of Pg1 contains the assumption that additional yield can be maintained indefinitely. Please provide in detail the support for this assumption. Further, describe the economic models sensitivity to this parameter alone and then with fishing mortality (F) added. The analysis must recognize that fishing mortality (F) plays a role in future population status not just CMR.

Efforts are currently underway to reduce fishing mortality on American shad stocks along the entire east coast in order to rebuild depressed or overfished stocks. Please describe in detail the sensitivity of the economic model to the effects of management in relation to the economic assessment.

1995	183,954	247,578	248,865
1996	137,560	173,751	184,501
1997	37,747	136,312	149,470
1998	254,094	219,390	232,548

All values are in pounds.

117. The 1st sentence on Pg 3 states "The exvessel price was the average price per pound of American shad landings adjusted to 1998 dollars and was assumed to be constant." Please provide detailed support for the assumption that the mean exvessel price per pound of American shad adjusted for 1998 dollars was constant. Further, please provide evidence relative to the models sensitivity to the average price per pound.

118. Without benefit of model details, discussion of the appropriateness of assumptions and the model sensitivity to the various data values and assumptions, the statements regarding model outputs can't be verified. However, a simple comparison of model outputs against the NMFS reported values for American shad indicated that there is gain in value to commercial fishers by allowing more American shad to survive.

The valuation estimated for the CMR impact on American shad, ranging from $4,014 to $14,818 annually, are not useful until the final American shad model results are available and properly employed in the economic model. Further, the results shouldn't be used until such time as the questions and points raised above are fully addressed.

Please verify that the American shad model is the final version; rerun all estimates for economic value considering the whole estuary not just the New York portion and provide consideration for the American shad recreational fishery in this analysis.

119. The American shad economic valuation provides no valuation for the recreational fishery for American shad caught in the Hudson River. This is a serious oversight and needs to be addressed in detail before any final values can be calculated. A detailed analysis of the American shad recreational fishery must be presented and then factored in the economic model.

There are three other species, which have played a major role in the DEIS, for which no economic evaluation was undertaken. These are Bay Anchovy, River Herring and White Perch. There are extensive sections in the DEIS that discuss impacts on these three, yet none of them were given benefit of an economic valuation to the Hudson River ecosystem or to potential users. Bay Anchovy have limited utility to commercial or recreational harvest but are an important link in the food web of the Hudson River. The River Herring are also an important link in the Hudson River foodweb and have commercial and recreational value. Finally, the White Perch is a major native estuarine species that has some value as a recreational fish but has been removed from the commercial market by pollution.

Please provide a detailed rationale for not considering the economic value of Bay Anchovy, River Herring and White perch.

<u>The following are additional comments on the DEIS:</u>

120. The delta T provided in Tables IV-6, IV-9, and VI-11 indicate degrees Centigrade as the units. Please confirm.

121. The 12,000 gpm auxiliary pump identified on Page IV-9 does not appear on Figure IV-5. Please indicate the location of this added pump.

122. Page IV-12, first full paragraph indicates that a debris barrier wall was attached to the top 4 feet of the bar rack on Unit 2. Wasn't it Unit 3 that had the debris barrier added, or is there an additional barrier at both units?

123. Table IV-10, Discharge and Waste Stream Flows for Indian Point does not indicate a permitted discharge for the screen wash water / fish return systems, as do Roseton (Table IV-8) and Bowline (Table IV-13). This discrepancy should be addressed in the new permit for Indian Point.

124. Table IV-11 indicates that the Discharge Type for Bowline is a shared diffuser. However, on Page IV-17, Paragraph b. the statement is made that "Each system terminates in an underwater multiport discharge diffuser." This description is consistent with staff's understanding and differs from the characterization in the table of a shared system. Please clarify.

125. Figure V-34 provides striped bass ysl and pysl densities; the two lines on the graph are not differentiated. Please correct.

126. Page V-71, 2nd Paragraph begins with the statement, "The end of the PYSL stage, when striped bass larvae change from living on their stored energy reserves .... Shouldn't the life stage referred to here be YSL? Please clarify.

127. A minor inconsistency on the duration of striped bass PYSL stage exists on Page 70, last paragraph, where it is indicated to last about 30 days, and on Page 72, 3rd paragraph where the PYSL stage duration is indicated to be about 3 weeks. These estimates should be similar.

128. Figure V-41 provides a graph of the annual abundance indices for the period 1976 through 1990, while the figure heading indicates that the information provided would be for 1974 through 1997. Please correct as necessary.

129. Table V-17 heading indicates information to be provided for 1985 - 1990, while the table indicates years 1991 through 1996, and then 1999, which year /data seems to be in error. Please correct as necessary.

130. The lines labeled YOY and CEMR on Figure V-51 appear to be reversed. Please check, and correct if necessary.

131. Page V-85: the R squared values for white perch cumulative entrainment mortality for the 1974 through 1979 period (very top of page), and the value for the period 1989 through 1997 are exactly the same (2nd paragraph), strongly suggesting one of the values is in error. Please check, and correct as necessary.

132. Table V-15, Table V-19, etc: Please provide estimated YOY population for striped bass, white perch, Atlantic tomcod, American shad, blueback herring, alewife, and bay anchovy per table headings.

133. Figure V-52 and narrative at the bottom of Page V-88: the lines in the figure appear to be mislabeled based on the narrative provided. Please check, and correct if necessary.

134. Page V-94 discusses temperature, using degrees Fahrenheit and refers to Table V-24 in which temperatures are given in degrees Centigrade. Please revise the text or table so that the same units are used in a given discussion and the accompanying table.

135. Page V-158 indicates that the fish community would be assessed based on Regions 1-5 and Regions 6-12. Please explain why the community in Region 0 was not included you your discussion.

136. Figure V-117, and others where this type of graphic appears indicates negative mean densities for organisms in Regions 1-5. We assume the negative densities are an artifact of the software used to generate the figure. Please confirm this assumption, or provide an explanation of the meaning of negative densities.

137. The last sentence on Page VI-8 indicates that viability studies on impinged blue crabs are currently underway at Bowline Point. Please provide the scope of work under which these studies are being conducted, and any available interim results.

138. The1st paragraph on Page VI-27 indicates that an *offshore* discharge exists for Indian Point Units 2 & 3. Please refer to Figure IV-11: IP's discharge is a shoreline-bulkhead diffuser, according to this figure. Please correct as necessary, or explain.

139. The last sentence on Page VI-32 in the next to the last paragraph indicates that blueback herring have declined in the upper reaches of the Hudson, and throughout its range. However, Page V-105 under Abundance Indices for blueback herring, "..from 1979 through 1997, there was a slight increasing trend (+1% per year) in the FSS juvenile index (Table V-27)". Please address this apparent discrepancy.

140. The first sentence under Roseton Units 1 & 2 indicates that the "...screens have been modified to reduce the number of times fish encounter and then swim away from the screens before they are removed from the intake." Please explain further what modifications have been made to the screens and what data exist that support this statement.

141. The first sentence on Page VIII-5 indicates that a one unit outage for the entire 32 week entrainment season would result in a 50% reduction in entrainment CMRs for all species. Staff perception is that the flows at Roseton are such that rather less than a 50% reduction in impact would occur during a one unit outage. See also Appendix VIII-1-A, Attachment 2a. Please explain.

142. The last sentence in Section b on Page VIII-6 appears to be incomplete.

143. The darkened areas on Figures VIII-2&3 are labeled Incremental Impact; actually, they should be labeled "Flow Mitigation" or something similar. If staff understand the figures, the darkened areas represent difference between efficient flows and the lower flows required by the Hudson River Settlement Agreement, and one of the mitigative elements of the current proposed action, and therefore the darkened areas represent mitigation rather than impact. Please confirm.

144. Table IV-2 provides the water flow rates and the associated fish protection points associated with reduced flows (reduced below efficient flow) that accrue to Indian Point (but not the other facilities due to their use of efficient flow). Table VIII-6 seems to provide the details of how the estimate in Table IV-2 was generated, but includes two additional species not included in the estimated FPP from Table IV-2 - the American shad and spottail shiner. If these two species are excluded from the calculation, please explain why adding the CMR at efficient flow and the CMR at permit flow, and then subtracting the latter from the former does not yield the estimate provided in Table IV-2.

145. Table VIII-7 provides estimates of the megawatt hours lost due to the use of efficient cooling at the Indian Point units, and provides a cost for this lost generation as well. The 10,619 lost megawatts at Unit 2 is estimated to cost $320,000, or about $31.13 per megawatt, while Unit 3s 9077 megawatts lost at a cost of $270,000 would translate into a cost of $29.74 per megawatt. In a Times Union article published on March 20, 2000, a Mr. Don Hintz of Entergy indicates while discussing the cost of producing electrical energy at Indian Point: "Entergy could be generating power for as little as 1.5 to 2 cents per kilowatt hour ..." or $15 to $20 dollars per megawatt. Please explain the difference in these estimated costs ($30 per megawatt compared to $15 to $20) to produce power at Indian Point.

146. The first full sentence on Page VIII-8 at the top of the page, indicates a concern for the operational practice of shutting circulating water pumps on and off several times each day. During the time that Roseton experimented with cycling of CWPs, were there documented stresses imposed on equipment? If so, please provide such documentation.

147. Pages VIII-16 & 18 indicate that the closed system evaporative cooling towers alternative for each of the facilities would include the capability to return to once-through cooling. Would you please provide more information on this capability, such as the time needed to convert from one cooling mode to the other; and any operational penalty that may accompany use of once-through cooling on this dual-capability system. What is the incremental cost to have this dual mode capability, compared to a closed cycle system that did not have this ability?

148. Please provide an estimate of the additional cost per megawatt hour of electricity produced by each of the facilities under the three scenarios of 40, 50, and 60 years from startup to end of life as shown in Table VIII-8.

149. Staff were not able to reproduce the estimated salt deposition from cooling tower drift that is provided for each of the facilities. Please provide the calculations that you used to generate the estimates, including assumptions about salinity in the intake make-up water. Over how large an area would this deposition likely occur?

150. The last full paragraph on the page VII-29 includes the citation (LMS, 19901). Please provide the correct citation, and include it in the reference section.

151. Please provide a copy of the paper referenced on Page XII-56 entitled: McLaren, J.B. and L.R. Tuttle. 1999. Fish survival on Fine Mesh Traveling Screens. In EPRI, Power Generation Impacts on Aquatic Resources. Conference Proceedings April 12-15, 1999.

152. The last sentence in the first full paragraph in the Appendix on page V-3-17 indicates "juvenile alewives" when it seems it was meant to say juvenile anchovy. Please check and correct as necessary.

153. There appears to be a problem with the data provided in Appendix VI-1-A, Tables X-1, X-2a, X-2b, & X-3. Please check and correct as necessary. If Table X1 is correct, please provide further explanation that clarifies and explains why the data is correct as is.

154. Appendix VI-1-A, Table X-5 provides the permitted flows from facilities in the Hudson River with capacities greater than 50 mgd. Note that the flows at Indian Point are approximately 5 times that of the Lovett Station, located nearby across the river. With mechanical mortality for American shad fairly high (Table X-16), how does one account for the data in Table X-20a that indicates Lovett with equal and frequently higher CMR than the much larger Indian Point? Even harder to reconcile is the 44 times greater flow at Indian Point compared to Westchester County RESCO, and the approximately equal or occasionally greater American shad CMR at RESCO. By inspection of Table X-20b, CMR estimates for Atlantic Tomcod, there is on average an approximate 5 times greater impact on tomcod at Indian Point compared to Lovett so one has the impression that the model formulation is okay, but that the data inputs cause the model output to provide some counter intuitive results. Please comment on these observations and indicate whether some model inputs should be reexamined.

155. Appendix VIII-2-A, Attachment b is not legible. Please provide a better quality drawing.

156. Annual ELS mortalities at each of the plants (in their current configuration) are in the range of tens- to hundreds-of-millions (Appendix VI-1-D-1&2). For example, the annual average entrainment mortality from Indian Point 2&3 facility is: 11-13 million American Shad, 326 million Bay Anchovy, 372-467 million River Herring, 46-158 million Striped Bass, and 139-243 million White Perch(taking the mortality over the period of years analyzed and presenting the average low [table D-1] and average high table [D-2] values).

The DEIS should address, with respect to the preferred alternative and each other alternative, how the adverse impacts of Bowline, Indian Point, and Roseton (BIPR), expressed in mortalities of early life stages (ESL) of fish(eggs, yolk sack larvae and post-yolk sack larvae) are minimized to reach the Best Technology Available standard.

The DEIS must thoroughly address as alternatives for the subject power plants hybrid, closed-cycle cooling, 32 weeks of outages during the entrainment season, or any other feasible alternative that would reduce mortalities to substantially equivalent levels. Justification in the DEIS for the preferred alternative does not adequately assess why such other alternatives are rejected.

157. In Table X-23, the impact of Indian Point on the September 1 YOY for the whole 152-mile estuary has been as high as 9% of the American shad, 39% of the tomcod, 21% of the bay anchovy, 7% of the river herring, 46% of the striped bass, 14% of the spottail shiner, and 28% of the white perch. The annual entrainment mortality impact of each of these plants on the number of young-of-year produced in the Hudson River Estuary is high, in terms of the overall population numbers of each species, the consequences to the environment of the Hudson River, its estuary, and to recreational and commercial uses.

The DEIS must develop a more thorough analysis of alternatives such as hybrid, closed-cycle cooling, 32 weeks of outages during the entrainment season, or any other feasible alternative that would reduce mortality to substantially equivalent levels.

158. Assuming no through-plant survival, mortality figures have run as high in individual years as a 79% reduction in September 1 Spottail Shiner YOY (1977), a 63% reduction for Striped Bass (1986), 60% reduction for American Shad (1992), 53% for Atlantic Tomcod (1985), 45% for Alewife and Blueback Herring combined (1992), 44% for White Perch (1983), and 33% for Bay Anchovy (1990). Assuming the applicant's estimates with through plant survival the numbers are still substantial and are, respectively 25%, 27%, 52%, 44%, 41%, 39%, 30%, and 33%.)

The alternative selected does not adequately show how the subject plants will mitigate the impacts of once-through cooling on the Hudson River Estuary, as described in Appendix VI. A thorough assessment of the available technology must be completed to assess whether a level of protection equivalent to that achievable with closed-cycle cooling and an alternative intake design, construction, and location, will achieve reductions in the mortality impacts greater than that achieved by the proposed alternative.

159. Through-plant survival estimates used in Appendix VI-1-D-1 may over-estimate survival. Test organisms were only held for 48 hours, and were taken from the discharge canal. They were not held for a long enough time to assess whether or not mortality from blue sac disease would result. Also, the test organisms had not gone through the entire cooling water process, as they did not go through the diffuser-type discharge structure, nor experience the shock of returning to ambient temperature river water from the heated effluent stream. The actual value may lie somewhere between the two figures. However, in the absence of definitive information, it is more prudent to protect the natural resources by assuming the higher mortality rate.

The DEIS should be revised to employ the assumption that 100% of entrained organisms die, as in Appendix VI-1-D-2 to assess whether greater protection of fish species can be accomplished.

160. The DEIS does not substantiate why the "Fish Protection Point" system should be considered the preferred alternative.

The preferred alternative in the DEIS would attempt to establish an entitlement to constant mortality of fish species. The DEIS does not substantiate the "Fish Protection Point" sufficiently to describe a preferred alternative that mitigates or minimizes fish mortalities in a major river and estuary system. Nor does it adequately treat how it constitutes an application of new technologies to reduce impacts to fish species, consistent with federal and state laws and policies.

Furthermore, the outage days selected by the system were days on days of low fish mortality. The effect appears to be that the Fish Protection Point system would actually save fewer fish than were saved under the current outage system. Also, impacts would be shifted among the species. While the current outage system tends to target the reproductive period of Striped Bass, an important gamefish, under the Fish Protection Point system, the necessary points could be accumulated on tomcod (an early spawner) leading to increased impacts on striped bass.

Alternative days or longer periods of outages should be addressed to increase the potential mitigative effect of this alternative.

161. The DEIS did not provide an adequate context for comparing the cost of cooling towers, or other mitigative measures that would provide a similar level of protection.

For example, taking Indian Point 3, the annualized cost of the tower was estimated at between $20 and $39 million per year. This cost may be given an incorrect, subjective meaning without some sort of context. In comparison, 32 weeks of outage would provide comparable levels of protection, but would cost $202 million in lost generation. (Taking the average of their summer, winter, on-, and off-peak rates yields $36.25/MWh, multiplying by the rated capacity of 1034 MWe and the number of hours in 32 weeks.) Assessing the mitigative technologies will combine an assessment of their mitigative impacts with periods of operation different from those outages described for the preferred alternative, perhaps including providing electricity to the market throughout the year.
The cost of all other mitigative technologies should be compared to the cost of lost generation from the 32-week outage, timed to coincide with the entrainment season.

Another basis might be the value of the plant, which is being sold for $1.12 Billion. Or the value of the electricity produced per year. The DEIS must contain an assessment of alternative mitigative technology in these contexts in order to fully compare the value of such alternatives against the preferred alternative.

162. The DEIS did not evaluate in detail or cost out Gunderboom as an option for Bowline or Roseton. These may be feasible alternatives that might provide levels of entrainment-impingement protection that approach those of closed-cycle cooling.

The cost of this alternative and an assessment of its application should be provided.

163. In the DEIS, the striped bass model is provided in support of density-dependence based in part on the following observation: that despite increases in adult numbers over the years there was not an increase observed in the numbers of young stripers in beach seine samples.

The beach seine data sampled the same areas each year. These areas were both 1)accessible and easy to seine, and 2) places where catching young stripers was likely. Marginal habitats, or areas with low striper numbers 20+ years ago (when the study started) were not sampled.

The DEIS must assess the relative adequacy of sampling/seining locations and the accuracy of model dependance on such sampling/seining.

164. The modeling produced for the DEIS does not adequately explain its predictions for long range impacts on adult populations from lost Y-O-Y.

The models fail to include nomographs showing the effects of low, medium, and high density dependence. There was no user's guide to the spreadsheet models provided until late in the comment period. The specific shortfalls, even after many years of work and many meetings, are identified in the attached report.

The DEIS should include comparative predictions of impact to fish species from the preferred alternative and all other alternatives that do not depend on the modeling.

165. In describing the action on page IV-1 the DEIS mentions some of the standards that will need to be met in granting a permit, but not all of them. Specifically, the applicant fails to mention that the intake location, design, construction and capacity must be deemed to be the best technology available for minimizing adverse environmental impact. Nor does the applicant say that it must meet all applicable standards, limitations, and other requirements of State and Federal law.

Please make those changes.

166. Concerning Page V-20 "Westchester Resource Recovery Plant" the slot openings are not 0.5 mm, they are 2 mm.

167. The Thermal section on page VI-3 Paragraph B. 1. a. ii. fails to mention the additional thermal stress to entrained organisms of going from the hot discharge water back to the cooler ambient temperature of the river.

Please expand the paragraph to discuss the impacts to organisms of the stresses caused by going from hot water to cool or cold in the discharge of the used cooling water.

The value of the commercial fishery generates value-added for all stages of distribution and marketing. The DEIS only addresses the economic rent associated with the catch and sale of fish to wholesalers. Wholesalers and retailers also retain a portion of the value of the fish above and beyond operating costs and normal profit. This value is a contribution to the economy with secondary impacts or a multiplier effect on the economy (Sport Fishing Institue 1988. The economic impact of sport fishing in the state of New York. Washington D.C., December). If the DEIS addressed these components the commercial value of striped bass fishery would likely be significantly higher. Please revise this discussion and include these components.

168. Concerning the citations in the DEIS, please provide the full reference for the following:

Chapter V

- Pg V-37 - Gattuso et al. (1998)
- Pg V-38 - Briggs et al. (1979)
- Pg V-39 - Carcao et al. (1997, 1999)
- Pg V-46 - Kimbrough and Doemland (1999)
- Pg V-56 - Odum (1971), Pimm (1991)
- Pg V-57 - Pelczarski and Schmidt (1991), Brosnan and O'Shea (1996b)
- Pg V-59 - ISC (1997), Strayer et al. (1999)
- Pg V-71 - Eldridge et al. (1983)
- Pg V-72 - Richards and Rago (1999)
- Pg V-81 - Hubbs and Lagler (1958)
- Pg V-85 - Darmer (1987)
- Pg V-87 - NAI (1991)
- Pg V-89 - NAI (1997), Dunning (1997)
- Pg V-96 - Woodhead (1992), Nittel (1976), ISC (1994, 1997)
- Pg V-98 - Leim (1926)
- Pg V-99 - Kahnle et al. (1988)

- Pg V-101 - NYSDEC (1987)
- Pg V-116 - Brosnan and O'Shea (1996a)
- Pg V-116 - Brosnan and O'Shea (1996b)
- Pg V-118 - Waldman (1996)
- Pg V-119 - Ross and Bennett (1995), Taubert (1980a), Washburn and Gillis Associates (1981)
- Pg V-122 - Hoff et al. (1988)
- Pg V-123 - Geoghegan (1992), Kahnle et al. (1998)
- Pg V-124 - Bain et al. (1998), Thompson (1991), NMFS (1998)
- Pg V-127, 128, 130, 131 - MAFMC (1998)
- Pg V-130 - MAFMC and ASMFC (1989), MAFMC 1989
- Pg V-136 - Villoso (1989), Shepard and Grimes (1983)
- Pg V-137 - Daiber (1956a), Peterson and Peterson (1979), Welch and Breder (1923)
- Pg V-140 - Hrabit et al (1998)
- Pg V-142 - Burczynski (1987)
- Pg V-145 - Mills (1996)
- Pg V-150 - Schaffter and Kohlhorst (1997)
- Pg V-153 - Sulkins and Van Heukelem (1986), Epifanio et al. (1989)

169. On Page V-73 the sentence in last paragraph states " Age 1+ striped bass from habitats located within and outside of the river move into the area sampled during the winter mark-recapture program. "

This statement is an important assumption to the assertion that the age 1+ and age 2+ indices are more reliable measures of recruitment than the BSS and JSB surveys and to the accuracy of any population estimate generated from the mark-recapture program. It is entirely reasonable that fish that emigrate from the estuary early in the first summer of life do not return to the river to overwinter, but use one of the many other suitable wintering areas in the New York Bight. It is also reasonable to expect that the proportion of fish that leave and overwinter elsewhere varies among years. Both of these movement patterns would reduce the usefulness of the Age 1+ and age 2+ indices as measures of recruitment and would bias the population estimates.

Please provide observations or data supportive of the assumption.

170. The concluding sentence to the last paragraph on page V-73 states "Since a year elapses between marking and recapture, tagged fish have ample opportunity to mix randomly with untagged fish from all nursery areas used by the Hudson River stock, both within and outside of the river."

The assumption of random mixing alluded to in this sentence is critical to the population estimators used in the population estimates. Please provide supporting data or analysis.

171. Paragraph three on Pg V-79 states "Entrainment (Table V-18) had no detectable effect on striped bass abundance. Entrainment did not prevent the appearance of strong year classes of YOY striped bass, even when the abundance of eggs and larvae was low. It probably did not affect recruitment because the natural processes controlling recruitment occurred after the period

when entrainment occurred and the level of entrainment was too low to affect the natural processes determining recruitment"

The paragraph is not supported by any data or analyses. Please provide such data or analysis.

172. Please provide the full reference for the following text citations:

- Pg VI-17 - TI (1976a)
- Pg VI-18 - IA (1978a)
- Pg VI-22 - Consolidated Edison: Power Authority of the State of NY (1978a), LMS (1968, 1978c)
- Pg VI-27 - NTAC (1972), EPA (1974, 1977)
- Pg VI-29 - NAS (1972)
- Pg VI-31 - EA (1978c)

173. Under Appendix VI-2-C - Mark/Recapture Methods on Pg 10 it states "Equal catchability for tagged and untagged fish."

The evaluation of this assumption focuses only on the issue of gear selectively. It essentially ignores the possibility that marked and unmarked fish of the same age class may not be equally vulnerable to recapture gear because fish sampled for marking in the first year may not have the same migration pattern as those that did not overwinter in the sample area.

Please provide supportive data.

174. Under Appendix VI-2-C - Mark/Recapture Methods on page 11 it states "Ratio of tagged to untagged fish within the area sampled equal to the ratio for the population as a whole"

The evaluation of this important assumption consists of speculation that a full year between marking and recapture encourages thorough mixing of the marked and unmarked fish. It is likely that fish that leave the Estuary early in life move far enough along the coast that they do not mix with the fish that remain and are marked. Supportive data on ratios of marked to unmarked fish for comparison to fish sampled in the Estuary could be obtained from various studies that collect young striped bass in the New York Bight and should be provided.

175. Under Appendix VI-4-A - Striped bass population modeling, consists of a listing by category of available data, followed by several paragraphs which provide sources and a critique of some of the data sets listed. The text material cites Tables (1-8) as actual data inputs.

In general, evaluation of this section is difficult in that it is not clear how much of the data provided in Tables (1-8) were actually used as model inputs. Examples of omissions and confusion are provided in the following comments specific to each subsection in the Materials and Methods section.

176. On page 4 some of the items listed as available data in categories a-h are not described in the following sections so it is not clear what was actually available for use in the model. For example, category (d) suggests that data are available on ocean and in-river catch and exploitation rates and size limits. The following section on "ocean and in-river harvest and survival" (pg 5) does not address in-river or marine recreational losses or in-river exploitation

rates for any type of fishery. Which exploitation rates and losses were actually used in the model as inputs cannot be ascertained. The following sections also do not mention estimates of mortality from ocean catch and release mortality (category - e) or estimates of juvenile survival (category - f). Again, it was not clear which data were available and which were actually used. Even where a category of data is discussed in following sections, descriptions do not specify which data were actually used in the modeling.

177. On page Pg 4-5, concerning age structure item 3 indicates that the age distribution is from fish caught by DEC in the River. Table 4 referenced in item 3 indicates that the data were from the DEC marking program. Neither reference specifies whether the data are from the haul seine or electrofishing, or both. Striped bass are marked from both gears, but only data from the haul seine are used for age structure because the electrofishing collections seem to be biased toward smaller and presumably younger fish. Neither reference indicates gender of the fish.

178. On page 5, concerning maturity, fecundity, length, and mass-at-age, the maturity at age data (percent mature at age) cited in this section (Hoff et al., 1998) are for fish collected in the Estuary. Since most striped bass spawned in the Hudson Estuary appear to leave the Estuary prior to maturity, one would suspect that there are immature fish at age that did not return to the estuary during the spring spawning season. These fish would not be available to the sample used in the cited work. Maturity at age is percent of all fish both in and out of the river that are mature at a given age. Thus, the cited information would overestimate maturity at age for younger age classes in the model. Accordingly, please revise this discussion or explain why it should not be revised.

179. The text on page 5 concerning ocean and in-river harvest and surviva cites Crecco (1993) as a source of F estimates in Table 6 from 1954-1995 and also indicates that DEC has estimated survival from 1989-1994. Given current and historical assumptions of M (current, M=0.15, and historical, M=0.2), the two time series produce different values of Z or F during the years of overlap (1989-1994). The text does not indicate which data series was used. Table 6 also does not specify if the listed values for F are total F on the stock or the ocean component of F.

This section also references commercial in-river (bycatch losses) and ocean harvest of striped bass in Table 7. The bycatch losses from 1980 through 1997 in Table 7 do not agree with and are increasingly smaller than the estimates made by NYSDEC and reported to ASMFC. Perhaps the values in the table are for reported landings. If so, they would be an underestimate of actual bycatch since sale of striped bass taken from the Estuary has been banned since 1976 because of PCB contamination. Table 7 only indicates DEC as the source. It does not provide a complete reference so the data cannot verified.

This section makes no mention of losses to the recreational fishery. Recent ASMFC and DEC estimates of directed and discard losses to the recreational fishery often greatly exceed estimates of directed and discard losses to the commercial fisheries both in the mixed stock ocean and Hudson River in-river fisheries. Although estimates of proportion of the mixed stock ocean harvest that is of Hudson River origin is not know, estimates of losses to the in-river recreational fishery have been made by DEC and are reported to ASMFC.

This section also indicates that ocean catches are for NJ, NY, RI, Ct, and MA. However, no attempt was made to partition the harvest among spawning stocks. The relative contribution of Hudson River fish has varied through the time series depending on relative recruitment levels in contributing stocks. Van Winkle et al. (1988), Fabrizio (1987), and various ASMFC publications provide analyses that should allow speculation on general changes in proportion of Hudson River fish in the ocean commercial harvest.

The various estimates of the Hudson contribution to ocean landings should be used in the model unless the model proves insensitive to level of ocean losses from the Hudson River stock. Note that the first sentence at the top of page 14 indicates that harvest was partitioned for the years 1969 through 1975. It does not indicate if harvest was partitioned for the rest of the modeled time series.

180. There is no indication in the discussion of CPUE data in the second paragraph on page 6 or in Figure 1. We cannot evaluate the usefulness of the time series of CPUE data without an explanation of effort data used. Please provide an explanation.

181. The first sentence of the second paragraph on page 8 states that "We have allowed for additional fishing mortality in three blocks of years, 1932 to 1953 ( ), from 1954 to 1985 ( ), and from 1988 to 1995 ( ).

Please indicate the meaning of this statement and provide some supportive rationale for the three time stanzas. It appears that this "additional" fishing mortality is an estimated parameter that accounts for any mortality not accounted for in reported harvest data. It is not clear if mortality is held constant during each of the time periods or allowed to vary annually. The text suggests that the "additional mortality" comes from ocean harvest prior to 1954 and then in-river recreational and unreported ocean harvest for the 1954-1985 and the 1988-1995 time periods. It is not clear if this is speculation or if sources of mortality are in some way confined to these sources. It would be appropriate if a range of values for this category could be provided in the results section. The smaller these values are relative to the levels of mortality from known sources the more confidence in the model outputs.

182. The sentence in the second paragraph on page 11 states " For the WLO and SBMR indices we assume they are proportional to YOY abundance."

Please provide analyses that supports the contention that the SBMR indices are proportional to YOY abundance. The SBMR index was obtained form mark recapture population estimates over a 1.5 yr time period. The estimate methodolgy includes many assumptions which are important to accurate estimates.

183. The second sentence on page 13 states "This does assume that the other sources of fishing mortality were in-river, and therefore is not correct for the period prior to 1954 when we used other fishing mortality to explicitly represent ocean fishing."

It is not clear from this statement how ocean fishing was then treated after 1954. It is also not clear if the model addresses commercial ocean discards or directed and discarded recreational harvest. Please clarify these points.

184. Assumptions on page 14, under long term abundance trends, about relative population size in 1935, 1950, and 1980, set the assumed ratios between pairs of these values as truth, and then uses these truths to confine model trajectory of population size. The text justification for selecting these relative values is that they were "based on the historical evidence discussed

above". Presumably, this reference means the citation to Goodyear (1988) in the last paragraph of page 5. However, the materials in Goodyear (1988) provide only a very general summary of abundance change in the Atlantic coastal stock. Both Goodyear (1988) and the authors admit that the abundance levels discussed were probably most descriptive of the Chesapeake stocks of striped bass and not that form the Hudson. On page five, the authors state "It is unclear how relevant this description is to the Hudson River stock". Even if the cited materials were for the Hudson stock, they are too broad to be used a justification for the ratios selected. If these ratios are indeed important to model operation, then we need a more thorough discussion of the rationale for their selection.

Please provide this detailed rationale.

185. On Page 6-12 of Appendix VI- 3 - A, Ch. 6, there is an indication of exceedences of thermal criteria for the discharges at Indian Point Units 2 & 3. Please evaluate whether the preferred alternative, or any other alternatives, will eliminate these exceedences, and, if not, what impacts can be predicted over the course of the permit. What impacts have occurred as a result of these exceedences over the operating life of the plant to date?

186. The DEIS does not report on the discharge from the outfalls of radionuclides. Please identify the scope of Nuclear Regulatory Commission jurisdiction and indicate the corresponding scope, if any, of NRC regulatory preemption of State jurisdiction over the same discharges from these outfalls.

Exhibit 5

Summary of the Entergy Due Diligence Process

New York Power Authority

Memorandum

November 27, 1996
WJC-96-119

To: EMG

From: W. J. Cahill Jr. for WJC

Subject: Entergy Due Diligence Findings

Even though our negations with Entergy did not produce an agreement, there is still valuable information that is the product of their due diligence effort. Attached is the summary of their findings and recommendations that is intended for your use. I expect that you will share this information with your staff and utilize the recommendations to improve the efficiency of your organization. If you have any questions please contact Rich Lauman.

Summary of the Entergy Due Diligence Process

The Process

The objective of the Entergy due diligence process was threefold:

- Verify the condition, performance, and cost information underlying the proposed management agreement,
- Identify and material factors that could impact either the structure or content of the agreement,
- Identify costs associated with transition to standards that can result in the high performance levels that NYPA wants from its nuclear plants

The evaluation involved a significant expenditure of time from both Entergy and NYPA staff. The evaluation was focused into 20 functional areas made up of approximately 40 individual elements. There were over 60 team members from Entergy that spent three weeks on site.

The evaluation was modeled after and used predetermined criteria that was based on industry and INPO standards. Lessons learned by Entergy from the ANO diagnostic evaluation and the pre-merger evaluation of Gulf States Utilities River Bend plant were also incorporated into the process. The Entergy team members were chosen based on their depth of applicable expertise and skills. The individuals selected included officer, director and manager level individuals as well as specific subject matter experts. The emphasis of the fact-finding process was on the personal interaction and observations of the team.

Safety Culture Assessment

Part of the due diligence process was a Nuclear Safety Culture assessment. This was performed by independent consultants that have performed over 30 similar evaluations over the past three years. The process consisted of eighty confidential interviews with NYPA employees. Twenty percent of the interviews were with supervisory / manager level employees and eighty percent were with working level employees including bargaining units. The individuals were asked to rate certain characteristics of the nuclear safety culture both now and one to two years ago. A numerical scale was used to compile the answers and comparisons were made to industry data from the consultants past evaluations.

Summary of the Entergy Due Diligence Process

The aspects of the overall environment and nuclear safety culture that were assessed included:

- the understanding of NYPA's nuclear safety policies and expectations
- perceptions of the effectiveness and visibility of Speak Out
- perceptions of the environment for raising nuclear safety issues and concerns
- performance of the site in resolving nuclear safety and quality issues
- employee willingness to raise issues with his or her supervision and up the chain of command and with other key organizations
- management effectiveness and influence on the overall environment for raising and resolving nuclear safety issues
- employee job satisfaction and moral
- effectiveness of key business processes
- adequacy of employee - supervisory relations, including company - union relations.

Overall Results

In the area of ***Organizational and Business*** issues, Entergy observed that an overall, strategic framework for business planning, which should be the origin for budgeting and all other planning is lacking. Additionally, nuclear governance and accountability is not clearly focused. Critical functions report outside the CNO which can create conflicting priorities, barriers to communication, differing goals and measures, and inconsistent perceptions of service and performance levels.

Entergy recommended creating separate and distinct human resource policies for the nuclear department to recognize the unique qualifications of individuals in the industry and to facilitate attracting, retaining and effectively utilizing the personnel. In a similar vein, Entergy recommended separating the nuclear procurement process from the rest of NYPA's to better meet the needs of the nuclear organization.

Entergy reinforced that there should be open lines of communication and easy access between the CNO and the Licensing and QA groups and the other internal oversight committees. Noting that it is essential for the CNO to bear ultimate responsibility for these areas, having reporting relationships outside the nuclear organization potentially diffuses responsibility, communication and effectiveness.

Entergy recommended the formation of a Nuclear Committee of the Board of Trustees. This is similar to the way Entergy is organized and they feel it serves their Board well.

Summary of the Entergy Due Diligence Process

In the areas of ***Regulatory Issues and Key Constituencies,*** Entergy found that our working relationship with the NRC at the plants is open and constructive, but Entergy would try and be more proactive. Entergy noted that the regulatory climate is changing creating uncertainties for all nuclear operators. This uncertainty is fueled by the relatively new NRC Chair, new NRC Commissioners, management changes at NRC headquarters, and new regional leadership. The increased scrutiny and compliance - based focus by the NRC stemming from the Millstone situation is evidence of this change.

In areas outside of the NRC relationship, Entergy found that other than Rockland County, local governments and offsite agencies show strong support for the two plants. Working relationships with the State agencies are good and the cooperative agreements with Con Edison and Niagara Mohawk were opportunities that could be built upon.

Results - JAF

Entergy concluded that "recent improvements at FitzPatrick should allow the plant to maintain average performance". NYPA's investments in major equipment upgrades (condenser retubing, LP turbine rotors, feedwater heater replacement) were a positive sign and would support continued operation. Entergy felt that the material condition of major equipment is good but there are a number of minor issues to be resolved. The plant facilities were noted to be "excellent" except for the temporary buildings.

Teamwork among the site organizations appeared to work well and the decentralization of the engineering organization was effective (although the backlog diminished the positive effects) and implementation of the training program appears to be effective.

Improvements were noted in business planning although improvements are needed in the strategic planning area as noted above, and linking of the strategic planning process to the budget so that the budget becomes an effective management tool. The O&M spending levels were noted to be consistent with budgets and should be adequate to achieve higher performance levels. There was concern that too much pressure for a 45 day refuel outage would risk eliminating necessary work from the outage.

Summary of the Entergy Due Diligence Process

Entergy felt that the current organizational structure and accountabilities of the site dilute the site focus as exemplified by:

- No site Vice President
- No real focal point for site accountability
- Key functions have off-site or out-of-nuclear reporting
- Key projects are managed by corporate, rather than plant, project managers
- Corporate engineering control of programs compounds problems with on-site engineering groups

The backlog of work in the maintenance and design engineering areas are too high. Entergy got the impression that the JAF staff felt that the maintenance backlog was low but it is higher than that found at top quartile plants, plus there are some long-standing equipment deficiencies. There was recognition that the high priority engineering items have been reduced but the total is still higher then desirable.

The review identified that our work processes are not results oriented. The examples cited were:

- the maintenance work processes are bureaucratic and complicate accomplishing work;
- the work control processes are cumbersome; and
- having design engineering maintain responsibility for modifications without involvement of plant or system engineering dilutes the plant focus and ownership.

Entergy felt that there is no coordinated sense of drive for continuous improvement and that there is a willingness to live with long-standing equipment issues. Examples used to support this included:

- numerous oil leaks;
- operator work arounds;
- long-standing temporary modifications;
- systems operating in manual versus automatic; and
- operations not clearly "owning" the plant and driving the processes.

Summary of the Entergy Due Diligence Process

Results - IP3

Entergy recognized the significant investment that NYPA has made in IP3. Capital improvements noted as examples included the steam generator replacement, main condenser retubing, low pressure turbine replacement feedwater heater replacement, new condensate demineralizers and improvements to the intake structure. The health physics program was recognized as good, along with the action tracking program. It was felt that the operating experience program was well executed.

It was recognized that relationships with the NRC and outside agencies and governments, except Rockland County, were good.

Entergy felt that the change and improvement needed at IP3 was still very significant. The efforts have been to focus on restart that there is no long term plan for focus on operations.

Entergy's perspective on backlogs is that they must be reduced significantly and immediately. They noted that the volume of DER's is overwhelming and simply responding to this level of DER's makes it difficult to make headway with strategic planning and work control.

It was felt that the plant technology is inadequate to support high performance levels as evidenced by a plant process computer that does not meet industry standards and a document control system that relies on manual records retrieval which is two generations behind the current technology.

With respect to Engineering, Entergy observed that the Engineering groups are:

- consumed by day-to-day fire-fighting;
- long-range projects are progressing at a slow rate;
- the decentralization effort has not been efficient;
- having system engineering report to design engineering does not reflect a high performance organizational design; and
- corporate engineering control of site programs compounds problems with on-site engineering groups.

Regarding the upcoming refuel outage Entergy felt that it can not be accomplished in the planned schedule and budget that we were utilizing at the time of their assessment. There is insufficient time available to perform adequate outage planning and in their estimation, a long and costly outage would be expected. Entergy noted a dependence on outside contractors to manage and run refueling outages which minimizes ownership and participation by the plant staff.

Summary of the Entergy Due Diligence Process

There was a recommendation for timely development and implementation of the improved technical specification program and that we should continue to upgrade the license and design basis documents to support plant operations.

Entergy observed that our procedures and processes are excessively cumbersome and not results oriented. They recommend a site-wide, systematic approach for process improvement be undertaken to help improve overall plant effectiveness and efficiency. Evidence of the need for dramatic change is the observations that work control is not focused on supporting Operations and Maintenance needs, improvement in budgeting and cost control measures are needed along with improving the cost control culture, long range, strategic business planning and budgeting tools are needed.

Maintenance work processes were noted to be bureaucratic and complicate getting work accomplished. Improvement in maintenance is needed in the following areas: work planning; preventative maintenance; procedures; utilization of minor maintenance; and productivity.

Improvements are needed in the site facilities. The current environment is inadequate to provide a professional work environment. The areas needing immediate attention are administrative, maintenance, and warehousing.

The teamwork at the plant was noted to be weak. Supporting this conclusion is that Operations does not "own" the plant and drive the processes; prioritization of work is fragmented with various departments making determination without regard to integration into an overall site plan; coordination and communication are poor resulting in low productivity; many people have developed a bunker mentality rather than trying to help each other and the plant.

There are similar organizational issues at IP3 as JAF. It was noted that JAF has achieved some organizational strengths that IP3 has yet to achieve. Among the issues include:

- No site Vice President
- No real focal point for site accountability
- Key functions have off-site or out-of-nuclear reporting
- Key projects are managed by corporate, rather than plant, project managers
- Corporate rather than plant, management if key projects is not in the interest of achieving high plant performance levels.

Summary of the Entergy Due Diligence Process

There are potential environmental issues that can restrict plant operability These issues include the Hudson River Settlement agreement for a reduction in fish mortality; sludge disposal, and underground storage tanks.

Cultural Assessment Results - JAF

There is the perception of a good safety culture at JAF. The environment is perceived as being conducive for identifying nuclear safety and quality issues and individuals are comfortable raising issues to supervisors or through the non-conformance process and, to a lesser extent through the QA organization.

Personnel believe that they are encouraged to raise issues and more problems are being identified now than they were in the past and the trend is improving.

The single greatest problem the assessment identified at JAF was management's inability to deal with human performance and accountability issues. State laws or union requirements were seen by many as restrictions on the ability to discipline or even constructively criticize employees. Most of those interviewed felt that poor performers were generally tolerated and worked around. There is the perception that plant problems, regardless of the facts, for the most part were seen as equipment, process or procedure related rather than personnel related.

Management, particularly first line supervisors, feel that they have only limited ability to discipline union employees which adds to the perception of the difficulty in dealing with personnel performance and accountability. Managers also feel that they have been told to hold union employees accountable but in practice they feel that there are too many restrictions to be effective.

The assessment results identified that the general opinion is that work planning and scheduling are improving and the refuel outage is well planned and based on a realistic schedule.

The corrective action process was seen as being well supported by all levels of the site however, many feel that the non-conformance process is becoming overloaded which has the potential to divert attention away form more important issues. Many complained of the administrative

Summary of the Entergy Due Diligence Process

burden of the system, especially on minor issues and felt that a better approach to screening and prioritization is necessary.

Employee confidentin the JAF Speakout program was rated overall as slightly less than adequate. Management support for the program was seen by many as decreasing in the past year. Most view Speakout as not a viable alternative for raising nuclear safety and quality concerns. To the extent that it is used, it is used primarily for personnel related issues.

There is the general perception that JAF is in reasonable good shape (costs, operations and regulatory) and that is has successfully recovered from it's time on the NRC's "Watch List". There is a concern, however, that the site does not know what is needs to do now to continue to improve and possibly avoid a relapse. Suggested actions to overcome perceived barriers include:

- a better model of accountability for performance
- a better working relationship with union management to ensure that common goals are achieved
- a more efficient corrective action process
- a better focus on the achievement of site goals

Cultural Assessment Results - IP3

The nuclear safety culture at IP3 is perceived as being generally good and seen as improving. It is generally believed that IP3 is headed in the right direction in improving nuclear safety culture but there is general concern that progress cannot ~~be maintained~~.

Management is seen as promoting a questioning attitude and an open safety environment and there is a perception that the site is more aggressive in addressing potential safety issues. Most indicated that they would be willing to raise nuclear safety issues to their supervisors and up the management chain without any fear of retribution.

While there is a perception that the safety culture has improved significantly, perceptions are still low compared to many other industry sites. Key programmatic elements of a strong safety culture are still in the formative stage. Areas identified include the corrective action program, safety evaluations, self assessments, regulatory performance and responsiveness, operating experience and best practices are still seen as being in need of improvement. The work planning process is viewed by many as a significant weakness.

Management is seen as promoting a strong safety culture and proper behaviors but not doing enough to address barriers in the way such as accountability and weak programs and processes.

Employee confidence in Speakout has improved at IP3 and the present rate is consistent with the industry average for similar types of programs. The program is seen as lacking strong management support: " just another required program driven by NRC requirements". Management is not seen as having portrayed Speakout as an integral component of the nuclear safety culture or as having used it strategically.

The factor that is having the greatest impact on attempts to improve the IP3 nuclear safety culture, as identified by this assessment, is the size of the backlog. There is a perception that the backlog has so overwhelmed engineering and maintenance that the site's ability to be proactive in improving areas such as corrective action, safety assessments, regulatory performance and incorporation of industry best practices is being stifled. Many believe that it is difficult for the station to be proactive in improving because of the burden in keeping up with the normal workload, not to mention reducing the backlog. Morale appears to be lowest in the engineering group where the backlog is a significant issue.

Communication and teamwork are generally seen as improving however, many still perceive mixed messages and not enough emphasis on how goals should be met. Many cite an absence of a long term vision, continued crisis management and long hours as a barrier to continuing performance improvement.

Perception is that there is a lack of clear management direction in terms of vision, goals and objectives. Numerous changes in management in recent years is seen as a contributing factor and many feel that while there have been many changes at the senior management level, there have been too few changes at the middle level managers and supervisors. Many perceive current management as still being in a reactionary, crisis management mode.

Many employees have felt blamed and unable to control work for which they are being held responsible. There is a belief that while accountability has improved, it has been directed at the organizational level and not on individuals. There is a need seen to address the

Summary of the Entergy Due Diligence Process

individual performance problems that are shifting the work burden to the better employees.

Many perceive the NRC as implicitly dictating priorities, driving the station's focus toward emergent, highly visible issues and away from those area that will ensure longer term and lasting success.

The corrective action program is still not widely appreciated as a cornerstone for a successful nuclear safety culture. It is still seen by many as a process driven by NRC commitments rather than a process to solve problems.

Many feel that their working conditions are inadequate and unprofessional which reduces productivity and morale.

Exhibit 6

"Indian Point 3 pipe break leaks toxins into river"

Indian Pt. 3 pipe break leaks toxins into river

By Cathleen Fromm
Staff Writer

A break in an underground pipe at the Indian Point 3 nuclear power plant in Buchanan led to the release of 1,600 gallons of a toxic solution into the Hudson River earlier this month, utility officials said yesterday.

The pipe leaked an average of about 180 gallons of sodium hypochlorite — a solution that is 12.5 percent chlorine — into the Hudson River daily from June 5 to 13. The break in the pipe was discovered Friday, said Jim Steets, spokesman for the New York Power Authority, which owns the plant.

The chlorine solution, used to stop organisms from growing in the plant's water system, is toxic and may have killed some marine life in the river — although the scope of the affected area has not yet been calculated, Steets said.

Steets said he believed the broken pipe was due to the erosion of a culvert underneath the pipe. The rusted culvert caused gravel separating the two pipes to wash away, removing support for the chlorine-solution pipe. The weight of the pipe ultimately caused it to collapse, he said.

"It's an underground pipe that had not been recently worked on, and it's not a reflection of poor performance by individuals."

— Jim Steets, spokesman, New York Power Authority

But Glenn Tracy, a senior resident inspector for the U.S. Nuclear Regulatory Commission, said the break's cause was still a matter of speculation.

The pipe is supposed to carry the toxic solution from a tank to a bay where it is mixed with water from the Hudson. The water is then sent through the plant to cool components like emergency diesel generators which would run the plant in case of a blackout.

The water with the chlorine solution would ultimately be dumped back into the river. But the pipe leak allowed the undiluted chlorine solution to flow directly into the Hudson.

The problem was discovered several days after the plant switched the pipe used to send the chlorine solution from its tank to the bay. The plant can alternate between two pipes.

From Jan. 1 to March 29 —when the now-broken pipe was being used — the chlorine solution was found most of the time in water sent to the bay. For that reason, the utility does not believe the pipe was leaking prior to June, Steets said.

"There was clear evidence there was chlorine in the system (earlier this year), whereas from June 5 through the 13th, it was obvious there wasn't," Steets said.

The utility will determine how to repair the pipe over the next few weeks. In the meantime, chlorine is being pumped into the water system through another pipe.

The amount and concentration of the chlorine discharge exceeded state permitted limits. The state Department of Environmental Conservation, the federal Nuclear Regulatory Commission and the U.S. Coast Guard were notified.

Petty Officer John Wolf of the Coast Guard said a hearing officer from his agency would determine whether to assess a penalty. DEC spokesman Greg Dolan said his agency was awaiting a full report from the Power Authority before determining whether any action was necessary.

The Indian Point 3 plant has been shut down since February 1993 because of management and performance problems. It is not expected to restart until the end of the year.

Steets said the chlorine discharge is not related to the plant's other problems.

"It's an underground pipe that had not been recently worked on, and it's not a reflection of poor performance by individuals," he said.

The NRC's Tracy said he believed the leak was due to a design flaw and the utility pursued the problem once it was found.

Exhibit 7

"Mildly radioactive gas release found"

Saturday, October 23, 1993.

Mildly radioactive gas release found

By David Talbot
Staff Writer

For more than a decade, the New York Power Authority has allowed slightly radioactive gases to escape unchecked into the air and submitted inaccurate reports on the releases, Gannett Suburban Newspapers has learned.

And on Sept. 14, workers at the Indian Point 3 nuclear power plant accidentally dumped the wrong 900-gallon tank of mildly radioactive waste water into the Hudson River.

The radiation levels involved are too low to raise any health or environmental concerns, U.S. Nuclear Regulatory Commission and utility officials say. Federal law allows low-level discharges under tight controls.

But the NRC has ordered the utility to calculate the levels of extra releases since 1980, when a gas-removal device was disconnected from waste plumbing and replaced with another device that filters only particles.

For 13 years, the utility submitted radiation-release reports based on the assumption the device was in place, NRC Senior Resident Inspector Glenn Tracy said.

"They released more than they thought they released," he said.

The radioactive gases escaped into the air from waste-liquid tanks adjacent to an employee parking lot.

Ralph Beedle, Power Authority vice president for nuclear generation, said the 900-gallon dumping reflected sloppy procedures.

"What it says is your command and control system is not as solid as it can be," he said.

The waste liquid is produced when the utility flushes the reactor's primary cooling system.

In another incident, workers on Sept. 18 spilled 1,000 gallons of boric acid inside the plant because they forgot to close a drain valve on a tank. No one was injured, and equipment was not damaged.

All three matters are under NRC review for possible enforcement action. The radiation releases were reported to the NRC by utility workers Oct. 1.

"These kinds of things need to be controlled," Tracy said. "If they can't be controlled during a shutdown, how can we have confidence it will be controlled during operations?"

Beedle later made a similar remark and said many such procedures were being revamped. The plant has been shut since February.

flaws at Indian Point 3 do not reflect any laxity in regulatory oversight. He said the NRC had always made sure many important systems were intact and functioning.

No risk study done

With all systems working perfectly, the chance of a reactor accident at Indian Point 3 is about 1 in 3,500, if the reactor operates for 30 years. A study of the increased risk at the plant, taking into account the recent findings, has not been done.

In March, Gannett revealed that a $1.1 million reactor shutdown computer called AMSAC was broken for six months in 1992. It later emerged that the system had been crippled by a software glitch since it was installed in 1989.

AMSAC is designed to kick in after other automatic shutdown systems fail — a 1-in-a-million chance in any one year. It happened in 1983 at the Salem 1 nuclear plant in Hancocks Bridge, N.J. Workers there shut down the plant manually.

Tracy, the NRC senior resident inspector, discovered the AMSAC problems and many other faults.

Selin said Indian Point 3's problems were similar to those at the handful of other troubled nuclear plants on the NRC's "watch list," including the Power Authority's James A. Fitzpatrick plant near Oswego.

But he said that, given a 14-month Fitzpatrick shutdown for safety breakdowns beginning in late 1991, the NRC should have moved faster on Indian Point 3 — perhaps by six months. The NRC assigned Indian Point 3 "watch list" status in June.

"Why the (utility) management ever let it get to this situation is not something I can answer in retrospect," Selin said. "If the concern is for the future, I wouldn't share that. If the concern is how did we ever get in this problem, I would share that

Exhibit 8

"Treasures in the Landfill"

Treasures In The Landfill

Three NY Nuclear Plants Send Contaminated Sludge to Local Landfill

Andy Molloy

SINCE EARLY 1988 the three nuclear power plants that sit on the shores of Lake Ontario in Oswego, NY have been treating on site their sewage waste produced at the plants in "non-nuclear areas." They then ship the waste to the Minetto Wastewater Treatment plant. This treatment process uses all sorts of little one-celled animals to convert human waste into something less waste-like and more like fertilizer. Bacteria eat the organic material that is sent in, and the one-celled critters eat the bacteria (sort of like a mini food web). When the original waste has been through this and a few other steps, it is sent as concentrated sludge on its way to the Bristol Hill county landfill.

Oswego County has had a law on the books since 1990 that prohibits radioactive waste material from entering their solid waste management system. That means it cannot go through treatment plants or end up in county landfills. They prohibit regulated isotopes and also radioactive material that is "below regulatory concern" (BRC). BRC is a category of radioactive waste that agencies like the Environmental Protection Agency and Nuclear Regulatory Commission came up with to define radioactive material that they feel is safe enough to go into the regular waste stream. These agencies' reasoning, along with the nuclear industry's, was that not all levels of radioactivity are bad and the nuclear plants should be allowed to dump the really low level stuff (as they put it) in normal landfills and have it be treated like any other garbage. They argue that this waste contains amounts below background radiation levels and shouldn't be confused with more harmful levels.

Concerned residents in Oswego County and across the country didn't buy this normalizing of even minute amounts of radioactive waste. Oswego residents went to their county government with concerns about BRC waste; this spurred the county to ban the material. Much of the concern was that communities wouldn't be able to monitor this BRC waste to tell if it really was of inconsequential levels. Others argue that not enough is known about these materials to set such levels as "harmful" and "safe." Still others were concerned about the strategy the nuclear industry was using to bolster their case that nuclear power is an acceptable form of energy supply. The nuclear power industry has been trying to allay the public's fears on many levels, from simplistic ads in national newsmagazines touting nuclear power as the answer to global warming, to renaming low level radioactive waste to innocuous sounding "below regulatory concern." The incredible problem of having no socially or environmentally acceptable way of disposing of nuclear plant-generated radioactive waste is a thorn in the nuclear industry's side. The myth of cheap and free nuclear power has already been dispelled. BRC categories may be a first step twords convincing the public to change their view of the industry.

When a Syracuse television reporter named Jean Kessner and two Volney residents, Chris and Howard Rose, went to the Oswego local government armed with information that showed that the nuclear plants had in fact shipped some minutely contaminated sludge to the county waste treatment plant and that it was being buried in the county landfill, red flags went up. This happened back in November of 1993.

> **The incredible problem of having no...acceptable way of disposing of nuclear plant generated radioactive waste is a thorn in the nuclear industry's side.**

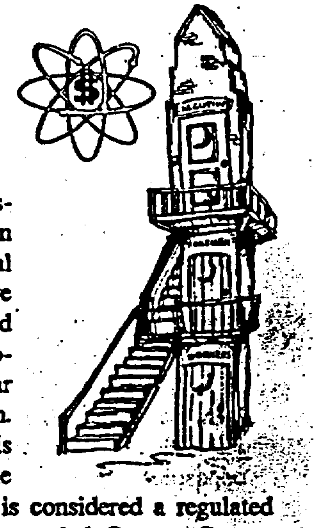
Oswego County publicly denied they knew this was happening. The county immediately wrote to the New York Department of Environmental Conservation (DEC) asking why they weren't told that contaminated sludge was coming out of the nuclear plants. Oswego County said they were mostly concerned about the health of people working at the sewage treatment plant and at the landfill, and whether the landfill would be contaminated. The DEC wrote back assuring them that it was an oversight that the county hadn't been told. According to Niagara Mohawk, which runs two of the three nuclear plants, just one out of 121 loads of sewage waste was contaminated. They also said that the level of radioactivity was 450 times below the state regulatory limits. Why, you could even sit on a pile of the sludge for an entire year and receive less than 10% of the allowable dose of 100 millirems, according to the DEC.

Oswego County put out a position paper (dated 12/1/93) soon after, that stated they were confident that the sludge disposed in the landfill posed no threat to human health, worker safety or the environment. They based this on the minute quantities, that only one load of sewage was contaminated, and that DEC said no additional action had to be undertaken at this time. Nonetheless, Oswego County stated they would:

(1) test new sludge from the nuclear plants as it became available (with the help of the DEC),
(2) if feasible, set up radiation monitoring devices at the landfill (DEC would help the county set and run the monitors)
(3) revise the county waste laws to set "specific regulatory limits based on the revised NY regs of 1993."

Oswego County's denial of knowledge and their stated concern for health and safety may have other reasons behind it There are those who believe the county did know this was going on. And if they knew, were they then negligent in adhering to their own law? Chris Rose thinks this may be closer to the truth. "The county is not concerned [with the shipments] other than they got caught and want to cover themselves."

Records obtained from the Oswego Department of Public Works show that the shipping of contaminated waste was not a recent thing. All three plants were shipping contaminated sewage waste since 1989. NiMo may be correct (independent verification notwithstanding) in saying only one load was contaminated, *but this was only for 1993*. Niagara Mohawk shipped 12 contaminated loads (by their admission) out of 738 delivered to Minetto since 1989 (see Table 1). The NY Power Authority shipped 165 contaminated loads out of 180. Over 90% of the Fitzpatrick loads were radioactive to some degree (Table 1). This shipping of known contaminated sludge started in 1989, even though in 1990, both agencies indicated that no radioactive material of any sort was going into the waste stream.



The year 1990 was when the Nuclear Regulatory Commission enacted the BRC plan to permit very low-level radioactive waste to enter the normal garbage stream. The three plants were supposedly not interested or considering the policy. According to a Herald Journal article (4/20/90) NiMo "doesn't plan to seek NRC approval to dispose of waste from its Nine Mile 1 and 2 plants near Oswego, mostly because of public perceptions." The article also states that the spokesperson for the Fitzpatrick Nuclear Power plant run by the NY Power Authority indicated, "the utility is not planning such disposal and is not actively supporting the policy."

These statements don't tell what was really happening. Contaminated waste was already being allowed into the waste stream; it is only now that the public is finding out what has been going on all along.

Some of the concern comes from the types of radionucleides being generated at the plants and put into the waste stream. Much of this material is Cobalt-60, and officials time and again state how the amount of Cobalt-60 is much less than even background or naturally occurring radiation levels.

But Cobalt-60 is not the same as these background types of radiation. A report put out by the Department of Radiology, School of Medicine at the University of Pittsburgh states that Cobalt-60 can be a health hazard at levels far lower than are presently set in regulations. The report stated that studies of very low levels of these radioactive materials "have indicated that the chronic, long-lasting exposures they produce appear to be thousands of times more serous per unit-dose than the short exposures to X-rays or gamma rays from nuclear explosions on the basis of which the present standards were set."

The report states that the latest studies indicate "that inhaled or ingested radioactive materials released by bomb-tests and by nuclear reactors at very low doses of only a few millirads per year, well below the levels of natural background radiation, damage the immune system far more seriously than the naturally occurring radium, cosmic radiation or medical X-rays." Could not repeated dumping of minute amounts over many years add up to unsafe levels? Even though the possibility of ingesting these materials may be hard to imagine, inhaling could be a possibility for workers or those around the sludge drying or landfilling process.

It was a television reporter that had to break this news to the county and public. One issue this whole exposure has brought up is whether Oswego County's own law against disposal of BRC radioactive material or regulated isotopes was violated by the nuclear plant administration. Whether or not this material is of the BRC category or is considered a regulated isotope has not been settled. Oswego County is waiting until the DEC rules on it and they are also waiting until sometime later this year when DEC will bring out its new regulations on levels of radioactivity. One question the Oswego Department of Public Works might face is, "Could the Bristol Hill landfill become classified as a low level radioactive waste site because of what has happened?"

Interestingly, the nuclear plants most recent application to ship on-plant sewage sludge for 1994 (filed on November 30, 1993) was rejected due to "incomplete application." A four page memorandum from DEC to the three plants listed items that needed to be answered before an application would be granted.

The Town of Volney is not sitting around to find out. They recently passed a local law banning "any radioactive waste" from the Bristol Hill Landfill. They feel that until more information comes out on just what level of radioactivity is safe or allowed they need a stronger local law than Oswego County's "no BRC or regulated isotope waste." This certainly doesn't make nuclear plants pleased, as the next shipment of sludge is scheduled for this July. It will be more expensive to ship the waste somewhere else for treatment and disposal. S. David Freedman, the new president and CEO of the New York Power Authority, has given the Fitzpatrick Plant two years to make money or he claims it will be shut down. They will have that much harder a task if they can't unload their sludge locally. Town of Volney supervisor Howard Rose says of the closing of the landfill to contaminated sludge, "We want to play it safe." It seems a prudent choice.

Andy is a former staffperson for the Peace Council. He is attending SUNY ESF where he is working on a project with the endangered Chittenango ovate amber snail.

Table 1: Radionucleides Detected in Loads of Sewage Sludge Delivered to Minetto

Facility	Year	Total Shipments	Number of Detections
New York Power Authority (Fitzpatrick)	1989	25	25
	1990	41	41
	1991	31	26
	1992	57	50
	1993	26	23
Niagara Mohawk Power Corp. (Nine Mile I, II)	1989	72	5
	1990	113	1
	1991	126	0
	1992	154	5
	1993	273	1

Data supplied by Oswego Department of Public Works. NYPA figures include detections for Manganese-54, Cobalt-60, Zinc-65, Cesium-137. Niagara Mohawk included detections only for Cobalt-60. A detection means that the shipment delivered tested positive for contaminants.

Exhibit 9

Miscellaneous Documents Related to Entergy Corporations Public Utility Subsidiaries

1) Statement of Gary L. Groesch, August 12, 1999
2) Alliance for Affordable Energy, Report to the Council of the City of New Orleans
3)Public Utility Commission of Texas Final Order
4)New Orleans City Council PressRelease

STATEMENT OF GARY L. GROESCH
CITY COUNCIL UTILITY COMMITTEE
AUGUST 12, 1999

Entergy corporation began in 1992 when it became clear that Middle South Utilities, Entergy's predecessor, had a name and reputation damaged beyond repair due to the massive economic failure of Middle South's nuclear power program. However, as we now know, Entergy's name change did not change their old stripes, so to speak. Entergy's first CEO Ed Lupberger, quite an unpleasant fellow by all accounts, failed to keep the lights on reliabily because he and his high-flying pals were too busy creating failed multi-billion business ventures around the planet. Enter Mr. Wayne Leonard, a nice fellow by all accounts, who puts out his first annual report with bold orange and black letters that state "we've made a big change," and "dedicated to keeping the lights on." When I first read them, I remember being a bit puzzled. The Alliance for Affordable Energy has long labored under the belief that "keeping the lights on" is a constant, a fundamental *raison d'etre* of the electric utility business, not the subject of a "big change" during times of management flux.

The Alliance nevertheless welcomed the statements of Entergy's new management team -- headed by J. Wayne Leonard -- that promised to eliminate the excesses of its former chief, Mr. Ed Lupberger, and rededicate the company's efforts toward services important to customers such as good electrical reliability. However, fifteen months after Mr. Leonard's elevation, we are sorry to report little real change. Worse, this latest series of events smacks of the worst of the Lupberger era: maintenance failures, poor planning, and unreliable public statements.

Mr. Leonard had better use these rolling blackouts as a wake-up call. Anytime you have nine power plants fail in whole or in part in a 24 hour period. Thats not bad luck. That's not even bad maintenance. That's a maintenance meltdown. It's like the school system in Orleans Parish finding out that 70% of the children failed a standardized math test. It's a catastrophe. If I were Wayne Leonard, I would fire the whole lot of them and hire some real talent. Is anyone going to trust a company that cannot keep fossil plants running successfully to maintain a bunch of geriatric nuclear plants like Pilgrim? By the way the non- failure of the nine nuclear plants was sandwiched in between unexpected shutdowns of the River Bend nuclear plant and Waterford 3 nuclear plant.

And your public relations people have been even worse. From the very beginning, they have been telling half truths, quarter truths, and outright lies, and even as late as yesterday they are still playing the old "you can't have the document game." They refused to release this report to the newspaper, the television people, and to the Alliance for Affordable Energy. Does that sound like a professional public relations plan. This tells me that Entergy is simply afraid of real scrutiny. A Big Change. I Don't Think So. I'd fire the whole lot of them and hire some professionals.

The full story of the Friday, July 23 rolling blackouts has had to leak out over time. Entergy's initial press release on July 23 blamed the rolling blackouts on the heat wave and "high electrical demand levels across the eastern United States." The truth is that 1) this recent weather, while very hot, was no record-setter, 2) no other electric utility in Louisiana or elsewhere in the U.S. was experiencing trouble except Entergy, 3) Entergy owns a subsidiary called Entergy Power which was selling 800 megawatts outside the Entergy system during the rolling blackouts and 4) at least nine power plants which are owned and maintained by Entergy had failed completely or were producing power at a fraction of their potential.

Concerning the last point, these failed power plants constituted 12% of Entergy's entire electrical capability, a maintenance "meltdown" by any standard. During the mass evacuation in front of Hurricane Georges, there were far fewer automobile breakdowns on I-10 on a percentage basis than Entergy experienced with its power plants on July 23. This can mean only one thing: the average New Orleanian maintains his or her automobile better than Entergy maintains its power plants!

It gets worse. In a kind of *deja vu*, on Saturday, July 31, an underground electrical fire on Canal Street knocked out power for four hours to downtown businesses and some parts of the French Quarter. This is reminiscent of the explosions, flying manhole covers and shooting flames that bedeviled the French Quarter several times last summer, knocking out power on at least two occasions for ten hours or more.

Consider three reasons why these blackouts are happening and will likely continue.

First, the City Council of New Orleans and the Louisiana Public Service Commission are too easily assuaged by promises of change by Entergy. Typically, there is a spike of interest by Louisiana regulators in electric reliability issues after high-profile electrical outages but little substantial follow-up. Entergy knows that Louisiana elected officials seem unwilling to fine the company for poor reliability. By contrast, in 1997 the Texas Public Utilities Commission fined Entergy nearly $9 million for poor electric reliability stemming back nearly a decade. The Alliance believes that is why 58% of the customers affected by the July 23 rolling blackouts live in Louisiana although Louisiana constitutes only 41% of the company. Not surprisingly, Entergy chose far fewer Texas customers to suffer rolling blackouts on a per capita basis than Louisiana customers. New Orleans is evidently the softest touch of all since twice as many customers in New Orleans were affected by the rolling blackouts on a per capita basis than any other part of the Entergy system. Is it any wonder that New Orleans has the worst electric reliability on the Entergy system, and arguably in the United States?

Second, in 1996 Entergy was allowed to dismantle its legally mandated energy efficiency programs in New Orleans and to stall the implementation of energy efficiency programs in Louisiana and elsewhere. This ensured that growing peak electrical demand would outstrip Entergy's available supply much sooner than expected. Without significant investments in helping consumers become more energy efficient, operational tightness in the summer will continue indefinitely causing future blackouts, especially when "glitches" happen such as power plants failures. By contrast, the City of Austin, one of New Orleans' chief regional competitors, has been practicing energy efficiency investments for years. Its federally recognized, award-winning strategy has made thousands of Austin homes and businesses more energy efficient. Summing all of its energy savings, Austin now has what it terms a "Conservation Power Plant" which saves what would otherwise require the output of a 380-megawatt power plant, about one-fourth of the community's total electrical load. Of course, Austin easily sailed through July 23, Entergy's crisis day of rolling blackouts, with a very comfortable 20% margin of safety over its electrical demand.

Third, after Hurricane Georges and the French Quarter outages, Entergy filed for a change in the rules and policies related to its electrical service in New Orleans. Among many questionable requests, Entergy is attempting to fashion a litigation shield from civil damages caused by electrical outages which are the result of its negligence, even its gross negligence. If granted, Entergy would have little incentive to maintain its electrical system because it would enjoy virtually complete immunity. Entergy has even requested the right to refuse to comply with governmental orders issued under the police powers of the Mayor in the event of a declared emergency such as a hurricane. If granted, Entergy could refuse a direct order by civil authorities to reenter the City of New Orleans after hurricane devastation.

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ALLIANCE for AFFORDABLE ENERGY

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August 13, 1999

Honorable James Singleton
Council member at Large

Honorable Eddie Sapir
Councilmember at Large

Honorable Suzanne Haik Terrell
Councilmember, District A

VIA FACSIMILE

Honorable Oliver Thomas
Councilmember, District B

Honorable Troy Carter
Councilmember, District C

Honorable Roy Glapion
Councilmember, District D

Honorable Ellen Hazeur-Distance
Councilmember, District E

Re: Rolling blackouts of July 23

Dear Councilmembers:

I am providing the Council with the following information in response to a request by Councilmember Glapion. It clearly shows the disproportionate and unfair burden placed upon Orleans Parish ratepayers (both east and west banks) by Entergy's rolling blackouts of July 23, 1999. I am also including a chart (attachment 1) which displays the following information.

There were 555,680 Entergy customers interrupted during by the rolling blackouts of July 23 throughout the entire 4-state/5-jurisdiction system (attachment 2 is a chart associated with a July 29, 1999 front page article in the Times-Picayune). The above-mentioned affected customers are a subset of Entergy's total number of customers which is 2,495,000 customers (see Entergy's website: www.entergy.com/companyinfo/index.htm). In other words, 22% of Entergy's customers were blacked out for some period of time during the July 23 crisis.

One of the goals of Entergy's Curtailment Policy and Procedure (Entergy Response to Council Question 1-11) is to "Distribute the demand curtailment as equitably as possible." As you will see, this goal was not achieved during the July 23 rolling blackout.

Entergy New Orleans Inc. has 189,000 electric customers on the east bank of Orleans Parish. 84,994 of those customers were interrupted by the July 23 rolling blackout. This means 45% of ENO's ratepayers were blacked out.

On the west bank of Orleans Parish, Entergy Louisiana Inc./Algiers (ELI/Algiers) serves approximately 19,000 electric customers. 7,094 of those customers were interrupted during the July 23 rolling blackouts (Entergy response to Council Question 1-10). This means 37% of ELI/Algiers customers were blacked out.

In toto for Orleans Parish, there are 208,000 Entergy customers; and 92,088 customers were interrupted during the rolling blackouts of July 23. **That means 44% of Orleans Parish ratepayers were blacked out during this crisis, twice the Entergy system average.**

In contrast, Entergy Arkansas Inc. has 629,000 customers. 80,364 of those customers were interrupted during the July 23 rolling blackouts. Only 13% of Entergy's Arkansas customers were blacked out, nine percentage points below the system average.

Entergy Mississippi Inc. has 388,000 customers. 53,290 of those customers were affected by the July 23 rolling blackouts. Only 14% of Entergy's Mississippi customers were blacked out, eight percentage points below the system average.

Entergy Louisiana Inc. has 928,000 Louisiana customers outside of Orleans Parish. This includes the former Gulf States Utilities customers (Louisiana only) but not the ELI/Algiers customers which are regulated by the New Orleans City Council. Of the group of Entergy Louisiana customers outside of Orleans Parish, 232,213 were interrupted during the July 23 rolling blackouts. That means that 25% of Entergy's Louisiana customers outside of Orleans Parish were blacked out, three percentage points above the system average.

Entergy Gulf States Inc. has 342,000 customers, all in Texas. Of that group, 97,725 were affected by the July 23 rolling blackouts. That means that 29% of Entergy's Texas customers were affected by the rolling blackouts, seven percentage points above the system average.

If you have any questions, please give me a call.

Sincerely,

Gary L. Groesch

Gary L. Groesch
attachments
cc. City Council Regulatory Office

Attachm

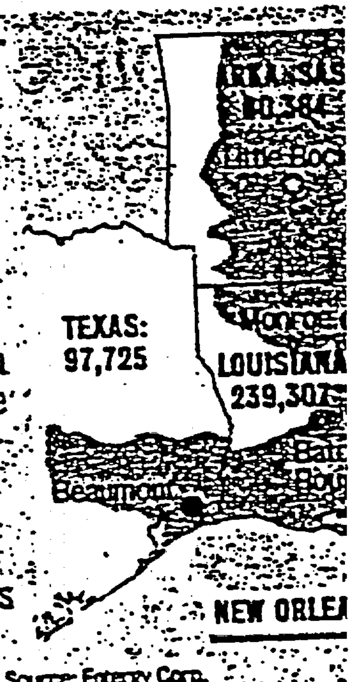
Distribution of Entergy's July 23 Rolling Blackouts by Jurisdiction

	Orleans Parish			Louisiana Outside Orleans Parish	Arkansas	Mississippi	Texas	Total Entergy
	Eastbank	Westbank	Total New Orleans					
number of Entergy ratepayers	189,000	19,000	208,000	928,000	629,000	388,000	342,000	2,495,000
Entergy ratepayers blacked out	84,994	7,094	92,088	232,213	80,364	53,290	97,725	555,680
percentage blacked out	45%	37%	44%	25%	13%	14%	29%	22%

Times Picayune 7/29/

LIGHTS OUT

Sparked by the heat wave blanketing much of the nation, Entergy cut power to more than half a million customers in the company's four-state territory on Friday. A look at how many customers lost power:



*Excludes New Orleans. Source: Entergy Corp.

PUC DOCKET NO. 18249

ENTERGY GULF STATES, INC. § PUBLIC UTILITY COMMISSION
SERVICE QUALITY ISSUES §
(SEVERED FROM DOCKET NO. 16705) § OF TEXAS

FINAL ORDER

This Order addresses electric service quality issues relating to Entergy Gulf States, Inc. (EGS or the Company). The Commission concludes that the quality of EGS' electric service to its customers in Texas has been less than adequate, specifically since Entergy Corporation acquired Gulf States Utilities, Inc., in 1993. The record evidence reveals a lack of effective and prudent maintenance policies, uneven spending in the area of operations and maintenance (O&M), cuts in experienced personnel, and consequent deterioration in the quality of service. The management of EGS is structured in a way that fails to link resource availability with appropriate performance accountability.

The Commission further concludes that the difficulties EGS has experienced with its quality of service are not simply "customer perception" problems, as claimed by the Company.[1] The problems are real and must be addressed by the Company in a timely and serious manner. To motivate the Company to revise its current approach and promote long-term commitment toward service quality and reliability, the Commission orders a two-part solution designed both to deal with past problems and implement remedies for the future. First, the Company's authorized return on equity (ROE) that otherwise would be adopted in Docket No. 16705[2] will be reduced by 60-basis points and

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[1] EGS Initial Brief (IB) at 4 (Dec. 2, 1997); *see also*, Tr. at 231.

[2] *Application of Entergy Texas for Approval of Its Transition to Competition Plan and the Tariffs Implementing the Plan, and for the Authority to Reconcile Fuel Costs, to Set Revised Fuel Costs, to Set Revised Fuel Factors, and to Recover a Surcharge for Underrecovered Fuel Costs*, Docket No. 16705 (pending).

Proceeding with EGS' rate case. SOAH established a four-phased hearing schedule to address the numerous transition and rate issues in Docket No. 16705. The service quality issues were to be dealt with in the "Competitive Issues" phase, scheduled to begin in early November 1997.

After EGS and interested parties had filed written testimony and exhibits,[4] but before the Competitive Issues phase commenced at SOAH, the Commission determined that it would itself hear and resolve the service quality issues. Accordingly, on November 4, 1997, the Commission issued an order severing the pending service quality issues from Docket No. 16705, establishing Docket No. 18249 to deal with those issues, and establishing procedures by which the Commission would hear and rule on the case.

The Commission convened a hearing on the merits of EGS' service quality on November 20 and 21, 1997. Chairman Pat Wood and Commissioner Judy Walsh presided over the hearing. The participating parties included the Company, the Cities, the High Load Factor Commercial Customer Group (HLFCCG), and the General Counsel, all of whom presented their direct cases and conducted cross-examinations. Chairman Wood and Commissioner Walsh also directed questions to the witnesses. Observers from the Office of Public Utility Counsel (OPC) and the Attorney General's Office attended the hearing. The active parties filed initial and reply briefs on December 2 and 9, 1997, respectively. OPC filed a statement on December 2, 1997, supporting the briefs of the Cities and HLFCCG and the Attorney General's Office filed a statement on December 9, 1997, in support of the same briefs.

[4] Some of the testimony, particularly from the Company's witnesses, was originally pre-filed for the Revenue Requirement phase.

II. Background

Entergy Gulf States, Inc., is a public utility subject to the jurisdiction of this Commission in accordance with Public Utility Regulatory Act (PURA) §§ 14.001, 31.001, 32.001, 33.122, and 36.001 through 36.156.[5] EGS is a wholly-owned subsidiary of Entergy Corporation (Entergy), a holding company incorporated in Delaware and registered with the federal Securities and Exchange Commission in accordance with the Public Utility Holding Company Act. Entergy acquired Gulf States Utilities, Inc., to create EGS, effective on December 31, 1993.[6]

EGS operates in Louisiana and Texas, and is affiliated through its holding company with investor-owned electric utilities located in Louisiana, Mississippi, and Arkansas.[7] The EGS service territory in Texas is located in the southeastern part of the state, and contains industrialized areas in the vicinity of Beaumont and Port Arthur, as well as a coastal zone. The differing geographic and climatic characteristics of the Company's service territory have led to the creation of three distinct sectors: Western I (suburban with dense trees), Western II (rural with fewer trees), and Gulf (both rural and urban).

Entergy's headquarters is in New Orleans; EGS' principal office in Texas is located in Beaumont. In Texas, the Company serves approximately 318,279 customers[8] and has 21,817 miles of distribution lines.[9] There are 394,865 poles[10] in its system, with

[5] Public Utility Regulatory Act, TEX. UTIL. CODE ANN. 11.001-63.063 (Vernon 1998).

[6] *Application of Entergy Corporation and Gulf States Utilities Company for Sale, Transfer, or Merger*, Docket No. 11292 (Mar. 25, 1994).

[7] Entergy Arkansas (including the Arklahoma Corporation), Inc., Entergy Louisiana, Inc., Entergy Mississippi, Inc., and Entergy New Orleans, Inc. These companies, together with EGS, form the "Operating Companies."

[8] *Ice Storm '97 Field Investigations*, Project No. 16301, at V-25 (June 24, 1997).

[9] *Id.* During the hearing, however, Company representatives referred to 11,000 miles of distribution lines in its Texas system. Tr. at 301.

431 feeders.[11] The transmission system--built as early as 1924, with approximately half of the lines added in the 1950's and 1960's and only 12 percent of lines built or rehabilitated after 1977--has shown generally good performance.[12] This Order is concerned predominantly with the state of the Company's distribution system.

III. Discussion and Analysis of Issues

A. General Concept of Reliability

Electricity plays a vital role in our lives. Most, if not all, aspects of our society, including industrial production, commerce, and individual lifestyles, are built around a reliable and adequate supply of electrical energy. People have come to depend on electricity being available when they need it. In fact, for most customers, delivery of electrical power and reliability of its delivery have become two inseparable expectations. Electric utilities generally recognize and accept this dependence and have responded to it by constructing and operating generation and delivery systems of superior reliability.[13] State law formalizes the utilities' obligation to provide reliable service in PURA § 37.151. Reliability, however, is not a static concept. As customer bases grow and systems age, utilities face new challenges that must be acknowledged and resolved to maintain reliable service.

In addition to sufficient generating capacity, transmission and distribution facilities are built so that a specified degree of reliability is achieved. The goal is to provide required amounts of energy with no, or few, interruptions, while maintaining a reasonable cost of the overall system. Smooth and continuous interaction of the various

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[10] General Counsel Ex. 5, Burrows Direct Testimony at 33, Attachment JDB-2.

[11] General Counsel Ex. 24.

[12] General Counsel Ex. 1, Ethridge Direct Testimony at 6.

[13] NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL, RELIABILITY CONCEPTS 1-2 (Feb. 1985).

elements of the electrical system results in reliable performance of the overall system. For consumers, this reliability is reflected in uninterrupted power supply, the degree of which may be measured by the frequency, duration, and magnitude of adverse effects on consumer service.

B. Legal Standards

PURA imposes various obligations on utilities and the Commission regarding the provision of electric service to Texas consumers. Specifically, PURA § 37.151 requires that a regulated utility provide continuous and adequate service in its certificated service territory. PURA § 38.001 directs utilities to furnish service, instrumentalities, and facilities that are safe, adequate, efficient, and reasonable. Parallel responsibilities rest with the Commission. In accordance with PURA § 36.052(3), the Commission must consider the quality of a utility's services in establishing a reasonable return on invested capital.[14] This same section of PURA directs the Commission to consider the quality of the utility's management and the efficiency of its operations when establishing a reasonable return. Moreover, PURA § 38.071 authorizes the Commission to order an electric utility to provide "specified" improvements in its service.

C. Analysis of Issues

The Commission's analysis of the issues in this case is divided into five general topics: (1) physical facilities, maintenance, and monitoring; (2) vegetation management;

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[14] There are several precedent cases in which the Commission reduced ROE to address inadequate quality of service. *See, e.g., Application of General Telephone Company of the Southwest for Authority to Increase Rates,* Docket No. 3094, Final Order, 6 P.U.C. BULL. 92, 123 (Aug. 8, 1980) (imposing penalty on company for inadequate service quality); *Application of General Telephone Company of the Southwest for Authority to Increase Rates,* Docket No. 3690, Final Order, 7 P.U.C. BULL. 11, 39 (June 18, 1981) (sustaining penalty due to persistence of poor service); *Application of General Telephone Company of the Southwest for Authority to Increase Rates,* Docket No. 4132, Final Order, 7 P.U.C. BULL. 646, 648 (Jan. 14, 1982) (lifting penalty after service was shown to improve for a sufficient period of time); *Application of Houston Lighting and Power Company,* Docket No. 4540, Final Order, 8 P.U.C. BULL. 75 (Dec. 6, 1982) (reducing company's ROE because of service quality and reliability concerns).

(3) emergency preparedness, response, outage restoration, and treatment of storm data; (4) personnel levels, management practices, and spending levels; and (5) pockets of unreliable service and overall customer service. The following narrative lays out essential points of the relevant issues; with additional, specific information contained in the Findings of Fact in Section IV.

1. Physical Facilities, Maintenance, and Monitoring

a. Condition of Poles

As stated above, EGS' transmission system does not pose serious concerns since it has performed adequately over the last few years, during which only a minimal number of transmission-related outages or circuit-breaker operations occurred. EGS' inspection and treatment programs relating to its transmission system seem to be working satisfactorily, with transmission line rights-of-way (ROW) appearing generally clear.[15] For these reasons, the Commission concludes that the physical state of the Company's transmission system is adequate. The remainder of this Order will address the Company's distribution system and related services.

Primary evidence for the condition of EGS' distribution system, including wires, poles, pole appurtenances, and transformers, comes from the Osmose Wood Preserving Company (Osmose) inspections conducted in 1995 and 1996, a report filed by Drash Consulting Engineering, Inc. (Drash), and limited Staff surveys.[16] In general, most of the poles in the Texas portion of the Company's distribution system are in good condition. There are, however, numerous poles with physical deficiencies or in need of extensive and comprehensive vegetation clearing.[17]

[15] General Counsel Ex. 1, Ethridge Direct Testimony at 6-8, 41-43.

[16] General Counsel Ex. 1, Ethridge Direct Testimony at 15; General Counsel Ex. 4; General Counsel Ex. 5, Burrows Direct Testimony, Attachment JDB-3.

[17] *Id.* at 5.

The Osmose inspectors, contracted by EGS in 1995 and 1996, examined approximately 37,000, or 10 percent, of the poles and crossarms and found that on average 17.9 percent of poles in eight different areas showed structural decay.[18] The actual percentages, however, varied greatly, with one area having more than 37 percent of the poles with some decay, a condition clearly impermissible for any transmission and distribution (T&D) system.[19] While the Osmose inspections were not random, and in fact, as the Company asserts, focused on particularly troubled spots, the results show that there are many poles in unsatisfactory condition.

The purpose of the Drash report, contracted for by the Commission, was to collect data regarding the condition of EGS' overhead distribution system. The survey was based on a sample of 33 uniformly distributed substations from the Texas portion of EGS distribution system.[20] The Drash inspectors examined 582 poles on various feeders originating at these substations.[21] The Drash survey found 59 poles with structural deficiencies and 72 poles with ROW encroachments.[22] During the hearing, EGS raised questions about the accuracy and statistical reliability of the Drash report. The Commission concludes that the Drash study lacked specific evaluation criteria and necessary randomness to draw conclusions about the entire EGS Texas system. The Commission, however, does not reject the Drash report, as requested by the Company;[23] rather, the Commission relies on the report to the extent that its findings have been confirmed by the Osmose inspections and Staff surveys. Taken together, the collected

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[18] General Counsel Ex. 5, Burrows Direct Testimony at 17.

[19] *Id.* Appendix Workpapers at 2.

[20] *Id.* at 19.

[21] *Id.* at 20.

[22] *Id.* at 21-22.

[23] Tr. at 552-60, 606-15.

data persuasively indicate that numerous poles show decay, are in need of repair or replacement, and that vegetation growth poses a serious problem on some ROWs.

b. Pole Inspection Program

The Company conceded that it does not have a traditional pole inspection program in place.[24] Since the Osmose inspections in 1996, there have been no pole or crossarm inspections on Texas territory.[25] Post-merger, EGS reduced the number of inspections; for example, in 1995, 29,294 poles and 43,941 crossarms were inspected, but in 1996, only 7,939 poles and 11,908 crossarms underwent inspections.[26] The Company is now planning to hire Osmose to carry out a ten-year inspection program that will cover the entire system (35,000 poles inspected annually).[27] Evidence presented in the case makes it clear that EGS' pole inspection and repair work cycles have not been sufficiently rigorous, continuous, or frequent to maintain all of its facilities in the condition required to meet its reliability and service obligations under PURA.

c. Maintenance Practices

A review of maintenance records shows that line maintenance and vegetation control are reactive in nature;[28] there is a lack of written, specific, and preventive maintenance policies;[29] and priority is given to capital additions to the detriment of adequate maintenance practices.[30] For example, total line-miles actively maintained by

[24] Tr. at 176, 751-52.

[25] Tr. at 170, 177-78.

[26] General Counsel Ex. 19 at Bates Stamp 0194741.

[27] Tr. at 751-52.

[28] General Counsel Ex. 4, Gonzalez Direct Testimony at 6-8, Drash Report at 45-46.

[29] Tr. at 59; HLFCCG Ex. 1, Patton Direct Testimony, Entergy Internal Audit and Risk Assessment.

[30] General Counsel Ex. 1, Ethridge Direct Testimony at 19-20; General Counsel Ex. 8; General Counsel Ex. 19.

the Company's employees dropped 30 percent from 1994 to 1996.[31] The Company's internal risk assessment study points to an absence of a strategic plan, and consequent inadequacies in resource sharing and work planning.[32] Based on the evidence, the Commission concludes that EGS has failed to establish and carry out distribution maintenance policies in a manner sufficient to ensure adequate and reliable delivery of electric service.

d. Data Collection

The Company presented a variety of data to support its claim of good performance; however, the accuracy of its data collection practices came under a great deal of scrutiny during the hearing, bringing into question the ability of the Company to monitor its performance fairly. The parties debated at length the merits and mechanics of various system monitoring tools and reporting standards. These include: (1) System Average Interruption Frequency Index (SAIFI), a measure of the number of interruptions per year for the average customer;[33] (2) System Average Interruption Duration Index (SAIDI), a measure of the total interruption time experienced by the average customer;[34] (3) Customer Average Interruption Duration Index (CAIDI), defined as the ratio of SAIDI/SAIFI;[35] (4) Distribution Interruption System (DIS), a database to capture reliability performance and indices for individual feeders;[36] (5) Average System Availability Index (ASAI),[37] a measure of the total time of service availability to the average customer; and (6) TACTICS, which captures data on every device down to the

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[31] Tr. at 737.

[32] General Counsel Ex. 30 at 2.

[33] HLFCCG Ex. 1, Patton Direct Testimony at 9-12.

[34] *Id.* at 10.

[35] *Id.*

[36] *Id.* at 11.

[37] General Counsel Ex. 3, Eckhoff Direct Testimony at 20.

transformer level to measure each device's operational performance and impact on customers.[38] In addition, the Company utilizes a System Control and Data Acquisition device (SCADA) to measure data for large interruptions such as feeder breaker outages,[39] and the new Automatic Mapping and Facilities Management System (AM/FM), developed in order to determine where an outage occurred and what device caused it, which will be completed by the year 2000.[40]

General Counsel, Cities, and HLFCCG argued that the number of customers affected by outages and the duration of such outages are difficult to determine because EGS excluded relevant information between 1994 and 1996.[41] For example, for the first six months of 1996, the Company reported 35 to 40 percent fewer outages than were reported on average during the first six months of the years 1991-94.[42] In trying to explain the discrepancies in the data, Company officials described changing data collection standards applied to the various outage-causing events. At different times, the Company excluded outages caused by equipment failures; outages affecting feeders with fewer than 500 customers; storms, generation or transmission outages; or trees falling into the ROW ("non-preventable" trees).[43] The Company data is generally confusing and comparisons over a period of several years are difficult to make because of changing standards;[44] in addition, the inaccuracies are further compounded because, for example, outages that affect small numbers of customers can nevertheless result in very long outage durations, especially when those feeders are energized last.[45]

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[38] Tr. at 448-450.

[39] Tr. at 238, 443.

[40] Tr. at 429-30.

[41] *See* HLFCCG Ex. 2, Entergy Southwest Reliability Report 1994-1996; Tr. at 41-43.

[42] HLFCCG Ex. 3 at slide 9.

[43] Tr. at 41-44, 54, 62-66.

[44] *Id.*; HLFCCG Ex. 2 at Bates Stamp 0232514.

[45] Tr. at 67.

The evidence shows that Company linemen sometimes made subjective determinations as to the cause, duration, or effect of an outage, thus causing the Company's SAIFI and SAIDI numbers to be unreliable.[46] The evidence also revealed that most historically deficient feeders serve rural customers.[47] This observation is supported by EGS' testimony that it prioritizes restoration of feeders serving the greatest numbers of customers, thus leaving those in lower-density areas (most likely rural) to experience recurring service reliability problems.[48]

General Counsel, Cities, and HLFCCG asserted that the Company has manipulated information to show better performance.[49] A significant problem with the Company's use of performance and reliability indices is that they reflect outage frequency and duration on a system-wide rather than feeder-by-feeder basis which can mask poor performance of individual feeders.[50] For example, EGS reported a system-wide SAIDI of 133 minutes for 1996,[51] but this measure failed to reveal that 83 feeders or primary circuits experienced outage times in excess of 200 minutes.[52] The average customer on these circuits experienced an outage duration of 3.3 hours.[53] More notably,

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[46] Tr. at 47-48.

[47] Tr. at 707, 821

[48] The Rebuttal (redacted) Testimony of Dereck Hasbrouck on behalf of the Company contains this quote: "One important fact to keep in mind when considering a customer or group of customers who consistently receive less reliable service than the average customer is that there are geographic and environmental conditions beyond the utility's control. These conditions, in combination with the construction cost considerations may effectively limit the realistic reliability expectations for customers in certain areas. In EGS Texas' service territory, the Bolivar Peninsula and Sabine Pass may be examples where these constraints come into play." EGS Ex. 11, Hasbrouck Rebuttal Testimony at 39.

[49] Tr. at 278-79, General Counsel Ex. 3, Eckhoff Direct Testimony at 54.

[50] General Counsel Ex. 3, Eckhoff Direct Testimony at 18, Appendix H and I; Tr. at 41-67; HLFCCG Ex. 1, Patton Direct Testimony at 12-14.

[51] General Counsel says SAIDI in 1996 was 157 minutes. General Counsel Ex. 22; HLFCCG Ex. 1, Patton Direct Testimony at 13.

[52] HLFCCG Ex. 1, Patton Direct Testimony at Exhibit ADP-3.

[53] *Id.*

customers on feeder Tamina encountered 41.3 hours of outage time in one year.[54] It is apparent that system-wide averages used by the Company cannot be relied on to disclose many of the localized service difficulties.

The historic data presented by the Company is not accurate and consistent as the Company itself admitted to not collecting all relevant data,[55] changing the standards for data collection, and submitting inconsistent data for ASAI and SAIFI.[56] Even the Company's internal audit revealed that reporting of outages has not been consistent.[57] EGS cannot correctly measure how many individual customers lose service because of an outage affecting parts of a feeder.[58]

The Commission, concludes that the types of information monitoring and reporting tools relied on by the Company are useful, but they must be employed uniformly and consistently to be meaningful measures of service quality. The Commission finds that the level of EGS' service quality and reliability, as documented through the Company data, is unreliable because the data fail to record and report all events accurately and consistently. Pockets of inadequate service are ignored by system-wide measures, and such measures do not identify recurring individual-feeder problems.

2. Vegetation Management

Vegetation management is the catch-all description for programs involving the removal of trees, bushes, or vines that overhang, grow into, or toward conductors strung

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[54] General Counsel Ex. 3, Eckhoff Direct Testimony, Appendix H.

[55] Tr. at 706.

[56] General Counsel Ex. 3, Eckhoff Direct Testimony at 54.

[57] Cities Ex. 1, Lawton Direct Testimony at 12.

[58] Tr. at 445-46.

along the Company's ROW. The purpose of vegetation management is to ensure, to the greatest extent possible, that vegetation in, or near, the ROW does not come into contact with the conductors and thereby cause wire breakage or ground faults.[59] During the hearing, Company witnesses referred to scheduled tree trimming, carried out on a three-year cycle in urban areas and a six-year cycle in rural areas. The evidence presented, however, was not clear on whether EGS actually followed the stated cycles.[60] Nonetheless, the Company argued that its vegetation management has been adequate and consistent with industry practice.[61] In fact, EGS asserted that it had improved vegetation management and introduced efficiencies when compared to the pre-merger period.[62]

General Counsel, Cities, and HLFCCG presented extensive evidence to document serious neglect of vegetation management and consequent heightened risk to the distribution system. The majority of incidents included in the evidence involve three types of vegetation-related damage: wires expanding down into vegetation due to increased load or lack of under-clearance; overhanging limbs breaking or growing into wires in non-inclement weather; and limbs or trees bending or breaking onto wires due to wind, ice build-up, or other adverse weather conditions. These parties also argued that the ROW surveyed were in need of extensive clearing and that vegetation encroachments posed unacceptable risks.[63] Cities claimed that neglected vegetation management multiplied the severity of the ice storm in January 1997.[64] The number and duration of

[59] Tr. at 176-178.

[60] Tr. at 602, 728.

[61] EGS Ex. 10, Ervin Rebuttal Testimony at 55, 59. EGS states that more than 80 percent of the Company's vegetation management expenditures are allocated to trimming, which is above the industry norm.

[62] EGS Ex. 8, Ervin Supplemental Direct at 22.

[63] General Counsel Ex. 4, Gonzalez Direct Testimony at 6-8; General Counsel Ex. 1, Ethridge Direct Testimony at 8-11.

[64] Tr. at 305-08.

vegetation-caused service interruptions almost doubled in the last four years,[65] and vegetation-related SAIDI and SAIFI have worsened since the merger.[66]

The author of a vegetation management study, commissioned by the Company, observed that there were areas where maintenance clearing had been deferred until brush reached the conductors.[67] This same study proposed specific and comprehensive ways for ROW maintenance, but the Company presented no evidence that the study's findings had been implemented. An e-mail sent in August of 1997 by an EGS network manager in Beaumont identified trees touching conductors as one of the preventable root causes of several recent outages.[68]

The Commission concludes that the level of the Company's vegetation management is unacceptable and has significantly affected the reliability of the distribution system in recent years. While such a deficiency may not in itself impact a typical system severely, this deficiency is magnified when the inadequacy of the infrastructure and the nature of the weather in the Company's service area are taken into account.[69] The lack of preventive vegetation control efforts by the Company and neglect of regular vegetation clearing have led to the creation of unnecessary risks. The Commission does not suggest that "ground-to-sky" tree trimming is necessary, but the Company clearly has significant room for improvement. The recent hiring of 30 new vegetation clearance crews, while welcome, confirms the existence of an unacceptable

[65] HLFCCG Ex. 1, Patton Direct Testimony, Exhibits ADP-10, ADP-13 (illustrating values for system-wide SAIDI for Texas increased from 21.17 in 1994 to 40.36 in 1997, and SAIFI doubled, from .31 in 1994 to .63 in 1997).

[66] General Counsel Ex. 37.

[67] General Counsel Ex. 27, Environmental Consultants, Inc., Report on Distribution Line Clearance Program (Jul. 1994) at 1-2-3.

[68] HLFCCG Ex. 6.

[69] Tr. at 308.

backlog in vegetation control.[70] As will be discussed below, the Commission is also concerned that managers in Texas have no clear line of authority or resources necessary to implement effective vegetation management policies.

3. Emergency Preparedness, Response, Outage Restoration, and Treatment of Storm Data

a. January 1997 Ice Storm

In mid-January 1997, many parts of Texas experienced a severe ice storm; disruptions of electric service were sustained by most utilities in the state.[71] The impact on EGS' territory was particularly hard. At one time, up to 120,000 of EGS' customers were without power and it took seven days to complete the restoration process.[72] Utilizing help from other utilities and contract workers, EGS had more than 2,700 personnel working to restore service.[73] In assessing the Company's performance, EGS officials compared it to that of other utilities and concluded that its efforts were not only adequate, but even "very good."[74] They blamed most of the damage on excessive ice.[75]

This view was not shared by the other parties.[76] HLFCCG played excerpts from taped conversations conducted by the Company's dispatchers during the storm, which highlighted insufficient numbers of personnel and initially inadequate efforts to repair the damage.[77] The Cities asserted that they had to use their own employees for repairs,

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[70] Tr. at 730-31, 787.

[71] General Counsel Ex. 2B, Hughes Workpapers, Ice Storm '97 Field Investigations Project 16301 at II-1.

[72] EGS Ex. 8, Ervin Supplemental Direct Testimony at 53.

[73] *Id.*

[74] *Id.* at 74.

[75] *Id.* at 74-75.

[76] Tr. at 379; Cities Ex. 1, Lawton Direct Testimony at 12.

[77] Tr. at 87-92.

including the handling of live wires.[78] and that in some instances they were unable to reach Company employees at all.[79] One of the Cities' exhibits was a letter. dated August 17, 1995, from several fire chiefs in EGS' service territory to the Company describing various problems with emergency procedures. such as not being able to reach the Company's 1-800 telephone number.[80] Some other cities' representatives testified. however, that the Company's restoration efforts were good.[81] The significant disparities in the Company's response to the damage caused by the ice storm suggest a need for greater and clearer communication between the Company and all cities. including development of contacts before an emergency occurs.

The Company has an emergency plan on file with the Commission; the plan contains no obvious deficiencies.[82] As is industry practice, EGS also has agreements with other utilities for emergency cooperation; those agreements. however, are not in writing.[83]

The January 1997 ice storm was certainly a severe storm that would have adversely affected even the best-maintained distribution system. EGS' distribution system, however, is not the best-maintained. A major cause of the outages during the storm were broken or bowed ice-laden tree limbs overhanging the wires. Tree limbs in ROW overhanging distribution lines pose a threat to system reliability, and are largely within EGS' control. The Company's failure to clear the limbs before the storm was a

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78 Tr. at 376.

79 Cities Ex. 2. Kimler Direct Testimony at 2.

80 Cities Ex. 2. Kimler Direct Testimony at 7.

81 Tr. at 377, 381, 391.

82 General Counsel Ex. 2, Hughes Direct Testimony at 21.

83 Tr. at 676-77.

major factor in the number and duration of outages experienced by customers.[84] While Company's initial efforts to mobilize and deploy additional non-EGS personnel were slow and cause concern,[85] vegetation management failures greatly aggravated the situation. The Company has experienced major storms in 1994, 1995, and 1997.[86] The weather, however, cannot be an excuse for poor service. While the Commission does not expect 100 percent reliability, the system must be built and maintained taking the local geographic and weather conditions into account.

b. Treatment of Storm Data

The Commission has required utilities to report the causes of interruptions, including the extreme storms. EGS, however, excludes outage duration and frequency data from its SAIDI and SAIFI reports if the data are attributable to a "major storm."[87] As defined currently by the Commission, major storms include situations in which there is a loss of power to 10 percent or more of customers in a region over a 24-hour period and full restoration is not achieved within 24 hours.[88] EGS' definition of a major storm counts any event in which 10 percent or more of a region's customers are interrupted for 24 hours or more, and is similar to the Commission's definition.[89]

HLFCCG argued that interruptions associated with major storms should be included in the computation of reliability indices. HLFCCG maintains that the design and maintenance of lines, and therefore their condition under the stress of severe weather, is within the control of the utility.[90] Exclusion of major-storm interruptions from

[84] General Counsel Ex. 2, Hughes Direct Testimony at 17.

[85] Tr. at 379.

[86] Tr. at 214, 377.

[87] Tr. at 54.

[88] EGS Ex. 10, Ervin Rebuttal Testimony at 30.

[89] *Id.*

[90] HLFCCG Ex. 1, Patton Direct Testimony at 14.

reliability indices could encourage reduced preventive maintenance, including vegetation management, and reductions in force needed for restoration efforts.[91]

The Commission is reluctant to allow the Company to exclude major-storm data from its overall reports because such reports may be incorrectly perceived as an indication that overall service quality is better than it actually is. Also, leaving major-storm data out may obscure the fact that poor management and maintenance, and not just the severity of the weather, contribute to or cause a weather event to become serious enough to be classified as a "major storm." Despite a great deal of controverting testimony by customer groups, the Company continues to assert that the acknowledged problems during the 1997 ice storm were a "storm-of-the-century" aberration.[92] Allowing the Company to carve out major storms from its outage-reporting data would mask the seriousness of service quality problems that occur on its system under all conditions.

The Commission understands that if a truly major storm affects the system, the Company cannot be expected to restore power and respond to increased customer calls as fast as it would in a more "normal" or day-to-day situations. Therefore, the Commission will allow the segregation of major from non-major storm data in outage frequency and duration reports. The major storms, defined by the severity of the weather conditions, rather than by the outage duration, will be reported and evaluated separately, as discussed in the "Remedies" section below.

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[91] *Id.* at 15.

[92] Tr. at 225; EGS Ex. 10, Ervin Rebuttal Testimony at 32-35.

4. Personnel Levels and Management Practices; Spending Levels

a. Personnel Levels

All parties agreed that post-merger personnel cuts were executed, ostensibly, in order to save costs. The Company asserted that cuts were possible because of increased efficiencies and that the permanent employees were simply replaced with contract workers.[93] The other parties maintained that cuts were not only too extensive, but resulted in a loss of many years of worker experience that could not be compensated for by contract workers who may lack knowledge of the system or loyalty to the Company. For example, General Counsel witness Ethridge cited the forced departure of 66 employees with an average of 18 years of experience each.[94] A precise number of lost employees was not conclusively proven: the Company maintained that total net loss was only 23,[95] but HLFCCG, for instance, asserted that in the space of three years, the jobs of 67 linemen were eliminated.[96]

A related issue concerned the Company's ability to evaluate contract workers' performance: while the Company felt confident about increased efficiency of its hiring practices, it did admit to not having performance measures for contract workers.[97] General Counsel presented Company documents showing that controls over contract worker management were not effective.[98] An internal risk assessment audit, conducted by the Company, also concluded that no formal and consistent process exists to monitor

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[93] Tr. at 160, 236; EGS Ex. 8, Ervin Supplemental Direct at 19; EGS Ex. 10, Ervin Rebuttal Testimony at 51.

[94] General Counsel Ex. 1, Ethridge Direct Testimony at 37.

[95] Tr. at 236; EGS Ex. 10, Ervin Rebuttal Testimony at 52.

[96] HLFCCG IB at 6 (referring to General Counsel Ex. 16 at 2, and Ex. 17 at 2).

[97] Tr. at 249-50.

[98] General Counsel IB at 14 (referring to HLFCCG Ex. 13, Entergy Internal Audit and Risk Assessment).

contractor performance, that management employees do not generate necessary reports to allow proper monitoring, and that distribution contracts are not competitively bid.[99] An additional concern presented by Cities dealt with the decrease in the number of operational staff while regulatory staff increased; this led Cities to conclude that the Company had insufficient focus on system maintenance matters.[100]

The Commission concludes that, post-merger, EGS cut many experienced employees, some of whom were consequently replaced by contract workers. The Commission, however, will not prescribe what personnel levels the Company should maintain. It is up to EGS to make sure it has enough workers to carry out proper maintenance and necessary emergency responses, along with having well-defined performance measures for both regular and contract employees.

<u>b. Management Practices</u>

Because the various operational entities under the holding company are split both along functional and geographic lines, tracing management structure poses some difficulties. According to Company witness Johnny Ervin, a network manager is located in Beaumont, along with a reliability supervisor.[101] There are two levels of customer service managers located in Beaumont; the vice president of customer service is located in Jackson, Mississippi. During the hearing, however, the Company presented its director of performance measurement, located in Little Rock, Arkansas, to speak on customer service issues. The network manager and reliability supervisor report to a franchise director (in Beaumont) and reliability director (in New Orleans, Louisiana), respectively. Both of these directors report to a senior vice president of distribution operations, who is located in New Orleans and is actually employed by Entergy Services, Inc. The senior

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[99] HLFCCG Ex. 1, Patton Direct Testimony, Risk Assessment Attachment at 3-4, 6.

[100] Cities Ex. 1, Lawton Direct Testimony at 12; Tr. at 164.

[101] Tr. at 789-794; the entire description of the management structure is taken from these pages of the transcript.

vice president answers to a utility group president, who has above him the chief operating officer and, finally, the chief executive officer of Entergy. According to Mr. Ervin, this reflects a new and "flatter" organizational structure, designed to promote better communication.[102] None of the managers in Beaumont reports to the EGS president, who has offices in Beaumont and Austin, Texas.

The Commission has concerns regarding the Company's management structure. It is not clear from the evidence that managers actually have the authority and matching resources to supervise their specific areas.[103] Those responsible for system reliability have little control over the vegetation management area, even though vegetation management has a major impact on how well the T&D system functions. The Company's internal audit concluded that there was no overall strategic plan in place to set performance strategies, and that hindered management in accomplishing business objectives and goals.[104] While EGS' representatives explained that recent changes in management structure were aimed at increasing communication, they also revealed that there is no structured way for the management to track and resolve problems reported by the employees.[105] In addition, managers' bonuses are tied in part to cost-cutting which may conflict with efforts to improve system performance.[106]

The Commission concludes that those who are responsible for the reliable performance of the Company's distribution system in Texas must also have the necessary authority and resources at their full disposal to maintain the system. The managers in the Texas territory must have clearly delineated powers and should be accountable to a

[102] *Id.*

[103] Tr. at 791-92.

[104] HLFCCG Ex. 1. Patton Direct Testimony, Internal Audit and Risk Assessment at 4.

[105] Tr. at 204-05.

[106] Tr. at 475, 847. General Counsel Ex. 20. Also, EGS internal risk assessment studies for vegetation management and distribution maintenance list cost-cutting as a major business goal.

unified higher management. The current, bifurcated management structure, under which local Texas supervisors report to multiple supervisors, is an obstacle to effective and reliable operation of EGS' Texas system.

c. Spending Levels

An issue addressed at length in this docket involved the Company's record of investment in the T&D system, particularly in maintenance. While there is hardly a substitute for sufficient O&M expenditures, the Commission will not prescribe a specific level of spending that may guarantee adequate service quality, and, at present, is not keenly interested in past expenditure levels. The Commission is primarily interested in results. As noted in the March 7, 1997 Supplemental Preliminary Order in Docket No. 16705, the Commission recognizes "that there may be a point of diminishing returns above which the dollars or resources allocated to service quality become unreasonable and fail to be cost effective."[107] That crossover point is not set in this docket, and it is not intended to be set. EGS is responsible for determining adequate spending levels and for the appropriate allocation of resources to O&M, distribution capital additions, and other categories in order to meet its obligation to provide adequate service quality.

In the hearing, EGS witnesses maintained that the Company had increased transmission and distribution spending since the 1993 merger; that inspection and measurement standards had improved; and that its spending on service quality programs equaled or even exceeded that of other utilities.[108] It is not certain, however, that EGS actually increased spending because expenses were not categorized clearly. Increased spending, if any, shows just that--increased spending; it does not measure how the quality of service has improved, or whether the service is adequate in accordance with PURA.

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[107] Supplemental Preliminary Order at 2, Docket No. 16705 (Mar. 7, 1997).

[108] Tr. at 760; EGS IB at 7-10.

Nonetheless. EGS is required to provide *continuous and adequate* service in accordance with traditional reasonable and necessary cost standards.[109]

In a memo dated October 31, 1995, a Company official discusses vegetation maintenance spending in the Southern Region and points to a recently implemented 20 percent reduction in allocations which, he expresses, cannot be sustained by any region without an adverse effect on customer service.[110] The parties generally agreed that spending on O&M decreased, while distribution capital additions slightly increased.[111] The Internal Audit department of the Company in its distribution risk assessment study identifies the budget process which allocates dollars to the regions based on past history rather than system needs as one of the problems that needs to be resolved.[112]

After evaluating the record evidence, the Commission concludes that expenditure levels for O&M are confusing and unclear, and pose a problem regarding tracking and accountability. While the Commission declines to state specific amounts to be spent, proper tracking and accounting of expenditures, both by type and jurisdiction, are essential. For example, the Company was unable to explain a 50 percent increase in the miscellaneous Federal Energy Regulatory Commission (FERC) Account 588.[113] It is virtually impossible to ascertain how much of the O&M budget is actually spent in the Texas jurisdiction or for distribution capital additions as compared to system maintenance.

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109 The Commission would expect some increases in spending since the 1993 merger because GSU, facing bankruptcy, would have presumably reduced even the necessary expenses.

110 General Counsel Ex. 28 at 2.

111 Tr. at 134, 248; 353-54; General Counsel Ex. 1, Ethridge Direct Testimony at 20, 27; Cities Ex. 1, Lawton Direct Testimony at 8.

112 General Counsel Ex. 30 at 7.

113 *Id.* at 9; Tr. at 153-54.

The Commission concludes that expenditures for O&M must be readily available and verifiable. The same applies to the oft-mentioned, but never specified or quantified, "increased efficiencies" used to justify cutting costs.[114] For such claims to have any weight, the Company must have a ready and reasonable explanation together with supporting documentation.

5. Pockets of Unreliability; Customer Service

a. Pockets of Unreliability

One of the issues identified in the Supplemental Preliminary Order in Docket No. 16705 involves pockets of particularly unreliable service,[115] such as the feeder Tamina, which had 41.3 hours of outage time in one year.[116] Rural customers are more likely to experience outages and wait longer for restoration. The Company admits to areas of lower reliability[117] and agrees that "outliers" must be improved.[118] The Company's practice--seemingly logical--of first restoring and clearing areas with most customers has led to the same customers experiencing repeated lower-quality service. In addition, the Company maintains a list of "politically sensitive" accounts, which suggests that some customers may receive preferential treatment.[119]

The Commission concludes that there should be a high standard of service for all customers, including a set minimum standard below which no customer would fall, and

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[114] EGS Ex. 8, Ervin Supplemental Direct at 16, 19-20.

[115] Supplemental Preliminary Order at 3, Docket No. 16705 (March 7, 1997); *see also* General Counsel Ex. 7 at 36.

[116] General Counsel Ex. 3, Eckhoff Direct Testimony, Appendix H.

[117] Tr. at 122, 223, 652.

[118] Tr. at 223-24.

[119] Tr. at 396-97.

that the Company needs to bring all of its worst performing poles and feeders into compliance with that minimum standard.

b. Customer Service

The Company has maintained, from the outset of this case, that its service is not deficient, but that it simply faces a "customer perception" problem. The Company knows that it has a large number of customers who are not satisfied with their electric service.[120] Based on the record, the Commission concludes that EGS customers' perceptions are justified. The same concerns were reflected in the testimony of city officials charged with protecting the health and safety of their citizens. Of particular note was the evidence that a municipality was compelled to call upon its volunteer firefighters to disconnect live electric wires because the Company's personnel were not available to perform this highly dangerous task.[121]

The Company's inadequate service quality is not necessarily an outgrowth of a lack of "money" or "expenditures." The Company has available funds that should be sufficient to provide higher-quality service, as may be gathered from the fact that the entire O&M budget was not spent.[122] It should be noted that the internal risk assessment study on distribution line construction and service restoration lists as the first priority improvement in customer perception of energy delivery and improvement in reliability only as a second priority.[123]

EGS' customers and the Commission believe that the Company has an obligation to provide continuous and adequate service, and that significant improvements in EGS'

[120] Tr. at 219. The Company's internal customer survey showed declining satisfaction levels from 1995 to 1996, Tr. at 198-200.

[121] Tr. at 376.

[122] Tr. at 468-70.

[123] General Counsel Ex. 30 at 1.

performance are needed. Section D. below, outlines the outcomes EGS must attain for the Commission to be satisfied that those improvements have been made. An improvement in EGS performance will eventually lead to more favorable perceptions and evaluations by the Company's customers.

D. Remedies

Based on the foregoing analysis, the Commission concludes that the Company's service quality must be improved. The following incentive plan lays out remedies to help EGS achieve such improvements. The five essential components of the plan are as follows:

1. A reduction in the return on equity divided into two parts: an adjustment component that recognizes EGS' current service quality is not adequate, with amounts to be refunded to customers, and an incentive-pool component to encourage future improvements in service quality;
2. Adoption of minimum and target levels for SAIDI and SAIFI as recommended in General Counsel's testimony, including improvement in the worst- feeder performance; establishment of standards for major-storm data; and reporting requirements;
3. Partial adoption of customer service performance benchmarks as recommended in General Counsel's testimony;
4. Establishment of a quality assurance requirement to ensure improved performance through the hiring of an independent consultant consistent with the amended, non-unanimous stipulation; and, to guarantee the accuracy of all data, hiring by the Company of an independent auditor to review all reports.[124]
5. A customer information and notification requirement.

[124] EGS had filed an amended, non-unanimous stipulation regarding the hiring of an independent consultant to assess Company's distribution system, including a review of the service quality processes. The Commission approved the stipulation with modifications on January 15, 1998.

1. **Reduction in the Return on Equity and Incentive Pool**

Drawing from the recommendation in the testimony of Cities' witness Lawton, the Company will be assessed a 60-basis point reduction in its ROE adopted in Phase II of Docket No. 16705. This reduction shall be implemented in recognition of the historically inadequate performance of EGS' distribution system. The Company will be required to refund current overcollections, including all appropriate taxes, for the period starting with June 1, 1996, the effective date of any rate reductions ordered in Docket No. 16705, up to the effective date of this order.[125]

Going forward, the Company will collect the amount equal to one-half of the 60-basis point reduction, plus appropriate taxes, and deposit that amount in an interest-bearing escrow account to create an incentive pool. The Company may earn this escrowed amount back by achieving specific performance targets. The other one-half of the 60-basis point reduction, plus appropriate taxes, will be retained by the ratepayers. At the end of each 12-month evaluation period, starting on January 1, 1998, if the Company fails to achieve stated performance benchmarks in any of the three areas (SAIDI and SAIFI minimum levels, SAIDI and SAIFI target levels, and customer service), a corresponding portion of the incentive pool will be refunded to distribution-level customers divided on a pro-rata basis within each customer class, except as noted below. If the Company successfully reaches all of the benchmarks, the full amount of the incentive pool will revert back to EGS.

Performance will be evaluated, and the incentive pool will be divided, according to three measures: (1) improvement in the minimum performance levels for SAIDI and SAIFI for worst feeders; (2) improvement in the target performance levels for SAIDI and SAIFI for average feeders; and (3) improvement in customer service performance, which

[125] The effective date of this Order for the purposes of the requirements set forth herein is the date on which the Order is signed.

has five components: (a) billing-error rate, (b) connection rate at the call center, (c) timeliness in completing service and meter installations. (d) timeliness in completing line extensions, and (e) timeliness in replacing and/or repairing service and street lights.

For the purposes of determining what amount, if any, the Company will earn back, the portions of the incentive pool will be represented by the following benchmarks: SAIDI and SAIFI minimum value improvements for the "worst" feeders (described below) will count as one-third of the pool; SAIDI and SAIFI target value improvements will count as one-third of the pool; and customer service improvements will count as one-third. Failure to achieve a measure will result in refunds to the affected customers based on the requirements for that specific measure. SAIDI and SAIFI will be calculated on a feeder-specific basis.

The Company has stated it does not have the ability to measure customer-specific feeder performance, and thus cannot calculate customer-specific refunds. For the first measure, however, refunds shall be provided to all customers taking service from a feeder that fails to meet the SAIDI and SAIFI minimum acceptable levels as recorded over a one-year period. These refunds are more customer-specific than currently contemplated by the Company, but because only a small number of feeders is expected to fall into this category, the refund calculations should not pose an insurmountable problem.[126] For the second measure, if the Company fails to achieve the specified SAIDI and SAIFI target level improvements, refunds shall be made to all Texas, distribution-level customers. For the third measure, failure to meet the standard for any of the customer service components will result in pro-rata refunds to each of the distribution-level customers. Distribution-level customers are meant to be those Texas, retail residential and small commercial ratepayers whose contract demands are less than or equal to 100 kW.

[126] The Company states that it does not have the ability to tie specific feeders to specific customers; it is expected, however, that the number of feeders involved is such that manual calculations will be possible or the Company can use its TACTICS program. Tr. at 445-46.

Feeder-specific refunds shall be distributed in a single billing period in proportion to and limited by each customer's total annual electric usage (i.e., no customer shall receive a refund greater than the total amount paid by that customer for the service in that year). If any money remains in the pool, the amount shall be refunded to all distribution-level customers on a pro-rata basis. All refunds shall be labeled "Service Quality Refund" on the customer's bill and shall be directed to the current customer receiving service at a given premise.

2. Minimum and Target Performance Levels

a. Frequency and Duration of Interruptions

The performance benchmarks are drawn from General Counsel's testimony with some adjustments. General Counsel proposed that the Company measure the duration of interruptions using the Average System Availability Index (ASAI). The ASAI index and the SAIDI index are closely related. Since the Company is required to report SAIDI under the Commission's service quality rules, that index will be used as the duration measure. General Counsel, HLFCCG, and Cities agree that performance should be measured feeder-by-feeder rather than through a system average. EGS has accepted a feeder-by-feeder approach for outage frequency.[127] General Counsel's proposal for feeder-by-feeder SAIFI and SAIDI targets is presented in Table 1, where the SAIDI targets are converted from the ASAI values recommended by General Counsel.[128] The Commission adopts the following performance targets for use by EGS as its reliability performance standards.

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[127] Tr. at 228.

[128] General Counsel Ex. 3, Eckhoff Direct Testimony at 7. HLFCCG recommends an annual feeder-by-feeder standard for SAIFI of 3 interruptions and for SAIDI of 200 minutes. HLFCCG Ex. 1, Patton Direct Testimony at 29.

Table 1: General Counsel's Proposal for Interruption Performance Measures

Index Value	Minimum Acceptable Value (annual)	Target Value (annual)
SAIFI	3.8 interruptions	2.6 interruptions
SAIDI	315 minutes (5.25 hours)	158 minutes (2.63 hours)

Source: Eckhoff Direct Testimony at 7.

General Counsel's testimony indicates that distribution feeders serving approximately 90 percent of EGS' Texas customer meters met the minimum acceptable values for SAIDI and SAIFI in 1996.[129] Distribution feeders serving approximately 75 percent of EGS' Texas customer meters met the target values in 1996.[130]

b. Minimum Performance Benchmark

General Counsel presented testimony to show that 10 percent of EGS' feeders fall below the minimum acceptable values for SAIDI and SAIFI. As part of the remedial plan, the Company must achieve 95 percent compliance with the minimum acceptable values in 1998, so that no more than 5 percent of distribution feeders serving EGS' Texas customer fail to meet the minimum acceptable values for SAIDI and SAIFI. For the following year, the compliance level will be raised to 100 percent, so that no EGS' Texas distribution feeders will fall below the minimum acceptable value for SAIDI and SAIFI. The Company will maintain or exceed the 100 percent compliance with this standard in the subsequent years.

To document and track this improvement, the Company shall identify the worst-performing feeders in the following way: all of EGS' 431 Texas distribution feeders shall be ranked from best to worst according to SAIFI numbers. A list of the worst 10 percent

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129 General Counsel reported that feeders serving 89.97 percent of EGS' Texas customer meters met the SAIFI minimum value, and 90.84 percent met the ASAI minimum value. General Counsel Ex. 3, Eckhoff Direct Testimony at 33-34.

130 General Counsel reported that feeders serving 75.6 percent of EGS' Texas customers met the SAIFI target value, and 76.86 percent met the ASAI target value. *Id.*

shall be submitted as a part of the June 15, 1998 Electric Service Quality Report filing. Because the report asks for data on the worst 5 percent of the feeders, the Company shall supplement its filing for the purposes of this Docket. If the Company fails to meet the minimum acceptable value benchmark or the major-storm restoration measure, as described below, for that year, one-third of the incentive pool amount will be refunded to customers served by all non-complying feeders.

c. Target Performance Benchmark

In 1998, for all feeders, the Company must achieve 85 percent compliance with General Counsel's recommended target levels for SAIDI and SAIFI to retain the corresponding portion of the incentive pool (i.e., the Company must improve up to the target levels an additional 10 percent of its feeders, from 75 to 85 percent). In the following year, SAIDI and SAIFI compliance with the target levels will be raised to 90 percent of feeders, and this level will be maintained or exceeded in the future. If the Company fails to meet the target performance benchmark, one-third of the incentive pool will be refunded to all Texas distribution-level customers.

d. Treatment of Major-Storm Data

The record shows that extreme weather events can cause major outages. For the purposes of record-keeping and performance evaluation, it is necessary to define extreme events according to actual weather conditions rather than the effect weather has on the T&D system. EGS shall define extreme weather as an ice accumulation of at least one inch of ice within the period of 24 hours, or winds greater than 80 miles-per-hour. The Company shall keep its records in a way that includes all weather events, and a separate set that includes only the major-weather events. The determination of the Company's performance regarding SAIDI and SAIFI benchmarks shall be calculated based on the all-inclusive data. In addition, the Commission adopts as the performance measure for major-weather events the complete restoration of all customers' electric service no later than 120 hours after the initiation of such an event (i.e., when an accumulation of one inch of ice or 80 mph wind have been recorded). Failure to achieve this measure will preclude the Company's recovery of the one-third of the incentive pool associated with the SAIDI and SAIFI minimum acceptable level compliance for that year.

If an extreme-weather event occurs on the system, and the Company believes it has a detrimental effect on the overall performance for that year, the Company may submit a good cause exception filing for the Commission's consideration on whether to include such an event in the annual evaluation of compliance with set benchmarks.

e. Reporting Requirements

As discussed above, the Company shall file collected data regarding performance measures on a semi-annual basis. In addition to that filing, on March 1 of each year beginning in 1999, the Company shall file a proposed reconciliation statement showing the level of achievement with the established benchmarks to qualify for any part of the incentive pool. The filing shall be audited by an independent auditor prior to filing, and the auditor's report shall be filed with the proposed reconciliation statement. If and when the Commission approves the filing, the Company shall retain the appropriate portion of the pool or refund the corresponding portion to its Texas distribution-level customers, as directed by the Commission. SAIDI and SAIFI shall be defined according to the Commission's Electric System Service Quality Report filing (PUC Project No. 15013), and shall be reported according to the schedule set forth on the form (May through October data due on December 15; November through April data due June 15 of each year). EGS filed the initial report on or before December 15, 1997. In its December filing each year, EGS shall, for the purposes of this Docket, provide an annual, audited summary of data as well.

3. Customer Service Performance Benchmarks

The performance measures listed below in Table 2 are drawn from General Counsel's recommendations, with the exception of security and street light replacement, which is based on a recommendation made by the Company.[131] In its reply brief, EGS adopted many of the components of General Counsel's recommended performance measures for customer service.[132] For the purposes of this remedial plan, each customer service measure will be computed for the time interval noted in Table 2, and reported to the Commission every six months, consistent with the filing dates for the service quality reports, as a separate Customer Service Report. If all five targets are achieved by EGS in one given year, the customer service portion of the incentive pool will be retained by the Company for that year; otherwise, that portion of the incentive pool will be refunded to distribution-level customers on a pro-rata basis.

Table 2: Performance Targets for Customer Service Measures

Customer Service Measure	Performance Target
Billing-error rate	The Texas system average monthly rate of actual customer over-billing errors per 1000 customers shall not exceed five.
Call center performance	For every five-day period within any given month at any EGS call center, 85 percent of repair service calls, calls to business offices, and other calls shall be answered within 30 seconds.
Service installation	In any distribution substation service area, 90 percent of applications for new electric service and meters not involving line extensions or new facilities shall be filled within five working days, excluding those orders in which a later date is specifically requested by the customer. Service installation compliance will be measured on a quarterly basis.
Line extensions	In any distribution substation service area, 85 percent of requests for line extensions or new facilities shall be completed within 60 working days, excluding those orders in which a later date is specifically requested by the customer. This standard includes orders for new service and other services, installations, moves, or changes, but not complex services. Line installation compliance will be measured on a quarterly basis.
Light replacements	In any distribution substation service area, 90 percent of all customer reports of security and streetlight outages shall be corrected within 48 hours. Light replacement compliance will be measured on a quarterly basis.

Note: Definitions of specific terms are adopted from J.B. Goodman Direct Testimony, Attachment JBG-8.

131 General Counsel Ex. 7, Goodman Direct Testimony; General Counsel Ex. 5, Burrows Direct Testimony, Attachment JBG-8.

132 EGS Reply Brief at 17-21.

4. Quality Assurance Proposal; Independent Consultant; and Independent Auditor

According to the terms of the amended, non-unanimous stipulation, the Company shall hire an independent consultant to assess the distribution system, develop strategies for improvement, revise data collection practices, and set up evaluation criteria procedures spelled out in the order approving that stipulation as modified.[133] Testimony in this docket exposed inconsistencies in EGS' collection, recording, and reporting of service quality indices, including SAIDI and SAIFI. The Company shall develop a quality assurance program that guarantees accurate and consistent reporting of all collected data. The Company shall file its quality assurance proposal no later than July 1, 1998.[134] This proposal shall be developed with the input and in conjunction with the work done by the independent consultant hired under the terms of the amended, non-unanimous stipulation. To guarantee that all data and reports collected by EGS and filed with the Commission are accurate and consistent, the Company shall hire annually an independent auditor to review such data and reports. The selection process for an independent auditor will be guided by the same criteria as outlined in the amended, non-unanimous stipulation for the selection of an independent consultant.

5. Customer Information/Notification

The final component of the incentive plan is the information and notification requirement. Following its annual reconciliation statement filed with the Commission, the Company shall include an insert in bills to its customers that explains the service quality requirements, the Company's performance during the preceding annual period,

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133 On December 17, 1997, EGS, OPC, HLFCCG, Cities, and General Counsel, jointly filed a supplementary motion for entry of an order consistent with proposed amendments to a previously filed non-unanimous stipulation.

134 The quality assurance requirement appears consistent with the amended non-unanimous stipulation related to hiring a service quality consultant filed by EGS and other signing parties, on December 17, 1997.

and the amount of the refund to distribution-level customers. The insert shall contain instructions to customers on who to contact to report broken or malfunctioning street lights. The proposal for the scope and content of the bill inserts shall be included in the Company's annual reconciliation filing.

IV. Findings of Fact and Conclusions of Law

The preceding discussion explains the Commission's factual and legal conclusions with regard to the issues presented in this docket. In accordance with TEX. GOV'T CODE ANN. § 2001.141, the Commission separately states the following findings of fact and conclusions of law.

A. Findings of Fact

Procedural History

1. On November 27, 1996, EGS filed with the Commission its transition/rate case in Docket No. 16705.

2. The Commission referred the case to SOAH on December 5, 1996. The preliminary order issued by the Commission on January 24, 1997, in Docket No. 16705 directed that the docket "address specific service quality standards that will apply after the transition [proposed by EGS]."

3. On March 7, 1997, the Commission issued a supplemental preliminary order in Docket No. 16705 that focused specifically on service quality issues. That order delineated three questions which must be addressed: (1) Whether EGS has an effective and prudent management policy in place that devotes sufficient resources to ensure adequate and reliable service to its ratepayers; (2) Whether there appear patterns of variable service quality in EGS' service territory, and if so, what is the cause and potential resolution of these variations; (3) Whether the Commission should implement procedures, and if so, what procedures can it implement, to monitor service quality on EGS' system, and to respond to situations in which EGS' service quality falls below the benchmark levels.

4. SOAH segmented the hearings in Docket No. 16705 (SOAH Docket No. 473-96-2285) into four phases to address numerous transition and rate issues separately. The service quality issues were scheduled for hearing in early November 1997, in the "Competitive Issues" phase of the case.

5. At the November 4. 1997 Open Meeting, Chairman Pat Wood, III, and Commissioner Judy Walsh voted to sever the service quality issues from Docket No. 16705 and determined that the Commission itself would hear and resolve these issues.

6. An order issued on November 4. 1997, established Docket No. 18249 to address the service quality issues. The order also established procedures by which the Commission would hear and rule on the service quality issues directly.

7. Chairman Wood and Commissioner Walsh convened and presided over a public hearing on the merits on November 20 and 21, 1997, to address EGS' service quality issues. EGS, Cities, HLFCCG, and General Counsel submitted their testimony and exhibits into evidence and conducted cross-examination. The Chairman and Commissioner Walsh also directed questions to the witnesses.

8. EGS, Cities, HLFCCG, and General Counsel filed post-hearing briefs in this docket on December 2. 1997. Reply briefs were filed by these same parties on December 9, 1997. The Office of Public Utility Counsel and the Attorney General's Office filed statements on December 2 and 9, 1997, respectively, supporting the briefs of the Cities and HLFCCG.

<u>Notice</u>

9. Hearings held on November 20 and 21, 1997, were properly noticed in accordance with TEX. GOV'T CODE ANN. §§ 551.041, 551.043, 2001.051, and 2001.052.

10. This matter was scheduled for discussion in open meetings convened on December 17, 1997, and January 14, 1998, for which notice was given pursuant to TEX. GOV'T CODE ANN. §§ 551.041 and 551.043.

<u>EGS</u>

11. EGS is a public utility subject to the jurisdiction of this Commission in accordance with PURA §§ 14.001, 31.001, 32.001, 33.122, and 36.001 through 36.156.

12. EGS is a wholly-owned subsidiary of Entergy, a holding company incorporated in Delaware and registered with the federal Securities and Exchange Commission in accordance with the Public Utility Holding Company Act.

13. Entergy acquired Gulf States Utilities, Inc., to create EGS, effective as of December 31, 1993.

14. EGS operates in Louisiana and Texas, and through its parent holding company is affiliated with investor-owned electric utilities located in Louisiana, Mississippi, and Arkansas. Entergy's headquarters is located in New Orleans, Louisiana.

15. EGS' Texas service territory covers the southeastern part of the state. EGS' principal office in Texas is located in Beaumont.

Management Structure

16. In Beaumont, EGS employs, among others, a network manager and a reliability supervisor. These managers report to a franchise director, also located in Beaumont.

17. The network manager's and reliability supervisor's responsibilities include managing and dealing with system reliability, outages, restoration, and vegetation management.

18. The franchise director located in Beaumont reports to a reliability director, headquartered in New Orleans, who in turn reports to the senior vice president of distribution operations, employed by Entergy Services, Inc.

19. In New Orleans, the vice president of distribution operations answers to a utility group president, who reports to a chief operating officer, and ultimately the chief operating officer of Entergy.

20. The network manager, reliability supervisor, and franchise director do not report to the EGS president, who has offices both in Austin and Beaumont.

21. The Company management structure is ill-suited to assure best supervision of the T&D system in the Texas territory. The supervisors in Texas answer to multiple directors in Louisiana, do not have all the necessary resources at their disposal, and their bonus incentives are tied in part to successful cost-cutting.

Transmission System

22. The construction of EGS' transmission system started in 1924. Half of the transmission lines currently in service were added in the 1950's and 1960's. Since 1977, 12 percent of the lines have been newly built or rehabilitated.

23. The Commission finds that the physical state of EGS' transmission system is adequate; few transmission-related outages or circuit breaker operations occurred.

24. Transmission line Row appear to be clear.

25. The EGS transmission system appears to provide adequate, continuous, and reliable service.

Physical Condition of Distribution System and Pole Inspection Program

26. EGS serves approximately 318.279 customers in Texas. The distribution system in the state is comprised of 21,817 miles of electric lines; 394,865 poles; and approximately 431 feeders.

27. EGS contracted with Osmose Wood Preserving Company to perform inspections of EGS poles and crossarms in Texas for the years 1995 and 1996.

28. In 1995 and 1996, Osmose field inspectors inspected a total of 37,233 wood poles in eight different areas. The poles reviewed account for 9.4 percent of the total number of poles in EGS' Texas system.

29. Although the Osmose inspections focused on particularly troubled spots of the distribution system in Texas, certain areas revealed a number of deficient poles that was excessive by any measure.

30. Osmose survey results show wide fluctuations in percentages of poles with decay, from 8 to 37 percent, with the average percentage being 17.9 percent.

31. EGS proposes to implement a new pole inspection program, through which approximately 35,000 poles will be inspected annually, so that all poles in the Texas jurisdiction will be inspected by the end of the 10th year.

32. General Counsel selected Drash Consulting Engineering Inc. to survey 33 uniformly distributed substations from the Texas portion of the EGS distribution system.

33. General Counsel recommended that Drash inspect a representative sample of 591 poles on feeders originating from these 33 substations, of which Drash visually surveyed 582, or 98.42 percent, of poles.

34. The Drash report picked for inspection approximately every 5th, 10th, or 15th pole from the substation. The age of the poles was determined by visual inspection.

35. Drash filed its report on August 11, 1997, in which it identified 59 of 582 poles with structural deficiencies, such as rot, decay, or leaning, and 72 poles with encroachments by tree limbs and vegetation build-up.

36. The Drash survey did not use specific criteria by which to evaluate the condition of the poles, but relied on the inspectors' experience.

37. Beginning on May 12, 1997, the Commission Staff performed limited, random inspections of EGS' poles in the Vidor, Orange, Bridge City, Port Arthur, and Port Neches areas. The Staff inspections also encompassed the northern portion of the system to the western limits of EGS' service area.

38. By August 1997, the Commission Staff surveyed 60 poles, and found that 6.7 percent had equipment deficiencies and 63 percent had ROWs problems.

39. In general, the distribution system is in adequate condition; however, there are numerous poles with decay, in need of repair or replacement, and many lines and poles that need vegetation clearing.

40. The inspection program carried out by the Company has not been sufficiently extensive or adequate to fulfill its purpose of securing reliable service.

41. The Company's distribution system maintenance practices have failed to assure continuous and adequate service to EGS' customers.

Reliability Indices and Performance Standards

42. EGS uses the following standards and systems to collect and record performance measures: System Average Interruption Frequency Index (SAIFI); System Average Interruption Duration Index (SAIDI); Distribution Interruption System (DIS); TACTICS; and a System Control and Data Acquisition devise (SCADA). General Counsel also used the Average System Availability Index (ASAI) as an outage measure.

43. EGS begins to record a specific outage only after a customer calls in to the Company to complain. Timing of the outage duration starts after the customer alerts the Company.

44. System-wide, the average customer in EGS' Texas territory experienced outages totaling 133 minutes (as recorded in SAIDI) in 1996. The system-wide SAIFI in Texas for 1996 was 2.648 interruptions.

45. Fifty of 431 feeders (11.6 percent) in the EGS' Texas system were below the minimum ASAI standard recommended by General Counsel (99.94 percent or 157 minutes), while 37 (8.58 percent) feeders missed the minimum SAIFI standard of 3.6 interruptions per year.

46. Eighty-three feeders or primary circuits experienced outage times in excess of 200 minutes during 1996.

47. Eighteen feeders, serving 9,457 meters, are "historically deficient"[135] for SAIFI, and seventeen feeders, serving 10,835 meters, are "historically deficient" for ASAI.

48. Nine percent of the meters did not meet minimum ASAI standards. Similarly, 10 percent of the meters fell below minimum SAIFI benchmarks.

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[135] Historically deficient feeders are those with consistently poor performance over a period of several years.

49. Customers on several feeders suffered significantly more interruptions than the average customer, and with lengthier outages: feeders Tamina and China recorded SAIDI scores of 2,477 minutes and 934 minutes, respectively, while feeder Dobbin reached a SAIDI value of 699 minutes. Feeder Pleasure scored 10.2 interruptions, feeder Crystal had a SAIFI of 8 interruptions, and Cordrey scored 7.56 interruptions.

50. Sixty-five feeders with approximately 58,000 customers have a SAIFI rating less than the 10-year Company average.

51. EGS testified that it restores first those feeders with the highest numbers of customers. Likewise, it clears vegetation first on the feeders with the most customers.

52. EGS excluded certain data in calculating its reliability indices. In 1994, the Company ceased counting outages in areas with less than 500 customers. For the first six months of 1996, the Company reported 35 to 40 percent fewer outages than were reported on average during the first six months of the 1991-94 time-frame.

53. The average outage duration during the first three years after the merger went up to 2.4105 hours, from the average of 1.8220 hours during the seven years preceding the merger.

54. By September 1996, the number of outages reported increased by 80 percent from 1995, due to a greater number of small outages recorded.

55. EGS prepared a Reliability Report for the Southwest Region, issued in May 1994, that summarized reliability performance for the year, compared actual performance with Company goals, identified problem areas, and reported corrective actions.

56. Equipment failures were excluded from the May 1994 Reliability Index, as were outages attributed to public damage, non-preventable trees, load curtailment, transmission line outages, instantaneous outages, and planned outages. EGS began reporting these types of outages again in September 1995.

57. EGS excluded from its performance measures and reliability indices data collected during episodes of extreme weather conditions in February 1994 and January 1997.

58. The measure of outage duration does not take into account either the number of customers who fail to alert the Company to an outage, or the length of time a customer has suffered an outage prior to notifying the Company.

59. Linemen working for or on behalf of EGS make subjective determinations as to the cause, duration, or effect of an outage, which may hinder true and accurate reporting of the outage causes.

60. EGS records and reports its reliability and performance data based on system-wide measures. This method of reporting overlooks recurring individual feeder problems and pockets of disproportionately low service quality.

61. EGS is not technically equipped at the present time to measure SAIDI and SAIFI performances at the individual customer level. The Company, however is able to calculate performance indices on a feeder-by-feeder basis.

62. The Company's data and compiled indices are unreliable because of changing data collection standards, failure to report all relevant information, and manipulation of the data.

Vegetation Management

63. The purpose of vegetation management is to ensure to the extent possible that vegetation in or near ROWs does not come into contact with the conductors and either break the wires or cause ground faults.

64. Many of the outages in EGS' service territory result from trees or tree limbs falling into EGS' ROWs or distribution lines.

65. EGS stated that it has a six-year, rural tree-trimming cycle; it calls for a 20-foot clearance. Trees in urban areas, according to the Company, are trimmed on a three-year cycle. The Company did not offer persuasive evidence that these cycles were actually followed.

66. The Company stated that 80 percent of EGS' vegetation management expenditures are allocated to cyclical tree trimming.

67. Texas vegetation management expenses in the post-merger period were $4.99 million in 1994, $5.09 million in 1995, and $4.735 million in 1996. The decrease in spending between 1995 and 1996 is attributed by the Company to unexplained efficiency gains.

68. The total line-miles actively maintained by the Company dropped approximately 30 percent in 1996 from the 1994-1995 levels; EGS witnesses did not explain this decrease.

69. Vegetation management spending increased by 34 percent in 1997, a significant part of which went towards the January 1997 ice storm cleanup costs.

70. Vegetation-related SAIDI and SAIFI values have worsened since the merger. System-wide SAIDI values for Texas have increased from 21.17 in 1994 to 40.36 in 1997. SAIFI values have also increased from 0.31 in 1994 to 0.63 in 1997. As of

September 1997, the SAIDI level for 1997 exceeded the SAIDI value for the entire year in 1996.

71. Network managers in EGS' Texas territory have the responsibility to ensure adequate service reliability. Network managers, however, do not directly supervise or fully control the vegetation management program.

72. A 1994 study by Environmental Consultants, Inc. (ECI), proposed specific recommendations for EGS' vegetation management to include herbicide and tree trimming based on plant species, equipment scheduling in the planning process, aggressive pursuit of tree removals, and performance measures for contractors. EGS has not implemented the recommendations proposed by ECI.

73. Entergy's Internal Audit department conducted a comprehensive risk assessment study of the vegetation management program in 1996, and concluded that sufficient strategic planning had not occurred to ensure that Entergy met its objectives. The study also found that the Alliance Agreement between Entergy and vegetation management contractors was not being consistently applied in the various regions, and did not meet business objectives.

74. Power lines cannot be shielded 100 percent from all contact with vegetation; however, the Company's inability to develop and carry out prudent vegetation management policies has resulted in major service disruptions.

75. EGS' management structure does not provide those responsible for ensuring service reliability with direct authority to address or prevent vegetation-related outages.

76. The Company does not have a strategic plan to guide vegetation management efforts.

77. Neglect and backlog of vegetation management projects has posed unacceptable risks of increasing and recurrent service outages, especially during major storms.

78. The Commission finds that the Company's vegetation management efforts have not been adequate, have led to a backlog in vegetation clearing, and have resulted in an unacceptably high risk to the system.

Emergency Preparedness, Response, and Outage Restoration

79. In June 1996, EGS conducted a drill simulating an emergency situation in order to test its emergency response and restoration plans.

80. EGS' emergency plan and procedures are on file with the Commission, and were reviewed by the Commission Staff after the ice storm in January 1997.

81. In Docket No. 16301. *Ice Storm '97 Field Investigations Project*, the Commission Staff concluded that EGS had a good emergency plan in place before the ice storm of January 1997.

82. The Commission defines "major storm" as a weather-related event in which there is a loss of power to 10 percent or more of the customers in a region over a 24 hour period and with all customers not restored within 24 hours.

83. EGS defines major storm as any event in which 10 percent or more of a region's customers are interrupted for 24 hours or more.

84. Many parts of Texas experienced an ice storm of significant magnitude that began early on January 12, 1997, and lasted through the afternoon of January 13, 1997.

85. Most utilities in Texas experienced disruptions in service during the January 1997 ice storm.

86. EGS should have been better prepared to deal with the January 1997 ice storm, given that it had experienced major weather events in 1994 and 1995, and that it had successfully conducted emergency drills in 1996.

87. During the ice storm in January 1997, up to 120,000 of EGS' Texas customers were without power. Restoration took seven days to complete, with temporary emergency crews mobilized from Louisiana, Mississippi, and Arkansas.

88. By January 16, 1997, EGS had more than 2,700 personnel deployed to restore service on various parts of its Texas system.

89. At the public hearing on November 20, 1997, city officials from the towns of Port Neches, Orange, and Nederland described numerous episodes in which the numbers of EGS workers, equipment, and materials were insufficient to deal adequately with emergency situations. Other officials from Cleveland, Dayton, and Port Arthur gave favorable reports of EGS' performance during the January 1997 ice storm.

90. Mr. Dick Nugent, representing the city of Nederland, testified that after several attempts to reach EGS personnel, city officials had to retrieve an EGS supervisor from his house in Nederland to help them with power restoration efforts.

91. Mr. A.R. Kimler, from the city of Port Neches, testified that local firefighters were deployed to cut down live power lines because EGS stated there were not enough employees to respond at the time.

92. The impact of the January 1997 ice storm was greatly exacerbated by the Company's failure to maintain its ROWs clear of excessive vegetation.

93. While the Company has emergency plans in place, not all personnel are familiar with the plans, a fact that may have accounted for the Company's uneven and delayed restoration efforts during the January 1997 ice storm.

94. It may be uneconomic for EGS to build, operate, or maintain a 100 percent storm-proof system. The January 1997 ice storm, however, revealed that EGS must implement a better preventive maintenance program and faster customer response initiatives.

95. Segregation of major-storm data from non-major storm data in outage duration and frequency reports provides a more accurate method to evaluate EGS' performance on a day-to-day basis, as well as during crisis events.

96. The standard for classifying major storms is to be defined in terms of the severity of the weather-related event, rather than in terms of the impact on the T&D system. Feeders subject to major storms can be defined as those experiencing an accumulation of one inch of ice or more within a 24-hour period, or those exposed to winds of at least 80 mph.

97. EGS' outage restoration efforts during the January 1997 ice storm would have been more effective if: (1) EGS had been more diligent in its preventive vegetation management practices; and (2) it had a better communication and management program in place to deal with emergency situations.

98. The effect and incidence of lightning strikes did not materially affect the quality of service offered by the Company.

Spending Levels

99. System-wide transmission spending followed a generally increasing trend since 1992. No data was presented for transmission O&M expenditures on the Texas portion of the system.

100. Between 1994 and 1996, distribution maintenance spending decreased by $4 million each year. Half of the spending cuts ($2 million each year) is attributed to overhead line maintenance.

101. Miscellaneous distribution expenses recorded in Federal Energy Regulatory Commission (FERC) Account 588 increased from just under $3 million in 1991-1993, to $10.3 million in 1995, and $12.4 million in 1996, an increase EGS could not explain.

102. FERC has designated Account 588 for mapping, records, communications, and other miscellaneous expenses such as clerical, stenographic, and janitorial work at buildings.

103. EGS decreased its level of spending for pole and appurtenance replacements by 50 percent during the years 1995 and 1996.

104. EGS' O&M spending has been uneven, lacks clear accounting, and proportionately more is spent on distribution capital additions than on distribution system maintenance.

105. In 1995, most of the spending for distribution capital additions was in the Louisiana area.

106. Efficiency savings have not been identified nor proven in areas where spending levels had been reduced.

107. The Company witness could not explain whether any of the savings from the unspent T&D budget were credited according to the merger agreement.

Personnel Levels

108. The Company has carried out substantial cuts in the number of employees assigned to T&D operations: 95 distribution employees in 1995-1996 and 26 in 1997. EGS has increased its use of contract workers during the same periods for a total net decrease of 42 permanent linemen and servicemen since the merger.

109. Since the merger, most the terminated T&D employees were replaced with contract workers. Sixty-six of the terminated T&D employees had on average of 18 years experience with the Company.

110. The Company has no performance measures to evaluate contract-worker efficiency.

111. The ratio of contract employees to permanent linemen and servicemen is now 2:1. The Commission does not oppose the use of contract employees. The present ratio of contract employees to permanent staff, however, is high, particularly in light of the extensive experience lost when many of the permanent employees were laid-off.

112. EGS is expected to structure its line maintenance and vegetation management programs in such a way that adequate numbers of properly trained and supervised employees are promptly available.

113. EGS hired 30 additional contract crews in October 1997. specifically to remedy a backlog of vegetation management projects.

114. The Company lacks a clearly stated strategic plan for vegetation management, and priorities are driven primarily by budget considerations.

Customer Service

115. An EGS customer survey reveals that satisfaction results decreased among all classes of ratepayers and for all components of service from 1995 to 1996, as more customers classified EGS service as "fair" or "bad" than "very good" or "helpful."

116. EGS did not track customer complaints prior to 1995, nor did it track customer service performance standards. EGS began a complaint management system in January 1997 to document every complaint called in to the Company.

117. The Company's automated voice response unit, substituted for live employees, has not led to increased customer satisfaction.

118. EGS has failed to implement sufficient customer service procedures and has a high number of dissatisfied customers.

119. The Company also has, by its own admission, pockets of particularly inadequate service.

120. In a letter dated September 19, 1997, State Representative Mark Stiles wrote to the Commission expressing concern over an increase in the number of EGS customers who contacted him to complain of poor service by EGS.

121. EGS acknowledges that it has a large number of customers who remain unsatisfied with their customer service.

122. EGS' customer service quality is clearly deficient based on the numerous complaints to the Commission and Texas Legislature, and as indicated in the Company's own survey data.

B. Conclusions of Law

1. Entergy Gulf States, Inc. (EGS) is a public utility as defined in PURA § 31.002(1).

2. The Commission has jurisdiction over issues addressed in this Order in accordance with PURA §§ 14.001, 31.001, 32.001, 33.122, 36.001-36.151, and 38.071.

3. The Commission has jurisdiction over all matters relating to the conduct of a hearing in this case, in accordance with PURA § 14.051.

4. This Order is issued in accordance with TEX. GOV'T CODE ANN. § 2001.141.

5. PURA § 37.151(2) requires that EGS provide continuous and adequate service in its certificated service territory

6. EGS is obligated, pursuant to PURA § 38.001, to furnish service, instrumentalities, and facilities that are safe, adequate, efficient, and reasonable.

7. EGS has failed to provide continuous and adequate service to many of its customers, as required by PURA §§ 37.151(2) and 38.001.

8. In establishing a reasonable return on invested capital, the Commission is required, among other things, to consider the quality of the utility's service. PURA § 36.052(3).

9. The Commission, after notice and hearing, may order an electric utility to provide specified improvements in its service and in a specified area if (a) service in the area is inadequate or substantially inferior to service in a comparable area; and (b) requiring the company to provide the improved service is reasonable. PURA § 38.071.

V. Ordering Paragraphs

1. Upon issuance of a final order in EGS' pending rate case in Docket No. 16705, the Company shall calculate the revenues equal to 60-basis points, and appropriate taxes, of the ROE established in Docket No. 16705.

2. Within 30 days after issuance of the final order in Docket No. 16705, the Company shall submit to the Commission its calculation of the revenues equal to 60-basis points, and appropriate taxes, for Commission review and approval.

3. If a rate reduction is ordered in Docket No. 16705, the Company shall refund to its customers an amount equal to 60-basis points of its ROE authorized in Docket No. 16705, plus appropriate taxes, for the period from June 1, 1996, through the effective date of this Order.[136]

4. As of the effective date of this Order, the Company shall reduce collections from customers by an amount equal to 30-basis points, and appropriate taxes, of the ROE authorized in Docket No. 16705.

5. As of the effective date of this Order, the Company shall establish an interest-bearing escrow account into which it shall deposit, on an on-going basis, the amount equal to 30-basis points, and appropriate taxes, of its ROE authorized in Docket No. 16705.

[136] If the final order in Docket No. 16705 does not mandate any refunds to customers, there will not be a refund of 60-basis points to customers based on this Order for the period from June 1, 1996, up to the effective date of this Order.

6. The Company shall hire an independent consultant, according to the conditions set out in the amended, non-unanimous stipulation regarding the hiring of consultants, as approved with modifications by the Commission in this docket. The consultant shall assess the distribution system, develop strategies for improvement, revise data-collection practices, establish evaluation criteria, and perform any additional work as set out in the amended, non-unanimous stipulation.

7. No later than July 1, 1998, the Company shall file a quality assurance proposal governing the collection, recording, and reporting of SAIDI, SAIFI, and any other relevant service quality measures.

8. Twice annually, and starting on June 15, 1998, the Company shall file the Electric System Service Quality Report to document SAIDI and SAIFI feeder-by-feeder data for each six-month period and a listing of the worst performing 10 percent of the Company's feeders with their performance data. At the same time, the Company shall file its Customer Service Report.

9. Beginning in 1999, and no later than March 1 of that and each subsequent year, the Company shall file with the Commission its reconciliation proposal for the funds held in escrow according to this Order for the prior calendar year. The Company's annual filing shall be audited by an independent auditor, and the audit shall be filed with the reconciliation proposal. The independent auditor shall be selected jointly by the Company and interested intervenors in Docket No. 18249, using the same selection process as the process applied in hiring of an independent consultant.

10. If the Commission determines that the Company has achieved the performance standards set out in this Order for a minimum acceptable level of improvement for SAIDI and SAIFI for the 10 percent of worst feeders and, if applicable, major-storm restoration process, the Company may retain one-third of the amount in escrow for that year; otherwise, the Company shall refund that amount to its Texas distribution-level customers taking service from the non-complying feeders, as explained in section D(1) and D(2)(b) of this Order. If the Commission determines that the Company has achieved the performance standards set out in this Order for the target level improvement for SAIDI and SAIFI, the Company may retain one-third of the amount in escrow for that year, otherwise, the Company shall refund that amount to all its Texas distribution-level customers, divided on a pro-rata basis within each customer class. If the Commission determines that the Company has achieved the performance standards set out in this Order for customer service, the Company may retain one-third of the amount in escrow for that year; otherwise, the Company shall refund that amount to its Texas distribution-level customers divided on a pro-rata basis within each customer class.

11. In conjunction with its annual reconciliation filing, the Company shall submit a proposal for customer notification. At a minimum, the proposal shall include the content and format for a billing insert that explains the service quality requirements. the Company's performance for the preceding year. street light reporting instructions and telephone number, and the amount of the escrow pool retained by the Company and/or refunded to customers.

12. The Company shall develop and implement, within the six months of the effective date of this Order, a media campaign to inform and educate customers in its Texas service territory about the importance and proper procedure for reporting to the Company malfunctioning or broken street lights.

13. All other motions, requests for entry of specific findings of fact and conclusions of law, and any other requests for general or specific relief, if not expressly granted herein, are hereby denied for want of merit.

This Order reflects the opinion of Chairman Wood and Commissioner Walsh. Commissioner Curran was not present at the adjudicatory hearing conducted in this docket, and did not participate in the final order deliberations.

Attachment #1

Electric Power System Emergency Report

U.S. Department of Energy
Energy Information Administration
Form EIA-417R

OMB No. 1901-0288
(Expires 8/31/99)

The U.S. Department of Energy, in order to meet its national security requirements and responsibilities contained in the Federal Response Plan, has established mandatory reporting requirements for electric power system incidents or possible incidents. Such incidents are to be reported to the Department through its Emergency Operations Center on a timely basis. This center is open 24 hours per day, 7 days a week and it can be reached by Voice: (202) 586-8100, by FAX (202) 586-8485 or by E-Mail at WTCHOPC@OEM.DOE.GOV.

Report of:	Interruptions: (Y) X (N) __	Name of Utility, Control Area Operator, or Electrical System Operator: Entergy
	Voltage Reduction: (Y) __ (N) __ ___ Percent (%)	
	Public Appeal: (Y) X (N) __	
	Vulnerability Action: (Y) __ (N) __	
	Other Incident: (Y) __ (N) __	

System(s) and/or Area(s) Affected	Entergy

Date and Time at Which the Incident Began:	Date: July 23, 1999	Time: 14:42	Time Zone: Central

Date and Time *of Service Restoration, Return to Normal Voltage Levels or Return to Normal System Operations*:	Initial Projected Date: July 23	Final Date: July 23, 1999
	Initial Projected Time: 17:30	Final Time: 17:00
	Time Zone: Central	Time Zone: Central

Numbers of Customers Affected: 557,354	Amount of Load Involved: 900 MW's

Electric Power System Emergency Report
Form EIA-417R

NARRATIVE DESCRIPTION OF THE EVENT

rovide a brief description of the event. Include as appropriate: the cause of the incident, equipment lamaged, critical services interrupted, and any effects on neighboring system(s):

The Entergy system went into the day on July 23rd projecting that industrial interruptible load and some scheduled wholesale limited-firm load would need to be curtailed in order to maintain the required level of operating reserves. During the day, about 2100 MW's of generation were lost. With adequate amounts of purchased power unavailable, Entergy was forced to shed 900 MW's of firm load from 14:42 until approximately 17:00. 557,354 customers were affected by this load shedding action during the rotating outage. Entergy made a public appeal requesting voluntary reduction of electrical usage around noon on July 23, 1999.

Report prepared by: Larry D. Ables

Title: Director-Operations Management
Telephone Number: (281) 297 - 3507

Address:
10055 Grogans Mill Road, Suite 300
The Woodlands, Texas 77380

Incident reported by:

Telephone No: (281) 297 - 3507 FAX No: (281) 297 - 3737 E-Mail: lables@entergy.com

(Y) X (Y) X (Y) X

Attachment #2

Date: July 23, 1999
For Release: Immediately
Contact: Cyril Guerrera
(504) 840-2599

High Electrical Demand in Eastern United States causes Request for Voluntary Reductions

NEW ORLEANS – High temperatures and high electrical power demand levels across the eastern United States are causing Entergy to ask customers to voluntarily reduce their usage of electricity.

Entergy anticipates having enough power to meet the needs of its residential, commercial and non-interruptible customers, but is asking customers to take these actions to help Entergy and its neighboring utilities conserve power.

Entergy will begin to curtail certain industrial and wholesale customers with special agreements that allow them to be curtailed.

Electrical power demand has continued to increase and reserves are low for electric utilities across the eastern United States. If electricity usage continues to increase, periodic temporary power outages could begin among residential and commercial customers. These are expected to be short power curtailments that affect different groups of customers at different times.

The standard temporary outage length is thirty minutes, but it is possible it could be shorter or longer, depending on the situation.

Periodic temporary power outages should not affect electricity to customers who provide public safety or public health services.

Some ways customers can reduce their electricity usage include:

Air Conditioning Tips

- Raise the central air conditioner thermostat to 78 degrees. Window units should be adjusted accordingly.
- Use energy efficient electric ceiling fans and portable fans to circulate air and help occupants feel cooler.
- Close window blinds, drapes and curtains to reduce warming in the home from direct sunlight.

- Check the air conditioner to be sure it is clean.

General Energy Saving Tips

- Delay laundering clothes, washing dishes, bathing, etc. until later in the evening or early morning. These activities produce moisture and increase humidity in the house, making the air conditioner work harder.
- Wash clothes with cold water, cook foods at the lowest possible setting, and resist the temptation to open the oven door while baking.
- Do not allow cooled air to escape from the home. Check caulking around doors and windows. Close the fireplace damper. Fill holes and gaps where wiring and pipes enter the house.
- Make sure your clothes dryer and attic are vented properly.

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For immediate release

Contact: Energy & Resource Consulting Group, LLC
Joseph Vumbaco
303-843-0600

THE COUNCIL OF THE CITY OF NEW ORLEANS ADDRESSES CONTINUAL ENTERGY NEW ORLEANS, INC. ELECTRIC RELIABILITY PROBLEMS

Entergy New Orleans ordered to quickly improve electric system reliability and customer service or face potential penalties.

DENVER, CO, July 16, 1998 - Plagued with numerous outages, equipment failures and poor and declining electric service reliability in the New Orleans East portion of the City, the Council of the City of New Orleans, at its July 16th meeting, ordered Entergy New Orleans ("ENO") to greatly improve its service reliability and customer service practices. The Council voted unanimously to adopt Resolution R-98-460 ("Resolution") which requires ENO within thirty days to file a Service Remediation Plan ("Remediation Plan") to address electric reliability problems in New Orleans East and the customer service process it utilizes in the reporting and response to customer outages in New Orleans. "You get the worst possible grade on customer service. The days of coming to this City Council and paying lip service to customer service problems are over," said Council President James Singleton addressing representatives of ENO who were present at the meeting.

Energy & Resource Consulting Group, LLC ("ERG") of Denver, Colorado, in its role as the Technical Advisor to the City Council for all electric and gas utility matters, recently performed an independent investigation of ENO's service reliability and quality problems. In its report to the Council, ERG has determined that significant problems exist with the distribution system serving this area of the City. Joseph A. Vumbaco, ERG's Engagement Director, advised the Council that "basically, major portions of both ENO's underground and overhead distribution systems serving New Orleans East are either at or past the end of their useful lives. The majority of these systems must be either replaced in total or significantly upgraded to provide acceptable levels of service reliability. There is no technical reason why ENO's efforts cannot be greatly accelerated to accomplish same in the next eighteen months!"

The New Orleans East area consists of a major industrial area, the Alamaster-Michoud Industrial District ("AMID"), large commercial facilities, and a mix of numerous residential neighborhoods and small commercial establishments. During the past several years, numerous outages, distribution equipment failures and extremely poor electric system reliability have affected the majority of ENO's commercial and residential customers in New Orleans East. Last year representatives of ENO were ordered to appear before the Council when a major industrial customer, the Folger Coffee Company, experience continual outages which affected its ability to produce its product at its facilities in New Orleans East. ERG, on behalf of the Council, assisted Folger Coffee in developing a remediation plan with ENO to rectify the service reliability problems Folger's was having with ENO's electric service.

Councilmember Ellen Hazeur-Distance, whose Councilmanic District E includes the affected area, advised ENO that "the businesses and residents of New Orleans East have endured poor service reliability and frequent outages for far too long. My constituents deserve significantly better service. The level of customer complaints about poor service are getting worse rather than better. Any Service Remediation Plan had better set forth a detailed approach to accelerating the resolution of the service reliability problems in New Orleans East." Ms. Hazeur-Distance further admonished ENO for "their lack of responsiveness" to her numerous written requests over the past two years for ENO's solution to solving the continual electric outages that have plagued the eastern area of the City.

Under the provisions of the Louisiana Constitution and City Charter, the City Council acts as the regulator which exercises primary jurisdiction over two of Entergy Corporation's operating subsidiaries, Entergy Louisiana, Inc., which provides electric service to approximately 621,000 customers in the Algiers area of the City and ENO which provides electric and gas service to approximately 189,000 customers in the remainder of Orleans Parish.

The Resolution adopted by the Council on July 16th requires ENO's Remediation Plan to provide the Council within thirty days:

- A substantive evaluation and analysis of the root causes of the reliability problems;
- ENO's proposed technical and engineering approach to remediation of the problems;
- A finite time schedule for completion, including construction budget and fiscal quarterly expenditures;
- Priority and interim projects to quickly alleviate the most severe customer service quality complaints and problems; and
- Such other analysis and information as may be required by the Council and ERG to evaluate the effectiveness of ENO's proposed plans.

The Resolution also addresses the manner in which customer calls are handled by ENO in its customer call centers. ENO was directed to appear at the Council's Utility Committee meeting of August 13th to respond to Councilmanic concerns on customer service activities of ENO. In 1997, in response to customer complaints in this area, the Council opened a docket (UD-97-5) on ENO's customer service policies and procedures. The Resolution also directs ENO to provide in its filing a record history of the outages and service interruptions that have occurred throughout New Orleans for each Councilmanic District for the 12 months ending June 30, 1998 to include:

- Date and time of the outage and number of customers affected;
- Duration of the outage;
- Cause of the outage; and
- Remediation efforts to correct the causal factors or root cause of the outage.

The Remediation Plan filing requirement is the initial step in the Council's evaluation of ENO's performance on electric reliability matters with the intent of improving the level of service provided to all of ENO's electric and natural gas customers.

Enclosure: Resolution R-98-460

# # #

ENTERGY NEW ORLEANS, INC.
CITY OF NEW ORLEANS
POWER OUTAGES OF JULY 23, 1999

Response of Entergy New Orleans, Inc.
to the First Set of Data Requests
of Requesting Party: City Council–

Question No.: City Council 1-1 (CLJA001) Part No.: Addendum:

Question:

Please provide a detailed understanding of the events leading up to the initiation of load curtailment of ENO customers.

Response:

Projected Reserves Above Firm Load for 7/23 Peak (Mw)	Date	Time	Remarks	
2100	7/22/99	3:55 PM	Expect to curtail about 1500 Mw of Interruptible/Curtailable Retail load and Limited Firm Wholesale load on 7/23.	
2100	7/22/99	6:30 PM	Discussed public appeal for voluntary conservation. Decided situation did not warrant this action.	mechan
1000	7/23/99	7:00 AM	Operating Subcommittee met. Overnight changes: • Waterford 1 unavailable for peak (400 Mw). • Additional small derates totaling 500 Mw. • Load forecast increase (200 Mw). Put in place plan to curtail all Interruptible/Curtailable Retail load and Limited Firm Wholesale load on 7/23.	– failur – failur
1000	7/23/99	8:03 AM	Entergy declared NERC Energy Emergency Alert Level 1	
700	7/23/99	8:07 AM	Ninemile 5 derated (about 300 Mw)	–failure
500	7/23/99	8:30 AM	Baxter Wilson 1 derated (about 200 Mw)	– failure
500	7/23/99	10:00 AM	Reviewed situation with Entergy Senior Executives.	
500	7/23/99	12:00 PM	Public appeal issued for voluntary conservation.	
500	7/23/99	12:00 PM	Entergy declared NERC Energy Emergency Alert Level 2.	
50	7/23/99	1:19 PM	White Bluff 1 derated (about 450 Mw).	– failure

Question No.: City Council 1-1
(CLJA001)

(250)	7/23/99	1:42 PM	Baxter Wilson 1 off (about 300 Mw).	– failure
50	7/23/99	1:42 PM	Received SPP Emergency Assist (about 300 Mw).	
250	7/23/99	2:00 PM	Received SPP Emergency Assist (additional 200 Mw)	
(250)	7/23/99	2:30 PM	Lost 500 Mw SPP Emergency Assist. No SPP Emergency Assist available for the rest of the day.	
(350)	7/23/99	2:30 PM	Lost 100 Mw of purchased power.	
(1000)	7/23/99	2:35 PM	Knew White Bluff 1 (about 350 Mw) about to go off. Knew 300 Mw purchase to end at 2:45 PM. Decided to curtail firm load.	– failure
(100)	7/23/99	2:42 PM	Began curtailment of 900 Mw of firm load.	
(100)	7/23/99	2:45 PM	Lost 300 Mw of purchased power as expected.	
(100)	7/23/99	2:45 PM	Entergy declared NERC Energy Emergency Level 3.	
(100)	7/23/99	3:01 PM	White Bluff 1 off as expected (about 350 Mw).	
(100)	7/23/99	3:15 PM to 3:30 PM	Purchased 300 Mw of power. Returned service to 300 Mw of firm load.	
(50)	7/23/99	3:30 PM	Baxter Wilson 1 on line (about 50 Mw).	
(550)	7/23/99	3:40 PM	Willow Glen 5 off (about 500 Mw).	– failure
(50)	7/23/99	4:00 PM	Purchased 500 Mw of power.	
0	7/23/99	4:41 PM	Waterford 1 on line (about 50 Mw).	
300	7/23/99	5:00 PM	Purchased 900 Mw of power. Returned service to 600 Mw of firm load. All firm load restored.	

Entergy's New Management Needs Least-Cost Plan for Power Shortage
by
Gary Groesch, Executive Director, Alliance for Affordable Energy

Last summer, because of several high-profile electrical blackouts in the French Quarter and elsewhere, the community focused attention on Entergy Corporation's now-admitted failure to adequately maintain the electrical system for the last five years or so. This summer, the lights may again go out for another reason. According to a recent article in the *Times-Picayune* (Sunday, May 23, "Sweating Out the Summer"), Entergy's rapidly growing peak demand is outstripping the ability of the system to supply reliable electric power.

Since 1994, Entergy's peak demand has risen almost 12%. Most of this increase is the result of huge industrial customers being placed on deeply discounted "interruptible" rates. "Interruptible" means that Entergy can cut off the power to these industries in the event that the demand for electricity outstrips the available supply. Industries with large electrical needs often favor interruptible rates because their utility bills are reduced substantially and, until recently, the possibility of having their electricity interrupted was practically nil.

Over time, such business practices are not sustainable. Deep discounts remove any incentive for the industrial customer to conserve electricity. Worse, residential and commercial rate payers, whose energy usage is often inflexible, see their rates creep up over time because they pay the difference between the deeply discounted industrial interruptible rate and a much higher rate that would otherwise by paid by that industry for firm power.

Last summer, Entergy's electricity demand shot up to an unexpected and dangerous record level. Entergy's response – to cut off the electricity to dozens of industries that voluntarily signed up for interruptible rates – was met by howls of protest from those same industries that evidently believed the term "interruptible" did not apply to them.

This year, Entergy appears to be responding to this illegitimate industrial outcry by planning to restart a group of polluting, inefficient, 1950s-era power plants. To give you an idea what this means, imagine the tailpipe pollution from starting up five hundred or so 1955 Ford Fairlanes after sitting idle for several decades. Needless to say, the air around those old power plants will be thick with everything except oxygen.

The high-cost of firing up these inefficient mothballed power plants will be borne primariliy by residential and small commercial rate payers, rather than by large industries that reap the benefits by not being interrupted while continuing to pay dirt-cheap interruptible rates.

The Alliance for Affordable Energy has three strong recommendations:

- First, Entergy should shelve its plan to restart its mothballed power plants.
- Second, Entergy must tell its industrial customers who chose interruptible rates that they will be interrupted as often as necessary to maintain the integrity of the system or they must elect to pay full industrial rates. If an industry chooses the latter option, then every residential and commercial rate payer would thus be entitled to a rate reduction.
- Third, Entergy should go to state and city regulators immediately with a "Least-Cost"

energy plan designed to protect the integrity of the electrical system. Least-Cost Planning (LCP) was agreed to by Entergy in 1991 but discarded by Entergy in 1995 at the advent of the now-stalled deregulation debate. LCP is an investment strategy that directs utility investments in the most cost-effective – including costs to the environment such as increased air pollution – method of providing an energy service, e.g. lighting, heating, air conditioning, and motor power. The least-cost method may mean, for example, saving megawatts through installation of a million energy-efficient, compact fluorescent lights or producing megawatts through construction of a state-of-the-art combined cycle combustion turbine power plant. Each potential energy investment is evaluated by its total cost and then ranked for investment, cheapest first.

Entergy's forty-year old electric generators would clearly fail the "least-cost" test because of their inherent inefficiency (old power plants use twice the fuel per kilowatt hour as modern ones) and pollution.

Before it was dismantled, the Least-Cost Program in the City of New Orleans actually weatherized and insulated 11,000 homes, saving participating homeowners nearly 23% on their overall utility bill. More important to this discussion, large amounts of energy were saved which lowered demand and put off the cost of more power plants. Commercial and industrial rate payers have potential for even more cost-effective energy savings than residential customers. In an analysis done for the Alliance, Amory Lovins, universally recognized as the world's leading expert on energy efficiency, estimated that nearly half the electrical demand of Orleans Parish could be met through cost-effective energy efficiency investments in the commercial sector.

The City of Austin, one of New Orleans' chief regional competitors, has been practicing least-cost planning for years. Its federally recognized, award-winning energy efficiency investment strategy has made thousands of Austin homes and businesses more energy efficient. Summing all of its energy savings, Austin now has what it terms a "Conservation Power Plant" which saves what would otherwise require the output of a 380-megawatt power plant, about one-fourth of the community's total electrical load. Of course, the Conservation Power Plant has no pollution whatsoever and costs only a fraction of the real thing.

The Alliance urges Entergy's new management to reconsider its plan to pollute Louisiana's already burdened environment with yesterday's technology and instead to begin laying the foundation for sustainable economic growth through energy efficient planning and advanced technology investments.

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Exhibit 10

P.D. Schneider, "Nuke Workers worried about jobs, safety." The Palladium Times, July 20, 2000

The Pallad

THURSDAY, JULY 20, 2000, 18 PAGES OSWEGO COUNTY'S HO

VOL. 76 NO. 247 Home page address is: Pall-Times.com

Nuke workers worried about jobs, safety

By P.D. SCHNEIDER

Senior Staff Writer

SCRIBA — Saying turnover is mounting and morale plummeting, a nuclear employees group wants the U.S government to delay the sale of plants here and in Westchester County.

But the New York Power Authority, which owns the James A. FitzPatrick and Indian Point 3 plants, calls the request by the Nuclear Generating Employees Association "nonsense."

The debate appears bound for court. NGEA says it will file suit by early August against the Power Authority and plant-buyer Entergy Corp. of Louisiana.

"NGEA will be filing in less than 14 days ... a lawsuit ... the outcome of which could materially alter or even nullify the agreement" between the Power Authority and Entergy, NGEA's lawyers wrote this week in papers filed with the U.S. Nuclear Regulatory Commission.

At issue are the effects of the Entergy deal on NGEA's 400 members. About 185 work at the 825-megawatt FitzPatrick plant.

Entergy hopes to close Sept. 7 on a $967 million deal for IP3, near New York City, and FitzPatrick, but can't without NRC's OK. The plants would be operated as two limited-liability partnerships: Entergy Nuclear-FitzPatrick and Entergy Nuclear-Indian Point.

NGEA, comprised of managers and other non-union employees at three NYPA sites, charged this week that the authority and Entergy have been sending conflicting messages about salaries and benefits after the sale.

The resulting confusion, Scriba-based NGEA claims in legal papers, has hurt morale and increased turnover.

NYPA, though, was sharply critical this week of NGEA's petition to the feds and the group's claims that plant employees aren't hearing straight talk about salaries, benefits and pensions.

"It's nonsense," NYPA spokesman Jack Murphy told *The New York Times*. "Before we entertained an offer from anybody, including Entergy, one of our primary requirements was

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that our employees would go to the new company at the equal salary and the same level of benefits."

Attempts to reach Murphy for further comment were unsuccessful. Entergy has said it would maintain employee numbers and salary levels, but hasn't specified how long it would do so.

More important to residents of Scriba and nearby towns, is that NGEA is raising the safety issue.

"We're concerned that a decline in morale could present a safety concern eventually," said Richard Wiese, a FitzPatrick outage coordinator who founded NGEA and is a board member. "Is it a danger now? No. Our concern is what happens as more people leave."

Wiese said he knows just from signing farewell cards of about 30 people who have left FitzPatrick this year for jobs outside NYPA. He said that number "is more than 100 percent above" that who leave in a typical year.

"The Power Authority is having trouble keeping employees," he said Wednesday. "There's no guarantee there will be a workforce here for Entergy."

CERTIFICATE OF SERVICE

I, Timothy L. Judson, on behalf of the Citizens Awareness Network, Inc., hereby certify that copies of the Citizens Awareness Network's Request for Hearing and Petition to Intervene were served upon the persons listed below by e-mail and with a conforming copy deposited in the U.S. mail, first class, postage prepaid, this 31st day of July, 2000.

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