STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

Docket No. 3655

In RE: Block Island Power Company)
Request for a Rate Change Application)

PREFILED TESTIMONY OF STAN FARYNIARZ

ON BEHALF OF TOWN OF NEW SHOREHAM

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Stan Faryniarz. I am a Senior Consultant with La Capra Associates, 20 Winthrop Square, Boston Massachusetts.

Q. PLEASE DESCRIBE YOUR FIRM.

A. La Capra Associates ("La Capra") is a consulting firm specializing in electric industry restructuring, energy planning, market analysis, and regulatory policy in the electricity and natural gas industries. For over twenty years, our firm has served a broad range of organizations involved with energy markets -- public and private utilities, energy producers and traders, financial institutions and investors, consumers, regulatory agencies, and public policy and research organizations.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I am an energy economist and transactions specialist with 19 years of experience in areas including power supply procurement and management, wholesale and retail power transactions, power project financial analysis and due diligence, asset and utility valuations, integrated resource planning and analysis, and electric utility cost of service and rates. My principal client base over that period has been public power systems and, more recently, large retail customers.

I have managed the electric power supplies of several Vermont consumer-owned electric utilities, and have advised other electric utilities and large industrial customers regarding specific power transactions and risk management strategies.

I have prepared numerous valuation analyses of power projects and assets, combined portfolios of assets, and utilities. This work has involved power assets in the northeast U.S., Ohio, Arkansas and Canada. I have evaluated the economics, contract structure, ratepayer security, development prospects or going-forward value of dozens of renewable, non-renewable merchant and Qualifying Facility power projects in the northeast U.S. and Canada. I have conducted this work for regulators and private capital and quasi-public capital providers.

My experience includes the preparation of over a dozen electric and water utility allocated cost of service and rate design studies, rate unbundling studies and rate path projection studies for or involving utilities in the northeast U.S. and North Carolina.

I have prepared, or have overseen the preparation of all or portions of integrated resource plans for several Vermont utilities, and I am a load forecasting specialist.

A copy of my resume is attached to my testimony as Attachment SCF-1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Town of New Shoreham.

Q. HAVE YOU PREVIOUSLY PROVIDED EXPERT TESTIMONY?

A. Yes, I have provided testimony on power costs, power supply management and planning, contracts, performance assurance and ratepayer security, valuations of specific generation and utility assets, rates and rate design in a number of regulatory jurisdictions. These include testimony filed in cases before regulators in Vermont, Maine, Pennsylvania, Rhode Island and Nova Scotia, Canada.

Q. HAVE YOU PREVIOUSLY PROVIDED EXPERT TESTIMONY BEFORE THE RHODE ISLAND PUBLIC UTILITIES COMMISSION?

A. Yes, I submitted and sponsored testimony in a special rate design case initiated by Narragansett Electric, on behalf of a long-term client of mine, Amtrak, in Docket 2867.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been asked by the Town of New Shoreham to provide recommendations concerning the need for long-term, integrated resource planning by Block Island Power Company (BIPCO or "Company"), including recommendations concerning the implementation of demand side management measures by BIPCO.

I have offered testimony regarding BIPCO's proposal to expand its current June-September seasonal rates to include May and October and have provided the Commission with recommendations on rate design changes that should be considered to apportion cost responsibility more squarely on summer consumption and to effectuate some peak load response.

Finally, I have offered testimony regarding the very high level of losses that BIPCO has been experiencing, and the Company's stated need for new diesel generation.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Town of New Shoreham's interest in long-term resource planning and rate design issues related to BIPCO's recently-requested general rate increase was preceded by its November 23, 2004 Complaint against Block Island Power Company, which was filed with the Division. A copy of the Town's Complaint is attached to my testimony as Attachment SCF-2. From my review of the Company's filing and responses to discovery requests, it appears that the Company has not engaged in long range resource planning during the past 7-9 years, ever since it opted to construct diesel engines rather than a cable to the mainland after its 1998 Consent Decree with the EPA was signed.

It has done very little by way of demand side management measures to control its continuously growing peak demand. Similarly, the Company has not recently conducted any cost allocation study or attempted to design rates to reflect principles of cost causation. Instead, in this case it proposes to expand its seasonal charge period into two shoulder months, to generate increased revenues. This rate design change fails to send appropriate price signals to the peak period users, where price signals are most needed to influence growth in peak demand.

I recommend that the Commission, along with other actions taken in response to BIPCO's general rate increase request, order the Company to begin immediately to fulfill its strategic planning responsibility to ratepayers and investigate a reasonable number of supply side generation options, distribution system improvements, demand-side management programs and rate design changes to assure BIPCO ratepayers that their utility is pursuing a resource strategy that is likely to be least cost over the long-term planning horizon.

Q. DID YOU HAVE AN OPPORTUNITY TO FAMILIARIZE YOURSELF WITH BLOCK ISLAND POWER COMPANY FOR PURPOSES OF PREPARING YOUR TESTIMONY?

A. Yes, I have read the testimony by BIPCO representatives in support of the Company's application for a general rate increase, discovery responses produced by BIPCO in response to interrogatories submitted by RIPUC, the Rhode Island Division of Public Utilities and Carriers and the Town of New Shoreham, together with other documents and material pertinent to this case.

Q. WHAT CHARACTERISTICS OF BLOCK ISLAND POWER COMPANY HAVE YOU FOUND IMPORTANT TO YOUR ANALYSIS?

A. First, BIPCO's electric rates are significantly higher than the electric rates of its mainland Rhode Island counterparts. For example, in 2003, BIPCO's average retail rate was 26.4 c/kWh, 22.11 c/kWh for residential consumption. By way of comparison, the comparable residential retail rate for Narragansett Electric was approximately half that level.

Second, BIPCO is a small utility, with a limited level of energy sales and a relatively small number of customers. The draft distribution study indicated that it had 1668 customers and 12,322 in MWh sales for the year ended May 2004. Nevertheless, the changes in circumstances that have occurred since the early to mid 1990s and the lack of initiatives taken by BIPCO since that time demonstrate the need for the Commission to direct system planning improvements.

Q. PLEASE DESCRIBE THE RECENT HISTORY OF BIPCO AS IT RELATES TO RESOURCE REQUIREMENTS AND RESOURCE PLANNING.

A. BIPCO has not come before the Commission for general rate relief since the early 1990s, although it has obtained cost recovery through its fuel adjustment clause for certain non-fuel costs, such as environmental remediation charges and diesel generator lease expenses.

During this long hiatus between general rate filings, BIPCO has experienced significant growth in the level of retail energy sales and in its peak demand. BIPCO's own witnesses acknowledge that these factors enabled it to avoid seeking rate relief until now.

In the mid to late 1990s, in response to Commission directives that the Company file a long range resource plan, BIPCO submitted to the Commission a request that it be authorized to invest in a submarine cable to the mainland as an alternative to constructing and operating new diesel generators on Block Island. BIPCO's response to the TOWN-52 data request contains documents, including prior BIPCO testimony, explaining the Company's long range planning efforts. These plans were also submitted to the Rural Utilities Service, or RUS. While the Commission approved this supply plan, BIPCO has testified that the Commission later gave BIPCO the flexibility to implement *either* the submarine cable project *or* the diesel construction option. BIPCO has further testified that the submarine cable option's economics became less favorable and the project more risky after the costs associated with the Narragansett Electric Company mainland connections increased.

Since the preparation of BIPCO's last long range plan, the circumstances in which BIPCO operates have changed significantly. The

Company has experienced a material growth in peak demand. In addition, the cost of fuel used by BIPCO has escalated dramatically. BIPCO also has experienced problems with the operation of its diesel emissions pollution control systems, which it testifies have not performed up to expectations. BIPCO also has testified as to the need for ongoing maintenance requirements of its diesel fleet. BIPCO has stated that it obtains fuel supplies by having fuel brought over by ferry on oil tanker trucks. It maintains several oil storage facilities on island, which it has previously testified would need to be expanded if it continued on a course of adding more and more diesel engines to meet growth in peak demand.

During this period of time, there have also been some improvements in various alternative supply side generation technologies (particularly renewables) that BIPCO previously examined as part of its earlier long range resource planning activities. The assumptions it used in screening those its options have changed dramatically, everything from installed costs, to avoided fuel costs, to lower costs of capital, etc.

As noted above, BIPCO has experienced an ever growing increase in peak demand. For example, the peak demand reported by BIPCO has grown from 2725 kW in 1995, to 3775 kW in 2004, an average annual rate of increase of 3.3% per year over the last 10 years. BIPCO has projected growth in peak demand to 7MW by approximately 2020 in a draft distribution study report provided to the Town. This peak demand occurs during the summer period. Kilowatt-hour energy sales have also increased.

To date, BIPCO has not obtained any material supply-side resources other than diesel generation. Its involvement in energy conservation programs has been minimal over the past several years, and there have been no load control initiatives, despite continued growth in peak demand and kwh energy consumption. In fact, at this point, BIPCO lacks a recent long-term load forecast, any DSM programs or load control devices, has given no consideration to a mainland cable option since 1998, has made no recent review of other feasible supply side alternatives, has given no consideration to interruptible rates, nor any consideration to a rate design other than its proposed expansion of its summer seasonal billing period.

Finally, I understand from BIPCO's filings that its General Manager, Mr. Wagner, who appears to be the only individual with utility background and experience, has announced his retirement.

I. INTEGRATED RESOURCE PLANNING

Q. ARE POWER SUPPLY RESOURCES AN IMPORTANT COMPONENT OF THE PROPOSED RATE INCREASE?

A. Yes. A significant portion of the proposed rate increase results from the Company's plan to install an additional diesel engine generating unit and effect other maintenance on other generators. As the testimony of various Company witnesses indicates, debt service, depreciation and carrying costs on its diesel engine generating fleet, together with O & M and environmental compliance (emissions and groundwater protection), constitute the greatest single component of BIPCO's cost of service, not to mention fuel costs passed through the FAC.

Q. HAS THE COMPANY PROVIDED ADEQUATE JUSTIFICATION FOR ITS PLANNED CHANGES TO ITS GENERATING CAPACITY?

A. No, it has not, and I will discuss this further in the last section of my testimony. BIPCO proposes to install a new diesel unit of the same technology that it has used in the past, and to retire an existing unit, without so much as an underlying cost-benefit analysis of its diesel generation fleet management & attrition plans.

Moreover, BIPCO has presented no recent or rigorous review of generation options beyond the diesel engines that it has come to rely on in the past. These options include, potentially, on and off-shore wind power, other renewable options such as sewerage-produced methane-fired generation, or an underwater cable link to mainland generation.

Other potential cost-effective resources include demand-side management (e.g. load control and energy efficiency) and peak use rate design & interruptible rate options. BIPCO's responses to TOWN-56, 64, 109 and 111 indicate that the Company has not considered these measures recently, if ever. Furthermore, aside from a net metering program, BIPCO appears not to have tried to access potential contributions from customer-owned generation.

In summary, from our review of BIPCO discovery responses, the Company has not <u>recently or rigorously</u> studied the economic and other benefits (e.g. fuel and unit diversity, monetized or unmonetized environmental, improved customer service, etc.) of meeting customer demands differently than the diesel engine default approach it has come to rely on to this day.

Rigorous investigation of, and a fair comparison between, alternative supply and demand-side options for meeting customer demands are why many state regulatory commissions have required utilities to engage in ongoing Integrated Resource Planning. BIPCO recognized these obligations in the past, when directed by the Commission to do so, but has since failed to engage in this critical activity.

Q. HASN'T BIPCO PROVIDED EVIDENCE OF ONGOING SUPPLY SIDE RESOURCE STUDIES?

A. BIPCO provided a draft document from a consultant which is not much more than some assembled materials available from the internet and descriptions of a handful of supply side options. These technologies may have been screened for application to BIPCO, but the use of outdated fuel and capital cost assumptions, for instance, do not represent current going-forward economics of some key potential options. For instance, the study the Company commissioned does not adequately consider the fuel savings benefits from small-scale wind power.

None of these materials revisit the economics of a cable to the mainland, despite the sharp increases in the price of oil, and evidence of growth in demand for oil, together with increased instability in world markets. Given BIPCO's failure to conduct ongoing review of supply side alternatives since opting for new diesels and its planned addition of another new diesel later in 2005, there is little reason to believe that BIPCO will give serious consideration to supply side options other than diesel unit additions – without Commission intervention and direction.

Q. WHAT IS AN INTEGRATED RESOURCE PLAN?

A. Among the best definitions of an integrated resource plan (IRP) that I have come across is the statutory requirement in Vermont.[1] Vermont regulators define an IRP as

> "a plan for meeting the public's need for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs."

In summary, an integrated resource plan involves careful, rigorous, quantitative and qualitative review of a host of feasible supply-side generation, transmission and distribution improvement options and demand-side management and load control measures. The objective is to compare costs and benefits as evenly as possible, and test combinations or "portfolios" of such options on an integrated basis, to arrive at the projected least cost going-forward portfolio under a reasonable range of

[1] See Title 30 V.S.A. §218c.

projected macroeconomic and operating conditions the utility could face over a long-term planning horizon.

Q. WHY IS INTEGRATED RESOURCE PLANNING IMPORTANT TO A PUBLIC UTILITY AND ITS CUSTOMERS?

A. It is fundamentally important that such planning be done by franchise monopoly utilities that operate in the public trust. This is so that ratepayers, in this case BIPCO ratepayers, can be assured of reliable and safe electricity service, at a just and reasonable price, that promotes economic efficiency and proper allocation of limited societal resources.

Without adequate integrated resource planning, ongoing or less frequent resource acquisition or management opportunities that can lower costs, improve service or both, can be overlooked. Such opportunities could include generation, transmission or distribution efficiency improvements, and demand-side management measures, including load control, energy efficiency or rate design initiatives. Opportunities to lower costs or improve service can often be identified in some or all of these areas, but utility planning and engineering staff must be vigilant about cost-effectively uncovering and studying them.

Q. SHOULD THE COMMISSION EXPECT A SMALL UTILITY LIKE BLOCK ISLAND POWER COMPANY TO ENGAGE IN LONG RANGE PLANNING PRACTICES LIKE INTEGRATED RESOURCE PLANNING?

A. Absolutely. Though the scale of the efforts required by a small utility like BIPCO could be less, and less expensive, than that required of a larger utility, no monopoly utility system should be exempt from appropriate long-term resource planning. If it were, reliable, safe and economic service to ratepayers would be jeopardized.

Strategic resource planning is undertaken regularly by even the smallest commercial and public enterprises, because current and future income, customer growth and satisfaction, and long-run organizational success all depend on such planning. The ratepayers of BIPCO and residents of the Town of New Shoreham deserve no less from the Company. Moreover, given the unique island nature of the BIPCO system, it cannot simply initiate strategies that have been effective for other grid-connected utilities. This uniqueness makes it particularly incumbent on BIPCO to analyze its options creatively.

In the past, the Commission has recognized that long range planning should be conducted by BIPCO. It required the Company to submit long range plans. In its response to TOWN-52, the Company provided documents related to the long range resource plan submitted at the direction of the Commission around 1996. Both the Commission and, in turn, BIPCO, recognized the critical importance of long range planning and demand side management in carrying out the Company's public service obligations. At the time, the Company submitted evidence of its long range resource plans to the RUS in order to gain approval of a Construction Work Plan in 1997.

As a borrower from the Rural Utilities Service (RUS), a subdivision of the U.S. Department of Agriculture, using tax-exempt, publicly-financed, below-market debt, BIPCO is expected by the RUS to engage in long range planning (LRP). The RUS specifies standards for its borrowers that require long-range strategic planning and publishes Bulletins that promulgate these standards. Attached to my testimony as Attachment SCF-3 is Bulletin 1724D-101A, an electric system long-range planning guide for RUS borrowers. Given that the RUS expects BIPCO to engage in a long range planning process, it is not unreasonable for the Commission to continue to require the same.

Q. WHAT DOES THE RUS REQUIRE OF ITS BORROWERS?

A. Article 3.1 states:

> "(i)t is the responsibility of the system planner, hereafter called the planning engineer, to sort out available information to determine the optimum approach for the individual system to use in attempting to provide adequate capacity and quality of service in a reliable, economical, and environmentally acceptable manner."

Q. HAS BIPCO FULFILLED ITS RESPONSIBILITIES PURSUANT TO THE RUS GUIDELINES?

A. My review of articles 3 and 4 of the RUS LRP requirements suggest that while BIPCO has engaged in some activities specified by the RUS, by and large it has failed to meet even the most basic requirements since the mid-to-late 1990s. A review of BIPCO's discovery responses in this docket confirms that very little of the activity specified within the LRP Bulletin has occurred with respect to: a) recent review of economic supply options other than the diesel default strategy, or b) addressing high distribution system losses. Further, the Company admits it has not been investigating demand-side initiatives to control load, nor has considered redesigning rates to strengthen the possibility of load response.

Q. BLOCK ISLAND POWER COMPANY IS NOT CONNECTED TO THE MAINLAND POWER GRID. HOW DOES THAT AFFECT ITS LONG RANGE PLANNING PROCESS?

A. Without access to the ISO-NE wholesale marketplace, the Company's generation options are limited to those that can be physically located on Block Island or perhaps nearby offshore.

Q. DO YOU HAVE ANY RECOMMENDATIONS IN RECOGNITION OF THIS CONSTRAINT?

Yes. In order to determine whether this limitation can be overcome, BIPCO's long range planning process should take into account the feasibility of obtaining power from the mainland by means of a submarine cable, which might be owned by BIPCO or other parties. The Company appears to agree in its response to TOWN- 103 that the cable to the mainland option needs to be re-examined. A fresh review of the economics of a submarine cable project connecting the island with the New England grid is warranted as one part of a Block Island IRP effort. This review should consider the volatile present and going forward fossil fuel price environment BIPCO and its ratepayers would otherwise face if it continues with a diesel-only generation base, since the cost of diesel fuel is driven by oil prices. At over $50/bbl currently due to global demand rising faster than production, oil prices have doubled in the last few years, and few are projecting any downward trend to materialize soon. Thus, the cost of diesel fuel will also remain high and volatile, burdening BIPCO ratepayers to whom such high and volatile costs are passed through the fuel adjustment charge (FAC). Mr. Wagner, who has testified in this case for the Company, even recognized BIPCO's exposure to volatile and increased fuel costs when he testified in 1996 regarding the Company's long range resource plan. Oil prices have escalated since then.

The Company now has access to low-cost, below-(private) market debt available through the RUS. Investigation of whether low-cost RUS financing could leverage the economics of a cable project should be undertaken. The potential for grant funds to help underwrite the cost of a submarine cable also merits investigation, given that grant funds have been applied in other instances to aid small utility capital projects, for instance the underwater cable project connecting the Fox Islands Electric Cooperative in Maine. Attached to my testimony as Attachment SCF-4 is an article describing a federal USDA grant for this project.

BIPCO's study should also include, as part of an IRP, a review of the host of market supply options that would then become available to meet Block Island Power Company wholesale requirements. This may be an especially attractive strategy for BIPCO because it typically uses more summertime energy and incurs higher demands on the weekends, thus if it did have access to ISO-NE energy markets it could buy much of its requirements at (off-peak) weekend wholesale rates.

Because a cable connection would allow two-way trade (e.g. affording BIPCO the ability to sell excess energy, ICAP or ancillary services to ISO-NE particularly during non-summer months), the added optionality of a cable project to the BIPCO supply portfolio should be studied as well.

In considering the economics of cable, BIPCO should revisit the substation costs (rather than just accepting the prior cost estimate by Narragansett Electric) to connect a submarine cable to the mainland grid, since this cost apparently figured significantly in BIPCO's decision in the late 1990s to abandon the cable project.

Finally, the Company is expected to continue to have some cost exposure going forward regarding compliance with clean air and other environmental requirements associated with its diesel engines, and must manage fuel deliveries by tanker trucks carried over by ferry. Access to the broader New England wholesale market, with its widely available pool of cleaner-burning natural gas generators and other facilities, should be fairly compared against the costs of continued (and likely escalating) environmental compliance costs and risks BIPCO will otherwise face. BIPCO has previously testified that extended reliance upon diesel generation would cause it require additional fuel storage facilities and incur additional fuel storage costs. These associated capital and environmental compliance factors should all be taken into account.

BIPCO should also explore, through a request for proposals (RFP) process, the willingness of potential power suppliers to partner with it in pursuing methods for financing the cost of a submarine cable to the mainland, in addition to the option of RUS or grant financing discussed above. Such partnering might include, but is not necessarily limited to, a supplier's paying the upfront capital costs, which would be passed through to ratepayers in the form of a surcharge over a period of years. Other business models may emerge from the RFP process and BIPCO should be free to solicit a range of proposals.

Q. DO YOU HAVE SPECIFIC RECOMMENDATIONS REGARDING THE CONDUCT OF INTEGRATED RESOURCE PLANNING BY BLOCK ISLAND POWER COMPANY?

A. Yes. I recommend that the Company undertake a review of a limited number of potentially feasible supply side options, including a mainland cable project, potential renewable supply options such as onshore and offshore wind or methane recovery projects, the potential offered by access to current and future customer-owned generation, as well as continued reliance on diesel generation. In this review of supply-side initiatives, I suggest the Company consider some cost-effective distribution system improvements as well, since line losses have averaged over 10% the last 3 years, and maximum voltage drops during peak periods have averaged at least double the level acceptable to the RUS, according to the draft distribution study report submitted by BIPCO's consultants in late 2004.

In addition, and alongside the supply side options, the Company should review cost-effective demand-side management (DSM) options, particularly load control options for the summer peak season. It should focus first on the 93 demand-metered customers who consume close to half of the summertime energy, driven largely by air conditioning and refrigeration loads. It is these high demand commercial customers which are primarily driving the system peak demand at BIPCO, and BIPCO's stated need for the new diesel engine for which the Company is seeking rate recovery in this docket. Working with these customers to undertake some cycling of these loads and alleviate peak system demand pressure could be cost-effective, and could forestall capacity additions.

These limited measures, targeting the "low hanging fruit" among the demand-metered customers, could be put in place relatively quickly as compared to broader residential programs (which might be the next step, particularly an air conditioning cycling program).

Finally, the Company should consider, as part of or together with an IRP, some cost-effective rate design options. Those that appear to show the most promise would be higher summer peak demand and service charges to boost the price signal to customers that drive the need for new capacity. Higher summer season marginal cost pricing could be effective at stimulating some peak load reduction. My review of BIPCO's current tariffs suggests that more could be done in this regard, particularly for demand-metered general service customers who may face less of an electricity bill impact from higher demands at peak times than the lower-use residential, general service and public authority customers who also pay a summertime system charge. Besides potentially affording more revenue recovery for BIPCO, such a tariff adjustment, if steep enough, could curtail system demands by summertime end-users who have so far shown little price response to BIPCO's current seasonal rate structure.

This review should begin immediately because BIPCO load and power requirements continue to grow, before further commitments to new diesel engines are made.

Q. WHAT TIME FRAME HAVE YOU RECOMMENDED BE USED FOR A LONG RANGE INTEGRATED RESOURCE PLANNING STUDY?

A. Most integrated resource plans cover a planning horizon of from 10-20 years into the future.

In the case of Block Island Power Company, a longer-term horizon such as 20 years would be appropriate. This is partly because of the capital-intensive nature of most of its supply-side options besides the diesel engines, whose economic impact within the BIPCO portfolio should be measured over their useful lives. A related reason has to do with the likely source of BIPCO capital for long-lived generation, distribution system or demand-control projects. The RUS will generally finance economic generation projects over a period of up 20 – 25 years, while long-lived transmission and distribution projects can gain even longer-term loans.

The IRP should cover a period of time to allow long-lived projects a chance to compete against shorter-lived diesel engine replacement projects. BIPCO's consultants in the mid 1990s also chose to use a 20 year horizon in their long range resource planning and evaluations, as shown in the Company's response to TOWN-51. Mr. Wagner's testimony from 1996, included in the Company's response to TOWN-52, supported a 15-20 year planning horizon.

II. SUPPLY SIDE OPTIONS

Q. PLEASE DISCUSS FURTHER THE SUPPLY SIDE OPTIONS YOU HAVE SUGGESTED BE EVALUATED AS PART OF BLOCK ISLAND POWER COMPANY'S IRP STUDY?

A. I suggest that BIPCO conduct an economic screening in four areas, based on "avoided costs" defined by the generation expansion costs of continuing to add diesel engines.

First, BIPCO should make a long-term projection of its load and energy requirements, and the costs to meet them. This "avoided cost" stream should consist of a buildout of diesel engines and their capital, fixed and variable O & M, and fuel costs. Developing an avoided cost stream will allow the Company to evaluate the costs and benefits of other projects against its default diesel engine portfolio.

At the same time, the Company should solicit interest and request proposals from merchant firms or other vendors for the following kinds of projects:

- Mainland cable connection;

- Renewable wind or methane recovery projects; and

Distribution system improvements/line loss recovery.

Additionally, the Company should contact Champlins Marina, the Sewage Plant and any other customers with grid-connected generation or generation that could be grid-connected, to investigate how such generation could be tapped, if available, to help meet Block Island Power system peaks.

A request for proposals (RFP) from third parties could be a useful way to find and screen resource options without committing significant Company resources on options that it would otherwise have to uncover, investigate and develop itself.

To be sure, the Company will have to commit resources to developing the RFP, pulling together the kinds of load and system information responding firms will need, working with such firms in the development of their proposals and seriously evaluating those that show the most promise. The data in the draft distribution study provides a good foundation. Virtually all of the remaining data exists or could be developed from discovery responses produced by BIPCO in this docket.

Managing an RFP and an integrated resource planning process will require more Company effort than it has dedicated to date, but BIPCO ratepayers will ultimately be the beneficiaries if cost-efffective alternatives to a future of high fuel cost and potentially high environmental costs associated with diesel engine buildouts can be found.

Q. ARE YOUR RECOMMENDATIONS CONSISTENT WITH RUS LONG-RANGE PLANNING GUIDELINES?

A. Yes. Article 3.7 of the RUS Bulletin prescribes that:

> "System planning can be divided into five distinct tasks, as follows:
>
> a. Basic data should be maintained and continuously updated to facilitate the evaluation of newly proposed alternatives throughout the LRP period.

b. The existing system should be analyzed to ascertain its ability to serve present and projected requirements. Objectives of the owners should be considered in the system analysis. The planning engineer should determine what additional capacity is needed and what facilities will need replacing during the long-range planning period. This information will aid in the judicious selection of alternatives.

c. Once the system requirements have been determined, various alternative plans can be formulated which will satisfy these requirements.

d. By careful application of present worth analysis or some other valid economic analysis procedure, the owner or engineer can select the optimum plan for the projected requirements. It is extremely important that each alternative evaluated provides for adequate quality of service, environmental acceptability, and adequate system capacity at each level of the LRP period. Some alternatives may provide a temporary excess of capacity. This excess should be justified through reduced overall construction costs or reduced losses.

e. When starting a new construction work plan (CWP), the LRP should be reviewed in light of actual system developments to determine whether it needs to be revised or updated. A CWP should then be prepared to determine which of the facilities demonstrated to be necessary in the LRP will be most appropriate to install during the immediate work plan period."

Q. IS THE COMPANY LIKELY TO FIND COST-EFFECTIVE SUPPLY SIDE PROJECTS THROUGH AN RFP?

A. Some options may present themselves if the RFP is carefully constructed so third party developers or engineering and construction firms perceive an opportunity to profit from providing and developing quality supply-side proposals. Such firms would have to be convinced that BIPCO is serious about actually developing its options, however, in order to get the kinds of thoughtful and feasible options, customized to Block Island, that the Company should be pursuing as part of its integrated resource planning.

Towards that end, a Commission order requiring the Company to request and review such third-party options, and pursue development of those that show the most promise, would send a signal to third parties that

BIPCO is prepared to make commitments beyond adding the occasional new diesel engine where justified.

Q. CAN THE COMPANY DO ANYTHING ELSE TO INCENT COST-EFFECTIVE SUPPLY SIDE PROPOSALS?

A. Yes. Among the most attractive assets that third-party developers should recognize in responding to a BIPCO RFP, is the Company's access to low cost debt from the RUS. Because the kinds of supply-side projects that could make sense for BIPCO are highly capital-intensive, leveraging their economics with debt whose interest rate might be as little as half of the cost of privately placed debt, should allow such long-lived capital-intensive projects to compete on an even footing with the diesel engine default approach that has been adopted by BIPCO so far.

The Company, having successfully qualified as an RUS borrower, has an enormous cost of capital advantage over other private utilities, who now face interest rates that are rising due to actions by the Federal Reserve. Exploiting that advantage should be a key integrated resource planning strategy adopted by BIPCO.

III. DEMAND SIDE OPTIONS

Q. TURNING NOW TO THE DEMAND SIDE, WHY SHOULD DEMAND SIDE MANAGEMENT (DSM) FACTOR INTO BLOCK ISLAND POWER COMPANY'S LONG RANGE PLANNING PROCESS?

A. Block Island is a summer tourist destination with a peak season that runs primarily from June through September when the weather is considerably warmer. Its recent summertime peaks have all occurred in these months, in fact in the last 10 years, all but one occurred in August (in 2000, the peak occurred in September).

The Company requests rate recovery for a new diesel engine associated with an ever increasing summer peak load. That load is very likely driven by the significant refrigeration, air conditioning and hot water requirements of commercial establishments. To an ever increasing degree, air conditioning loads of the residential customers are also pushing system peaks.

Managing the requirements of these end uses, and coincident system demands they cause, should be a primary focus of BIPCO.

Q. WHAT DEMAND SIDE MANAGEMENT MEASURES SHOULD THE COMPANY EVALUATE?

A. Those loads and customers that could curtail summertime peak demands when the system peaks should receive the most attention first, in consideration of the pending requirement for new capacity.

Given what the Company says is a need for new capacity this summer, the first priority should be load control. Since a relative handful of the large demand-metered customers account for a significant proportion of system peak demand, they should be approached first. The Company could reach out to these larger customers with curtailable loads (particularly refrigeration, air conditioning or hot water), and offer an interruptible rate that would provide incentives to interrupt such uses for relatively short periods of time when the system is at or near peak. This type of interruptible rate could be voluntary, effectuated with a phone call or other simple means of communication, and offer either lower overall base charges, or an attractive per interruption credit, in exchange for a period of interruption when needed. Of all the broad category of DSM measures that BIPCO could implement, this interruptible rate program is likely able to be placed in service in the least amount of time.

Proof of concept could begin as early as this summer if a trial program, with a limited set of customers, could begin in the next few months.

A simple ripple control or other means of cycling large demands to periods of lower BIPCO system coincident demands, could also be cost-effective and defer the point at which new capacity is needed to meet those peaks. Controlling coincident demands is cost-effective because the addition of capacity to meet the end uses described above, which are often concentrated over a relatively few hours, is extremely expensive at low load factors. For instance, data supplied by BIPCO in its 2004 Long Range Distribution Planning Report, show system load factor, in 1999 a relatively low 40%, has since declined by almost 7%, to 37.3% last year. Therefore, a means of cycling or deferring these coincident peak loads, even for alternating and short periods of time, or pushing some of them to BIPCO system off-peak periods, could be very cost-effective.

There are still less than 100 demand-metered customers on the BIPCO system that account for close to half the summertime electricity consumption. Reaching out to the demand-metered customers in particular, together with an attempt to institute an interruptible rate program or in a few cases to access customer-owned generation, is likely to identify the most cost-effective DSM and afford BIPCO an opportunity to aggressively control growth in demand caused by a relatively small proportion of its customer base.

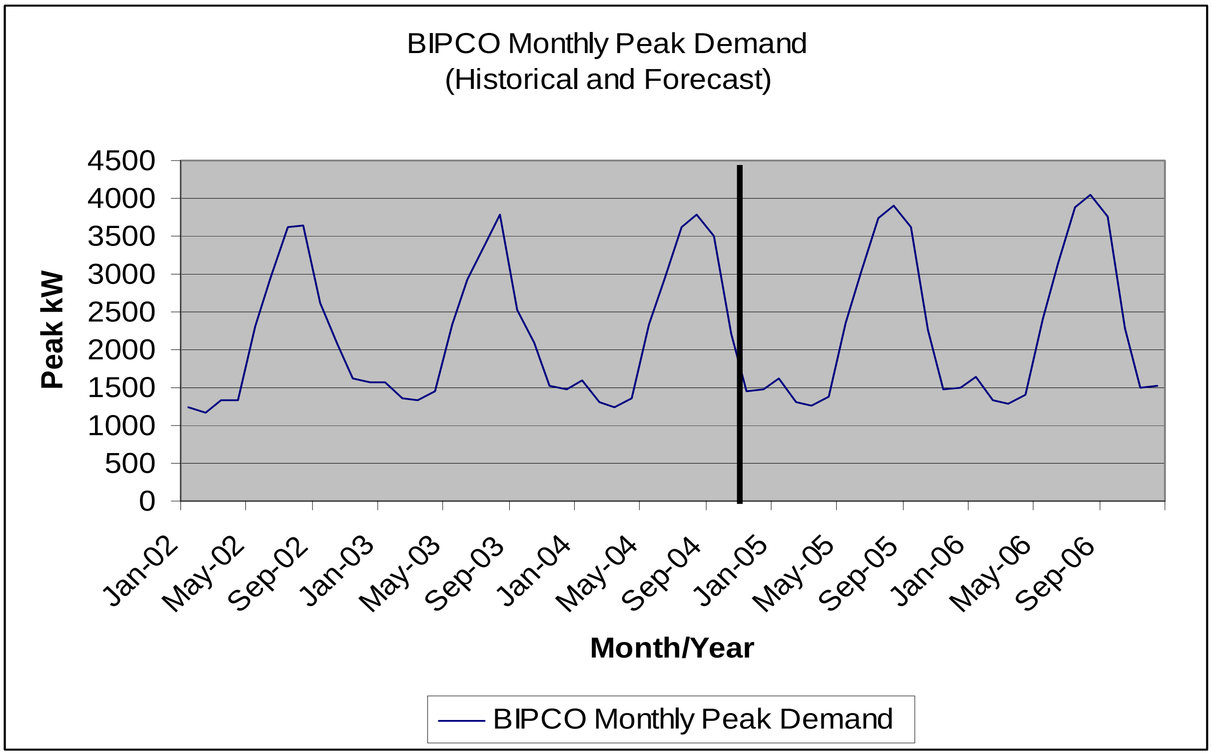
Once successful in reaping the most easily identifiable load control measures, BIPCO could concentrate more broadly on residential uses like the control of air conditioning.

IV. COST ALLOCATION AND RATE DESIGN

Q. WHY IS COST ALLOCATION IMPORTANT IN THE CASE OF BLOCK ISLAND POWER COMPANY?

A. The Company's rate case evidence and recommendations raise a number of cost allocation issues.

I have touched upon perhaps the most important cost allocation consideration already. The Company's filing, interrogatory responses and request for rate recovery of a new diesel engine and other generation costs, leave no mystery that summer seasonal uses are driving the need for this new capacity.



Fairness and the ratemaking principle of cost causation require that those customers that cause the need for new capacity, the marginal consumers at peak times, should pay for most or all of the cost of this new capacity. In BIPCO's case, this is particularly important because of the cost impacts of adding relatively lumpy new increments of system capacity (like the proposed new diesel engine and other generation "fixes" proposed in this case).

Q. WHY IS RATE DESIGN ALSO IMPORTANT HERE?

A. Rates are designed in part to ensure revenue sufficiency, but they also serve as an important signaling mechanism to ensure that customer decisions to consume more power at various times take into consideration the contemporaneous cost of providing that power. This dynamic promotes economic efficiency and leads to lower overall costs of service, all else being equal.

Q. THE COMPANY HAS PROPOSED EXTENDING THE SUMMER SEASONAL RATES TO THE SHOULDER MONTHS OF MAY AND OCTOBER, PRIMARILY FOR REVENUE SUFFICIENCY REASONS. IS THIS APPROPRIATE FROM A RATE DESIGN PERSPECTIVE?

A. No, I recommend that the Commission deny approval for this rate design change.

It is clear that if the Company needs new generating capacity, it is because of growth in peak summertime load.

The marginal cost of demand in the peak summer months is quite high. Additional summer peak demand increases the need for capacity, or increases the chance of reliability problems if no new capacity were to be added.

Absent some extraordinary changes to BIPCO loads, the Company's summer peak will almost assuredly occur in one of the four summer months of June – September as it has in each of the past 10 years. Charging a higher block rate for two additional months does not send the correct price signal, because those are not months in which marginal costs (particularly of capacity) are the highest.

From another perspective, if customers reduce their usage in May or October, that action does nothing to solve the BIPCO capacity problem. Furthermore, adding two months at the higher summer rate might create a perception that rates are increasing less than if the current rate structure is maintained, but all that would actually happen is the wrong customers or loads would be paying for the increased costs - and the signal to curtail peak summer use is being muted.

Q. WHAT RATE DESIGN CHANGES WOULD YOU RECOMMEND BE INSTITUTED WITHIN THIS RATE CASE, PURSUANT TO AN IRP INITIATIVE OR IN SOME OTHER COMPANY FILING?

A. Since the Company does not have separate rate classes for summer users, additional revenue responsibility can be allocated to summer users through rate design, including increasing summer block rates, particularly for the demand-metered commercial customers. Such a rate design will send better price signals.

Summer seasonal rates should at least approach the marginal cost of new capacity.

Instead of extending the current summer seasonal rates to shoulder months as the Company has suggested, I recommend that the entire increase be collected through increases to current 4-month summer seasonal rates. There is a much better probability that customers would respond to such a price signal and BIPCO would see some resulting load reduction. While price sensitivity (economists call this the "price elasticity of demand") of various customers has yet to be measured, there will surely be some price level that does lead to load reductions – reductions that might forestall the need for a lumpy addition of new capacity.

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS FOR BIPCO RATE DESIGN CHANGES?

A. Yes. Some further redesign of the current summer seasonal rate structure may be warranted.

Note that the non demand-metered rates, and the public authority tariff, contain a "System Charge" that is paid by customers who use twice as much in a summer month as in a winter month. This provision is somewhat unclear. For instance, it is not clear whether this will be paid only in months when usage is double the average or will be paid in every summer month (i.e. a seasonal “ratchet” which is what the Company seems to administer).

The system charge concept is another way to signal higher summertime marginal costs to non demand-metered customers, and also to allocate more costs to customers who contribute heavily to the summer peak. Improving the tariff language to strengthen the price signal (denoting specifically the seasonal ratchet) seems worthwhile. If the tariff communicates clearly that crossing the threshold into having to pay the system charge will affect all summer bills, some customers may reconsider and curtail marginal consumption during those months.

For reasons that are not clear, while there is both a system charge and a demand rate for public authority customers, there is no equivalent system charge on the demand-metered general service rate. The only higher price signal in the demand-metered rate is that the demand and energy charges are higher in the summer. In any case, unless there is a clearly communicated ratchet, a higher demand rate charged only based upon the actual demand reading for that month, will probably be a lower “penalty” for summer usage than the System Charge in the other non demand-metered rates.

I recommend that the Commission order a BIPCO rate redesign that boosts the price signal to all demand-metered customers. For the demand-metered general service commercial customers, this might involve a higher demand rate, adding a system charge comparable to the public authority tariff, or both. For all customers, I recommend the Commission order BIPCO to increase the price signal associated with summertime usage to clearly define a ratchet effect on bills from high marginal summertime consumption.

Q. BLOCK ISLAND POWER COMPANY IS A SMALL UTILITY WITH A LIMITED CUSTOMER BASE. IS IT REASONABLE FOR IT TO PREPARE OR HIRE CONSULTANTS TO CONDUCT A LONG RANGE INTEGRATED RESOURCE PLAN STUDY TO EVALUATE THIS RANGE OF SUPPLY SIDE AND DEMAND SIDE OPTIONS AS YOU HAVE RECOMMENDED?

A. Yes. As I stated earlier, small utilities and RUS borrowers in other states are required to engage in the type of resource planning and management described herein, and do so with the objective of lowering system revenue requirements and cost burdens on ratepayers. Those that do it successfully achieve real, measurable results in lowered costs and increased customer satisfaction, outcomes that all utilities should continuously strive for.

The Company should be able to cost-effectively identify a manageable number of new resource options without causing an undue burden on ratepayers. The Commission saw fit in the early 1990s to direct the Company to conduct long range planning and load management programs. The need for this type of planning and implementation remains as strong today as it was over a decade ago.

Q. HOW MUCH WILL THE TYPE OF WORK THAT YOU HAVE RECOMMENDED BE LIKELY TO COST?

A. The answer depends on the BIPCO staff time that can be dedicated to planning, how efficiently and effectively BIPCO works with customers (particularly the demand-metered customers) for DSM and an interruptible rate program, and the supply-side proposals BIPCO can leverage from merchant or other third party developers and firms. I would argue that more internal staff time should be dedicated to the type of integrated resource planning I have proposed herein, and managing any DSM or interruptible rate program that results from this work, than has been expended by BIPCO management to date. I am not convinced that all of this work requires the use of consultants or substantial additional BIPCO staff, though some consulting expertise is advisable. I understand that BIPCO has only 8-9 employees at present and therefore will need to evaluate the costs and benefits of staffing additions and reliance upon outside consultants.

It is probable that a good quality integrated resource plan would cost approximately $50,000 - $100,000 if prepared by an outside consultant, depending in large part on the support provided by the Company in the areas of data gathering, customer outreach and other support. Implementation of DSM or interruptible rate measures would require additional funds over time. As noted above, a trial for specific measures would be an economic way to initiate these measures and test their effectiveness before a full DSM program is implemented. Similarly, in the case of supply side options such as wind, it may be possible to have a vendor fund the data gathering to determine the feasibility of a wind project and the benefits that might be expected from the project, if the Company can demonstrate that it is serious about considering a range of supply side options.

If the Commission approves such expenditures as requested by the Company, it should be allowed to book the costs and track them separately, and recover them over a reasonable period during which the benefits will also accrue to customers, or perhaps a longer period if the benefits take longer to offset the costs.

Q. WHO SHOULD PAY FOR THIS WORK, AND HOW SHOULD THESE COSTS BE RECOVERED?

A. Block Island Power Company should be required to undertake the planning and other initiatives described herein for the benefit of ratepayers, and the costs should be tracked separately as I noted above.

BIPCO should also be ordered to investigate all grant and other available funds for planning and DSM, and pursue those resources aggressively.

The surcharge concept as expressed by Mr. Edge for BIPCO is probably an appropriate means of paying for this work because it also allows those revenues targeted to planning and DSM to be accounted for separately. I recommend that the cost level for an IRP be approved by the Commission after review and approval of an IRP submission made by BIPCO as a result of the decision in this proceeding. I further recommend that a seven year amortization period be used for recovery of the IRP. I base this recommendation upon the Company's track record of not having conducted a long range resource plan since the 1996-1998 time frame. Should the Commission require the Company to make more frequent submissions of IRPs, or should the Company develop a better track record of routinely conducting and updating its long range planning, this amortization period may be adjusted in the future. Thus, I recommend that if the cost of an approved IRP were $70,000, $10,000 would be built into the rates of the Company.

As to DSM activity, I propose a surcharge of 2.3 mills per kWh, with 2 mills directed at Company-sponsored DSM and .3 mills directed to the State Energy Office for Renewables programs consistent with R.I.G.L. § 39-2-1.2(b). Again, if grants are available to BIPCO for funding DSM activity, then they should be ordered to exhaust all such possible funds before being allowed to utilize ratepayer-supplied funds for DSM.

I strongly recommend the Commission consider setting some planning and DSM objectives that BIPCO must satisfy, perhaps on the recommendation of a planning and DSM advisory committee that includes the Town of New Shoreham, before allowing BIPCO the opportunity to realize any of those revenues, however, to ensure BIPCO ratepayers are getting the best return for those planning dollars. At a minimum, the Commission should require BIPCO to file a proposal for planning and DSM activities, and funding, that is consistent with those objectives and conditions, and with an opportunity for the parties in this case to comment, before being allowed to implement any surcharge-based funding for planning and DSM.

Q. WHAT IS THE COST IMPACT UPON THE COMPANY'S RATEPAYERS?

A. The cost impact will depend upon the costs that BIPCO is authorized to incur and the amortization or surcharge time frame for their recovery from ratepayers. The cost impact to ratepayers of an IRP and DSM surcharge should be under $50,000 per year while in effect, and the average bill impact per ratepayer should be under $25.00 per year assuming a uniform surcharge per kwh is used to recover costs. However, the Commission should consider loading much of the surcharges, if approved, into summer rates, since much of the load growth on the BIPCO system for which planning and DSM is required, is coming from summertime consumption.

Q. ARE THERE COST IMPACTS THAT ARISE FROM THE FAILURE OF A SMALL ELECTRIC UTILITY TO ENGAGE IN INTEGRATED RESOURCE PLANNING?

A. Absolutely. The Company's default strategy of continuing to add diesel engines would commit its ratepayers to continuing to pay for high cost and volatile diesel fuel and environmental compliance, while other, more cost-effective opportunities could be foregone. Over time, the "regrets" associated with BIPCO's failure to identify and develop alternatives could be measured in the hundreds of thousands of dollars to millions of dollars, and in polluted air and groundwater or other environmental costs.

Q. WOULD IT BE REASONABLE TO PRE-FUND THE COSTS ASSOCIATED WITH THIS WORK TO ALLEVIATE ANY IMPACT THAT THE COST OF THIS WORK WOULD OTHERWISE HAVE UPON THE COMPANY'S FINANCIAL CONDITION?

A. A number of approaches to funding cost-effective IRP and DSM work could be employed.

The key funding features that the Town of New Shoreham believes are crucial for the Commission to order would include:

a) sequestering and booking separately any IRP or DSM surcharge revenues (if allowed), and the costs for these IRP and DSM activities, and

b) only allowing BIPCO access to ratepayer-supplied revenues dedicated to these activities once they have been undertaken and managed properly; that is that measurable preset goals and objectives are realized before BIPCO would be allowed to book this income.

Q. HOW SHOULD THE COMMISSION ASSURE THAT ITS DIRECTIVES HAVE BEEN PROPERLY CARRIED OUT BY THE COMPANY?

A. As I have stated, the Commission should adopt directives in this proceeding for BIPCO to comply with. It should direct BIPCO to submit for Commission review a proposed IRP study based upon the costs that I have estimated as reasonable for this task. If BIPCO wishes to spend more, the additional expenditure should be at risk until BIPCO's next rate case or another proceeding in which the Commission may review the reasonableness of the amount expended. The Commission should give the Company a firm date by which to submit a proposed IRP study to the Commission, which should be within 120 days after the date of the Commission's order, so as to allow time for input in the early stages from stakeholders such as the Town.

If the proposed IRP study meets with Commission approval as to scope and specifications, the Commission may authorize BIPCO to proceed and conduct the IRP study. Upon completion, BIPCO would file its study with the Commission together with its plans based upon study results.

Q. SHOULD THE COMMISSION ALLOW FOR INPUTS INTO THE IRP PROCESS BY INTERESTED PARTIES SUCH AS THE TOWN?

A. Yes. The Division of Public Utilities and Carriers, the Town of New Shoreham and BIPCO ratepayers all have an interest in successful planning and DSM outcomes, and as such their input at the front-end of the process is paramount. BIPCO should be directed to begin the process by soliciting the input of these and any other parties with a legitimate interest in the outcomes. Stakeholders also should be afforded an opportunity to submit comments on any IRP proposal submitted to the Commission so the Commission receives the benefit of their input in acting on the IRP proposal.

Q. HOW DO YOUR RECOMMENDATIONS COMPARE TO THE PRACTICES FOLLOWED BY OTHER SMALL ELECTRIC UTILITIES?

A. I have worked for utilities as small as BIPCO that are required to engage in integrated resource planning and implement DSM activity to the levels I have prescribed herein. Again, while smaller systems may have fewer overall cost-effective opportunities for lowered resource costs, these utilities are not exempt from this planning because it is designed to lead to lower or stabilized costs for ratepayers.

Put another way, ratepayers in smaller systems deserve the same level of rigorous planning and resource management as their counterparts in much larger systems.

Q. HAVE YOU REVIEWED THE ENERGY POLICIES IN RHODE ISLAND FOR CONSISTENCY WITH YOUR RECOMMENDATIONS HERE?

A. Yes. I believe my recommendations are consistent with Rhode Island state energy policy.

VI. DISTRIBUTION SYSTEM LOSSES

Q. DID YOU HAVE AN OPPORTUNITY TO REVIEW THE COMPANY'S DRAFT DISTRIBUTION SYSTEM STUDY?

A. Yes.

Q. DO YOU HAVE ANY COMMENTS ON THAT DRAFT AS IT RELATES TOTHIS PROCEEDING?

A. I am very concerned about the reported voltage losses that BIPCo appears to have been experiencing for some years.

Q. WHAT ARE VOLTAGE LOSSES, AND HOW DO THEY AFFECT THE COMPANY AND ITS CUSTOMERS?

A. These are energy losses experienced over the distribution system, between the generator bus and the customers' meters. They vary with the square of the distribution system voltage, the distance between generation source and load, and other factors such as ambient temperatures, circuit design, circuit loadings, etc.

The higher the losses, the higher the cost to serve load, because more generation (and associated cost) is required per kWh of consumption by customers when losses are higher.

Q. **DO LINE LOSSES AFFECT THE COMPANY'S REVENUE REQUIREMENTS?**

A. Yes. A review of the Company's most recent FERC Form 1 report, for the year ended May 31, 2004, shows an average retail rate of $264.07/MWh.[2] The Company reported line losses over the past 3 years of approximately 1,250 MWh per year.[3] This means that line losses cost approximately $330,000 per year in each of the last 3 years. If the Company could reduce its losses by half through improvements to the distribution system, it could reduce costs by $165,000 and its need for revenues. Put another way, BIPCO ratepayers may be paying up to $165,000 per year too much for BIPCO service, because BIPCO has allowed its distribution losses to rise to a level that is twice what other systems, with similar customer densities, typically experience.

Longstanding line loss problems are symptomatic of a neglected distribution system. As such, the Commission should take into account this substandard performance by the Company when it deals with management-related aspects of the revenue requirements, such as rate of return or, more to the point, management fees. Management should not be rewarded for chronic, substandard performance of its distribution system and, consistent with remedies the Commission may impose for the failure to conduct cost-effective resource planning, instead should be penalized with lower rates of return or management fee compensation.

This issue has flown below the radar screen in between BIPCO rate cases, during which time BIPCO management has received many

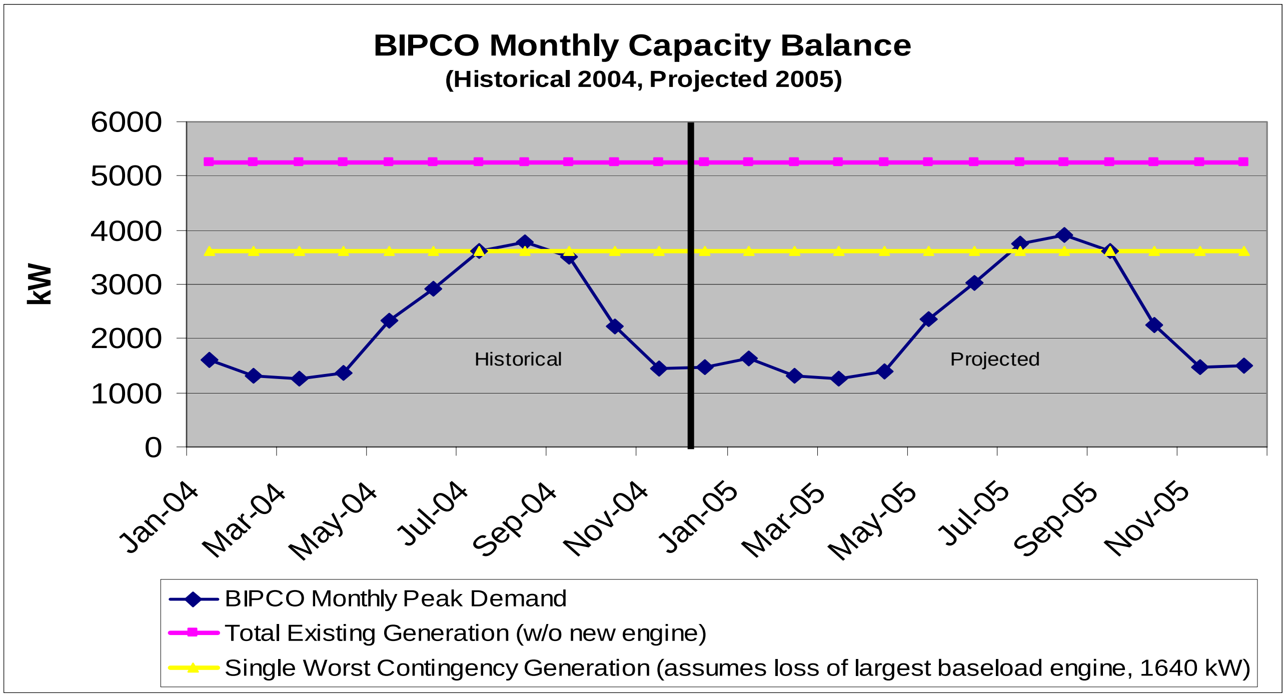
[2] $2,776,620 in reported retail revenues (p. 300), divided by 10,514.7 MWh of sales (p. 301).
[3] In response to the Division's second set interrogatories, interrogatory 9.

thousands of dollars in management fees without any investigation as to their reasonableness.

VII. BIPCO NEW GENERATION REQUIREMENTS

Q. HAVE YOU REVIEWED THE COMPANY'S STATED NEED FOR A PROPOSED NEW BASELOAD DIESEL ENGINE UNIT?

A. Yes. I prepared a monthly capacity balance exhibit for BIPCO reflecting actual 2004 load and projected 2005 load based on 2002-2004 growth rates (see the line in blue). I compared these loads to the Company's current diesel engine generation using two cases. The first assumes that all current generation is available to meet load (the pink line) and the second assumes that BIPCO's largest current generator is unavailable (the yellow line, also known as "Single Worst Contingency Generation"). [This latter presentation was done consistent with the Company's perspective on redundancy and reliability, but I believe the Company has probably been too conservative with this level of proposed reliability.]



Q. HOW SOON IS NEW BIPCO GENERATION NEEDED?

A. Even if one assumes that BIPCO should have generation capability (or generation plus resources that may include customer-owned generation, load control or interruptible rate curtailable load) that is enough to serve the system in the Single Worst Contingency case, which as I said previously is probably too conservative, BIPCO's peak exposure is projected to be only about 300 kW in the summer of 2005, and no more than 450 kW by 2006. If a lesser reliability/redundancy standard is adopted, BIPCO's generation deficiency for next couple of years disappears.

Q. DOES THIS LEVEL OF NEED, THE CONSERVATIVE SINGLE WORST CONTINGENCY NEED, JUSTIFY A NEW BASELOAD ENGINE OF 1,640 KW BE ADDED TO THE BIPCO GENERATION MIX?

A. There are features about its plan to acquire another diesel engine that are attractive, including the cost of acquisition and SCR controls, but I do not believe the Company's generation requirements for 2005 justify such a large baseload addition. Considering the potential of all of the measures I have cited herein to meet its resource requirements, or even a short-term rental of generation like it has done before, the Company could find its near-term requirements met without adding another large baseload diesel engine.

Q. DO YOU HAVE ANY FURTHER COMMENTS ON THIS PLAN?

A. Yes. The Company basically precluded consideration of any options other than new diesel generation by defaulting on its long range planning obligations, including the consideration of alternative sources of supply as well as demand side management measures. Also, it is far from clear from the Company's presentation and the analysis I prepared above, what extent the proposed diesel can be considered used and useful. It is not now in service and it has not gone through the permitting required before it can be placed into service. The permitted hours of operation have not yet been established. Given that this proposed unit is expected to be a test case for the vendor's new SCR technology, the operational characteristics of this proposed unit remain to be determined.

In summary, the Company has not shown that continued purchases of diesels make sense to meet its resource requirements. It has failed to demonstrate that the need for additional capacity could not have been satisfied or deferred through the implementation of other measures, including access to customer-owned generation, demand side management & load control, or interruptible rate programs. Further, as I have testified, it has failed to show that its existing capacity is being efficiently utilized. In other words, even assuming that it would make sense to replace an older unit with a new, more efficient unit, the amount of capacity being added has not been justified.

Q. **WHAT DO YOU PROPOSE?**

A. The Commission should closely monitor the permitting and construction processes associated with the Company's proposed diesel. The Town is reluctant to recommend denial of rate base recognition of the proposed diesel if the Company can meet the Commission's standards for rate base recognition of new plant. The Town will review the issue after the Company addresses the question whether it is entitled to rate base recognition for the proposed diesel, based upon the facts presented and Commission precedent.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. At this time, yes.

Attachment__(SCF-1) **STAN C. FARYNIARZ**

LA CAPRA ASSOCIATES

Senior Consultant

Mr. Faryniarz has consulted on power procurement & transactions, economic and rate analyses and strategic matters for a wide variety of energy industry and other clients in New England, the U.S. and Canada. He has an extensive range of skills and experience in economic and financial analyses, contract negotiations, regulatory, government and consumer relations for consumer and investor-owned utilities, their customers and other industry groups, economic impact studies and studies for clients undergoing legislative or regulatory scrutiny. Mr. Faryniarz has substantial expertise in the New England, NYPP & PJM power markets, particularly in matters related to wholesale and retail power procurement and transactions. He also specializes in operational and economic analyses for utilities, and industrial and aggregated commercial customers, and regulators. He evaluates, prepares and defends load forecasts, power cost and allocated cost of service analyses, rate design studies and tariffs, integrated resource plans, market studies, special contracts, asset valuations and other components of successful utility and power purchasing programs and operations. Mr. Faryniarz is an expert on power costing and pricing in the deregulated power supply markets of the northeast, and has substantial expertise in structuring, evaluating and costing forward contract-based and other power purchasing and hedging options.

RELEVANT EXPERIENCE

Power Procurement, Transactions & Planning

- Lead advisor to the National Passenger Railroad Corporation (AMTRAK) in utility interconnection issues, rates and rate design, and retail purchase power procurement for an annual $80 million portfolio of traction and non-traction accounts. Structured power shopping transactions, special contracts, counterparty credit guarantees and rate designs that have saved Amtrak many millions of dollars as they expand electrification of their Northeast Corridor train and station service.
- Recently a lead advisor to the Southeastern Pennsylvania Transit Authority (SEPTA) in implementing a procurement RFP for retail power supply, using a wholesale pass-through methodology.
- Power supply manager for a small Vermont rural electric cooperative, and a leader in contracting for and developing renewable resources as substantial additions to its power supply portfolio. Developed expertise in the New England renewables power market by acquiring a landfill methane baseload resource (and renewable energy certificates under NEPOOL GIS) to replace an expiring nuclear entitlement - for over 30% in direct power cost savings to the utility. Presently advising on the development of a substantial landfill methane and other renewable projects for this utility, as well as author of its strategic 20-year Integrated Resource Plan.
- A lead advisor to another Vermont rural electric cooperative that was successful in more than doubling its size via acquisition of a larger Vermont IOU system. Provided expert testimony to the Vermont Public Service Board on associated valuation matters, including forecast market prices and costs for the combined system’s net short position, and the decrement to value of a substantial partial-contract disallowance of one of the IOU system’s major supply contracts. Simultaneously advised this utility on procuring power supply to meet a 50% net short position starting at the end of 2003.
- An advisor to the Massachusetts Technology Collaborative and its Renewable Energy Trust on how to structure and evaluate requests for assistance from various renewable projects, using innovative

renewable energy certificate purchase & loan, and other option structures. Worked with the client in negotiating an assistance package for a landfill methane project proposed in central Massachusetts.

- Prepared feasibility studies and, in one case, a subsequent business plan, for several Chambers of Commerce in Vermont and Rhode Island on creation of commercial and industrial sector load aggregation (power buyers) groups.
- Managed the independent power purchasing program as a planning Special Counsel with the Vermont Department of Public Service, including rate and contract negotiations.
- Prepared several integrated resource plans for municipal electric and cooperative utilities in Vermont pursuant to Public Service Board regulations and Vermont 20-Year Electric Plan guidelines. Directly supervised the development of one of the plans for use in supporting a Vermont distribution cooperatives' landfill methane project request for $7.3 million in federal RUS loan financing.
- Evaluated numerous IRPs as a planning Special Counsel with the Vermont Department of Public Service.

Financial & Valuation

- Prepared valuations of billions of dollars of utility generation plant on behalf of Ohio and Arkansas regulators, for determinations of stranded cost position.
- Sponsored valuations and expert testimony involving a NASDAQ-traded energy company, an investor-owned transmission utility and consumer-owned electric utilities in Maine and Vermont.
- Provided valuations to private capital firms and Trout Unlimited on various northern New England hydro facilities and projects.

Cost Allocation & Rate Design

- Prepared and sponsored in testimony over a dozen cost of service, cost allocation, rate design and 3 demand elasticity studies for several electric and water companies in New England and one in Pennsylvania.

EMPLOYMENT HISTORY

La Capra Associates, Inc. — Boston, MA
Senior Consultant — *1999 - Present*

Decision Economics LLC — Underhill, VT
President & Consultant — *1994 - 1999*

Weil & Howe, Inc. — Augusta, ME
Consultant — *1990 – 1999*

Vermont Department of Public Service — Montpelier, VT
Special Counsel for Financial Analysis — *1986 – 1990*

EDUCATION

University of Vermont — Burlington, VT
Masters in Public Administration with extensive — 1986

M.B.A. curriculum in Finance and Statistics

Michigan State University East Lansing, MI
NARUC Graduate studies Program in Regulatory Economics 1986

University of Vermont Burlington, VT
B.A. in Economics, Cum Laude with Departmental Honors 1982
Awarded Kidder Medal, Most Outstanding Senior Man (Academic, Leadership and Service)

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
DIVISION OF PUBLIC UTILITIES AND CARRIERS

TOWN OF NEW SHOREHAM	)	
v.	)	**DOCKET NO.**
BLOCK ISLAND POWER COMPANY	)	

COMPLAINT

This Complaint is being brought by the Town of New Shoreham (the "Town" or "New Shoreham" against Block Island Power Company (the "Company" or "BIPCO") pursuant to R.I.G.L. §§39-4-3 and 39-4-10 and the Division's Rules of Practice and Procedure, Section 7.[1] The Division has jurisdiction and authority to conduct investigatory hearings on the Town's Complaint.[2] Through its Complaint, the Town requests that the Division (1) find and rule, after hearing, that BIPCO management's failure to conduct and implement an integrated resource plan and/or demand side management program constitutes an unjust, unreasonable and insufficient practice or act and (2) direct BIPCO to (a) conduct and implement a long-range integrated resource

[1] On October 12, 2004, the Town filed a Complaint against BIPCO with the Public Utilities Commission. On November 2, 2004, BIPCO moved to dismiss that Complaint on jurisdictional grounds, but did not file an answer. Concurrent with the filing of the instant Complaint with the Division, the Town has filed a Notice of Withdrawal of its Complaint before the Commission.

[2] Section 39-4-3 provides, in part, that upon written complaint made against any public utility by any town council that the rates or practices of the public utility are unjust or unreasonable, the Division shall conduct an investigation. Section 39-4-10 provides that if, upon hearing and investigation, the Division finds a public utility's practice, act or service unjust, unreasonable or insufficient, the Division "shall have the power to substitute therefore such other …practices, service or acts, and to make such order respecting, and such changes in the…practices, service, or acts, as shall be just and reasonable…."

planning process and (b) create and implement a demand side management program, both subject to Division review and approval. These actions are necessary to assure that BIPCO implements resources plans and policies that help control rising electricity costs on Block Island and reduce, to the extent practicable, the greenhouse gas and other pollution caused by complete reliance on diesel-powered generation..

BIPCO, while not subject to certain legislative electric restructuring mandates applicable to other electric utilities in Rhode Island, has failed to manage and operate its system in a reasonable and prudent matter, given common utility management standards for long-range integrated resource planning, consideration of alternative technologies and supply side resources, and implementation of demand side management programs to reduce the effects of long-term load growth upon the adequacy of existing electric generation to meet demand.[3] In addition, BIPCO continues to pay its owners a substantial management fee, despite their lack of expertise concerning the management of electric company operations and their failure to implement ongoing long-range utility planning and demand side management programs for Block Island. These continuing acts or practices by BIPCO management constitute unjust, unreasonable and insufficient acts or practices and have resulted and/or will result in unreasonable rates for the Town and BIPCO's customers, as growth in demand is left unchecked by an effective demand side management program and ratepayers are forced to absorb the escalating costs associated with oil-fired generation as the sole source of supply.

---

[3] It is well-settled that "…a public utility's service obligation includes a requirement to deliver energy services at least cost; that conviction is shared by utilities, regulators, legislatures and courts throughout the nation." *In re: Authority to Order Utilities to implement Demand Side Management Programs*, 122 PUR 4th 153,164 (VT PSB, Docket No. 5270-CV-1, March 19, 1991). The Rhode Island Public Utilities Commission has previously found that "…intensive C &LM represents Rhode Island public policy." *In re: Narragansett Electric Co., 113 PUR 4th 68, 73(RIPUC Docket No. 1939, May 16, 1990).*

Indeed, because ratepayers of BIPCO are paying rates substantially higher than the rates paid by mainland Rhode Island electric utility customers, it is imperative that the Division direct BIPCO to take all reasonable and prudent steps necessary to assure that it is providing electric power to the Town and its other customers on a reliable basis and at a reasonable cost.

In support of its Complaint, the Town states as follows:

1. The Town is a municipal corporation organized under the laws of the State of Rhode Island.

2. The Town is a customer of BIPCO.

3. BIPCO is a corporation organized under the laws of the State of Rhode Island and provides retail electric service to residential, commercial and governmental users of electricity within the Town and the geographical confines of Block Island, pursuant to regulation by the Rhode Island Public Utilities Commission and the Rhode Island Division of Public Utilities and Carriers.

4. By resolution dated October 4, 2004, the duly elected Town Council of New Shoreham authorized the filing of this Complaint.

5. The resolution well states the serious concerns of the Town regarding the rates and practices of BIPCO, which are incorporated herein by reference and made a part of this Complaint. A copy of the Town's resolution is attached hereto.

6. BIPCO provides electric power to its customers on Block Island through the operation of internal combustion engines which are fueled by oil. Because of BIPCO's extensive reliance upon internal combustion engines to meet year-round

demand for electricity, the operation of these facilities consumes a large amount of oil and produces emissions that may pose a threat to the environment.

7. Despite repeated requests by the Town, BIPCO has not developed or implemented a long-term integrated resource plan to meet the needs to Block Island ratepayers. It has not developed or implemented the types of plans and programs that other electric utilities, including small electric utilities, have developed and implemented.[4]

8. Given that Block Island users of electricity are not afforded a choice of suppliers of power or a sources of supply, the failure of BIPCO to conduct and implement on an ongoing basis integrated resource planning and demand side management measures has resulted in ratepayers being held captive to inefficient and uneconomical practices of BIPCO management.

9. These acts or practices of BIPCO management are especially unreasonable when considered together with BIPCO management paying itself dividends and management fees. Such management fees constitute an additional unreasonable practice under the circumstances.

10. The inefficient and uneconomical acts or practices of BIPCO management have caused, and will continue to cause, the electric rates paid by the Town and other consumers to be excessive. Perpetuation of BIPCO's current acts or practices all but guarantees future excessive electric rates paid by the Town and other consumers.

[4] For example, the Pascoag Utility District has implemented a demand side management program for 2004 with an annual budget of $149,500. While BIPCO is exempt from the Rhode Island Utility Restructuring Act, Pascoag Utility District illustrates that small utilities are capable of implementing demand side management programs. *See, In re: Pascoag Utility District Demand Side Management Programs for 2004,* Docket No. 3474 (December 22, 2003).

11. BIPCO's acts or practices are unreasonable and insufficient, based upon any reasonable standard for utility management, even taking into account the size of BIPCO. They are inconsistent with the energy polices of the State of Rhode Island.[5] While BIPCO is not subject to certain state legislation applicable to other electric utilities, it has not been excused from its fundamental obligation to provide service on a reliable basis and at a reasonable cost, and it has not been relieved from statutory scrutiny of its acts and practices by the Division.[6]

12. The persons to contact on behalf of the Town are as follows:

Alan D. Mandl, Esq.
Mandl & Mandl LLP
10 Post Office Square-Suite 630
Boston, MA 02109
Phone: (617) 556-1998
Email: alan@mandlaw.com
Fax: (617) 422-0946

Merlyn O'Keefe, Esq.
Packer & O'Keefe
1220 Kingstown Road
Peacedale, RI 02879
Phone: (401) 789-4850
Fax: (401) 782-4210

Nancy Dodge
Town Manager
Town of New Shoreham
PO Drawer 220
Block Island, RI 02807

13. The Town respectfully requests that the Division: (1) open an investigation in this matter; (2) convene a prehearing conference; (3) establish a schedule for the conduct of discovery, submission of pre-filed testimony, evidentiary hearings and

---

[5] *In Re: Narragansett Electric Co., 113 PUR 4th 68, 73(RIPUC Docket No. 1939, May 16, 1990).*

[6] *See, note 2 above.*

briefing; and (4) conduct evidentiary hearings. The Town requests that at least one hearing in this matter be conducted on Block Island.

14. After investigation and hearings, the Division should direct BIPCO to prepare a proposed integrated resource plan and demand side management program, for review and comment by interested persons such as the Town and review by the Division. After such review by the Division, the Division should order BIPCO to submit an integrated resource plan and demand side management program consistent with any directives by the Division.

15. As set forth in the Town's October 4, 2004 Resolution, the integrated resource plan and demand side management program of BIPCO should address, among other things:

a. a 10 year forecast of the power demand and energy consumption for Block Island
b. an assessment of the condition and efficiency of existing generation and distribution systems and their capacity to meet forecasted demand
c. a comprehensive demand side management program aimed at reducing significantly existing and forecasted demand
d. an assessment of all practical sources of generation, including alternatives to existing oil-fired generation, which may include, but is not limited to, methods for the development and financing of a cable to the mainland
e. a plan to upgrade the existing distribution system in order to improve the reliability of service
f. a review of cost allocation and rate structure to assure that a fair allocation of costs for meeting peak demand is implemented
g. a review of steps which BIPCO should take consistent with state policies regarding renewable energy

16. In carrying out a Division directive to prepare an integrated resource plan and demand side management program, BIPCO should be required to provide the Division with a list of independent, qualified consultants to assist BIPCO in preparing the integrated resource plan. BIPCO should be permitted to select any one or more of such

consultants that the Division finds to be independent and qualified to prepare the required integrated resource plan. The Division should direct that the preparation of a proposed integrated resource plan and demand side management program include a public process that affords the Town and other interested persons an opportunity to provide input and information that may be of assistance. The Division should request and review public comments on BIPCO's integrated resource plan and demand side management program submission as to adequacy and reasonableness and direct BIPCO to implement such practices as the Division finds just and reasonable, in accordance with R.I.G.L. §39-4-10.

17. The above-requested investigation and the relief requested by the Town are well within the Division's statutory authority. R.I.G.L. §§39-4-3, 39-4-10. These statutes provide the Division with express statutory authority to review the acts or practices of public utilities such as BIPCO and if, upon hearing and investigation, the Division finds a public utility's practice, act or service unjust, unreasonable or insufficient, the Division "shall have the power to substitute therefore such other …practices, service or acts, and to make such order respecting, and such changes in the…practices, service, or acts, as shall be just and reasonable…." The Rhode Island Supreme Court has recently recognized that planning activity by a public utility constitutes a practice, act or service for purposes of a complaint proceeding under R.I.G.L. §39-4-10.[7] Thus, the failure of a public utility to implement planning processes reasonably required of public utilities as part of their service obligations clearly falls within the scope and reach of an R.I.G.L. §39-4-3 complaint proceeding.

18. Other regulatory agencies have found that public utilities have a duty to continuously evaluate the needs of current and future customers in order to provide

[7] *Interstate Navigation Co. v. Division of Public Utilities and Carriers,* 824 A.2d 1282, 1289 (R.I. 2003).

adequate service, and that such duties encompass the pursuit of energy efficiency measures.[8] The Vermont Public Service Board, for example, disposed of claims by an electric utility that it lacked authority to direct the utility to implement cost-effective energy practices such as a demand side management program and that such directives constituted impermissible interference with management prerogatives. The Public Service Board found that its power to direct the utility to develop such programs stemmed from general legislation akin to R.I.G.L. §§39-4-3 and 39-4-10 to assure safe, reliable and efficient service. It found that its statutory power included the ability to direct the employment of up-to-date technology and utility practices in order to assure "reasonably adequate service." It found that energy efficiency is an integral part of a utility's public service obligation.

19. A very broad distinction may be drawn between (1) an investigation of and subsequent order by the Division regarding BIPCO's acts and practices, as expressly authorized under the above statutes, and (2) interference with BIPCO business judgments that do not have any adverse impacts on ratepayers. *Narragansett Electric Co. v. Kennelly*, 88 RI 56, 86 (1958).[9] If the Division were to conclude that it did not have the power to investigate a public utility's current acts or practices and, after hearing and on the basis of a proper record, direct a public utility to take specific actions or adopt specific practices after finding that the utility's current acts or practices were inadequate,

[8] *See, e.g., In re: Authority to Order Utilities to implement Demand Side Management Programs,* 122 PUR 4th 153,164 (VT PSB, Docket No. 5270-CV-1, March 19, 1991).

[9] As noted above, the Town originally filed a complaint against BIPCO with the Public Utilities Commission on October 12, 2004. On November 2, 2004, BIPCO moved to dismiss that complaint on the grounds that: (1) the Division, not the Commission, has jurisdiction to hear the complaint; and (2) even where such jurisdiction exists, the relief sought would interfere with BIPCO's management discretion. On November , 2004, the Town requested an extension of time within which to reply to BIPCO's Motion to Dismiss. The Town has withdrawn its Complaint before the Public Utilities Commission and filed the instant Complaint before the Division.

then it would be effectively repealing the express delegation of authority given to it by the General Assembly. It would lead to absurd results if a public utility could evade a Division investigation of its current acts or practices, specifically authorized by statute, by merely claiming that its acts or practices were management prerogatives that cannot be investigated by the Division. The General Assembly has not so constrained the Division.[10]

WHEREFORE, for the reasons above, the Town requests that the Division open a formal investigation of BIPCO, consistent with the Town's Complaint, and in accordance with its Rules of Practice and Procedure.

Respectfully submitted,

TOWN OF NEW SHORHAM

By its attorneys,

____
Alan D. Mandl, Bar No. 6590
Mandl & Mandl LLP
10 Post Office Square-Suite 630
Boston, MA 02109
(617) 556-1998

____
Merlyn P. O'Keefe, Bar No. 2439
Packer & O'Keefe
1220 Kingstown Road
Peacedale, RI 02879
(401) 789-4850

Dated: November 23, 2004

[10] Past decisions illustrate that the Division should conduct an investigation of BIPCo's acts or practices. For example, in *Berberian v. Public Utilities Hearing Bd.*, 145 A.2d 202(R.I. 1958), an evidentiary hearing was conducted in response to a complaint that a public transportation company's existing practices regarding the posting of schedule information at bus stops was inadequate.

Attachment__(SCF-3)

UNITED STATES DEPARTMENT OF AGRICULTURE
Rural Utilities Service

BULLETIN 1724D-101A

SUBJECT: Electric System Long-Range Planning Guide

TO: All RUS Electric Borrowers

EFFECTIVE DATE: Date of Approval

EXPIRATION DATE: Seven years from effective date

OFFICE OF PRIMARY INTEREST: Distribution Branch, Electric Staff Division

FILING INSTRUCTIONS: This bulletin is a reissue of Bulletin 1724D-101A that superseded RUS Bulletin 60-8, "System Planning Guide, Electric Distribution Systems" revised October 1980. Replace earlier issues of this bulletin and RUS bulletin 60-8 with this reissue.

PURPOSE: This bulletin provides general guidance in system planning for owners and engineers of electric systems and specific guidance for RUS electric borrowers in preparing their long-range engineering plans.

Adam Golodner — 5/10/95

Administrator — Date

TABLE OF CONTENTS

ABBREVIATIONS

BER	Borrowers Environmental Report
CFR	Code of Federal Regulations
CWP	Construction Work Plan
FCR	Fixed Charge Rate

G&T	Generation and Transmission (Borrower)
GFR	General Field Representative
LRP	Long-Range Plan
O&M	Operations and Maintenance
PRS	Power Requirements Study
REA	Rural Electrification Administration
RUS	Rural Utilities Service
SCADA	Supervisory Control and Data Acquisition
TIER	Times Interest Earnings Ratio

APPENDICES:

Appendix I	Definitions of Terms and Abbreviations
Appendix II	Suggested Table of Contents for Long-Range Engineering Plan
Appendix III	Fixed Charge Rate Calculation Guide
Appendix IV	Sample Form: Summary of System Planning Report

1. PURPOSE: The purpose of this bulletin is to provide general guidance in system planning for owners and engineers of electric systems and specific guidance for RUS Electric Borrowers in preparing their long-range engineering plans. Detailed guidance for preparing construction work plans is provided in RUS Bulletin 1724D-101B "System Planning Guide, Construction Work Plans."

2. REQUIREMENTS OF THE LONG-RANGE PLAN: The long-range plan (LRP) is a management tool and a guide for the following:

a. The most practical and economical means of serving future loads while maintaining high quality service to the consumers.

b. An outline for anticipated system changes in terms of major facilities, demand levels and associated costs.

c. An indication of future system costs for financial planning and decision making.

3. PLANNING FUNCTIONS AND GENERAL GUIDELINES: There are four major functions of system management: objective setting, planning, execution, and control. System planning also has these four functions. Load forecasts and various system standards should be developed for the system (objectives); the long-range system plan should be developed (planning); the necessary facilities should be constructed in the appropriate time frame (execution); and the LRP should be periodically reviewed to verify its continued applicability (control). Thus system planning is a continuing dynamic process which results in a plan that is broad enough to cover all foreseeable problems and is flexible enough to allow for revision to cover changing circumstances.

3.1 It is the responsibility of the system planner, hereafter called the planning engineer, to sort out available information to determine the optimum approach for the individual system to use in attempting to provide adequate capacity and quality of service in a reliable, economical, and environmentally acceptable manner.

3.2 Some plans may require revision within a short time of completion while others may require no significant revisions after several years of use. Regardless of the date of preparation, the LRP being used should be appropriate and should consider the latest information available.

3.3 Long-range system planning calls for analysis of the system far beyond the present design requirements. See Section 4.4 for details regarding criteria for long-range system planning. In several regions of the country, generation and transmission (G&T) cooperatives arrange for all members to update LRPs at one time to facilitate G&T planning.

3.4 A LRP provides a guide for developing the existing system toward the capacity level which will be required at the end of the planning period, through construction of new facilities and expansion or replacement of existing facilities at appropriate times. By using this approach, any interim change or system addition will be compatible with the needs of the final study level.

3.5 Although each system's LRP will be different, all plans should have the following basic provisions:

a. Orderly system development to minimize waste due to early obsolescence or inadequacy of facilities.

b. As much as possible, system expansion investment that is in step with expected loads. Maximum use of opportunities to improve the quality of service at minimal cost.

c. Provisions for future decisions to incorporate appropriate developments in equipment design and application.

3.6 Owners of many systems have, or will have, large and complex communication facilities for collecting and/or disseminating information related to load management such as; Supervisory Control and Data Acquisition (SCADA), Distribution Automation (D.A.), and/or remote meter reading and consumer accounting via telephone, radio, or power line carrier. It is recommended that a long-range communication study and report be performed periodically and that a summary of this report be included in the LRP. As an alternate, the communication study may be done immediately following the LRP.

3.7 System planning can be divided into five distinct tasks, as follows:

a. Basic data should be maintained and continuously updated to facilitate the evaluation of newly proposed alternatives throughout the LRP period.

b. The existing system should be analyzed to ascertain its ability to serve present and projected requirements. Objectives of the owners should be considered in the system analysis. The planning engineer should determine what additional capacity is needed and what facilities will need replacing during the long-range planning period. This information will aid in the judicious selection of alternatives.

c. Once the system requirements have been determined, various alternative plans can be formulated which will satisfy these requirements.

d. By careful application of present worth analysis or some other valid economic analysis procedure, the owner or engineer can select the optimum plan for the projected requirements. It is extremely important that each alternative evaluated provides for adequate quality of service, environmental acceptability, and adequate system capacity at each level of the LRP period. Some alternatives may provide a temporary excess of capacity. This excess should be justified through reduced overall construction costs or reduced losses.

e. When starting a new construction work plan (CWP), the LRP should be reviewed in light of actual system developments to determine whether it needs to be revised or updated. A CWP should then be prepared to determine which of the facilities demonstrated to be necessary in the LRP will be most appropriate to install during the immediate work plan period.

4. INITIAL STEPS IN SYSTEM PLANNING: Although actual planning procedures followed by each planning engineer may vary in detail from those described in this guide, for the sake of uniformity, planning engineers should make an effort to follow the format presented here. The RUS GFR is available to assist the owner and the planning engineer in developing a useful and acceptable LRP.

4.1 Preliminary Conference: The owner should arrange a preliminary conference with the planning engineer. The RUS GFR and the power supplier should also be invited to attend.

4.1.1 At this conference, the owner should provide the planning engineer with the following basic data:

a. Up-to-date copies of circuit diagrams, one set of detail maps and a system key map, all showing the existing system.

b. The latest RUS approved Power Requirements Study (PRS) because the LRP loads must be consistent with the PRS.

c. Local Planning Board maps or other data regarding existing and projected (i) population density; (ii) zoning and land use; and (iii) areas known to be environmentally sensitive.

d. Locations of existing and expected future housing developments, large power, irrigation and special loads.

e. The latest available data concerning load factors.

f. Detailed outage records for the distribution system, transmission system and power supplier delivery points. Causes of power supplier outages should be accounted for.

g. A copy of the owner's energy conservation plan along with information on any existing or proposed load management system.

h. Results of all recent voltage and current investigations, phase balance and sectionalizing studies and information on power factor of the system and of distinct areas of the system.

i. Present and projected wholesale power contracts and rates for both existing and planned power sources.

j. Existing and future fault current (or impedance) and voltage limit calculations from power supplier and their statement of future limits of capacity, provisions for future delivery (metering) points, and plans for future transmission lines.

k. Plans for any new transmission delivery points or voltage changes.

l. A copy of the latest RUS Form 300, "Review Rating Summary."

m. Cost summaries for recent construction of various types of facilities in the existing system and other records of operations on which cost estimates may be based.

n. Costs of metering points if furnished by others and charged in some manner to the borrower.

o. The cost and availability of new capital to a borrower, which should be studied and tested for sensitivity. (Trends should be established, on an embedded cost of capital for the life of the LRP. It is appropriate to include in the fixed charge rate (FCR) and a return on the member/owner's equity which is related to the borrower's Times Interest Earnings Ratio [TIER]).

p. The correct determination of the borrower's fixed charge rate(s) which is crucial to the proper selection of economic system improvements. There may be different fixed charge rates for distribution or transmission or communication projects; or for RUS financed or non-RUS financed projects. (Appendix III presents data useful in calculation of a FCR.)

q. In some planning alternatives, other related organizations' investments and their FCR may be needed.

r. The assumptions and methods used in arriving at the financial criteria. (It should also be documented in the LRP.)

s. Any other pertinent data related to the services to be performed by the planning engineer, such as possibilities for joint ventures with neighboring utilities, and the owner's current study of economic standard conductor sizes.

4.1.2 Much of the above information may already be in the possession of the engineer or available from billing files. The planning engineer should assist the owner in establishing and developing a procedure for updating this basic data file which will be useful in future planning activities. The planning engineer should also recommend methods of and locations for voltage and current investigations and methods for extracting the necessary load data from computerized billing files. This load data is invaluable for load forecasts, rate analysis, and long-range financial forecasts.

4.1.3 Since the LRP will be no better than the data on which it is based, the planning engineer should review the basic data for adequacy. The planning engineer should request any necessary additional data and recommend improvements in programs used for regular data collection and record-keeping. This will insure availability of sound data for continuing system planning activities.

4.2 Analysis of Existing System: The analysis of the existing system may indicate where alternate proposals are most likely to be economical and provide insight into the development of a practical transition from the existing to the proposed long-range system.

4.2.1 While the CWP covers many of the same topics as the analysis of existing system, the analysis of existing system should approach the subject from the standpoint of major, basic, design needs while the CWP should approach the subject from the standpoint of necessary changes in facilities within the context of established basic design. Therefore, even if a CWP has recently been completed, an analysis of existing system should be prepared for the LRP.

4.2.2 It will be necessary for the planning engineer to determine how the system load will be distributed among the various regions of the system. To predict with reasonable accuracy the requirements of these various regions of the system, by line section, substation area or by geographical sections, it is necessary to have information on the number of consumers, load per consumer, load growth potential, density, types of load expected, and total load for various regions of the service areas in the present and the projected system. Data should be collected for small enough unit areas to indicate boundaries of larger load density regions. Even a system which anticipates an overall zero or negative load growth must prepare for the possibility of some regional load growth. Valuable regional growth information may be obtained from local land use planning organizations, chambers of commerce, etc. An econometric model, if available, may provide some of this data.

4.2.3 The existing system should first be analyzed to determine how well the existing facilities are meeting the present needs of the system as indicated by metering and billing data. The areas of the system where it is difficult to achieve acceptable levels of system performance should be identified. This information along with the system growth patterns, discussed above, should indicate the areas where the most drastic or immediate action is needed.

4.2.4 In addition to such considerations as transformer capacity in existing substations, the planning engineer should review the space limitations for increasing the capacity of present substations. A determination should be made if there is room for installing recommended new circuits, if there is room for additional feeders along existing rights-of-way, if the substation can be expanded to include transfer (by-pass) buses or for upgrading high-side fuses to breakers, etc.

4.2.5 Studies should be made to determine which areas of the system are voltage limited and which are thermally limited and if some facilities are so old that they will need replacement during the term of the LRP based on age or deterioration.

4.2.6 If system aging studies have been performed on all or parts of the supply facilities of the system, then the results of these studies should be analyzed and included both in the analysis of the existing system and the engineering analysis used during the preparation of the LRP. If no such study has been previously prepared, the planning engineer should determine (generally by multi-year increments and percentages) and analyze the age of the supply facilities. Of particular concern are the facilities which will be beyond their useful life before the end of the planning period. The planning engineer should document this data and the methodology and assumptions used in deriving it, and use this information during the preparation of the LRP.

4.2.7 By comparing the performance of various areas of the system, the planning engineer can locate those sections which will benefit from more drastic improvement efforts. Analysis of the following conditions will indicate the level of performance of the existing system:

a. The results of voltage, current and power factor measurements, and voltage drop calculations for critical feeder points should be reviewed.

b. A service reliability study will indicate areas of the system which need special attention and may even indicate the general type of work which will be most cost effective in correcting such service deficiencies. Service interruption records for the preceding five year

period should be examined with particular attention given to interruption averages for each distribution feeder and for each substation. These averages will indicate major differences in service reliability in various regions of the system. Frequent and/or long duration outages should be noted and the probable cause determined. This information should be compared to the service reliability standard set by the owner. If the power supplier is responsible for an excessive amount of the outage time (typically, more than one (1) consumer-hr per consumer/yr averaged or trended over 5 years), this should be noted. The power supplier should be requested to supply comparable outage analysis for all similar delivery points.

c. Demand and energy losses are extremely important. Through review of operating records, the demand losses at peak time, and energy losses in kWh per year and in percent should be determined for substation and metering point areas throughout the system. These loss levels should then be compared with those of other similar borrowers. The probable cause of any excessive area losses should be determined and noted for possible corrective measures. Power factor analysis should be used to arrive at an economic power factor for the system, which should decrease losses.

d. O&M expenses on a system are dependent on such factors as cost of labor, load density, number, size, and age of facilities. By analyzing the O&M expense allocations on the system, those items with exceptionally high operating expense rates can be properly identified and methods of reducing those expenses evaluated. O&M items which appear not to be receiving adequate funds should be compared with outage and inspection reports to ascertain if additional emphasis is required. (Most systems are at an age where certain obsolescent components should be budgeted for orderly replacement. This may reduce O&M expenses.)

4.2.8 Based on the analysis of the existing system, the planning engineer should make recommendations for improving system performance and increasing system capacity for expansion. In addition, the planning engineer should recommend more detailed measuring or record keeping for those areas where data is inadequate. The basic data and analysis of the existing system should be prepared in draft form for use during the intermediate conference. Later the final report should be made a part of the system planning report. (See Appendix II).

4.3 Intermediate Conference: When the planning engineer has completed the analysis of the existing system, the owner should arrange an intermediate conference to discuss the study (to date) and the direction in which the study should continue. The conference should be attended by the manager, the operations manager and the line superintendent, any other appropriate system personnel, and the planning engineer. The RUS GFR and a representative of the power supplier should be invited to attend. The conferees should review the analysis and the basic data for adequacy, and determine if any additional data is needed and the method to be used in obtaining it. Basic planning criteria should be established for the LRP at this conference.

4.4 Criteria for Long-Range System Planning: Since the LRP should be used to guide the development of the system for a number of years, the criteria used in formulating the plan is of utmost importance. The owner has the primary responsibility for selecting the planning criteria. The recommendations of the planning engineer and the RUS GFR should be considered before selecting the planning criteria. The following brief discussions suggest some of the planning criteria that should be established.

4.4.1 The LRP should be designed to anticipate what needs to be done for the system to provide adequate and reliable electric service to the consumers over a long period. It is recommended that the LRP provide for the system requirements for 10 or more years in the future. For most systems, this will allow comparisons of alternate plans of providing for increased service in various parts of the system and in the system as a whole, without going to extremes of too short or too long a period to be credible.

4.4.2 Other long-range planning periods can and should be used if the choice for an alternate time period is adequately explained and justified by the planning engineer. The appropriate span of the planning period is a function of the following factors:

a. The anticipated load levels at the end of the planning period.

b. The forecasted growth rate of the system or major portions of the system;

c. The age of the electrical supply facilities, both at the beginning and the end of the period. Particular attention must be given to the percentage of the facilities which are or will be beyond their useful life; and,

d. The validity of the future economic factors, such as inflation rate, especially toward the end of the planning period, which are being used for the engineering economic analysis of the alternate plans in the study.

4.4.3 For growing systems, or systems which have areas of load growth, the following compound growth rate equations can be used to forecast loads beyond the period of the PRS.

Future Value = ES x (1 + i)n
where ES = existing system parameter
i = the annual average long-term growth rate
n = number of years.

System loads and growth rate should be consistent with the PRS.

4.4.4 Systems with negative, zero, or slow growth need a careful analysis of their special conditions to assure that their systems are optimized. For instance, feeder lines may require replacement due to age rather than because of thermal loading or voltage drop.

4.4.5 The effectiveness of the long-range demand level is generally more dependent on its relative magnitude than the time frame. In some critical situations, however, the exact time frame will determine which of two alternatives will be more economical. In such cases, more precision should be used in establishing the time frame during the plan selection phase.

4.4.6 Very seldom will a system have uniform load density and growth potential. However, by analyzing the system load and population and/or electric service maps prepared as suggested in section 4.2, and land use plans for the system area, those regions with similar requirements can be located and grouped for similar handling. Estimates of growth potential and realistic maximum energy usage per consumer should be incorporated to project ultimate area demand levels. Thus the total system demand and the average growth rate of the entire system will be determined by the demand and growth rate of the various portions of the system.

4.4.7 Depending on the size of the system, loads with more than a predetermined size (100-1000 kVA) of connected transformer capacity, and concentrations of small pumping and irrigation loads, should be identified by size and location. These special loads will require special consideration with regard to their demand on the system. Management should analyze the special loads presently served to determine the kW size for each of those to be considered in the LRP. Only those which are large enough to significantly affect the supply system need be analyzed. Those special loads that management is reasonably sure will be served by the long-range system should be provided for in the plan. Other special loads, not supported by reasonably firm data can be designed for on an individual basis as they develop.

4.4.8 A service reliability standard provides a basis on which management can evaluate system performance. The importance of service reliability should be reflected in the long-range system plan. Because of wide differences in operating conditions and local requirements, RUS does not attempt to specify a service reliability standard for all systems. However, each borrower should adopt a standard which will serve as a goal in the development of its system. The five consumer hours per consumer per year interruption rate used for loan applications should not be considered as a goal. Rather, system goals should be nearer one hour for suburban and two hours for rural consumers. Furthermore, it should be recognized that except during truly unusual major storms, consumers are not concerned with the source of an interruption. Whether the power is off only for their individual transformer or because of a power supplier's interruption, makes little difference to the consumer. Thus all sources of interruption should be considered for possible improvement in service reliability.

4.4.9 Any additional criteria which management is considering, should be carefully evaluated for its benefit to cost relationship and should be discussed thoroughly with the planning engineer and the RUS GFR.

5. DESIGN CONSIDERATIONS: The system should be designed to provide adequate, reliable, and quality service at a reasonable cost to all consumers. Many decisions made in formulating the LRP will affect or be affected by the system design. It is therefore important that the system planners are cognizant of these effects. The following discussions present items to consider in the design of the system.

5.1 Power Sources: Planning engineers should carefully consider the capacity and adequacy of all existing and prospective power sources. If the source is unable to supply the necessary quantity of power for its area, if the interruption record is poor, or if voltage levels will be inadequate, then alternative sources of power should be investigated. If the owner is a member of a G&T, these problems should be taken up with the G&T staff and/or the board. Interruption data should be recorded and evaluated on a regular basis for all existing power sources and interruption rates for prospective sources should be estimated based on records for facilities with similar characteristics.

5.1.1 The Public Utility Regulatory Policies Act of 1978 (PURPA) requires that electric utilities allow their consumers to interconnect privately owned generating equipment and requires the utilities to purchase power and energy from such facilities at reasonable prices. Thus the owner and/or the power supplier, through a coordinated effort if applicable, should establish a policy covering purchase of power from consumer-owned solar, wind, diesel, small hydro and co-generation installations. The owner should also consider the possibility of installing such facilities of its own as compared with the use of energy purchased from conventional generating facilities.

5.1.2 Differences in cost of power between alternative wholesale power sources should be considered (although it is usually unwise to design or redesign a system to take advantage of a temporary condition). Consideration should be given to the investment required in facilities to utilize the power and the availability of sufficient power when and where it is needed. The nearest or cheapest sources of power need not be selected if, overall, another source can be shown to be more appropriate. However, this option may not be appropriate for members of G&T's.

5.2 Transmission Lines: Although the LRP is not the place for detailed design of transmission lines, attention given to the proper aspects of transmission line planning may avert serious problems later. It is extremely important that the distribution system's LRP be coordinated with the LRP of the power supplier regarding transmission planning. Whether the transmission lines are owned by the distribution system or the power supplier, planning should be approached on a "one system" concept. Excessive costs for transmission facilities cannot be justified by minor savings on one part of the system. The converse is also true that excessive distribution plant should not be constructed simply to avoid transmission construction. Transmission facilities which are well planned will provide high continuity of service, long life of physical equipment, and safe operation at relatively low overall cost. The following factors should be determined for all transmission lines in the LRP.

5.2.1 The proposed line length, line-end points and future extensions should be approximated.

5.2.2 The voltage class of the transmission lines should generally be determined by the voltage of the line to be tapped. Occasionally an exception is justified due to superior reliability for a small increase in cost or where total benefits outweigh the added cost of the alternative.

5.2.3 Transmission conductors should be tentatively sized based on economic studies taking into consideration line losses, present and future power requirements, cost of upgrading the line when the conductor is no longer adequate, and the cost of carrying excess capacity until it is needed. Cost of stocking and hardware standardization should also be considered where a new conductor size has been indicated by other factors.

5.2.4 Environmentally sensitive areas along the corridor proposed for line routing should be avoided if possible. Also right-of-way requirements should be considered.

5.2.5 At least a rough check for stability and load flow characteristics should be made and if it indicates the need, more extensive studies (computer load flow, stability and transient network analyzer studies) should be performed. In some cases, load flow studies will influence the location and timing of major substation additions. The planning engineer should coordinate these studies with the owner and the power supplier.

5.2.6 The economy of radial feed substations should be weighed against the reliability of loop feed substations. The applicability of each design, as it pertains to the basic system design and established operating practices, should be carefully considered. Any proposed changes should be coordinated with the power supplier if applicable.

5.2.7 Acceptable transmission system voltage levels and variations from no-load (or light-load) to peak load need to be decided upon based on service voltage at a point of delivery, transmission line characteristics, load growth, type of load, distribution substation transformer characteristics, ability to regulate voltage on the distribution bus, and contractual provisions. For instance, some wholesale power contracts call for a +5% variation under normal conditions, and a -10% variation during a single contingency condition.

5.3 Substations: A major decision to be made in long-range planning is the optimum number and size of substations needed to provide services to the system. If possible, the cost and reliability of additional substations should be weighed against the cost and reliability of other alternatives. Decisions as to the exact location of substations should be reserved for consideration in the construction work plan, with only relative locations considered in the LRP.

5.4 Reliability: Generally, shorter lines from smaller substations will lead to higher reliability; however, line reclosers and sectionalizers will improve reliability to some extent on long radial lines. Multiple substation transformers (four single-phase or two three-phase units), loop feeds into substations, and the availability of a mobile transformer or mobile substation all improve reliability. The decision on the size and number of substations needed in the LRP should be made based in part on system experience with the source of interruption hours and the cost of improving reliability in those areas.

5.4.1 It is not always possible to use the most economical system configuration (conductor size, line voltage and number of phases) and still meet system standards for voltage levels, service reliability and economy. Service reliability should be improved to any portion of the line of supply to the consumer where it can be done at a reasonable expense. Estimates of the incremental improvement in service reliability can be developed from experience with similar facilities.

5.5 Primary Distribution Lines: Whether primary lines are constructed overhead or underground, effective planning is needed to avoid premature obsolescence of facilities. Owners should have performed a study of economic standard conductor sizes that will give guidance in selection of conductor size, circuit voltage and number of phases for economic construction and operation of new and converted overhead and underground distribution lines.

5.5.1 It is necessary to consider many factors in determining whether distribution line construction should be overhead or underground. Overhead lines generally involve lower construction costs and ease of constructing additions and of maintenance. Underground lines generally have less environmental concerns, are less affected by storms, have lower line losses and less voltage drop for a given ampacity. However, underground lines are sometimes subject to certain technical problems, such as difficulty in adding voltage control or sectionalizing equipment, and high replacement costs.

5.5.2 Distribution lines should meet the voltage standards required by RUS or any more stringent local regulations when required. Generally, maximum voltage drop at extremities of feeder taps and minimum power factor are specified.

5.5.3 In spite of the high cost of rebuilding lines, and the careful planning done in the past, it will often be necessary to increase the capacity of existing sections of distribution line. Before deciding to rebuild a line, careful consideration should be given to a number of factors including:

a. If the line is quite old and will need replacement by the end of the LRP period, then rebuilding with increased capacity may be a better way of obtaining increased ability to serve load than building an additional line. In some cases, considerable research may be needed to determine the age of various lines. However, rough estimates of effective age considering the amount of maintenance which has been performed will be adequate for these purposes.

b. Since the rebuilding operation will probably require replacement of most if not all poles, a different route may now be more desirable than the original one. For example, a line originally constructed on a right-of-way remote from the highway might be moved adjacent to the highway providing more economical maintenance of both the line and the right-of-way, with perhaps a net increase in reliability. Environmental considerations, or territorial limitations of course, may preclude any rebuilding of lines in a given area. The alternatives should be considered carefully before a decision is made to re-route a distribution line.

c. It may be practical to serve sections from an alternate circuit or substation for a time until an improvement is constructed.

d. If another system improvement, such as a new substation or an additional new feeder, is planned for the area in

the not too distant future, then the earlier construction of the other planned improvements should be considered.

5.5.4 When new distribution lines are needed, the routes should be chosen, where feasible, to be along improved roads to facilitate operation and maintenance and to provide maximum opportunity to serve existing and potential consumers. The specific details of the line location and design need not be determined until prior to the inclusion of the CWP.

5.5.5 Where it might be advantageous to change the system standard distribution voltage class, consideration should be given to all standard distribution voltage classes. Frequently only one alternative voltage will be feasible; however, occasionally a voltage class which was not considered at first will provide greater long-term benefits. After a voltage conversion has been made, a further conversion will not be feasible as many of the costs associated with another change would be incurred a second time with a smaller offsetting savings.

5.5.6 Virtually all systems use voltage regulators to maintain adequate voltage levels at extremities of distribution lines until major improvements can be justified. RUS recommends that some form of voltage regulation be used in substation and distribution metering points (unless a metering point has a well regulated supply). RUS further recommends that, in general, only one voltage regulator should be installed on the distribution line between any consumer and the substation. These are recommendations and not hard and fast rules. The LRP should provide for maintaining a regulated primary distribution voltage with a maximum voltage drop of no more than 8 volts at the extremities. Where more stringent requirements are imposed by local authorities, they must, of course, take precedence. Line drop compensation, which can improve operation and/or extend the range of voltage regulators, should be taken into consideration.

5.5.7 Consideration should also be given to the installation and optimum location of shunt capacitors on distribution lines. Capacitors provide a relatively low cost means to boost voltage and improve and control power factor. These improvements usually result in some demand reductions, energy conservation and lower power costs. Some voltage regulations can be achieved with the judicious sizing and locating of (usually switched) capacitor banks.

6. DEVELOPMENT OF THE LONG-RANGE PLAN: Because the plan should be based on the planning criteria, design considerations, basic data, and the analysis of existing system, little can be done regarding specific alternatives until after the intermediate conference. However, certain

existing conditions will be evident as problem areas requiring that alternative configurations be considered for later economic comparison. After the intermediate conference, the major steps discussed below should be taken to develop the LRP.

6.1 Exploratory Plans: Typically, the demand level established for the long-range system should be large enough to permit the planning engineer to explore many possible plans and system configurations. The planning criteria and design considerations established in the intermediate conference should be followed in developing each exploratory plan. Each plan should make maximum economical use of existing facilities or correct a major problem while satisfying the planning criteria to the greatest extent possible. System standards for voltage, service reliability, etc., should be maintained by those facilities installed during the transition from the existing to the long-range system. Generally, only major items such as substations, transmission lines, and distribution feeder main lines, should be considered. The following are typical considerations for exploratory plans:

a. Increase the capacity of existing substations and reconductor the distribution lines.

b. Install additional substations, effectively shortening the distribution lines.

c. Install loop feed transmission lines to substations.

d. Install radial feed transmission lines to substations.

e. Convert areas to a higher voltage class.

f. Replace distribution metering points with transmission metering points or substations.

g. Install additional feeders from existing substations.

h. Install inter-substation ties.

6.1.1 Due to the nature of the LRP and the approximations made in various projections, detailed calculations are seldom cost effective for analyzing exploratory plans.

6.1.2 The planning engineer may wish to consider other approaches to expand the existing facilities to serve the long-range load. In most cases, it will be possible to establish two or three preferred exploratory plans without the time-consuming task of laying out and comparing a large number of designs. If the criteria prove too restrictive causing the exploratory plans to be unreasonable, the planning engineer should inform management giving recommendations for modifying the criteria.

6.1.3 Each exploratory plan should consider the major facilities required to provide a transition from the existing to the long-range system. The plans should be expressed in terms of capacity, costs and estimated years of expenditures. A list of required major system improvements should be prepared showing costs and the projected years in which they will be needed, respectively, for each exploratory plan.

6.1.4 Although each exploratory plan may not be able to have the same capacity each year of the study period, each alternative must provide similar reliability and capacity at the long-range load level. For certain facilities, capacity constructed before it is actually needed may help pay for the additional ownership cost from savings realized by reduced losses and avoidance of cost escalations. However, other facilities may not provide these benefits and should not be constructed before they are absolutely necessary.

6.2 Comparison of Plans: The following are typical of the comparisons and considerations which should be made in connection with developing the exploratory plans. This should not, however, be construed as limiting consideration to these examples.

6.2.1 Although an existing distribution metering point might continue to be used in the long-range system to serve the increased load by increasing the size of the conductor on the main feeder, the costs and benefits of such a plan should be compared with those of a plan involving the construction of a transmission line and substation to replace the metering point. Reliability of service should be examined for each of the plans being compared.

6.2.2 Although existing substations might be used in the long-range system to meet the increased system load through the conversion of 12.5/7.2 kV distribution lines to 24.9/14.4 kV, the costs and benefits of such a plan should be compared with those of an exploratory plan involving the construction of additional substations and transmission lines. All foreseeable costs associated with converting to the higher voltage level should be considered in the comparison, including increased costs of transformers for connecting new consumers and for changing transformer installations to existing consumers. The costs that may result from possible changes due to additional clearances need not be considered unless they can be documented.

6.2.3 Reliability of service should be examined under each of the plans being compared. Normally, establishing new load centers would effectively shorten the distribution lines, whereas, voltage conversion may result in an effective sacrifice in reliability. Consideration should therefore be given to methods of obtaining an offsetting increase in reliability, such as installing two three-phase transformers or a mobile substation. The incremental increase in reliability and cost of each alternative should be evaluated. Consideration should also be given to such possibilities as loop-feed transmission to the substation or more sophisticated distribution line sectionalizing to improve the reliability of the supply. Thus, the exploratory plans to be compared can be made to have similar reliability levels.

6.2.4 Where it is deemed necessary to abandon a delivery point (distribution or transmission) because of excessive outages attributable to the power supplier, the planning engineer should present supporting outage data plus any other information available which will justify replacing the metering point.

6.2.5 If an exploratory plan calls for the construction of transmission facilities because the existing power supplier's facilities are inadequate or unreliable, the planning engineer should, in addition to making comparative economic studies, present data to show evidence that the existing power supplier has been contacted and has not corrected the inadequacies. The point of delivery for the proposed transmission facilities will need to be from a reliable power source. If a change in power supplier is involved, information should be furnished to show that the new power supplier's facilities are adequate and reliable. The savings, if any, resulting from the change in wholesale cost of power, gained through construction of the transmission facilities, should be commensurate with the additional investment in facilities necessary to make the change. It should be shown that this is the most beneficial means for providing the reliability or capacity needed.

6.2.6 It may be that the power supplier will not provide bulk power at or near the owner's load centers. If the owner considers construction of its own transmission facilities, a careful comparison should be made of long-range costs and benefits of constructing and operating the transmission option versus long and/or large capacity distribution lines from the alternative substation to the load center.

6.2.7 Each exploratory plan should be based on power sources that the planning engineer and system's management are reasonably sure will be available. Every attempt should be made to persuade the existing power supplier to furnish adequate and reliable sources of power where they are needed.

6.2.8 Where necessary, alternative recommendations should be made based on savings that would be realized if the power sources could be obtained closer to the load centers. These alternative recommendations should be provided only for those cases that appear reasonable and practical.

6.3 Plan Selection: The development of the LRP should not be restricted by the limitations of the existing system. Although it must be recognized that there are certain inherent benefits associated with the continued use of installed facilities, alternative proposals should be adopted if the projected benefits from the change will exceed the cost of the change. Several factors must be considered in selecting the recommended LRP.

6.3.1 The primary concern in plan selection will generally be for comparative economics. In evaluating alternative exploratory plans, it will frequently be necessary to compare plans with widely varying time/cost distribution, i.e., one plan may have high first cost and another plan may have high annual costs. Simply selecting on the basis of lowest first cost or lowest annual costs may eliminate the alternative which would provide the best service at the most reasonable cost to the consumer. There are numerous methods of performing economic comparisons: present worth, annual costs, capitalized annual cost, minimum revenue requirements, etc. Any good textbook on engineering economics will explain several of these methods. Whichever method is used, the following factors should be considered:

a. Time Value of Money - The dollars spent this year are worth more than the dollars spent next year.

b. Inflation - Labor and material costs are increasing and will most probably continue to rise.

c. Specific Fixed Costs of the Owner - The owner's system has historical fixed charge rates provided as basic data. These rates may change with replacement of older facilities (decreased O&M, increased taxes, etc.) and would be expected to be different in the future. See Appendix III, Fixed Charge Rate Calculation Guide.

d. Demand and Energy Losses - It should be recognized that not only will the peak-load demand losses and the annual kWh losses increase with the system load growth, but the cost of those losses will also most likely increase.

6.3.2 When the economic comparison indicates the costs of two alternative plans are within 10 percent of each other, a sensitivity analysis should be performed to verify the validity of assumptions. Increase in interest, inflation, energy losses, growth rate, etc., should be considered to determine if the selected plan is likely to become less feasible after the owner has become committed to it. The results of the economic analysis and sensitivity should be represented in tabular form and included in the LRP report.

6.3.3 If two plans are still close after analyzing their sensitivity to overall cost changes, other factors should be considered:

a. Energy Conservation - Although energy losses were considered in the economic analysis, if two plans will cost roughly the same amount but one plan will result in a net energy savings, then that plan should be given a priority credit.

b. Excess Capacity - Although each plan must provide the minimum capacity required to serve the projected system load, one plan may provide more excess capacity at the end of the evaluation period. In that respect the plan with excess capacity is superior.

c. Service Reliability - Although each plan must provide for minimum levels of service reliability, one plan may involve inherently better service reliability. In that respect this plan is superior.

d. System Labor Costs - If a system has labor costs below the national average, a more labor-intensive alternative may be appropriate. However, if additional labor is not available in the community, a large construction program will require use of outside contractors for a larger percentage of the work to be done, which may change the system's average labor costs.

e. Flexibility - One plan may be superior in its capability of further expansion beyond the LRP level while the other will require radical changes in basic design parameters at that point. For instance, a superior option would be one which has a longer useful life than other options. On the other hand, the plan which defers major expenditures has the value of increased flexibility to take advantage of future developments.

f. Solution of Chronic Problems - One plan may eliminate a problem which has given management continuous service problems while the other plan does not. This should also be considered.

6.3.4 The techniques of cost benefit analysis may be helpful in evaluating alternatives based on the above factors. A good textbook on cost benefit analysis will explain the procedure.

6.3.5 Annual costs that are common to all plans may be omitted from the summary but explanatory notes should be included.

6.3.6 While economic comparison is the primary basis for plan selection, there is no substitute for good judgment based on all available facts. In some instances, indeterminate factors may necessitate the inclusion of an alternative plan to the selected LRP.

6.3.7 All work sheets, sketches, maps, etc., used in developing and testing the LRP should be retained for future reference. At the discretion of the owner, they may be retained by the planning engineer or may be turned over to the system staff.

6.4 Draft Review Conference: Following completion of the exploratory plans and the preliminary selection of the LRP by the planning engineer, a conference should be held to review the rough draft of the LRP. The planning engineer, the system manager, and other appropriate personnel should attend the conference. The RUS GFR and a representative of the power supplier should be invited to attend this conference. Based on the decisions made at the conference, the planning engineer should prepare a summary planning report. (Appendix IV is a sample form for the "Summary of System Planning Report" which the engineer may elect to use).

6.4.1 The owner should review the draft LRP report to verify that the plan:

a. Is the result of adequate and appropriate data, engineering analysis and judgment.

b. Provides sufficient data to serve as a guide for preparation of construction work plans and long-range financial forecasts.

6.5 Preparation of the Long-Range Engineering Plan: The long-range engineering plan should present the planning engineer's analysis of the existing system and the recommended LRP including the transition to the long-range system. An alternative plan should be included if there are indeterminate factors. The report should not present detailed analysis of exploratory plans; it should contain sufficient explanatory data and summaries of engineering analyses of these plans. The superiority of the proposed plan should be indicated and the cost differentials should be shown in dollars. The method of economic analysis should be indicated. When appropriate, small sketches of the system, or sections of the system, should be used to simplify or replace written descriptions. It is also suggested that summaries of basic data, economic comparisons, costs data and engineering analysis be presented in the form of tables or graphs.

6.5.1 The planning engineer should make suggestions to the owner of appropriate items to be standardized, such as conductor sizes, substation capacity, etc.

6.5.2 New construction and major system improvement items should be tabulated with approximate cost estimates and the approximate year of installation. Groups of other system improvements, including increase in capacity of services and transformers should be tabulated with cost estimates for each year of the plan. Existing plant investments and estimated annual cost of connecting new consumers should also be included.

6.5.3 Most RUS borrowers have extensive replacement programs in effect which will continue through the transition to the long-range system. Ordinary replacements are those resulting from rot, corrosion, wear and tear, damage, etc., and do not involve an increase in capacity or quality of service. The estimated annual costs of ordinary replacements should be tabulated as a separate item in the cost summary, as should maintenance and system improvements for each exploratory plan. These items would be included in future CWPs. The cost of replacements in connection with system improvements should be included in the investment figures for the system improvements.

6.5.4 The cost data tabulations should be broken down by types of facilities such as distribution, transmission and generation, if any. The report should include graphs or tabulations of the projected kW demand as related to time for each substation area or areas which have different levels of usage. Management will thus be able to relate investment in facilities to the time of installation for use in preparation of long-range financial forecasts.

6.5.5 A note should be added indicating the month and year on which cost estimates are based. Normally, all cost estimates should be based on present price levels with appropriate escalation factors used to estimate future construction costs.

6.5.6 A circuit diagram should be prepared for each major step in the transition including the existing system and for the long-range system. The diagrams should show regulated and unregulated voltage drops resulting from system loading at each step with and without the recommended improvements. Transmission lines of the borrower's system, the power supplier, and other transmission lines traversing the owner's system should be shown on either the circuit diagram or on a separate transmission diagram.

6.5.7 Detailed calculations upon which engineering analyses and other planning investigations are based need not be included in the long-range planning report. However, summaries of findings and assumptions used should be included to help management determine the continued validity of and make revisions to the study. Also, a bibliography which identifies all data, external documents and judgement sources should be included. Normally, the planning engineer should retain the calculations and work sheets as long as the system planning contract is in effect. Upon completion or termination of the contract, these files should be made available to the owner.

6.5.8 Appendix II, "The Suggested Table of Contents for Long-Range Engineering Plan," can be used as a guide in organizing the report and its table of contents. The order in which major sections are listed may be changed if it will improve the report. However, care should be taken to see that the requirements of RUS electric loan policies and application procedures are fulfilled and the presentation demonstrates good practice for engineering reports.

6.5.9 The LRP information should be summarized in a format similar to the sample form in Appendix IV.

6.6 Acceptance of Plan: The long-range engineering plan is subject to acceptance by both the owner's management and by RUS. The owner's board of directors should signify its approval of the report by issuing a resolution. A copy of this resolution should be forwarded to the RUS GFR along with two copies of the report for RUS acceptance. At least five copies of the long-range engineering plan should be prepared: two copies are for the owner; two copies are for the RUS GFR; and one copy to be retained by the planning engineer. Other copies may be distributed to the power supplier and the Local Planning Board(s).

7. CONTINUING PLANNING ACTIVITIES: Planning for the future is a continuing process. Data should continually be collected to check the soundness of the existing plan and later to aid in preparing a new plan. The planning engineer should assist the owner in establishing methods for obtaining the required data from various operating records and files. Good system planning requires methods for keeping the plan up-to-date. It should also provide for CWPs to implement the transition through timely installation of facilities.

7.1 A CWP should provide a coordinated construction program. It should also provide much of the basic data needed in preparing the system's budget for additional capital investment. RUS Bulletin 1724D-101B, "System Planning Guide, Construction Work Plans," provides guidance in preparation, approval, and use of construction work plans. A well prepared construction work plan based on an accepted, up-to-date LRP is generally adequate to demonstrate planning support for a loan application to RUS.

7.2 The LRP should be reviewed prior to the preparation of a CWP to verify its continued validity. If the owner finds it necessary, due to unforeseen developments, more frequent reviews may be conducted. The basic data, design criteria, and assumptions used in its preparation should be compared with actual system developments. A recommended guide for reviewing and determining the adequacy of the current LRP, and documentation thereof, is found in RUS Bulletin 1724D-101B, "System Planning Guide, Construction Work Plans," Exhibit II-D1 (3 pages). If the LRP proves to be valid by the reviewer, it should be so documented in the construction work plan. If a revision to the plan is deemed necessary, the revision should be a separate concise report, with an appropriate title, properly dated and with the necessary references to the parts of the existing report that are being revised. The distribution of copies of any revisions should be the same as for the original system planning report. LRP revisions are subject to approval by the owner's board of directors and acceptance by RUS, similar to the acceptance of the original LRP.

7.3 Review (and revision as necessary) of the LRP will extend its useful life and indicate the need for a new plan when revisions are no longer adequate. Many things can happen to necessitate revision or replacement of the LRP. Loads may develop faster than projected in some areas and slower than projected in other areas; power suppliers may change their plans;
it may be necessary to provide for extensive transmission system construction; necessary rights-of-way may not be obtainable; laws and ordinances may change (such as requirements for underground line construction); and technological developments may occur. Any one of these may be reason for adjustment or replacement of the plan. Even if no major changes are needed, numerous minor revisions may necessitate a new LRP. The cost of planning activities should be considered as an investment which may minimize necessary expenditures. Thus long-range planning may be one of the most cost effective actions available to electric system management.

APPENDIX I

Definitions of Terms and Abbreviations

System Planning: System Planning is the careful analysis and evaluation of an electric power system, the consideration of alternative methods of meeting the electric power needs of the consumers, and the selection of the most promising of the viable alternatives for providing reliable, environmentally acceptable service at reasonable cost. System planning by RUS borrowers is manifested in the long-range plan (LRP) and the construction work plan (CWP).

Borrower: A Borrower is an organization which borrows or seeks to borrow money from, or arranges financing through, RUS for the purpose of constructing facilities or making improvements in that organization's electric system.

Owner: An Owner is the same as a Borrower, except that the term Borrower implies a relationship with RUS, while the term Owner implies a relationship with consultants, power supplier, etc. The responsibilities of the owner are generally carried out by the general manager (or person with similar title) of the owner.

Board: The Board is the board of directors or board of trustees of the owner. The board is responsible for setting policy including final approval of the LRP.

Planning Engineer: The planning engineer is the individual responsible for conducting all necessary studies and preparing the planning report. It is desirable that this individual be a duly registered professional engineer under state laws and recognized by RUS as being qualified in preparing LRPs. Although the planning engineer is usually an outside consultant, the planning engineer may be a member of the owner's staff or combination thereof. Although many Owner's staff engineers compile CWPs, an owner should evaluate the advantage of additional perspectives, skills and available time provided by an outside consultant when involved in the LRP.

Power Supplier: The Power Supplier is an organization from which the owner purchases wholesale power and energy. The role of the power supplier may be filled by a private power company, a governmental agency, or a generation and transmission cooperative (G&T) of which the owner is a member. In many cases, the owner purchases energy from more than one power supplier. In cases where all purchases are coordinated through one organization, that organization is the power supplier even if that organization has no generating capacity of its own.

SCADA: Abbreviation for Supervisory Control and Data Acquisition.

D.A.: Abbreviation for Distribution Automation, a system which enables an electric utility to monitor, coordinate and operate electric system and consumer components in a real-time mode from remote locations.

APPENDIX II

Suggested Table of Contents for
Long-Range Engineering Plan

I. Introduction

II. Purpose of Report

III. Summary of Report, Conclusion and Recommendations

IV. Analysis of Existing System and Basic Data
- A. Introduction
- B. Purpose of Analysis
- C. Summary of Analysis, Conclusion and Recommendations
- D. System Growth Patterns
  - 1. Land Use Plans
  - 2. Load Density Projections
- E. Capacity of Existing System
  - 1. Service to Present Loads
  - 2. Service to Future Loads
  - 3. System Performance
    - a. Voltage Levels
    - b. Service Reliability
    - c. Demand and Energy Losses
    - d. Operating Expenses
- F. Environmentally Sensitive Areas
- G. Adequacy of Basic Data
- H. Existing Communication Equipment and Methods

V. Planning Criteria
- A. Long-Range Demand Level
- B. Area Load Density and Growth Potential

C. Special Loads
D. Service Reliability
E. Financial Criteria
F. Other Criteria
G. Assumptions
H. Facilities and Equipment

VI. Long-Range Plan
A. The Recommended Plan
B. Alternate Recommendations
C. Exploratory Plans
D. Plan Selection
1. Examination of the Transition
2. Economic Justification
3. Other Justification

VII. Summary of Future Communication Equipment and Methods

VIII. Exhibits
A. Tabulations of Supporting Data
B. Sketches, Maps and Circuit Diagrams
C. Copies of Pertinent Correspondence
D. Bibliography
E. Other Exhibits

APPENDIX III

Fixed Charge Rate Calculation Guide

Following is some data to assist in the calculation of a Fixed Charge Rate. A fixed charge rate is composed of several factors: the cost of capital, operation & maintenance, taxes, insurance and depreciation. Calculating the cost of insurance as a percent of investment is difficult, and the result makes little difference; therefore, it can be ignored for most applications. The fixed charge rate is not an exact figure, but an estimate which is dependent on the quality of the assumptions involved in its calculation.
NOTE: References to annual Form 7 are based on the 06-94 Revision of Form 7:

COMPONENT
I. COST OF CAPITAL:
of FCR
A. It is important to recognize the cost of capital, which is greater than the cost of debt. This is because there is a cost of member equity. The return on equity portion

of this calculation can be figured in at least three ways. The Goodwin method includes the cycle of capital credits in calculating the return on equity. Or, one may adopt a return on equity that a state regulatory authority has declared to be adequate for electric utilities. Or, a TIER-based calculation such as is illustrated below, may be used.

B. Net TIER (Times Interest Earnings Ratio):

1. For future projects, TIER should be selected in accordance with the owner's Equity Management Plan.

2. For comparison, TIER for a past year could be calculated from data on the annual Form 7:

TIER = Interest [PartA, line15(b)] + Margins [Part A, line 27(b)] = $ $ = ____________

Interest [Part A, line 15(b)] $

C. CAPITAL STRUCTURE:

1. For future projects, the debt ratio should be in accordance with the owner's Equity Management Plan. Line of credit or short-term borrowing should be taken into consideration in long-term financial decisions.

2. For comparison, the debt ratio for a past year could be calculated from data on the annual Form 7:

Debt ratio = LTD (Part C, line 35) x100 = $ x100 = _________%

LTD (Part C, line 35) + Tot. Marg. & Eq. (Part C, line 32) $ +$

D. COST OF CAPITAL:

1. For future projects the cost of debt should be estimated carefully, taking long-term trends into account. A suggested form would be:

Proportion of debt		Long-range est. of interest rate		Component
		RUS		
%	x	%	=	% (a)
		Supplemental Lender		
%	x	%	=	% (b)
		Cost of debt = (a)+(b)	=	%

2. In case one needs to calculate the embedded cost of debt for a past year, it can be calculated from the annual Form 7:
[Embedded cost of debt] = Part A, line 15(b)
x 100 = $__________ x
100 = %

Part C, line 35
$__________

3. Weighted cost rate of debt:
Debt Ratio x
cost of debt =

(from I.C. above)
(from I.B. above)

______________ x
______________ = %

4. Cost of capital:
Wtd cost rate of debt
x TIER =

(from I.D.3. above)
(from I.B. above)

_________________ x
______________ = __________%
(CC)

II. OPERATION & MAINTENANCE:

A. For future projects, O&M should be selected to agree with the various plan alternatives. If a more costly alternative promises lower O&M, it should be reflected here.

B. For comparison, a historic distribution-plant O&M could be calculated by this form, with figures from the annual Form 7:

Part E Part F

line 14(a) line 7(a)

Net Distribution Plant, annual Form 7, last year
$ - $
= $____________

Net Distribution Plant, annual Form 7, 2 years ago
$ - $
= $____________

Average Net Distribution Plant last year
= $____________ (a)

Distribution Operations: Part A, line 5(b):
= $____________ (b)

Distribution Maintenance: Part A, line 6(b):
= $___________ (c)
O&M as a % of Avg. Net Distn. Plant [(b)+(c)]/(a) x 100; or estimated from II. A., above
__________% (O&M)

III. TAXES:

Property tax: annual Form 7, last year, Part A, line 13(b)
$___________ (a)

Plant the taxes were paid on: annual Form 7, 2 years ago, Part C, line 5 + line 20
$___________ (b)

Tax Rate: [(a)/(b)] x 100; or estimated future tax rate
% (Tx)

IV. DEPRECIATION:

Use an appropriate depreciation figure for the project alternative(s) being studied. Most owners use straight-line depreciation where the depreciation rate is the reciprocal of the asset's life.

Annual rate for coop, for plant or for classes of plant
___________% (Dep)

V. Total Annual Fixed Charge Rate = Cost of Capital (CC) + Oper. & Main. (O&M) + Taxes (Tx) + Depreciation (Dep) =
___________%

Bulletin 1724D-101A
Page

Attachment_(SCF-4)

NEPPA News Line

Vol. 37, No. 9 • September • 2003
Newsletter of the Northeast Public Power Association

Fox Islands receives USDA grant for underwater cable system

The rural development arm of The United States Department of Agriculture has awarded Fox Islands Electric Cooperative of Vinalhaven, Maine $2,633,522 in high-energy cost grant funds. The funds will be used to construct a submerged transmission cable to provide electric power to the islands of North Haven and Vinalhaven, located ten miles off the mid coast of Maine.

Fox Islands Cooperative General Manager David Folce

The present submerged cable, which provides the only source of power to the islands, is experiencing major reliability problems with 26 failures in the past six years and seven in 2002 alone. The construction of a new cable will provide reliable power and alleviate both the costly repair of the current source and the uncertainty of service.

Agriculture Secretary Ann M. Veneman made the announcement in July that projects in seven states would be the recipients of nearly $15 million in grant money.

"This grant is a blessing to the community," said Fox Island Cooperative General Manager David Folce, who experienced another two-cable failure a month after the announcement. Folce said that they are in the process of obtaining the required permits and completing an environmental study. The Cooperative is also applying for a Rural Electric Services loan to fund the rest of the $6.1 million project.

"All the paperwork slows things down but we are very thankful for this grant," said Folce. "It can't happen fast enough."

The USDA funds for these grants are being provided for the first time and are available for improvement of energy generation and distribution facilities serving communities with extremely high-energy costs. Grants may be used for the acquisition, construction, installation, repair, replacement or improvement of energy generation, transmission or distribution and will help assure access to reliable energy services. Further information on rural programs is available at a local USDA Rural Development office or by visiting USDA's web site at www.rurdev.usda.gov.