

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

OPINION NO. 01-5

CASE 00-E-0005 - Proceeding on Motion of the Commission to
Examine Costs, Benefits and Rates Regarding
Distributed Generation.

OPINION AND ORDER APPROVING PILOT
PROGRAM FOR USE OF DISTRIBUTED
GENERATION IN THE UTILITY
DISTRIBUTION SYSTEM PLANNING PROCESS

Issued and Effective: October 26, 2001

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BY THE COMMISSION:

INTRODUCTION

Shortly after adopting standardized interconnection requirements (SIRs) for small distributed generation (DG) units,¹ the Commission instituted this proceeding to investigate "costs, benefits, and rates regarding distributed generation."² At the same time, the Commission initiated a separate investigation regarding standby rates,³ and determined that the two proceedings

¹ Case 94-E-0952, Competitive Opportunities for Electric Service, Opinion No. 99-13 (issued December 31, 1999).

² Cases 00-E-0005 and 99-E-1470, Order Instituting Proceedings (issued January 10, 2000), p. 2.

³ Case 99-E-1470, Insuring Into the Reasonableness of the Rates, Terms and Conditions for the Provision of Electric Standby Service.

should be coordinated. Meetings in the coordinated proceedings began on April 5, 2000, following the submission of written statements of interests by parties. A collaborative process commenced, under the direction of Administrative Law Judges William Bouteiller and J. Michael Harrison. The proceedings followed two tracks thereafter, one for consideration of distributed generation (DG) issues and the other for consideration of standby rates issues. This opinion and order addresses DG issues, and standby rates are addressed in an opinion and order contemporaneously issued in Case 99-E-1470.

Following a series of informational and educational presentations, a working group discussion on DG issues was held on June 29, 2000. The utilities and non-utilities agreed to file position statements addressing DG issues, and the utilities filed a joint statement on August 18, 2000, while non-utility parties filed a joint collaborative statement on August 30, 2000.

After analyzing these reports, Staff circulated a list of areas of agreement and disagreement between utilities and non-utilities, and that list was addressed at an October 4, 2000 meeting. A committee (the DG Committee) was formed and charged with the responsibility of attempting to reach agreement on DG issues where possible.

After several meetings and considerable collaborative effort, the DG Committee issued a report limited to addressing how DG could be integrated into the utility planning process. Although there was substantial agreement among the parties, there also remained some different points of view on a few significant issues. These areas of disagreement, as well as several DG issues beyond the matter of using DG in the utility planning process that were raised in the position papers, were further discussed at a Committee meeting held on January 22, 2001.

It became evident at the January 22 meeting that some non-utility parties were unsatisfied with the airing of other DG matters, suggesting that there were important issues beyond the scope of those issues gleaned from the earlier collaboration and position papers. They argued that the Commission should give greater consideration to measures for encouraging the development of DG.

Following certain limited amendments to the DG Committee's report, it was re-filed on January 24, 2001. Thereafter, the parties filed two sets of comments. Initial and reply comments on the DG Committee's report were filed, respectively, on February 28 and March 16, 2001. Those comments were limited expressly to discussing issues related to the report, six of which had emerged in the discussions. Initial comments were filed by the electric utility companies (the Utilities),⁴ Honeywell Power Systems, Inc. (Honeywell), The Pace Energy Project and the Natural Resources Defense Council (Pace/NRDC), Multiple Intervenors (MI), the National Energy Marketers Association (NEM), the New York State Consumer Protection Board (CPB), 1st Rochdale Cooperative Group, Ltd. and Coordinated Housing Services, Inc. (1st Rochdale), and Plug Power, Inc. (Plug Power). Replies were filed by MI and the Utilities.

Following a meeting held on January 29, 2001, a comment cycle was established to address issues remaining beyond the matters raised in the Report. Subsequently, comments were

⁴ Signatories to these comments included Central Hudson Electric and Gas Corporation (Central Hudson), New York State Electric and Gas Corporation (NYSEG), Niagara Mohawk Power Corporation (Niagara Mohawk), and Rochester Gas and Electric Corporation (RG&E). In a separate submission that dealt with an unrelated matter, Consolidated Edison Company of New York, Inc. (Con Edison) and Orange and Rockland Utilities, Inc. (O&R) expressed agreement with the Utilities' submission.

filed on March 21, 2001 by various non-utility parties (the Non-Utilities)⁵, and separate comments were filed by Harbec Plastics, Inc. and Northern Development, LLC (Harbec). On May 1, 2001, the six Utilities filed their response to the Non-Utility Parties, as did Local 1-2, Utility Workers Union of America, AFL-CIO and Local 97, International Brotherhood of Electrical Workers (the Unions).

STATE ENVIRONMENTAL QUALITY REVIEW ACT (SEQRA)

The basic purpose of the State Environmental Quality Review Act (SEQRA)⁶ and its related administrative regulations (6 NYCRR, Part 617) is to incorporate the consideration of environmental factors into the existing planning, review and decision-making processes of state, regional and local government agencies at the earliest possible time. To accomplish this goal, SEQRA requires that all agencies determine whether the actions they are requested to approve may have a significant impact on the environment, and, if it is determined that the action may have a significant adverse impact, prepare or request an applicant to prepare an environmental impact statement (EIS).

An agency must first determine whether the action is subject to SEQRA.⁷ The SEQRA regulations define three categories of actions. The three categories are "Type I," "Type II," and "unlisted" actions. "Type I" actions are those actions or

⁵ Joining in this position statement were 1st Rochdale, American Wind Energy Association, Azure Mountain Power Company, CPB, Distributed Power Coalition of America, IEC Engineering, P.C., Pace/NRDC, and Plug Power.

⁶ New York Environmental Conservation Law, Article 8 (McKinney 1997).

⁷ 6 NYCRR Part 617.6(a)(1)(i).

projects determined to carry with them a presumption that they are likely to have a significant adverse impact on the environment and may require the preparation of an environment impact statement.⁸ "Type II" actions are those actions or classes of actions which have been determined not to have a significant effect on the environment or are otherwise precluded from SEQRA review.⁹ Type II actions do not require an EIS or any other determination or procedure under the SEQRA regulations.¹⁰ "Unlisted" actions are all those actions or classes of actions that are not otherwise categorized as Type I or Type II.¹¹

The approval contemplated in this proceeding is not a Type I action, nor is it clearly a Type II action. Therefore the approval contemplated is properly classified as "unlisted" action requiring SEQRA review and the Commission, as lead agency, should conduct an environmental assessment and determine the significance of the actions proposed.

In making the environmental assessment pursuant to SEQRA, the lead agency is directed to compare the impacts which may be reasonably expected to result from the proposed action with the several criteria listed in 6 NYCRR 617.7(c). Each of these criteria is descriptive of a different category of consequence, change or effect which, if reasonably expected to result from the proposed action, is deemed an indication that the proposed action may have a significant effect on the environment. To facilitate that comparison, SEQRA requires completion of an Environmental Assessment Form or "EAF" describing and disclosing the likely impacts of proposed

⁸ 6 NYCRR Part 617.4(a)(1).

⁹ 6 NYCRR Part 617.5(a).

¹⁰ 6 NYCRR Part 617.6(a)(i).

¹¹ 6 NYCRR Part 617.2(ak).

actions.¹² Subsequent to the DG subcommittee's January 24, 2001 report, staff prepared an EAF.

The action contemplated in this proceeding is the Approval of a pilot program for use of distributed generation in utility distribution planning processes. The pilot program, designed to develop the policies and procedures for integrating DG alternatives into the utilities' distribution planning process, would commence with the 2001-2002 planning season and be in effect for three years.

Approval of this pilot program and utility implementation are not likely to result in significant environmental impacts. Under the program, as more fully described below, the Utilities will forecast distribution system needs and issue an RFP to elicit proposals for customer-owned distributed generation capacity which could satisfy those needs. Each utility will issue a limited number of RFPs (a maximum of two RFPs in each of years two and three of the pilot project, except Con Edison would issue four RFPs in year three).

The pilot program does not contemplate authorization to site or permit any of the distributed generation projects, but assumes any such projects will be subject to any applicable federal, state or local permitting or registration requirements. Approval of the pilot program does not prejudge the location, approvability, or comparability of the distributed generation projects to the distribution needs. It is not reasonable to know or anticipate locations, or the impacts of the distributed generation projects to be evaluated by the Utilities at this time. A narrative discussion of the assessment follows.

¹² 6 NYCRR Part 617.6(a)(3).

THE ENVIRONMENTAL ASSESSMENT

Approval of the pilot program will not result in any physical change to utility facilities nor will it result in construction of new facilities. The process contemplated in the pilot program will, however, require utilities to examine distributed generation alternatives to a very limited number of distribution needs to be identified in its distribution planning process. Neither the distribution needs, nor the possible alternatives, are known at this time. It is unreasonable to contemplate utility distribution needs or the alternatives until the pilot program is initiated.

Because no known physical activity or change will result from the approval of the pilot program, it is unreasonable to speculate on changes to the environment, impacts on community plans, growth or any other impacts.

The appropriate time to evaluate site specific impacts of actual projects will be during the permitting and approval of a project that had been selected by the utility as an alternative to the distribution upgrade. The pilot project is of limited duration. Information regarding environmental characteristics of bidders and of the utility upgrade projects will be collected during the pilot program and used to evaluate the program at the end of the three years. Before committing to further courses of action, the Commission will consider the evaluation of the pilot program.

As lead agency, we determine that the actions proposed in the petition will not have a significant impact on the environment, and we adopt a negative declaration pursuant to SEQRA. Because no adverse environmental impacts were found, no

public notice requesting comments is required or will be issued.¹³

INTEGRATION OF DG IN UTILITY PLANNING

The "Report of the Designated-Parties Committee Regarding the Integration of Distributed Generation in Utility Planning Processes" (the Report) was submitted on December 21, 2000, and revised on January 24, 2001.¹⁴ The Report expressly deals only with development of a process for consideration of DG as a resource by the utilities in their distribution system planning processes. The utilities would consider contracts for customer-owned DG when they would obviate the need for additional distribution system investment. Although the utilities would have discretion to contract for the provision of DG energy into the system, the energy typically would be for consumption by the DG customer only (i.e., "behind the fence"), and the distribution savings would be realized through avoided load growth or avoided distribution facilities replacement. The utilities could also install their own investment in DG as part of this process, when the load source would achieve distribution efficiencies.

The Report recommends a three-year pilot program designed to develop the policies and procedures for integrating the DG alternative into the utilities' distribution system planning process. The specific objectives would be:

- To determine whether distribution system needs can be satisfied on a least cost basis by creative and competitive means;

¹³ A Notice of Determination of Non-Significance for this unlisted action is attached as Appendix A. The completed EAF will be retained in our files.

¹⁴ The Report is attached hereto as Appendix B.

- To develop case-specific information on DG costs, benefits, and impacts across a range of distribution system conditions;
- To refine methods for evaluating customer-owned DG proposals against traditional system improvement projects;
- To determine whether a competitive process using requests for proposals (RFPs) is a viable and optimal means of eliciting a market response to the utility's distribution system needs.¹⁵

The utilities would annually screen their forecasted distribution system needs and, subject to specified limitations, issue RFPs to elicit proposals for customer-owned DG capacity. Following a technical feasibility and economic evaluation, the utility would enter contracts for DG options, when preferable to a distribution project. After three years, a determination would be made whether the RFP process should be continued or modified.

The Planning Process

The utilities' annual planning process cycle commences at the end of the peak load season. The process identifies system needs on the basis of various time horizons, ranging from prior to the beginning of the next peak load season out to ten years. The assessment process identifies capacity deficiencies, and also system needs unrelated to capacity (e.g., substandard voltage conditions). The process is generally completed within several months.

The report recommends that, although the utilities would retain the discretion to use other approaches to considering and administering DG, the planning process would be augmented with the issuance of RFPs for the installation of

¹⁵ Report, p. 3.

customer-owned DG capacity and the evaluation of responsive proposals. Each utility would designate a company representative to coordinate DG-related communications between the utility and customers or DG developers.

RFP Procedures

The Report contains a number of criteria for the consideration of DG proposals:

- RFPs would be issued only for system needs that require at least 18 months to satisfy from the date they are recognized.
- Satisfaction of the system need by DG must be technically feasible.
- DG would be considered as a means of satisfying load growth or the need for expansion or construction of a unit substation or area substation or, at the utility's discretion, for projects on a radial distribution feeder on which load may be temporarily islanded.
- DG would be considered only for projects above specified threshold costs.¹⁶

Each utility would be obligated to issue a maximum of 2 RFPs in each of years two and three of the project, except that Con Edison would issue 4 RFPs in year three. Up to one-half of these required projects may be satisfied with utility-owned DG.

The RFPs would be issued allowing sufficient time to permit (1) the submission and evaluation of bids simultaneous with the screening process for non-DG alternatives, and (2) customer installation commitments prior to the time the utility must engineer and construct an alternative project. The

¹⁶ The threshold for Con Edison and NIMO would be \$750,000, and the threshold for NYSEG would be \$500,000. For Central Hudson, RG&E, and O&R, the threshold would be \$250,000 if enough projects are not identified at the \$500,000 level.

RFP would include specified information sufficient to permit an informed response from bidders.¹⁷

In view of the resources required to prepare bids and to review them, the utilities will issue RFPs only for those needs that are most definite and least likely to change. Nonetheless, the utilities would reserve the right to cancel, postpone or modify RFPs after they are issued, without liability to participating bidders.

The Report includes bidder pre-qualification procedures. Potential DG providers must provide information, identified in a questionnaire (Appendix 4), designed to demonstrate technical competence and financial stability, as well as the ability to fulfill DG obligations. Only pre-qualified customers and developers would be permitted to respond to RFPs, and the utility may also require financial security or performance guarantees for selected projects.

In responding to an RFP, a bidder must provide enough information for the utility to evaluate the proposed DG installation, or multiple installations by the same bidder, and assess whether it would adequately satisfy the identified system need. The response should contain an amount of proposed compensation, which would not be divulged to competitive bidders.

The DG proposal must provide for the same level of system reliability and assured quality of service to the utility's customers as the alternative distribution system upgrade. The RFP proposal will include a proposed level of redundancy. The customer would be responsible for the cost verifying that DG units are operated in compliance with its

¹⁷ Such information includes the area of the installation, the MW requirement, the nature of the distribution system need, milestone dates, special technical requirements, and other relevant information.

contract with the utility, and would also reimburse the utility for any system modifications or interconnection costs entailed by the DG installation.

In evaluating DG proposals, the utilities will consider a present-value comparison of the compensation proposed by bidders with the cost of the alternative distribution facility project as well as factors such as technical feasibility and project risk. The level of compensation is to be determined through the bidding process, and would be limited to the avoided cost of the alternative distribution system project.¹⁸

The parties could not agree on whether the utilities should include in its cost comparison reduced or changed service revenues resulting from the DG installation. This issue is addressed below, along with other issues remaining undecided and raised in comments concerning the Report.

Advance Notice

Customers and DG developers that satisfy the pre-qualification requirements would be entitled, upon request, to receive a confidential advance notice report listing expected RFPs that would not be issued within the next year. The notice is intended to provide potential bidders additional time to respond to longer-term system needs. The list of anticipated RFPs in the advance notice would be updated annually.¹⁹

¹⁸ The avoided cost would not include the cost of avoided transmission facilities subject to New York Independent system Operator (NYISO) control or the jurisdiction of the Federal Regulatory Commission (FERC).

¹⁹ Customers or developers could submit DG proposals at any time, but utilities would be obligated to consider only those proposals submitted in response to an RFP.

Implementation Schedule

During the first of the program's three years (the 2001-2002 planning year), the utilities would screen their budgeted projects to identify potential RFP projects with in-service dates on or after the spring of 2003. RFPs would not be issued during the first year, but the utilities would be free to consider unsolicited proposals from pre-qualified customers or developers.

During the 2002-2003 planning year the utilities would issue RFPs for projects with in-service dates during or after the spring of 2004. Similarly, RFPs would be issued the following year for projects coming on line in the spring of 2005 or later.

Matters Requiring Further Consideration

The Report lists several "matters requiring further consideration,"²⁰ and these matters have been the principal focus of the comments submitted by the parties. These matters include:

- Contract terms and conditions
- Economic Indifference
- Cost Allocation
- Environmental Considerations

Each of these issue areas will be addressed in turn, following a review of the general thrust of the comments.

Overview of the Comments

The Utilities express some reservations about their commitment to the program recommended in the Report. They suggest that hearings, where factual issues could be explored

²⁰ Report, pp. 14-18.

through presentation and cross-examination of witnesses, would benefit the process. They also argue that all other DG issues, such as proposals to compensate DG users for reducing market prices, should be held in abeyance pending the experience gained from this proposed pilot program.

For the most part, the comments of the other parties concerning the outstanding issues imply general support for the pilot project. Pace/NRDC expresses support for the program, but says it is important that the pilot be conducted in a manner that captures the intended information and insights on the workability of the RFP program, the case-specific information on DG costs, benefits, and impacts, and the methods for evaluating customer-owned DG projects against traditional distribution system improvement projects.

1st Rochdale argues that the proposed program does not move quickly enough to remove barriers, especially related to standby rates and interconnection requirements, that discourage the installation of customer-owned DG facilities. 1st Rochdale also argues that a greater number of potential projects should be considered, that the lead time for projects potentially addressed by customer-owned DG be reduced from 18 months to 12 months, and that utilities should be allowed to substitute their own DG projects for customer-owned DG only if sufficient bids are not received from customers or developers.

Honeywell shares the concerns expressed by these other parties, and proposes an even broader expansion of the project to an offering of "a minimum of 10 RFPs . . . for each viable technology that is commercially available."²¹ Plug Power, similarly, suggests attempting to gain "the broadest experience

²¹ Honeywell's Comments, p. 5.

possible" by contracting for DG projects "serving a variety of areas with varying load characteristics."²²

In their reply comments, the Utilities oppose as unworkable 1st Rochdale's suggested reduction in lead times for DG projects, and Plug Power's proposed principle of balance. With respect to the latter, the Utilities argue that attempting to achieve a balance among commercial, industrial, and residential DG projects would be unrealistic for the pilot, given the limited number of RFPs envisioned. Moreover, the Utilities argue that introducing customer class as a factor would improperly skew the process of finding the best projects and, essentially, that customer class is not a relevant evaluative consideration.

Contract Terms and Conditions

The Report suggests that, to the extent possible, contracts between utilities and DG developers should be based upon a standard form with terms and conditions governing the installation and operation of customer-owned DG. The Report suggests that the contract should specify, among other things, the amount and timing of the utility's payments, the installation date for the DG capacity, the obligation to operate the DG at times designated by the utility, penalties for failure to operate, the term of the contract, and financial security to be provided by the DG owner.

The Committee did not develop specific terms, and suggested further collaboration for the development of terms. However, further collaboration was not conducted on contract terms. Because the parties could not agree on contract term issues, they were asked to submit comments on: (1) whether there should be a standardized contract for use by the utilities and

²² Plug Power's Comments, p. 1.

bidders; (2) whether certain core contract terms are needed in any event; and (3) whether there should be limitation of liability terms for the protection of utilities against defaulting DG providers, in either contracts or tariffs.

In their initial comments, the Utilities argue against standardized contracts, but argue that contracts should contain "standard core terms that could vary from company depending upon individual circumstances."²³ The Utilities provide an appendix with descriptions of contract terms that could serve as core provisions. Although the Utilities suggest that the other parties might address these suggested terms in their reply comments, only one of the non-utility parties has filed reply comments, and the proposed terms are not addressed.

Several other parties comment on contract issues in their comments. NEM focuses its comments on interconnection requirements and contracts, arguing that requirements for equipment, design criteria, and testing, already established in New York for units of less than 300 kVa on radial distribution systems, should be expanded to larger units and all distribution systems. NEM also argues that standardized interconnection contracts are needed to provide potential bidders with enough certainty to properly formulate bids. NEM has not commented specifically on the terms of the contracts at issue here between utilities and DG bidders in the RFP process, which are not intended to include interconnection terms. However, NEM more generally opposes the imposition of insurance requirements on DG owners, arguing that the additional cost would create an additional barrier to the proliferation of DG.

MI supports the Utilities' position that, while certain core terms may be important, parties must have flexibility in negotiating contracts. Any current attempt to

²³ The Utilities' Initial Comments, p. 26.

develop standardized terms would be time consuming, MI argues, and would unduly delay implementation of the program. Utilities should be allowed to negotiate reasonable terms, from among a variety of available options, for recovery if a DG developer defaults. If a developer feels a utility is not negotiating fairly, MI adds, it may seek redress from the Commission.

Pace/NRDC and 1st Rochdale, however, argue that standardized fair and reasonable contractual terms will be needed for a successful RFP program. Pace/NRDC maintains that utilities will have more bargaining power and will be able to demand concessions that will jeopardize projects financially. Although price, payment, and performance terms must be established for each contract, Pace/NRDC argues, other terms are susceptible to generic resolution. Moreover, standardized terms will reduce transaction costs, and enhance participation in the bidding process by clarifying the rights and responsibilities of participants.

In reply comments, the Utilities state that they are amenable to developing standardized core provisions for contracts, and have offered proposed terms to start the process of arriving at standardized core provisions. Regarding indemnification, the Utilities oppose NEM's arguments, asserting that the establishment of insurance requirements will not constitute a barrier to DG development.

Economic Indifference

The Report includes a section dealing with issues relating to the economic indifference of the Utilities in deciding whether to satisfy a system need through customer-owned DG or through a distribution facility project. The Report identifies four principles:

- The payments made to customers installing DG should be reflected in utility rates through the normal rate-making process.
- Customers owning DG should pay appropriate tariff rates for standby or other retail services they receive from utilities.
- Stranded costs that may result from the installation of DG should be properly treated in utility rates.
- The performance of DG should be monitored and considered in future rate cases to determine whether it affects the utilities' operations and services subject to performance incentives.

There has been no controversy over the underlying idea that payments to customers installing DG are costs that should be reflected in rates.²⁴ In a somewhat related matter, Pace/NRDC and Honeywell argue that the amount a utility should be allowed to recover in rates when it rejects bids, and goes ahead with the distribution system project instead, should be limited to the cost estimate for the project used in comparing the project to submitted DG proposals. This proposal is designed to prevent the utility from unreasonably biasing the evaluation process in favor of its own projects. The Utilities did not address this recommendation in their reply comments.

The second matter relating to economic indifference reflects the concern that if customers with DG do not adequately compensate a utility for the costs they impose on the system through their standby or other delivery service rates, they

²⁴ There also appears to be no controversy over whether the actual revenue stream reflecting revenues "lost" when a customer installs DG should be used in setting rates. There is considerable controversy, however, over whether a utility should be allowed to *consider* estimates of lost revenues in evaluating the economics of competing options under the RFP pilot program.

would be subsidized by other utility customers or the utility, and the utility would not fairly consider DG alternatives. The parties recognize that proper rates for DG customers are under consideration in this proceeding, as addressed below.

The Utilities argue that installation of DG could result in some stranded distribution costs, and they observe that there was no resolution of proper treatment of such stranded costs in the Report. The Report observes that some of the non-utility parties maintain that different approaches to rate making could affect utility perceptions of risk in this regard.²⁵ In a related matter, 1st Rochdale argues for a rate of return incentive to curb utility disincentives. The Utilities respond to that proposal, claiming that no incentive to adopt a DG alternative is needed if it proves to be the economically prudent alternative based on the comparative analysis analysis.

No parties have commented on the fourth concern, so it appears the parties agree with the Report that any effect of DG performance on utility services and operations subject to performance incentives should be observed through experience and addressed in future rate cases.

Cost Allocation

The Report reflects agreement among the parties that DG providers would pay for interconnection and system modification costs, as noted earlier. Interconnection of DG to the system may make system modifications necessary. According to the Report, these may be relatively minor, but in other cases may be extensive and expensive. For now, the report recommends that these costs be allocated to DG customers or developers on a

²⁵ A proposal designed to reduce utility risk is promoted by some non-utility parties in their discussion of other DG issues (beyond the pilot RFP process) below.

first-served, basis, so that each developer would be responsible for all of the system modification costs its project causes.

Non-utility parties do not discuss the cost allocation issue in the context of the RFP program, but as indicated earlier NEM stressed in its comments the importance of resolving interconnection issues for the future development of DG generally. The Non-Utilities in their submission on other DG issues, moreover, argue for a comprehensive review, among other things, of the cost allocation between a DG owner and other utility customers of equipment required on the utility side of the meter.

Lost Revenues

As observed above, the parties could not agree entirely on the factors to be considered by utilities in evaluating bids. One factor that the Report identified was consideration of lost revenues. One view is that in comparing the cost of a distribution upgrade to the cost of a DG alternative, in computing the latter revenues lost from the installation of the DG should be added to the compensation requested by the bidder. The competing view is that imputation of lost revenues as a cost factor improperly favors the utility's distribution project, and would result in the rejection of DG projects.

The Utilities argue for imputation of lost revenues on the ground that the lost revenues amount to a cost that will be allocated to other ratepayers. Thus, according to the Utilities, other ratepayers would be subsidizing DG alternatives if the lost revenues from the DG provider are not included in the avoided cost of the distribution project upgrade. Failure to impute lost revenues, they assert, would improperly bias the

process in favor of the DG project.²⁶ MI agrees with the Utilities.

Pace/NRDC argues that imputing lost revenues will result in rejection of the DG option no matter how small the rate impact as compared to the option's overall benefit. By biasing resource selection towards options for which the utility suffers no revenue erosion, Pace/NRDC asserts, the program would unfairly discourage DG development. Because "lost revenues exist only in relation to the utility's sunk investment and are not part of the cost of the distributed resource," Pace/NRDC maintains, the process would not identify the resource with the lowest marginal cost and therefore "treating lost revenues as a cost is inconsistent with economic theory."²⁷ Pace/NRDC also argues that the imputation proposal is analogous to the "unit cost" test applied in connection with DSM, that is, whether a DSM option would require a rate increase for non-participants, and notes that the Commission determined the unit cost test should not be applied exclusively in evaluating DSM projects.²⁸ Similarly, NEM argue that DG should be evaluated on the basis of its ability to provide benefits to the system, customer, or the environment. 1st Rochdale argues that lost revenues represent a transfer payment and are irrelevant to an assessment of cost and benefit economics. It is sufficient, 1st Rochdale maintains, that lost revenues can be tracked and recovered in rates.

²⁶ The Utilities cite Case 88-E-241, Orange & Rockland Utilities, Inc., Opinion and Order Establishing Guidelines for Bidding Programs (issued April 13, 1989), p. 13, where the Commission endorsed accounting for lost revenues in setting prices for demand-side management (DSM) bids.

²⁷ Pace/NRDC Comments, p. 2.

²⁸ Case 29409, Plans for Meeting Future Electricity Needs in New York State, Opinion No. 88-20, Opinion and Order Concerning Integrated Planning and Ratemaking Issues (issued July 26, 1988).

Environmental Impacts

The Committee members could not reach agreement on the treatment of environmental considerations in the proposed RFP process. The Report related two competing approaches. Under one approach, proposed DG projects would be subject to the same environmental requirements as the Commission has imposed on DG installations generally, namely, that customers obtain all required environmental and other permits prior to construction and operation of DG units. The other approach, supported in comments by Pace/NRDC, would be to include an additional pre-qualification requirement imposing emission restrictions designed to disqualify the most polluting DG technologies. According to Pace/NRDC, this would be a conservative requirement, permitting most technologies but effectively precluding internal combustion, diesel-fueled generators. Further, Pace/NRDC asserts, utilities ought to factor varying environmental impacts into their assessment of competing DG proposals.

The Utilities, NEM, and MI support the first option, to consider any DG proposal that would comply with existing laws and permitting requirements. The Utilities and MI also argue that utilities should not have to evaluate varying impacts of alternative DG proposals.

In their comments, the Utilities argue that their consideration of emission impacts should be limited to ensuring by contract that the DG bidder will agree to comply with all applicable environmental requirements and standards. Considering environmental issues would unduly complicate incorporation of the DG option into their distribution plant planning process, the Utilities argue, leading to a protracted and contentious process. Moreover, they argue, it would be speculative to attempt a priori environmental assessments. The Utilities also oppose rejection of technologically and

economically superior alternatives on environmental grounds, arguing as well that the experience and information gained from such projects should not be lost in an effort to implement standards more stringent than those required by environmental regulatory authorities.²⁹ The Utilities also question the efficacy of implementing more stringent standards for the small number of projects involved in the pilot, noting that such standards would not be imposed on unsolicited DG projects undertaken by customers.

Other Factors

The Report did not deal with interconnection issues beyond noting a need for utilities and winning bidders to communicate and negotiate on interconnection and system modification costs. NEM commented, however, that there should be a refined methodology for bid evaluation, in particular stressing its perceived need for uniform standards to apply with respect to interconnection contracts, interconnection standards, and approval processes. More certainty in these areas is needed, NEM argues, for DG developers to properly formulate bids.

As noted earlier, the Utilities and MI, in general terms, argue that rigid standardization would be counterproductive at this early stage of development of the use of DG in the utility planning process.

²⁹ MI argues that rules and regulations affecting the permitting of generating projects, promulgated by the New York State Department of Environmental Conservation (DEC) in concert with the federal Environmental Protection Agency (EPA), adequately address DG environmental concerns.

Discussion

1. General Concerns

With respect to the more general concerns of the parties discussed above, we do not agree with the Utilities' suggestion that evidentiary hearings would be beneficial with respect to any of the RFP program issues we have discussed. The program is a measured response to a need for the development of additional experience and information concerning the costs and benefits of DG, and the usefulness of DG for the Utilities in their planning processes. We do agree with Pace/NRDC, however, that it will be important to carefully accumulate and analyze the information provided by the pilot project for purposes of refining future policies. We therefore direct the utilities to submit reports at the conclusion of the pilot program. These reports will be reviewed at that time, along with input from other participants, in this proceeding.

We do not construe the concern of parties such as 1st Rochdale--that the RFP program without more provides inadequate support for DG development--as opposition to the pilot program itself. Concerns about interconnection requirements have been addressed elsewhere, and are discussed below, as are other issues raised concerning DG by the parties. Standby rate issues are addressed elsewhere as well.

Moreover, we are not persuaded by arguments that the scope of the proposed pilot should be expanded, or that lead time should be reduced. As a practical matter, lead time could not be substantially reduced in view of the normal time requirements associated with utilities' planning and construction processes. It is important, as well, to insure adequate time for the collection of information and evaluation of the program, the importance of which we have stressed above. As to the scope of the program, the Utilities have the discretion to enter into additional contracts if warranted.

Moreover, with respect to Plug Power's concerns, we would expect any residence-oriented DG project, if large enough, would be fairly evaluated in the program. No project should be substituted for a superior one, however, on the basis of the type of customer load the DG serves.

2. Contract Terms

The parties appear close to agreement on general issues respecting contract terms. It may very well prove helpful and efficient to standardize certain core requirements and responsibilities, and we will require further negotiations in this proceeding for that purpose. Any progress arrived at in this connection over the next year will yield benefits when contracts are written early in the RFP process.

3. Economic Indifference

Pace/NRDC and Honeywell raise a legitimate question about utilities underestimating in the first instance the costs of their own distribution system improvement projects. Utilities would not benefit clearly from such an approach, however, unless such costs and payments to DG developers were automatically recovered through revenue adjustment mechanisms. Otherwise, the utilities have a continuing incentive to operate efficiently and minimize costs. The utilities do not propose, and we will not permit, such costs to be recovered through automatic adjustment. These costs will be reflected in the normal rate change process established for each utility in its rate plan. Accordingly, there is no need to limit rate recovery in the fashion suggested by Pace/NRDC and Honeywell.

The discussion of stranded distribution system costs in this context is somewhat curious. For one thing, it seems unlikely that actual decreased use and reliance on existing distribution facilities would materially occur in connection

with DG for which a utility pays in order to avoid incurring the costs of additional facilities or upgrades that would otherwise be needed. For another, the "stranding" of costs refers to the loss of revenues when a customer formerly connected to the system disconnects and leaves. The customer-provided DG here would presumably not create a stranded distribution cost problem, assuming customers remain connected to the utility's system and pay appropriate rates for services received, as discussed below in connection with standby rates. The issue seems material, therefore, mainly when a customer with its own DG is not connected to the system.³⁰

Regardless, the issue is one of lost revenues. Although, as mentioned above, no party claims utilities should be denied recovery of lost revenues, there is no need to recover lost revenue if, as discussed below, utilities account for lost revenues in their bid evaluations. The avoided cost of the avoided distribution system upgrade compensates for any estimated lost revenues and, therefore, they would not have to be recovered from other customers.

4. Cost Allocation

The proposal in the Report to allocate interconnection and system modification costs on a first-served basis for purposes of the RFP pilot program is not controversial. This does not resolve larger issues of cost responsibility, raised by the non-utilities and discussed below, about how such costs should be treated for DG generally, beyond this pilot program.

It is important for utilities issuing RFPs under the pilot program to assist potential DG providers, on request, by

³⁰ Thus, to the extent there is a stranded cost problem, it would appear to result mainly in utilities favoring customer-owned DG of customers connected to the system, over those who are not.

providing as much information as possible about the interconnection and system modification requirements likely to attend specific potential DG projects.

5. Lost Revenues

Lost revenues are a proper factor to consider in a bidding process, as they would create additional cost burdens on other ratepayers. This is why the unit cost test was taken into account in considering DSM projects. Unlike the DSM programs of a decade ago, we expect the RFP pilot project for DG to focus more narrowly on its stated goals and to involve far fewer, if any, lost revenues. In developing methods for comparing the economics and reliability aspects of distribution upgrades with DG alternatives, nonetheless, imputed lost revenues is a relevant factor.

It is unclear at this time how frequently or to what degree DG options might entail lost revenues. In some instances, utilities might actually experience increased revenues from customers moving to the standby rates authorized in the opinion and order issued contemporaneously in Case 99-E-1470. It is also unclear how significant the lost revenue factor may prove to be in the analysis of bids or negotiation of contracts.

As discussed above, utilities need not be permitted to recover in rates any revenues lost from installation of DG occurring in response to utility RFPs when the lost revenues are factored into the bid evaluations.

6. Environmental Impacts

We agree with the majority of the parties that it would not be fruitful, and could be counter-productive at this time, to introduce environmental impacts as an evaluation factor in the bid analysis. Nor has a persuasive basis been presented

to consider imposing stricter standards than those already imposed by environmental regulatory agencies. These are issues that would unduly complicate the utility distribution planning process, and are better left to the proper regulatory authorities.

One of the objectives of the distributed generation pilot program is "to develop case specific information on DG costs, benefits, and impacts" and to refine methods of evaluating customer owned-DG proposals. Although we agree that environmental impacts and benefits need not be included in a utility's bid evaluation process, appropriate environmental information and characteristics of the DG bids should be submitted by bidders and evaluated by the utilities in their assessment of the three year pilot program. That information will provide one aspect of the case-specific information to be used to refine the methods of evaluating DG proposals in the future. Many DG projects, subject to environmental regulatory processes, can file permit or permit application information as well as applicable conditions or mitigation measures, as a means of compliance with the environmental data filing requirements.

7. Summary

We approve the proposed RFP project, consistent with the above discussion. As we discussed, the utilities may consider lost revenues, but need not evaluate environmental impacts, in assessing competing DG proposals. However, utilities should collect environmental characteristics of DG projects which are bid, and use such information to evaluate the three year pilot program. The utilities should commence the project in the 2001-2002 planning season.

OTHER DG ISSUES

The Non-Utilities, in their submission on other DG topics, discussed all matters of concern to them, including all topic areas addressed in these collaborative proceedings. In particular, the submission included some discussion of their concerns regarding both the use of DG by utilities in distribution system planning, a topic that is addressed elsewhere in this opinion an order, and the development of standby rates, which is addressed in a contemporaneous opinion and order. In this section, we will address the other issues raised by the Non-Utilities.

Interconnection Issues

The Non-Utilities contend that interconnection costs continue to present a major obstacle to the development of DG markets. The actions taken by the Commission in Opinion No. 99-13 do not go far enough, they assert, in addressing these matters.

Specifically, the Non-Utilities recommend that an investigation be opened to establish SIRs for DG systems with a capacity less than 300 kVa that are intended to be operated in parallel with network distribution systems,³¹ and to establish SIRs for DG systems between 300 and 10,000 kVa operating in parallel with all distribution systems. According to the Non-Utilities, the existing SIRs, which define the hardware elements of an interconnection and the respective responsibilities of the parties, provide a suitable starting point for this further investigation. This is especially true, they assert, because the technical interconnection requirements would vary with the

³¹ The SIRs established in Opinion No. 99-13 apply only to DG of 300 kVa or less operating in parallel with radial distribution systems. Con Edison's service territory contains network distribution systems.

size and characteristics of individual generators and, while minimum requirements are prescribed, there are no maximum requirements.

The Non-Utilities also contend that the Commission should consider modification of the existing SIRs. According to the Non-Utilities, the following issues are among those that should be revisited:

- Direct Transfer Trip (DTT) requirement guidelines should be revisited, to determine when DTT is needed, what alternatives are available and, if there is a need for DTT with small plants, whether the equipment costs can be limited to tolerable levels.
- The criteria for requiring a dedicated transformer should specify the technical conditions under which it may be required.
- The appropriate circumstances should be identified for cost allocation between the DG owner and other utility customers of equipment on the utility side of the meter.
- The application of the SIRs to both new and existing DG units should be affirmed.

These matters could be further resolved, the Non-Utilities assert, through further collaborative proceedings or through technical review by design consultants retained by the Department of Public Service or the New York State Energy and Research Development Authority (NYSERDA).

The Non-Utilities also recommend institution of a proceeding to investigate the reasonable and necessary costs incurred by utilities in processing interconnection requests. Charges imposed by utilities, they maintain, can be so substantial as to make DG interconnection economically prohibitive. They argue that generally applicable fees, tariffs, or rates should be established for the conduct or review by utilities of all studies or other procedures attending interconnection, including but not limited to the utility

application fee, Coordinated Electric System Interconnection Review, Interconnection Design Package, and Facility Testing. They argue as well that the Commission should require that utility bills to DG owners include sufficient detail regarding services and associated equipment costs for the DG owner to readily determine whether the services are performed competently, fairly, and at reasonable prices.

Because the potential interconnection of a variety of small plants is a relatively new phenomenon, a utility may frequently incur very substantial costs to review an entirely new variety of DG. To assist in keeping these costs to a minimum, reducing the likelihood that these costs will make DG installations prohibitively expensive, the Non-Utilities recommend funding, through the Systems Benefit Charge (SBC) fund or other NYSERDA programs, for advancing the state of interconnection art.

The Utilities respond that the Non-Utilities propose, essentially, to reopen and substantially expand Case 94-E-0952, beyond the scope of matters dealt with in Opinion No. 99-13. These suggestions are outside of the scope of this proceeding, they maintain, and the Commission has already acted on the SIRs to the extent it was inclined to do so. Moreover, greater than 300 kVa interconnection requirements are currently being addressed by Institute of Electrical and Electronic Engineers, (IEEE) Standard P-1547, which is likely to be the object of further proceedings in New York.

A decision to allocate SBC funds could not properly be made in this proceeding, the Utilities add, in which the full scope of SBC allocations and funding priorities is not under review.

Environmental Permitting

The Non-Utilities urge the Commission, in cooperation with the New York State Department of Environmental Conservation (DEC) and NYSERDA, to convene technical workshops to consider ways to streamline, update, and coordinate state and local regulatory review and approval processes for the siting of on-site DG.

The Utilities respond that this might be a useful exercise, but that the need for additional generating capacity in New York could also be served by adequate central station generating capability, so that attention might just as productively be paid to streamlining permitting processes for those facilities. Moreover, the Utilities continue, the Commission's ability to streamline processes involving local government review and permitting is limited. This proceeding should not be prolonged to consider this topic, they assert.

DG Ownership Rules

Plug Power, with the support of some of the Non-Utilities but not others, recommends identification and removal of restrictions against utility-owned DG that may attend the new regulatory environment and the transformation of utilities into transmission and distribution providers. According to Plug Power, these restrictions could prevent the full realization of the potential benefits of DG.

The Utilities respond that the roles and responsibilities of industry participants have been and will continue to be under scrutiny in other generic PSC proceedings, including the Competitive Markets proceeding. Thus, they maintain, there is no need to review those issues in this proceeding.

Utility Financial Disincentives

Pace/NRDC, Plug Power, and the American Wind Energy Association jointly propose that utilities and other interested parties should jointly study and report to the Commission on alternative forms of performance-based regulation that remove the link between profits and sales. These parties argue that, because of potential lost revenues, utilities seek to discourage DG development. A revenue-cap regulatory mechanism, for example, would remove that incentive by assuring the utilities that they would not lose revenues as a result of DG penetration.

In response, the Utilities argue that existing regulatory policies do not create barriers to DG, and that modification of the current rate recovery mechanisms is outside of the scope of this proceeding. Abandonment of cost-of-service regulation, the Utilities continue, would have implications far beyond the effects on DG development, and therefore is beyond the scope of this proceeding. The Utilities note that no specific incentive mechanisms are proposed by these parties, so that they do not have the opportunity to respond here. Moreover, they argue, in general terms the Utilities would oppose the provision of economically unwarranted rewards for DG, and that no basis has been shown to presume that DG provides positive benefits.

Discussion

We are not persuaded that the SIR requirements for less than 300 kVa systems should be revisited at this time. DG interconnection requirements are beyond the scope of this proceeding. Regardless, the Non-utilities do not demonstrate that the existing SIRs for units less than 300 kVa should be revisited. The current SIRs do not require provision of a DTT device. However, to avoid the potential hazards of an "islanding" condition during a utility outage, the utilities are

permitted to require DTT devices when they can demonstrate the need for them.³² Similarly, a utility must demonstrate the need for a dedicated transformer before one may be required.³³ Experience will be gained in applying the SIRs on the circumstances in which these requirements are needed.

The determination that the SIRs should be applied only to new units³⁴ does not need to be revised. Requiring an applicant to comply retroactively may force costly installation revisions. Parties may petition for revision of the existing rules.

The issue of including network distribution systems in the Commission's SIR would best be explored in Case 94-E-0952. The complex technical issues involved with attempting to craft a standard procedure for interconnection of distributed resources to a network system warrant a separate and distinct process. The consideration of a possible increase in the capacity limit (currently at 300 kVa) for systems covered by the restrictions of the SIR will also be included in this proceeding.

We are concerned about the potential for interconnection costs and procedures to discourage the development of DG. The Non-Utilities do not illustrate how reasonable specific rates or tariff requirements for utility interconnection charges could be developed, however, and we expect that such an effort would be largely ineffective. Utilities should, as the Non-Utilities suggest, make the nature and details of their interconnection charges clear to DG owners. We will take no action on these matters, however, until the experience of the RFP pilot program is available for evaluation.

³² Opinion No. 99-13, supra, p. 19.

³³ Ibid., p. 17.

³⁴ Ibid., p. 3.

The non-utilities seek a determination at this time that costs for equipment on the utility side of the meter can be allocated between the DG owner and other utility customers. The parties remain deeply divided on this issue, as the utilities have strenuously opposed allocating costs caused by DG installations to other customers. We generally strive to reflect cost causation in rates, and in the "Guidelines for the Design of Standby Service Rates" we approve today in Case 99-E-1470, we include as a rate design principle that the cost of additional interconnection facilities should be recovered directly from customers that install on-site generation through separate charges. It is inadvisable to initiate at this time any consideration of cost allocations among utility customers with respect to DG-related costs. In reviewing the RFP pilot results, however, we will consider arguments about the costs and benefits of DG-related system enhancements, and about fair allocation of them among customers.

There is no apparent need to address at this time the application of permitting processes to DG installations. The Non-Utilities have not explained what processes should be improved or streamlined, or suggested how we could effectuate changes in such processes.

With regard to Plug Power's suggestion, there is no immediate impediment on the realization of the full benefits of DG development imposed by restrictions on utility use of DG. The RFP pilot process approved in this order contemplates consideration of DG installations on the utility side of the meter. Any issues regarding the efficacy of that approach may be considered at the conclusion of the pilot program.

There is no reasonable basis for undertaking a new review of ratemaking incentive mechanisms at this juncture. Utilities' rates are set under plans and mechanisms that have been worked out over a number of years, to reflect the

transition to competitive markets and the need to encourage operating efficiency. This approach should not be disrupted lightly. Moreover, it has not been demonstrated that utilities seek to discourage DG development because of potential lost transmission and distribution service revenues. The Utilities have a reasonable opportunity to earn a fair return under existing policies, as their arguments imply. Accordingly, we see no need for a proceeding to consider alternative approaches to rate regulation.

CONCLUSION

As discussed herein, we approve the proposed RFP pilot project for the consideration by utilities of the use of DG in their distribution system planning processes. We expect the three-year program to commence with the 2001-2002 planning season.

Other issues raised involving DG do not require attention in this proceeding at this time. Interconnection issues are being addressed on a regular basis in Case 94-E-0952, and principles for standby rates are being established in a contemporaneous opinion and order. We will continue this proceeding to address, first, possible requirements for utility DG contracts, and to further address the costs and benefits of DG at the conclusion of the RFP pilot project.

The Commission orders:

1. The pilot RFP program for the use of distributed generation by utilities in their distribution planning, as set forth in the DG Committee's January 24, 2001 report is approved, for commencement in the 2001-2002 planning season, consistent with the discussion in this Opinion and Order.

2. This proceeding is continued.
By the Commission,

(SIGNED)

JANET HAND DEIXLER
Secretary

CASE 00-E-0005

APPENDIX A

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 00-E-0005 - Proceeding on Motion of the Commission to
Examine Costs, Benefits and Rates regarding
Distributed Generation.

NOTICE OF DETERMINATION
OF NON-SIGNIFICANCE

NOTICE is hereby given than an Environmental Impact Statement will not be prepared in connection with the approval by the Public Service Commission of a pilot program for the use of distributed generation in the utility distribution system planning process, based on our determination, in accordance with Article 8 of the Environmental Conservation Law, that such an action will not have a significant adverse affect on the environment. The exercise of this approval is an unlisted action, as defined in 6 NYCRR §617.2(a)(i).

Based on our review of the record, we find that the proposed action, which will approve a three year pilot program requiring utilities to issue RFPs for a limited number of distributed generation projects as potential alternatives to identified distribution needs, will not have a significant adverse environmental impact, because the pilot program is limited in duration, the potential number of projects are limited, any distributed generation projects, if selected, will obtain all appropriate permits, licenses and registrations, and the site and type of generation is unknown at this time.

The address of the Public Service Commission, the Lead Agency for the purposes of the environmental quality review of this project, is Three Empire State Plaza, Albany, New York 12223-1350. Questions may be directed to John Smolinsky at (518) 474-5368, or at the address above.

JANET HAND DEIXLER
Secretary

CASE 00-E-0005

APPENDIX B

**STATE OF NEW YORK
PUBLIC SERVICE COMMISSION**

**Proceeding on Motion of the Commission to)
Examine Costs, Benefits and Rates Regarding)
Distributed Generation)**

Case 00-E-0005

**REPORT
OF THE DESIGNATED-PARTIES COMMITTEE
REGARDING THE INTEGRATION OF DISTRIBUTED GENERATION
IN UTILITY PLANNING PROCESSES**

**Submitted: December 21, 2000
Revised: January 24, 2001**

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**STATE OF NEW YORK
PUBLIC SERVICE COMMISSION**

Proceeding on Motion of the Commission to)
Examine Costs, Benefits and Rates Regarding) **Case 00-E-0005**
Distributed Generation)

**REPORT
OF THE DESIGNATED-PARTIES COMMITTEE
REGARDING THE INTEGRATION OF DISTRIBUTED GENERATION
IN UTILITY SYSTEM PLANNING PROCESSES**

In accordance with the procedures established by the Presiding Administrative Law Judge at the October 4, 2000 conference in this proceeding, the committee of designated parties¹ ("Committee") submits this report regarding the integration of distributed generation ("DG") in the system planning processes of electric utilities.

I. SUMMARY

Overview and Assumptions

The Committee's essential goal is to provide for the objective and timely consideration of DG as a resource in the distribution system planning processes of electric utilities and for only this purpose. There are other DG issues which the Commission may consider that are not directly related to the installation of DG as a means of avoided utility distribution investments

The planning processes addressed in this report are those which the utilities use in connection with electric distribution facilities that are subject to the jurisdiction of the Public Service Commission (hereafter referred to as "distribution system"). The

¹ The Committee is composed of the following members: Harvey Arnett of the Commission Staff; James Bunyan of Niagara Mohawk Power Corporation; Peter Chamberlain of E Cubed Company, LLC; Henry Host-Steen of New York State Electric & Gas Corporation; Donald Stauber of Consolidated Edison Company of New York, Inc.; Edward Taylor of Consolidated Edison Company of New York, Inc.; and Fred Zalzman of Pace Energy Project.

report does not address the planning process applicable to transmission facilities that are subject to the control of the New York Independent System Operator and/or the jurisdiction of the Federal Energy Regulatory Commission.

This report focuses on the consideration of customer-owned DG. However, it envisions that DG may also be owned by utilities, provided that customers are afforded a fair opportunity to satisfy the utility's objectives through the installation of customer-owned DG. In either case, "ownership" includes actual ownership and other contractual arrangements in which a third party may install and/or operate the DG at the request of the customer or utility. Such third parties may include the unregulated corporate affiliates of the utility, provided that the utility does not extend preferences to its affiliates in violation of code of conduct requirements.

The Committee's recommendations in this report are based upon the following noteworthy assumptions:

1. The customer-owned DG which utilities are to consider in their planning processes is limited to DG that is operated in parallel with the utility systems and that supports load for which the customer pays the utility the rates and charges for standby service or other service under the utility's filed retail tariff; provided that a utility may, in its sole discretion, consider customer-owned DG that is electrically isolated from the utility's system.
2. Customer-owned DG will be connected to customer-owned wiring on the customer's side of the utility meter, unless a utility, in its sole discretion, allows the connection of customer-owned DG to the utility's distribution facilities in a particular case.
3. This report does not address electricity generated by customer-owned DG that flows into a utility's distribution facilities. Utilities may contractually agree to allow such flows in accordance with Commission regulations regarding interconnection.
4. The utility must perform a site-specific system impact review of each potentially winning DG proposal to identify the various restrictions, modifications, and requirements that may be necessary to interconnect DG at that site.
5. It is not anticipated that the amount of DG capacity that is installed during the next three years will require systemic changes in the utilities' system planning, engineering, operations, or system design software. As DG penetration increases to certain levels, major changes in those areas may be required. Existing planning tools, such as computer models, may become inadequate and may require major modification or replacement. Effectuation of such systemic changes could affect the RFP process because it would require more time than will be available for the processing of an RFP.

Conclusions and Recommendations

Many DG technologies are just now entering the market with the level of scope and scale necessary to resolve uncertainties regarding cost and performance. Consequently utility distribution system planners, DG developers and other stakeholders have limited practical experience in evaluating the impacts of customer-owned DG capacity on distribution system costs and performance and the effectiveness of such DG capacity as a substitute for distribution facilities. Many traditional utility planning processes are not designed to evaluate the potential for customer-owned DG to satisfy distribution system needs in a cost-effective fashion.

Consequently, the Committee recommends the adoption, on a test basis for a three-year period, of the policies and procedures outlined herein for planning and implementing distributed generation as an alternative solution to the needs of utility systems. More specifically, the objectives of this recommendation are as follows:

1. To determine whether distribution system needs can be satisfied on a least cost basis by creative and competitive alternative means;
2. To develop case-specific information on DG costs, benefits, and impacts across a range of distribution system conditions;
3. To refine methods for evaluating customer-owned DG proposals against traditional distribution system improvement projects; and
4. To determine whether a competitive solicitation process using requests for proposals ("RFPs") is a viable and optimal means of eliciting a market response to the utility's distribution system needs.

The procedures recommended by the Committee envision that utilities would annually screen their forecasted distribution system needs to identify those that might be satisfied through customer-owned DG capacity. Subject to specified limitations, the utilities would issue RFPs to elicit proposals for customer-owned DG that might satisfy the intended system need. The utilities would evaluate responsive proposals technically and economically as alternatives to a distribution project. If the DG project is the preferable alternative, the utility will contract with the customer regarding its construction and operation.

The Committee recommends that the policies and procedures described in this report be evaluated after three years of experience. Based upon the implementation of

DG and the lessons learned, the parties should determine at that time whether the process proposed by this report for customer-owned distributed generation should be continued or modified.

The Committee also recommends that further consideration be given to the DG-related matters discussed in Section VI of this report. Specifically, the essential terms and conditions of the contract between the utility and the DG-owning customer should be developed and standardized through further consideration in this case. Consideration should be given, in appropriate cases, to ratemaking arrangements that would render utilities economically indifferent in choosing between distribution system projects and customer-owned DG as they implement the procedures proposed herein. If a significant amount of DG is installed over time, consideration should also be given to the method of allocating among DG owners the cost of modifying utility systems to accommodate DG

II. PLANNING PROCESS

A. Current System Planning Process

The current planning process of electric utilities is implemented on an annual cycle, with special consideration given to unusual events that occur within the year. The process coordinates the involvement of various departments and professional disciplines that participate in the system planning and reinforcement program.

The annual process commences, at the end of the utility's peak-load season,² with a tabulation and analysis of the actual loadings that were experienced on distribution and transmission facilities during the prior summer and winter peak periods. That actual load data, information relating to load growth generally, and data relating to specific anticipated significant load increments is used as the basis for a load forecast. The forecasted load for specific facilities is compared to the capacity, reliability, and performance of those facilities in order to identify capacity deficiencies. The assessment process also identifies the system needs that relate to factors other than capacity (e.g.,

² The utilities that experience their system peak loads during the winter commence their planning cycle in March or April. Utilities that have a summer peak commence their planning cycle in August or September. All utilities perform essentially the same activities in their planning processes. However, because of the difference in commencement times for the planning cycle, the time available for particular activities within the planning process may differ slightly from utility to utility. As a result, the process proposed by this report must be adjusted to accommodate the timing of the planning process of individual utilities.

substandard voltage conditions). This process is generally completed within several months.

The system needs identified by the assessment process have various time horizons. Some needs must be satisfied prior to the commencement of the following peak-load season.³ Others have longer lead times: commonly, two, three, five, and ten years. The one-year needs are the most numerous, but are also generally small in terms of project size and cost.

The continuing process evaluates the available responsive actions for resolution of the system need. The potential responsive actions are examined in terms of technical adequacy, project cost, timeliness, and other considerations, in accordance with the utility's planning and engineering standards and guidelines. When the optimal action is selected, design and detailed engineering work is performed, and the facility modification or construction work is scheduled and planned.

The schedule for the continuing evaluation and engineering and design work is dependent upon the lead time for the particular system need. For the one-year needs of a summer-peaking utility, the evaluation and engineering work must be performed during the winter following recognition of the need, and construction or facility modifications occur during the spring. A winter-peaking utility must perform the corresponding planning and engineering during the summer following recognition of the need and the corresponding construction during the fall. For longer-term needs, the evaluation and engineering work proceeds on a longer schedule consistent with the need's lead time. For the five- and ten-year projects, for example, the detailed engineering and construction may be deferred for a period of years.

The system planning process is repeated annually. The continuing need for projects with multi-year lead times is re-evaluated in subsequent annual reviews, which may lead to changes in the scope or timing of the project or to the elimination of the project.

B. Integration of DG Into the Planning Process.

Consideration of DG should be integrated into the utilities' system planning processes in a manner that permits effective consideration of DG without impeding the process. System capacity, reliability, and performance depends upon the timely and

³ This report refers to such needs as "one-year needs" even though such needs must be satisfied in less than one year from the time at which the need is recognized.

orderly conduct of the planning and construction process. At the same time, the public interest may benefit from the consideration of DG alternatives in the planning process as a potential means of resolving utility distribution system needs.

The consideration of DG can best be accomplished through the incorporation of two additional steps in the planning process. The first step would consist of (i) the issuance by utilities of requests for proposals (“RFPs”) for the installation of customer-owned DG as a means of satisfying utility distribution system needs and (ii) the consideration of responsive customer DG proposals. The second step would entail the provision of advance notice to customers and DG developers of the prospect of a future RFP in connection with system needs that have an extended lead time.

The utilities may consider supplemental methods of considering and administering customer-owned DG as a planning resource. Individual utilities retain discretion to propose and implement other approaches to considering and administering DG.

Under the modified process, utilities would remain responsible for system planning and reliability, and customers would be notified of, and allowed to respond to, distribution system needs that might be satisfied through customer-owned DG. The process modifications are intended to enable utilities to consider and, where appropriate, to rely upon customer-owned DG without otherwise changing the planning process or adversely affecting electric system reliability.

Each utility would designate a staff representative to serve as a contact for DG-related matters. The representative would coordinate DG-related communications between the utility and customers or DG developers.

III. RFP PROCEDURES

The procedural steps included in the proposed RFP process are discussed and depicted in Appendix 1 to this report. Appendix 2 depicts an estimate of the time required for individual steps of the proposed process for a system need with an 18-month lead time on a summer peaking utility. The corresponding time line could be developed for a winter-peaking utility by deferring each of the dates on Appendix 2 by six months.

A. Criteria for Issuance of RFPs

During the three years commencing in fall 2000, as part of their annual system planning process, utilities would review their forecasted distribution system needs and identify which, if any, of those needs might be satisfied through the installation and operation of customer-owned DG. In screening their distribution system needs and identifying those for DG consideration, utilities would be guided by the following criteria:

1. Lead Time. RFPs would not be issued in connection with system needs that must be satisfied in less than 18 months from the date they are recognized.
2. Technical Feasibility. DG would not be considered in situations where, based upon a preliminary assessment, the installation of DG is technically infeasible or could not satisfy the system need because of technical considerations.
3. Type of System Need. DG would be considered where the distribution system need arises because of load growth or involves the expansion or construction of a unit substation or an area substation, and may be considered, at a utility's discretion, for projects on a radial distribution feeder on which load may be temporarily islanded.
4. Project Cost. System needs that can be cured through distribution facility upgrades costing less than a specified amount would not be considered for DG treatment. The specified amount for each utility is stated in Appendix 3 to this report.

Although the guidelines are structured as criteria for the screening of distribution system needs, the utilities may in their discretion issue RFPs for particular system needs that do not satisfy the guidelines. Similarly, if the number of distribution system needs that satisfy the guidelines exceeds the annual number of RFPs discussed in Section III.B of this report, the utility may select for RFP treatment those needs which appear to be most amenable to resolution by the installation of DG.

B. Number of RFPs

The maximum number of RFPs that the individual utilities would be obligated to issue annually is set forth in Appendix 3 to this report. Where the number of a utility's distribution system needs meeting the screening criteria set forth in Section III.A is greater than the designated number of RFPs to be issued by that utility in accordance with this Section III.B, the utility should select the projects which further the objectives stated in Section I of this report. Each utility has the sole discretion to select projects

that are below the dollar threshold listed in Appendix 3 and count those projects towards its target, where they believe the lower cost project presents better DG opportunities than the more costly projects.

The designated number of RFPs for each utility recognizes that utility staffing resources will be required for the simultaneous administration of multiple RFPs. The proposal also contemplates that there may be years in which a utility's distribution system needs are such that the designated number of RFPs will not be issued. If in any year a utility proposes to issue less than its designated number of RFPs, it will submit a letter to the Director of the Office of Electricity and Environment explaining the reduced number of RFPs.

The installation and operation of utility-owned DG may be counted against a utility's designated number of RFPs under certain circumstances. For a utility-owned DG project to be so counted, the utility must either (i) solicit bids from DG developers/vendors for the purchase and/or installation of the particular utility-owned DG project, or (ii) utilize in the project a DG developer/vendor that the utility has retained through a competitive process to function as the utility's agent for DG projects generally. The number of utility-owned DG projects that may be counted by each utility against the utility's designated number of RFPs is set forth in Appendix 3.

C. Timing and Content of RFPs

Where issuance of an RFP is indicated by the screening process, utilities would issue the RFP as early as possible, consistent with the risk that the project may be cancelled or modified through the utility planning process. In general, the RFP should be issued in time to permit (i) the submission and consideration of customer-DG responses simultaneous with the screening evaluation of non-DG alternatives and (ii) customer installation commitments prior to the date by which the utility must undertake detailed engineering and construction of an alternative project.

The RFP published by the utility should specify the following:

- the area of the electric system on which the DG must be installed,
- the size of the distribution system need in MW,
- the nature of the distribution system need,
- the date for the submission of RFP responses, the date for execution of a contract for the installation and operation of the DG, and the in-service date of the DG,

- special technical requirements (e.g., reliability, operating restrictions, and protective relaying requirements), and
- Any other utility-system circumstances necessary for the preparation of DG proposals.

In order to assure the competitiveness of the DG proposals submitted in response to the RFP, the RFP will not specify the estimated cost of the alternative distribution facility project.

D. Cancellation, Postponement, and Modification of Projects

The preparation of DG proposals in response to RFPs will entail the commitment of resources by customers and DG developers. Accordingly, in selecting distribution system needs for RFP treatment, utilities will give priority to those needs that have the greatest likelihood of going forward and will not issue an RFP if there is a reasonable probability that the forecasted need will disappear or significantly change prior to project implementation.

System needs that are identified through the system planning process often change or disappear over time. This is particularly true of needs that have multi-year lead times or that are based upon anticipated load growth. Consequently, the utility reserves the right to cancel, postpone, or modify the RFP after issuance.

Upon receipt of proposals in response to an RFP, the utility will evaluate the responses and will contract with the selected qualified customers for installation and operation of the DG. The utility, and the customer or developer, will become committed to the DG project at the time of the contract.

E. Bidder Pre-Qualification

Customers and DG developers intending to submit DG proposals in response to an RFP shall first demonstrate their ability to install DG through the utility's bidder pre-qualification process. The customer or developer may request pre-qualification as a bidder at any time by submitting to the utility a completed copy of the questionnaire that is included as Appendix No. 4 to this report.⁴ The utility will evaluate the customer's or developer's technical and financial ability to implement DG proposals based upon the

⁴ Because some portions of the questionnaire are less germane to customers than to DG developers, discretion should be exercised in its use for customers.

Appendix No. 4 information and publicly available ratings (e.g., Dunn & Bradstreet or Standard & Poors). The utility will perform the evaluation objectively and will not unreasonably deny qualification. Applications for pre-qualification should be accepted unless the customer or developer fails to demonstrate the requisite technical competence or financial strength to prepare a bona fide response to an RFP and to implement DG projects.

Each utility would maintain a list of pre-qualified DG bidders. The utility will mail a copy of each RFP to the pre-qualified bidders, and would consider only those responses to RFPs that are submitted by pre-qualified bidders. In addition, the utility would provide access to the utility's Advance Notice list (discussed in Section IV below) only to pre-qualified bidders.

The utility may subsequently require the pre-qualified customers and developers whose DG projects are selected through the RFP process to satisfy financial security or performance guarantees that are reasonably necessary to assure the construction and operation of the DG project in a fashion that satisfies the distribution system need addressed by the RFP. Such requirements would be established by the contract between the utility and the DG customer or developer.

F. Submission of DG Proposals by Customers and Developers

DG proposals submitted by customers and developers in response to RFPs shall include all information necessary (1) for the technical evaluation of the proposed DG installation and (2) for the utility to determine whether the proposal adequately satisfies the system need addressed by the RFP. Each proposal shall include sufficient DG capacity to reliably satisfy the system need specified in the RFP, without consideration of DG capacity proposed by other bidders. However, an individual proposal may aggregate the capacity of all of the DG units that the bidder proposes to install at various sites in response to the RFP; provided that, as sited, the aggregated capacity satisfies the intended system need.

The bidders shall also include in their bids the amount that they propose to be paid by the utility for satisfying the distribution system need and substituting for an alternative distribution facility modification or reinforcement. The bidders shall not disclose the amount of their compensation proposals (or the other terms of their bids) to other bidders.

G. Reliability

DG units have various levels of operating reliability depending upon their technology. Those reliability levels, in turn, differ from the reliability of the facilities constituting electric distribution systems (*i.e.*, transformers, breakers, feeders, poles, *etc.*).

This variation in reliability levels must be recognized and accommodated in substituting DG for distribution facility upgrades. The substitution of DG must not degrade system reliability or the quality of utility service to customers. Where DG units are substituted for distribution facility upgrades, the DG units included in an RFP proposal must provide reliability and assurance of availability, when needed, that are equivalent to those distribution facility upgrades. In general, this will require some level of redundancy of the DG capacity in order to assure satisfaction of all statewide and local reliability requirements applicable to the electric system.

The level of redundancy shall be proposed by the customer or DG developer in the proposal submitted in response to the RFP. The redundancy proposal will be subject to review and acceptance by the utility. The Director of the Commission's Office of Electricity and Environment will resolve any disputes relating to redundancy. The customer's proposal and the utility's review shall be grounded, to the extent possible, upon publicly available, industry-recognized, technical information.

H. Customer Cost Responsibility

The customer installing DG shall reimburse the utility for interconnection costs and for system modification (*e.g.*, circuit breaker replacements) costs that the utility incurs because of the customer's DG installation. Because such costs are site specific, they cannot be estimated until the RFP proposals are received and reviewed. At that time, the utility would estimate the total system modification costs for each potentially winning bidder. The utility would notify the bidder submitting the best bid of its cost responsibility, and the bidder would determine whether to proceed with its DG proposal in light of its cost responsibility. The DG customer would also be responsible for the cost of monitoring and communication equipment necessary for the utility to verify that the DG units are operated in accordance with the terms of the contract between the customer and the utility. If a dispute arises with respect to a bidder's cost responsibility,

the bidder may request that the Director of the Commission's Office of Electricity and Environment review the appropriateness of the utility's cost estimate.

I. Evaluation of Customer DG Proposals

The utility will evaluate the technical and economic aspects of the DG proposals that are submitted in response to RFPs.

The utility's technical review would evaluate the interconnection of the particular proposed DG units, at their specific sites, to ensure that they are capable of interfacing with the utility system safely and without detriment to the utility's service to other customers.

The utility's economic evaluation will entail a present-value comparison of the compensation proposed by DG bidders to the cost of the alternative distribution facility project. However, the Committee members could not reach consensus with respect to whether the evaluation should recognize the net reduction in revenues that the utility would experience because of the installation of the DG. Some Committee members propose to impute such changes in revenues by comparing the present value of (1) the cost of the distribution facility project for which the DG would be substituted and (2) the sum of (a) the amount of compensation that the bidder includes in its proposal and (b) the net reduction in revenues that the utility will experience because of reduced or changed services resulting from the DG installation. The members supporting the imputation proposal regard the net change in revenues as an economic burden that might otherwise be borne by ratepayers generally. On the other hand, one Committee member opposes the imputation of the net change in revenues on the belief that such revenues should not be treated as a "cost" for purposes of project evaluation. The member maintains that the imputation would favor the utility's distribution facility project and could result in the rejection of DG projects. The member believes that it is appropriate for the utility to track and recover through rates the net change in revenues that result from the implementation of DG. The Committee is presenting the imputation issue to the parties for further discussion and to the Commission for decision as a policy matter.

Regardless of the outcome of the revenue imputation issue, the cost of the avoided distribution facility project would include only those costs that the utility would incur if it pursued that project. However, in evaluating the alternatives, utility should make reasonable efforts to consider differences in power quality, reliability, project risks, cost risks, and flexibility to respond to changing circumstances.

The utility should perform its technical and economic evaluation objectively. Its decisions should be consistent with good utility practice and the utility's obligation to provide safe and reliable electric service at the lowest reasonable cost.

The compensation that the utilities pay for DG projects would be determined through the bids submitted confidentially in response to RFPs, rather than through an administrative or regulatory process. The compensation would

be limited to the avoided cost of the particular distribution facility project that is deferred or eliminated because of the RFP DG project. The compensation would not include avoided costs associated with transmission facilities that are subject to ISO control and/or FERC jurisdiction.

IV. ADVANCE NOTICE

Utilities would provide advance notice of an anticipated RFP in situations where the RFP would not be issued for a year or more from the time when the RFP is first anticipated. The notice should specify the same categories of information as included in an RFP; the advance notice listing would not state the estimated cost of the alternate distribution facility project. The notice is designed to provide customers and DG developers with additional time to respond to longer-term system needs than would be provided by the RFP process itself.

The advance notice, consisting of a list of anticipated RFPs, would be provided upon request and on a confidential basis to customers and DG developers that satisfy the bidder qualification requirements discussed in Section III.E of this report. The advance-notice listing would be up-dated annually as part of the system planning process, and within the year in response to significant changes.

Unlike an RFP, the notice would not invite the submission of DG proposals. Customers and DG developers could submit DG proposals at any time, but utilities would not be obligated to consider unsolicited DG proposals as a means of satisfying utility system needs.

V. IMPLEMENTATION SCHEDULE

The process proposed in this report for the consideration of DG should be evaluated in three years. The parties have compiled available data relating to DG and have weighed it in preparing this report. However, there remain technical and economic uncertainties that warrant the reconsideration of the process and criteria proposed in this report after some experience has been obtained. The utilities would initiate that reconsideration by submitting, to the Director of the Commission's Office of Electricity and Environment and to the parties to this case, a report on DG activities undertaken during the three years.

During the first of the three years (*i.e.*, the 2000-2001 planning year), the utilities will perform the following preliminary implementation steps:

- The utilities would screen their budgeted projects, using the criteria discussed in Section III.A of this report, to identify potential RFP projects with in-service dates during or after the spring of 2002. The utilities will not issue RFPs during the first year, but may in their discretion consider unsolicited DG proposals from qualified customers or developers.
- The utilities would establish and make available the Advanced Notice listing and review bidder qualifications.

During the 2001-2002 planning year (*i.e.*, *commencing* in fall 2001 for summer peaking utilities, and spring 2002, for winter peaking utilities), the utilities would issue RFPs for projects with in-service dates during or after the spring of 2003. Similarly, RFPs would be issued the following year for projects coming on line in spring 2004 or later.

VI. MATTERS REQUIRING FURTHER CONSIDERATION

A. Contract Terms and Conditions

In cases where a utility concludes that the DG proposals submitted in response to an RFP are preferable to the alternative distribution facility projects, the utility will execute contracts with each of the selected customers and developers. To the extent possible, the contracts should be based upon a standard form that specifies the terms and conditions to govern the installation and operation of the customer-owned DG. In particular, the contract should specify the amount and timing of the utility's payments in recognition of the DG, the installation date for the DG capacity, the obligation to operate the DG at times designated by the utility, penalties for the failure to operate, the term of the contract, and financial security to be provided in connection with the DG.

The terms and conditions of the contract have not been developed. However, the Committee recommends that they be developed in this collaborative proceeding and submitted as part of the parties' final report to the Commission.

B. Economic Indifference

The process proposed in this report envisions that the utilities will, in certain respects discussed above, exercise discretion in considering DG in their planning processes. In order to encourage the utilities to exercise that discretion objectively and reasonably, the utilities should be economically indifferent in deciding whether to satisfy a system need through customer-owned DG or through a distribution facility project.

There are several factors that bear on the economic indifference of utilities. First, by pursuing customer-owned DG in lieu of a distribution facility project, utilities may forego an investment that otherwise would be included in rate base and would earn a return. To offset that foregone investment, the payments that utilities make to customers installing DG in response to an RFP should be reflected in rates through the normal ratemaking process. This treatment will benefit customers generally in that the amounts included in rates to address the system need would be less than they would have been if the utility had pursued a distribution facility project.

Second, economic indifference requires that customers owning DG should pay appropriate tariff rates for the standby or other retail service that they receive from utilities. The principles to be used in designing such rates are under consideration in Case 99-E-1470.

Third, the prospect of incurring stranded costs might affect utility judgments unless the prospect is properly addressed. The utility parties contend that stranded costs may result from the installation of DG and that any such stranded costs should be duly treated in Case 99-E-1470 and in utility rate cases. The payments that utilities would make to customers installing DG in response to RFPs will tend to facilitate the installation of customer-owned DG. Accordingly, utilities should be afforded a reasonable opportunity to demonstrate the existence of, and to recover costs that are stranded because of the installation of DG. On the other hand, some non-utility parties believe that different regulatory approaches will influence utilities' perception of DG. Under the price caps applicable in utility restructuring plans, customer-owned DG can translate into lost sales, lost revenues, and lost profits.

Fourth, the performance of DG should be monitored over time to determine whether it affects the utilities' operations and services that are subject to performance incentives. The parties lack sufficient experience with DG to anticipate whether DG will have such an effect. It is recommended that this issue be considered in rate cases after sufficient experience has been obtained.

C. Cost Allocation

This report envisions that interconnection and system modification costs will be allocated on a first-come, first-served basis to DG developer/customers (see Section III.H above). Under that allocation method, each DG developer/customer will take the

system as it exists when it proposes its project and will be individually responsible for the interconnection and system modification costs that its project causes.

In some cases, the required system modifications may be relatively minor. In other cases, the required modifications will be extensive and expensive. The extent of the system modifications and costs will depend upon various factors, including the size of the DG project and the electric system conditions, particularly the adequacy of circuit breakers to accommodate increased fault duty. It is uncertain how the larger system modification costs may affect individual DG projects if those costs are allocated to individual projects. In cases where a modification benefits multiple DG projects, it may be in the public interest to allocate the costs to all of the DG projects that benefit from the modification.

Such a cost allocation methodology is beyond the scope of this report. However, the issue of cost allocation among DG projects may merit further consideration as experience is gained with those projects.

D. Environmental Considerations

The Committee members have not reached agreement regarding the treatment of environmental considerations in the proposed RFP process. One proposed treatment of environmental considerations is to require compliance with existing environmental requirements, as provided by the Commission's standard interconnection requirements ("SIR") for DG. The other proposal, advanced by Pace Energy Project ("Pace"), is (1) to establish specified emission limitations for DG proposals submitted in response to RFPs and (2) to develop methods for explicitly considering environmental differences in the evaluation of DG bid proposals.

In support of its proposal, Pace states that DG alternatives can vary widely in their environmental performance, specifically that a typical small diesel generator's emissions rate for NO_x is about 100 times that of a modern combined cycle plant (0.11 lbs/MWh vs. 10-41 lbs/MWh). Accordingly, Pace states the following:

In addition to meeting the bidder qualifications specified in Section III.D, Pace recommends that participation in the RFP process be

conditioned on the bid project meeting minimal environmental performance standards. Under the Pace proposal, for the three year implementation period, participation in the RFP processes would be conditioned on achieving the following emissions rates:

NOx .35 lb/MWh
CO .90 lb/MWh.

Pace submits that this is a conservative screen, intended to bar only the most highly polluting DG units. Pace argues that, at these levels, an uncontrolled internal combustion diesel generator would be foreclosed from participating, but other DG technologies would most likely qualify.

Further, no procedure is currently in place to assess environmental variances in the bid evaluation process. During this three-year implementation plan, utilities are encouraged to supplement their dollar-value analysis by testing alternative methods for explicitly considering the environmental differences of bid projects.

The other Committee members believe that DG projects that are proposed pursuant to the DG process should be subject to the same environmental requirements as the Commission has imposed on DG installations generally. The SIR environmental requirement is as follows:

Customer shall obtain all environmental and other permits lawfully required by governmental authorities prior to the construction and for the operation of the unit during the term of this agreement.

The Committee members supporting the SIR environmental requirements advance the following reasons for adoption of those requirements in connection with the RFP process:

First, there is no reason to impose environmental standards on DG projects solicited through the RFP process that differ from those

applicable to unsolicited DG projects undertaken solely at the initiative of a customer. Second, the environmental benefit of the Pace proposal would be relatively small (given the term and scope of the RFP process); and by restricting proposals in the RFP process, the Pace restrictions would hinder the process's objective of developing information regarding the cost and benefit of DG. Third, the timeline envisioned for the RFP process (Appendix 2) does not allow sufficient time for an environmental evaluation of DG proposals by the utilities. If such an evaluation were imposed, the timeline and the 18-month screening criterion would have to be re-visited.

VII. CONCLUSION

The Committee submits this draft report to the Presiding Judge and to the other parties in this case for their consideration. The Committee believes that the recommendations made in this report are reasonable and commends them to the parties as matters to be endorsed to the Commission.

Respectfully submitted,

Harvey Arnett

James Bunyan

Peter Chamberlain

Henry Host-Steen

Donald Stauber

Edward Taylor

Fred Zalcman

APPENDIX 1

PROCEDURE FOR EVALUATION OF DG ALTERNATIVES

Figure A-1 is a flowchart illustrating the recommended framework for evaluation of DG as an alternative to distribution facility expenditures. The steps in the process include the following:

- 1. *Identify the distribution system problem and need drivers.***
The need drivers behind a distribution system problem may include, among other things, overloaded conductors or apparatus, low, high, or fluctuating voltages, connection of new customers, physical deterioration, technical obsolescence, and reliability issues. This information is part of the prioritization approach currently in use, and will continue to be used by the asset managers in determining how limited resources will be directed.
- 2. *Develop a distribution facility solution.***
This is the traditional step of identifying a problem solution based on distribution system construction work. The evaluation proceeds from this step to step 9 on the left branch of the flowchart on Figure A-1 and to step 3.
- 3. *Does the system need satisfy the four screening criteria for RFP projects, and has the utility issued the designated number of RFPs?***
The application of screening criteria is necessary because the distribution system projects number in the hundreds, and it would be impractical and prohibitively expensive to develop and consider DG alternatives for all of them. Distributed generation may be effective in addressing certain needs, such as capacity expansions associated with load growth, or the expansion or replacement of a unit or area substation. However, DG would be ineffective for others such as physical deterioration of poles.
To proceed with further consideration of DG, it is necessary to determine preliminarily whether the installation of DG is technically infeasible in light of circumstances existing on the utility system.
Because of timing constraints inherent in the utility planning cycle and the time required for evaluation of DG proposals, DG will not be considered in connection with system needs that have a short lead time.
The issuance of an RFP will also depend upon whether the cost of a distribution facility solution to a distribution system need is less than a designated amount or whether the utility has issued a designated number of RFPs during the year.
- 4. *The utility develops and issues an RFP.***
With respect to distribution system needs identified by the screening process, the utility will issue RFPs soliciting DG proposals as solutions to the system need. The RFP will be sent to customers and DG developers that qualify as bidders.
- 5. *Bidders submit their detailed DG proposals.***

In response to an RFP, Bidders will submit proposals to install DG as an alternative to a distribution facility project. The proposals will contain all information necessary for evaluation of the bid, including the amount that the bidder proposes to be paid by the utility for providing the DG capacity.

6. *The utility performs a technical and economic evaluation of the DG proposals.*

The DG proposals must be examined to confirm that they are an appropriate technical and economic fit for the situation. It is possible that DG may appear worthy of consideration on a generic screening basis, but when detailed design is done costs or other considerations not apparent at a generic level may surface and indicate that the DG solution is not a good solution for the distribution system needs.

The utility excludes bids that include proposed payments that exceed the cost of the alternative distribution facility project and ranks the remaining projects by their merits. For the potentially winning proposals, the utility estimates the interconnection and system modification costs for which the bidder would be responsible.

7. *Does the bidder accept the responsibility for interconnection and system reinforcement costs?*

The utility notifies the bidder of the estimated interconnection and system modification costs, and the bidder determines whether its proposal is still economic.

8. *Drop DG as an alternative, focus on distribution facility solutions.*

If negative findings result from the tests in steps 3, 6, or 7, then DG may be dropped from further consideration as a solution for the distribution system need.

9. *Utility compares DG and distribution facility proposals technically and economically and selects preferred alternative.*

Utility develops the present value revenue requirements for each surviving distribution facility and DG alternative. Utility compares the present values, risks, impacts on company labor and other resources, technical and operational advantages and problems, and other relevant considerations. At this step, DG may be viewed either as a complete substitute for the distribution facility project, or as a means to defer that project for a specified period of time.

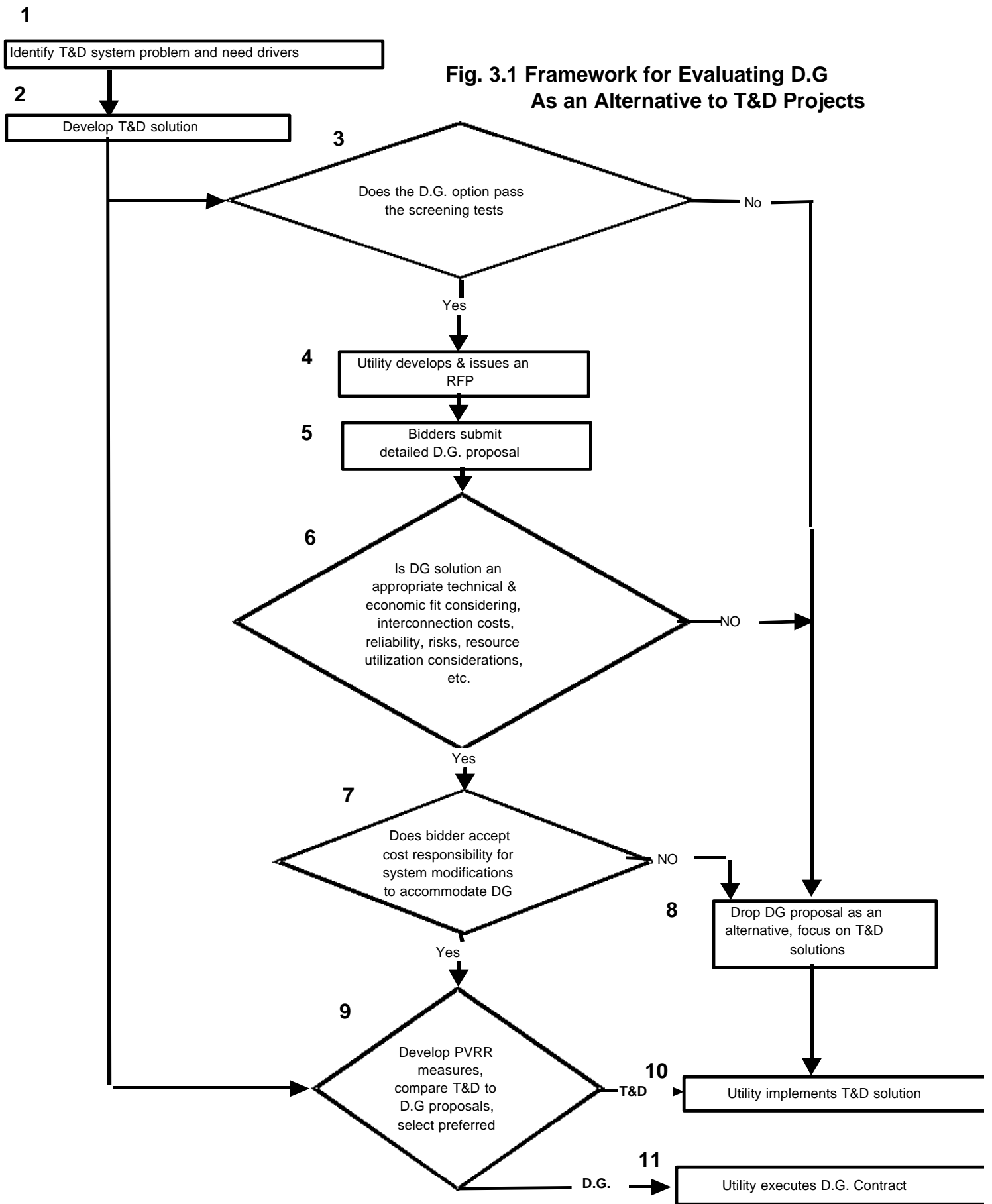
10. *Utility implements distribution facility solution.*

If a distribution facility project is the preferred alternative, the utility performs detailed engineering, procures equipment, and constructs the project.

11. *Utility and customer execute a DG contract, and customer implements DG project.*

If a customer-owned DG project is the preferred alternative, the customer (or DG developer) and the utility execute a contract for the installation and operation of the DG project. The customer (or developer) installs and operates the DG in accordance with a schedule and procedures specified by the contract.

Fig. 3.1 Framework for Evaluating D.G As an Alternative to T&D Projects



APPENDIX 3

LIST OF MINIMUM PROJECT COSTS AND DESIGNATED NUMBERS OF RFPs

This appendix specifies the number of RFPs and the project costs that are referenced in Sections III.A and III.B of the report and that shall apply during the second and third years of the three-year process proposed by the report. The number of RFPs and project costs were developed through negotiations by the parties, and their agreement to the number and costs is specifically conditioned upon the qualifications listed below.

1. Designated Number of RFPs

The maximum number of RFPs that each utility would be obligated to issue annually in accordance with Section III.B of the report is as follows:

- Con Edison: 2 RFPs in year two and 4 RFPs in year three;
- Each other company: 2 RFPs in each of years two and three.

2. Company-owned DG Projects

In accordance with Section III.B of the report, each utility may count the following number of utility-owned DG projects against its designated annual number of RFPs:

- Con Edison: 1 utility-owned DG project in year two, and 2 such projects in year three;
- Each other company: 1 utility-owned DG project in each of years two and three.

3. Project Cost

The threshold project cost referenced in Section III.A of the report for each company is as follows:

- Con Edison and Niagara Mohawk: \$750,000;

- NYSEG: \$500,000;
- Central Hudson, RG&E, and O&R: \$500,000, provided that these companies will consider projects costing between \$500,000 and \$250,000 if they have fewer than the designated number of RFP projects with a cost in excess of \$500,000.

4. Qualifications

The designated number of RFPs and project costs will be applied in accordance with the Committee report and subject to the following particular conditions:

- For reasons of public safety and equipment protection, DG units will not be installed on any primary distribution feeder or subtransmission circuit that is designed for ungrounded operation.
- No company will be required to issue more than its designated number of RFPs in any year.
- No company will be required to issue an RFP for any distribution system project (as defined in Section I of the report) that would cost less than the threshold amount specified by this Appendix for the company.
- If in any year a utility proposes to issue less than its designated number of RFPs, it will submit a letter to the Director of the Office Electricity and Environment explaining the reduced number of RFPs.

B. Type of ownership:

Sole Proprietor _____
Partnership _____ Private _____ Public _____
Corporation _____ Private _____ Public _____
State of Incorporation _____ Date Inc. _____ NA _____

If partnership, identify County Clerk's office where filed.

Please provide copy of Certificate, if applicable.

C. Name of Principals, Officers & Partners Title

D. Name and address of other companies which your officers, partners, owners, principals, etc., have an affiliation (e.g., other partnerships or company ownership's, board seats, controlling interest of stock, etc.). Describe nature of affiliation for each person.

II. FINANCIAL

A. Please furnish one copy of your current and previous year's Financial Statement including Profit and Loss and Balance Sheets. Also, an Independent auditor's statement must be attached for your request to be considered.

B. Annual gross revenues for the last three years.
Year Gross Revenues (\$)

- C.** Bank References
Bank Contact Name - Telephone
Number
- D.** Bond References
Bond Company Contact Name - Telephone number
- E.** Was your Company reviewed by Dunn & Bradstreet?
Yes ___ No ___ If No, why not?

Provide a copy of all credit ratings that have been issued in the last three years.

III. BUSINESS

- A.** Give a brief history of the Company. Describe the type of projects normally done by your Company.
- B.** What is the approximate dollar value of the average job the Company handles?
- C.** List the five largest projects completed during the last 2 years. Provide additional sheets as necessary and brochures, if available, describing other recently completed projects. Indicate customer name, dollar value of your contract, year completed, scope of work and name and telephone number of customer's representative.

- D.** Customer References for completed and in progress contracts - List at least six completed and three in progress. Please include at least three of the largest projects listed above and especially include customers whose projects are most akin to the Utility Industry. Identify if your Company was the "prime" or "sub" contractor and scope of your work. If you were the "sub" provide name and address of the prime contractor. Indicate customer name, dollar value (your portion), and contact name and telephone number.
- E.** Does your Company have a policy statement that defines quality goals and objectives? Yes ____ No ____
Is the policy understood and implemented throughout all organizational levels? Yes ____ No ____ State policy and describe method of implementation.
- F.** Are you a member of any Contractor's Association?
Yes ____ No ____ If yes, please identify.
- G.** Do you have a preference with respect to the area you will service?
Yes ____ NO ____ If yes, please identify.
- H.** Have you ever done any work for Company as a sub-contractor?
Yes ____ NO ____ If yes, list jobs with dates and name of prime contractor(s), dollar value, Company location and scope of work.

- I. Has your Company ever failed to complete any work awarded to you? Yes ____ NO ____ If yes, please state when, where and why the job was not completed?
- J. Has any Officer, Partner or Principal of your Company ever been an Officer, Partner or Principal of another company that failed to complete an awarded contract? Yes ____ No ____ If yes, please identify the person and state when, where, and for whom and why the job was not completed?

Has your Company or any Officer, Partner or Principal of your Company been convicted of a felony relating to business or financial matters? If so, please provide specifics.

- K. Has your Company ever been removed from an Approved Bidders List? Yes ____ No ____ If yes, explain.
- L. List Building Trade Unions with which you have signed agreements and provide copies of the signature pages of these union agreements. Note that no consideration will be given to contractors that do not employ local Building Trade Unions having jurisdiction for work performed.

- M.** Does your Company sub-contract to others? Yes _____
No _____ If yes, list some of the sub-contractors and describe the type of work they perform.
- N.** List major equipment owned by the company and the locations where it is based. Equipment listed must be in good operating condition. Use a separate sheet.
- O.** List major Material Suppliers.

IV. PERSONNEL

- A.** Does the Company perform its own engineering?
Yes _____ No _____ Drafting? Yes _____ No _____
Where you respond No please identify who provides this service if applicable.
- B.** Provide a table listing superintendents, their specialties, years of experience as superintendents and length of service with your Company.

- C.** Personnel Distribution:
 Total number of permanent employees _____
 Total management/professional staff _____
 Engineers _____ Salespersons _____ Draftsmen _____
 Equipment Operators _____
- D.** Please provide Company organizational chart.
- E.** What has your average work force (craft trades) been for the last two years?

V. ADDITIONAL INFORMATION

Please provide any additional information relevant to an evaluation of your firm's capability.

Prepared by:

Signature	Date
Print or Type Name	
Title	