STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

CASE 98-E-0405

NUCLEAR GENERATION AND THE COMPETITIVE ELECTRIC MARKET

INTERIM REPORT

Presented In Collaboration
By The Active Parties

June 1999

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EXECUTIVE SUMMARY

INTRODUCTION

This proceeding continues the Commission's effort to foster competitive opportunities in the State's electricity markets. Specifically, Opinion No. 98-7 directed that a collaborative proceeding be initiated to examine whether and how nuclear power should be subjected to the competitive market. The parties to the proceeding established a three-part agenda[1] for this proceeding: an administrative determination of nuclear "to go" and "not to go" costs; the business organization alternatives available for the ownership and operations of nuclear facilities; and, various policy matters associated with the potential changes to the nuclear industry in New York.[2] This Interim Report, prepared at the request of the Commission, presents a collaborative approach for implementing the first agenda item, which would provide a framework to determine whether nuclear generation of electricity can economically compete with non-nuclear sources of generation. This approach applies to situations where ownership of the nuclear plant remains with the utility or a regulated affiliate. The administrative approach would not be necessary in the event of continued cost-of-service regulation, a sale of the plant, or a plant shutdown.

The first collaborative conference in January 1999 was attended by about 100 participants from diverse interest groups. Parties established a process to guide the collaborative effort. The process began with a series of informational meetings, which established a common understanding of the operation and costs of nuclear plant production. The informational meetings were followed by group discussions where the principles of an administrative approach were forged. While the parties agreed to approach each of the three issues in segments (mentioned above), they agreed to make no final recommendations to the Commission until they have adequately discussed and analyzed all topics.[3]

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1 Each item of the three-part agenda formed a separate "segment" in this proceeding.

2 This proceeding considers the future of the four investor-owned nuclear plants. It does not address the two plants owned by the New York Power Authority.

3 Participation in this proceeding by a party does not constitute an endorsement of all the principles or

SEGMENT 1 -- "TO GO" AND "NOT TO GO" COSTS

Segment 1 -- the focus of the Interim Report -- reflects a process by which to administratively subject nuclear power to market-based pricing. To implement this approach for those circumstances in which ownership of a plant remains with the utility or its affiliate**,** two of the three key issues were considered: how administratively-regulated plants would obtain revenues and which nuclear costs would be exposed to market pricing. The parties have not yet dealt to any substantial extent with the third key issue, developing appropriate frameworks for subjecting relevant costs to market pricing. When properly implemented, market prices should encourage and allow nuclear plant owners to make rational economic decisions regarding future operation of the plants while also accounting for public policy concerns.

Revenues would be obtained when the nuclear unit sells its output into the competitive market (after that market is established by the ISO) or through bilateral agreements. "To go" costs are defined in this Interim Report as those nuclear costs that could be avoided with a permanent shutdown. "To go" costs would be exposed to market pricing. Nuclear costs, which have already been incurred or would not be avoided by a permanent shutdown, are referred to as "not to go" costs and recoverable "not to go" costs would not be exposed to the market.[1]

Under such an administrative approach, the utility would make the run/retire decision based upon its ability to recover in the market the costs that can be avoided by shutdown. Proper differentiation of these "to go" costs that can be avoided from those that cannot, is critical to the success of this approach. If "not to go" costs are improperly classified as "to go" costs, raising them above the market price, the nuclear plant would be shut down even though it would have been an economical source of power. This would have unnecessary adverse impacts on customers, workers and host communities. On the other hand, if "to go" costs are classified as

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statements contained in this Interim Report, nor does any party waive its rights in this or any other proceeding.

1 It is neither economically nor operationally feasible to cycle nuclear plants; and cycling, even if possible, would avoid few if any costs. Nuclear fuel already in place or contracted for would not be avoided. Virtually no other O&M costs could be avoided because the plant must be maintained in accordance with its NRC operating license requiring, for example, essentially all of the work force to be retained until the plant is permanently shutdown.

"not to go" costs, more cost-efficient generation would not run or might not be built causing higher costs for consumers, reduced competition and lost opportunities for other communities.

It is important to note that "not to go" costs are not necessarily the same thing as, and should not necessarily be considered equivalent to, strandable costs. Any portion of "not to go" costs that are mitigated by plant power sales revenues or are imprudently incurred, would not be considered strandable. The quantification and regulatory treatment of recoverable stranded costs are not addressed in this report.

The parties conclude that nuclear plant costs can be grouped into six categories: existing plant investments, future plant investments, expenses related to nuclear fuel, decommissioning costs, property taxes, and other operating and maintenance expenses. Each of these groups of costs are analyzed and discussed extensively in the report with the rationale for recommending treatment as "to-go" or "not-to-go" provided on pages 21 through 35.

SEGMENT 2 -- BUSINESS ORGANIZATION STRUCTURE

Segment 2 will examine various operating/ownership scenarios (business organization structures) under which nuclear plants might operate in the future, including retention by the utilities under either a cost-of-service regulation scenario or a market-based approach, sales to third parties, and shutdown. Consideration of the issues, and relative merits, regarding the structural alternatives, together with Segment 3 issues, has now started.

SEGMENT 3 -- PUBLIC POLICY CONCERNS

Actions taken in this proceeding may have public policy ramifications. In Segment 3, interested parties will consider the potential impacts that may result from the actions considered in this proceeding which they believe must be considered herein, including, for example, impacts on real property taxes, the environment, reliability, economic development, health and safety, and externalities.

Outreach efforts to increase public involvement in this proceeding were held in the host communities during February 1999. Additional public outreach will occur during the Summer and Fall of this year.

STATE ENVIRONMENTAL QUALITY REVIEW ACT (SEQRA)

The May 1996 Final Generic Environmental Impact Statement for the Competitive Opportunities Proceeding addressed nuclear power issues. However, policies now being considered may have impacts beyond those considered three years ago. A Draft Supplemental Environmental Impact Statement will be prepared and released for comment in July 1999.

REBUTTABLE PRESUMPTION

Opinion No. 98-7 establishes the rebuttable presumption that nuclear power should be priced on a market basis to the same degree as power from other sources. It is too early in the proceeding for the parties to be able to reach a consensus that nuclear power should be subjected to market pricing. Parties may yet seek to rebut the presumption put forward by the Commission.

CONCLUSION

The parties to this collaborative process have made considerable progress in defining and categorizing “to go” and “not to go” costs for their application in Scenarios 7, 8, and 9 presented in the Interim Report. While considerable progress has been made in Segment 1, as noted above, there are a number of issues which still require further consideration in this proceeding, including development of a framework for subjecting nuclear power to market prices. In addition, the issues considered here may require further consideration following Segments 2 and 3.

INTRODUCTION AND BACKGROUND

In 1993, the Commission began to consider whether and how New York should transition to competition in the electric industry. To do so, it commenced a collaborative proceeding to develop a set of principles to guide this transition and to develop competitive market models. In 1996, the Commission issued Opinion No. 96-12, a policy statement setting forth the Commission's vision for electric competition in New York. Opinion No. 96-12 established certain goals for the New York electric market, which were subsequently reflected in a series of Orders approving the rate/restructuring settlement agreements executed by the Investor-Owned Utilities (IOU).

By notice issued August 27, 1997, the Commission invited comments and reply comments on a "Staff Report on Nuclear Generation," in which Department of Public Service Staff (Staff) had set forth its tentative conclusions regarding the treatment of nuclear generation following the transition to a competitive electric market. In March 1998, the Commission issued Opinion No. 98-7,[1] in which it reviewed the comments and determined a need for further inquiry.[2] In Opinion No. 98-7, the Commission adopted as "a rebuttable presumption the premise that nuclear power should be priced on a market basis to the same degree as power from other sources, and parties challenging that premise bear a substantial burden of persuasion."[3] It established this collaborative proceeding to recommend whether and how New York's investor-owned nuclear generating plants should be subjected to market pricing or whether they possess attributes that warrant treating them differently from other generation sources.[1] Specifically, the issues to be addressed relate to market treatment for nuclear power, the ownership of nuclear power plants, decommissioning issues, timing, permitted participants in the auction, alternatives or supplements to divestiture, and the effect on municipalities.

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[1] Case 98-E-0405, Nuclear Generation and the Competitive Electric Market, Opinion No. 98-7 (issued March 20, 1998.)

[2] Opinion No. 98-7 at 1.

[3] Opinion No. 98-7 at 44.

This proceeding is exploring the above issues as they relate to the three wholly investor-owned nuclear power plants: the Ginna Nuclear Power Station owned by Rochester Gas and Electric Corporation (RG&E); Indian Point No. 2 owned by Consolidated Edison Company of New York, Inc. (Con Edison); Nine Mile Point 1 owned by Niagara Mohawk Power Corporation (Niagara Mohawk); and, the majority IOU-owned Nine Mile Point 2, whose owners are RG&E, Niagara Mohawk, Central Hudson Gas & Electric Corporation, New York State Electric & Gas Corporation, and the Long Island Power Authority. Basic information about the plants appears in Appendix 9. This report does not address the two nuclear power plants owned by the New York Power Authority or the 18% of Nine Mile 2 owned by the Long Island Power Authority.[2]

On January 20, 1999, the case began with the first meeting of the parties in Albany. About 100 people attended. They represented various units of local and state government, school districts, labor unions, the investor-owned utility companies, environmentalists, various consumer groups and citizens. At this meeting, the parties identified the topics they would discuss and develop. They also began to organize the collaborative process and suitable ground rules were adopted.[1] The parties also established a three-part agenda for this proceeding: Segment 1 to explore the administrative determination of nuclear "to go" and "not to go" costs; Segment 2 to define the major alternatives available and address the Opinion No. 98-7 issues associated with the ownership and operation of nuclear facilities; and Segment 3 to explore the impact on various policy matters which would be caused by Commission actions associated with Opinion 98-7. These policy issues include health, safety, employment, economic development, impact on local communities, school funding, environmental matters, and real property valuation reductions. While the parties are examining the topics in this case sequentially, they have agreed to make no final recommendations to the Commission until they have adequately discussed and analyzed all topics. It is recognized that while a number of these issues may be treated generically, the application of them to the various plants may differ.

This interim report summarizes the progress made from January 1999 through May 1999, and the

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1 The parties participating in this proceeding are listed in Appendix 1.

2 For purposes of this report and with recognition of LIPA's ownership, Nine Mile Point 2 will be referred to as an IOU-owned plant.

results achieved, in the collaborative process. It also identifies the steps for the remainder of the proceeding.

PROCESS AND PROCEDURES

Segment 1 - "To Go" and "Not To Go" Costs

In February 1999, first segment activity began to focus on the nuclear generation facilities' role in the competitive electric market. This segment started with a series of presentations sponsored by various parties.

The parties agreed that educational presentations on a number of topics would prove beneficial. The first of these presentations was provided by Staff, explaining how the Commission has fostered a competitive electric market. Staff also described generally how rate regulation has been traditionally applied to investor-owned utility companies.

Thereafter, the utility companies sponsored three presentations. The first provided the group with information about the New York Independent System Operator (ISO) that will organize and operate a wholesale electric market in New York, operate the bulk power system considering transmission limitations and address reliability. The second addressed nuclear "to go" costs. This topic was also addressed in presentations provided by the Independent Power Producers of New York and the Hendrick Hudson School District. Subsequently, the group received two presentations concerning the decommissioning of nuclear facilities - one from the Pace Energy Project; the other from a consultant to the utility companies.

Each of the first-segment presentations provided ample opportunity for lively discussion. Parties with strongly held positions explored with one another the basis for their stances. Thereafter, at the Commission's request, the parties began to prepare this interim report.

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[1] The ground rules for the collaborative process appear as Appendix 3 to the report.

Segment 2 - Business Organization Structure

The collaborative group has identified ten potential representative alternatives for the ownership and operation of the investor-owned nuclear plants in New York. [1] The alternatives can be grouped into four categories, which are: (1) continued ownership and operation by the utilities under cost-of-service regulation; (2) continued ownership by the utilities with the plants subject to market pricing; (3) sales of the plants to unaffiliated third parties; and (4) shutdown prior to the end of the plant's NRC licensed life.[2]

The group plans to explore these alternatives in greater detail starting in June 1999. This segment of the proceeding will begin with a presentation sponsored by the electric utility companies.

Segment 3 - Policy Concerns

The third segment of this proceeding will provide interested parties, including representatives of the host communities, environmental groups, and unions, an opportunity to present issues associated with potential changes to the Commission's regulatory treatment of nuclear power. To this end, various parties have provided "interest statements" to help others understand their concerns.[1] Some of the issues to be discussed are highlighted below.

The 1998 Final State Energy Plan and the 1998 New York Power Pool Section 6-106 Report projected that additional system capacity would be needed between 1999 and 2004 under current reliability criteria. These assessments assumed that the four nuclear plants would operate at their current levels through the end of their respective operating licenses. Thus, absent energy efficiency improvements, conservation or new supply sources, removing some or all of the plants from the supply profile could cause the New York system to become reserve deficient. Moreover, in 1997, nuclear generation, including the New York Power Authority's two nuclear

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1 The list of the ten potential representative alternatives appears at pages 14 and 15, below.

2 The dates for the end of the plants' current NRC licensed lives are shown in Appendix 9.

generating plants, supplied about 20% of the electrical energy needs of the State. Therefore, any reduction in nuclear's share of the generation mix would alter the diversity of the electric system.

The Commission's goal in promoting competition in the electric industry over the past six years has been to foster economic development and prosperity throughout the State via lowered electric rates and increased customer energy choices. Consistent with this goal, an analysis of both the positive and negative impacts on economic development and electric rates should be performed before any final decision is made on the future treatment of nuclear generation. It is anticipated that a range of potential options for mitigation of stranded costs, including funds from divestiture in the event of a plant being sold or appropriate sharing of net operating revenues in the event of administratively determined "to go" costs, will be considered in this proceeding.

In addition to the statewide analysis discussed above, localized impacts need to be addressed. Host communities use property tax revenues received from the nuclear plants to, in part, pay for the responsibilities associated with hosting the plants. In addition, the plants comprise a substantial portion of the local tax base and are currently essential to the continued financial viability of these communities. Therefore, the communities are concerned about the impacts any potential Commission action may have on them. Further property tax concerns are accentuated because the communities' responsibilities will continue for a potentially lengthy period of time after the plants cease operation as generators. After the completion of decommissioning, the sites' future uses will be affected by and must be compatible with any long-term storage of spent fuel on the sites.

Although the Nuclear Regulatory Commission (NRC) pervasively regulates all phases of the safety of the nuclear plants and would remain the primary protection for safe operation of nuclear plants, the Commission stated that it cannot dismiss out of hand the concerns about safe operation that the marketplace might create.[2] Certain parties have questioned whether nuclear plants will be as safe in a competitive marketplace as they are now and whether existing regulatory oversight is

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[1] The parties' interest statements appear as Appendix 4 to the report.

[2] Opinion No. 98-7 at 15.

sufficient to ensure continued safe operation of the plants. Issues have also been raised, and presentations will be made, regarding the environmental effects of nuclear power, including external costs and benefits (i.e., costs and benefits not included in the market price of electricity) associated with nuclear power. These costs and benefits, which are typically borne by society at large instead of the owner of the generation plant and its customers, include socioeconomic, ecological, and public health impacts.[1] These issues will be explored to the extent they would be impacted by the Commission's potential changes in the regulatory treatment of nuclear plants.

Finally, Staff has and will continue to seek input on these issues from residents of the host communities in Westchester, Oswego, and Wayne Counties. Initial informational meetings were held in February in Peekskill, Oswego, and Ontario.[2] Additional public meetings are planned for July 1999. Towards the end of the collaborative process, public statement hearings will be conducted at each location.

State Environmental Quality Review Act

In May 1996, the Commission issued a Final Generic Environmental Impact Statement (FGEIS) in its Competitive Opportunities Proceeding (Case 94-E-0952) which analyzed a broad range of likely environmental impacts emanating from its policy to encourage electric competition in New York.

Since then, the Commission has acted on each of the electric utility companies' rate and restructuring plans. In each instance, Staff prepared an Environmental Assessment Form (EAF) which evaluated whether the proposed Commission action fell within the range of impacts considered in the FGEIS. In all cases, the proposed action was adequately covered by the FGEIS and no further SEQRA action was required.

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1 For example, the uranium fuel cycle is composed of many stages, from mining to fabrication, enrichment to operation, removal to storage. Each stage has ecological and/or public health costs and benefits.

2 Appendix 5 to this report contains a summary of public concerns voiced at these meetings.

While the FGEIS did address nuclear power issues, in this case Staff has concluded that the policies being considered are likely to have impacts that could go beyond those considered three years ago in the FGEIS. Therefore, Staff has requested the investor-owned utility companies to prepare a Draft Supplemental Environmental Impact Statement (DSGEIS). In keeping with the collaborative structure of this proceeding, the process being used to complete the DSGEIS encourages the parties to participate in the process and to provide early inputs.

On February 9, 1999, Staff led a brainstorming session at which the electric utility companies and interested parties formed a collaborative "SEQRA Working Group." The group developed an initial list of policy and operational scenarios, and environmental and socioeconomic issues, for consideration in the DSGEIS. From the results of this meeting, Staff prepared an outline for the DSGEIS that was circulated to the SEQRA Working Group members for their comments.

The electric utility companies prepared a second outline for the DSGEIS, based on Staff's initial draft and the SEQRA Working Group's comments. This draft was distributed on March 22 and discussed at a SEQRA Working Group meeting on March 25, 1999. On April 1, the final outline for the DSGEIS was distributed to the SEQRA Working Group members.

The DSGEIS will examine various operational scenarios which will be compared to a "no action" scenario through the year 2012, including:

- the utility companies continue to own the nuclear units and they retire the four plants early;

- the utility companies sell the nuclear units to third parties (or a consortium) and one plant is retired early;

- the utility companies retain one (or more) of the nuclear units and they sell the remaining units;

- the utility companies continue to own the units and they obtain plant life extensions; and

- the utility companies sell the units to third parties (or a consortium) and they obtain life extensions.

The DSGEIS will consider a range of environmental, social, and economic impacts associated with the Commission's decision regarding whether to subject the investor-owned nuclear plants to a competitive market place. The analysis will include, among other issues, the effect of the various operational scenarios on reliability, system-wide environmental and economic impacts, changes in quantities of nuclear materials generated or used, local impacts such as local tax revenues, local employment and economic activity and a discussion of health and safety for nuclear plant workers and the public resulting from possible implementation of the various economic alternatives being considered.

The utility companies are committed to completing a preliminary draft of the DSGEIS in July 1999. The SEQRA Working Group members will have a week to review and comment on the DSGEIS before it is filed. After Staff reviews the DSGEIS for completeness, it will be released, as required by statute, for a 30-day public comment period.

The Commission will prepare a Final Supplemental Generic Environmental Impact Statement (FSGEIS) after it receives any public comments and as part of any decision in this case.

FUTURE TREATMENT OF NUCLEAR GENERATION

To determine how to treat nuclear power in a competitive environment, first the possible ownership and recovery scenarios for the plants must be considered. As shown below, the need to categorize costs subject to market pricing depends on who owns the plants and how they are owned. The ten scenarios to be considered by the collaborative group, which are representative of the range of reasonably foreseeable outcomes, are:

1. Retention of the units by their present owners and continued cost-of-service regulation by the Commission.

2. The combined operation of the nuclear units by an operating company, with the present owners of each unit retaining responsibility for the costs of the unit's operation and its dispatch in the market, with continued cost-of-service regulation of the units' owners by the Commission.

3. A sale or auction of the units to non-affiliated entities.

4. A transfer of the nuclear units to other affiliates of the utility.

5. A spin-off of a nuclear unit to an independent company which would be solely responsible for the unit's subsequent operation.

6. The combined operation of the nuclear units by an independent generating company with the owners of that company sharing responsibility for all the costs of the units and their dispatch in the market and the generating company being responsible for the subsequent operation of the units.

7. Retention of the units by their present owners who would look to market revenues to recover certain future operational costs of the facilities.

8. A transfer of the nuclear units to regulated affiliates of the utility.

9. The combined operation of the nuclear units by an operating company with the present owners of each unit (or regulated affiliates) retaining responsibility for the costs of that unit's operation and its dispatch in the market, with the owners of each unit looking to market revenues to recover certain future operational costs.

10. Shutdown of the units with decommissioning to follow.

At this time, no determination has been made as to which of these scenarios (or any other scenario) is best suited for any nuclear plant or combination of plants. It may be the case that different solutions are best for various plants. Nevertheless, these scenarios can be grouped into four categories that reflect the ways the plants may or may not be subject to market pricing.

The first category covers situations where continued cost-of-service regulation, or some variant, is retained. These include Scenarios 1 and 2. In these scenarios, the Opinion No. 98-7 presumption against such regulation presumably has been rebutted. If all prudent plant costs are recovered in regulated rates, there is no need to differentiate costs in this category's scenarios.

The second category involves a sale of a nuclear plant. Scenarios 3, 4, 5, and 6 fall into this category. If a nuclear plant is sold to a third party, there is no need to categorize any of the plant's future costs because the only source of recovery available to the owner is the market.

The third category considers a plant shutdown. Scenario 10 is the only scenario in this category. If a plant shuts down, none of its costs are subject to the marketplace because no costs are attributable to ongoing operations. Any concerns about the risk and responsibility for future operation are moot and cost categorizations need not be considered.

The fourth category involves continued ownership of a nuclear plant by the utility or a regulated affiliate with the plant subjected to market pricing. Scenarios 7, 8, and 9 fall in this category. The underlying premise here is that a plant will not operate, if it is not economically justified by market conditions over an appropriate period, or otherwise justified by public policy considerations. Under this approach, appropriately defined costs would be used by the utility to make run/retire decisions and to provide a benchmark for determining the portion of market revenues, if any, that exceeds those costs put to market. Because the plants continue to be owned by regulated companies, it is necessary to administratively identify various categories of costs. The following sections of this report, entitled "An Administrative Approach for Pricing Nuclear Power" and "Classifying Nuclear Power Costs," discuss the concepts of how such an administrative approach could function.

AN ADMINISTRATIVE APPROACH FOR SUBJECTING NUCLEAR GENERATION TO MARKET PRICES

Three key issues are at the core of any inquiry on how to use an administrative approach to subject nuclear power to market pricing. The most basic issue is how will administratively regulated plants obtain revenues in the competitive generation market. The second issue, flowing from this initial question, concerns the identification of the nuclear costs that would be exposed to market pricing and those costs that would not. Once the revenues and costs are identified and defined, a formal approach/framework is needed to subject appropriate costs to market prices. This needs to be done in a manner that encourages and allows nuclear plant owners to make rational economic decisions regarding the future operation of the plants and accommodates such provisions as the Commission may make for public policy concerns.

Nuclear Revenues Under Market Pricing

Nuclear power plants' operating revenues can come from sales made either inside or outside New York through bilateral contracts or by selling into one or more locational based marginal price (LBMP) markets, such as the one being established by the ISO. Operating revenues and net consumer benefits are likely to be maximized when the plant owners have the opportunity to choose between bilateral contracts and spot market sales. With such freedom, the plant's alternatives may be maximized, potentially enabling markets to operate more efficiently.

There will be both a day-ahead energy market and a real-time energy market. The ISO is designed to encourage suppliers to bid into the energy markets generally at their variable operating costs (i.e., the costs which vary directly with the quantities of generation). The ISO is required to commit units so as to reliably serve the New York load at the lowest total bid cost, selecting first those plants with the lowest bid costs and adding the next least expensive units until there is enough generation to serve total load. The market-clearing price for energy and ancillary services will be the highest accepted bid in the state, subject to LBMP. In the event that a lower cost generator is taken off line or shut down, the next least expensive generator(s) submitting a bid will be committed to serve the load thereby resulting in increased prices.

As load varies during the day, so will the amount of generation needed. During hours of peak usage, expensive "peaking units" may be needed, leading to higher energy prices. During off-peak hours, the higher energy bids will not be needed and energy prices will tend to decline. At times, constraints within the transmission system will require the operation of higher-cost generators in some regions because cheaper generation from outside regions cannot reach the local load. This will produce different market prices on each side of the transmission constraint.

For nuclear units, most production costs in the short run are fixed rather than variable. Reducing the output of the nuclear plant for a few hours is not likely to generate savings and may even increase costs. As a result, nuclear units are expected to bid at very low costs (e.g., zero) to assure that they operate continuously as "baseload" units. During each hour, they will be paid the same LBMP as all other suppliers operating that hour in the respective day-ahead or real-time energy market. In other words, nuclear generation will generally be a market price taker for any sales in the wholesale market.

In addition to selling energy into the ISO market, suppliers, including nuclear plants, have the option of signing bilateral contracts with energy service companies (ESCOs) and end-use customers. These customers could be located either in New York or elsewhere. Such contracts can protect both buyers and sellers from the risks of unpredictable variations in the ISO's energy prices.[1] Contract prices would not be determined by the ISO; they would be negotiated between suppliers and customers or their representatives, such as power marketers or load-serving entities (LSE). Such contracts may be for energy, capacity or both. In some cases, contract prices may reflect the average ISO energy price expected by the market. In other cases, buyers may be willing to pay a premium for energy generated by certain suppliers (e.g., green power).

The ISO will require customers (or their LSE) to purchase "installed capacity" to ensure enough

[1] Parties to a bilateral transaction like participants in the spot market will be required to pay the cost of congestion between the generator and the load associated with the bilateral contract. The cost of the congestion can be firmed up by the parties buying a Transmission Congestion Contract.

generation to meet peak loads reliably. The initial requirement is a continuation of current New York Power Pool requirements that utilities own generation equal to the state's expected peak load plus a 22% reserve margin (to handle generator outages, extreme weather, etc.). The installed capacity market will be an additional source of revenue for generators.

While there will also be a market for ancillary services, nuclear plants are not expected to receive significant revenues from this market. The plants' provision of ancillary services is minimal and consists primarily of the provision of voltage regulation support.

As with any market, it is difficult to make accurate price forecasts for electricity.[1] However, there are some general guidelines. First, if too many plants were to shut down, there would not be sufficient generation to meet the installed capacity requirement and to serve peak load. Second, market revenues must be high enough to satisfy the plant owner's required revenues and profit margins over time, thereby placing a floor on long-term average market prices. Fuel prices will be the most significant driving force on the floor price. Finally, market prices, either now or in the future, may induce the installation of new generation. In theory, as new entrants compete for sales, they will limit price increases or drive down prices. Factors such as fluctuations in fuel cost, transmission and distribution (T&D) constraints and outages, levels of import and export capabilities to and from other energy markets, unplanned large generator outages, weather extremes, and costs of current and future emissions allowances may cause market prices to be volatile.

[1] Real markets are neither perfect nor are they entirely predictable. As an example, barriers to market entry can obstruct competitive markets and cause them to operate inefficiently.

"To Go" Costs/"Not To Go" Costs

An administrative approach for subjecting existing nuclear power to market pricing requires a determination of those nuclear production costs that will be covered by the revenues from the sale of the plant's output. Basic economic principles provide guidance for making this determination. Production facilities generally should be operated only when the revenues from the sale of the goods produced exceed the costs incurred to produce the goods over a suitable period of time. As used here, the costs incurred to produce the goods refer only to the incremental amounts spent, which can generally be thought of as variable costs. Fixed costs, which have already been spent or must be spent even if production ceases, do not meet this definition. All decisions about the production levels should, therefore, be based on whether revenues obtained from the sale of the product exceed the incremental (or marginal) cost of production over time.

Different terms have been used to apply this concept of variable and fixed costs to electric utility generation. For purposes of this report, variable costs (costs incurred to produce power which can be avoided if the plant is permanently shutdown) are referred to as "to go" costs. Fixed costs (costs already incurred or costs which are not avoided if the plant is permanently shutdown) are referred to as "not to go" costs. An administratively determined approach for market pricing of nuclear power requires workable definitions and categories of "to go" and "not to go" costs.

The Commission wants the collaborative to examine the proper definition of "to go" costs, their relationship to running costs, and the degree, if any, to which costs might be allowed even if they exceed the wholesale price of electricity.[1] This issue will need to be examined to allow the collaborative to make progress beyond the conceptual phase of the administrative approach to subjecting nuclear plants to market pricing. Additionally, the Commission has acknowledged, and some parties agree that some aspects of this inquiry may not be ripe for examination until the ISO is in place and the new power markets have begun to develop.[2] This discussion is not applicable to each and every alternative available to an investor-owned utility.

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[1] Opinion No. 98-7 at 39.

[2] Opinion No. 98-7 at 10.

Generating Plant Characteristics

Ultimately, the "to go" costs for all electric generators are based on the costs that can be avoided by a plant shutdown. Unlike nuclear power plants, the costs of many other generation resources can be significantly reduced by a change in operation. Most fossil-fired plants can be cycled from full power to shut down, and vice versa, over a period ranging from hours to a few days. Many costs, the most notable of which is fuel, are avoided when these plants do not operate or operate at reduced levels. Many fossil plants can be placed on "cold standby" status and remain out of service for months or even years. Placing a fossil unit on "cold standby" allows the owner to save not only fuel and variable operational and maintenance (O&M) costs but also to significantly reduce costs for items that do not vary directly with output, such as labor expenses. A fossil unit can be returned from "cold standby" status by re-staffing the plant and by performing any maintenance or overhauls that are necessary to make the plant operational.

Nuclear plants do not offer similar intermediate operational options for purposes of avoiding costs. Due to their design and complexity, nuclear plants cannot economically start and stop frequently, or ramp up and down quickly, to follow load. While their fuel costs are low in comparison to fossil fuels, once fuel has been purchased and fabricated for a fuel cycle (approximately 18 to 24 months) these costs become fixed and are unavoidable. Labor costs for nuclear facilities are significantly higher than for fossil-fired plants due to the need for hundreds more highly trained and qualified employees who safely operate these plants. For these reasons, it is not economical or operationally feasible to cycle nuclear plants. Any attempt at short-term nuclear plant cyclic operation or shutdown(s) would avoid few, if any, costs and may increase them.

Nuclear plant "Other O&M" costs may not be avoided by changes in operation. The plants must be kept in a condition consistent with Nuclear Regulatory Commission (NRC) regulations and their operating licenses. For example, staffing, maintenance, security and radiation protection functions continue even if a plant is taken out of service. Moreover, regardless of its operational status, a plant would continue to be a temporary storage site for spent nuclear fuel. Thus, special considerations must be taken into account when comparing the characteristics of nuclear plants to fossil-fired plants and determining which costs are related to continuing operations (i.e., "to go" costs).

In June 1998, Con Edison prepared an analysis pursuant to requirements in its rate/restructuring settlement of the "to go" and "not to go" costs of various types of generating plants (attached as Appendix 6).[1] As shown there, and in this report, most of the costs of a nuclear plant can be avoided only with a permanent shutdown. Thus, the appropriate inquiry, when considering nuclear production "to go" and "not to go" costs, is not whether they could be avoided if the plant operates at reduced levels or is shut down for a short time period, but rather, whether the costs could be avoided if the plant was permanently closed. Therefore, this report is premised on a definition of "to go" costs being those costs which would be avoided with a permanent plant shutdown.

CLASSIFYING NUCLEAR POWER COSTS

The second step in the analysis of how to subject nuclear power to market pricing is to develop a complete list of nuclear generating costs and to classify each cost component as a "to go" cost, a "not to go" cost, or some combination of the two.

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[1] While Appendix 6 presents an approach for determining "to go" costs, its value for purposes of this report is its focus on "to go" cost differences for types of generation facilities.

Nuclear costs can be grouped into six categories:[1]

1. Existing Plant Investments
2. Future Plant Investments
3. Expenses Related to Nuclear Fuel
4. Decommissioning Costs
5. Property Taxes
6. Other Operating and Maintenance Expenses

These six categories capture the expenses a company incurs when it generates electricity at a nuclear production facility. The utility companies have provided illustrative examples of nuclear plant costs based on the historical averages experienced at the investor-owned New York plants.[2] Each of these categories is addressed below in greater detail. Two principles were used to classify each cost component: (1) "to go" costs are the costs that would be avoided if a plant were permanently shut down; and (2) "not to go" costs are not necessarily the same thing as and should not necessarily be considered equivalent to stranded costs.

1. Existing Plant Investments

Existing plant investments can be divided into six subcategories:

A. Plant Net Book Value
B. Capital Additions
C. Construction Work in Progress (CWIP)
D. Materials and Supplies
E. Deferred Costs Related to Nuclear Activities
F. Return, Interest and Federal Income Taxes

[1] The parties will consider a range of externalities (external costs and benefits) that are not addressed in the market price of electricity. Such externalities may include impacts on economic development, system reliability, real property taxes, nuclear safety, public health, and the environment.

[2] See Appendix 7.

A. Plant Net Book Value

"Plant net book value" is the plant investments the investor-owned utility has made less cumulative depreciation. These costs are "not to go" costs because they are related to investments that have already been made and, as such, cannot be avoided by closing the plant.

B. Capital Additions

This item refers to plant investments made during the utility company's current rate/restructuring settlement period (settlement period). Capital additions made during the applicable settlement periods are considered "not to go" costs. It is anticipated that each company's capital additions will be scrutinized on a case-by-case in the next round of rate proceedings. All parties have the right to argue the prudence or economic justification of any capital addition. Opinion No. 98-7 stated that limiting recovery of settlement period investments to those passing a market test deserves further study. This would include an examination of its underlying premise that a market test might differ from the traditional prudence test and an assessment of whether imposition of any market test would be consistent with the approved settlements.[1] The Collaborative has briefly discussed this issue; however, a consensus has not yet been reached.

C. CWIP

This item refers to investments in incomplete construction projects at nuclear stations on the date the settlement period ends. Like capital additions, these expenditures are "not to go" costs because they will be incurred before the expiration of the current utility rate/restructuring plans. However, these investments are subject to the same prudence review as capital additions and the recovery of these investments may be disallowed if found to be imprudent. All additions to CWIP made after the settlement period will be considered "to go" costs and, as such, would be subject to market pricing, unless established as necessary to support decommissioning or otherwise provided for in individual proceedings.

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[1] Opinion No. 98-7 at 33.

D. Materials and Supplies

Materials and supplies are purchased and held by the utility company to meet its day-to-day operating and maintenance responsibilities, and the possibility of unexpected events at a nuclear plant that could require immediate repair. While these expenses are "not to go" costs because they will be incurred prior to the expiration of each of the settlement periods, they are subject to the same prudence review and disallowance standards as apply to capital additions and CWIP.

Materials and supplies prudently purchased to facilitate shutdown and decommissioning are "not to go" costs, since decommissioning is not avoided if a nuclear plant closes. All other purchases of materials and supplies made after the end of the settlement period will be considered "to go" costs and would be subject to market pricing.

E. Deferred Costs Related to Nuclear Activities

This category refers to past nuclear expenses incurred by a utility company that are recovered in rates over an extended time period. One example of such expenses is the studies required by the NRC to maintain a plant's operating status. Such studies provide long-term benefits, since they help to keep the plant in an operational mode. While competitive entities would have to recognize these items as expenses in the year incurred, regulatory accounting permits utilities to record them as assets and to "depreciate" them over the period they provide benefits. The ratemaking process mirrors this accounting procedure in that it permits recovery of deferred items in rates over the period the asset is being depreciated.[1] Thus, deferred costs are similar to plant investments. To the extent these nuclear expenses have been incurred and are being collected in rates, the costs are "not to go" costs because they cannot be avoided with a plant shutdown. Any utility deferral requests for expenses incurred during the settlement period will be subject to the same standards that apply to capital additions, CWIP and materials and supplies.

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[1] In the future, it is not expected that utility companies will be able to defer costs associated with their business segments that are not under cost of service regulation.

F. Return, Interest, and Federal Income Taxes

These items refer to the carrying costs of obligations incurred to finance plant investments. They are "not to go" costs. The regulatory treatment of the financing costs associated with capital additions, CWIP, materials and supplies and deferred costs incurred during the settlement period should be consistent with the treatment of the underlying expenses in each of these categories.

2. Future Plant Investments (After the Settlement Period)

The second category of nuclear expenses consists of two components:

- Capital Additions Required to Operate a Plant
- Capital Additions Required to Shutdown/Decommission a Plant

Future investments consist of capital additions in nuclear plant, CWIP, and materials and supplies. They also include the interest, return, and federal income taxes related to the capital additions. To the extent future investments at nuclear power plants are made to ensure that the plants continue to operate safely and efficiently, consistent with all regulatory requirements, they are "to go" costs because they are incurred in the future and they can be avoided if the plant permanently shuts down. Appendix 8 provides a few examples of such investments.

However, some investments at nuclear plants are made to facilitate shutdown and decommissioning. Most of these investments occur when the plant approaches the end of its useful life. Since decommissioning is not avoided when a nuclear plant permanently closes, future investments made to facilitate shutdown and decommissioning are "not to go" costs. Appendix 8 also provides several examples of investments that fit this category.

The examples in Appendix 8 are not all-inclusive. It is likely that some investments will be required both to operate and decommission a plant and, as such, they are not entirely "to go" or "not to go" costs. Due to differing facts and circumstances at each of the four nuclear plants, additional work will be needed on a case-by-case basis to refine the types of investments and, in cases where overlaps exist, develop ways to allocate them to appropriate categories.

3. Expenses Related to Nuclear Fuel

This category consists of four components:

A. Nuclear Fuel Expense

B. Fees Related to Uranium Enrichment Prior to 1992

C. Spent Nuclear Fuel Disposal Fee

D. Nuclear Fuel Contract Costs

A. Nuclear Fuel Expense

Uranium is the fuel of nuclear power plants. It is specially processed to meet each plant's individual needs. The basic unit of nuclear fuel is a nuclear fuel assembly, which consists of an array of fuel rods arranged in a square lattice. Groups of fuel assemblies, known as regions or batches, are inserted into the reactor. All the fuel assemblies in the reactor are collectively known as the core. When a reactor is refueled, not all of the fuel assemblies in the core are replaced. Depending upon the reactor's power output and the length of time it is to operate until the next refueling, approximately 25% to 60% of the core may be replaced.

Utility companies may begin buying uranium (and in some cases conversion services) a number of years before the fuel assemblies are inserted into the reactor. In addition, utility companies must finalize fuel fabrication services about 18 months before the fuel assemblies are inserted into the reactor. The process to fabricate nuclear fuel assemblies may take up to six months. Also, the companies must order uranium-enrichment services about three months before the fuel assemblies are fabricated. The process to enrich uranium takes about three months. These time periods are typical, but for various reasons, utility companies may procure services related to nuclear fuel well in advance of these times.

Nuclear fuel can be thought of as a capital addition that is required to operate the plant. Most future nuclear fuel expenses can be avoided with a permanent plant shutdown. Therefore, prior to making a commitment to purchase new nuclear fuel, the fuel is generally classified as a "to go" cost. However, a portion of nuclear fuel expense is a "not to go" cost. When a nuclear plant is permanently shutdown, the reactor will have unspent nuclear fuel (attributable to the fact that not all of the fuel assemblies in the core are replaced at each refueling) and unamortized costs that cannot be avoided. Since the unspent fuel and any purchased fuel not used (net of any resale proceeds) will no longer generate power, they are "not to go" costs.

B. Fees Related to Uranium Enrichment Prior to 1992

In 1992, federal legislation was enacted which imposed a decommissioning and decontamination (D&D) charge on all utilities that had used the government's uranium-enrichment services prior to that year. The amounts collected will be used to perform D&D activities at the three government facilities where uranium-enrichment activities are performed. D&D charges are to be collected through 2008. Inasmuch as the basis of the D&D charges are the historical (pre-1992) purchases of governmental-enrichment services, they are unrelated to future nuclear plant operations. These payments are not avoidable if the plant closes and thus, they represent "not to go" costs.

C. Spent Nuclear Fuel Disposal Fee

The federal government currently requires utility companies that operate nuclear plants to pay a 0.1 cent/kWh fee to cover the costs of removing and permanently disposing of spent nuclear fuel. This charge is avoided when a plant is permanently shutdown and ceases to produce energy. Thus, the spent nuclear fuel disposal fee is a "to go" cost.

It is recognized, however, that the federal government keeps track of the amounts contributed by each utility toward the disposal of spent nuclear fuel for each nuclear plant. It is possible that, in the future, the government could require a utility to contribute additional amounts for the disposal costs of fuel already consumed if the funds generated by the 0.1 cent/kWh fee were deemed insufficient to cover actual spent nuclear fuel disposal costs. Under such circumstances, any additional charges associated with spent nuclear fuel prior to the end of the settlement period would be considered a "not to go" cost.

D. Nuclear Fuel Contract Costs

Utility companies continue to enter into supply contracts for nuclear fuel components for a specified term. While such contracts do not require payments for nuclear fuel components that are not delivered, they may or may not specify fees if the contracts are terminated early for the purchaser's convenience. In general, the termination fees of nuclear fuel components procured under contracts that provide for such fees should be treated the same as the contract termination charges contained in contracts for other goods and services. However, termination fees for contracts entered into before the end of the settlement period are costs that are not avoidable with a permanent plant shutdown. While this is a characteristic of "not to go" costs, the Commission has the ability to consider the prudence of any termination fees in light of the other provisions of the contracts. Termination fees for contracts entered into after the end of the settlement period would generally be considered “to go” costs, unless it is demonstrated that ratepayers benefited from a sharing of lower fuel costs from the contract.

4. Decommissioning Costs

Decommissioning is the process employed to remove and dispose of all radioactive materials, to dismantle existing structures, and restore the site to an acceptable condition. Decommissioning nuclear power plants is inevitable. Owners of nuclear plants must, at some point, incur expenses to decommission them. Decommissioning costs, therefore, cannot be avoided as the result of a permanent plant shutdown, although the need to begin incurring major costs would begin with a permanent shutdown decision. Thus, decommissioning costs are "not to go" costs because the obligation to decommission the facilities has already been incurred.

While the characterization of decommissioning costs as "not to go" is straightforward, the relationship of decommissioning costs to "to go" costs and the establishment of a proper economic framework for a plant owner to make run/retire decisions is more complex. As discussed below, a significant portion of nuclear plant operating and maintenance expenses are not avoided for a number of years after a decision is made to permanently retire a plant. Additional complicating factors that can significantly impact the cost of decommissioning include: (1) the amount of funds then available versus the amount needed for decommissioning, (2) disposal site availability and costs associated with low-level waste disposal, (3) the decommissioning method used (immediate dismantlement or long-term SAFSTOR), (4) the timing and manner for the Department of Energy (DOE) to fulfill its contractual obligations for disposal and management of spent fuel and, (5) the timing of the shutdown (end of licensed life, early unplanned, or early with some planning period prior to shutdown.)

The following is a simplified illustration of a potential schedule for an end-of-life immediate decommissioning of a Pressurized Water Reactor.[1]

ACTIVITY	START	END
Submit cost estimates to NRC	5 years prior to shutdown	At shutdown
Planning prior to shutdown	3 years prior to shutdown	At shutdown
Wet storage of spent fuel	At shutdown	5 years after shutdown
Dismantlement and removal of contaminated structures	At shutdown	6 years after shutdown
Removal of remaining structures supporting spent fuel pool	5 years after shutdown	8 years after shutdown
Long-term dry storage of spent fuel	5 years after shutdown	Unknown - estimated 15-30 years after shutdown
Dismantlement and disposal of dry storage facility	After DOE removes all fuel	1 year after starting dismantlement
Unrestricted release of the property	After dry storage facility is disposed of	1 year after start

1 Although the timing of the activities may vary, a boiling water reactor decommissioning schedule would be similar.

This schedule shows that the vast majority of decommissioning funds will be spent within eight years after shutdown. The decommissioning fund balances for the New York investor-owned nuclear plants range from approximately 13% to 50% of the amount needed for an end-of-life immediate decommissioning campaign. Earnings on these funds have accumulated at a higher rate than initially projected, which will reduce the amounts needed to be funded in the future. An early shutdown would constitute a multi-year loss of tax-favorable contributions and earnings on the fund and, with immediate dismantlement, is likely to require borrowing to finance decommissioning costs.

While decommissioning costs are "not to go" costs, the decommissioning process, is complex and highly uncertain. Three principal cost components of decommissioning are indeterminate. One major decommissioning cost is the handling of spent nuclear fuel. Although the DOE has been statutorily and contractually obligated since 1982 to begin removal of spent nuclear fuel from reactor sites for permanent disposal by January 1998, it has not done so and is currently in default of its obligations. The date of commencement and rate of removal of spent fuel from nuclear plants cannot currently be projected with any accuracy. Spent nuclear fuel is likely to remain on site for many years. The added cost of on-site storage of spent fuel, until DOE takes title to and/or removes it, will increase incrementally with continued plant operation after the settlement period. This increment will be a "to go" cost. Additionally, whether or not decommissioning is postponed, if utility claims against the DOE for its failure to accept spent fuel result in appropriate damage awards and/or the DOE otherwise compensates the utilities, total decommissioning costs would be reduced accordingly.

A second major cost component of decommissioning is the disposal of low-level radioactive waste. The amount of radioactivity embedded in physical structures and the quantity of low-level radioactive waste to be disposed after decommissioning at a nuclear plant generally becomes fixed after a few years of operation and does not vary appreciably with a decision to continue operation. The Federal Low-Level Radioactive Waste Policy Amendments Act of 1985 provided that each state shall be responsible, either by itself or in cooperation with other states, for the disposal of low-level radioactive waste generated within its borders and offered the states incentives to develop new capacity. Thus far, while additional commercial disposal facilities for selected low-level waste types have been opened, no new disposal capacity has been made available due to this federal law. Thus, the cost and availability of low-level radioactive waste disposal options is highly uncertain. However, with the availability of commercial disposal sites, total estimated disposal costs have been reduced. Decommissioning delay leaves open the possibility that new state, compact or additional commercial facilities might become available.

A third cost component of decommissioning is the extent to which decontamination activities must be pursued to enable a surrender of the NRC license and release of the site for other uses. There is currently no consensus between NRC and the federal Environmental Protection Agency on appropriate residual radiation levels. Decommissioning delay leaves open the possibility that NRC regulations may change and result in lower decommissioning costs.

Beyond these principal cost components, there is also considerable uncertainty as to when, following permanent shutdown of a nuclear plant, actual decommissioning activities would commence. The owner of a permanently shutdown nuclear plant can choose to immediately decommission the plant or to defer decommissioning for up to 60 years by putting the plant in a SAFSTOR mode. A decision to postpone decommissioning may be less expensive to the public because it provides more time for the utility company to gain experience by observing others, more time for technological improvements in the process, more time to allow for new entrants into the decommissioning contractor market, more time for low-level radioactive materials to decay, and more time for decommissioning funds to accrue. Delayed decommissioning may also provide for a smoother transition process for labor and local communities. A decision to postpone decommissioning also takes advantage of the time value of money. Any decision to decommission at a later date is likely to be cost effective, as long as the annual escalation in decommissioning expense is expected to be less than the time value of money to the utility company and its ratepayers.

A decision to postpone decommissioning, however, is not without risks. To date the escalation rate on disposal costs associated with low-level radioactive waste has far exceeded inflation.

Delays in decommissioning could also lead to the situation where some of the current low-level sites are no longer a disposal option for New York. Decommissioning delay also leaves open the possibility that the NRC may at some future date adopt different regulatory requirements which could increase the cost for a utility to fulfill its decommissioning responsibilities.

All of these considerations converge to produce a situation in which a utility company's present value cost of decommissioning varies markedly, depending on when decommissioning occurs and the process(es) employed to meet this responsibility. With the exception of certain spent fuel storage costs,[1] decommissioning is a "not to go" cost, in the sense that it cannot be avoided with a permanent plant shutdown. It does represent a cost that changes, depending on how the process is managed.

5. Property Taxes

Property taxes, like other operating and maintenance expenses, are a component of nuclear production costs. However, property taxes, unlike other operating and maintenance expenses, do not change significantly, if at all, based upon production. This is due significantly to the currently approved methodology for valuation of generation facilities owned by an IOU. Hence, property taxes are a “not to go” cost.

However, assuming the Commission presumption is not rebutted, it is expected that some portion of these taxes should be treated as a “to go” cost that must be recovered from the marketplace. Because of the additional risks and community obligations inherent with the presence of nuclear facilities (e.g., possible nuclear accident, emergency preparedness planning), local host communities have expectations that future changes in property tax levels take place on a phased basis. To recognize these expectations and avoid excessive hardship, a majority of the parties believes a portion of property taxes needs to be included as a "not to go" cost for a phase-down period, to be determined on a case-by-case basis. The length of any such phase-down period should be adequate to provide the communities the opportunity to adjust to any erosion of tax

[1] To the extent continued operation of a plant increases spent fuel, the incremental cost of storing the additional spent fuel is a “to go” cost.

revenues. Moreover, the communities seek mitigative measures to ease any burdens caused by this tax erosion. In addition, the portion of property taxes that would be incurred following permanent plant shutdown are clearly "not to go" costs.

All relevant issues and concerns related to property taxes, as well as proposals for dealing with the potential tax base consequences associated with subjecting the nuclear plants to competition, will be addressed in Segment 3 of this proceeding.

6. Other (Non-Fuel) Operating and Maintenance Expenses (Other O&M)

The following definition lists the cost elements that make up "Other O&M." This section also considers how "Other O&M" expenses are affected by the status of the plant (i.e., during normal plant operation, pre-shutdown planning, and decommissioning).

A. Cost Element Definition

"Other O&M" costs include, but are not limited to, the following components:

- Labor - salaries, wages, and expenses related to company employees.
- Contract Work - work performed under contract by other companies or individuals; includes legal, accounting, data processing, training, plant maintenance, fabrication, inspections, and engineering.
- Materials and Supplies - direct purchases and/or issues from inventory.
- Transportation - cost of operating transportation and work equipment.
- Dues, fees, governmental assessments, rents, leases, and maintenance agreements.
- Electric use at site facilities and station service.
- Insurance - liability and property.
- Sales and use taxes.

"Other O&M" typically includes the cost of services provided by the following nuclear workgroups: operations, radwaste, fire protection, maintenance, chemistry, radiation protection, technical support, security, engineering, finance, licensing, information management, human resource development, procurement, and management.

B. Plant Status

"Other O&M" costs are incurred during the three phases of a nuclear plant's status: (1) normal plant operation, (2) pre-shutdown planning, and (3) decommissioning. During normal plant operations, "Other O&M" costs are incurred at generally predictable levels without major cost fluctuations. The length and scope of outages (planned and unplanned) have the biggest impact on the level of "Other O&M" costs incurred during this period.

Prior to a planned permanent shutdown, there is a transition period when a plant continues to operate but planning is underway for final shutdown and decommissioning. During this phase, technical planning can be started, certain NRC licensing documents can be prepared and approved, and staff reductions can be planned. The amount of pre-shutdown work that can be accomplished depends on whether the plant shutdown is planned, including the length of the available planning period, or if the shutdown is unplanned. It is important to note that "Other O&M" costs incurred for pre-shutdown work are incremental to normal plant operation.

Once a plant is shutdown and decommissioning commences, "Other O&M" costs will continue to be incurred as part of the decommissioning responsibility but at lower levels. The treatment of these decommissioning costs is addressed above.

Once a decision is made to close a facility, initial decommissioning planning is completed, and the necessary NRC approvals are obtained, activity and staff levels at the plant may be ramped down over a period of about fifteen months in the first phase of the decommissioning process. Costs (primarily labor) begin to be avoided during this period. The NRC requires that a number of systems remain functional, as long as the spent nuclear fuel pool is in use. The last core of fuel must remain underwater for five years after use. After five years, it may be removed to dry cask storage. Thereafter, the remainder of the plant decommissioning can be completed. The onsite storage of fuel after completion of decommissioning could be lengthy. Thus, the ramp down of

"Other O&M" costs will tend to plateau at the expense level to maintain the fuel in dry storage, which is relatively small. For example, while the end of Nine Mile Point 2's operating life is 2026, the last spent nuclear fuel is not expected to be removed from the site until 2044. Similar results are expected for "Other O&M" under the SAFSTOR approach.

IMPORTANT "TO GO" COST CONSIDERATIONS

Market Requirements

An appropriately designed and implemented “to go”/not to go” cost methodology will serve as an economic framework to determine whether nuclear generation of electricity can economically compete with non-nuclear sources of generation. In a competitive generation market, nuclear plants, as any other generators, must know their "to go" costs to determine the economics of plant operation. Plant operation is economical when the revenues received from the market are greater than the "to go" costs. In the event that they are not, cessation of operations may be warranted. Thus, a nuclear plant, like any other generator, will operate if its owner expects the market, in conjunction with anticipated future plant performance, to allow recovery of, at a minimum, the plant's "to go" costs over a relevant time period.

Because the economics of whether a plant operates depends on the relationship between market revenues and "to go" costs, it becomes imperative that “to go”/not to go” costs are appropriately determined. Costs that are improperly categorized as "to go" costs will diminish the economic efficiency of the market.

Over the course of one or more fuel cycles, operation of a nuclear plant will be regarded as being economical, if the plant's market revenues from selling various generation products (energy, capacity, and ancillary services) into the market are greater than its "to go" costs. As such, decisions regarding future operation of the plants will be dependent upon the nuclear plant owner's "to go" costs, as defined by this proceeding and the owner's expectations of future market prices and plant performance.

Earlier in this report, ten possible ownership scenarios were identified and discussed. Of these, only three require the categorization of "to go" and "not to go" costs instances where a nuclear plant continues to be owned by one or more regulated entities or affiliates and the costs, which can be avoided by shutting down the plant, are to be recovered in prices set by the market.

Assuming a utility-owned nuclear plant is subject to market prices, the division of costs between "to go" and "not to go" may influence that utility's determination whether to continue operating the plant. If the division of costs were improper, it could also interfere with the functioning of a competitive generation market.

If "not to go" costs are improperly classified as "to go" costs, thereby raising total "to-go" costs above market prices while actual avoidable costs are below market prices, the nuclear plants will be forced to shut down. A shut down of these plants, in turn, would have adverse financial impacts on customers, plant and local workers, and the host communities. Customers would continue to bear costs determined by the Commission to be recoverable and prudent, which are related to unrecovered investments, decommissioning, disposition of spent fuel, and other costs not avoided by a plant shutdown, including any improperly classified "to go" costs. Customers would forego any possibility of benefiting from the below-market "to go" costs that would have been provided by these plants, and they would likely face higher market prices. Moreover, with a shutdown prior to the license termination date, customers could face additional shutdown and decommissioning costs.[1] Customers could also experience a decrease in fuel diversity, system reliability, and air-quality benefits provided by the nuclear power plants. The communities that host the nuclear plants would lose tax revenues and plant employees would lose their jobs. Closing these plants would result in significant reductions in the purchase of goods and services locally and regionally which, in turn, would cause further unemployment.

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1 An unplanned shutdown results in the need to continue operating and maintaining the plant while plans for decommissioning are made.

On the other hand, if the costs that would be avoided by a plant shut down are classified as "not to go" costs, thereby resulting in nuclear plants displacing more cost-efficient generation in the market, customers would face higher costs associated with nuclear generation and the benefits of competition would be reduced. If nuclear plants were permitted to continue to operate under these circumstances, their continued operation would increase pressure on other existing generators in the State, which may cause the other generators to permanently or temporarily shut down their facilities. This, in turn, could cause the host communities to lose all tax revenues and employment associated with the plants. Continued operation of the nuclear facilities under such circumstances could also cause developers to forego the development of new generation in New York. If this occurs, additional construction and operation jobs and tax revenues for the communities that would have hosted the new generators would be lost. These could be the same communities where nuclear generators shut down. In addition, the improper classification of “to go” costs as “not to go” costs could deter the development of cleaner renewable technologies; such as, wind, solar, and fuel cells, and programs for energy conservation and efficiency. For all these reasons and others, it is imperative to categorize "not to go" costs and "to go" costs properly.

Strandable Costs As Distinguished From "Not To Go" Costs

As discussed above, all previously incurred costs that cannot be avoided in the future, if a nuclear plant is shut down, are considered "not to go" costs. Additionally, future costs prudently incurred after plant retirement will be “not to go” costs. In contrast, "strandable costs", as related to nuclear investments, are the portion of a utility company's prudently incurred costs for a nuclear generation facility that may not be recovered from its electric energy and capacity sales made at market prices. In other words, any portion of "not to go" costs that the Commission determines will be recovered through net market revenues or the Commission determines were imprudently incurred are not stranded costs. The collaborative parties intend to engage in a discussion of the differences between "not to go" and stranded costs, but they have not yet done so. General frameworks for strandable cost mitigation and recovery options for the various ownership/operating scenarios will be discussed in Segment 2. Recovery of these costs will be subject to Commission review in individual company proceedings. Consequently, the quantification and regulatory treatment for recoverable stranded costs are not addressed in this report.

"TO GO"/"NOT TO GO" COSTS AND MARKET PROCEEDS

In the three scenarios that the utility companies could continue to operate nuclear facilities, the costs associated with each such nuclear plant must be separated into "to go" and "not to go" costs, based on the general framework outlined above. The "to go" costs would be subject to the market place, and their recovery would depend solely on revenues received from the market. “Not to go” costs determined by the Commission to be recoverable will be collected through a wires charge or by some other means.

Depending on how "to go" costs are categorized, market revenues may exceed a nuclear plant's "to go” costs and provide an opportunity for net operating revenues to be realized. These net operating revenues can provide a potential source of funds to mitigate “not to go” and/or strandable costs. Therefore, they should be allocated in a manner that represents a fair balancing of risks and rewards between the utility and its customers. As with the specific allocation of nuclear costs between "to go" and "not to go," an appropriate mechanism for the allocation and sharing of market revenues is anticipated to be determined by the Commission on a case-by-case basis for each utility company.

REBUTTABLE PRESUMPTION

The parties generally agree that the Commission's rebuttable presumption to price nuclear power on a market basis ultimately depends upon all factors examined in this proceeding (i.e., economic concerns, restructuring options, and policy issues). Indeed, some parties have already expressed concerns about the rebuttable presumption, arguing that it could adversely impact safety, fuel diversity, total plant emissions, local economies, employment and the potential for early plant shutdown, if “to go” costs are not properly defined. Other parties support the rebuttable presumption believing that subjecting nuclear generation to market forces is necessary to avoid the potential subsidization of nuclear plants, to create a level playing field, and to afford customers rate relief.

Accordingly, this report should be viewed with the understanding that while the parties have identified the concepts of how such an administrative approach might function, there is no consensus at this time that nuclear power should be subject to market pricing. Some parties will seek to rebut the presumption at the appropriate time for them to do so.

CONCLUSION

The parties to this collaborative process have made considerable progress in defining and categorizing “to go” and “not to go” costs for their application in Scenarios 7, 8, and 9. While considerable progress has been made in Segment 1, as noted above, there are a number of issues which still require further consideration in this proceeding, including development of a framework for subjecting nuclear power to market prices. In addition, the issues considered here may require further consideration following Segments 2 and 3.