

**ANALYSIS OF
STRATEGIC ORGANIZATIONAL OPTIONS
FOR THE LONG ISLAND POWER AUTHORITY**

A Study By
The Brattle Group
For
The Long Island Power Authority

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Executive Summary

The Long Island Power Authority (LIPA) is a municipal electric utility that serves Long Island and parts of Queens. Most of LIPA's resources are focused on operating and maintaining its electric transmission and distribution system and, in this regard, it can be considered primarily a "T&D utility," even though the majority of its expenses in customer bills are for generation (purchased power and fuel). LIPA is currently operating under a fairly unique organizational structure under which most of the work associated with carrying out utility field operations is performed by a service provider (National Grid USA) under a contractual agreement referred to as a Management Services Agreement (MSA).

The subject study of LIPA's organizational options was motivated by the upcoming expiration of the current MSA and the need to determine its replacement model. *The Brattle Group* was retained by LIPA to conduct a Strategic Organizational Study in the latter half of 2010, with the expectation that work would be completed with sufficient time for LIPA to consider Brattle's analyses and recommendations in developing its strategic options for the organization going forward. This has been accomplished.

The objective of our study concerning LIPA's strategic organizational options is to clarify and assess the strategic organization alternatives available to LIPA by estimating the cost structure for each of the options and determining the impact that implementation of each would have upon retail electric rates. Furthermore, the objectives of the study include our ranking of options based upon the above referenced quantitative analysis and consideration of other factors, such as risk and option values, which may be less amenable to quantification but which are nonetheless qualitatively important.

Specifically, the strategic organizational options included:

- 1) An option under which the National Grid portion of LIPA's work force would be transferred to the LIPA organization (the "Municipalization" option);

- 2) An option under which LIPA continues to outsource much of its T&D, customer service and various planning, corporate and administrative functions, albeit under a different contractual arrangement with its service provider (the “ServCo” option); and
- 3) An option under which LIPA would sell its assets and business to a private enterprise, with the private enterprise becoming the electric utility for Long Island and part of Queens (the “Privatization” option).

LIPA’s Board of Trustees and customers are acutely aware that LIPA’s retail electric rates are among the highest in the country and that customer satisfaction with LIPA is low. Accordingly, the current study has placed considerable emphasis on analyzing at a detailed level LIPA’s current cost structure and the cost structures likely to be realized under the various strategic options. We also considered additional factors that may impact LIPA’s selection of a strategic organizational option, including consideration of the risks associated with effectuating a strategic option and the opportunities or lack of opportunities (i.e., options) to exit or change from an option. Our study and conclusions were based primarily on economic analysis. Finally, we also factored in our general views of the electric utility industry and organizational effectiveness.

In conducting our analysis, we developed a baseline for LIPA’s cost structure and revenue requirements. We then examined costs to determine how they could change if each of the organizational options were implemented. The source for these costs was an extensive review of empirical data regarding LIPA’s costs and performance, as well as such data on other electric utilities. Specifically, the baseline cost structure for LIPA was developed by reviewing and analyzing detailed data for LIPA and National Grid disaggregated by functional work area and category of cost. In determining costs under each organizational option, we considered LIPA’s historic performance against other utilities (benchmarking analysis) and utility experiences with cost savings and reorganizations. We also applied the experience of our consulting team in the electric utility industry in specifying the size of plausible changes.

Using detailed historic data provides a strong foundation upon which to develop analysis. However, studies of this nature – that is, projecting the cost structure and rates for a yet to be

formed and implemented organizational option – inherently involve projections and uncertainties. Accordingly, the projected cost structures included in this study should not be construed as *absolute* forecasts of what would necessarily occur. The actual costs that may be realized are dependent upon numerous influencing factors, some of which almost assuredly will change from our understanding today. Instead, these projections are intended to measure the *relative* differences between the strategic options.

In order to ensure that our projections are as objective as possible, and to understand how they depend on certain factors, we have developed high and low cost scenarios surrounding a mid-case scenario. We believe that these present a meaningful range of possibilities and risk.

The major areas of LIPA's costs can be categorized as either operating costs or financing costs. Operating costs cover the annual expenses associated with running an electric utility, including labor and related (non-labor) expenses, as well as expenses associated with depreciation and amortization of utility property, plant and equipment. Financing costs related primarily to the carrying charges (interest) on LIPA's utility plant. We also included taxes in that category. Together, these form LIPA's annual revenue requirement, or the costs that it must cover in its electric rates to remain whole. This was equal to approximately \$3.8 billion in our baseline analysis, which translates into an average rate of 18.2 cents per kWh.

Operating Costs. LIPA's transmission and distribution (T&D) operating cost are roughly \$557 million per year in the baseline case, which translates into approximately 2.7 cents per kWh. A majority of these costs reflect the costs of National Grid, LIPA's current service provider, fulfilling its obligations under the MSA. These T&D costs comprise only a modest portion, about 15%, of LIPA's total cost per kWh. Given LIPA's annual kWh sales are slightly more than 19,000 GWh, a change in costs of roughly \$200 million per year has about a 1 cent per kWh impact on average rates. This means it would be necessary for a new organizational form to cut out about a third of operating costs in order to achieve a one cent rate reduction.

Cost benchmarking analysis, as well as benchmarking of LIPA's level of distribution reliability, indicates that LIPA operates at a relatively efficient and effective level compared to other

utilities. In particular, on a T&D cost per kWh basis, it is more cost efficient than the average for the investor owned utilities (IOUs) in New York State. This finding is important because it indicates that there probably is no opportunity for LIPA to dramatically reduce the costs of its T&D and Customer Service operations (which constitute the majority of its work force and its T&D operating costs), irrespective of organizational form.

Certain operating costs are likely to vary across organizational options (including some reductions and some increases). The most notable cost reductions could likely be achieved under the Privatization option. We assume that privatizing LIPA would come about by merging or being acquired by an IOU, and that new owner would already have a range of planning, corporate and administrative capabilities in place. By combining with LIPA, the new entity would need less than the sum of its own existing staff plus LIPA's current planning, corporate and administrative resources, so it probably could reduce costs.

Operating costs would most likely increase slightly under the Municipalization and ServCo options, primarily because there are additional costs associated with creating an autonomous organization in regard to facilities, staffing and systems. The ServCo option also includes a profit that is paid by LIPA to the service provider; this cost is avoided under the Municipalization option. However, fully municipalizing LIPA would involve transferring employees of a private utility to the municipal utility. This may require that the employees move from their current pension plan (private plan) to the plan under the New York State and Local Retirement System, which is estimated to have a higher level of expense per employee than the current private plan. We included that assumption in our mid-cost scenario, but we also recognized that it is possible that an alternate approach may be worked out. We thus included a low cost case in which pension levels stayed at their current level (with no increase on a per employee basis).

A significant area for cost savings under all three of the strategic organizational options involves LIPA's payments of property taxes (which it pays on the power plants which are owned by National Grid but used by LIPA under a Power Supply Agreement) and payments in lieu of taxes (PILOTs) which it pays to taxing jurisdictions primarily concerning their T&D properties.

Surveys by the American Public Power Association (APPA) indicate that LIPA pays significantly more than the panel average on a per dollar of revenue basis. Reducing the percentage of PILOTs and property taxes to LIPA's overall revenue requirement by a relatively small amount results in \$30 to \$40 million per year in savings for the Municipalization and ServCo options, respectively, which largely offsets the projected cost increases associated with facilities, staffing and systems.

Financing Costs. LIPA currently pays interest expenses on its debt (\$6.8 billion) of roughly \$330 million per year; these costs constitute about 9% of its annual revenue requirements. As a municipal utility, LIPA's debt is tax exempt. This would continue under the Municipalization and the ServCo options. However, financial structure and the costs of capital under a Privatization option would change considerably. Specifically, the privatized utility would be financed using roughly a 50%/50% combination of equity (on which it would need to pay a risk-appropriate return to investors) and taxable debt. Investor owned electric utilities have rates regulated by state regulatory commissions which have established rules and guidelines concerning the return on capital that they allow in rates. We applied the precedents set by the New York Public Service Commission to the case of a privatized LIPA. We estimate that the pre-tax weighted average cost of capital (which includes the combination of debt and equity) for the privatized utility would be roughly 10.73%, compared to LIPA current cost of capital of about 5%. This means that LIPA's costs would go up by roughly \$438 million per year due to financing costs alone under the Privatization scenario.

Financing under the Privatization scenario is further complicated by current market conditions. LIPA's debt is made up of a combination of "callable" and "non-callable" bonds. This means that LIPA cannot simply pay off all of its bonds at face value if it were privatized. Instead, if LIPA were sold, it would have to set up a fund by which it could continue to meet its obligations on bonds until they are eligible to be retired. Unfortunately in regard to satisfying this obligation, LIPA's current average coupon rate is roughly 175 basis points above the current market rate. That is, the market value of LIPA's debt is materially above its book value, and as a result, LIPA would need to raise approximately \$961 million more than its current debt (and swap) obligations in order to defease its bonds. This increases the cost of privatization.

Any savings in operating costs that LIPA may be able to realize under a Privatization scenario would be overwhelmed by the increase in financing costs, even before we consider the additional costs of defeasing its bonds. However, there is a possibility that LIPA could be acquired at a premium over its book value, because the common stock of many investor owned utilities currently trade at market prices in excess of their book value per share, and utility mergers and acquisitions also typically involve control or strategic premiums of a few percent. We analyzed these typical mark-ups, but found that using the levels of premium observed in the utility market is not sufficient to make the Privatization option feasible from a rate standpoint.

Additional Factors. Our analysis indicated that the Municipalization and ServCo options have very similar levels of overall costs, though with somewhat different component costs beneath the surface equivalence. We thus considered additional factors that may serve to further differentiate the two. These included differences in: the risk associated with the transition from LIPA's current organizational structure to a fully municipalized or ServCo model; risk associated with developing and implementing upgraded or new information system, especially customer facing systems; option values associated with the terms and structures of the organizational alternatives; and contract and incentive issues.

We found positive features as well as drawbacks for both the Municipalization and ServCo options. The general arguments in support of implementing the Municipalization option focus on the coherency and conventionality of the organization that would be created. However, fully municipalizing LIPA would require a large scale transformation of the current organization, from approximately 100 employees to roughly 2,000 employees. Also, the governance and processes under which a fully municipalized LIPA would operate may include constraints in certain key areas, such as governmental restrictions on the terms and conditions of employment and procurement. There also may well be a variety of legal and institutional issues that need to be tackled before full municipalization could be effectuated; resolution may require political and legislative actions.

The case for ServCo starts with the fact that it provides access to private sector managerial expertise and scale of operations from the ServCo provider, while preserving the attractive financing advantages of a tax-exempt entity. An additional advantage of the ServCo option is that it has more long-term flexibility to support future reorganizations than does the Municipalization option. In all likelihood, implementing the Municipalization option is a “once-and-for-all” decision; ServCo has been designed to create a “portable” self-contained entity and to include an exit provision. Offsetting these potential benefits is the concern that a third-party provider of ServCo inherently faces somewhat limited and under-specified incentives to serve LIPA’s interests unequivocally (i.e., a “principal-agent problem”).

A primary area of risk associated with LIPA’s organizational transformation concerns the development and implementation of systems, in particular customer-facing information systems. It is likely that development and implementation of these systems will be more efficient under the ServCo model, because the service provider should be able to leverage the expertise that it has demonstrated in its own utility systems and operations. Completing this task would most likely be more difficult under the Municipalization option, though it is not insurmountable. Importantly, the slightly higher level of implementation risk under the Municipalization option (compared to ServCo) does not rise to the level of affecting power system performance. Rather, it is a matter of possibly higher development costs, and perhaps delays or glitches in early roll-out, which may create managerial or customer frustration.

Overall Conclusion and Recommendation. We found a “bright line” difference in cost and rate impacts between the Privatization option, on the one hand, and the Municipalization and ServCo options on the other. In contrast, we found that cost differences between Municipalization and ServCo are likely to be quite narrow. We found that the average rate impact was barely lower under the ServCo option than under the Municipalization option in our mid-case scenario, but that difference is small compared to some of the uncertainties surrounding exactly how various costs could change under either form. It is not difficult to change assumptions and reverse this ranking. That is, any cost differentials (between the Municipalization and ServCo options) are not material nor reliable enough on a relative basis to have a significant impact upon rates, or to be a basis for preferring one option over the other.

Overall, we recommend adopting the ServCo model because it retains the efficient operations achieved by privatized utilities while taking advantage of tax exempt financing. It also reduces transitional risks, thereby probably expediting improvements in customer service. This approach also reduces the transitional risks (compared to the Municipalization option) associated with organizational transformation and information system development, thereby expediting improvements in customer service and shifting many risks associated with transitional issues away from itself and to the service provider. Finally, it is not a once and for all decision; LIPA can move to a fully municipalized utility if it finds resolution of the open issues are conducive to such.

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Chapter I

Study Overview

A. INTRODUCTION

The Long Island Power Authority (LIPA) is a corporate municipal instrumentality and a political subdivision of the State of New York, created by the State Legislature under and pursuant to the Long Island Power Authority Act. For all intents and purposes, LIPA is a municipal electric utility. Its operations are funded through revenues from the sale and delivery of electric power, and its expansion is funded by tax-exempt debt secured by those revenues. Electric rates charged to customers are determined each year by LIPA's governing body, its Board of Trustees, by estimating its revenue requirements and expected sales for the coming year. These are the same general procedures used by municipal utilities around the U.S.

When LIPA was established in 1986, but in 1998 acquired the Long Island Lighting Company (LILCO) which was a combination electric and gas utility on Long Island that owned and operated electric generating plants as well as an electric transmission and distribution (T&D) system, in addition to its gas utility facilities. LIPA retained the electric T&D facilities as well as an ownership stake in the Nine Mile Point nuclear power plant. It did not retain the electric generating facilities located on Long Island nor any of the natural gas facilities. These were transferred to KeySpan Corporation¹ which was subsequently acquired by National Grid USA.²

LIPA is responsible for supplying the full scope of electric requirements to its customers. It serves a peak demand of roughly 6,000 MW, and has a department responsible for ensuring that reliable power is procured in a cost-efficient manner. The majority of LIPA's electric power requirements are procured through contracted power resources. Most of LIPA's resources are focused on operating and maintaining its electric transmission and distribution system.³ In this regard, LIPA is largely a "T&D utility," even though the majority of its expenses in customer bills are for generation (purchased power and fuel).

¹ KeySpan Corporation was formed in 1998 by the merger of Brooklyn Union Gas Company and LILCO.

² National Grid USA is a wholly owned subsidiary of National Grid plc.

³ Here, LIPA resources refer to resources directly employed by LIPA plus contracted resources.

LIPA itself has a relatively small, managerial staff of roughly 100 employees, who are responsible for planning and the corporate administration of LIPA. Most of the work associated with carrying out utility field operations is performed by a service provider (National Grid USA) under a contractual agreement referred to as a Management Services Agreement (MSA), which utilizes a base of roughly 1,900 employees (full-time equivalents) largely dedicated to LIPA. The MSA arrangement has been in place since LIPA's inception, although it has been amended on occasion. Thus, the majority of LIPA's operations are performed by the service provider while LIPA owns the primary operational assets (i.e., the T&D system).

The MSA will expire at the end of the year 2013. LIPA has had a dozen or so years of experience operating under the MSA and has identified areas of success as well as concerns. Thus, LIPA needs to determine the organizational structure for its operations post-2013. These include: an option to fully municipalize its operations; an option to privatize its operations; and an option to modify its contracting arrangements into a dedicated "ServCo". The transitional issues associated with migrating utility operations covering over one million customers from one organizational arrangement to another is formidable, and accordingly requires a lead time of 18 to 24 months.

The subject study of LIPA's organizational options was motivated largely by this upcoming expiration of the current MSA and the need to determine its replacement model. *The Brattle Group* was retained by LIPA to conduct a Strategic Organizational Study in the latter half of 2010, with the expectation that work would be completed with sufficient time for LIPA to consider Brattle's analyses and recommendations in developing its strategic options for the organization going forward. This has been accomplished.

How the expiring MSA will be replaced is very important, indeed central, to LIPA's future operational performance and strategic success. However, only a modest portion of LIPA's total cost of delivered power will be directly affected by this decision. LIPA's total annual T&D operations and maintenance (O&M) expenses are about \$557 million, or 15% of total costs (around \$3.8 billion). T&D O&M, then, are responsible for about 2.7 cents out of 18.2 cents per

kWh overall.⁴ Given LIPA's annual kWh sales of a slightly more than 19,000 GWh, a change in costs of roughly \$200 million per year has about a 1 cent/kWh impact on average rates. This means it would be necessary for a new organizational form to cut out about a third of T&D O&M in order to achieve a 1 cent rate reduction.

B. STUDY OBJECTIVE AND APPROACH

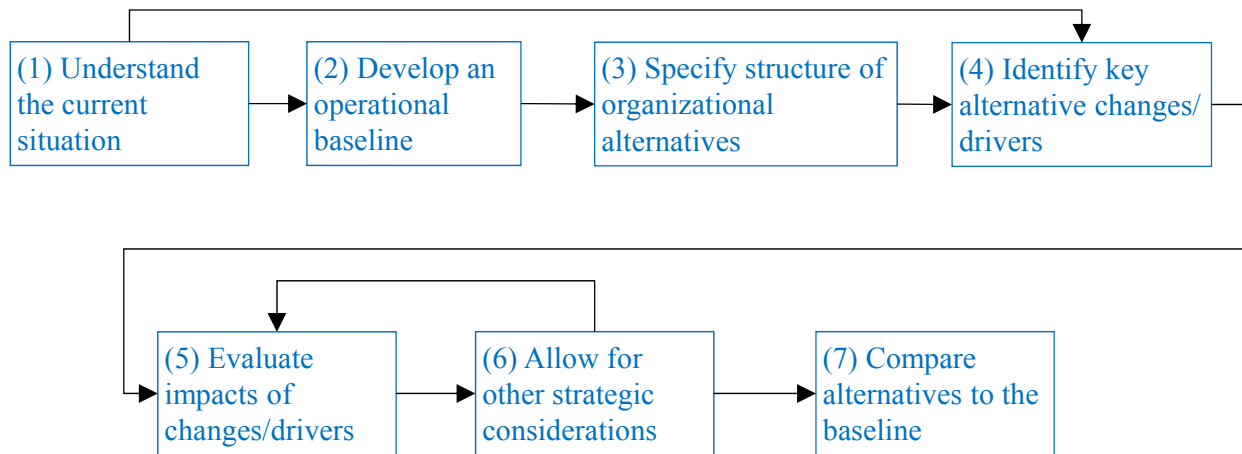
The objective of our study concerning LIPA's strategic organizational options is to clarify and assess the strategic organization alternatives available to LIPA by estimating the cost structure for each of the options and determining the impact that implementation of each would have upon retail electric rates. Furthermore, the objectives of the study include our ranking of options based upon the above referenced quantitative analysis and consideration of other factors, such as risk and option values, which may be less amenable to quantification but which are nonetheless qualitatively important.

The span of LIPA's responsibilities as an electric utility includes procurement of power supply as well as delivering power to its customers. This study is concerned primarily with the work activities and resources that are included under the MSA. These include the T&D and customer service functions, as well as various planning, corporate and administrative functions. The scope of this study does not include the costs associated with fuel and purchased power and/or capacity, except to the extent that changes in the organizational structure for LIPA's T&D and customer service functions, as well as various planning, corporate and administrative functions may somehow impact the costs of fuel and/or power.

The general approach that we used to conduct this study closely follows the objectives established for the study, and is summarized in Figure I-1, below.

⁴ As explained in Chapter II, LIPA's power costs are not generally amenable to change in any way that is related to the organizational alternatives being considered here. They mostly depend on wholesale market conditions that will face any organizational form LIPA may adopt.

Figure I-1
Graphic Summary of Project Approach



LIPA has examined the various organizational options available to it on at least two separate occasions: initially in 2005 and subsequently in 2009-2010.⁵ The latter study recognized that additional data concerning operational costs and effectiveness (which were not considered in that study) was needed and would likely provide more specific information concerning the impacts that the strategic options would have upon LIPA's rates. Accordingly, this study has addressed that gap, with substantial analysis of past operating experience.

LIPA's Board of Trustees and customers are acutely aware that LIPA's retail electric rates are among the highest in the country, and that customer satisfaction with LIPA is low (despite, as described later, relatively good T&D costs and service reliability). Accordingly, the current study has placed considerable emphasis on analyzing LIPA's current cost structure and the cost structures likely to be realized under the various strategic options at a detailed level. Specifically, for this study we:

- Reviewed LIPA cost data at a detailed level, drawing from multiple data sources (discussed in greater depth later in this chapter).

⁵ The 2005 study was conducted by FTI Consulting and the 2009-2010 study was conducted by Lazard.

- Developed a revenue requirement and average rate model which was calibrated to both LIPA's operating budgets and recent actual costs. Once normalized (for non-recurring adjustments), this became the baseline upon which the costs and rates for the strategic organizational options could be compared.
- Compared LIPA's operating costs and performance against other electric utilities by completing a benchmarking analysis, in order to determine possible areas where costs could be reduced.
- Reviewed reliability performance and customer satisfaction scores for LIPA and other utilities, to see if reliability was being traded off against costs, or if customer satisfaction was being driven by quality of service.
- Developed projections of the costs structures for the various strategic options and determined the differences between LIPA's current costs and those that may be realized should the strategic options be implemented.
- Determined any changes that the structure of the alternate organization would have upon financing costs. This would include: the rate of interest that the new entity would pay on debt; its return on equity if the financing of the new entity included an equity component; and any financing costs that would need to be incurred to transition LIPA from its current structure to a new one.
- Ranked the strategic options based on cost and rate impacts.

We also considered additional factors that may impact LIPA's selection of a strategic organizational option. These include the risks associated with effectuating a strategic option and the opportunities or lack of opportunities (i.e., options) to exit or change from an option. These factors are not as quantifiable in the context of organizational analysis, compared to, for example, estimating the risks associated with power supply choices and/or the option values associated with fuel contracts. Nonetheless, these factors, even if only addressable in qualitative fashion, become increasingly important when rankings based on rate impacts are close.

Studies of this nature – that is, projecting the cost structure and rates for a yet to be formed and implemented organizational option – inherently involve projections and uncertainties. Accordingly, the projected cost structures included in this study should not be construed as *absolute* forecasts of what would necessarily occur. The actual costs that may be realized are dependent upon numerous influencing factors, some of which almost assuredly will change from

our understanding today. Instead, these projections are intended to measure the *relative* differences between the strategic options.

Conducting this analysis requires that the consulting team has a firm understanding of the functional work areas that are used by utilities in the course of running their business. We apply empirically-based data where available. Specifically, we analyze and consider benchmarking analyses and analyses presented by utilities that have been involved in restructuring and mergers and acquisitions, as well as past performance data of LIPA itself. However, projecting the cost structure for the organizational options necessarily involves the application of judgment, informed by experience in working in the utility industry. In order to ensure that our projections are as objective as possible, and to understand how they depend on certain factors, we have developed high and low cost cases around a mid-cost case. We believe that these present a meaningful range of possibilities and risk.

C. STRATEGIC ORGANIZATIONAL OPTIONS

LIPA identified three broadly defined strategic options in the Request For Proposal (RFP) associated with this study. These were:

- 1) An option under which the National Grid portion of LIPA's work force would be transferred to the LIPA organization (the "Municipalization" option);
- 2) An option under which LIPA continues to outsource much of its T&D, customer service and various planning, corporate and administrative functions, albeit under a different contractual arrangement with its service provider (the "ServCo" option); and,
- 3) An option under which LIPA would sell its assets and business to a private enterprise, with the private enterprise becoming the electric utility for Long Island and part of Queens (the "Privatization" option).

The Municipalization and ServCo options are each forms of municipal utilities, in the sense that LIPA would remain a corporate municipal instrumentality and a political subdivision of the State of New York. Importantly, LIPA would remain eligible to receive tax-exempt financing under

both of these options. In this regard, the Municipalization option may be considered to be a “full” municipalization and the ServCo option may be considered a “partial” municipalization.

Evaluation of these organizational options requires examination of the likely changes in operating and financing costs which, in turn, requires clarity concerning the specific details associated with each organizational option. As an initial work step in our study, we developed detailed definitions of the above organizational options, and checked with LIPA to ensure that our expanded definitions and assumptions stayed loyal to their original intentions.

Clarity concerning the specifications of the strategic organizational options is particularly important to completing our analysis in an accurate manner because it informs the development of the detailed assumptions that, in turn, determine the projected costs and retail electric rates associated with each option.

1. Municipalization Option

The Municipalization option involves the elimination of the majority of services that are outsourced to LIPA’s current service provider and the incorporation of most, if not all, work activities under LIPA. Services that are currently outsourced to providers other than the current service provider, such as vegetation management, would continue in their current form. Also, the sharing arrangements between LIPA’s retail electric operations and National Grid’s retail gas operations on Long Island and in Queens concerning meter readers and call center personnel would continue as-is. This latter type of sharing arrangement between overlapping electric and gas utilities is a common industry practice.

We assumed that the transition from LIPA’s current organizational structure to a full municipalization would require various transition decisions and steps, including:

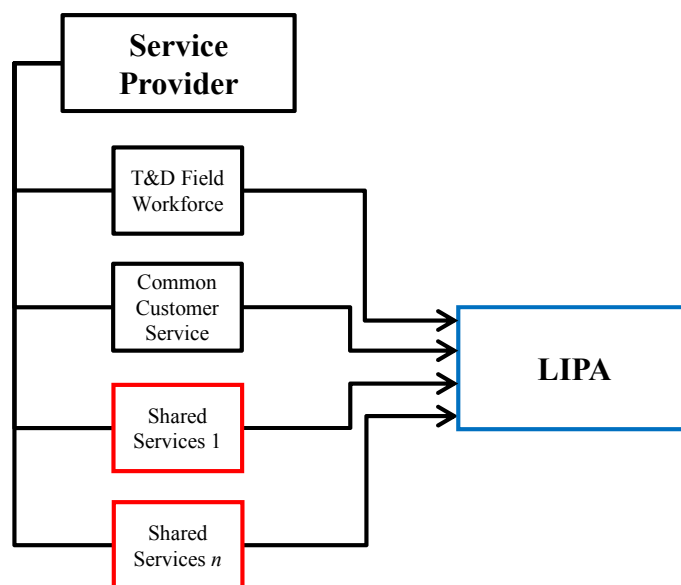
- Determining whether or not the current Board of Trustee structure and governance model is appropriate and sufficient to meet the requirements of a fully municipalized system.
- Transferring to LIPA the critical assets, facilities and systems necessary to operate and maintain the T&D System and which are now owned or controlled by National Grid.

- Transferring the current workforce from National Grid to LIPA.
- Determining whether employees of the general workforce are to be public or private employees and consulting with the Governor's Office and the IBEW labor union concerning labor agreements and retirement systems.
- Recruiting senior management and supervisory personnel as necessary to plan for, direct and administer for the expanded work force.
- Developing and implementing an information system transition plan.
- Determining whether or not changes in operating structure have impacts on cash flow and/or debt covenants or affect bond ratings.

2. ServCo Option

Under its current arrangement with National Grid (the MSA), LIPA receives a range of services from various departments within the National Grid organization. The structure of this arrangement is depicted in Figure I-2.

**Figure I-2
Depiction of LIPA-National Grid
Organizational Relationship**



Personnel comprising the field operations provided to LIPA by National Grid (i.e., the T&D and customer service field forces as well as the call center) are largely located on Long Island. Such field operations require full time focus. Accordingly, the field force works exclusively or near exclusively on LIPA-related matters.

Support in some functional areas requires less than full time or dedicated attention; they are needed for specific projects or intermittently throughout the course of the year. In providing these shared services to LIPA, National Grid treats LIPA as one of its operating utility subsidiaries. Specifically, National Grid has pooled a range of specialized services (such as accounting or certain planning function) and deploys these resources to its operating companies (including LIPA) as needed. In this way, the resources used in providing these functions are essentially “shared,” and the operating company is charged for a portion of the total work force. When costs are appropriately allocated, the sharing arrangement should result in savings to each operating utility (through capture of scale and scope economies, as well access to specialized expertise); the fee charged should be less than if the operating company were to employ such resources in a dedicated and full time fashion.

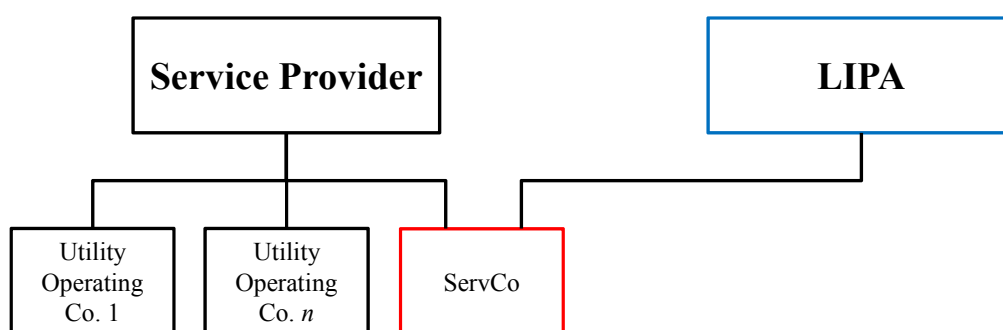
LIPA’s current MSA arrangement suffers from two primary areas of deficiency. First, it has limited control over the various National Grid resources. This deficiency arises largely because of contractually driven “principal-agent” problems – in which the interests of the provider (agent) and the customer (principal) may diverge in ways not easily monitored or controlled contractually. That is, much of the work force serving LIPA are employees of National Grid (the agent) and take direction from National Grid management. The motivation of the agent is not always aligned with the needs and motivations of the principal (LIPA). Such control issues are most noticeable within the shared service functions, in which LIPA may not receive the attention and priority needed to effectively complete work requirements.

Second, LIPA’s fees to National Grid for MSA-related services are through a combination of formulas and “pass through” payments. National Grid provides LIPA with some access to its cost accounting system, but LIPA is not able to fully view the full scope of costs in a transparent and understandable manner. National Grid allocates shared costs among its operating subsidiaries and to LIPA; the cost allocation process is opaque to LIPA.

LIPA has developed an alternative to the current MSA-based contractual relationship which is referred to as the ServCo option. We base our assumptions concerning ServCo largely on the definition and specifications that were developed by LIPA and responded to by utilities proposing to fulfill the service provider role.⁶

A visual depiction of the ServCo model is provided below in Figure I-3.

Figure I-3
Depiction of ServCo Organizational Structure



Like the expiring MSA, ServCo involves a contractual arrangement that would be between LIPA and a utility that would become LIPA’s service provider. This contractual arrangement means that there will continue to be the possibility of principal-agent problems. However, ServCo differs from the current MSA arrangement in two critical areas.

First, ServCo is designed to be a dedicated and self-contained subsidiary that is comprised of employees, systems, and resources that are dedicated to LIPA-related activities. Importantly, the ServCo option is also designed to be transportable; that is, once the ServCo is established, LIPA has the option to move the entity in its entirety from its place as a subsidiary of the service provider to another entity – such as a subsidiary of LIPA, another utility, or another service provider.

⁶ Utilities responded to LIPA’s RFP “To Provide Electric Utility Management Services (UMS) To The Long Island Power Authority” issued in 2010.

Second, payments to the service provider will be primarily a pass-through plus a profit component. As the services provided will come from the dedicated and self-contained ServCo, the costs should be transparent. It is possible, however, that costs incurred on a pass-through basis may be higher or lower than would be the case under a formula-based and shared services regime, and oversight, incentives and management were introduced specifically to address such issues.

The transition from LIPA's current structure of organization to a ServCo structure may involve the transfer of ownership from National Grid to another utility's subsidiary. If so, the transition will require several decisions and activities:

- Transferring to LIPA the critical assets, facilities and systems necessary to operate and maintain the T&D System which are now owned or controlled by National Grid.
- Transferring the current workforce from National Grid to the new service provider.
- Developing and implementing an information system transition plan.

The transition from LIPA's current organizational structure to a ServCo structure will also require the establishment and implementation of a joint operating committee (JOC) composed of representatives from LIPA and the service provider, which will be responsible for setting and monitoring the overall direction of ServCo. Implementation of ServCo will also require that working relationships be developed between functional area leads and staff at LIPA and the service provider. We understand that the relation between LIPA and the ServCo provider will not be limited contractual oversight. Instead, the LIPA management team will be integrally involved in ServCo decisions and even line management, such that duplication of effort is minimized and LIPA's stand-alone capabilities are strengthened.

3. Privatization Option

The Privatization option involves the sale of all or part of LIPA's assets to a privately-owned concern. Potential acquirers include investor-owned utilities and private groups of investors. Privatization of public (municipal) utilities have occurred relatively infrequently in the United

States.⁷ However, a variety of public services in other parts of the world were privatized in the 1990s, driven by initiatives undertaken by federal governments and/or intergovernmental institutions, such as the International Monetary Fund and the World Bank. Such privatizations included government-owned Postal, Telephone & Telegraphs (PTTs) as well as electric utilities in the United Kingdom and former Soviet republics, as well as in several developing countries.

The primary motivation behind these international privatizations involved the belief that the private sector was more cost efficient at operating utilities than were governments. Analysts estimated that government-owned and operated enterprises were exceptionally cost inefficient; political favors and employment objectives had served to increase the staffing levels to unsustainable levels. Privately operated utilities in, for example, the United States operated at a much higher level of efficiency, suggesting that the savings these privatizations could realize would be large – more than enough to offset any transaction costs and increases in the costs associated with higher financing costs. Indeed, this generally proved to be the case. Sometimes very large cost savings were realized, primarily through labor-related savings (i.e., headcount reduction) and improvements in supply sourcing.

Two other factors also contributed to the movement to privatize government-owned utilities. Fiscal and economic conditions during this period placed a burden on government treasuries, a situation that could be mitigated through the infusion of funds from the sale of government assets. Finally, government-owned utilities in various areas around the world had not appropriately re-invested in infrastructure. Privatizing these enterprises put the burden of capital formation and risk bearing, as well as public reaction to associated rate increases, upon a private, non-governmental third party.

The success of past utility privatizations has also been dependent upon the parallel establishment of strong regulatory agencies. Generally, countries which put U.S.-like regulatory frameworks in place were able to minimize rate increases, avoid degradations (or even improve upon) service quality, and advance capital formation.

⁷ It is more common that private utilities may buy specific assets from a municipal utility or vice-versa.

As will be discussed in more detail in Chapters II and III, the non-productive assets on LIPA's balance sheet combined with higher costs of financing for a privatized company compared to a municipal utility, make it imperative that the privatized utility be able to realize significant cost reductions in order to avoid a rate increase. Accordingly, we adopt a critical assumption for our analysis of the Privatization option: the acquiring entity should be an existing investor-owned utility. We adopt this assumption because we expect that potential cost savings will be greatest for a utility with scope, scale and experience, because:

- Utilities experienced in T&D operations are equipped to share best practices with affiliates in order to gain efficiencies and/or enhance performance. However, there are limits to the potential for cost reduction in field operations. Unlike power production and certain managerial services, there are not material economies of scale in T&D field work. We use an empirically based approach to estimate the potential for efficiency gains in T&D and Customer Service operations. Specifically, we benchmarked LIPA's level of cost efficiency against multiple panels of utilities to determine a realistic range in which a privatized entity may be able to realize cost savings.
- Utilities involved in mergers and acquisitions (with other utilities) generally report that a ripe area for savings comes from elimination of duplicative corporate and administrative functions and staff across the two (or more) organizations. These functions tend to have greater scalability than do field operations functions, and can serve a larger base with proportionally less incremental staff additions.

The transition to a privatized structure will involve a series of work steps involving the transfer of ownership of LIPA's assets to the new entity, as well as the transfer of LIPA employees to the extent requested by the new owner. It will also involve the transfer of assets (such as facilities and vehicles currently owned by National Grid and used for LIPA operations) and employees from National Grid to the new entity. The costs associated with these activities are typically factored in to the price paid by the acquiring entity, along with other transaction related costs, such as advisory and financial services.

4. Common Assumptions

We made several key assumptions that we applied when analyzing each of the strategic organizational options:

- Maintenance or improvement of service delivery quality is a high priority. Modifications (i.e., headcount reduction) to the delivery field force (i.e., the T&D and Customer Service work forces) will be made only if benchmarking analyses suggest that LIPA is operating at a notably inefficient level.
- Facilities and fleets could be readily transferred (to either LIPA, another service provider or an investor-owned utility) through either purchases or leasing arrangements.
- LIPA will move ahead with upgrades to key information systems; cost differences may be realized across organizational options to reflect the potential to leverage existing systems and/or expertise to development and/or implementation efforts.
- Labor rates (for bargaining units and mid-level management employees) are comparable to other regional utilities and do not appear to offer opportunities for cost reduction; union contracts are anticipated to remain in force under similar terms and conditions.
- Conditions do not mandate more (or less) capital expenditures on T&D assets than is currently budgeted (i.e., the system is in reasonable condition); inventory and major equipment spares (e.g., transformers) do not require significant reduction or additions.

Additional assumptions associated with the organizational options are included in Chapter III of this report.

D. DATA

As discussed in the section concerning project approach, above, our analysis is empirically based where possible. We were able to develop data sets which informed our analysis in three areas:

- We used historic data describing the functional activities under the MSA to develop the baseline costs of LIPA's current operations (presented in Chapter II).
- We used utility benchmark data (included in Chapter II) and data concerning costs and benefits for utility mergers and acquisitions (presented in Chapter III) to project the operating costs for the various strategic organizational options, if they were to be implemented.
- We reviewed New York State Public Service Commission dockets to determine allowed capital structures, returns on equity and rates of return, as well as financial market data concerning premiums of market values above book values for utility equities and merger and acquisition premiums – all reviewed in order to determine financing costs (presented in Chapter IV).

1. Baseline Data

We devoted considerable time and attention to determining LIPA's cost structure and average rates. This became the baseline against which was determined the extent to which implementation of the strategic organizational options resulted in a rate increase or decrease to LIPA's customers on average. We developed this baseline analysis at a detailed level. Specifically, our analysis estimated the operating costs by categories of expenses for each of the functional areas around which LIPA and National Grid are organized.

We reviewed the cost data included in LIPA's annual operating budgets (as projected as well as those updated to reflect actual performance). From this, we were able to develop overall cost structure and detailed information concerning expenditures made directly by LIPA. However, the majority of LIPA's costs concerning its T&D, customer service and corporate and administrative are incurred by National Grid and charged to LIPA. Thus, it was very important to review and analyze National Grid's cost data at a detailed level.

Through LIPA, we were able to access National Grid cost accounting records for its LIPA operations. This system is referred to as the Financial Data Mart (FDM). The FDM provides records for costs at a purchase order (PO) level. We used data queries to extract data and organize it in terms of cost categories and functional areas. Extracting and re-compiling cost data from the FDM was a time consuming process. Work on data compilation was completed during the initial phases of our project work, which was during the latter part of 2010 and the early part of 2011. Accordingly, National Grid data was available for the calendar year 2009. We used these data at the detailed level to conduct cost analysis. (As will be discussed below, the time period for this data was appropriate for use in our utility benchmarking analysis.) National Grid cost data was provided to LIPA at a more aggregate level. We adjusted the 2009 detailed breakdown from National Grid as the basis of functional level cost analysis. These data were then adjusted to reflect 2010 totals, net of certain non-recurring costs and variances from normal operational burdens.

2. Benchmark Data

Investor-owned utilities are required to file an annual report with the Federal Energy Regulatory Commission (FERC). These reports, referred to as FERC Form 1 reports, include consistent and comparable cost data, as dictated by the requirements of FERC's Uniform System of Accounts (USOA). We compiled all of the T&D and customer service cost data for 123 retail electric utilities in U.S. We subsequently defined "peer panels," groupings of utilities against which to compare LIPA's performance (which are presented in greater detail in Chapter II of this report). Utilities file their FERC Form 1s roughly at mid-year for their performances in the prior calendar year. For this study, we used FERC Form 1 data for the 2009 calendar year. These data were directly comparable to the 2009 cost data (recorded by National Grid for LIPA operations) that we extracted from National Grid's FDM.

We also reviewed estimates of the costs and potential savings resulting from, or predicted to result from other utility organizational changes that have occurred in the past throughout the industry. These kinds of cost reduction projections are developed by utilities when they are proposing mergers and/or acquisitions. Utilities are regulated by state and federal energy commissions. Their competitive reorganization activities are also overseen by the U.S. Department of Justice (DOJ) and the U.S. Federal Trade Commission (FTC), especially when mergers and/or acquisitions are involved. In defense of their proposed merger and/or acquisitions, utilities file reports which estimate the benefits to consumers, typically in terms of gains in efficiencies and reduced costs. Derivation of these net benefits involves the costs that they will incur to implement the merger and/or acquisition (i.e., the transaction and transition, or integration, costs) and the efficiencies that they may gain through consolidation and scale.

3. Financial Data

Under the Privatization option, the acquiring entity (an investor-owned utility) would finance its acquisition, as well as ongoing capital investments, through a combination of equity and taxable debt. Estimating the new costs associated with such financing involves detailed calculation (and is the subject of much of Chapter IV). Estimating these costs also requires making numerous assumptions concerning financing parameters. Fortunately, there is a considerable base of data

to support the development of these assumptions. These come from two primary sources: data concerning the rates for financing instruments (utility debt and equity) are readily available from several data providers, and data concerning regulatory treatment of utility finances is codified in regulatory orders and opinions at the state and federal level.

We examined three types of financial data in support of the analyses that we present in Chapter IV:

- We compiled data covering decisions by the New York Public Service Commission for all of the electric utilities in the state concerning the capital structure and cost of capital (equity and debt) that the Commission allows the State's utilities to include in ratemaking proceedings. As will be discussed in Chapter IV, this has a major impact upon the rates and hence revenues that a utility will be allowed to realize; cash flows and net present value (NPV) are a primary determinant of a utility's value in the marketplace and an indication of potential acquisition price.
- We also compiled data concerning the historic and current cost of utility debt, and compared this to the historic and current cost of municipal debt issued by LIPA and public utilities in general.
- Finally, we examined the financial market value for utility assets. Specifically, we compiled equity prices for a panel of T&D electric utilities (i.e., those that are similar to LIPA in terms of asset composition) and compared the book value of their equity with the current market price. This provided an indication of the premium above book value that investors have recently been willing to pay for a T&D utility. We also examined premiums paid for equity for utilities that were acquired by investors or another utility in the past few years.

E. ORGANIZATION OF REPORT

We present our analysis, findings, conclusions and recommendations in six chapters including this one. We provided an overview of the objectives and scope of our study, together with a discussion of the approach we used to complete our work earlier in this chapter. We also introduced the specifications for the strategic organizational options that we analyzed, and presented the scope of data that we relied upon in the course of our analysis.

- In **Chapter II**, we analyze LIPA's operations and cost structure. This analysis is used to develop a baseline of LIPA's costs and revenue requirements, as well as average rates. This baseline becomes the point against which the costs and rates that

we project for each of the strategic organizational options are compared. We also present the result of our utility benchmarking analysis. This provides an empirical basis from which we can estimate cost efficiency gains that may be able to be realized if LIPA's T&D operations were placed within the alternate organizational structures.

- We provide the results of our analysis and projections of operating costs for each of the strategic organizational options in **Chapter III**. Operating costs refer to the labor and non-labor expenses (such as materials, supplies, leases and services) that a utility incurs in running its business. For this study, which is focused on the organizational structure associated with LIPA as a T&D utility, our analysis of operating costs refers to but largely excludes analysis of fuel and power costs, LIPA's largest cost area.
- We present the issues, factors and considerations concerning the financial costs in **Chapter IV**. The structure of LIPA's finances does not change if LIPA were to adopt the municipalization options; that is, (full) Municipalization or ServCo (partial municipalization). However, financing costs would be considerably different (compared to the current structure and cost of financing) for the entity that acquired LIPA. In this chapter, we also introduce how regulatory oversight and ratemaking calculations are different under a Privatization scenario, compared to LIPA's current approach to setting rates.
- In **Chapter V**, we present a framework for assessing qualitative factors that need to be considered prior to selecting a preferred strategic option. Each strategic option has associated levels of risk. Additionally, selection of an organizational structure may close or maintain other options. Risks and options are quantifiable factors in many areas of utility operations. For example, risks and option values are quantified when assessing fuel and power contracts. However, such quantification is less applicable to large organizational issues. We provide context for factoring in risk and options to the strategic organizational analysis in this chapter.
- We summarize our conclusions and recommendations in **Chapter VI**.

Chapter II

LIPA Operations

The starting point of our rate impact analysis involves the development of a baseline of costs and average rates against which we can assess the impact that may result from implementing alternate organizational structures. In this chapter, we introduce and discuss LIPA's current organizational structure and approach to operating as an electric utility. We also analyze LIPA's cost structure and derive its rates for electric power. The cost structure associated with LIPA's current mode of operations provides the baseline from which we assess the impacts that alternative forms of organization may have upon rates for LIPA customers.

A. BASELINE REVENUE REQUIREMENT

LIPA prepares operating budgets each year that segment its costs into categories that are generally used in the electric utility industry. It also reports the actual costs incurred for prior years against budgets as data becomes available. In 2010, LIPA incurred operating expenses equal to roughly \$3.9 billion on sales of 20,784,750 MWh. This resulted in an average rate of 18.6 cents per kWh.

We examined LIPA's actual 2010 costs to determine whether these actual costs accurately reflected a "normal year." Our review found that there were several instances of significant and non-recurring expenses that were atypical in the course of LIPA's routine utility operations. Most notable of such non-recurring expenses was the roughly \$169 million that LIPA incurred associated with storm restoration, and approximately \$2 million that LIPA paid for a soon-to-expire New York State special assessment (i.e., tax).

We developed a 2010 pro-forma revenue requirement for LIPA by removing (from LIPA's actual 2010 revenue requirement) the two above referenced non-recurring expense areas and by including the level of cash reserve targeted by LIPA when it sets its annual operating budget

(\$75 million).¹ We use the adjusted 2010 revenue requirement and resulting average rate for electric service as a baseline for additional analysis.

A comparison of LIPA's actual 2010 costs and revenue requirements with our baseline is presented in Table II-1, below.

Table II-1
Comparison Of LIPA 2010 Revenue Requirement
With Brattle Baseline

	2010 Actual (\$000)	Adjustments (\$000)	2010 Adjusted (\$000)	2010 Adjusted Average Rate (¢/kWh)	
Fuel and Purchased Power Costs	\$1,879,839	\$0	\$1,879,839	9.0	50%
T&D O&M Expenses					
LIPA Direct	\$120,390	\$0	\$120,390	0.6	3%
Outsourced - National Grid					
O&M	\$576,632	-\$169,493	\$407,139	2.0	11%
MSA profit	<u>\$29,135</u>	<u>\$0</u>	<u>\$29,135</u>	<u>0.1</u>	<u>1%</u>
Total Outsourced	\$605,767	-\$169,493	\$436,274	2.1	12%
TOTAL	\$726,157	-\$169,493	\$556,664	2.7	15%
PSA O&M Expenses					
PSA (excl. property taxes)	\$262,293	\$0	\$262,293	1.3	7%
PSA property taxes	<u>\$183,333</u>	<u>\$0</u>	<u>\$183,333</u>	<u>0.9</u>	<u>5%</u>
TOTAL	\$445,626	\$0	\$445,626	2.1	12%
Taxes					
Revenue Taxes	\$64,247	\$3,302	\$67,549	0.3	2%
Payments in Lieu of Taxes	<u>\$217,397</u>	<u>\$0</u>	<u>\$217,397</u>	<u>1.0</u>	<u>6%</u>
TOTAL	\$281,644	\$3,302	\$284,946	1.4	8%
Depreciation and Amortization					
Utility plant	\$149,611	\$0	\$149,611	0.7	4%
Other	<u>\$101,505</u>	<u>\$0</u>	<u>\$101,505</u>	<u>0.5</u>	<u>3%</u>
TOTAL	\$251,117	\$0	\$251,117	1.2	7%
Interest Expense	\$330,493	\$0	\$330,493	1.6	9%
Other Income (Expenses)	\$112,739	-\$66,294	\$46,445	0.2	1%
Reserve	\$57,383	\$17,617	\$75,000	0.4	2%
Total Rev. Req.	\$3,859,520	-\$82,280	\$3,777,240	18.2	100%
MWh sales	20,784,750		20,784,750		
¢/kWh	18.6		18.2		

¹ In electric utility and regulatory parlance, "normalizing" revenue requirements and/or budgets involves adjusting unusual expenses as well as adjusting kWh sales to reflect more typical weather conditions (i.e., "weather normalization"). We use LIPA's actual level of kWh sales for our analysis here; we do not adjust LIPA's kWh sales.

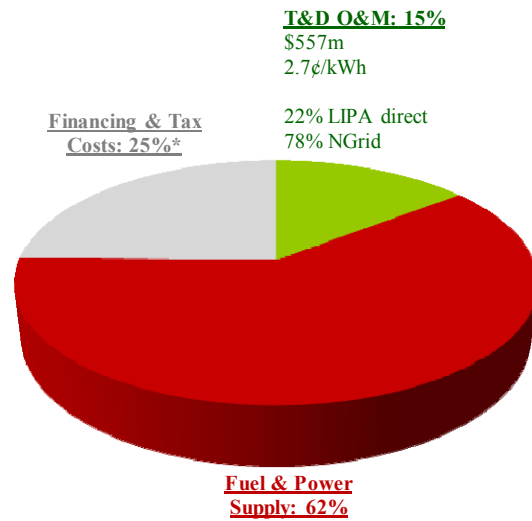
The revenue requirement for the 2010 baseline is roughly \$82 million less than LIPA's actual 2010 revenue requirement. As noted, this resulted from the reductions that were made to negate the effects of the extraordinary costs of storm restorations, which were then partially offset by increases in LIPA's cash reserve.²

The average rate associated with the baseline revenue requirement is 18.2 cents per kWh. We use this baseline of costs, revenue requirements and average rates as a comparison point against which to estimate the impacts that may be realized from implementing the various strategic organizational options introduced earlier. Specifically, we apply the costs projections that we developed for each strategic organizational option (in Chapter III) into a model of LIPA's annual revenue requirements. This allows us to estimate the extent to which overall revenue requirements and average rates change, holding kWh sales at actual 2010 levels. It is worth noting at the outset of this report that simple scenario analysis on this revenue requirement model indicates that in order to decrease in LIPA's overall rate by 1.0 cents per kWh requires a reduction in revenue requirements of about \$208 million (assuming no change in kWh sales).

The baseline 2010 revenue requirement can be examined in terms of cost composition. The breakdown of LIPA's total cost of operations for 2010 is summarized in Figure II-1.

² The above referenced adjustments also have an impact on revenue taxes paid by LIPA; adjustments to revenue taxes are also included in the Adjustments column of Table II-1.

Figure II-1
2010 Baseline Cost Composition



* “Other income” of -1% is not shown on the pie chart. Components do not appear to add to 100% due to rounding.

The composition of LIPA’s costs is in general not materially different from the cost structure of retail electric utilities in the U.S. The costs of power supply typically constitute the majority of the total cost (revenue requirement) for electric utilities responsible for delivering power to customers. In LIPA’s case, power costs accounted for over 60% of its total annual cost of operations.

LIPA various cost areas, summarized above and presented in further detail in the remainder of this chapter, can also be classified into rate areas. LIPA’s total average rate for electricity of 18.2 cents per kWh has two primary components:³

- **Power**, which primarily reflects the costs of LIPA’s procurement of fuel and energy.
- **Delivery**, which reflects non-energy/fuel expenses.

³ This analysis of LIPA’s costs and average rates reflect our 2010 baseline. As indicated, this is based on LIPA’s 2010 actual costs and kWh sales; we adjusted certain cost areas discussed earlier in this chapter.

The breakdown of the costs included in LIPA's Delivery charge (8.8 cents per kWh), compared to its total average rate for power (18.2 cents per kWh) is shown graphically in Figure II-2.

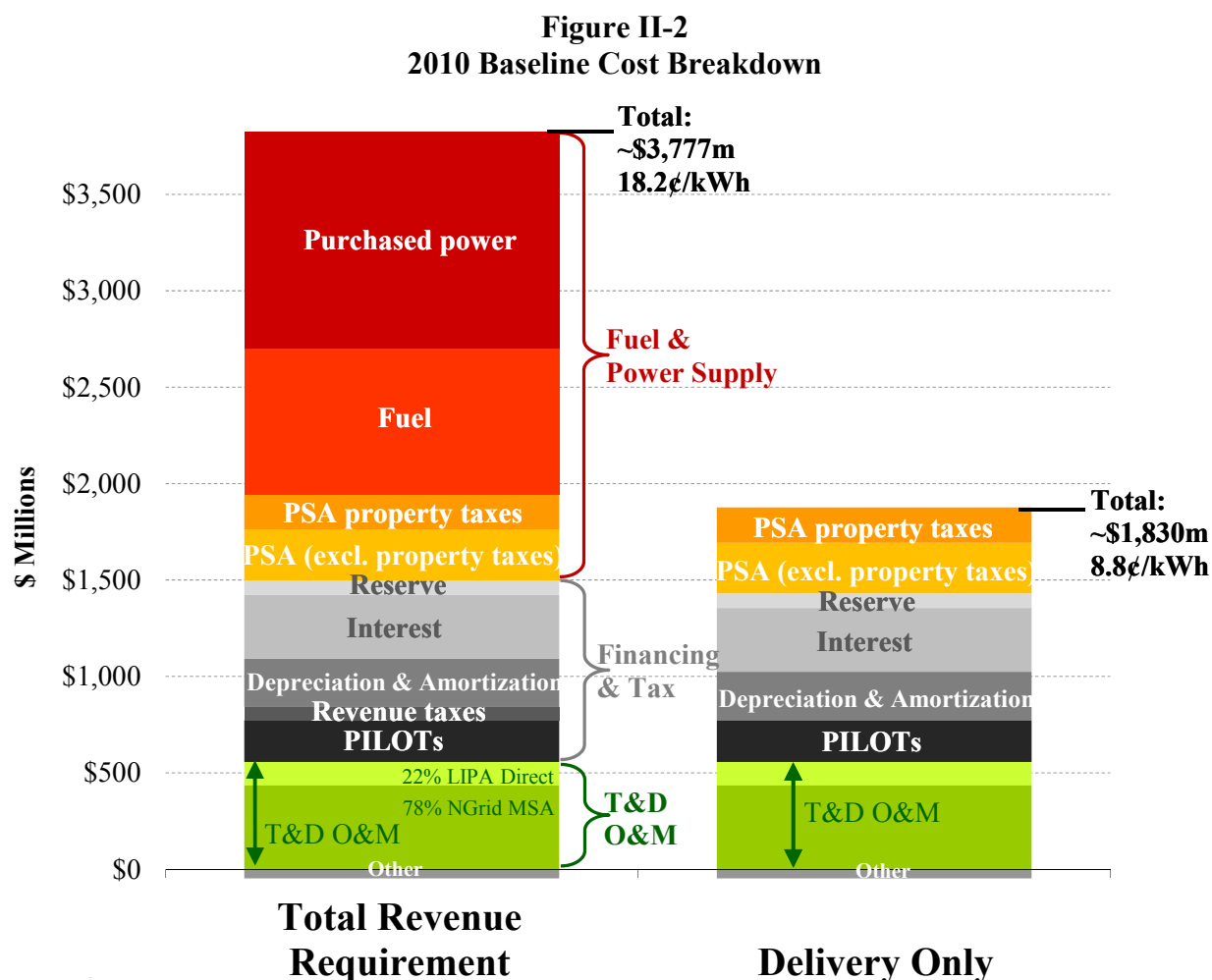


Figure II-2 shows that LIPA's Delivery charge (approximately 8.8 cents per kWh) is a subset of LIPA's total revenue requirement. It includes all of the costs that LIPA incurs in order to run its transmission and distribution system and to interface with its customers, including depreciation on LIPA's T&D plant. It also includes all of the costs associated with corporate and administrative functions, as well as the interest payments on LIPA's debt and taxes (notably property tax equivalents in the form of payments in lieu of taxes, or PILOTs). LIPA's Delivery charge also includes the costs associated with its Power Supply Agreement (PSA) with National Grid for rights to certain generating capacity assets. As shown in both Table II-1 and Figure II-2, the costs associated with the PSA alone were approximately \$446 million in 2010.

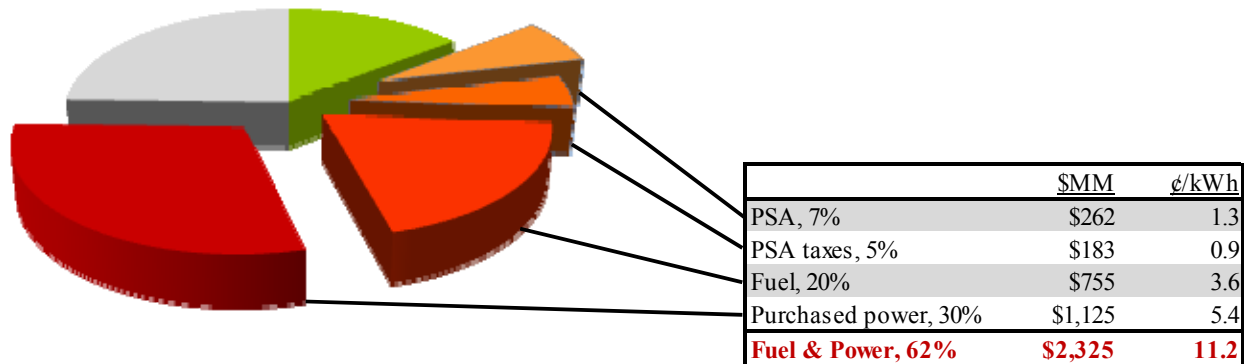
B. LIPA COST COMPOSITION

In this section, we take a closer look at the LIPA's cost areas. We begin with its highest dollar cost area, power supply.

1. Power Supply

The breakdown of LIPA's power supply costs are depicted in Figure II-3.

Figure II-3
LIPA Power Supply Costs



As shown in the figure, the costs for power supply by itself amount to roughly 11.2 cents per kWh. Most of these costs are associated with the purchases of fuel and power; an additional amount is associated with procuring generating capacity. LIPA receives about 25% of its energy from National Grid's GENCO (which includes LILCO's former generating facilities in Long Island) and another 8.5% from its ownership stake in the Nine Mile Point 2 nuclear power plant. The remainder of its energy purchases - which constitutes the majority - come from the wholesale energy market.

LIPA has two contracts with National Grid relating to procurement of power: a Power Supply Agreement (PSA) and an Energy Management Agreement (EMA). The PSA is related to the dispatch of and delivery of power from the GENCO generating facilities. The costs charged under the PSA include charges for: capacity associated with GENCO units; variable operating expenses (related to the amount of generation); and NOx and SOx emission credits. The rates

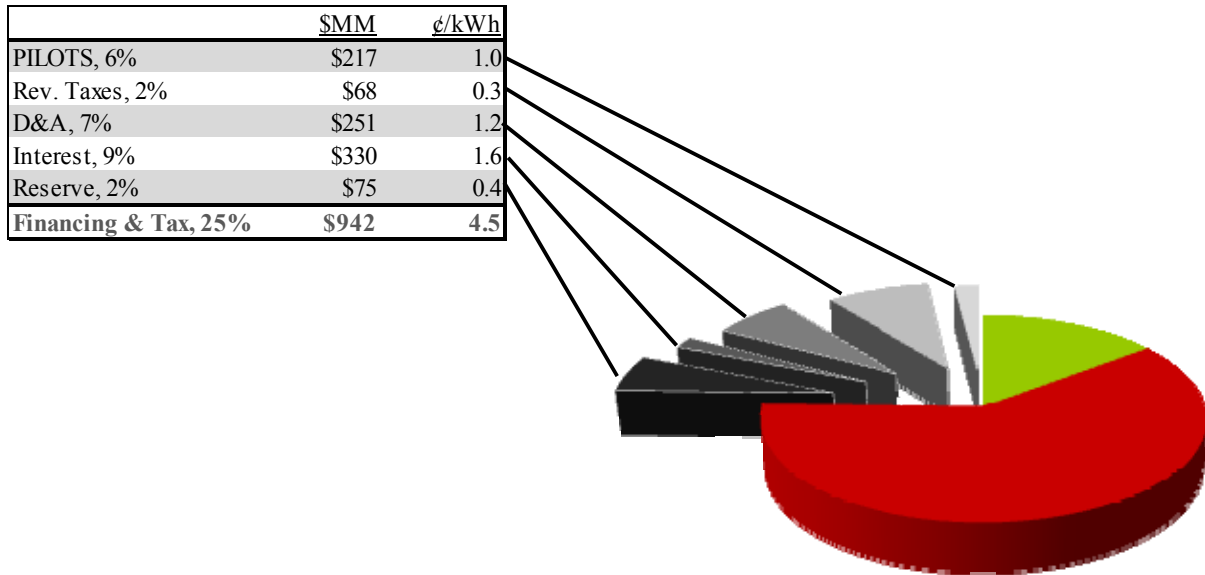
that National Grid charges LIPA are approved by FERC and were most recently reset in February 2009. The majority of the costs for services that LIPA receives under the PSA are related to capacity charges. GENCO has roughly 4,100 MW of capacity on Long Island. The majority of the generating plants, however, are steam turbines that are 40 or more years old. As a result of the inefficiency of some of these units, combined with opportunities presented by recently completed underwater transmission cables, LIPA has significantly reduced the amount of energy that it procures from GENCO in recent years.

LIPA's EMA with National Grid addresses fuel supply management and related services for the GENCO facilities. This allows LIPA to directly manage and pay for fuel and purchased power. Managing fuel and power purchases is a complex undertaking that involves extensive analysis. LIPA retained two advisors, ConEd Energy and Pace Global Energy Risk Management, to lead its effort in this area. While the annual cost associated with LIPA's EMA is relatively small (roughly \$10 million per year), it is under this agreement that LIPA manages its fuel and purchased power, its largest source of costs.

2. Interest, Taxes and Depreciation

Together, LIPA's interest payments on its outstanding debt, revenue and property taxes (or, because LIPA is a tax-exempt entity, payments in lieu of taxes), and depreciation expenses account for nearly 25% of LIPA's total revenue requirements. The breakdown for this cost area is shown in Figure II-4. (Note that this amount is more than the total expense that LIPA incurs to operate its T&D system.)

Figure II-4
LIPA Financing and Tax Costs



Interest and depreciation expenses together amounted to roughly \$581 million in 2010. Essentially, these costs reflected the carrying charges of adding to and/or upgrading LIPA's utility plant in service. LIPA also pays revenue taxes and targets to maintain a cash reserve in the event of unforeseen changes in business conditions. LIPA's operating budget and rates are based on costs and sales that it projects for the upcoming year but the possibility of increases in costs and/or lower levels of sales necessitate that it maintain a contingency fund, or "cushion." Hence, the need for a cash reserve.

Investor-owned utilities pay property taxes to local jurisdictions. LIPA, as a municipal utility, instead makes payments in lieu of taxes (PILOTs). It also pays property taxes, although indirectly, because property taxes incurred by power plant owners, including National Grid, include these costs in contracts to their counterparties, such as LIPA. A breakdown of LIPA's payment of taxes and PILOTs is included in Table II-2.

Table II-2
LIPA's Payments of Taxes and PILOTs

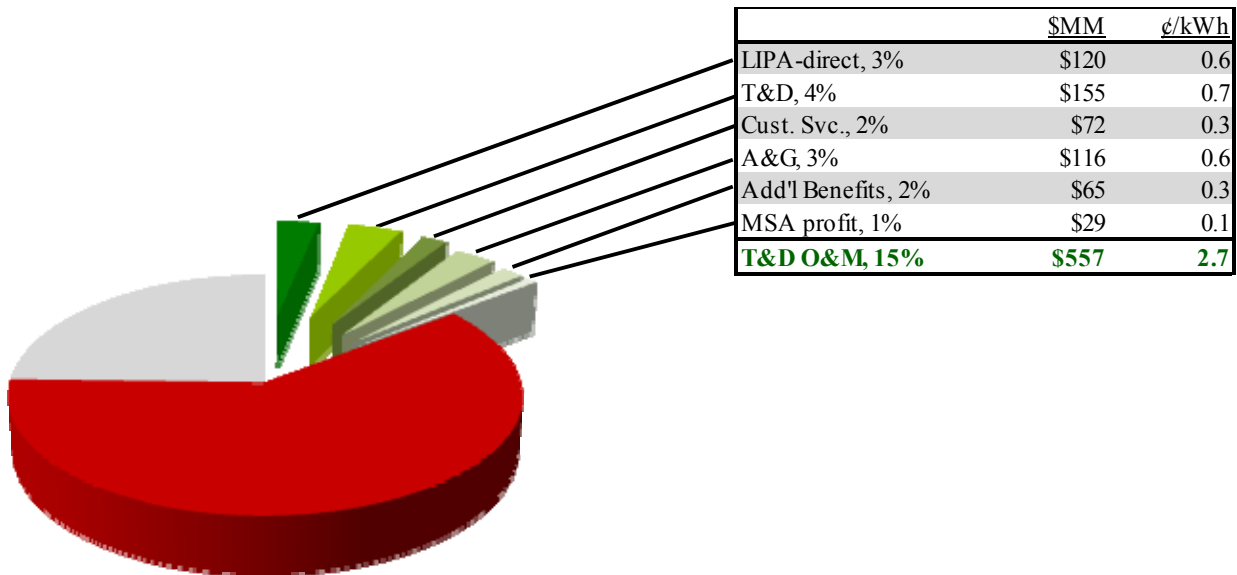
	2009 (\$000)	2010 (\$000)
Revenue Taxes	\$55,308	\$64,247
Long Island and New York City	\$180,308	\$203,444
Nine Mile PILOTs	\$3,619	\$3,619
Merchant Power Plants	\$10,417	\$10,300
Other	\$0	\$0
Metropolitan Commuter Transportation Tax	\$28	\$34
Total PILOTs	\$194,372	\$217,397
Property Taxes on NGrid Power Plants (PSA)	\$176,282	\$183,333
Property Taxes on other Purchased Power Agreements	\$6,090	\$3,275
NYS Temporary Conservation Assessment	\$0	\$44,973
Petroleum Business Tax and Motor Fuels Tax	\$6,090	\$4,537
Sales and Use Tax on Purchases	\$9,081	\$17,936
Total Other Taxes, PILOTs and Assessments	\$197,543	\$254,054
Total State and Local Taxes, PILOTs and Assessments	\$447,223	\$535,698

3. Delivery Operations

The remaining 15% of LIPA's revenue requirement, which covers about \$557 million, reflects the costs of running LIPA's electric delivery operations. Delivery operations are made up of T&D field operations, a sizable and the most visible part of LIPA's delivery organization, its installation, meter reading and customer service organization, and planning and corporate and administrative work areas. The entirety of the delivery organization's functions may be referred to as T&D operations and maintenance (T&D O&M), with "T&D" as used here defined to include field operations, customer service, corporate and administrative functions and cost areas.

The breakdown of this cost area is shown in Figure II-5.

**Figure II-5
LIPA Transmission and Distribution Costs**



Of the total \$557 million:

- Approximately \$296 million (53%) is associated with labor related expenses, including the direct cost of labor plus expenses associated with benefits and pensions.
- Roughly \$232 million (42%) reflect non-labor related expenses, such as materials, supplies and outside contractors.
- We estimate the remaining roughly \$29 million (5%) is the profit realized by National Grid as part of its fulfillment of the MSA.

Nearly 80% of the costs in this area are paid by LIPA to National Grid as part of the MSA. Payments to National Grid include a portion that is set through a formula established in the contract and a pass-through of expenses incurred above the formula base. National Grid may also expend funds on capital additions. Such amounts are included as additions to LIPA's utility plant and realized in its annual operating budget through annual depreciation and amortization expenses.

A breakdown of LIPA payments related to T&D O&M is summarized in Table II-3.

Table II-3
LIPA's Payments to National Grid

	2010 Adjusted (\$000)
Actual MSA Manager Compensation Fee	\$275,542
Estimated O&M costs incurred	\$246,407
Estimated MSA "profit"	\$29,135
Other O&M costs per LIPA budget	\$160,732
Total MSA-Related Costs	\$436,274
<u>LIPA direct incurred O&M costs</u>	<u>\$120,390</u>
Total T&D O&M Expenses	\$556,664

The table indicates that LIPA payments related to T&D O&M were approximately \$557 million in 2010. The MSA contract includes three primary components: a management compensation fee (based on a formula based fee in exchange for a specifically defined scope of work); a pass-through of costs for operations and maintenance related work that are beyond the scope of the compensation fee related work; and the pass-through of expenditures that National Grid makes that are considered additions to LIPA's utility plant (i.e., capitalized expenditures). LIPA's 2010 payments related to its T&D capital budget was about \$270 million, which is reflected separately as depreciation and amortization costs.

Throughout much of the remainder of this chapter, we estimate the costs underlying LIPA's revenue requirements at a detailed level. As indicated earlier in this report, in subsequent chapters we adjust various elements of LIPA's cost structure and revenue requirements in order to estimate the impact that implementing alternate forms of organization may have upon the rates that LIPA (or a successor organization) charges its customers. We compared the payments (above) that LIPA made to National Grid with the detailed cost data describing National Grid's LIPA related operations as contained in National Grid's FDM⁴ system. We then used the difference between these two as an estimate of National Grid's profit on its account with LIPA;

⁴ Financial Data Mart.

we calculated this amount to be approximately \$29 million for 2010. We present a summary of this calculation in Appendix B.

C. LIPA ORGANIZATION AND WORK FORCE

LIPA is a full service electric utility but does not own power generation facilities and thus does employ a labor force that works at power plants. However, it is responsible for operating and maintaining its transmission and distribution system that serves over one million customers; hence, it may be referred to as a “T&D” utility. Meeting such a charter requires that LIPA employ, directly or indirectly, a sizable work force.

Since its inception in 1998, LIPA has outsourced the majority of its operations to a service provider under a Management Services Agreement. This has resulted in the service provider, National Grid, employing the majority of the work force that is responsible for LIPA’s ongoing operations.

1. Work Force

LIPA itself has slightly over 100 employees that are organized along departmental lines that cover the full range of functional areas needed for utility operations. A breakdown of LIPA’s directly employed staff by functional areas is presented in Table II-4, and an organization chart for LIPA is included as Appendix A.

Table II-4
LIPA Functions and Direct Staffing Levels
(FTE = Full-Time Equivalent)

Functional Area	LIPA Direct Staff (FTEs)
EE/DR/Renewables	12
Environmental Regulation	3
Regulatory, Rates, & Pricing	4
Customer Accounts & Services	6
Marketing & Sales	5
Media/Government Relations	7
Accounting & Finance	19
Finance: Risk	1
Legal	11
Power Markets	13
Facilities/procurement	3
IT	5
HR	6
Other/corporate	3
T&D O&M	7
Total	104

LIPA's directly employed staff are involved in two broad areas of responsibility: 1) overseeing and managing the contract and work performed by National Grid under the MSA; and, 2) conducting a range of planning and corporate administrative functions, related to but largely independent of the activities conducted by the service provider.

As shown in Table II-4, over half of LIPA's employees are involved in the planning associated with: power supply (Power Markets), direct oversight of LIPA's programs involving energy efficiency, demand response and its renewable energy initiatives; and the corporate administrative functions involving accounting, legal and governmental and media relations. Less than 10% of LIPA's staff are involved in T&D operations, primarily because the majority of work is conducted by National Grid. LIPA is responsible for overseeing and managing the contract (i.e., MSA) but does not directly perform nor manage T&D field work.

We examine later in this report how the LIPA staff would be impacted if other organizational structures were adopted. Overall review of LIPA staffing and work activities indicates, however, that elimination of a contract-based outsourcing of LIPA's electric delivery operations would not result in a wholesale elimination of the work currently performed by LIPA staff.

As the service provider under the MSA, National Grid supplies the vast majority of employees necessary to meet LIPA's operational requirements. The resources that National Grid brings to LIPA operations may be classified into two broad categories:

- “**Dedicated**” resources refer to those employees who work exclusively or near exclusively on LIPA related operations. These include the vast majority of the T&D field force and the resources responsible for meter reading, the call center, customer account offices, and other similar functions.⁵
- “**Shared**” resources refer to the portion of the National Grid work force that provides services to National Grid's operating companies. For example, this would include National Grid's legal and accounting departments, which provide support to the operating companies and allocate their employee's time among them.⁶

This “pooling” and sharing of specialized resources is a common practice within utility holding companies (i.e., those with multiple operating companies); the aim of which is to gain efficiencies by using a common pool of resources to work on specialized work areas. In practice, highly specialized resources are not needed on a full time basis unlike the case with, for example, the T&D work force. In this way, the holding company employs a department of specialized resources that can be deployed to each operating company as needed; the operating company is

⁵ Technically, the labor force involved in meter reading and the call center work read meters and field calls for both LIPA's electric operations and for National Grid's gas operations. Such an arrangement is not uncommon, even when the electric company and gas company are unaffiliated, because it avoids the duplication of work activities (e.g., the same locations must be visited by meter readers for customers that receive both electric and gas services). LIPA and National Grid both plan on continuing this arrangement, even under circumstances if their contractual relationships (similar to the current MSA) were to be terminated. We consider the full time equivalent (FTE) meter reading, customer service field personnel and call center personnel that are allocated to LIPA to be “dedicated” employees even though they are technically “shared” with National Grid's gas operations.

⁶ In this regard, National Grid considers LIPA as a utility operating company in its cost accounting system, so it can allocate labor and other costs under its cost allocation system.

charged for a portion of the work force which in theory should be less than if the operating company were to employ such resources in a dedicated and full time fashion.⁷

National Grid does not directly provide a complete breakdown of its labor force in its FDM or via another form. However, we were able to estimate the National Grid labor force involved in LIPA operations through the combination of cost and accounting data included in the FDM (particularly the cost category that represents direct labor costs), the labor rates associated with various functional work areas, along with various documentation provided to LIPA that specifies work force head counts. We were also able to determine the breakdown between dedicated and shared resources as the FDM designates whether incurred costs were directly assigned to LIPA or allocated. Because shared resources involve portions of resources on a part time basis, we employed a generally accepted practice of measuring National Grid's resources used in serving LIPA in terms of their full time equivalency, with labor count measured as full time equivalents (FTEs).

We estimated that National Grid employs approximately 1,913 FTEs to meet its obligations to LIPA. National Grid's FDM provides data by work areas, which can be consolidated into functional areas. We assigned the National Grid labor force that is assigned to LIPA (on a dedicated or shared basis) into 21 functional areas. Table II-5 presents the National Grid FTEs working for LIPA by functional area. It also differentiates resources between those that are dedicated or shared.

⁷ The economics of such an arrangement depends upon the "fairness" of the utility holding company's system of cost allocation, which is typically codified in a Cost Allocation Manual (CAM). We did not have access to National Grid's CAM, therefore we could not assess the appropriateness of the allocation of commonly incurred costs that are allocated to LIPA.

Table II-5
LIPA Functions and Staffing Provided by National Grid
(FTE = Full-Time Equivalent)

Functional Area	NGrid Staff Serving LIPA		
	Dedicated (FTEs)	Shared (FTEs)	Total (FTEs)
EE/DR/Renewables	24	13	37
Environmental Regulation	0	10	10
Regulatory, Rates, & Pricing	5	8	13
Customer Accounts & Services	28	412	440
Marketing & Sales	0	30	30
Media/Government Relations	0	2	2
Accounting & Finance	0	45	45
Finance: Risk	0	10	10
Legal	0	14	14
Power Markets	14	44	58
Facilities/procurement	0	43	43
IT	0	50	50
HR	0	28	28
Other/corporate	0	46	46
T&D Operations & Maintenance - Lines & Subs	522	0	522
T&D Maintenance - Veg Mgmt	8	0	8
T&D Operations - Service	124	0	124
T&D Operations - General/Other	189	10	199
T&D Operations - Systems	35	8	43
T&D Operations - Engineering	115	0	115
T&D Operations - Planning/Management	77	0	77
Total	1,140	773	1,913

We estimate that the total LIPA work force – that is, the sum of LIPA directly employed staff plus the effective FTEs assigned by National Grid – is approximately 2,017. Staff levels by functional area are shown in Table II-6 below. The previously referenced Appendix A also includes the relationships and interfaces between the LIPA and National Grid functional areas.

Table II-6
LIPA Functions and Total Staffing Levels
(FTE = Full-Time Equivalent)

Functional Area	Total Staff Serving LIPA		
	LIPA (FTEs)	NGrid (FTEs)	Total (FTEs)
EE/DR/Renewables	12	37	49
Environmental Regulation	3	10	12
Regulatory, Rates, & Pricing	4	13	17
Customer Accounts & Services	6	440	446
Marketing & Sales	5	30	35
Media/Government Relations	7	2	9
Accounting & Finance	19	45	64
Finance: Risk	1	10	11
Legal	11	14	25
Power Markets	13	58	71
Facilities/procurement	3	43	46
IT	5	50	55
HR	6	28	34
Other/corporate	3	46	49
T&D Operations & Maintenance - Lines & Subs	0	522	522
T&D Maintenance - Veg Mgmt	0	8	8
T&D Operations - Service	0	124	124
T&D Operations - General/Other	7	199	206
T&D Operations - Systems	0	43	43
T&D Operations - Engineering	0	115	115
T&D Operations - Planning/Management	0	77	77
Total	104	1,913	2,017

Review and examination of the data along with additional information provided by LIPA led us to observe that:

- More than 50% of the total LIPA labor force is involved in T&D planning, operations and/or maintenance, with the majority of resources directly involved with hands-on work concerning operations and maintenance of LIPA's transmission and distribution lines and substations.
- Over 20% of the labor force is involved in customer service, which includes the field force responsible for reading meters and other field functions, as well as the work force covering LIPA's call center.

- LIPA's planning and corporate administrative functions primarily involve National Grid resources which are pooled and shared among LIPA and National Grid's operating companies.
- Nearly 90% of the National Grid work force that provides service to LIPA are estimated to be located on Long Island.

2. Direct Labor Costs

The direct cost of labor associated with the FTEs discussed above is based on expenses incurred concerning salaries and hourly-based wages. From an accounting standpoint, the costs associated with labor are recorded by both LIPA and National Grid as direct labor expenses (i.e., excluding additional expenses associated with benefits and pensions, which we discuss in the next section).

Table II-7 presents a breakdown of LIPA's direct labor expenses by functional area. The table includes the work force directly employed by LIPA as well as our estimate of National Grid's labor force that works on LIPA operations.

Table II-7
Estimate of Direct Labor Dollars Serving LIPA Functions

Functional Area	Employee FTEs			2010 Direct Labor Cost (\$000)	2010 Average Labor Rate (\$/FTE)
	National Grid	LIPA	Total		
EE/DR/Renewables	37	12	49	\$5,519	\$113,047
Environmental Regulation	10	3	12	\$1,137	\$92,268
Regulatory, Rates, & Pricing	13	4	17	\$2,035	\$122,082
Customer Accounts & Services	440	6	446	\$28,967	\$64,997
Marketing & Sales	30	5	35	\$1,860	\$53,652
Media/Government Relations	2	7	9	\$1,032	\$112,559
Accounting & Finance	45	19	64	\$5,748	\$89,808
Finance: Risk	10	1	11	\$704	\$64,027
Legal	14	11	25	\$2,831	\$114,299
Power Markets	58	13	71	\$4,174	\$58,795
Facilities/procurement	43	3	46	\$5,087	\$110,589
IT	50	5	55	\$6,007	\$108,566
HR	28	6	34	\$3,923	\$115,700
Other/corporate	46	3	49	\$5,677	\$116,239
T&D Operations & Maintenance - Lines & Subs	522	0	522	\$24,434	\$46,827
T&D Maintenance - Veg Mgmt	8	0	8	\$833	\$104,452
T&D Operations - Service	124	0	124	\$14,464	\$116,938
T&D Operations - General/Other	199	7	206	\$23,511	\$113,859
T&D Operations - Systems	43	0	43	\$3,084	\$72,307
T&D Operations - Engineering	115	0	115	\$9,579	\$83,077
T&D Operations - Planning/Management	77	0	77	\$7,667	\$99,839
Total	1,913	104	2,017	\$158,274	\$78,475
T&D	1,088	7	1,095	\$83,572	\$76,343
Customer Services and Rates	453	9	462	\$31,002	\$67,055
Planning, Corporate, and Administrative	372	88	460	\$43,700	\$95,036

The table indicates that the total operating expenses of direct labor in 2010 was approximately \$158 million. The direct labor expenses for LIPA's directly employed work force was less than 10% of this total. The table also shows that the average direct labor expense⁸ per FTE was approximately \$78,000. Labor rates for each functional area are averages derived from FDM data on hours worked (where available) and direct labor billings, supplemented with information on actual observed FTEs by LIPA staff. These averages reflect the composition of resources for

⁸ Note that approximately 30% of direct labor cost in the T&D O&M functions are included in LIPA's capital budget (not expensed) so are not included here.

each functional area (i.e., senior and/or specialty resources have higher labor rates; more junior and/or clerical resources have lower labor rates); they are not intended to represent the market value of a specific staff function.⁹

3. Pension and Benefits Costs

The total cost of labor-related expenses also includes the costs associated with benefits, pensions, and other post-employment benefits (OPEBs). The total benefit and pension expense (for LIPA and National Grid combined) in 2010 was roughly \$138 million. When added to the cost of direct labor (approximately \$158 million), the total of labor-related expenses in 2010 was approximately \$296 million.

The accounting underlying benefits is straight forward as employees have prescribed packages of benefits, such as dental, medical and vision care, as well as paid vacation time. Accounting for pensions and OPEBs is somewhat more complex, however, because defined contribution plans requires actuarial analyses.

LIPA and National Grid have different retirement plans. Furthermore, the National Grid portion of the work force is composed of a combination of bargaining unit and management personnel, which fall under different separate plans. Both LIPA and National Grid record annual benefit and pension (including OPEBs) costs as separate expense items in its accounting records. Thus, we were able to observe the ratios of: 1) benefits to direct labor costs; and 2), pensions (including OPEBs) to direct labor costs, as well the combined ratio of total benefit and pension costs to direct labor costs.

Benefit and pension cost data by functional area for LIPA and National Grid are provided in Appendix C. The appendix also derives the ratio of benefits to direct labor costs and the ratio of pensions to direct labor costs.

⁹ Labor rates are based on that portion of total labor costs that are accounted for as O&M expenses. The utility labor force, especially the field force, is dispatched to numerous work orders; some of these are accounted for as capital while others are accounted for as expenses. Thus, the labor rate for the T&D work force involved in “O&M Lines and Subs” is less than the total labor rate for this work force, which would reflect the sum of the labor costs that are expensed as O&M and the labor costs that are capitalized.

The ratio for LIPA's benefits to direct labor cost was approximately 33% in 2009. The corresponding ratio of pensions (including OPEBs) to direct labor was 25% for that year with the combined ratio of total benefits and pensions to direct labor totaling 58%. This ratio has increased slightly over time. It increased again in 2010, to 68%.

The ratio of benefits to direct labor costs observed for National Grid, as reported in the company's FDM, was 36% and the ratio of pensions (including OPEBs) to direct labor cost was 53%. This resulted in a total ratio of benefits and pensions to direct labor of 89%. Relying on a comparison of the ratios for LIPA and for National Grid's LIPA operations suggests that LIPA's benefit and pension costs were lower than National Grid's. It also suggests that LIPA's pension plan, which is part of the New York State and Local Retirement System, is considerably less expensive on an annual expense basis than is National Grid's.

Closer inspection of the benefits and pension entries at the functional level, however, indicated there appeared to be sizable lump sum expenses (totaling roughly \$54 million in 2009, adjusted to roughly \$64 million for 2010) assigned to the Human Resources and Other/Corporate functions and charged to LIPA. (The areas of apparent adjustment are highlighted in the table in Appendix C.) Discussions with LIPA accounting personnel indicate that these expense charges appear to be adjustments, as opposed to standard plan increases.

Given these apparent non-standard adjustments, we concluded that a ratio of total benefits and pensions to direct labor costs of 89% (i.e., 36% plus 53%) was not the appropriate ratio for the National Grid labor force for use in forward looking analyses.¹⁰ Removing the adjustment (or "catch up" of benefits and pensions) resulted in a ratio of total benefits and pensions (including OPEBs) for National Grid of approximately 45%. It also resulted in a ratio of benefits and pensions to direct labor costs for the combined LIPA and National Grid entity of approximately 46%. While we included the entirety of benefits and pension expenses in our baseline (i.e., \$138 million), we segmented the benefit and pension "catch up" adjustment from the remainder of the "core" benefit and pension expenses. This allowed us to use the adjusted ratios (58% for LIPA,

¹⁰ We did not have direct access to National Grid personnel during the course of our study. It is our understanding that LIPA staff reviews and discusses such adjustments to benefits and pension charges to ensure that they are appropriate under the terms and conditions of the MSA.

46% for National Grid and 46% for the combined labor force) as the baseline for benefit and pension calculations.

D. LIPA NON-LABOR EXPENSES

Non-labor related expenses include the materials and supplies that are needed for T&D and administrative and general (A&G) operations that are not capitalized, as well as payments for outside services such as audits, outside counsel, consultants and contractors.¹¹ The total amount of non-labor O&M expenses was approximately \$232 million in 2010. This was roughly 42% of the total non-labor plus labor expenses. Roughly 37% of the total expenditures on non-labor O&M expenses were incurred directly by LIPA, with the remainder paid by National Grid.

The breakdown of the non-labor expenses for LIPA and National Grid by functional area is presented in Appendix D. The appendix also shows detail by category of non-labor expense. It shows that non-labor expenses associated with materials and supplies constitute the largest category of non-labor O&M expenses (just under 40%). Nearly 30% of non-labor expenses are for payments for outside services and contractors. These expenses include payments for outsourced T&D related services (notably for tree trimming services) and various other professional services. Also, approximately 20% of non-labor expenses fall in a general corporate category, which includes a variety of such services. The remaining expenses, just over 10% of the total non-labor O&M expenses, are associated with systems, leases of facilities and vehicles, and equipment and associated taxes.

The appendix also shows that the majority (roughly 69%) of LIPA's direct expenditures on non-labor O&M are for materials and supplies associated with LIPA's energy efficiency, demand response and renewables programs.¹² The largest non-labor expense cost area for National Grid was outside services and contractors (roughly 35%), most of which was associated with work

¹¹ GAAP and regulatory accounting guidelines determine if expenditures on materials, supplies and equipment may be expensed or capitalized. Generally, major expenditures made for capital programs (such as building a new substation) are capitalized.

¹² LIPA's initiatives concerning energy efficiency include its Efficiency Long Island (ELI) program and smart meter pilots. LIPA's initiatives concerning renewable energy include the Solar Pioneer and Solar Entrepreneur programs and the Backyard Wind initiative.

areas within the T&D function. Some of these outside services, such as tree trimming, go towards the ongoing maintenance of LIPA's T&D system.

Examining the ratio of non-labor O&M to labor-related O&M is an informative metric that is typically reviewed in budgeting and financial planning exercises. Such a ratio is particularly useful when it is normalized; that is, after any one-time and/or extraordinary expenses – either labor or non-labor – are taken into account. Thus, the ratio of non-labor O&M expenses to labor-related O&M expenses provides a useful starting point for analyzing aspects of budgets and financial plans. Budget preparation, however, requires thorough consideration of future conditions. It also requires that the impact of future capital plans be taken into account, as placing new utility plant in service typically is accompanied by additional O&M expenses to operate and maintain the plant, all other things being equal.

Above, we discussed the composition of labor-related O&M expenses and indicated that the total for that expense category (i.e., direct labor expenses plus expenses relating to benefits, pension and OPEBs) was approximately \$296 million in 2010, composed of roughly \$158 million in direct labor expenses and \$138 million in benefits, pensions and OPEB related expenses. We presented a breakdown of benefits, pension and OPEB related expenses and indicated that the data suggested that an adjustment had been made that served to inflate these expenses above a normal increase. When we removed these benefit and pension “catch up” expenses, this category of expenses was reduced to roughly \$231 million (i.e., roughly \$296 million less \$64 million).

This resulted in a nearly exact one-to-one relationship between labor-related O&M and non-labor O&M, and suggests that increases in labor costs, which reflect the combination of additions to the work force and the effects of inflation, are accompanied by proportionate increases in non-labor expenses. This reflects the fact that increases in work force size generally mean that there is a greater work load and, all other things being equal, is accompanied by additional expenses in materials, systems, leases and fleets, as well as the services supplied by external contractors (unless labor additions were designed to “in-source” previously outsourced labor).

We further reviewed the makeup of LIPA's overall non-labor O&M expenses (i.e., the total of such expenditures by both LIPA and National Grid) to assess whether all of LIPA's non-labor expenses would move with the observed one-to-one ratio. Summary statistics concerning LIPA's non-labor O&M is included in Table II-8, below.

Table II-8
Composition of LIPA's Non-Labor O&M

	(\$000)	(%)			
<u>Ratio Non-Labor O&M to Labor O&M</u>			<u>Composition of Non-Labor O&M</u>		
2009 Labor O&M	\$249,457	55%	T&D	20.5%	
2009 Non-Labor O&M	\$205,437	45%	Rates + Markets	37.9%	
Total O&M	\$454,893	100%	Corporate	41.7%	
<u>Excluding Benefits Catch Up</u>			Total Non-Labor O&M	100.0%	
2009 Labor O&M	\$195,016	49%	Materials	39.4%	T&D*
2009 Non-Labor O&M	\$205,437	51%	Outside Services/Contractors	28.4%	11.4%
Total O&M	\$400,453	100%	Systems	2.2%	8.4%
			Rents/Leases	2.0%	36.8%
			Fleet Leases	3.8%	88.1%
			Tax	4.3%	45.1%
2009 Non-Labor EE/DR/Renewables	\$60,464	29%	Other	19.9%	5.3%
			Total Non-Labor O&M	100.0%	
			LIPA	41.9%	
			National Grid	58.1%	
			Total	100.0%	

* Percentage of category associated with T&D.

The table indicates that nearly 30% of non-labor O&M expenses are associated with LIPA's initiatives concerning energy efficiency, demand response and renewables. Expenditures on these initiatives likely reflect decisions independent of labor considerations and will not vary as labor costs are increased or decreased (unless, of course, that additional labor was added to the work force explicitly to support an expansion of these programs).

For purposes of developing our baseline analysis, we assumed that the ratio of non-labor expenses to labor expenses was approximately 70%, with variations on this average being observed across the various functional areas.

E. LIPA ASSETS AND BALANCE SHEET

All of LIPA's T&D plant is included as assets on its balance sheet. This reflects the electric plant in service that is used to provide electric service to customers on Long Island. National Grid

owns various buildings and storage yards on Long Island from which its LIPA-related work force are housed and materials and equipment are stored. LIPA has the rights to acquire these properties at fair market value at the termination of the current MSA. The asset side of the balance sheet also includes LIPA's 18% ownership of the Nine Mile Point 2 nuclear power plant, as well as the amortized value of the acquisition premium that it paid when it acquired LILCO in 1998.

LIPA's balance sheet as of 2010 is presented in Table II-9.

Table II-9
LIPA 2010 Balance Sheet
(\$000)

Assets		Liabilities and Net Assets	
Cash and Cash Equivalents	371,264	Current Liabilities (Excl. Regulatory Liabilities)	1,168,720
Investments	124,283		
Rate Base Assets	7,337,745	Regulatory Liabilities	164,520
Net PP&E	6,459,718	Long Term Debt	6,394,949
Deferred Charges	88,748	Capital Leases	2,970,126
Regulatory Assets	789,279	Other	879,652
Acquisition Adjustments	2,629,216	Non-current liabilities	559,932
Other	1,115,459	Borrowings	114,520
Deferred Outflow - Commodity Derivatives	65,782	Commodity Derivative Instruments	66,611
Deferred Outflow - Financial Derivatives	66,705	Financial Derivative Instruments	81,277
Non-cash Current Assets	680,211	Asset Retirement Obligations (NMP2)	7,380
Promissory Notes	155,425	Claims and Damages	20,207
Nonutility Property and Other Investments	74,679	Deferred Credits	203,637
Other Long Term Accounts Receivable	72,657	Net Assets	319,720
Total Assets	11,577,967	Total Liabilities and Net Assets	11,577,967

The table shows that LIPA total net assets are equal to approximately \$11.6 billion, of which:

- Utility property plant and equipment (PPE) is equal to roughly \$6.5 billion. PPE is the net balance of the ongoing process of adding, retiring and depreciating utility plant. In LIPA's case, this involves for its T&D assets the starting balance of utility plant that it received from LILCO plus the additions of plant, such as enhancement and expansions of T&D lines and substations, less the retirement of old plant and the depreciation of original plant still in service along with depreciation on newer plant.
- Included in the PPE are capital leases associated with generation and transmission (G&T) assets are equal to roughly \$3.6 billion. These reflect the leasing arrangements including, for example, the sub-sea transmission facilities that connect

LIPA's grid with New England ISO (via the Cross Sound Cable) and with the PJM (via the Neptune Cable).

- Acquisition premium equal to approximately \$2.6 billion, which is the amortized value of the premium above the book value of productive assets that LIPA paid to LILCO in 1998. This is considered to be a "regulatory asset" because it is not an asset in the traditional accounting sense; that is, it has no tangible value. It can also be considered to be a "non-productive asset."
- Short-term cash and equivalents are equal to approximately \$1.1 billion. This is matched by same amount of similar short term and regulatory liabilities. Various regulatory assets comprise the remainder of current liabilities.

The liability side of LIPA's balance sheet appropriately matches the asset side and is composed of:

- Short- and long-term debt equal to approximately \$6.8 billion.
- Capital lease obligations equal to roughly \$3.0 billion.
- Obligations associated with short-term cash and equivalents equal to roughly \$1.4 billion.

LIPA's balance sheet has an impact upon LIPA's rates through two primary means. First, depreciation on capital expenditures is included as an expense in LIPA's annual operating budgets. Second, financing charges (in LIPA's case, interest paid on debt) represent large annual expenditures. This is typical as electric utilities have very large annual capital budgets, involving hundreds of millions of dollars for the ongoing upkeep and enhancement of their electric systems. These budgets, in fact, could be much larger if the utility is involved in a specific, major project, such as the construction of a power plant or major transmission line. The terms and conditions associated with financing such capital additions can have a significant impact upon rates.

Both of the above factors need to be considered when assessing organizational alternatives to LIPA's current structure. Depreciation expenses may be affected under conditions in which an organizational option requires the addition of utility plant; the new plant would need to be acquired (impacting financing costs) and depreciated (creating an annual expense). Perhaps more significantly, it is also possible that an organizational option will change LIPA's status as a

municipal instrumentality, causing it to forego tax-exempt financing. Such a change would have a considerable impact on financing costs, and is largely the focus of Chapter IV of this report.

F. LIPA OPERATING PERFORMANCE

LIPA is one of the largest public power utilities in the country. Table II-10 shows LIPA's relative position among public power utilities in terms of annual kWh sales and number of customers.

Table II-10
LIPA Ranking in Sales and Customers

Rank	Company	2009 Sales (GWh)	Rank	Company	2009 Customers (000)
1	Salt River Project	26,181	1	Los Angeles Dept of Water & Power	1,449
2	Los Angeles Dept of Water & Power	23,789	2	Long Island Power Authority	1,116
3	CPS Energy	20,027	3	Salt River Project	946
4	Long Island Power Authority	19,271	4	CPS Energy	701
5	Memphis Light Gas & Water	13,720	5	Sacramento Municipal Utility District	594
6	JEA	12,299	6	JEA	418
7	Austin Energy	12,036	7	Austin Energy	409
8	Nashville Electric Service	11,667	8	Memphis Light Gas & Water	406
9	Sacramento Municipal Utility District	10,692	9	Seattle City Light	395
10	Santee Cooper	10,205	10	Nashville Electric Service	360

Source: EIA-861 data.

It is also sizable with respect to many investor-owned utilities (IOUs), comparable to a mid-sized IOU in the U.S.

Electric utilities routinely compare their performance in certain key areas, such as reliability, in a process referred to as benchmarking. While few utilities are truly completely comparable because of differences in geography, topography, customer density and many other factors, they are able to compare themselves in terms of benchmarking “metrics,” such as operating cost per customer, or cost per kWh.¹³ Utilities also measure and compare their level of service reliability, which is measured in terms of the frequency and duration of outages. Importantly, when

¹³ More detailed and customized studies employ statistical and econometric techniques to determine the extent to which underlying factors influence may explain levels of performance.

benchmarking reliability, utilities remove the effects of natural disasters and major storms from reliability metrics.¹⁴

Relevant benchmarking analysis also relies upon the identification of a “peer panel” of comparable utilities. We selected three panels against which to assess LIPA’s relative cost performance. These panels were composed of IOUs because LIPA is a comparatively large electric utility and operates in conjunction with an investor-owned utility. Also, the Federal Energy Regulatory Commission (FERC) requires that investor-owned electric utilities annually file detailed information concerning their costs and other aspects of operations via FERC’s “Form 1,” a standard template for data submission. The FERC also specifies how costs are to be reported by defining categories in a uniform system of accounts (USOA), which ensures the ability to compare similar areas of similar costs.¹⁵

We defined and conducted a benchmarking analysis of LIPA’s cost performance using three panels:

- **National Panel:** Composed of all electric utilities in the U.S. filing FERC Form 1 reports, covering roughly 123 electric utility operating companies. Consolidations in the electric utility industry have reduced the number of utility holding companies to roughly 65. However, in many cases the acquired utilities continue to operate as subsidiary operating companies and are required to file separate FERC Form 1 reports.¹⁶
- **Neighboring/Similar Utility Panel:** Covers the electric utilities that operate in geographic areas that are similar to LIPA and/or electric utilities with characteristics similar to LIPA. This panel is a subset of the National panel; it allows us to more closely match unique characteristics stemming from operating in the northeast and environs. This panel is composed of 27 IOUs.
- **New York State Utility Panel:** As the name implies, this panel includes the six IOUs that operate in the state of New York. Use of this panel is of interest because

¹⁴ Measures of reliability are defined by regulatory commissions, such as the New York State Public Service Commission, and by trade organizations that collect and study such data, such as the Edison Electric Institute (EEI).

¹⁵ Individual utilities may exercise discretion within the confines of the USOA, so it is possible that utilities may make different accounting entries at the work order level for largely similar types of expenditures.

¹⁶ For example, The Southern Company is the holding company for five operating utilities, each of which files a separate FERC Form 1. Also, each of the electric utilities that are owned by National Grid file a separate report.

intra-state comparisons are frequently used in states, such as New York, that are served by multiple IOUs. The same state regulatory commission also regulates these utilities.

A listing of the utilities included in each of these panels is included in Appendix E.

1. Cost Benchmarking

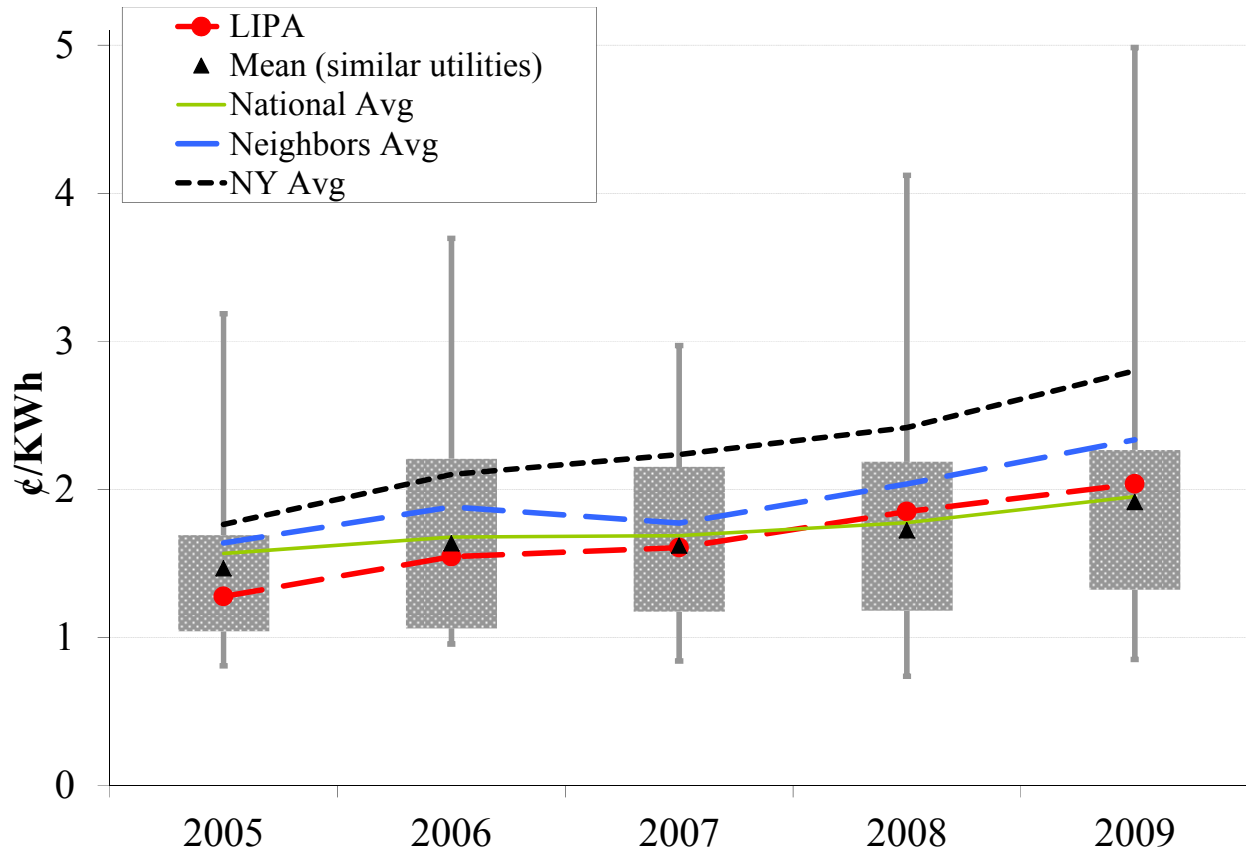
We reviewed LIPA's cost of delivering electricity to customers in its service territory, as well as the various detailed cost components that make up its delivery cost.¹⁷ Specifically, these costs include all of a utility's costs *excluding* the costs of operating and maintaining power plants (if it owns and operates such) and the costs of purchasing power. It also excludes the costs of financing (e.g., interest payments) and taxes. As was noted earlier, the cost associated with power supply for LIPA and for other electric utilities is substantial, typically more than 60% of a utility's total cost structure.

What is left after these exclusions is the cost of operating a utility's transmission and distribution system, the cost associated with customer service, accounts, installations and meter reading, and the costs of its various planning, corporate and administrative functions (referred to as administrative and general expenses, or A&G). Alternatively stated, these are the costs associated with running a T&D utility. In benchmarking parlance, we refer to this grouping of non-power related costs as non-generation, non-fuel operations and maintenance expenses (or Non-Gen NFOM for short). This is roughly equivalent to the portion of LIPA's costs that are included in the scope of the subject study.

Figure II-6 summarizes LIPA's cost performance in Non-Gen NFOM on a per kWh basis against the three panels of utilities.

¹⁷ The FERC requires that investor-owned utilities under its jurisdiction file Form 1s during the calendar year following the year of operation. The field work and data gathering phase of our study was completed during the latter half of 2010 and the first quarter of 2011, before utilities filed their 2010 Form 1s with the FERC. Accordingly, we used data for 2009, the most current data available, for our benchmarking analysis. We also examined prior years to determine whether any individual year represented aberrant behavior. We found that 2009 was reasonably representative of utility cost data and appropriate to use in this study. We also found that LIPA data and performance was consistent between 2009 and 2010.

Figure II-6
LIPA Non-Gen Non-Fuel O&M Costs
 (Annual Costs Compared to Utility Panels)



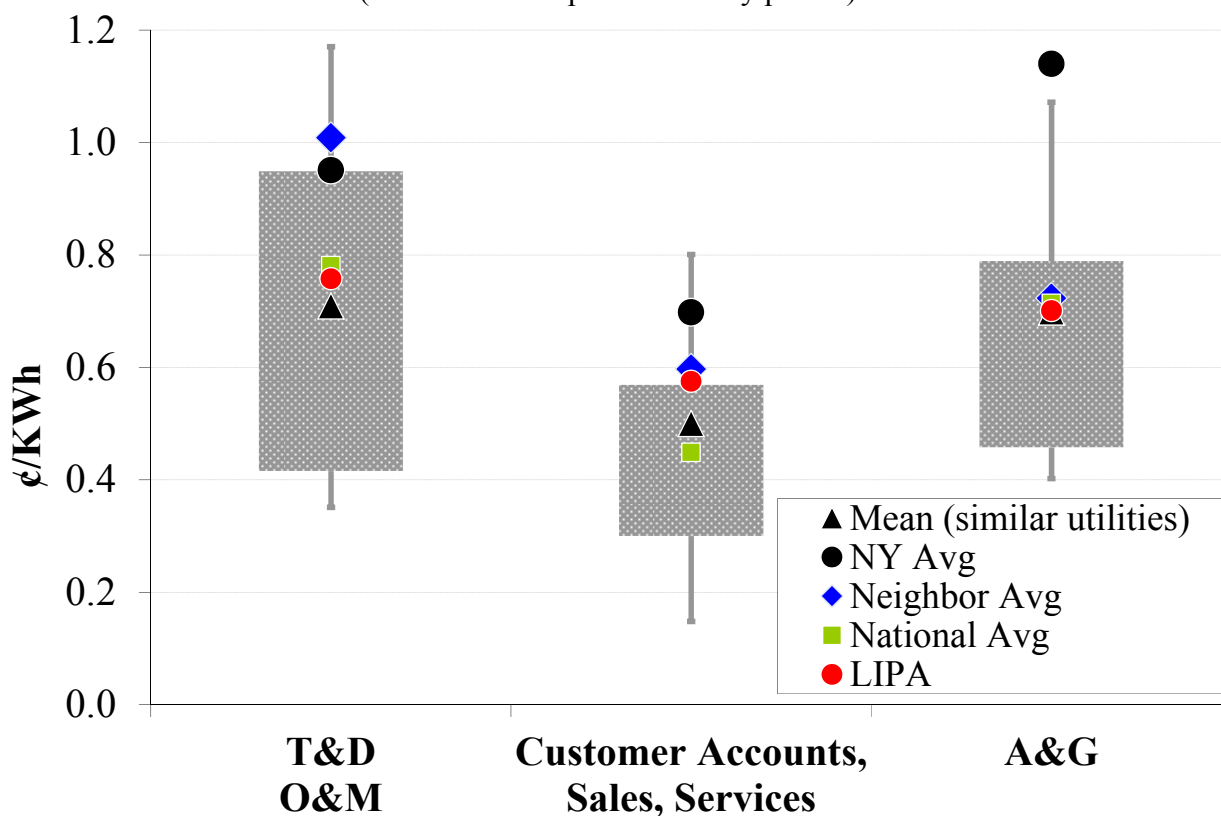
Source: FERC Form 1 data; LIPA budgets.

Utilities are typically ranked in terms of deciles and/or quartiles in benchmarking studies. For cost benchmarking, utilities strive to be the low cost provider, all other factors being equal. The grey boxes in Figure II-6 represent the band spanning the second and third quartiles, or the mid-range, for the National Panel. The figure also shows the high and low observations (i.e., the top and bottom of the vertical grey bar) for the National Panel, along with the averages for the Neighboring / Similar Utility panel and New York State Utilities panel.

Figure II-7 provides similar benchmarking depictions at a slightly more detailed level. Specifically, the figure disaggregates the total cost data to provide benchmarking results for the three primary cost areas that make up the Non-Gen NFOM metric, which include:

- T&D, which includes all areas of transmission and distribution operations and maintenance;
- Customer Service, which includes the business processes from installation of service to meter reading and call centers; and,
- A&G, which includes the planning, corporate and administrative functions needed to support utility operations and meet legal and regulatory requirements.

Figure II-7
LIPA Non-Gen Non-Fuel O&M Costs
 (2009 costs compared to utility panels)



Source: FERC Form 1 data; LIPA budgets.

Figures II-6 and II-7 indicate that LIPA is clearly in the mid-range in terms of its cost performance. In other words, LIPA is not higher cost (on a per kWh basis) than the national average, and is typically below the per-unit costs, on average, when compared to its geographic neighbors. We find this to be an important general indicator: It does not imply that there is no

room for improvement in operational efficiencies, but it does suggest that it is unlikely that a change in organizational structure would lead to a noticeable reduction in LIPA's cost of delivering electricity to its customers. LIPA is already quite cost competitive in the T&D arena.

2. Reliability Benchmarking

Electric utilities also examine their performance in terms of the reliability of their service delivery. These measures are important because unreliable service may be an indicator of under investment in the system or poor management, even if the utility is a low cost provider. In practice, utilities may adjust their level of spending – or be required to do so by regulatory commissions – when reliability is poor.

Reliability is typically measured in terms of the frequency and duration of customer outages, as measured by three (3) primary metrics.

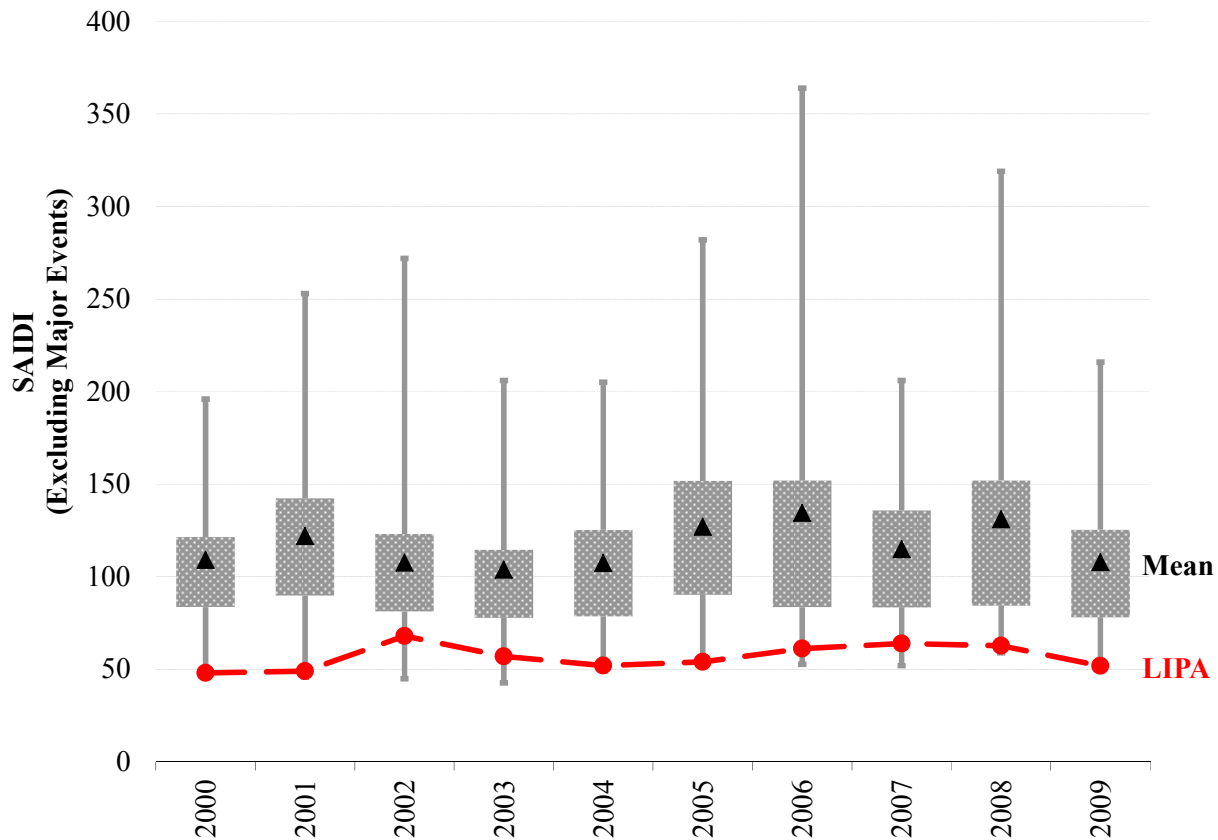
- SAIDI (System Average Interruption Duration Index): measured as the sum of all customer interruption durations divided by the total number of customers served.
- SAIFI (System Average Interruption Frequency Index): measured as the total number of customer interruptions divided by the total number of customers served.
- CAIDI (Customer Average Interruption Duration Index): measured as the sum of all interruption durations for interrupted customers divided by the total number of customer interruptions; this is the same as SAIDI divided by SAIFI.

Regulators frequently define the specifications as to what constitutes an interruption; it is typically specified in terms of minutes. In order to ensure that the metrics appropriately compare utilities when they are engaged in general operations, the effects of natural disasters, including major storms, are frequently excluded from the reported metrics.¹⁸

Figure II-8 depicts the recent 10-year history of SAIDI performance for both LIPA and a utility panel.

¹⁸ The appropriateness of a utility's response to major storms may be examined by regulators or other interested parties on a case-by-case basis.

Figure II-8
LIPA Reliability
 (Annual SAIDI metric compared to utility panel)



Source: First Quartile Consulting; Brattle research.

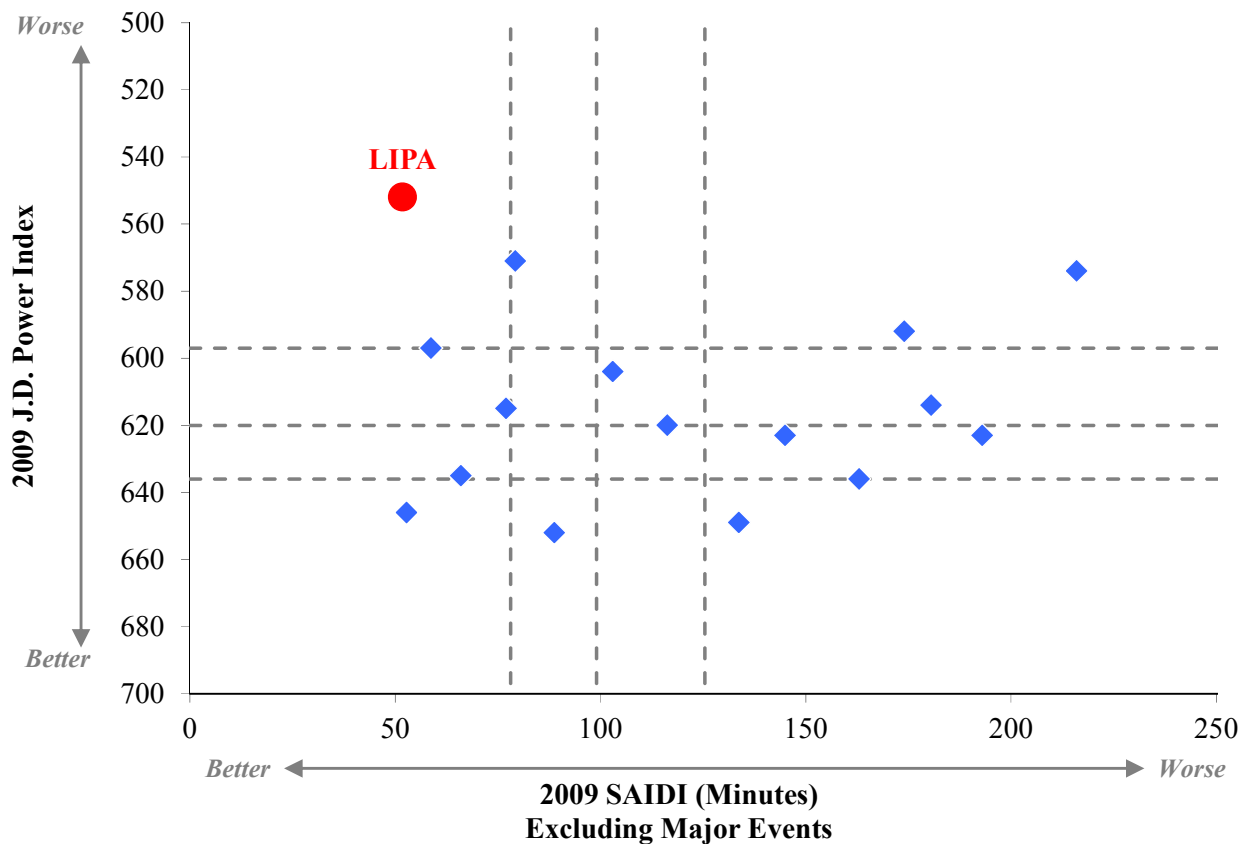
The above SAIDI reliability panel is composed of 33 electric utilities. This panel is a subset of the National panel. We used a different panel in benchmarking LIPA's level of comparable reliability; not all utilities publicly report their reliability performance data, which serves to reduce the potential size of a panel.

Review of Figure II-8 indicates that LIPA's electric distribution system operates at a very reliable level; that is, it exhibits a low average duration of service interruptions in the course of its normal operations. (We have not reviewed LIPA's performance in restoring power after a major occurrence, such as a storm, as part of our study.)

We also include a metric indicative of the level of customer satisfaction. The panel of utilities used in this area of benchmarking is made up of the 76 electric utilities that are included in the annual J.D. Power survey. The survey involves asking customers (through a variety of mediums) about their opinions of the electric utilities that serve them. It covers six areas of customer satisfaction, notably price, quality and reliability, customer service and communications, as well as an overall customer satisfaction. The cost and reliability metrics discussed above are quantitatively based, while the customer satisfaction metrics are based on opinions and perceptions.

We plotted the customer satisfaction metrics provided in the J.D. Power survey against utility reliability, as measured by SAIDI for the Reliability panel, in Figure II-9 below.

Figure II-9
LIPA Reliability and Customer Satisfaction
 (2009 values compared to utility panel)



Source: First Quartile Consulting; J.D. Power; Brattle research.

LIPA received a very low score for customer satisfaction. It is likely that LIPA's relatively high price for electric service (i.e., the combined rate for power and delivery) greatly influences customer satisfaction ratings. LIPA's customers also gave LIPA generally poor ratings on the metrics for power quality and reliability. Such a score is interesting in light of LIPA's relative benchmark ranking concerning its distribution reliability. However, it is possible that customers may be more concerned with storm response or other dimensions of customer service than they are with conventional utility measures of reliability.

G. FINDINGS

1. LIPA currently operates under a unique structure compared to electric utilities in the United States.

Electric utilities in the United States operate under two broadly defined regimes concerning their level of vertical integration. Certain state regulatory commissions have directed that electric utilities under their jurisdiction structurally separate transmission and distribution areas of operation from those of power generation. Other states have not embraced such restructuring and allow utilities to own and operate both power generation and T&D facilities. And still others, such as the New York PSC, forced utilities within the state to sell their generating assets so that a competitive power generation market could be created and fostered. In that sense, LIPA not owning generating assets, it is not unique.

Electric, natural gas and other utilities may also outsource various elements of their operations, generally when it is economically efficient to do so. For example, within the last decade or so, electric utilities have begun to outsource nearly all of their operations that perform vegetation management, or tree trimming.

LIPA is unique, however, in that it outsources the majority of its T&D operations to another utility that acts as a service provider (initially to KeySpan, which was subsequently acquired by National Grid). Since the majority of T&D operations is conducted by the service provider, LIPA's organizational structure is akin to the "government-owned, contractor-operated" (GoCo) model that is used by the U.S. Department of Energy (DOE) in operating its laboratories and manufacturing and production facilities. We are unaware of other utilities that operate under

such a GoCo structure, and therefore cannot review the experiences and performances of other utilities that operate within a similar structure.

2. Staff that is directly employed by LIPA are responsible for a combination of planning and corporate functions, as well as for overseeing and managing LIPA's MSA with National Grid.

LIPA's directly employed staff numbers slightly over 100 who are organized around traditional utility functional areas. Accordingly, LIPA's functional area designations largely match those of its service provider. Each of the services provided by National Grid are overseen, to some extent, by the related LIPA functional area. The majority of the services providers by National Grid are related to T&D operations and to Customer Services, areas overseen by LIPA's chief operating officer and its vice president of customer service. Other areas of service include corporate and administrative functions such as accounting and legal, which are overseen by the functional leads at LIPA.

Not all of the LIPA's business is conducted by National Grid, though, and LIPA staff are responsible for more than managing LIPA's contracts with National Grid. The focus of LIPA staff varies from function to function. For example, LIPA's T&D staff is relatively small and is primarily responsible for overseeing and managing the T&D portion of the MSA. But a greater proportion of LIPA staff are responsible for, among other functions and work activities, strategic and tactical level planning, financial reporting, and coordination with governmental agencies in New York State.

Thus, changing LIPA's organization structure from a purely contractual based structure will not result in the elimination of all of LIPA's currently directly employed staff, or a concomitant reduction in labor cost.¹⁹ We provide a more comprehensive discussion concerning our analysis of staffing levels and labor costs under the various strategic organizational options in Chapter III of this report.

¹⁹ As we discuss later in this report, organizational restructuring that involves the merger or acquisition of LIPA with or by another electric utility would likely result in the elimination of some duplicative corporate functions. This would result in the reduction of corporate function staff, either at LIPA or at the partnering utility.

3. Restructuring LIPA's organizational approach would likely not have a material impact upon the cost of power supply.

Procurement of power supply in an economically efficient manner is among the highest priorities for retail electric utilities; this is also the case for LIPA. Planning for and procuring power supply is an analytically rigorous undertaking that requires modeling of power markets within the constraints of available options, developing and managing complex contracts, and understanding and managing the business, operational and market risks attendant to power supply. LIPA serves the market that is located in the NYISO Zone K (i.e., essentially Long Island) and therefore has limited options for power supply because of its geographic position. It is at "the end of the cord," so to speak in relation to many options. Careful study of its situation and consideration of various options led LIPA to coordinate with developers to ensure the construction of the Cross Sound and Neptune transmission cables, which have expanded LIPA's power supply and capacity options beyond historic on-island resources.

Absent an organizational option that brings additional power supply resources and/or options to LIPA, it is unlikely that alternate organizational structure would, by itself, improve the processes currently in place to plan for and procure power supply for Long Island. We are careful to note, however, that the cost associated with this area constitutes over 60% of LIPA's annual revenue requirement and therefore deserves focused and ongoing attention under whatever organizational option is ultimately selected by LIPA.

4. LIPA operates at a comparatively cost efficient basis and at a high level of reliability.

Benchmarking analysis indicates that LIPA operates within a reasonable band of cost efficiency. While it is likely that LIPA, similar to most utilities, may be able to improve its performance in various areas of its operations, our analysis suggests that a change in organizational structure will not result in a materially significant reduction in T&D and Customer Service costs. Review of utility mergers and acquisitions indicates that costs in these areas are rarely targeted for downsizing and/or cost reductions.

Savings may be realized in corporate and A&G cost areas *if* LIPA were to be acquired by another utility that already had these functions in place and operating efficiently. Under those

conditions, costs to LIPA's customers would benefit by receipt of a portion of the benefits associated with scale economies and sharing of resources in the corporate and A&G functions.

5. Gains in operating efficiencies (i.e., reductions in operating costs) will result only in, at best, modest reductions in electric rates because LIPA's O&M cost together with the areas covered by the MSA account for approximately 15% of LIPA's cost structure and revenue requirements – a relatively small share of overall costs.

This is largely a matter of simple arithmetic. The combination of revenue requirements and LIPA's level of kWh sales means, all other factors being equal, that a one cent reduction in average electric rates can only be realized if LIPA reduces its operating costs by approximately \$200 million per year, or about 35% of total T&D annual costs of \$557 million. We believe this to be unlikely. The O&M costs that may be affected by a reorganization of LIPA include all of its T&D, Customer Service and A&G expenses. These costs span all of the expenses paid to National Grid under the MSA and expenses directly incurred by LIPA outside of power, fuel, taxes and interest on debt.

By way of example, a 10% reduction in these costs (i.e., \$55.7 million) would result in a rate decrease of less than \$0.0025 per kWh.

6. The non-productive assets on LIPA's balance sheet are sizable and present an obstacle to any possible sales of LIPA.

LIPA's balance sheet includes approximately \$2.7 billion in a regulatory asset that reflects the amortized value of the premium that LIPA paid to LILCO above the then book value of LILCO's assets. This acquisition premium amounted to the book value of LILCO's Shoreham nuclear power plant, then deemed to be a non-productive asset.

T&D focused utilities, such as LIPA, may be of interest to prospective investors, but such potential buyers would be far less interested in acquiring LIPA's non-productive assets. A sale of LIPA would likely be accomplished in one of two primary ways:

- An acquirer could purchase the entirety of LIPA (i.e., all of LIPA's assets – both productive and non-productive) and either, a) place all of these assets into rate base

(assuming that regulators would approve of such a proposal), or b), place only the productive assets in rate base and be willing to forego any return on the non-productive assets.

- An acquirer would pay for LIPA's productive assets (and puts those in rate base), but LIPA would retain its non-productive assets (and charge its former customers for the interest expenses on the associated debt).

In either case, the presence of non-productive assets on LIPA's balance sheet would complicate any transaction concerning its productive assets. We examine these issues in greater detail in subsequent Chapter IV of this report.

7. Projected pension expenses are an area of considerable uncertainty.

At least one of the strategic organizational options under study – Municipalization – involves a possible change in pension plans from the current retirement system administered by National Grid to the New York State and Local Retirement System, the system to which LIPA employees belong. Such a change may result in an increase in labor-related costs. Whether the transfer of National Grid employees requires a change in retirement systems is uncertain. Complicating matters, the future of employee tiers within the New York State system is also uncertain. Thus, a single point determination of the revenue requirement and rate impacts resulting from the possible implementation of a Municipalization option is not possible or appropriate.

Accordingly, we have adopted a scenario based analyses to assess the range of impacts resulting from implementation of each of the organizational options under study. Mid, high and low cases were developed for each of the cost areas for each option. In the case of projected pension expenses, scenarios were developed ranging from the maintenance of the status quo (i.e., no change in per capita pension expenses) to transitioning to the higher level of per capital pension expenses currently experienced at LIPA.

Chapter III

Operations Cost Analysis

Corporate restructurings and reorganizations may be undertaken for a variety of reasons. Generally, these are motivated by the need to expand into new markets, enhance competitive positioning, and/or improve operating efficiencies and reduce costs. As regulated enterprises, electric utilities have been keenly aware of the need to keep their operating costs as low as possible. The expiration of the MSA provides LIPA with an opportunity to select among three organizational options, each with different characteristics and potential impacts, with the overall intention of improving its cost structure and enhancing its service quality, while maintaining high reliability. Consequently, we examined the potential cost and service quality impacts associated with each option.

Although LIPA's transmission and distribution operations and maintenance costs (T&D O&M) are at industry average levels,¹ LIPA's overall average electric rate (at 18.2 cents per kWh in the 2010 baseline case) is among the highest in the country. Regional power supply prices, some inefficient local generation assets, and the remaining portion of LIPA's acquisition premium (sometimes referred to as the "Shoreham debt") are the primary drivers behind LIPA's relatively high rates; much of this is outside of LIPA's control. Nonetheless, LIPA's Board of Trustees, management, and customers are keenly interested in pursuing any initiative that could help reduce costs and rates without sacrificing reliability or safety. A primary objective of our study is to assess the impact that the organizational options available to LIPA – Municipalization, ServCo, or Privatization – may have upon costs and rates to electric customers on Long Island. We assume in our analysis that reliability and safety will not be compromised by adoption of any of the organizational options.

In this chapter, we assess how implementing these options will affect operating costs. Our estimates of these costs are an important and core part of this study. As suggested in the introductory chapter of this report, the Municipalization and ServCo options are each variations

¹ See the cost benchmarking discussion in Chapter II.

on LIPA as a municipal electric utility. In this way, the Municipalization option may more aptly be described as a “full municipalization” and the ServCo option may be considered a “partial municipalization”. The financing costs for these municipalization options (i.e., interest payments on debt) will largely be unaffected by restructuring LIPA from its current organization to either of these two options, unless one or both involve material levels of incremental capital investment, which we do not foresee.

On the other hand, implementing the Privatization option would involve a change from LIPA’s current tax-exempt status to that of a taxable, investor-owned utility. The financing impacts, which are presented in detail in Chapter IV, would be substantial. Therefore, in order to avoid a rate increase under Privatization, substantial reductions in operating costs – or other areas, such as fuel and purchased power - would be required in order to offset the increases in revenue requirements precipitated by higher financing costs. Careful assessment of the potential for reductions in operating savings, thus, is critical to accurately gauge the feasibility of the Privatization option.

We presented LIPA’s 2010 cost structure at a detailed level in Chapter II. Specifically, we reviewed and analyzed operating costs by category and function and set a baseline for costs and rates. In this chapter, we consider a range of cost outcomes (i.e., mid case, low case, and high case) for these options. The mid case represents our view of a likely outcome for each strategic option. It is possible, however, that costs in each cost category may vary over a range of outcomes due to uncertainty in a number of factors. Consequently, along with the mid case, we also estimate a high case and a low case.²

Finally, we compile the key points associated with our analysis in the Findings section of this chapter.

² Note that these cases are straightforward percentage adjustments to the mid case results. We do not apply probabilities to the cases as the available data and information do not support such an analysis.

A. DIRECT LABOR

Labor costs constitute roughly half of LIPA's 2010 baseline O&M expenses, and direct labor costs (i.e., excluding related costs associated with benefits and pensions) constitute the majority of total labor costs. Our analysis here is based on an analysis of LIPA's current operations and cost structure (presented in Chapter II), the location and composition of current resources in various functional areas, the breakdown of resources between dedicated and shared, and the anticipated level of incremental operating efficiency realized by the different organizational options. Such analysis also necessitates that our team apply their experience and expertise in utility operations, organization, and cost analysis, and is subject to the considerations described below.

As provided in Chapter II, the combined LIPA and National Grid work force consists of roughly 2,017 FTEs, the majority of whom are employed through National Grid.³ We noted that:

- More than 50% of the total LIPA labor force is involved in T&D planning, operations, and/or maintenance;
- Over 20% of the labor force is involved in customer service;
- Nearly 90% of the National Grid work force that provides service to LIPA is estimated to reside on Long Island.
- Roughly 20% of National Grid's work force is "shared" with LIPA, meaning that those resources are performing functions for both LIPA and National Grid; the primary shared work areas are in the planning, corporate and administrative functions. Technically, a significant portion of the Customer Accounts and Services work force are accounted for as shared resources, which we have not included in our estimate of shared resources here.⁴ As described in Chapter II,

³ The exact number of FTEs may change over the course of a year, as employees may leave National Grid or LIPA. Also, National Grid employees that are assigned or allocated to LIPA may be redeployed to work on other matters or for other National Grid operating companies.

⁴ If Customer Accounts and Services are included, National Grid's shared resources total approximately 40%.

these resources are not pooled in the same sense that administrative functions support multiple operating companies. Instead, they are dedicated to LIPA's electric and National Grid's Long Island gas operations.

These findings from Chapter II, combined with research and observations regarding utility reorganizations, lead us to several overarching conclusions concerning the range of impacts that we can expect from changes from LIPA's organizational structure.

First, and perhaps of most significance, we do not expect that there will be adjustments to LIPA's T&D work force under any of the strategic organizational options considered. This is primarily because our benchmarking analysis provides a strong indication that LIPA's T&D operations are relatively cost efficient and there are no obvious areas that a new management team would target for headcount or other forms of cost reductions, particularly as it pertains to the unionized workforce. We also reviewed the scope and scale of cost reductions undertaken by utilities as part of integration activities associated with mergers and acquisitions. These data indicate that there are few instances in which reorganizations target the T&D field force. This would almost certainly be the case for LIPA as it is unlikely that the management of a reorganized LIPA would risk compromising LIPA's high level of transmission and distribution system reliability. This is a materially important conclusion because it indicates that no adjustments (or a only a very minor one in the case of Privatization) were made to the roughly 1,088 FTEs involved in LIPA's T&D operations, meaning that under no option will there be a material impact on operating costs from changes in T&D staff levels.

Second, when utilities reorganize (particularly as part of mergers and/or acquisitions) reductions in headcount and labor cost are primarily associated with eliminating duplicative planning, corporate and administrative functions. Substantive cost savings in these areas will most likely be realized under the Privatization option because it would involve the merger or acquisition of LIPA with an investor-owned utility.

Third, the sharing of planning, corporate and administrative resources has both positive and negative consequences. LIPA has expressed varying levels of satisfaction with the sharing arrangement for certain services; notable concerns include lack of responsiveness in certain

functional areas and the absence in some functions of clearly-defined points of contact. However, sharing resources can lead to cost efficiencies which, when appropriately allocated among participating operating companies, should accrue in part to LIPA. Some additional headcount due to the loss of sharing arrangements will be required under the Municipalization and ServCo options.

Our fourth conclusion is less quantitatively oriented and deals primarily with the cultural and institutional dimensions of reorganizations. LIPA's current organization is able to leverage or benefit from the institutional expertise that is embedded within a large utility like National Grid. Such expertise may be lost, at least in part, if LIPA were to disassociate with a larger utility enterprise. In particular, we find that proven business and operational processes and procedures, such as those in customer accounting and service, and resident in a utility service provider or in comparison with an investor-owned utility, may need to be (re)designed or (re)developed under the Municipalization option. While it is possible that contractors or vendors with experience in particular areas, such as information technology (IT) or Power Markets, can be acquired to perform those functions, critical functions still will need to be internally provided on an ongoing basis. In addition, and not inconsequentially, the lack of embedded expertise with regard to a major systems deployment and implementation increases the risk associated with successful execution. Accordingly, as discussed later in this chapter, we made several modest adjustments to the level of FTEs in certain functional areas under the Municipalization option.

We present our analysis concerning the specific impacts that organizational restructuring will have upon the direct labor cost area in the sections below.

1. PRIVATIZATION

Chapter II provided a detailed breakdown of LIPA and National Grid FTEs in each of the 21 functional areas. Direct labor costs by functional area as well as average labor rates (i.e., direct labor cost per FTE on average) for these functional areas are shown in Table II-6.

The 2010 baseline direct labor cost is about \$158 million; FTEs involved in supporting LIPA operations add to 2,017, consisting of 104 FTEs directly employed by LIPA and 1,913 that support LIPA operations but are employed by National Grid.

We find that reductions in headcount will be most pronounced under the Privatization option. Our projections of staffing levels under the Privatization option are summarized in Table III-1.

Table III-1
Estimate of Direct Labor Dollars Serving LIPA Functions
Privatization

Functional Area	Adjustments to FTEs	2010 Incremental Direct Labor Cost (\$000)	2010 Privatization Total Direct Labor Cost (\$000)	
EE/DR/Renewables	(3)	(\$334)	\$334	\$5,186
Environmental Regulation	(3)	(\$334)	\$334	\$804
Regulatory, Rates, & Pricing	(5)	(\$570)	\$570	\$1,464
Customer Accounts & Services	(31)	(\$2,278)	\$2,278	\$26,689
Marketing & Sales	(5)	(\$556)	\$556	\$1,304
Media/Government Relations	0	\$0	\$0	\$1,032
Accounting & Finance	0	\$0	\$0	\$5,748
Finance: Risk	(3)	(\$230)	\$230	\$474
Legal	(5)	(\$584)	\$584	\$2,247
Power Markets	(15)	(\$1,669)	\$1,669	\$2,505
Facilities/procurement	(3)	(\$334)	\$334	\$4,753
IT	(11)	(\$1,194)	\$1,194	\$4,813
HR	(14)	(\$1,634)	\$1,634	\$2,289
Other/corporate	(10)	(\$1,160)	\$1,160	\$4,517
T&D Operations & Maintenance - Lines & Subs	0	\$0	\$0	\$24,434
T&D Maintenance - Veg Mgmt	0	\$0	\$0	\$833
T&D Operations - Service	0	\$0	\$0	\$14,464
T&D Operations - General/Other	(7)	(\$779)	\$779	\$22,732
T&D Operations - Systems	0	\$0	\$0	\$3,084
T&D Operations - Engineering	0	\$0	\$0	\$9,579
T&D Operations - Planning/Management	0	\$0	\$0	\$7,667
Total	(115)	(\$11,656)	\$11,656	\$146,619
T&D	(7)	(\$779)		\$82,794
Customer Services and Rates	(36)	(\$2,848)		\$28,154
Planning, Corporate, and Administrative	(72)	(\$8,029)		\$35,671
Sensitivities	Low	Mid	High	
Under/over-stated cost impact (% of mid case)	-20%		20%	
Incremental labor costs (\$000)	-\$13,987	-\$11,656	-\$9,324	
Incremental rate impact (¢/kWh)	-0.067	-0.056	-0.045	
Incremental rate impact (% of 2010 baseline)	-0.37%	-0.31%	-0.25%	

Note: Sensitivities are calculated on the absolute value ("abs") of the incremental direct labor cost which, in the case of Privatization, is the same as the net value.

As shown in the table, Privatization would affect staffing in most of the functional areas. All of the affected functional areas will realize a decrease in staffing levels, with the most notable impacts realized in the planning and corporate and administrative functions. The table also shows that, other than streamlining 7 management positions, we do not project staffing reductions in the T&D functional areas. Headcount reductions will be accommodated by two primary developments: a) increased efficiencies facilitated by upgraded IT systems and/or b) elimination of duplicative functions and back-office support.

The area of greatest headcount reduction under the Privatization option is projected to occur in the Customer Accounts and Services area, which would be reduced by 31 FTEs, from 446 to 415. This reduction is primarily due to anticipated increases in labor productivity derived from the introduction of a new customer information system. The new customer information system will produce efficiencies through, among other characteristics, more rapid customer data retrieval, enhanced integration with operations' systems, faster response to customer queries, and better tracking of customer representative effectiveness. These developments will allow for more rapid and efficient response by customer service representatives, which means that more inquiries can be handled by fewer staff. In addition, consolidating the customer service function with another electric utility will allow for the elimination of duplicative management positions, which will be assumed by the acquirer's existing management. These improvements are estimated to produce efficiency gains of approximately 10 percent in call centers, customer offices, and collections, which are well in-line with industry experience.

Another area of substantive reduction is in planning and corporate and administrative functions. Power Markets, for example, a critical function for LIPA, represents an opportunity for staff reduction on a consolidated basis. We assumed that the acquiring utility has power marketing management and expertise in place, and has fully staffed back, mid, and front office functions. The elimination of redundant positions in Power Markets in contract administration, forecasting, management, and support staff equate to an estimated reduction of 20% of current positions, or about 15 FTEs, in-line with industry practice and typical consolidations. Human resources (HR), IT, and other corporate functions are also likely to be affected. In fact, these corporate

support functions are typically among those that are most heavily affected by consolidation and such effects would be expected under implementation of the Privatization option. In addition, many of these corporate positions are currently located remotely (i.e., off of Long Island, or “off-island”); they are also typically composed of shared resources. The increase in expected efficiency of these functions is driven by elimination of duplicative support staff in areas such as communication, IT, benefits, and other similar work areas. A reduction of approximately 25%, or 35 FTEs, is consistent with experience, in-line with industry practices, and within expected norms.

The remaining reductions occur in a variety of functional areas but represent relatively limited adjustments. Projected reductions would also be realized in the functional areas that cover energy efficiency, demand response and LIPA’s initiatives involving renewable energy sources (referred to collectively in tables in this report as “EE/DR/Renewables”), as well as in the Environmental Regulation, and Regulatory Rates and Pricing functions. The labor reductions realized there are based on the elimination of staff associated with managing the service provider and minor consolidation efficiencies. As previously noted, with one exception, staffing in T&D Operations was not adjusted under any organizational restructuring scenario. Our reduction in T&D staffing here represents that one exception, although of a minor nature. Staffing was reduced by 7 FTEs in this category as the entirety of the staff are essentially involved in managing National Grid and the MSA. Privatization would eliminate the need for contract management and management oversight of the service provider; hence, the staff in this function (or an equivalent number of staff in the service provider) would not be required under the Privatization option.

The direct labor FTE reduction in the mid case totals 115, with an accompanying cost reduction of \$12 million. This equates to a reduction of approximately 0.056 cents per kWh (0.31%) in base rates. Sensitivity analyses were developed around the mid case of +/- 20 percent and result in direct labor incremental cost changes of -\$14 million in the low case, to -\$9 million in the high case, both of which represent reductions from the baseline estimates.

2. SERVCo

Table III-2 presents our analysis of staff level adjustments in the mid case for the ServCo option.

Table III-2
Estimate of Direct Labor Dollars Serving LIPA Functions
ServCo

Functional Area	Adjustments to FTEs	2010 Incremental Direct Labor Cost (\$000)	2010 Privatization Total Direct Labor Cost (\$000)	
EE/DR/Renewables	(3)	(\$334)	\$334	\$5,186
Environmental Regulation	3	\$262	\$262	\$1,400
Regulatory, Rates, & Pricing	6	\$681	\$681	\$2,716
Customer Accounts & Services	(26)	(\$1,956)	\$1,956	\$27,011
Marketing & Sales	0	\$0	\$0	\$1,860
Media/Government Relations	0	\$0	\$0	\$1,032
Accounting & Finance	10	\$1,113	\$1,113	\$6,860
Finance: Risk	(2)	(\$119)	\$119	\$586
Legal	0	\$0	\$0	\$2,831
Power Markets	15	\$1,669	\$1,669	\$5,844
Facilities/procurement	0	\$0	\$0	\$5,087
IT	(6)	(\$659)	\$659	\$5,349
HR	(5)	(\$584)	\$584	\$3,339
Other/corporate	0	\$0	\$0	\$5,677
T&D Operations & Maintenance - Lines & Subs	0	\$0	\$0	\$24,434
T&D Maintenance - Veg Mgmt	0	\$0	\$0	\$833
T&D Operations - Service	0	\$0	\$0	\$14,464
T&D Operations - General/Other	0	\$0	\$0	\$23,511
T&D Operations - Systems	0	\$0	\$0	\$3,084
T&D Operations - Engineering	0	\$0	\$0	\$9,579
T&D Operations - Planning/Management	0	\$0	\$0	\$7,667
Total	(8)	\$75	\$7,376	\$158,350
T&D	-	\$0		\$83,572
Customer Services and Rates	(20)	(\$1,274)		\$29,728
Planning, Corporate, and Administrative	12	\$1,349		\$45,050
Sensitivities	<u>Low</u>	<u>Mid</u>	<u>High</u>	
Under/over-stated cost impact (% of mid case)	-20%		20%	
Incremental labor costs (\$000)	-\$1,400	\$75	\$1,550	
Incremental rate impact (¢/kWh)	-0.007	0.000	0.007	
Incremental rate impact (% of 2010 baseline)	-0.04%	0.00%	0.04%	

Note: Sensitivities are calculated on the absolute value ("abs") of the incremental direct labor cost.

Most functional areas are projected to have some change in resource levels under the ServCo option, with the clear exception of T&D related functions. We projected staff adjustments in 9 of the 14 non-T&D functional areas. Unlike Privatization, staff adjustments under the ServCo option reflect a combination of increases and decreases to staff. This ranges from an increase in Power Markets staff (+15 FTEs) to a decrease in Customer Accounts and Services (-26 FTEs). The net result is an overall reduction of 8 FTEs, representing a net increase of \$75,000 in total direct labor costs. The nominal increase in costs accompanying a decrease in FTEs is driven by the fact that changes in labor costs reflect the average cost of the positions in the specific functional areas affected, which, as shown, vary by functional area. Given that FTEs are adjusted in many areas and that average costs per FTE vary by area, and that there is a relatively low total FTE adjustment, it is not surprising the net results produce a seemingly anomalous, but consistent result of lower staff numbers but slightly higher costs.

The largest adjustment is made to Customer Accounts and Services, which has been reduced by 26 FTEs, 20 of which are non-management staff. The rationale underlying the reduction is similar to that under the Privatization option: a new customer information system is anticipated to be implemented, thereby generating increased efficiencies in a number of areas, such as data retrieval, enhanced integration with operations' systems, faster response to customer queries, and better tracking of customer representative effectiveness. In addition, it was estimated that 6 positions would be unnecessary due to a reduction in management staff associated with the new contractual arrangements. It is worth noting that under the ServCo option, the non-management reduction of 20 FTEs is less than that anticipated under Privatization, where a reduction of 25 FTEs was projected. The reduction under ServCo reflects the consideration that the incentive to reduce staff in a ServCo organization is not as pronounced as it would be under a privatized IOU model.

Two other areas that saw substantive changes in FTE levels under the ServCo option were Power Markets and Accounting and Finance. In Power Markets, it was estimated that under ServCo an additional 15 FTEs, or approximately 20% of the current staffing level, would be required. This increase is driven by a number of factors, including the increasing number and complexity of power contracts, an expanding number of products and services being offered by

the New York and PJM RTOs, the continual evolution of rules and regulations in those markets, and the ever-increasing need for specialized market expertise and software to understand and effectively participate in those markets. These circumstances will be the case under each of the strategic options considered. However, unlike the situation under the Privatization option, where the acquirer will provide much of the needed expertise and resources through the leverage of its existing platform, the ServCo option will require additional staff. We estimated that approximately 44 of the 58 total National Grid resources in this function are shared, and of that shared total, perhaps one-third are located off-island. Thus, it can also be expected that the formation of ServCo, with a dedicated work force, will create a need for a higher proportion of dedicated, on-island resources within Power Markets. This projected expansion of staff is consistent with the noted factors and with the importance of this function, particularly as Power Markets is responsible for managing a large share of LIPA's total costs as represented by fuel and power purchases.

The Accounting and Finance functional area performs a number of functions, including: accounting & financial reporting; regulatory reporting; debt management; contract management & disputes; interface with National Grid (billing & payment processing; receipt and management of financial data from National Grid); and back-office support for the rest of LIPA. LIPA's accounting staff has identified several incidents in which the current service provider has not completely met its needs and requests, which suggests that the service provider is likely understaffed in some areas. In addition, LIPA would need to form separate tax and internal auditing departments, and add a process to provide rebates for its energy efficiency programs to Accounts Payable, among other increased responsibilities if it operated in a dedicated ServCo environment. Additional staff is anticipated to provide for better coordination and accountability and overall higher quality service. In addition, it was estimated that all of National Grid's Accounting and Finance staff represent shared resources, which would produce some need for enhanced staffing within ServCo's dedicated work force. The analysis resulted in a projection that the formation of ServCo would require the addition of 10 FTEs, or approximately 15% of the baseline total.

Other, smaller, adjustments in staff levels were made to some of the remaining functional areas with the largest of these adjustments occurring in Regulatory, Rates and Pricing (RR&P) (an

increase of 6 FTEs), IT (a reduction of 6 FTEs), and HR (a reduction of 5 FTEs). RR&P is responsible for pricing & rate design, load forecasting, load research, and attachments (i.e., agreements with other entities, such as cable or telephone companies, that want to “attach” wires or appendages to LIPA poles, or substations). There is a likely substantial increase in work load due to the increasing use of interval meter data and the ancillary activities attendant to that function, such as in pricing and rate design, as well as the fact that the formation of ServCo may result in some loss of service provider expertise, thereby requiring additional, incremental staff. In terms of HR and IT, all of the National Grid staff (28 FTEs in HR and 50 FTEs in IT) are shared, with approximately 50% of those shared staff located off-island. Interviews with LIPA management indicated that there are also some service quality concerns and interface challenges in these areas, mostly due to differences in systems and corporate strategies. Consequently, the formation of ServCo is anticipated to allow for greater management focus, an increased number of dedicated resources and efficiency improvements.

We also conducted sensitivity analyses around the net change in direct labor costs of \$75,000. As in Privatization, we assumed costs might be +/- 20%. However, sensitivity analyses around a net number that is the result of the addition of positive and negative adjustments, as in the ServCo option (unlike that in Privatization where all the adjustments were in one direction - negative), requires that the absolute value of the costs of the adjustments be used as the basis for the sensitivity calculation. By way of example, if two functions have a staff complement of 10 each, and one is increased by 5, and the other decreased by 5, the net change is 0. A sensitivity adjustment on the net number would only produce a 0 value. Clearly, this would be an incorrect result. Therefore, the proper methodology is to take the absolute value of each change (i.e., 5) and add them together to produce a value of 10, which then forms the basis for the sensitivity calculation. Using +/- 20% range would produce a sensitivity result of +/- 2 FTEs around the net change of 0. Similarly, we have used the same methodology in the ServCo option and arrive at a low and high sensitivity, as shown in Table III-2, of -\$1 million and +\$2 million, respectively.

3. MUNICIPALIZATION

Table III-3 presents our analysis of staff level adjustments in the mid case for the Municipalization option.

Table III-3
Estimate of Direct Labor Dollars Serving LIPA Functions
Municipalization

Functional Area	Adjustments to FTEs	2010 Incremental Direct Labor Cost (\$000)	2010 Privatization Total Direct Labor Cost (\$000)	
EE/DR/Renewables	(3)	(334)	334	\$5,186
Environmental Regulation	3	\$262	\$262	\$1,400
Regulatory, Rates, & Pricing	6	\$681	\$681	\$2,716
Customer Accounts & Services	(16)	(\$1,312)	\$1,312	\$27,655
Marketing & Sales	0	\$0	\$0	\$1,860
Media/Government Relations	0	\$0	\$0	\$1,032
Accounting & Finance	15	\$1,669	\$1,669	\$7,417
Finance: Risk	3	\$178	\$178	\$882
Legal	0	\$0	\$0	\$2,831
Power Markets	15	\$1,669	\$1,669	\$5,844
Facilities/procurement	2	\$223	\$223	\$5,309
IT	15	\$1,624	\$1,624	\$7,631
HR	10	\$1,167	\$1,167	\$5,090
Other/corporate	5	\$583	\$583	\$6,260
T&D Operations & Maintenance - Lines & Subs	0	\$0	\$0	\$24,434
T&D Maintenance - Veg Mgmt	0	\$0	\$0	\$833
T&D Operations - Service	0	\$0	\$0	\$14,464
T&D Operations - General/Other	0	\$0	\$0	\$23,511
T&D Operations - Systems	0	\$0	\$0	\$3,084
T&D Operations - Engineering	0	\$0	\$0	\$9,579
T&D Operations - Planning/Management	0	\$0	\$0	\$7,667
Total	55	\$6,411	\$9,702	\$164,686
T&D	-	\$0		\$83,572
Customer Services and Rates	(10)	(\$630)		\$30,372
Planning, Corporate, and Administrative	65	\$7,041		\$50,742
Sensitivities	<u>Low</u>	<u>Mid</u>	<u>High</u>	
Under/over-stated cost impact (% of mid case)	-20%		20%	
Incremental labor costs (\$000)	\$4,471	\$6,411	\$8,352	
Incremental rate impact (¢/kWh)	0.022	0.031	0.040	
Incremental rate impact (% of 2010 baseline)	0.12%	0.17%	0.22%	

Note: Sensitivities are calculated on the absolute value ("abs") of the incremental direct labor cost.

Similar to ServCo, most functional areas, with the notable exception of T&D, are anticipated to experience some change in FTE levels if LIPA were to municipalize. Of the 14 non-T&D functional areas, 11 are anticipated to see staff adjustments, with only two (EE/DR/Renewables and Customer Accounts and Services) expected to see reductions in staff. Total FTEs under Municipalization are projected to increase by 55, increasing total direct labor costs by about \$6 million. (By comparison, Privatization resulted in a decrease of 115 FTEs and a decrease of \$12 million in direct labor costs, and ServCo saw a decrease of 8 FTEs and an increase of \$75,000 in direct labor costs.) Given the baseline direct labor costs of \$158 million, Municipalization is estimated to increase total direct labor costs by 0.17%.

As was the case under the Privatization and ServCo options, the greatest reduction in staff was in Customer Accounts and Services, which saw a reduction of 16 FTEs. The reduction largely was driven by the installation of a new customer information system, which is expected to increase efficiencies in, among other areas, data retrieval, integration with operations' systems, faster response to customer queries, and better tracking of customer representative effectiveness. This system is anticipated to allow for the reduction of approximately 20 FTEs. Further, it was estimated that 6 positions currently associated with managing the service provider and the contract terms and conditions, would be unnecessary. However, as noted, implementing the Municipalization option carries with it the assumed loss of embedded institutional experience and expertise, as well as the loss of leverage that could be applied to system procurement and to a design and implementation vendor because of scale considerations. In addition, and in particular with regard to one of the more complex and critical IT systems within a utility (i.e., the Customer Accounting System), the lack of direct implementation experience or the ability to leverage a service provider's expertise in this area is considered a handicap. The loss of this expertise and leverage was considered to result in an incremental addition of 10 FTEs, which brings the net Customer Accounts and Services total to the aforementioned reduction of 16 FTEs.

Power Markets, Accounting and Finance, and IT were estimated to result in incremental additions of 15 FTEs each, and HR was estimated to increase 10 FTEs. The logic supporting the additional FTEs in Power Markets is the same as that described under ServCo. Namely, the increasing number and complexity of power contracts that LIPA is and will be managing, the

expanding number of products and services being offered by the New York and PJM RTOs, the continual evolution of rules and regulations in those markets, and the ever increasing need for specialized market expertise and software to understand and effectively participate in those markets. Also, as under the ServCo option, it was estimated that approximately 44 of the 58 total National Grid resources in this function are shared, and of that shared total, perhaps one-third are located off-island. Thus, it can be expected that Municipalization, with a dedicated work force, will create a need for a higher proportion of dedicated and on-island resources within Power Markets. Also, as was the case for ServCo, this projected expansion of staff is consistent with the importance of this function, particularly as it pertains to the large share of LIPA's total costs that are represented by fuel and power purchases.

The basis for adjustments to Accounting and Finance staffing are, again, similar to that for ServCo. The results of the analysis indicated that there was an indication that National Grid's current level of staffing to support LIPA's operations is below appropriate scale, largely because it has not met the level of service requested by LIPA. In addition, as discussed earlier, a fully municipalized LIPA would need to form separate tax and internal auditing departments, and add a process to provide rebates for its energy efficiency programs to Accounts Payable, among other increased responsibilities. In addition, it was estimated that all National Grid's Accounting and Finance staff represent shared resources, which would produce some need for enhanced staffing within a fully municipalized work force. Additional staff is anticipated to provide for better coordination and accountability and overall higher quality service. However, similar to Customer Accounts and Services, the loss or lack of institutional expertise and leverage is anticipated to cause a need for a larger incremental staff complement than under the ServCo option. Therefore, FTE incremental adjustments totaled an additional 15 (relative to 10 for ServCo).

In terms of HR and IT, all of National Grid staff (28 FTEs in HR and 50 FTEs in IT) are shared resources with approximately 50% of those shared staff located off-island. As mentioned previously, there are also some interface difficulties in these areas. We anticipate an increase of 25 FTEs (15 in IT and 10 in HR) under the Municipalization option. This differs from our projection under the ServCo option where we anticipate a reduction of FTEs in the HR and IT functional areas. LIPA's current HR and IT support a relatively small organization. Gearing

those departments up to support a much larger and complex fully municipalized LIPA will require some staff additions. Some of these will likely be transferred from National Grid while others will need to be recruited.

The HR function of a fully municipalized LIPA will be responsible for the recruiting process for a much larger organization. It will also be responsible for senior management recruitment and retention. This will likely require significant effort initially, and will also be an area of focus on an ongoing basis. LIPA's expanded HR function will also require additional resources to coordinate and, in some instances, develop training programs within the new and larger organization.

IT, like HR, will face similar challenges in terms of lost expertise and experience, concomitant with the need to develop, manage, and implement new systems and platforms, such as the customer information and finance and accounting systems.

Other, smaller, adjustments in staff levels were made to some of the remaining functional areas with the largest of these adjustments occurring in Regulatory, Rates and Pricing (RR&P), which shows an increase of 6 FTEs. There is a likely substantial increase in work load due to the increasing use of interval meter data and the ancillary activities attendant to that function, such as in pricing and rate design. Also, the formation of a fully municipalized utility is anticipated to result in the loss of some shared resource expertise, thereby requiring additional, incremental staff.

We also conducted sensitivity analyses around the net increase in direct labor costs of \$6 million. As was the case under the Privatization and ServCo options, we assumed costs might be +/- 20% around the mid case results. Similar to the case for ServCo, we used the methodology that incorporated the absolute value of the direct labor incremental costs to determine the appropriate sensitivity values. As shown in Table III-3, the absolute value of the incremental direct labor in the mid case is about \$10 million. The low and high sensitivities translate to about +\$4 million and +\$8 million, respectively.

B. PENSIONS AND BENEFITS

As discussed in Chapter II, Pensions and Benefits represent an important and substantive element of labor-related costs. The total pensions and benefits expense (for LIPA and National Grid combined) in 2010 was roughly \$138 million. When added to the cost of direct labor (approximately \$158 million), the total of labor-related expenses in 2010 was roughly \$296 million. As previously noted, while benefits calculations are relatively straightforward, those associated with pensions and other post-employment benefits (OPEBs) are more complex, in terms of accounting and actuarial analysis. In addition, LIPA and National Grid have different retirement plans, and the National Grid work force is composed of a combination of bargaining unit and management personnel, which fall under separate plans.

As previously described, we calculated the percentage of LIPA's (i.e., excluding National Grid) total benefits and pension costs relative to its direct labor costs. That percentage was 58% in 2009 and 68% in 2010. Similar calculations were made for National Grid, which resulted in finding that total benefits and pension costs were 89% of direct labor costs in 2009. On the surface, this would suggest that LIPA's pension plan, part of the New York State and Local Retirement System, may be less expensive than National Grid's plan. However, we found that National Grid made substantial charges to LIPA in 2009 and 2010. These charges appear to be adjustments, currently subject to review by LIPA.⁵ Consequently, we removed these adjustments and calculated a revised National Grid pensions and benefits percentage of direct costs. That percentage was 45%. In combination, National Grid's and LIPA's pensions and benefits costs are approximately 46%⁶ of direct labor costs, which we used for our baseline estimate.

1. PRIVATIZATION

We assumed that the pensions and benefits plans would remain unchanged from current levels if the Privatization option were to be implemented. It was also assumed that the incremental cost of pensions and benefits under the mid case for Privatization would be the current (adjusted)

⁵ We did not have direct access to National Grid personnel during the course of our study. It is our understanding that LIPA staff reviews and discusses such adjustments to pension and benefits charges to ensure that they are appropriate under the terms and conditions of the MSA.

⁶ Actual percentage is 46.138.

average of the combined LIPA and National Grid plans, which is 46% of direct labor costs. Applying this percentage to the incremental mid case direct labor cost reduction of \$12 million yields a reduction in benefits and pensions of \$5 million, as shown in Table III-4. The table also shows the effects to pensions and benefits in the mid case if the benefits and pension to direct labor ratio were to change to either 58% or 68%, representing LIPA's 2009 and 2010 costs.

Table III-4
Pensions and Benefits Costs
Privatization

Ratios: P+B / Direct Labor Cost	Adjusted P+B Costs (\$000)	P+B Cost Per FTE (\$)	Incremental P+B Costs (\$000)	Incremental P+B Per FTE (\$)	Rate Impact (¢/kWh)	% of 2010 Baseline Rate
46%	\$67,647	\$35,569	(\$5,378)	(\$2,828)	-0.026	-0.14%
58%	\$84,963	\$44,673	\$11,938	\$6,277	0.057	0.32%
68%	\$100,275	\$52,724	\$27,250	\$14,328	0.131	0.72%
Privatization Option Direct Labor Costs (Mid Case)	\$146,619					
Baseline P+B Costs (excl. Catch Up)	\$73,025					
Privatization Option FTEs	1,902					
2010 Baseline Rate (cents per kWh)	18.173					
	<u>Low</u>	<u>Mid</u>	<u>High</u>			
Low/Mid/High Direct Labor Costs	(\$13,987)	(\$11,656)	(\$9,324)			
Low/Mid/High P+B/Direct Labor Cost Ratio	46%	46%	46%			
Low/Mid/High Incremental P+B Costs	(\$6,453)	(\$5,378)	(\$4,302)			

The pensions and benefits impacts estimated for the mid, low and high cost cases were calculated by taking the direct labor costs for the mid, low and high cost cases for the Privatization option and multiplying by the corresponding benefits and pension to direct labor ratios. As indicated above, we used a ratio of 46% for each of the mid, low and high cost cases for the Privatization option. This reflects our assumption that an acquirer would not attempt to reduce pension costs nor would it be incented to increase those costs.

As indicated in the table, the resulting benefit and pension impact in the low cost case is a reduction of \$6 million, while in the high cost case, the associated reduction in benefit and pension expenses is projected to be \$4 million.

2. SERVCO

Similar to the Privatization option, the pensions and benefits plans under ServCo were assumed to remain unchanged. The assumption is considered reasonable given that there is no indication that LIPA is anticipating changes to its plan, or that the service provider under the new ServCo will seek to adjust the plans. Therefore, the mid case adjustment for pensions and benefits is based on the current ratio of 46% applied to the mid case direct labor costs. As shown in Table III-5, this resulted in an incremental adjustment to benefits and pensions of only +\$35,000.

Table III-5
Pensions and Benefits Costs
ServCo

Ratios: P+B / Direct Labor Cost	Adjusted P+B Costs (\$000)	P+B Cost Per FTE (\$)	Incremental P+B Costs (\$000)	Incremental P+B Per FTE (\$)	Rate Impact (¢/kWh)	% of 2010 Baseline Rate
46%	\$73,060	\$36,369	\$35	\$17	0.000	0.00%
58%	\$91,761	\$45,678	\$18,736	\$9,326	0.090	0.50%
68%	\$108,298	\$53,910	\$35,273	\$17,558	0.170	0.93%
ServCo Option Direct Labor Costs (Mid Case)	\$158,350					
Baseline P+B Costs (excl. Catch Up)	\$73,025					
ServCo Option FTEs	2,009					
2010 Baseline Rate (cents per kWh)	18.173					
	Low	Mid	High			
Low/Mid/High Direct Labor Costs	(\$1,400)	\$75	\$1,550			
Low/Mid/High P+B/Direct Labor Cost Ratio	46%	46%	46%			
Low/Mid/High Incremental P+B Costs	(\$646)	\$35	\$715			

High and low cases were also developed based on the high and low case incremental direct labor cost adjustments.⁷ It was assumed that the 46% benefits and pension ratio applicable in the mid case would hold in both the high and low cases, a reasonable assumption given that there is no apparent impetus or rationale to support changing or modifying these plans in the near future. The sensitivity cases resulted in a reduction of benefits and pension costs of \$646,000, and an increase of \$715,000 in the low and high cases, respectively.

⁷ Note that the adjustments to direct labor costs in the low and high cases, as previously discussed, reflect the use of the absolute value of incremental direct labor adjustments for each functional area.

3. MUNICIPALIZATION

The mechanics of calculating adjustments to benefits and pension costs under Municipalization, given changes in direct labor costs, are similar to those under the Privatization and ServCo options, with one important difference. As previously discussed, current National Grid employees provide service to LIPA operate under a pensions and benefits plan different than that for LIPA. LIPA's employees are included in the New York State program, while National Grid employees are covered by a different, privately administered plan. A fundamental assumption of the Municipalization option is that all staff would become employees of LIPA, hence the current National Grid plan would need to be transferred and become part of the New York State and Local Retirement System (NYSLRS). There is some uncertainty as to whether such a transfer would be mandated, or whether there might be a way to maintain the current National Grid benefits and pension cost structure, which, as shown earlier, is approximately 46% of direct labor costs. Conversely, it is possible that the transfer would entail bringing current National Grid employees into the New York State plan at LIPA's higher rates of 58% or 68% for 2009 and 2010, respectively. A final determination of that issue is well beyond the scope of this study and could even entail legislative clarification and/or actions.

Given the above, the potential choices for calculating the costs of plan changes with respect to the possible implementation of the Municipalization option are the following:

- 1) use the current benefits and pensions to direct labor cost ratio of 46% associated with the combined LIPA and National Grid plans;
- 2) use LIPA's 2009 ratio of 58%; or
- 3) use LIPA's 2010 ratio of 68%.

We adopted the assumption that a fully municipalized LIPA would require the transfer of current National Grid employees into LIPA and that those employees would be required to be included in the NYSLRS. We then used the ratio of benefit and pension expenses to direct labor expenses of 58% (LIPA's realized ratio for 2009) in estimating the benefit and pension impacts for the mid cost case for the Municipalization option. As shown below, adoption of this ratio results in an annual increase in benefits and pension costs of \$22 million.

Table III-6
Pensions and Benefits Costs
Municipalization

Ratios: P+B / Direct Labor Cost	Adjusted P+B Costs (\$000)	P+B Cost Per FTE (\$)	Incremental P+B Costs (\$000)	Incremental P+B Per FTE (\$)	Rate Impact (¢/kWh)	% of 2010 Baseline Rate
46%	\$75,983	\$36,674	\$2,958	\$1,428	0.014	0.08%
58%	\$95,432	\$46,061	\$22,407	\$10,815	0.108	0.59%
68%	\$112,631	\$54,362	\$39,606	\$19,116	0.191	1.05%
Muni Option Direct Labor Costs (Mid Case)	\$164,686					
Baseline P+B Costs (excl. Catch Up)	\$73,025					
Muni Option FTEs	2,072					
2010 Baseline Rate (cents per kWh)	18.173					
	<u>Low</u>	<u>Mid</u>	<u>High</u>			
Low/Mid/High Direct Labor Costs	\$4,471	\$6,411	\$8,352			
Low/Mid/High P+B/Direct Labor Cost Ratio	46%	58%	68%			
Low/Mid/High Incremental P+B Costs for New Staff	\$2,063	\$3,715	\$5,712			
Low/Mid/High Incremental P+B Costs for Existing Staff	<u>\$0</u>	<u>\$18,692</u>	<u>\$35,221</u>			
Total	\$2,063	\$22,407	\$40,933			

As indicated above, we recognize that it is possible that an alternate approach may be worked out, including the possibility that organizational or other arrangements may allow for current National Grid employees to retain their current benefit and pension plans. We thus included a low cost case in which pension levels stayed at their current level (with no increase on a per employee basis). We include this as a low cost case in which the ratio of benefits and pensions to direct labor is equal to 46%, the current ratio for the combined LIPA and National Grid work force.

We also developed a high cost case in which the ratio of benefits and pensions to direct labor is equal to 68% (the ratio observed for LIPA for 2010).

The adoption of this wide range of ratios is, we believe, reasonable given the high degree of uncertainty regarding the treatment of plan transfer. The mid cost case results in an increase in benefit and pension expenses of approximately \$22 million, while the low and high cases result in increases in benefits and pension expenses of \$2 million and \$41 million, respectively.

Changes in benefit and pension expenses are driven by two factors; the use of different benefits and pension to direct labor cost ratios (i.e., 46% and 68%), as well as the fact that those ratios are applied to the entire staff complement, not just the relatively small number of FTE additions.

C. PROFITS

Profits to the current service provider under the existing organizational structure are explicit and, potentially, implicit. Profits are explicit to the degree that they are derived from the MSA, which means that to the extent National Grid can provide service under the current fixed fee arrangement at a cost lower than its internal costs, it generates a profit. Profits may be implicit in the sense that certain costs to National Grid of staff or operations are either absorbed by LIPA (e.g., shared resources) or would be higher without LIPA (e.g., meter reading, purchasing economies).

As discussed in Chapter II, LIPA in 2010, LIPA paid National Grid approximately \$436 million in O&M related expenses. It also paid National Grid under the terms of the Power Supply Agreement (PSA). In total, O&M related payments to National Grid in 2010 (which do not include payments associated with the pass-through of capital-related costs) were roughly \$882 million. We estimated that profits to National Grid for 2010 were approximately \$29 million.

1. PRIVATIZATION AND MUNICIPALIZATION

Under Privatization, it is assumed that the acquirer would still seek to “profit” from its investment in LIPA. However, such anticipated profit would be embedded in its purchase price; therefore, anticipated profit is not relevant to our analysis of incremental change in operating expense. In terms of incremental change, the obvious and only conclusion is that the baseline profit component of \$29 million would be eliminated in all cases (i.e., mid, low and high).

Similar logic applies in the case of Municipalization. There will be no profit component under a fully municipalized LIPA structure, so the baseline profit cost of \$29 million is also eliminated.

2. SERVCo

The ServCo contract will include a profit component. As indicated above, we estimated that the profit level under the current MSA for 2010 was approximately \$29 million. For the mid and low cases under the ServCo option, we assumed a profit level of \$30 million, resulting in a nominal incremental increase of about \$1 million from the baseline in each case. For the high case, we estimated that the profit component might reach \$55 million, or slightly less than double the current estimate, resulting in an incremental change of \$26 million.

D. NON-LABOR O&M

Non-labor related costs include annual expenses for items such as materials, outside services, systems, and fleet leases, and comprise a significant percentage of costs associated with T&D Operations and Maintenance. As described in Chapter II and detailed in Appendix D, total non-labor costs for LIPA (including both LIPA and National Grid) were \$205 million in 2009 and \$232 million in 2010. Roughly 37% of the total expenditures on non-labor O&M expenses were incurred directly by LIPA, with the remainder paid by National Grid. A detailed breakdown of non-labor expenses by functional area and category is shown in Appendix D, and described more fully in Chapter II, but it is useful to highlight some of the more salient characteristics of non-labor O&M.

First, materials and supplies constitute the largest percentage of non-labor costs. In 2009, materials and supply charges totaled over \$81 million, or almost 40% of total non-labor expenses. Over \$59 million of these materials and supply costs were incurred in the Energy Efficiency/Demand Response/Renewables (EE/DR/Renewables) functional area. Those charges were associated with pass-through payments to suppliers for performance related to EE/DR/Renewables programs.

Second, 2009 charges associated with outside services and contractors totaled over \$58 million, or approximately 28% of 2009 total charges. Almost 45% of the outside services and contractor costs were incurred in the T&D functional areas. The largest cost category here was associated with vegetation management.

Finally, total non-labor O&M costs for 2010 of approximately \$232 million is almost exactly equal to the 2010 baseline component of direct labor plus pension and benefits cost of about \$231 million. (Note that the 2010 direct labor plus pension and benefits cost used here excludes the “benefits catch up charge” of \$65 million.) The ratio of direct labor plus pension and benefits costs to non-labor O&M, thus, is almost exactly 1:1.

Examining the ratio of non-labor O&M to labor-related O&M is an informative metric that is usually considered in utility budgeting and financial planning exercises. The ratio suggests, assuming it holds year-on-year, that a change in direct labor costs is proportionately reflected in non-labor costs. That means, for example, that an increase of \$1 in direct labor costs will be reflected by an increase of \$1 in non-labor costs, assuming a 1:1 ratio of direct labor to non-labor. The notion of a relationship between direct labor and non-labor is sensible. Increases in work force size generally mean that there is a greater work load and, all other things being equal, will be accompanied by additional expenses in non-labor costs in areas such as materials, systems, leases and fleets.

Naturally, the ratio varies from utility to utility, partly for operational reasons, and partly for accounting reasons, and will vary year-to-year depending on circumstances. However, this ratio is typically quite consistent; while there is no target ratio that utilities strive to meet, a ratio of 1:1 is not unusual. It is reasonable, then, to assume that a direct labor to non-labor ratio will hold at LIPA and can be used to calculate the incremental costs of non-labor O&M given direct labor changes.

Our analysis went deeper than examining the ratio at an aggregate level, by assigning non-labor O&M costs to functional areas and cost categories, directly analogous to the breakdown performed for direct labor costs. This disaggregation of LIPA’s non-labor O&M costs identified that the costs associated with EE/DR/Renewables functional area included the previously noted 2009 charge of approximately \$60 million. Since further investigation revealed that these costs were almost entirely related to pass-through payments associated with demand response and energy efficiency payments, we concluded that it was reasonable to exclude the EE/DR/Renewables non-labor cost when determining the appropriate ratio to use in calculating the non-labor O&M impact of a change in direct labor. Essentially, we normalized

the 2009 non-labor O&M total by excluding the EE/DR/Renewables costs from the calculation of the ratio. Excluding these costs resulted in direct labor plus benefits to non-labor O&M ratio of 1:0.71, meaning that for every \$1 incremental change (increase or decrease) in labor costs, non-labor costs changed by \$0.71 in the same direction.

Table III-7 shows the result of the calculation. Note that Table III-7, for illustrative purposes, also presents the results if different ratios were employed. The two additional ratios used were 1:1, and 1:0.80, the latter reflecting the exclusion of T&D non-labor O&M.

Table III-7
Non-Labor O&M Costs
All Options

	Privatization Option			ServCo Option			Municipalization Option		
	Low Case (\$000)	Mid Case (\$000)	High Case (\$000)	Low Case (\$000)	Mid Case (\$000)	High Case (\$000)	Low Case (\$000)	Mid Case (\$000)	High Case (\$000)
Incremental Direct Labor	(\$13,987)	(\$11,656)	(\$9,324)	(\$1,400)	\$75	\$1,550	\$4,471	\$6,411	\$8,352
<u>Incremental Pensions + Benefits (at baseline benefits-to-labor ratio*)</u>	<u>(\$6,453)</u>	<u>(\$5,378)</u>	<u>(\$4,302)</u>	<u>(\$646)</u>	<u>\$35</u>	<u>\$715</u>	<u>\$2,063</u>	<u>\$2,958</u>	<u>\$3,853</u>
Incremental Total Labor O&M	(\$20,440)	(\$17,033)	(\$13,627)	(\$2,046)	\$110	\$2,266	\$6,533	\$9,369	\$12,205
<u>Incremental Non-Labor O&M Adjustment</u>									
1:1 Labor / Non-Labor	(\$20,440)	(\$17,033)	(\$13,627)	(\$2,046)	\$110	\$2,266	\$6,533	\$9,369	\$12,205
1:0.80 Labor / Non-Labor (excludes T&D non-labor O&M)	(\$16,254)	(\$13,545)	(\$10,836)	(\$1,627)	\$87	\$1,802	\$5,195	\$7,450	\$9,705
1:0.71 Labor / Non-Labor (excludes EE/DR non-labor O&M) (excludes impact of increased pension rates in municipalization option)	(\$14,424)	(\$12,020)	(\$9,616)	(\$1,444)	\$78	\$1,599	\$4,611	\$6,612	\$8,613

1. PRIVATIZATION

Applying the ratio of 1:0.71 to the mid case results in a reduction of non-labor O&M costs of \$12 million. High and low cases, reflective of sensitivities of +/- 20% around mid-case incremental total labor O&M costs, result in reductions of \$10 million and \$14 million, respectively.

2. SERVCO

Applying the ratio of 1:0.71 to the mid case results in a nominal increase of non-labor O&M costs of \$78 thousand. High and low cases, reflective of sensitivities of +/- 20% around mid-

case incremental total labor O&M costs,⁸ result in an increase of about \$2 million and a reduction of about \$1 million, respectively.

3. MUNICIPALIZATION

Applying the ratio of 1:0.71 to the mid case results in an increase of non-labor O&M costs of about \$7 million. High and low cases, reflective of sensitivities of +/- 20% around mid-case incremental total labor O&M costs, result in increases of \$9 million and \$5 million, respectively.⁹

E. FACILITIES

LIPA's T&D operations, like other sizeable electric utilities, require substantial amounts of space in a variety of facility types, such as offices, warehouses, depots, and training centers, to safely and efficiently conduct operations. Facility costs in the form of lease and/or rental payments or depreciation of capitalized facility costs are relevant under any organizational structure. Estimates of current usage (i.e., square footage) and cost (\$ per square foot), however, were not readily available from the FDM, the primary data source of our analysis. While the FDM did include some cost information regarding leases and rents, it was not clear to what those charges related. In addition, it was apparent from discussions with LIPA management that the charges that were identified, approximately \$2 million as shown in the rents/leases category of National Grid's O&M non-labor accounts, were not the full facility costs to LIPA or, more importantly, what the costs to LIPA are likely to be under any of its organizational alternatives. Therefore, estimates of facility costs were developed using a secondary approach, in which we estimated the annual lease or rental expenses which would be incurred on an incremental basis under the strategic organizational options.

We estimated the annual market (lease or rental) cost of the facilities provided by National Grid under the MSA by taking as a starting point a list of facilities used to support LIPA operations compiled by LIPA and Navigant Consulting in late 2010. This study included square footage estimates of each facility along with estimated market lease rates based on real estate

⁸ Using the absolute value methodology previously discussed.

⁹ Note that these values exclude the impact of increased pension and benefit rates under the Municipalization option.

comparables. In total, the study identified 42 buildings on 17 sites that are either fully or partially dedicated to LIPA operations. These included the following; Training Facilities, Warehouse/Transport, Cafeteria, District Offices, Customer Service Centers, and a Call Center.

We expanded upon this prior analysis by recognizing the shared use of facilities for non-LIPA related activities and by associating facility use with each of LIPA's functional areas. We classified the list of buildings identified as supporting LIPA operations as either office space or specialized use (e.g. warehouses, repair garages, cafeteria, etc).

The office space component was determined to be a function of the number of "non-field" personnel supporting LIPA. Using a combination of data from the FDM and corroborating interviews with LIPA managers, we estimated the number and location of FTEs supporting each of LIPA's functional areas. These FTEs were then classified as either "field" or "non-field" personnel. The necessary office space for non-field personnel was then determined by multiplying non-field FTE count by an average employee space requirement of 230 square feet per FTE.¹⁰ This space requirement was based on a Government Services Administration (GSA) survey.¹¹ Space requirements for each functional area were then multiplied by comparable market values (on a \$ per square foot basis) associated with that facility as identified in the Navigant study, which generated an office space cost for each functional area.

In addition to office space, LIPA makes use of a number of specialized facilities including a training center, warehouses, repair garages, and fuel stations. In contrast to LIPA's office space requirement, specialized use facilities are not driven by FTE counts. Their size is either fixed or impacted by other factors. Our analysis assumed that LIPA would absorb the full extent of these facilities. Using the square foot estimates and prevailing market (lease or rental) rates provided in the Navigant study, we calculated the annual market cost of special use assets. This figure was then combined with the office space requirement to determine a total space requirement and associated annual cost.

The results of this analysis are shown in Table III-8, below.

¹⁰ Field personnel were not allocated facilities space (over and above warehouse, repair garage, fuel depots).

¹¹ http://www.gsa.gov/graphics/ogp/spaceuse_2002_R2P52_0Z5RDZ-i34K-pR.pdf

Table III-8
Annual Facilities Costs
All Options

Functional Area	National Grid Field (FTEs)	National Grid Non- Staff (FTEs)	Required Office Space @ 230 sq ft/FTE (sq ft)	Estimated Office Space Cost (\$/sq ft/yr)	Other Space Required (warehouse, cafeteria, and training areas) @ Blended sq ft/FTE (sq ft)	Average Cost of Other Space (\$/sq ft/yr)	Total Annual Facilities Cost (\$000)
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
EE/DR/Renewables		37	8,584	\$21.47	17,596	\$11.77	\$391
Environmental Regulation		10	2,260	\$21.47	4,633	\$11.77	\$103
Regulatory, Rates, & Pricing		13	2,990	\$21.47	6,129	\$11.77	\$136
Customer Accounts & Services	180	260	59,800	\$24.04	122,576	\$11.77	\$2,881
Marketing & Sales		30	6,900	\$24.04	14,143	\$11.77	\$332
Media/Government Relations		2	498	\$21.47	1,021	\$11.77	\$23
Accounting & Finance		45	10,350	\$21.47	21,215	\$11.77	\$472
Finance: Risk		10	2,300	\$21.47	4,714	\$11.77	\$105
Legal		14	3,167	\$21.47	6,491	\$11.77	\$144
Power Markets		58	13,340	\$21.47	27,344	\$11.77	\$608
Facilities/procurement		43	9,813	\$21.47	20,114	\$11.77	\$447
IT		50	11,500	\$21.47	23,572	\$11.77	\$524
HR		28	6,342	\$21.47	12,999	\$11.77	\$289
Other/corporate		46	10,544	\$21.47	21,613	\$11.77	\$481
T&D Operations & Maintenance - Lines & Subs	522	0	0	N/A	0	\$11.77	\$0
T&D Maintenance - Veg Mgmt	8	0	0	N/A	0	\$11.77	\$0
T&D Operations - Service	124	0	0	N/A	0	\$11.77	\$0
T&D Operations - General/Other	199	0	0	N/A	0	\$11.77	\$0
T&D Operations - Systems		43	9,811	\$21.47	20,111	\$11.77	\$447
T&D Operations - Engineering		115	26,519	\$21.47	54,357	\$11.77	\$1,209
T&D Operations - Planning/Management		77	17,662	\$21.47	36,203	\$11.77	\$805
Total	1033	880	202,380		414,831		\$9,400
Other Space							
Warehouses	[9]				372,748	\$11.08	
Cafeterias	[10]				33,641	\$17.91	
Training Areas	[11]				8,442	\$17.91	
Total Warehouse, Cafeteria, and Training Areas					414,831	\$11.77	
Blended sq ft/FTE					471		

Sources and Notes

[4]: Equals [3] * 230 sq ft per FTE.

[5]: Based on Navigant estimate of average price per sq ft per year for office buildings.

[6]: Equals [3] * 471 blended sq ft per FTE for warehouses, cafeterias, and training areas.

[7]: Weighted average of [9] through [11].

[8]: Equals ([4]*[5] + [6]*[7])/1000.

[9]-[11]: Based on Navigant estimate of total sq ft and average price per sq ft per year for other space.

We estimated that the total annual incremental lease and rental expense for facilities supporting LIPA operations will be approximately \$9.4 million; we then used a rounded expense of \$10 million as a reasonable annual incremental expense. Furthermore, we included this incremental

facilities related expense value in each case (mid, low and high cost cases) for each strategic organizational option.

F. DEPRECIATION AND AMORTIZATION

LIPA's annual depreciation and amortization expenses are associated with capital charges, the bulk of which for any utility reflect costs for field assets such as poles, transformers, wires, and substations. We have assumed for purposes of analysis that major incremental capital expenditures for those types of assets will not be required under any organizational alternative. However, other charges subject to depreciation or amortization, such as information systems, software, office furnishings and, notably, transaction and transition costs, were subject to examination.

Utility plant and equipment is subject to accounting standards and regulations, as is non-utility specific equipment, such as furnishings and software. As shown later, we have applied standard FERC approved depreciation schedules, where appropriate, to the relevant cost categories. However, certain categories of costs, such as transaction and transition charges are typically expensed in the year incurred. Our analysis, though, requires that when comparing the cost and rate effects of options that we use a single, "standard" year for our comparative basis. Thus, we amortized transaction and transition charges over 10 years, rather than record these as an expense incurred over one or two years

LIPA identified 72 systems that are routinely used in the course of its operations. These include the Customer Accounting System, as well as general ledger, meter reading systems, scheduling systems, geographic information system, systems used for crew dispatch and operations, fleet management, and document management systems. Most of these systems are owned and managed by National Grid. However, contract provisions give LIPA the right to transfer those systems to LIPA as requested.

Many of these systems will be transferred to LIPA in the case of each strategic organizational option; the incremental capital costs for such transfers will be largely the same across the organizational options. Some systems will likely not be transferred, especially under the

Privatization option because we assumed that the acquiring utility had certain core systems in place of sufficient scale to add LIPA to them at modest cost.

Two important information systems that are currently used by LIPA and owned and managed by National Grid would most likely not be transferred to the new entity. The current Customer Accounting System as well as the system used for finance and accounting are outdated and in need of upgrade and/or replacement. The costs of developing and implementing new systems will likely be substantial, and will differ across the strategic organizational options.

Developing and implementing systems involve a large up-front cost as well as ongoing costs associated with operations and maintenance. These large up-front costs are capitalized and included on a company's balance sheet. Depreciation on capital additions (including that associated with systems), then, becomes the expense which is included on a utility's income statement. Thus, the total capital cost associated with any major addition will have a modest impact on rates under the revenue requirement model for ServCo or a fully municipalized LIPA.

We show the incremental impact on depreciation and amortization expenses associated with implementing each of the strategic organizational options in Table III-9. The table indicates that the difference in depreciation and amortization charges from the highest cost option (i.e., Privatization) to the lowest option (i.e., ServCo) is only slightly more than \$5 million per year.

Table III-9
Annual Depreciation & Amortization of Capital Costs
All Options
Mid Case

	Privatization Option (\$000)	ServCo Option (\$000)	Muni Option (\$000)
<u>Transaction/Transition Costs</u>			
Transaction Costs (\$000)	\$50,000	\$0	\$5,000
Amortization Term (Years)	10	10	10
Amortized Transaction Costs - Annual (\$000)	\$5,000	\$0	\$500
Transition Costs (\$000)	\$50,000	\$20,000	\$30,000
Amortization Term (Years)	10	10	10
Amortized Transition Costs - Annual (\$000)	\$5,000	\$2,000	\$3,000
<u>Capital Additions</u>			
General Office - Information Systems (\$000)	\$0	\$65,000	\$78,000
Depreciation Rate - Per FERC Schedule	4.33%	4.33%	4.33%
Annual Depreciation Expense	\$0	\$2,815	\$3,377
General Office - Equipment (\$000)	\$0	\$0	\$50
Depreciation Rate - Per FERC Schedule	4.33%	4.33%	4.33%
Annual Depreciation Expense	\$0	\$0	\$2
General Office - Software (\$000)	\$0	\$0	\$1,025
Depreciation Rate - Per FERC Schedule	20%	20%	20%
Annual Depreciation Expense	\$0	\$0	\$205
General Office - Other (\$000)	\$5,473	\$6,048	\$6,411
Depreciation Rate - Per FERC Schedule	4.33%	4.33%	4.33%
Annual Depreciation Expense	\$237	\$262	\$278
Total Capital Additions	\$105,473	\$91,048	\$120,486
Total Incremental Depreciation & Amortization Expense	\$10,237	\$5,076	\$7,362

1. PRIVATIZATION

It is anticipated the in the mid case that there would be total incremental capital costs of \$105 million, as shown above but detailed below in Table III-10.

Table III-10
Total Capital Additions
Privatization

Functional Area	Office (\$000)	Systems (\$000)	Software (\$000)	Equip (\$000)	Transition / Transaction (\$000)	Total (\$000)
EE/DR/Renewables	\$197	\$0	\$0	\$0		\$197
Environmental Regulation	\$39	\$0	\$0	\$0		\$39
Regulatory, Rates, & Pricing	\$46	\$0	\$0	\$0		\$46
Customer Accounts & Services	\$2,352	\$0	\$0	\$0		\$2,352
Marketing & Sales	\$144	\$0	\$0	\$0		\$144
Media/Government Relations	\$12	\$0	\$0	\$0		\$12
Accounting & Finance	\$259	\$0	\$0	\$0		\$259
Finance: Risk	\$40	\$0	\$0	\$0		\$40
Legal	\$50	\$0	\$0	\$0		\$50
T&D Operations & Maintenance - Lines & Subs	\$0	\$0	\$0	\$0		\$0
T&D Maintenance - Veg Mgmt	\$0	\$0	\$0	\$0		\$0
T&D Operations - Service	\$0	\$0	\$0	\$0		\$0
T&D Operations - Systems	\$245	\$0	\$0	\$0		\$245
T&D Operations - Engineering	\$663	\$0	\$0	\$0		\$663
T&D Operations - Planning/Management	\$442	\$0	\$0	\$0		\$442
T&D Operations - General/Other	\$0	\$0	\$0	\$0		\$0
Power Markets	\$247	\$0	\$0	\$0		\$247
Facilities/procurement	\$228	\$0	\$0	\$0		\$228
IT	\$224	\$0	\$0	\$0		\$224
HR	\$78	\$0	\$0	\$0		\$78
Other/corporate	\$206	\$0	\$0	\$0		\$206
Transition cost					\$50,000	\$50,000
Transaction cost					\$50,000	\$50,000
Total	\$5,473	\$0	\$0	\$0	\$100,000	\$105,473
	5%	0%	0%	0%	95%	100%

The most significant incremental capital costs (\$100 million) reflect transition and transaction costs of \$50 million each.¹² Transaction costs reflect the one-time costs of investment bankers, lawyers, accountants, public relations specialists, lobbyists, and other advisors. Transition costs

¹² Transition and transaction costs are typically expense items, recorded in the year incurred. However, to normalize the rate effects and ensure greater comparability with the ServCo and Municipalization options, these costs were amortized over 10 years.

reflect the cost of making initial changes and bringing the new organization to a steady state. They are typically incurred over the course of a few years; they are not ongoing costs. Transition costs tend to be significant and typically include costs related to employee severance, relocation and retention, IT system consolidation, benefits adjustments, process and procedure integration, communication, training, and other like activities. We based our estimate of transaction and transition costs on experiences in the utility industry. We reviewed a sample of utility transactions involving mergers and acquisitions (M&As), which we summarize in Table III-11.

Table III-11
Sample Transition and Transaction Costs

Deal	Number of Customers (Mil)	Transition Period (Years)	Costs			
			Transaction - Bankers (\$)	Transaction - Other* (\$)	Integration (Annual) (\$)	Integration (\$/Cust/Yr)
Exelon - PSEG	9	4	\$21,170,000	\$20,000,000	\$89,731,750	\$10
PECO - Unicom	5.3	5	\$39,237,000	\$20,000,000	\$37,265,200	\$7
Allegheny - FirstEnergy	6.1	3	\$35,500,000	\$20,000,000	\$39,733,333	\$7
Ameren - Illinois Power	3.2	3	\$25,000,000	\$20,000,000	\$51,333,333	\$16
Average		3.75	\$30,226,750	\$20,000,000		\$10

* Estimated. Includes legal, accounting, public relations, lobbyists, other advisors.

As indicated in the table, we reviewed four transactions. The average incurred for transaction related costs was approximately \$50 million. In addition, transition costs, which naturally vary by the size and complexity of a deal, were normalized to result in a cost/customer/year of \$9.89. Assuming that the metric applies to LIPA with a customer base of 1.1 million, transition costs would total \$48.96 million (4.5 years¹³ x \$9.89/customer/year x 1.1 million customers), which we rounded to \$50 million.

The balance of annual depreciation and amortization expenses reflect charges associated with office equipment and furniture. We assumed that these items would need to be acquired new, or

¹³ Transition period length is uncertain, but given the likely legal and regulatory complexities involved in an acquisition of LIPA, a period (i.e., 4.5 years) longer than average was assumed.

purchased from the current service provider. These costs were estimated at \$5,750 per person.¹⁴ Table III-9, above, shows the annualized effects of such costs under Privatization (as well as under ServCo and Municipalization).

For the Privatization option, we assumed that the acquiring utility already had customer accounting as well as finance and accounting systems in place. We therefore did not include an incremental capital expenditure to develop and/or implement these systems under the Privatization option, nor do we show an associated depreciation expense in Table III-9.

Total incremental depreciation and amortization costs under the mid cost case for the Privatization option equals \$10 million. A sensitivity analysis of +/- 20% around the mid case yielded results of \$12 million and \$8 million increases in the high and low cases, respectively. These results are presented in Table III-12 (low case) and Table III-13 (high case), below.

¹⁴ This based on the results of analysis by Navigant Consulting which estimate office equipment and furniture costs to be: \$3,000 per person for office equipment; \$2,000 per person for desktops computers; and, \$750 per person for telecommunications services and support.

Table III-12
Annual Depreciation & Amortization of Capital Costs
All Options
Low Case

	Privatization Option (\$000)	ServCo Option (\$000)	Muni Option (\$000)
<u>% Change from Mid Case</u>	-20%	-20%	-10%
<u>Transaction/Transition Costs</u>			
Transaction Costs (\$000)	\$40,000	\$0	\$4,500
Amortization Term (Years)	10	10	10
Amortized Transaction Costs - Annual (\$000)	\$4,000	\$0	\$450
Transition Costs (\$000)	\$40,000	\$16,000	\$27,000
Amortization Term (Years)	10	10	10
Amortized Transition Costs - Annual (\$000)	\$4,000	\$1,600	\$2,700
<u>Capital Additions</u>			
General Office - Information Systems (\$000)	\$0	\$52,000	\$70,200
Depreciation Rate - Per FERC Schedule	4%	4%	4%
Annual Depreciation Expense	\$0	\$2,252	\$3,040
General Office - Equipment (\$000)	\$0	\$0	\$45
Depreciation Rate - Per FERC Schedule	4%	4%	4%
Annual Depreciation Expense	\$0	\$0	\$2
General Office - Software (\$000)	\$0	\$0	\$923
Depreciation Rate - Per FERC Schedule	20%	20%	20%
Annual Depreciation Expense	\$0	\$0	\$185
General Office - Other (\$000)	\$4,379	\$4,839	\$5,770
Depreciation Rate - Per FERC Schedule	4%	4%	4%
Annual Depreciation Expense	\$190	\$210	\$250
Total Capital Additions	\$84,379	\$72,839	\$108,437
Total Incremental Depreciation & Amortization Expense	\$8,190	\$4,061	\$6,626

Table III-13
Annual Depreciation & Amortization of Capital Costs
All Options
High Case

	Privatization Option (\$000)	ServCo Option (\$000)	Muni Option (\$000)
<u>% Change from Mid Case</u>	20%	20%	30%
<u>Transaction/Transition Costs</u>			
Transaction Costs (\$000)	\$60,000	\$0	\$6,500
Amortization Term (Years)	10	10	10
Amortized Transaction Costs - Annual (\$000)	\$6,000	\$0	\$650
Transition Costs (\$000)	\$60,000	\$24,000	\$39,000
Amortization Term (Years)	10	10	10
Amortized Transition Costs - Annual (\$000)	\$6,000	\$2,400	\$3,900
<u>Capital Additions</u>			
General Office - Information Systems (\$000)	\$0	\$78,000	\$101,400
Depreciation Rate - Per FERC Schedule	4%	4%	4%
Annual Depreciation Expense	\$0	\$3,377	\$4,391
General Office - Equipment (\$000)	\$0	\$0	\$65
Depreciation Rate - Per FERC Schedule	4%	4%	4%
Annual Depreciation Expense	\$0	\$0	\$3
General Office - Software (\$000)	\$0	\$0	\$1,333
Depreciation Rate - Per FERC Schedule	20%	20%	20%
Annual Depreciation Expense	\$0	\$0	\$267
General Office - Other (\$000)	\$6,568	\$7,258	\$8,334
Depreciation Rate - Per FERC Schedule	4%	4%	4%
Annual Depreciation Expense	\$284	\$314	\$361
Total Capital Additions	\$126,568	\$109,258	\$156,631
Total Incremental Depreciation & Amortization Expense	\$12,284	\$6,092	\$9,571

2. SERVCo

It is anticipated the in the mid-case that there would be total incremental capital costs of \$91 million, as shown above but detailed below in Table III-14.

Table III-14
Total Capital Additions
ServCo

Functional Area	Office (\$000)	Systems (\$000)	Software (\$000)	Equip (\$000)	Transition / Transaction (\$000)	Total (\$000)
EE/DR/Renewables	\$197	\$0	\$0	\$0		\$197
Environmental Regulation	\$74	\$0	\$0	\$0		\$74
Regulatory, Rates, & Pricing	\$109	\$0	\$0	\$0		\$109
Customer Accounts & Services	\$2,381	\$50,000	\$0	\$0		\$52,381
Marketing & Sales	\$173	\$0	\$0	\$0		\$173
Media/Government Relations	\$12	\$0	\$0	\$0		\$12
Accounting & Finance	\$316	\$15,000	\$0	\$0		\$15,316
Finance: Risk	\$46	\$0	\$0	\$0		\$46
Legal	\$79	\$0	\$0	\$0		\$79
T&D Operations & Maintenance - Lines & Subs	\$0	\$0	\$0	\$0		\$0
T&D Maintenance - Veg Mgmt	\$0	\$0	\$0	\$0		\$0
T&D Operations - Service	\$0	\$0	\$0	\$0		\$0
T&D Operations - Systems	\$245	\$0	\$0	\$0		\$245
T&D Operations - Engineering	\$663	\$0	\$0	\$0		\$663
T&D Operations - Planning/Management	\$442	\$0	\$0	\$0		\$442
T&D Operations - General/Other	\$0	\$0	\$0	\$0		\$0
Power Markets	\$420	\$0	\$0	\$0		\$420
Facilities/procurement	\$245	\$0	\$0	\$0		\$245
IT	\$253	\$0	\$0	\$0		\$253
HR	\$130	\$0	\$0	\$0		\$130
Other/corporate	\$264	\$0	\$0	\$0		\$264
Transition cost					\$20,000	\$20,000
Transaction cost					\$0	\$0
Total	\$6,048	\$65,000	\$0	\$0	\$20,000	\$91,048
	7%	71%	0%	0%	22%	100%

The bulk of these charges, just over 93%, are represented in two categories; Systems and Transition/Transaction. The balance, approximately 7%, is associated with office costs. Incremental systems costs are estimated at \$65 million and transition costs are estimated to be \$20 million. We do not expect that fully municipalizing LIPA will involve transaction costs.

(along the same lines as described for the Privatization option). Accordingly, we have not included an estimate for transaction costs for this option.

The \$65 million in system charges is associated with two systems, a \$50 million Customer Accounting System and a \$15 million system relating to finance and accounting. We believe that this is a conservative estimate because implementation of these systems, especially the customer accounting system, are complex and tend to be among the more expensive system deployments undertaken by utilities.

Total incremental depreciation and amortization costs under the mid cost case for the ServCo option equal \$5 million, as shown previously in Table III-9. A sensitivity analysis of +/- 20% around the mid case yielded results of increases of \$6 million and \$4 million in the high cost and low cost cases, respectively. These results are presented above in Table III-12 (low case) and Table III-13 (high case).

3. MUNICIPALIZATION

It is anticipated the in the mid-case that there would be total incremental capital costs of \$120 million, as shown above but detailed below in Table III-15.

Table III-15
Total Capital Additions
Municipalization

Functional Area	Office (\$000)	Systems* (\$000)	Software (\$000)	Equip (\$000)	Transition / Transaction (\$000)	Total (\$000)
EE/DR/Renewables	\$197	\$0	\$0	\$0		\$197
Environmental Regulation	\$74	\$0	\$0	\$0		\$74
Regulatory, Rates, & Pricing	\$109	\$0	\$0	\$0		\$109
Customer Accounts & Services	\$2,438	\$60,000	\$25	\$50		\$62,513
Marketing & Sales	\$173	\$0	\$0	\$0		\$173
Media/Government Relations	\$12	\$0	\$0	\$0		\$12
Accounting & Finance	\$345	\$18,000	\$0	\$0		\$18,345
Finance: Risk	\$75	\$0	\$0	\$0		\$75
Legal	\$79	\$0	\$0	\$0		\$79
T&D Operations & Maintenance - Lines & Subs	\$0	\$0	\$200	\$0		\$200
T&D Maintenance - Veg Mgmt	\$0	\$0	\$0	\$0		\$0
T&D Operations - Service	\$0	\$0	\$0	\$0		\$0
T&D Operations - Systems	\$245	\$0	\$0	\$0		\$245
T&D Operations - Engineering	\$663	\$0	\$50	\$0		\$713
T&D Operations - Planning/Management	\$442	\$0	\$25	\$0		\$467
T&D Operations - General/Other	\$0	\$0	\$200	\$0		\$200
Power Markets	\$420	\$0	\$25	\$0		\$445
Facilities/procurement	\$257	\$0	\$500	\$0		\$757
IT	\$374	\$0	\$0	\$0		\$374
HR	\$216	\$0	\$0	\$0		\$216
Other/corporate	\$292	\$0	\$0	\$0		\$292
Transition cost					\$30,000	\$30,000
Transaction cost					\$5,000	\$5,000
Total	\$6,411	\$78,000	\$1,025	\$50	\$35,000	\$120,486
	5%	65%	1%	0%	29%	100%

* Assumes Systems costs are 20% more costly than under ServCo due to loss of purchasing leverage.

The bulk of these charges, almost 94%, are represented in two categories; Systems and Transition/Transaction. The balance, approximately 6%, is associated with office costs. Incremental systems costs are estimated at \$78 million and Transaction/Transition costs at \$35 million. We have included an estimate for transaction costs of \$5 million as we believe that transformation to a complete municipal structure will likely require some legal and advisory assistance. To the extent such costs were incurred, the transaction cost would be significantly higher. The \$78 million estimate for system charges is associated with two systems, \$60 million for a Customer Accounting System and \$18 million for a Finance and Accounting system. These systems are estimated to cost 20% more under the Municipalization option than

under the ServCo option. The potentially higher cost is driven by the loss of expertise resident in a utility service provider that could be employed during vendor negotiations. An experienced service provider operating under the ServCo model would be able to apply critical lessons learned in the acquisition and implementation of most major systems, but especially to one as complex as customer accounting. Such expertise and experience are extremely valuable assets for what amount to, in many cases, “once in a career” system deployments. In addition, it is likely that the service provider itself may be able to offer customer accounting system services as a hosted provider. Thus, a service provider could not only provide expertise in direct negotiations, but also act as an embedded option or alternative to the outright system purchase, albeit at a cost.

Total incremental depreciation and amortization costs under the mid case for the Municipalization option equal \$7 million, as shown previously in Table III-9. A sensitivity analysis for the high cost case of +30% was applied from the mid case and yielded results of \$10 million. In comparison, a sensitivity for the low cost case of -10% from the mid case yielded results of \$7 million. These results are presented above Table III-12 (low case) and Table III-13 (high case).

The sensitivity range under the Municipalization option (i.e., -10% and +30%) is different than that applied under the ServCo option (i.e., +/- 20%). The primary basis for that difference is the fact that large system implementation costs are very difficult to predict accurately; we believe that such costs are subject to even greater variability under the Municipalization option, given the absence of a proven utility partner.

G. PILOTS, PROPERTY, AND REVENUE TAXES

Local governments at the municipal and/or county are typically responsible for leveling property taxes. These taxes are usually a primary revenue source used to support local education, police and fire protection, local governments and a range of local infrastructures. Property taxes, therefore, are an important revenue source to local governments and are politically sensitive, even in times of strong economic conditions. Governmental entities and non-profit organizations are exempt from paying property taxes, but typically make payments in

lieu of taxes (or PILOTs) to local taxing jurisdictions in order to compensate a local government for some or all of the tax revenue (usually property tax revenue) that it foregoes.

As described in Chapter II, LIPA paid over \$500 million in taxes or tax equivalents in 2010, most of which involved taxes (or payments in lieu of taxes) on property. Table II-1 in Chapter II presented a breakdown of those payments in which it was shown that LIPA paid roughly \$183 million in property taxes on power plants (owned by National Grid) under its PSA with National Grid. It also paid about \$217 million in PILOTs to property taxing jurisdictions on Long Island and Queens associated with LIPA's T&D properties.

State commissions, which regulate the rates charged by investor-owned utilities, review the expenses incurred by utilities under their jurisdiction for prudence as to whether the expenses incurred, including property taxes paid to local jurisdictions, were reasonable. Regulatory commissions also pay attention to levels of property taxes because overpayment of such could cause cross-subsidization among rate payers, which would violate a core goal of rate making. Such situations arise easily. For example, a utility could succumb to political pressures from a local taxing jurisdiction because it knows it can include these higher-than-appropriate costs in rates. However, spreading the excess costs across a wide body of its ratepayers means that all ratepayers would be paying for benefits that are realized by an isolated few. Thus, state regulatory commissions, including the New York State PSC, require that IOUs review and challenge property tax assessments, as appropriate.

Determining whether or not property taxes and/or PILOTs are correctly assessed involves specific and detailed analysis, which is beyond the scope of this study. However, as we introduced in Chapter II, electric utilities, trade groups, and regulators develop metrics in order to benchmark relative utility performance, and benchmarking studies have been conducted for property taxes. The American Public Power Association (APPA) conducted such a study by measuring the percent of net payments (i.e., payments in lieu of taxes) made by 340 public power systems as a percent of their utility revenues.¹⁵ The study found that the surveyed public

¹⁵ *Payments and Contributions by Public Power Distribution Systems to State and Local Governments*, American Public Power Association, 2008.

power systems paid property-like taxes on average equal to about 4.7% of their annual electric operating revenues. The average for public power utilities located in the northeastern part of the U.S. was 3.1% and the average for larger systems, where LIPA would fall, was 5.7%.

In Chapter II, we estimated that taxes represent approximately 13% of LIPA's 2010 baseline revenue requirement, with property taxes and PILOTs representing over 11%. Thus, LIPA paid property taxes and PILOTs as a percentage of its operating revenues that were almost twice as high as the APPA panel of U.S. public power utilities.

Numerous factors underlie these benchmarking statistics. By itself, the APPA study does not provide sufficient evidence for LIPA to challenge its level of PILOTs and property taxes. These challenges must be made on specific utility assets before individual taxing jurisdictions. However, we find that the results of the APPA study are informative and corroborate LIPA's decision to challenge the level of property taxes that it pays on National Grid's generating assets, as well as on other facilities.

For purposes of this study, we assumed that property taxes and PILOTs could be reduced going forward under each of the strategic organizational options. The dollar impacts associated with reducing property taxes and equivalent payments is a function of the dollar base of taxes and equivalents and the percentage by which these expenses could be reduced. As was presented in Table II-2 (Chapter II) property taxes and PILOTs paid by LIPA in 2010 were roughly \$420 million.¹⁶ For purposes of estimating dollar impacts, we made the assumption that limited the base of potential property tax and equivalent reductions to the amount that LIPA currently pays in PILOTs for its T&D assets (approximately \$203 million, as shown in Table II-2). We used this base amount as a conservative starting point; it is not meant to suggest that LIPA only consider challenges to taxes on its T&D assets.

We then selected potential percentages of reductions. We assumed that:

¹⁶ LIPA paid approximately \$217 million in PILOTs (\$203 million of which was to Long Island and Queens taxing jurisdiction related to LIPA's T&D assets), \$183 million in property taxes associated with the PSA and \$3 million involving other purchased power agreements. LIPA's total "tax bill" also included revenue taxes, a special New York State conservation assessment, and other taxes.

- Privatization could realize a 30% reduction to this dollar base. Such a reduction would result in a decrease in LIPA's property tax and PILOTs expenses of roughly \$61 million per year, and would bring LIPA's ratio of property-like taxes to annual electric operating revenues down from 11% to 8%. This is a sizable adjustment in absolute dollar terms but still leaves a significant difference when comparing the adjusted LIPA ratio with the average for large public power systems.
- We assumed a lower percent reduction (20%) under the ServCo option. Here, LIPA has motivation to bring property-like taxes down as aggressively as it would under the Privatization option. However, its governance structure still involves a higher level of community involvement and influence than does the Privatization option, hence we moderate the level of potential reduction slightly. Under ServCo, the projected reduction in PILOTs and property taxes is equal to roughly \$41 million.
- We moderated the possible percent reduction still further under the Municipalization option (to 15%). This is because a full municipal structure is likely to be less able to circumvent the political pressures associated with reducing property taxes. Under the Municipalization option, the projected reduction in PILOTs and property taxes is equal to roughly \$31 million.

Supporting data and calculations for these estimates are included in Appendix F.

The appendix also shows adjustments to revenue taxes. Any changes in revenue taxes are strictly mechanical adjustments that reflect changes in LIPA's revenue requirements. They are treated the same across the baseline case and for each of the strategic organizational options.

H. FINDINGS AND CONCLUSIONS

1. Strategic reorganization, by itself, presents limited opportunity for substantive reduction in annual operating costs.

LIPA's relatively cost efficient position as a T&D utility, combined with the composition of its work force, strongly suggest that reorganization will not produce major changes in its labor related cost profile, either in the form of increases or decreases. This is particularly true with regard to the T&D function, where over half the staff are assigned. Changes in labor-related costs are more likely to be seen in increases or decreases in corporate and administrative functions, but these are not enough to push (labor and non-labor O&M) costs down more than approximately \$29 million per year. In sum, when including all categories of analysis, annual operating costs in the mid cost case saw projected reductions of -\$93 million (-2.47% of the 2010 baseline) under the Privatization option, and reductions of -\$25 million (-0.66%) and -\$6 million (-0.15%%) in the ServCo and Municipalization options, respectively.

2. The largest single area of potential cost savings comes from reduction in payments for PILOTs.

A recent survey of public power utilities by the APPA indicates that LIPA's payments in lieu of property taxes to local jurisdictions is high relative to the panel of public utilities. Property taxes and PILOTs are a very sensitive and politically charged area, especially in the current economic climate. Nonetheless, it is a cost area that should be reviewed and, based on the preliminary conclusions following from the APPA report, pursued irrespective of organization option selection. While LIPA may have some discretion concerning how aggressively it challenges current PILOT levels, this would almost certainly not be the case under the Privatization option. Under that option, the NYS PSC would require that the IOU demonstrate that it is not cross-subsidizing one set of customers at the expense of another, and that property taxes were prudently incurred expenses. In the analysis of operating costs presented in this chapter, we assumed that reductions in PILOTs (depending on the organizational option) were appropriate based on the results of the APPA survey.

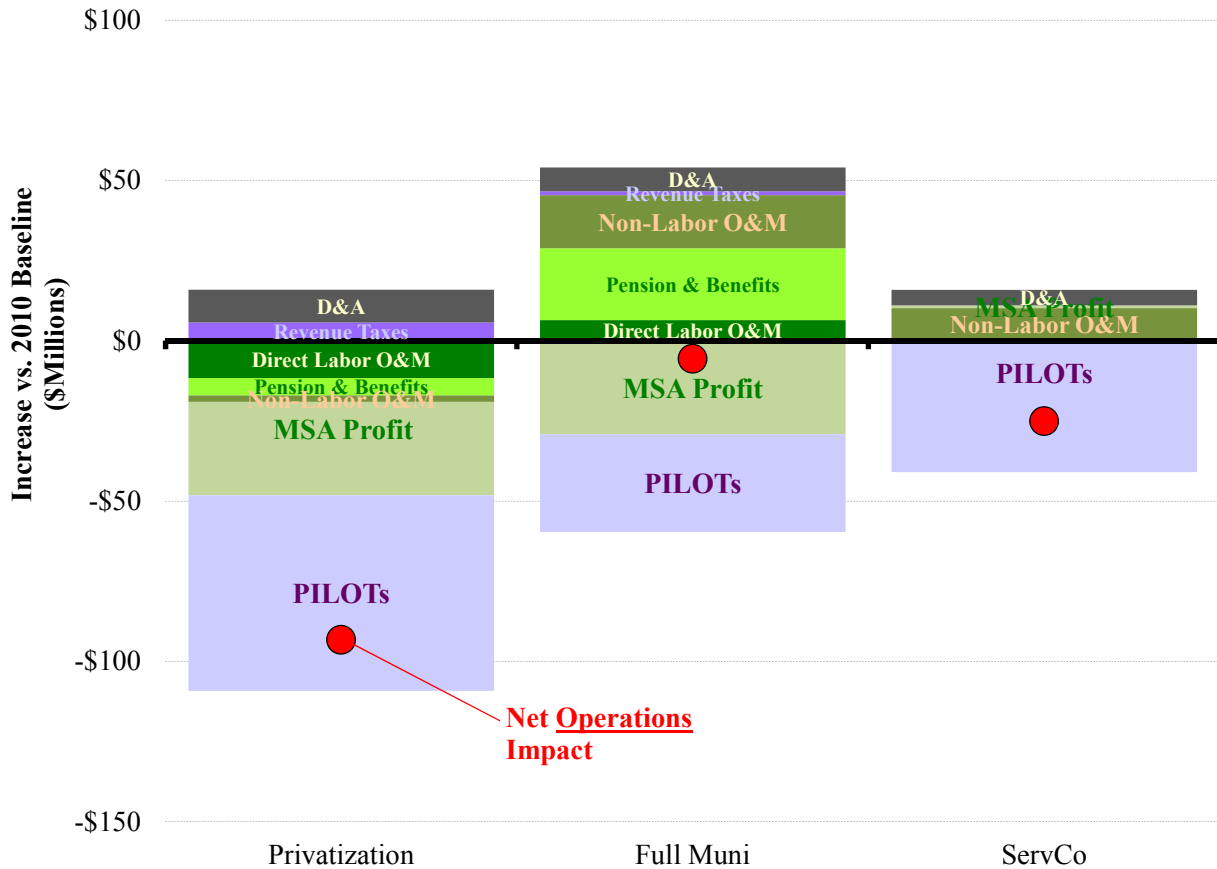
In our analysis, reductions associated with property tax adjustments represented over 65% of the net total savings under Privatization, and under ServCo and Municipalization the exclusion of property tax adjustments would turn each of those options from net operational reductions in cost to net increases.

3. Our analysis of operating costs clearly indicated that opportunities for cost reductions in O&M expenses and for LIPA's revenue requirements is most pronounced under the Privatization option.

The Privatization option is the only strategic organizational option that results in a reduction in labor related operating costs, although the level of increase of this expense area under the ServCo option is de minimis. This results from the adoption of the key assumption that privatization would be accomplished by LIPA's merger with and/or acquisition by another utility. In that case, we can identify duplicative staff and functions within the corporate and administrative areas. Absent this assumption – for example, if we assumed that an investment group, not a utility, would be the likely acquirer – those efficiencies would likely not be realized.

A summary of the differential in operating costs that we projected between the Privatization option and the two municipalization options – ServCo (partial municipalization) and Municipalization (full municipalization) are shown in Figure III-1 below.

Figure III-1
Incremental Changes to 2010 Baseline Operating Costs
All Options



4. We project overall levels of operating costs for the ServCo and Municipalization options that are very close to one another.

We estimate that the changes in direct labor, non-labor O&M and even PILOTs are relatively similar across the ServCo and Municipalization options. We have identified two primary areas of cost differentiation: profits and pensions.

In Chapter II, we estimated the current level of profit included in LIPA's payments to National Grid, which became part of our baseline of operating costs and revenue requirements. We subtracted out this baseline profit level in the Municipalization option but included it in the

ServCo model. (More specifically, we included a slightly higher level of profit for the ServCo option going forward).

A more controversial cost area involves pensions and benefits. In Chapter II, we estimated the ratios of pensions and benefits (separately and together) to direct labor costs. While informative in their own right, estimation of these ratios allowed us to modify levels of pensions and benefits for scenarios under Municipalization by increasing the ratio to be equal to LIPA's ratio. We were clear in Chapter II to note that the ratios were developed based on review of data and did not reflect any independent actuarial analysis of pension expenses for either LIPA or National Grid.

We assume that per unit pensions and benefits expense ratios will stay at their baseline levels under the ServCo and Privatization options. However, we point out that it is possible that these levels may increase under the Municipalization option. Whether per unit pension and benefits levels increase if current National Grid employees were to transfer to LIPA is unclear. Arguments have been presented supporting why pension costs would rise (e.g., some legal interpretations suggest that LIPA employees must be part of the New York State and Local Retirement System) and why National Grid's pension arrangement would stay in place (e.g., National Grid's current contract with the IBEW does not terminate for several years).

A range of factors will influence the outcome of this issue. Accordingly, we have included a range of possible outcomes in our scenario analysis under the Municipalization option. We keep pensions and benefits levels at their current rates in the low case scenario; in the mid case scenario we move National Grid employees (that would be transferred to LIPA) to pensions and benefits levels that reflect LIPA's 2009 ratio; and in the high case we move these same National Grid employees to the most recently (i.e., 2010) observed ratio for LIPA.

While the absolute dollars associated with pensions and benefits costs are material, variations in the costs within the range of sensitivity described does not alter our fundamental conclusion. The differential in operating costs between the Municipalization and ServCo options is too

minor to be used as the basis for clearly ranking one option above the other. Furthermore, modest adjustment to cost assumptions could easily shift the ranking from one to another.

We summarize the average rates that we project for each option within the mid-cost, high-cost and low-cost scenarios in Table III-16 below.

Table III-16

	Low Case (¢/kWh)	Mid Case (¢/kWh)	High Case (¢/kWh)
Privatization	17.686	17.724	17.762
ServCo	18.031	18.054	18.196
Municipalization	17.977	18.146	18.265

Note: Includes impact of PILOTs.

The mid-cost case as well as the high-cost and low-cost scenarios for the Privatization, ServCo and Municipalization options are included in Appendix G. For ease of comparison, we have reorganized the data included in these tables so that it is possible to compare the three options within each scenario. The mid-cost scenario for the three options is also included in Appendix G, as are similarly organized tables for the high-cost scenario and the low-cost scenario.

Chapter IV

Financing Costs

A. INTRODUCTION

Under its current organizational structure, LIPA has outstanding short- and long-term debt of roughly \$6.8 billion. In 2010, LIPA recorded interest expenses – that is, payment of the interest charges due on its outstanding debt – of approximately \$300 million, or 8% of its total revenue requirement. LIPA pays interest rates which reflect the tax-exempt cost of debt, because it is a municipal utility (technically, a corporate municipal instrumentality and a political subdivision of the State of New York). This level of interest expense would not change if LIPA were to re-organize under either the Municipalization or the ServCo, because these options both represent variations on LIPA's current standing as a municipal utility eligible to issue tax exempt debt.

A key benefit of being a municipal utility involves this ability to issue low-cost debt to finance nearly all capital investment. Investor-owned utilities, on the other hand, finance their utility plant through a combination of taxable debt and common equity. The combination of these two – equity and taxable debt – makes it so that, all other factors being equal, the revenue requirements for an investor owned utility will be greater than the corresponding revenue requirements for a municipal utility.

As was highlighted in the introductory chapter of this report, we have adopted rate impact as a primary evaluative metric for ranking the attractiveness of the strategic organizational options under study. In order to hold rates under a Privatization case roughly equal to the level of LIPA's current rates, the increased finance costs that will be realized because of the higher cost of capital for investor owned utilities must be offset by the combination of: improvements in operating efficiencies (i.e., reduced operating costs), the acquiring entity paying more than LIPA's book value, or the acquirer being willing to accept a rate of return well below typical utility securities experience.

We presented our projections concerning the reductions in operating costs that may be realized through implementation of the Privatization option in Chapter III. This chapter is primarily

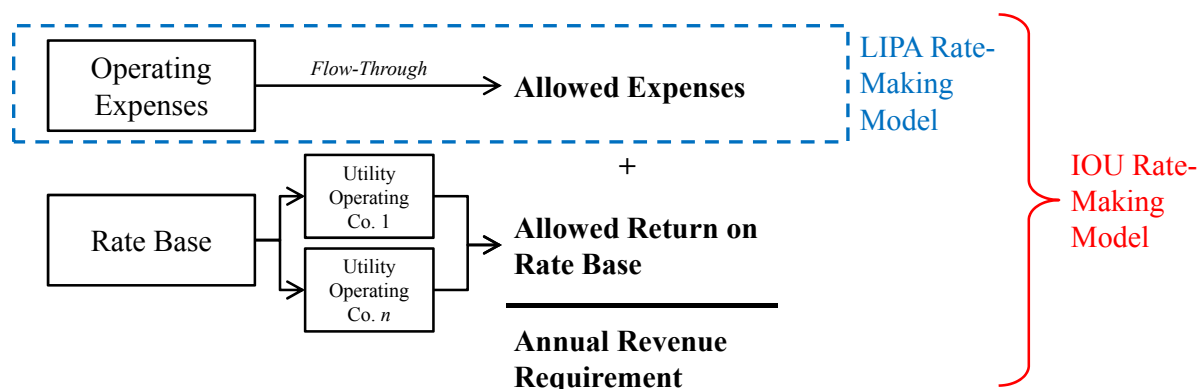
concerned with estimating the changes in financing costs expected to occur under the Privatization option.

B. UTILITY RATE MAKING

Under the Privatization option, rates for retail electric service would be proposed by the acquiring utility and set by the New York Public Service Commission, subject to their modification of the utility's proposal.¹ A utility that is considering acquiring LIPA would spend considerable effort in examining the rate-making climate in New York State and would develop estimates of the rates it would likely be allowed to charge its customers.² Those expected rates would be a primary determinant of the acquisition price that an acquiring utility would be willing to pay for LIPA because such rates are the primary determinant (together with projected kWh sales) of the level of revenues that the acquiring utility can expect to receive. Revenues, in turn become the starting point for the acquirer's profitability and valuation analyses, ultimately determining the offer price.

A general depiction of the IOU rate making process is shown in Figure IV-1 below.

Figure IV-1
Regulatory Revenue Requirement and Rate-Making Process
For Investor Owned Utilities (IOUs)



¹ We assume the acquiring entity would be another utility, because such a buyer is more likely to have the expertise and systems to capture potential operating savings.

² Setting rates is generally completed through a “rate case” process, in which detailed calculations and utility modeling support are considered, sometimes in a contentious manner.

The figure shows that the revenue requirements for investor owned utilities (upon which rates are based) are the sum of allowed expenses and an allowed return on the utility's rate base. The inclusion of an allowed return on rate base is the primary difference between ratemaking for IOUs and the way that LIPA (and other municipal utilities) set rates. The New York Public Service Commission (similar to other state regulatory commissions) determines a utility's allowed return on rate base by setting its rate base, capital structure and weighted average cost of capital.

Determining the eligible assets to include in rate base is an important part of the ratemaking process because rate base is, quite literally, the investment base upon which returns may be earned. For regulatory purposes, the primary component of rate base is the book value of the utility's "used and useful" assets; that is, those assets that are productive components of the generation, transmission and/or distribution of electricity to customers.³ Focusing on these assets for LIPA, and based on the standards that the NY PSC has historically applied, we estimate that a privatized LIPA's rate base would be approximately \$7.6 billion. The derivation of our estimate and its relationship with LIPA's balance sheet is shown in Table IV- 1, below.

³ In New York State, the formula for rate base includes used and useful assets as well as deferred charges, regulatory assets, less regulatory liabilities, plus an allowance for working capital. These are reflected in our \$7.6B estimate of rate base.

Table IV-1
Comparison of LIPA Balance Sheet And Derived Rate Base
(\$000)

Assets			Liabilities and Net Assets	
Cash and Cash Equivalents	371,264		Current Liabilities (Excl. Regulatory Liabilities)	1,168,720
Investments	124,283	Offset		
Rate Base Assets	7,337,745		Regulatory Liabilities	164,520
Net PP&E	6,459,718	Rate Base =	Long Term Debt	6,394,949
Deferred Charges	88,748	+7,337,745 RBAssets	Capital Leases	2,970,126
Regulatory Assets	789,279	- 164,520 Reg Liab	Other	879,652
Acquisition Adjustments	2,629,216	+ 399,814 Work Cap	Non-current liabilities	559,932
Other	1,115,459	= 7,573,039	Borrowings	114,520
Deferred Outflow - Commodity Derivatives	65,782		Commodity Derivative Instruments	66,611
Deferred Outflow - Financial Derivatives	66,705		Financial Derivative Instruments	81,277
Non-cash Current Assets	680,211		Asset Retirement Obligations (NMP2)	7,380
Promissory Notes	155,425		Claims and Damages	20,207
Nonutility Property and Other Investments	74,679		Deferred Credits	203,637
Other Long Term Accounts Receivable	72,657		Net Assets	319,720
Total Assets	11,577,967		Total Liabilities and Net Assets	11,577,967

Table IV-1 shows that LIPA's net property, plant and equipment (PPE), made up of its T&D plant in service and its capital leases for generation and transmission facilities, is the primary component of rate base. It also indicates that the amortized value of the acquisition premium that LIPA paid to LILCO at the time of its acquisition, considered a non-productive asset, is excluded from the rate base. We have not ruled out the possibility of the NY PSC allowing LIPA's \$2.6 billion non-productive asset into rate base. If this were the case, the rate base would equal approximately \$10.2 billion (\$7.6 billion + \$2.6 billion). The remaining \$1.4 billion on the asset side of LIPA's balance sheet represent short-term cash and equivalents, matched by roughly the same amount of current liabilities. This would not be included in rate base, since an allowance for net working capital based on a portion of operating expenses is included.

We reviewed the other factors which determine the dollar amount of allowed return on rate base by examining the most recent rate cases for New York State's investor owned utilities that went before the NY PSC. This is summarized in Table IV-2.

Table IV-2
Summary of NYPSC Approved
Capital Structure and Cost of Capital

Operating Company	Orange & Rockland Utilities Inc	Consolidated Edison Co of New York Inc	New York State Electric & Gas Corp	Rochester Gas & Electric Corp	Niagara Mohawk Power Corp	Central Hudson Gas & Electric Corp	Average
NY PSC Order Date	7/23/2008	4/24/2009	9/21/2010	9/21/2010	1/20/2011	6/18/2010	
Allowed Cost of Equity	9.40%	10.00%	10.00%	10.00%	9.30%	10.00%	9.78%
Debt / (Debt + Equity)	52.0%	52.0%	52.0%	52.0%	52.0%	52.0%	52.0%
Credit Rating	Baa1	A3	Baa2	BBB	A3	A3	
Cost of New Debt	5.9%	5.5%	5.9%	5.9%	5.5%	5.5%	5.73%
Pre-Tax Weighted Cost of Capital ("PTWACC") for LIPA							10.75%
After-Tax Weighted Cost of Capital ("ATWACC") for LIPA							6.49%

Sources:

New York Public Service Commission website.

Debt may include long term debt, notes payable, customer deposits, and preferred stock.

Cost of new debt is based on yield on Moody's Utilities BAA and A rated Bond Indices on April 18, 2011. From Bloomberg.

This table indicates that the NY PSC applies a debt ratio of 52% (i.e., debt divided by debt plus equity) irrespective of the utility's actual capital structure. It also indicates that the NY PSC set rates so that the utility had the opportunity to earn a return on equity of 9.78% on average. Combined with the marginal cost of new debt, this results in a weighted average cost of capital (WACC) on a pre-tax basis of 10.75% and an after-tax WACC of 6.49%.⁴ This cost of capital is a bit more than double LIPA's current cost of roughly 5.0%.

Applying the mechanics of calculating average rates (i.e., estimating revenue requirements based on a rate base of \$7.6 billion and a pre-tax WACC of 10.75%, using the operating costs that we projected for the Privatization option in Chapter II, and dividing by kWh sales) we estimate that the average rate for LIPA's customers under privatization would be approximately 19.3 cents per kWh. This represents an increase of 1.1 cents per kWh above our base case rate of 18.2 cents per

⁴ The effective income tax rate of 39.6% is based on a 35% federal rate and a 7.1% state rate. In addition, the tax component of revenue requirements must be grossed up for taxes due on the allowance itself. The cost of debt in this WACC calculation is the current interest rate for new long term utility debt. Actual NY PSC ratemaking uses the IOU's average rates on existing debt. However, we are assuming the new owner would use new debt to acquire LIPA.

kWh. Subsequently discussed cases include alternative means of paying for the remaining LIPA assets and some additional likely refinancing costs (of defeasance).

In scenarios that we develop later in this chapter, we use a return on equity of 9.75%. This generates a pre-tax WACC of 10.73%.

C. BOOK AND MARKET VALUES

It is possible that in privatization, LIPA could sell its assets and ongoing business to a new owner at a price that was greater than its book value. If this could be accomplished, the excess proceeds could be used to offset the above-described rate increases that would result because of the new owner's higher cost of capital.

In a variety of merger and acquisition cases throughout the utility industry, investors or acquiring utilities have paid more than book value for the target utility. However, when this has occurred, we are not aware of any case in which state or federal utility regulators have calculated the rate base using the market-based purchase price. Instead regulators have followed a well established convention that allowed returns to utility investors should be determined by multiplying the net book value of used and useful rate base assets by industry average market rates of return. This is because rate payers are paying for assets' full cost and carrying charges regardless of market circumstances. That is, investors are not bearing the risks of bad outcomes associated with the realized value of assets, so they are not entitled to any gains in value either. In this way, any difference between Market values and Book values are allowed by regulators to accrue to the rate payer. Regulators also reason that if rates were based on Market values of assets, those values would be circular, and could even be gamed by utilities through a cycle of buying and re-selling assets at multiples of book value.

Nonetheless, utilities have been acquired at multiples of book value, and utility equities commonly trade at multiples of book value. On the surface, paying a multiple seems financially unsound. That is, from the shareholders' standpoint, their base of investment is equal to the amount that they paid (the market value). Yet, because utility rates are regulated, they are only able to earn on book value (which is typically less than market value by a multiple). Investors

pay multiples above book value because they project a situation in which costs may decline before regulators adjust rates downward (a situation referred to as “regulatory lag”) or they are willing to “bet” on future opportunities. For example, investors may see future growth in sales where incremental costs are lower than average costs. Similarly, investors may believe that there are untapped opportunities for the utility to reduce costs significantly through efficiency gains and, importantly, to be able to keep the savings. Finally, there is also the possibility that an investor is willing to accept a return that is lower than that allowed by regulators.

As explained in Chapter III, we analyzed potential cost reductions and do not see those being so large or assured as to justify assuming LIPA would command a material multiple. We also do not expect the perceived growth opportunities to be large. Thus, there is a possibility that an acquirer would not offer any premium for LIPA. Nonetheless, we have further evaluated privatization as though a multiple might be paid. To do this, we analyzed the ratios of market prices for utility equities to their underlying book value for retail electric utilities across the U.S. From this universe of observations, we defined a panel of electric utilities whose core business was in the transmission and distribution segment, similar to the focus of LIPA’s operation. This market value to book value analysis is summarized in Table IV-3.

Table IV-3
Observed 2010 MV/BV Ratios in Utility Equity Prices

Holding Company Name	Equity MV to BV Multiple	PP&E Multiple	T&D (%)
NSTAR	2.3x	1.5x	100%
CenterPoint Energy Inc	2.1x	1.3x	100%
Wisconsin Energy Corp	1.8x	1.3x	70%
PG&E Corp	1.7x	1.3x	70%
PPL Corp	1.5x	1.2x	69%
Northeast Utilities	1.5x	1.2x	93%
CH Energy Group Inc	1.4x	1.2x	96%
UIL Holdings Corp	1.4x	1.2x	100%
NorthWestern Corp	1.4x	1.2x	80%
Sempra Energy	1.4x	1.2x	75%
Unitil Corp	1.3x	1.1x	100%
FirstEnergy Corp	1.3x	1.1x	88%
Consolidated Edison Inc	1.3x	1.2x	98%
Edison International	1.2x	1.1x	86%
Central Vermont Public Service Corp	1.1x	1.0x	74%
Pepco Holdings Inc	1.0x	1.0x	100%
<i>Average</i>	1.5x	1.2x	87%
<i>Median</i>	1.4x	1.2x	90%

The table shows that the average multiples of market values to book values for the utility equities included in the panel for 2010 is equal to 1.5. These multiples are down from 2006, when we found the market value to book value multiples for a similar panel of electric utilities to be roughly equal to 2.2x. Our recent estimate (1.5x for 2010) is borne out anecdotally by the recent announcement of an offer made by Fortis, a Canadian distribution utility, to acquire Central Vermont Public Service Corp. The table above shows that equity in Central Vermont was trading at a market value to book value multiple of 1.1x. Fortis announced that it would pay a 44% premium for Central Vermont equity, bringing the market value to book value multiple for Central Vermont equity equal to 1.54x.⁵

⁵ The 1.5x average M/B ratio we applied is based on just the premiums for traded IOU equities. When a merger occurs, there is often an additional “control” or “strategic” premium paid, typically around 5-20%

The average market value to book value multiple in the 2010 T&D utility panel (of 1.5x) cannot be applied directly to LIPA, however. This is because the multiples cited here apply to equity prices, not asset values. For investor owned utilities, assets are funded through a combination of roughly equal amounts of debt and equity. This means the equity market multiple is about half as great when applied to all of its long term capital. We can estimate the implied multiple that investors appear to willing to pay for utility plant (technically, its property, plant and equipment or PPE) by considering the debt to equity ratios of each of the utilities in the panel. When this is done, we find that the average market value to book value of utility equities (of 1.5x) translates into a multiple of market value to book value for PPE equal to 1.2x.

Thus, it is possible that, based on recently observed market conditions, an acquiring utility may be willing to pay a premium of 1.2 times the book value of LIPA's productive assets. If so, that payment of 0.2x above PPE book value would raise approximately \$1.3 billion more in new capital.

D. ACQUISITION PRICE, RATE BASE, RATES AND RETURNS

Acquisition price, rate base, rates and the return on investment to the acquiring entity are inter-related, co-dependent variables. Our projection for each of these variables under a Privatization option requires making assumptions about the others. As discussed above, regulatory precedents and history allow us to specify likely valuation conditions and to estimate resulting rates with a reasonable level of precision. However, each of the variables above must be recognized as having some uncertainty, especially in regard to the size of rate base that would be recognized by the NY PSC and the market multiple (if any) that a buyer might be willing to pay. Therefore, we needed to develop multiple scenarios to capture the range of possible outcomes associated with these variables under the Privatization option.

We summarize four scenarios defined to reflect variations in assumptions concerning these variables in the sections below. For each of these scenarios (and the cases within each), we

above the prevailing market value of the equity. It is not clear that a LIPA acquirer would pay this much again, above and beyond a conventional M/B markup. However, even a much larger than typical multiple would not make privatization less costly than the Municipalization or ServCo options.

estimated average electric rates as well as rates of return (which will vary according to how much is paid in acquisition and how much rates are allowed to increase). We used the baseline for 2010 kWh sales and the mid-cost scenario for operating costs under the Privatization option (presented in Chapter III).

1. Market Value / Book Value = 1.0x

In this first scenario, we assumed that an acquiring IOU would not pay a premium above book value to purchase LIPA. We present two cases under this scenario. In the first, the rate base and the acquisition price are equal to the book value of LIPA's productive assets. In the second, the rate base and the acquisition price are equal to the book value of all of LIPA's utility assets, productive assets and non-productive.

Table IV-4
Scenario Set A: Market Value / Book Value = 1.0x

	Case 1	Case 2
Rate Base	\$7.6 Billion (Productive Assets Only)	\$10.2 Billion (Productive + Non-Productive Assets)
Market Value / Book Value	1.0x	1.0x
Acquisition Price	\$7.6 Billion	\$10.2 Billion
Remaining Assets (Book Value)	\$2.6 Billion	\$0
Average Rate (cents per kWh)	19.3	21.3
Return On Equity	9.75%	9.75%

This scenario provides a good example of the impact that changes in financing costs, by themselves, can have upon LIPA's rates. Case 1 demonstrates that LIPA's rates would increase from their current rates to 19.3 cents per kWh. The acquisition price in this case would cover LIPA's \$6.8 billion in debt (excluding the impact of bond defeasance, which we discuss later in this chapter), but it does not cover the book value of all of LIPA's assets. This would leave LIPA responsible for \$2.6 billion in assets (a cure for which is discussed below, in Case 3).

Case 2 sets the rate base and acquisition price equal to the book value of all of LIPA's assets; that is, its productive and non-productive assets. In many regards, this is not a far fetched case. Although utility commissions have a preference for the inclusion of just used and useful assets in rate base, virtually every commission allows recovery of some non-performing assets if they were acquired in the past under credible, prudent circumstances. The LILCO acquisition premium may qualify for this interpretation, and LIPA's customers are already used to including the debt service and amortization expenses associated with these assets in rates. However, average rates would increase substantially, to 21.3 cents per kWh, under this scenario.

We address the gap left in Case 1 above by presenting a third case. The difference between LIPA's total asset value of \$10.2 billion and the \$7.6 billion identified as used and useful (i.e., productive) assets is \$2.6 billion. This is equal to the remaining un-amortized value of the acquisition premium paid by LIPA when it acquired LILCO in 1998, which we designated as a non-productive asset. We expect that an acquiring utility would not be interested in purchasing this non-productive asset, especially if it expected that the NY PSC would not include it in rate base and/or if it expected rate increases to be minimal or capped. However, LIPA would need some kind of alternative cost recovery mechanism for these amounts in that situation.

In Case 3, presented below, we assume that LIPA creates a special purpose entity (SPE) with the sole purpose of collecting funds to amortize the remainder of LIPA's non-productive asset. This is actually the least expensive foreseeable way of dealing with these assets, since it might preserve (as assumed herein) their tax-exempt debt financing. However, this would involve incurring some additional costs, such as special legal restructuring steps whose feasibility and cost we have not evaluated as part of this study.

Table IV-5
Scenario Set A: SPE

Case 3	
Rate Base	\$7.6 Billion (Productive Assets Only)
Market Value / Book Value	1.0x
Acquisition Price	\$7.6 Billion
Remaining Assets (Book Value)	\$2.6 Billion
Average Rate (cents per kWh)	19.3
Return On Equity	9.75%
Assets In LIPA SPE	\$2.6 Billion
Interest Rate	5.00%
SPE Rate (cents per kWh)	1.0
Total Rate (cents per kWh)	20.4

The table shows that the combination of privatizing part of LIPA's assets (the productive ones) and using tax exempt financing through LIPA to finance the non-productive assets results in average rates that are a bit less than a full privatization case (Case 2). Even here, however, rates would increase by just over 2 cents per kWh, increasing to 20.4 cents per kWh from the baseline of 18.2 cents.

2. Market Value / Book Value = 1.5x

In the next scenario, we consider the situation under which an acquirer would pay a premium for LIPA's assets. We use the results of our review of recent transactions in the utility equity market as the basis for the market value to book value ratio. As described above, we found that the average ratio of market value to book values for 2010 utility equities was approximately 1.5x. We also found that this translates into an average ratio of market value to book value for all of those utility's PPE assets of roughly 1.2x. Since LIPA has no equity, it is this 1.2x multiple that would be applicable to it.

We applied these multiples to Case 3, in which an IOU would acquire LIPA's used and useful assets of \$7.6 billion, but it would be willing to pay roughly \$1.3 billion more than this for them. An SPE is created to cover the remaining \$1.3 billion in assets.

Table IV-6
Scenario Set B: Market Value / Book Value = 1.5x

Case 4	
Rate Base	\$7.6 Billion (Productive Assets Only)
Market Value / Book Value	1.5x (= Multiple on PPE of 1.2x)
Acquisition Price	\$8.9 Billion
Remaining Assets (Book Value)	\$1.3 Billion
Average Rate (cents per kWh)	19.3
Return On Equity	7.19%
Assets In LIPA SPE	\$1.3 Billion
Interest Rate	5.00%
SPE Rate (cents per kWh)	0.5
Total Rate (cents per kWh)	19.9

The market multiple serves to defray some of the obligations remaining for LIPA. Specifically, it is applied to reduce the size of the \$2.6 billion SPE to \$1.3 billion, half of the value of the SPE under Case 3. Therefore, the average rates in this case (19.9 cents per kWh) are less than under Case 3, but they still represent an increase of 1.7 cents per kWh over the baseline.

3. Rate Cap

In the above scenarios, we determined rates by making assumptions about rate base and acquisition price. In this scenario we examine the rate of return that an acquiring IOU would have to accept if rates were capped at the current 18.2 cents/kWh average level.

Table IV-7
Scenario Set C: Rate Cap

	Case 5	Case 6	Case 7
Rate Base	\$7.6 Billion (Productive Assets Only)	\$10.2 Billion (Productive + Non-Productive Assets)	\$7.6 Billion (Productive Assets Only)
Market Value / Book Value	1.0x	1.0x	1.5x (= Multiple on PPE of 1.2x)
Acquisition Price	\$7.6 Billion	\$10.2 Billion	\$8.9 Billion
Remaining Assets (Book Value)	\$2.6 Billion	\$0	\$1.3 Billion
Average Rate (cents per kWh)	18.2	18.2	18.2
Return On Equity	5.79%	1.94%	4.27%
Equivalent Operating Cost Offset Percent of LIPA O&M Budget	\$450 Million 81%	\$633 Million 114%	\$348 Million 62%

Cases 5, 6 and 7 are based on the assumptions concerning rate base and market multiples (and hence acquisition price) that we used for Cases 3, 2 and 4. In those earlier cases, we solved for rates assuming that the new utility would be allowed to earn a normal return on equity (ROE) equal to the average rate that has been allowed by the NY PSC in recent rate cases for the State's investor owned utilities. For Cases 5, 6 and 7, we instead reverse these calculations, solving for ROE while we hold rates constant at the current baseline level.

We find that these cases are relevant to consider because LIPA's rates are currently considered high by customers and regulators. This suggests that while the Privatization option may present a variety of positive attributes to many observers, it is unlikely that it could be implemented together with a rate increase.

Case 5 presents the situation under which the acquiring utility could not receive the 19.3 cents per kWh estimated in Case 1, where the IOU earned an return on equity (ROE) of 9.75%. Instead, the IOU would only be able to earn an ROE of 5.79%. The more the acquiring utility pays for LIPA assets, the lower will be its return on equity when rates are capped at the baseline level, all other factors being equal. In Case 7, the acquirer would pay a multiple of 1.2x of PPE for LIPA's productive assets; it would consequently earn an ROE equal to about 4.27%.

Case 6 represents a circumstance in which the NY PSC allows all of LIPA's assets (productive and non-productive) to be included in rate base, as was the assumption in Case 2. In this case, however, we assume that rates are capped at 18.2 cents per kWh. The acquiring utility, having invested \$10.2 billion in LIPA, would only be able to earn a return on equity of 1.94%. Importantly, such rates of return on equity are below current utility bond costs, while those bonds are senior to equity in claims on cash flow and are much less risky. Thus, it is wholly implausible that any investor would accept these returns – meaning it must either expect a material rate increase or believe it has some other means of obtaining savings that restore acceptable returns.

Rates can also be kept at current levels if the acquiring utility can find savings in operating costs sufficient enough to offset the increases in financing costs. In this way, the IOU would not have to sacrifice its earnings. As we discussed in the introductory chapter and elsewhere in this report, the opportunity to realize improved operating efficiencies and reductions in costs are factors that frequently motivate utility mergers and acquisitions and organizational restructurings. Utility mergers and acquisitions are typically among investor owned utilities, however. The savings realized need only offset the costs of implementing the reorganization; they do not need to offset the increased costs associated with changing from tax-exempt financing to a combination of taxable debt and equity. In other cases – notably when government owned utilities and telephone companies were privatized in the U.K. and in other parts of the world – savings were expected to be significant because of the bloated cost structures associated with government owned enterprises.

The above table includes an estimate of the amount of cost that would have to be trimmed from LIPA's current O&M operating budget in order for the acquiring utility to hold rates at current levels and earn an ROE of 9.75%. The table indicates that these amounts are very high and, in our view, impossible to meet. At the extreme, they comprise most of the entire T&D cost of operations, which we also showed were already in line with IOU national averages. We discuss more realistic targets for cost savings in Chapter III of this report. There, we see opportunities for reductions in operating O&M that are closer to \$100 million than they are to the equivalent cost offsets included in Table IV-7, (and \$100 million of such savings have been included already in the above Privatization rate impact estimates).

We present a final scenario in which an acquiring utility is willing to pay enough to LIPA to retire all of its obligations while also keeping rates at their baseline levels. We consider such a scenario because it presents a desirable end state. However, as seen below, it places the acquirer in an implausible, likely infeasible situation.

Table IV-8
Scenario Set D: No Rate Increase / No Obligations

Case 8	
Rate Base	\$7.6 Billion (Productive Assets Only)
Market Value / Book Value	3.25x (= Multiple on PPE of 1.9x)
Acquisition Price	\$13.2 Billion
Remaining Assets (Book Value)	-\$3.0 Billion
Average Rate (cents per kWh)	19.3
Return On Equity	2.26%
Assets In LIPA SPE	-\$3.0 Billion
Interest Rate	5.00%
SPE Rate (cents per kWh)	-1.2
Total Rate (cents per kWh)	18.2

We started this case with a set of assumptions similar to those used in Case 1. That is, the NY PSC would allow the acquiring IOU to include just LIPA's used and useful assets in rate base. With the allowed return on equity of 9.75%, this resulted in average rates equal to 19.3 cents per kWh. For this case, we then solved for the market multiple that would be needed for the acquirer to provide sufficient funding for: a) LIPA to retire its obligations and b) to set up an annuity to, in effect, reimburse rate payers on Long Island and Queens for the difference between the rates that would be charged by the acquiring IOU (19.3 cents per kWh) and the baseline rates (18.2 cents per kWh).

The table shows that an acquirer would need to pay a multiple above the book value of productive assets equal to 1.9x, equivalent to a market value to book value ratio for equity of roughly 3.25x. (No such multiples are ever observed for normal utilities in the financial market.) This would result in LIPA receiving a purchase price of approximately \$13.2 billion. It would then use the \$3.0 billion above the book value of its total assets (\$10.2 billion) to set up a fund to pay-out its current ratepayers. We modeled this pay-out mechanism in the same way that we modeled the SPE in the scenarios above. In this case, however, the SPE would make payments to customers, instead of charging them.

We consider this case to be largely illustrative for several reasons. To make such an arrangement work, we estimate that the acquiring utility would have to be willing to accept a return on equity of 2.26%. This is an exceptionally low return, e.g., below much less risky long term municipal bond rates. It is completely infeasible unless the acquirer sees extremely significant growth opportunities that are not apparent to current LIPA management or ourselves.

E. BOND DEFEASANCE

As shown above on LIPA balance sheet, it currently holds short- and long-term debt equal to approximately \$6.8 billion. These notes and bonds were issued and guaranteed by LIPA, and have terms and conditions attached. Bond holders are entitled to receive prescribed payments (that reflect the interest rates associated with the series) from LIPA at scheduled intervals.

The bonds issued by LIPA are composed of a combination of “callable” and “non-callable” bonds. Callable bonds can be redeemed or paid off by the issuer prior to the bonds' maturity date. Call provisions are often part of corporate and municipal bonds, but usually not bonds issued by the federal government. For callable bonds, the issuer has the option to redeem the bond on specified dates (shown on a call schedule) and prices prior to maturity. Callable bonds are more risky for investors than non-callable bonds because an investor whose bond has been called is often faced with reinvesting the money at a lower, less attractive rate. As a result, callable bonds often have a higher annual return to compensate for the risk that the bonds might be called early, or they include a call exercise premium that would have to be paid at the time. Bonds that do not have this call provision are, logically, referred to as non-callable. Typically, because investors are not asked to accept the risk of their bonds being redeemed prior to maturity, non-callable bonds have a lower annual return than callable bonds.

In the case under which LIPA would be acquired in its entirety, it would receive proceeds from its acquirer and would no longer have assets or revenues with which to back its outstanding bonds. It would also have proceeds that, hopefully, would be equal to or greater than the amount of outstanding debt. Under a simple scenario, LIPA would pay off its bonds. Specifically, it would pay bond holders the face value of the bond plus any accrued interest and, from that point on would end its bond related obligations.

In practice, the advance refunding of bonds is more complex. Rather than simply paying off the face value of the old debt immediately, bond covenants require that new funds must be obtained and set aside to replace some of the payouts that the old bonds would have provided to their investors. If interest rates are different (lower) at the time of refinancing than the average rates on the old debt, this can require providing more new funds than the face value of the old debt. This is the case for LIPA's debt at the present time. Current interest rates on comparably risky government securities of similar maturities are tens to even hundreds of basis points below LIPA's bond coupon rates. The result is that approximately \$960 million more debt will have to

be raised to create a pool of new debt that reproduces the old debt's payouts.⁶ These new funds must be set aside in escrow and pledged to the former bond holders, so that they do not experience a loss of payout or an increase in risk (impairment of creditworthiness).

The legal documents that controlled the security provisions for the bonds will be said to have been "defeased," meaning that those provisions generally no longer apply to the bonds. Importantly, the legal documents typically establish requirements for the quality of investments that must be placed in escrow in order to defease the lien placed on the security for the bonds. In LIPA's case, its bond agreements require that it defease its debt with U.S. Treasuries or state and local government bonds. An interesting result associated with defeasing debt is that it is not unusual for bonds that have been advance refunded to receive a higher credit rating from one or more credit rating agencies due to the establishment of an escrow account holding highly rated investments.

Municipal bonds are most frequently defeased when the municipality is trying to lower its overall cost of borrowing; it is seeking to lower its interest payments by paying off bonds it has previously issued at higher than current market interest rates with newly issued refunding bonds that pay interest at a lower rate. This is similar, at least at its most basic level, to a home owner refinancing her house. In other cases, such as would possibly be the case for LIPA if the Privatization option were implemented, the bonds must be defeased in order to satisfy legal covenants or restrictions.

Bond market conditions are a very important factor when a municipality is considering defeasing bonds (as are mortgage interest rates, typically, the primary factor for a homeowner considering refinancing). LIPA's average coupon rate on its roughly \$7 billion of debt is 4.5625%. This is considerably higher than current market conditions; the current average rate for state and local government bonds of comparable risk and maturity is 2.8094%. This makes a gap between LIPA's coupon rate and the current market rate of approximately 175 basis points. It also means the market value of LIPA's debt is currently well above its book (face, par) value, and much of

⁶ Approximately \$80 million of this is already reflected in liabilities for certain securities that are marked to market on LIPA's balance sheet, so the net effect is around \$882 million, used below in tables estimating the rate impacts of defeasance.

this difference must be returned to the bondholders. Thus, current market conditions add to the previously discussed incremental financing costs associated with implementing the Privatization option.

LIPA has counsel and advisors on matters concerning its bonds and have included LIPA's bond issues, including all the terms and conditions concerning redemptions, in the data and programs that they run on LIPA's behalf.⁷ They have estimated that defeasing LIPA's bonds under current market conditions would cost LIPA an additional (roughly) \$961 million; that is, in addition to the cost of principal and accrued interest. Specifically, their estimate is composed of:

- Roughly \$666 million to defeasing LIPA bond issues of roughly \$6.7 billion. In making this calculation, they assumed that LIPA's debt would be defeased through its first call date, not for its full life and if a debt series has coupon rates which make it less economical to call, it will be defeased to maturity. Review of LIPA debt indicates that most of LIPA's debt is callable within about 10 years of issuance at no or low penalty.
- Approximately \$295 million to cover the cost of terminating \$1 billion of fixed-for-variable interest rate swaps. To defease these obligations, LIPA's counter-parties would receive fixed payments. These interest rate swaps are non-callable swaps, but they are currently in the money for the counter-parties. If LIPA terminated these swap agreements, they need to be marked to market (to make the fixed payment recipient whole).

We conducted a simplified market valuation of LIPA debt in order to estimate the difference between the face value of LIPA's bonds and the market value of U.S. Treasury securities, the debt that would be used to replace LIPA's bonds. We reviewed all of LIPA's bond issues and placed them in three groups to reflect term: bonds which will mature in 0 to 5 years; bonds which will mature in 6 to 15 years; and bonds which will mature in 16 to 30 years. By its design – that is, aggregating LIPA's bond issues into three average bond issues, instead of the bond-by-bond analysis conducted by LIPA's financial advisor, the results of our valuation analysis, summarized in Table IV-9, do not precisely match the advisor's detailed analysis. However, they do provide intuition and confirmation for the magnitude of the defeasance cost developed by LIPA's financial advisor.

⁷ LIPA's financial advisor for matters concerning issuance of bonds is Public Financial Management, Inc.

Table IV-9
Calculation of Bond Defeasance as of 6/2/2011

Tenure	Par Plus Zero Coupon Appreciation (\$) [1]	Average Interest Rate [2]	Interest Rate (High) [3]	Interest Rate (Low) [4]	Treasury Security Average Yield [5]	Weighted Average Maturity [6]	Market Value of Treasury Securities (\$) [7]	Excess Present Value of Treasury Securities (\$) [8]
0-5 years	1,452,818,798	4.342%	5.720%	0.230%	0.768%	11/28/2013	1,488,243,984	35,425,186
6-15 years	2,245,076,691	5.089%	5.940%	4.000%	2.690%	10/6/2021	2,568,001,863	322,925,172
16-30 years	3,018,350,139	5.118%	6.250%	4.085%	4.085%	11/26/2031	3,415,106,502	396,756,363
Total	6,716,245,628						7,471,352,349	755,106,721

Source: Bloomberg, last accessed 6/10/2011, and "Sources and Uses of Funds," prepared by Public Financial Management, Inc, pp. 3-7.

Notes:

[2]: Derived by weighting interest rates by the market values of LIPA's bonds.

[6]: Derived by weighting days to maturity by the market values of LIPA's bonds.

[7]: Calculated from par amount of LIPA's debt assuming average treasury security yield and weighted average maturity.

[8]: [7] - [1]

Our simplified analysis indicates that LIPA's bonds, with a face value of roughly \$6.7 billion, is approximately \$755 million less than the market value of U.S. Treasury securities with similar maturities. (This ignores the swaps that also have to be marked to market for liquidation). The market value of the Treasury securities in the table above were derived through the combination of interest rates and maturities. For bonds of similar maturity and risk, lower interest rates result in higher bond prices (or market values). Thus, the market value of U.S. Treasury securities under the current market conditions is roughly \$7.5 billion while the face value of LIPA's bonds is roughly \$6.7 billion. This relationship is obviously sensitive to market conditions, hence to the timing of any transaction. If interest rates were to increase (not currently likely) it would tend to reduce the defeasance cost (because it would narrow the spread between LIPA's coupon rates and current interest rates). However, this would also tend to raise the cost of new utility bonds, and the cost of equity for the acquiring utility. The overall effect on rate increases accompanying privatization would likely be worse, despite the reduced defeasance costs.

We find that our valuation analysis is generally in line with the more detailed analysis completed by LIPA's financial advisor. The difference in market values that we estimated in our analysis (of approximately \$755 million) would increase to roughly \$850 million if we were to increase the terms of maturities in each of our three categories of bond issues by just one year.

F. RATE IMPACTS

We began the discussion concerning rate impacts for the Privatization option in section D of this chapter. The analysis there indicated that average electric rates for LIPA's customers would increase in all cases in which the acquiring utility would be allowed to earn the average ROE allowed by the PSC in New York State (9.75%). We also found that when in circumstances when rates were held at the current baseline levels, the acquiring utility would have to either forego a substantial amount of earnings or it would have to find very high levels of savings in LIPA's operating O&M expenses.

The impact of adding the cost of defeasing LIPA's bonds on top of this makes either the rate impact of privatization more pronounced or it makes the returns realized by the acquiring IOU still lower. We show our estimate of average rates including the cost of bond defeasance in Table IV-10.

Table IV-10
Rate Impact with Defeasance Cost

	Defeasance Case
Rate Base	\$7.6 Billion (Productive Assets Only)
Defeasance Cost	\$882 Million
Acquisition Price	\$8.45 Billion
Remaining Assets (Book Value)	\$2.6 Billion
Average Rate (cents per kWh)	19.7
Return On Equity	9.67%
Assets In LIPA SPE	\$2.6 Billion
Interest Rate	5.00%
SPE Rate (cents per kWh)	1.0
Total Rate (cents per kWh)	20.7

We based our estimate in Table IV-10 upon the assumptions that were used for Case 1. Rate base was set to include LIPA's productive assets only. We then included the cost of bond defeasance in the acquisition price but financed it with debt only. This resulted in an average rate charged by the acquiring utility of 19.7 cents per kWh; it would earn a return on equity of roughly 9.67%. Similar to the approach taken in Cases 3, 4 and 8, we then assumed that LIPA would retain its non-productive assets, hold them in an SPE and finance it with tax-exempt debt. This added 1.0 cents per kWh to rates, as it did in Case 3.

This resulted in a total average rate of 20.7 cents per kWh. We regard this as among the lower rates possible when accounting for recovery of the costs of defeasing LIPA's bonds.

G. FINDINGS AND CONCLUSIONS

1. Our overarching conclusion for this chapter is that the increases in financing costs under the Privatization option overwhelm any of the gains in operating efficiencies plausibly realized for that option.

We estimate that privatization would result in an increase of approximately \$438 million in annual revenue requirements due to financing costs alone, excluding any costs associated with defeasing LIPA's bonds. Several other changes also occur under Privatization that impact this increase:

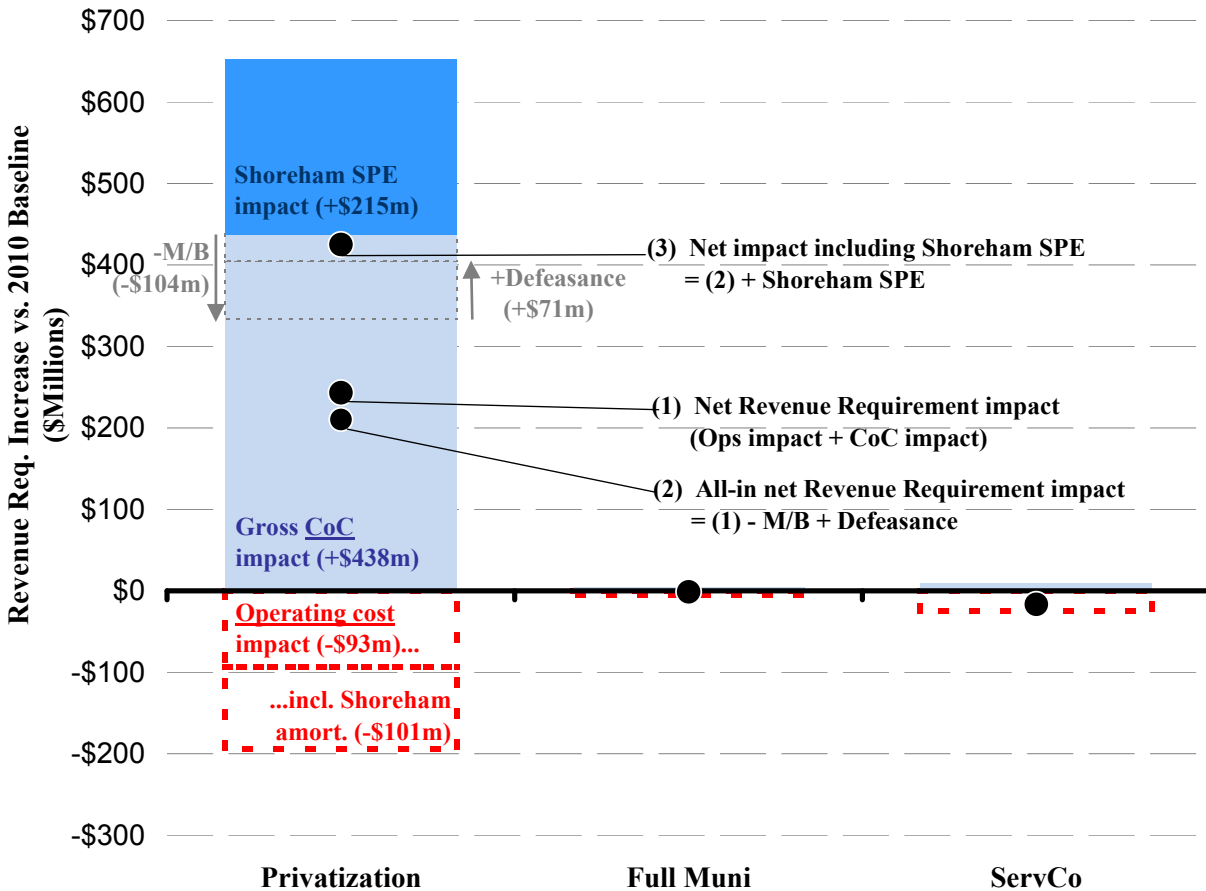
- \$93 million reduction in operating cost savings
- \$101 million reduction due to Shoreham amortization avoided by the new owner if that cost is put in a new SPE
- \$215 million increase in costs from that new Shoreham SPE
- \$71 million increase in costs due to carrying extra debt needed to defease existing bonds
- Possible, \$104 million decrease from the acquirer paying more than book value for LIPA's PPE.

Altogether, these result in a total cost increase slightly larger than \$400 million. This would result in an increase in electric rates to rate payers on Long Island of roughly 12%.⁸

The composition of changes in LIPA's 2010 baseline revenue requirement is shown in Figure IV-2 below.

⁸ Currently, LIPA includes its annual lease payments for capitalized leases as part of fuel and purchased power expenses. Capitalized lease expenses include depreciation, fixed and variable O&M and financing charges. It is possible that, under a Privatization option, regulators would only allow a portion of these payments in rates. While the extent of such an adjustment is uncertain, we estimate that it could be as much as \$0.005 to \$0.006 per kWh.

Figure IV-2
Total Impacts On Revenue Requirements and Rates
Compared To 2010 Baseline
(\$ Million)



The figure demonstrates that the impact of the financing costs under the Privatization option is significant compared to the changes in operating costs, so much so that it obscures (graphically) the incremental changes in operating costs under the ServCo and Municipalization options.

2. Even optimistic variations on the Privatization option involve increased financing costs.

As we discussed throughout this chapter, generally accepted methodologies used by regulators to set electric rates have been well codified. Projecting average electric rates under the Privatization option involves trade-offs. Keeping rates at or near the 2010 baseline, however,

would require a combination of unreasonably large cost reductions, implausibly low ROEs, and/or the need for other entities to cover non-productive assets.

These trade-offs are presented in Table IV-11.

Table IV-11
Trade-Off Across Rate-Making Determinants

Acquisition Terms and Structure:				U & U assets in	U & U assets	U & U assets in
		As-is	All-book	RB + SPE	in RB + SPE + defeasance	RB + SPE + defeasance + M/B of 1.5x equity
Acquisition Value	(\$Bil)	\$10.2	\$10.2	\$7.6	\$8.5	\$9.7
Rate Base (RB)	(\$Bil)	n/a	\$10.2	\$7.6	\$7.6	\$7.6
Rates from RB	(¢/kWh)	18.2¢	21.3¢	19.3¢	19.3¢	19.3¢
Shoreham SPE	(¢/kWh)			1.0¢	1.0¢	1.0¢
Amortization of defeasance	(¢/kWh)				0.3¢	0.3¢
Rebate from acquisition premium	(¢/kWh)					-0.5¢
Total Rate	(¢/kWh)	18.2¢	21.3¢	20.4¢	20.7¢	20.2¢
Earned ROE	(%)	n/a	9.75%	9.75%	9.67%	7.13%
Required cost reductions for all-in 18.2¢ rate	(\$Mil)	\$0	\$633	\$450	\$519	\$417
ROE with rates capped at 18.2¢	(%)	n/a	1.94%	5.79%	3.77%	2.54%

3. The significant rate impact associated with the Privatization option largely removes this option from consideration.

This should not be interpreted to mean there is anything intrinsically undesirable about privatization. To the contrary, it offers the potential for larger operating savings. However, what this finding highlights is the extremely attractive situation LIPA currently enjoys from having 100% tax-exempt debt financing. This saves LIPA ratepayers hundreds of millions of dollars per year – billions in present value compared to conventional IOU financing – so it should not be discarded lightly, nor imagined that private efficiencies can easily replace this significant advantage.

We base our conclusion here on the evaluative criteria established at the outset of our study and discussed in Chapter I. Specifically, we developed a rate impact model as the primary method for quantifying the impacts that may be realized under the three organizational options considered.

As discussed earlier in this chapter, regulatory precedents and accounting allow us to estimate rates and value utility businesses with a strong level of precision. While there are inevitably areas that are subject to judgment by regulators – and thus may affect the ultimate rate that an IOU would be able to charge its customers – we do not expect any of these to significantly impact the estimates of rate base, return on equity and other elements of financing costs that we have presented throughout this chapter.

There is also some degree of uncertainty about precisely how attractive LIPA's assets and customer base might be to a new owner, which could only be resolved with an actual solicitation of interest. Therefore, "testing the market" might appear an attractive option in order to check our analyses concerning purchase price. However, we strongly doubt that any potential buyers would reach materially different conclusions than we have presented about the costs and constraints in changing ownership. Moreover, privatization requires its own lengthy process of soliciting and vetting offers. Once initiated it may interfere with other options to such an extent that it becomes the only option; that is, it becomes an irreversible process. Such a gamble may well be worth it – if we were not confident that privatization would be accompanied by a significant rate increase.

Also, LIPA has recently received proposals for Utility Management Services (UMS) from interested utilities and is currently discussing the details associated with moving forward with this option. Concurrently pursuing the Privatization option and negotiating a UMS contract would probably be quite difficult, largely because it involves the same pool of candidates.

4. Inclusion of financing costs has no impact on the ServCo and Municipalization options; projected average rates under these options remain a virtual tie.

The only differences between the financing costs in the baseline case and those included in our projections for the ServCo and Municipalization options reflect minor changes in the level of capital expenditures. We increased the dollars required in order to finance any incremental additions to new plant. However, these additions were financed at LIPA's average rates of interest of its debt.

A summary of rate impacts as well as the estimated impact on a representative customer bill is shown in Table IV-12.

Table IV-12
Illustrative Summary of Rate and Bill Impacts

	Rate (¢/kWh)	Change from Base Case (%)	Illustrative* Monthly Impact of Customer Bill (\$/Mo)
2010 Baseline Case	18.2	n/a	\$140.84 (absolute)
Privatization**	20.4	+12.1%	+\$17.08
ServCo	18.05	-0.7%	-\$0.93
Municipalization	18.15	-0.1%	-\$0.21

* Monthly bill based on average revenue requirement and monthly consumption of 775 kWh.

** Note that the rate under privatization is estimated to range from 20.2 to 20.7 ¢/kWh.

Chapter V

Additional Factors

The primary focus of this study has been to assess the differences in costs and rates across the strategic organizational options considered. We projected costs and rates by estimating the “steady state” condition of each option; that is, the cost structure underlying the organizational options when implemented. As was included in Chapter III, we also included the amortized costs associated with completing a transaction (especially relevant for the Privatization option; referred to as the “transaction costs”) as well as the costs associated with completing implementation and integrating new work forces into the reorganized entity (referred to as “transition costs”).

We estimated the relative difficulties of achieving these steady state conditions in our cost projections. As described in previous chapters, we found a material (“bright line”) difference in projected costs between the Privatization options and the two municipalization-like options. Despite potential operating savings (if purchased by another regional utility) under Privatization and enhanced performance incentives under privatization, there were far larger financial costs of moving away from 100% tax-advantaged debt financing currently enjoyed by LIPA to the 50/50 debt/equity, income taxed capital structure of an investor owned utility. These increased financing costs are likely to be on the order of most or even all of the current total operating costs of running the T&D operations of LIPA today, making it implausible that a prospective owner might anticipate offsetting them with operational cost savings, or that such an owner would be willing to purchase LIPA under a rate freeze.

Thus, the choice is between the Municipalization and ServCo options – which turn out to have very similar overall costs, though with somewhat different component costs beneath the surface equivalence. We factored three additional factors into the assessment process.

- Differences in the level of complexity of the transition and likelihood of failure between the Municipalization and ServCo options.
- Option values associated with the organizational options.

- Qualitative factors, notably differences in incentives and in managerial and political preferences concerning an end-state, all other factors being equal.

In this chapter, we present our insights as to the likely most critical factors that distinguish ServCo from Municipalization and vice-versa, but we are inherently not able to provide an assessment of managerial or political tolerances and preferences. This ultimately is a decision that only the current management and its Trustees can make.

A. STRATEGIC OPTIONS: STRENGTHS AND WEAKNESSES

Just as the costs are nearly equivalent for Muni and ServCo, their qualitative pros and cons are also somewhat equivocal, with strengths and weaknesses for each, especially when viewed in abstraction as general possibilities rather than specific plans from particular sponsors.

1. Case For Municipalization

The qualitative arguments in support of implementing the Municipalization option focus on the coherency and conventionality of the organization that would be created. All the employees would work directly for the same, single entity, and there would be no future discontinuities of control or managerial approach occasioned by changes in ServCo contracts. Municipal utilities are common in the US, and many perform very well, with operating efficiencies and total cost per kWh comparable to well-run IOUs. LIPA is a big enough utility that there should not be any issue of losing important economies of scale or scope if it were to be fully municipalized, although loss of institutional expertise during the transition could be problematic. A fully municipalized LIPA could be more transparent and directly responsive to customers than a two-stage ServCo entity.

There are several factors that offset, in part, the benefits that may be accrued under the Municipalization option. First, fully municipalizing LIPA would require a very large organizational transformation, enlarging LIPA's current staff level of approximately 100 employees to roughly 2,000. This would require developing and placing a senior team that is sufficiently experienced in directly managing a fully functioning utility. It will also involve a range of logistical human resource and information system coordination issues.

Second, it is likely that a fully municipalized LIPA would face constraints in certain key areas of its operations. This includes constraints on terms and conditions of employment and procurement. Specifically, most likely, a fully municipalized LIPA would not be able to offer direct compensation levels or incentive bonuses/rewards that will be competitive with those offered by IOUs, especially for upper management position. Thus a fully municipalized LIPA would likely face challenges in attracting and retaining employees with senior and/or specialized expertise.

Third, fully municipalizing LIPA would also constrain contracts with outside contractors for operational related services (currently procured through LIPA's service provider) to follow New York State's procurement rules and approval process. These may involve solicitation constraints, timing, or approval criteria that could potentially interfere with the typical business patterns for T&D utility operations.

Fourth, the governance structure under the Municipalization is open and inclusive to community involvement. Such a structure has certain benefits, especially regarding transparency, but it also adds steps and time to the decision making process, and it involves input from more disparate parties who have varying degrees of familiarity with the available alternatives and who may also have motivations that do not always mesh well with each other or reflect widely held views. This is particularly in contrast to the governance structure under the Privatization option, but it may also differ from the ServCo, in that the latter allows the ServCo provider to enjoy the more focused and responsive governance of a private, competitive corporation. Best practices among IOUs have broadened communications and interaction with interested communities within their service area. However, presentation and discussion concerning both routine and strategic issues is not a public matter under the IOU governance structure, and decisions can be made in a more streamlined fashion, subject to adherence to law and regulation.

Finally, there are a variety of issues whose resolution may require political and legislative actions. These include legislative action that may be required to set LIPA up to be a fully municipalized utility. It also includes decisions concerning whether current employees of the service provider would remain in a pension system similar to their current plan or be moved into

the New York State and Local Retirement System. These issues are not insurmountable. However, there is material uncertainty surrounding the ultimate outcomes (pension systems provides a good example) and, in any event, the legislative process, such as it may be required, takes time to complete.

2. Case For ServCo

The case for ServCo starts with the fact that it provides access to private sector managerial expertise and scale of operations from the ServCo provider, while preserving the attractive financing advantages of a tax exempt entity. A moderate management fee (of a few tens of millions of dollars per year) is paid in lieu of the much more costly (several hundred million dollars per year) increase in pre-tax cost of capital that privatization would entail. Second, a ServCo offers the potential for a speedier, more certain transition to improved systems for measuring, monitoring, and providing service.

LIPA has operated under a contractual outsourcing arrangement for over a decade. Much has been learned about how to make T&D outsourcing more effective; e.g., via creation of a truly dedicated service company whose incentives depend on performance targets rather than on cost tradeoffs, with more LIPA oversight of budgets and employment.

The analysis of cost and performance benchmarking studies (presented in Chapter II) revealed that LIPA is already operating relatively efficiently and reliably. That analysis also pointed out that LIPA has extremely poor customer satisfaction ratings. Thus, it should be a strategic priority to improve the customer interface while simply holding operating costs and reliability to their current, very competitive levels. Some of LIPA's processes, databases, and computer systems in billing, call service, and customer and managerial information are outdated, inadequately integrated, and/or inconvenient to use to support improved operations. Therefore, a ServCo provider with substantial, proven experience in these skills and systems should be able to jump-start LIPA's campaign to improve on these dimensions.

An additional advantage of the ServCo option is that it has more long-term flexibility to support future reorganizations than does the Municipalization option. In all likelihood, implementing the

Municipalization option is a “once-and-for-all” decision. ServCo has been designed to include an exit provision (which we discuss in greater depth later in this chapter). Thus, ServCo can readily transition in the future – into a fully municipalized utility, an alternate ServCo provider (with the benefit of new expertise being infused by the next provider), or even privatization. This flexibility to reorganize, especially to do so opportunistically, if/when future circumstances make it attractive, is valuable provided there is significant flexibility and low cost to exercise such rights.

Offsetting these potential benefits is the concern that a third-party provider of ServCo inherently faces somewhat limited and under-specified incentives to serve LIPA’s interests unequivocally. That is, it always faces some degree of concern about protecting its own profitability vs. optimizing LIPA’s performance; the ServCo provider could “game” the reward/penalty structure of the UMS contract. However, a good contract combined with the incentive structure for ServCo employee compensation can mitigate this concern.

B. RISK OF REORGANIZATION

Reorganizing LIPA from its current structure to a ServCo or Municipal structure involves a degree of risk. As discussed earlier, we estimated the expected costs associated with making a transition from the current organization to proposed organizational options. In the cost projections presented in Chapter III, higher transition costs generally reflect more complex transition plans. There are risks, however, that the reorganization process will take more time and/or be more costly than expected.

Our review of the organization of LIPA’s T&D operations indicates that the organization and operations are already largely stand-alone and will continue much as in the past under any alternative; thus, they are substantially insulated from many transition risks. An exception may involve a dramatic change in benefits and/or pensions that would serve to disrupt the motivation and loyalty of the work force. This also means that there is little incremental risk of catastrophic failure if either the ServCo or Municipalization options are adopted, beyond the typical level of risk associated with running an electric utility. In particular, there is no concern that one form of organization is worse than the other, or worse than in the past, at being able to “keep the lights

on”. However, risk differences may arise and be more specifically identifiable concerning the development and transition of systems.

We described the need to replace and/or upgrade several of LIPA’s critical information systems, especially for the customer-facing functions. The costs of developing and implementing these systems varies slightly between the ServCo and Municipalization options, but any cost differences are not material – especially regarding rate impacts, as the capital costs for system development are included in rates as a depreciation expense. Delayed or substandard implementation could also dampen customer enthusiasm for new interfaces – such as improved billing formats and information, rollout of conservation and smart grid measures, website improvements, and the like – that are intended to increase customer satisfaction. Potential risk also centers on the possibility of errors, slow transaction processing or event response, and/or lack of public explanation (transparency) for controversial aspects of company performance (such as pattern and rate of storm response, or rate increases needed due to upstream environmental improvements) that may frustrate customers. While the stand-alone economic values of these potential customer frustrations are small, their collective importance in improving the climate of customer relations is large, which in turn could affect more material decisions such as whether to accelerate debt servicing to reduce outstanding liabilities.

There are transition risks in both approaches. ServCo has a transition window built into it for the new provider to become assimilated into LIPA operations and to transfer planning and operational systems to LIPA-dedicated platforms. Service providers being considered by LIPA have demonstrated their experience in system development and implementation. Importantly, they have also agreed to face performance penalties for failure to implement the new upgrades in a timely fashion. This suggests that LIPA has been able to transfer some of this implementation risk under ServCo, while it would retain all such risk under the Municipalization option.

Beyond the logistics associated with transitioning and implementing critical information systems, as referenced earlier in this report, moving LIPA from its current structure to a fully municipalized utility involves a range of activities, some of which may involve legislative

actions at the State level. These activities do not merit consideration if LIPA were to transition from its current organization to a ServCo model.

C. OPTION VALUE

While it is always possible, at least in principle, to change organizational structures as management and its Board of Directors (or Trustees) see fit, we are not aware of any case in which a privatized IOU changed its form of organization to that of a municipal utility, or vice-versa. More common are changes in internal organizational structure (e.g., changing from a geographic focused form of organization to one that is more focused on customer segments, or shifting out of generation towards being just or primarily a T&D entity with regulated operations). Thus, for all intents and purposes, the Privatization and Municipalization options are largely “once and for all” decisions. ServCo, on the other hand, is designed to include an exit or renewal optionality. Furthermore, it is designed to be largely dedicated (i.e., self-contained) and transportable. Hence, its design makes it amenable to future conversion and assimilation into LIPA as either a fully municipalized utility or a private company. A critical provision of the ServCo contract, should it be executed, is, therefore, its termination provision, which could allow a timely and cost effective method for LIPA to leave the ServCo arrangement. That is, the termination provisions we understand are being negotiated for the USM offer contracts should provide LIPA with an economically attractive option value – specifically, a low cost “put option” - to abandon the ServCo structure and contract for the other forms, if and/or when appropriate circumstances arise.

In general, such organizational strategic optionality can be valuable for the same reasons that an actual put option on a common stock is valuable; it is insurance against a relative drop in value of the current arrangement. So-called “real options” have become an important part of strategic corporate planning and valuation in the last 20 years or so. The mathematics of option valuation for securities was developed in the late 1970s and early 1980s, but it soon became apparent that many multi-stage contingent business decisions can be evaluated in the same manner, mathematically, as put and call options on securities. The logic is that an option gives the holder the right but not the obligation to change positions at (or up to) some future point in time for a fixed or predictable transition cost. If and when the value of the alternative to which the rights-

holder can switch is greater than the transition cost, it becomes attractive to exercise the option. Prior to that occurrence, the option has a present value equal to the probability of the benefits it could confer. Likewise, multi-stage corporate decisions give their managers the right but not the obligation to make contingent future adjustments to an initial strategy or business plan. Methods of real options analysis apply this insight to valuing corporate decisions that offer off-ramps or on-ramps for altered business operations in response to shifting conditions. If some strategies or assets offer more such prospects, they tend to be more valuable – particularly more valuable than a “due course” evaluation would suggest (for pursuing them under expected conditions with no contingent adjustments).

Applying such an option framework to LIPA and ServCo may, in practice, be more conceptual than formal. The option framework discussed above is typically applied to specifically defined transactions (such as fuel prices). Options can be exercised because triggering conditions are observable: that is, the holder of an option can tell when its rights are “in the money” or not. For LIPA, unlike for the holder of an option on a traded security, the payoffs from exercising the option to leave ServCo for another form are not directly observable. This means there will not be any bright line, objective measure to justify triggering the option.

Nonetheless, there are plausible circumstances in which the ServCo termination option could become meaningful and attractive to exercise. These begin with “safety valve” situations. If LIPA is dissatisfied with material aspects of the utility services that it receives from the service provider, it can terminate the USM and seek another service provider, owner, or self-managing structure. Other factors may also lead LIPA to exercise the termination option. For example, LIPA may find that it prefers a higher degree of control over day to day operation, or tax code changes could make privatization far less costly (lower costs of refinancing) for investors or ratepayers. Thus, the ServCo termination options provide both defensive and offensive opportunities for LIPA

D. FINDINGS AND CONCLUSIONS

In Chapters II and III we presented an analysis of LIPA’s current form of organization and also quantified the changes that would likely occur under the three strategic options under study.

There, we found that LIPA's T&D operations would not be compromised by moving to either a ServCo or fully municipalized structure. We also noted that the overall cost and rate impacts associated with the ServCo and Municipalization options were very close.

In an ideal situation, the cost differential across strategic organizational option would be material and consideration of additional factors would be supplemental. The situation here, however, is quite different from that. We find that the costs and rate impacts projected for the ServCo and Municipalization options are at a virtual tie. Our findings and conclusion concerning these additional considerations may thus take on more importance.

1. The ServCo model retains the financial advantages of municipalization, but it is also a partial privatization model (or "privatization light").

Earlier in this report, we referred to the ServCo option as a partial municipalization option because under it LIPA would remain a municipal utility, albeit with a high degree of outsourced services. This is correct and important, in light of how significant the cost advantages of the tax exempt structure are compared to IOU financing. However, seen in another light, ServCo can be considered to be partial privatization because an IOU conducts and manages its operations. Indeed, this can be inferred to be partly responsible for why LIPA already has operational costs and reliability levels that are highly competitive with private sector utilities. Under ServCo, it pays a management fee (part of which is a profit to the service provider) instead of having to pay a return on equity to investors. This translates into paying approximately \$30 million a year in profit versus \$400 million or more per year in higher costs of financing.

2. For the termination optionality included under the ServCo contract to have value to LIPA, it must be considered in proactive terms.

The proactive side of the option involves LIPA consciously assessing its operational and financial performance as well as industry market conditions in order to determine if moving from ServCo to either the Privatization or Municipalization makes sense. As discussed above, such a determination is not an easy one, and its monitoring need not take the form of constantly

repeated studies of the costs or pros and cons of further reorganization. LIPA has already investigated changing its organizational structure on at least three occasions, including this one, over the course of the last decade. In each case, the economics underlying the alternate strategic organizational models were analyzed.

However, consideration for changing LIPA's organizational structure also involves strategic level direction and decisions that fall outside of economic studies. These involve setting strategic directions and resolving threshold questions that fall within the purview of LIPA's Board of Trustees. In particular, understanding the legal steps that would be needed to pursue either privatization (such as what assets and liabilities could or could not be transferred to a new owner, vs. would have to be bought out) or municipalization (such as what would be required to establish pension coverage for the transferred employees) would be very helpful to assessing when or whether to reorganize again. Also, monitoring and reporting on the fulfillment of milestones for self-sufficiency under the ServCo structure would be helpful, especially insofar as critical transition steps were completed successfully. (For instance, completion of transfer and calibration of customer interface systems is probably a threshold matter before further reorganization would be reasonable to consider.)

We find that the value associated with the ServCo termination option provision increases with such proactive consideration. Absent that, ServCo's option value is largely reactive, and is a safety net if performance under the ServCo contract is found to be unacceptable.

3. ServCo allows LIPA to transfer much of the risk associated with organizational transformation, as well as to expedite implementation of service improvements.

We identified the costs and general risks associated with transforming LIPA from its current structure to a fully municipalized utility. Logistical issues will present challenges to the timing and implementation of a fully municipalized model. As we introduced above, the sheer transition from a 100 employee organization to one that has roughly 2,000 employees is accompanied by numerous coordination and transition issues involving human resources and information systems.

Additional areas of risk involve the improvement (through upgrades or overall replacement) of some of LIPA's customer facing information systems. While delay of failure of these efforts will not lead to a failure of LIPA's electric system, it will be noticed by customers, and may impede LIPA's efforts to improve its relationships with its customers. A well-qualified ServCo provider can provide valuable expertise and platforms for upgrading LIPA's customer interfaces, and should be able to develop and implement systems more quickly and with less development risk than a fully municipalized LIPA could accomplish "from scratch."

None of the above issues and risk elements are insurmountable under either form of organization. As mentioned, the lights will assuredly stay on under the Municipalization option. Nonetheless, ServCo provides a mechanism to resolve open issues and complete transformation without LIPA assuming all of the risk associated with organizational and information system development and implementation.

4. The ServCo model has merit by itself.

The current organizational structure under which LIPA outsources the majority of its T&D operations was created to address specific and unique circumstances facing customers on Long Island. Since it has been put in place, LIPA and its customers have been able to benefit from materially lower costs of capital than a conventional utility. During that time, LIPA has also developed significant experience concerning how to contract for private sector managerial expertise in T&D operations. That this form of organization has merit is evident from the general level of cost efficiency and distribution reliability that its predecessor MSA arrangement has produced. The ServCo will be designed to be a more dedicated subsidiary organization, which should address many of the various shortfalls that have been identified under the MSA.

The details of the ServCo model may also evolve over time. In one respect, ServCo is a very modern form of organization, utilizing periodic competitive infusions of outside services to find new ways to control costs and increase quality.

Chapter VI

Conclusions and Recommendations

This study was concerned primarily with assessing the relative feasibility and attractiveness of LIPA implementing a new form of its corporate organization going forward. LIPA's current organizational structure is largely centered around its Management Services Agreement (MSA) with National Grid, which will expire in the near future, so it must be replaced with another contractual-based organizational structure (ServCo), reorganize as a self-contained municipal-style utility, or be acquired by a new private owner. Each of the three possible organizational options represents a departure from the current form of organization to a greater or lesser degree. The organizational options were analyzed primarily in terms of the impact on average electric rates to LIPA's customers.

Our study was strategic in nature in that it examined LIPA's corporate structure, its approach to its responsibilities associated with operating an electric utility, and financing impacts. It was also conducted at a very detailed level in order to ensure that the consequences and materiality associated with each organizational option were appropriately considered. In particular, we considered a substantial amount of data on LIPA's past costs and service quality, its projected budgets, and the details of costs associated with services it has been receiving from National Grid under the expiring MSA. This fills a gap in prior reorganizational studies, which did not have the opportunity to review and develop a financial model of T&D operations based on data representing actual performance.

In this chapter, we present our overall conclusions and recommendations, which are based on the analysis presented in the preceding chapters of this report.

1. Cost and rate impact analysis clearly indicates that implementation of the Privatization option would result in an average rate increase for LIPA's customers; this serves to remove privatization as an option at the current time.

Analysis indicates that implementation of the Privatization option would likely result in gains in operating efficiencies (or, alternately stated, in reductions in operating costs). However, these

gains would not be terribly large, in large part because the current MSA structure already captures some of the benefits of private sector management of T&D operations. Our benchmarking studies indicated that LIPA's T&D costs are quite reasonable relative to national averages and other similar utilities. Indeed, they are generally below the averages for other NY IOUs. We found there is potential for approximately \$100 million in potential operating savings, the large majority of which consists of avoided profit payments to the MSA (or its replacement) and reduced PILOT payments. However, these somewhat uncertain savings would be more than offset by the much more certain increases in the costs associated with financing the privatized operation, which include the costs associated with providing investors with a return on equity as well as the addition of taxes on income at the federal and state level.

Rates for LIPA as a privatized (investor owned) electric utility can readily be estimated because the rate making process for regulated utilities is relatively prescribed and the NY PSC treats all the existing IOUs in a fairly similar fashion. Accordingly, we have strong confidence that our projections for rate impacts under the Privatization option are accurate; we provide a range of outcomes that reflect variations in critical assumptions.

Rate increases under privatization could be moderated slightly by "partially privatizing," but this could involve creating multiple new entities in order to service all of LIPA's obligations. The concept here would be to privatize only LIPA's productive assets and have LIPA (or other successor, special purpose entities) retain and finance its non-productive assets. Under these conditions, the privatized utility would have a rate base of used and useful assets equal to roughly \$7.6 billion. With this, plus accounting for roughly \$100 million of annual reductions in operating costs, average rates would increase from the baseline level of 18.2 cents per kWh to 19.3 cents per kWh. Importantly, a LIPA legal entity would still need to exist and pass on another 1 cent per kWh to customers in order to fund the amortization of the non-productive assets that were not privatized.

We also considered the moderating impact that use of “two county rule” financing might have on the overall cost of privatizing LIPA.¹ Legal counsel to LIPA provided guidance concerning interpretation and eligibility on this matter, and concluded that use of this type of financing (exempt from federal income taxes) does not apply to acquisitions. That is, such financing, if it were available, could only be used for financing additions to plant in the future. It would not have an affect on the financing available to acquire and privatize LIPA’s existing assets. In essence, there is no apparent way to keep the debt financing advantages LIPA currently enjoys while also becoming privately owned.

2. The overall costs associated with the ServCo and Municipalization options, as well as their associated impacts on average electric rates, are roughly equal.

We found that the average rate impact was barely lower under the ServCo option than under the Municipalization option in our “mid case” scenario, but that difference is small compared to some of the uncertainties surrounding exactly how various costs could change under either form, so it is not difficult to change assumptions and reverse this ranking. The core costs and activities (e.g., T&D operations and maintenance) under both options are very similar in many regards, with a few points of distinction in the managerial and corporate support areas.

The costs under the ServCo option include a payment reflecting a profit to the service provider; this is not included as an operating expense under the Municipalization option. The operating costs under the Municipalization option probably would include an incremental increase in benefit and pension expenses; this has been assumed in the mid case. As there is significant uncertainty concerning the treatment of pensions should current National Grid employees be transferred to LIPA, we also conducted “low case” (which keeps pension related costs at current levels) and “high case” scenarios.

Excluding these two cost areas – pensions and profits – the cost structures associated with these two options are very close. Even when applying the scenario reflecting current LIPA levels of

¹ The “two county rule” refers to interest on Private Activity Bonds described in Section 1414(a) of the Internal Revenue Code of 1986. Exceptions to federal income tax (set forth in Section 142 of the Code) include facilities used for local furnishing of electric energy or gas.

pension costs (part of the low-cost Municipalization scenario) and the high-cost option for ServCo, the difference in rates is within a few tenths of a cent per kWh. While this certainly represents a considered impact in absolute terms, these cost differences are not material nor reliable enough to have a significant impact upon rates, or to be a basis for preferring one option over the other.

3. Implementation risk is higher under the Municipalization option than under the ServCo option.

A primary area of risk associated with LIPA's organizational transformation concerns the development and implementation of systems, in particular customer-facing information systems. It is likely that development and implementation of these systems will be more efficient under the ServCo option, because the service provider should be able to leverage the expertise that it has demonstrated in its own utility systems and operations. Under the Municipalization option, LIPA would need to acquire such expertise, through contract or direct hire. This is not an insurmountable challenge, but one that is more difficult than the ability to leveraging expertise under the ServCo option. Getting its customer-facing systems right is clearly important to LIPA and it will be a part of LIPA's efforts to improve customer satisfaction. Development and implementation "failure" in this area would likely result in delay, higher development costs, and perhaps some managerial and customer frustration with transitional systems, but it would not place LIPA's T&D operations at risk.

4. ServCo is an approach that captures some of the benefits of privatization while preserving the financing advantages of public, tax-exempt debt, and its design is an improvement on the existing MSA.

Our finding that the financing costs of switching to private ownership under NY PSC conventional ratemaking would be prohibitively expensive can be interpreted more positively as demonstrating how attractive the current tax-exempt debt financing is to LIPA and its customers. Thus, strategies that preserve this advantage are desirable. However, it would also be desirable to have the discipline and managerial insights, employee performance incentives, and process experience and systems of a private IOU to help direct T&D operations. The ServCo structure

accomplishes this – as demonstrated in part by the fact that LIPA’s operational costs and service reliability are already quite competitive with national averages among IOU utilities.

However, there have been some areas of concern under the current MSA, including issues such as lack of transparency concerning costs and staffing, and disagreements over the tradeoffs between capital expenditures (replacements) and operating expense approaches (repairs) to managing costs and quality. The proposed ServCo structure has a considerably different contract structure than the current MSA, including more dedicated staffing with LIPA oversight, stand-alone capabilities, cost-based pricing with LIPA responsibilities for capital and operating budgets, and profit incentives tied to progressive realization of performance targets (not cost reductions or cost tradeoffs). These characteristics should make a contractual based organizational structure more transparent, more accountable, and more adaptive than in the past.

5. ServCo has two additional attractive features: it is portable and provides option value (flexibility) to adjust in the future, if needed or desired.

The fact that ServCo is being developed as a dedicated organization also creates the possibility of its portability, i.e., its direct transfer to a fully municipalized or privatized organizational structure or a ServCo successor. Essentially, LIPA is transferring the risk of developing a stand-alone organization to the service provider.

We understand that the termination option provisions being negotiated with ServCo bidders are flexible and relatively inexpensive. In particular, they may not include termination payments for years of lost profits, but instead involve covering adjustment costs and minor fees. This inexpensive flexibility, if incorporated, is valuable in that it allows LIPA to exit the contract with its service provider if it dissatisfied with its performance. While it is not currently foreseen that this optionality would be exercised, we find that there are foreseeable circumstances, as well as open questions and issues, the resolution of which could make fully municipalizing or even privatizing more attractive. Notably, these open issues include such matters as: the pension treatment of current National Grid employees as they are transferred to LIPA; the salary scales for LIPA executive management under the Municipalization option; the full scope and scale of

legislative issues required to complete the municipalization process; and the impact on budgeting, operating and procurement practices under various New York State guidelines. In principle, though less likely, it is also possible that changes could occur in corporate or municipal tax law that would make privatization involve less of a refinancing penalty.

6. Overall, we recommend adopting the ServCo model. It retains the efficient operations achieved by privatized utilities while taking advantage of tax exempt financing. It also reduces transitional risks, thereby probably expediting improvements in customer service.

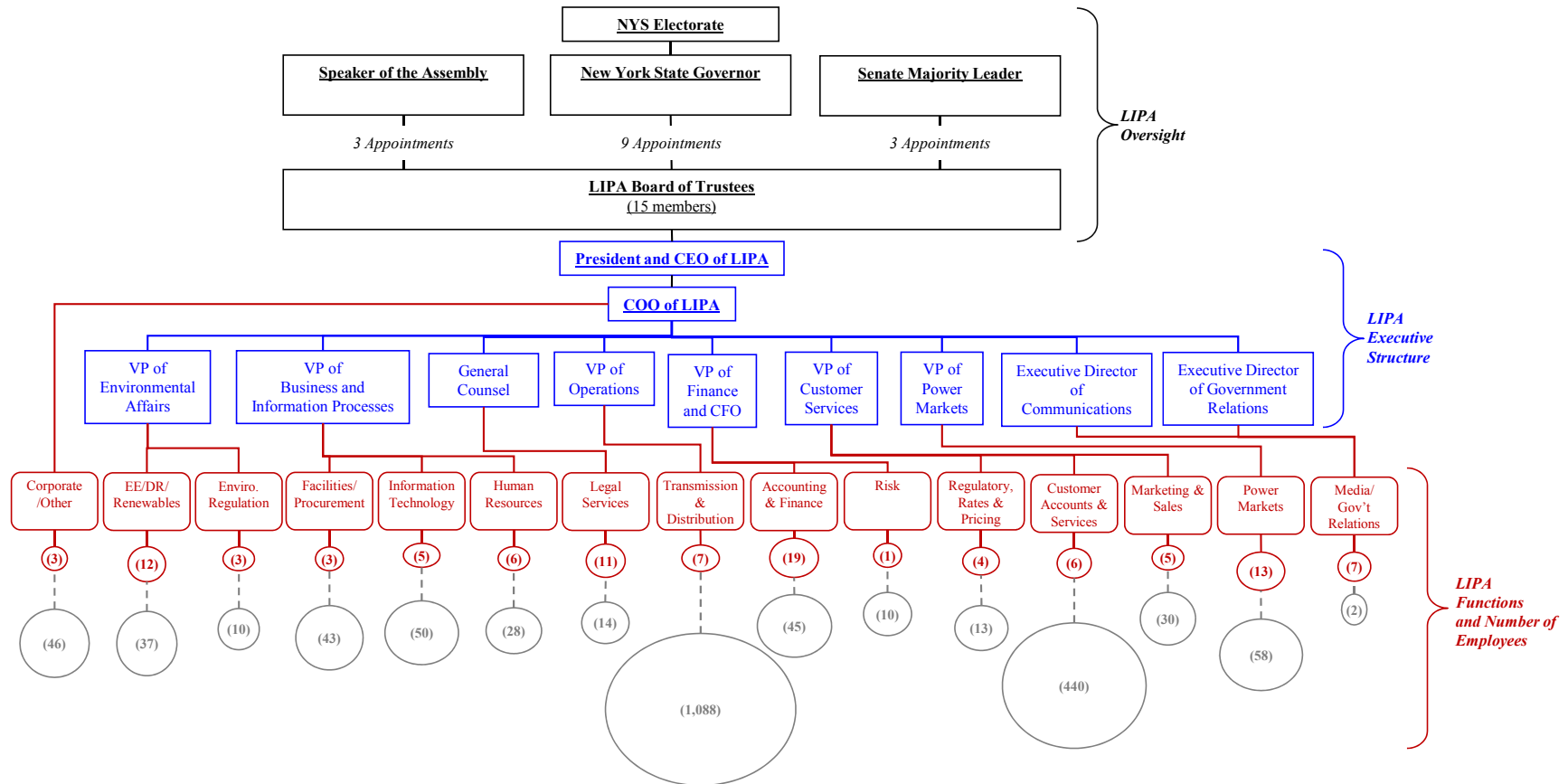
As demonstrated throughout this report, the cost difference between the ServCo and Municipalization options is too narrow to make cost ranking the sole basis of selection. Neither do the risk or option provisions strongly make the case for one option over the other – although these generally support preferring the ServCo model.

We find the most compelling area for supporting ServCo to be LIPA's relatively efficient level of operations in terms of cost and reliability under the current outsourced model. Prior shortcomings under this arrangement should be improved under the new ServCo model. This model is not without its drawbacks, including that it involves paying a profit component to the service provider and requires contract oversight. However, this model allows LIPA to take advantage of the efficiencies that have been demonstrated by IOUs without incurring the high cost of financing under a full privatization model. Essentially it is allowing LIPA to forego high financing costs in exchange for a much smaller management fee. It also allows LIPA to shift many risks associated with transitional issues away from itself and to the service provider. Finally, it is not a once and for all decision; LIPA can move to a fully municipalized utility if it finds resolution of the open issues are conducive to such.

APPENDICES

Appendix A

LIPA Organization, Functions, and Interface with National Grid



LIPA Functions
(LIPA total direct employees = 104)
(National Grid employees serving LIPA functions = 1,913)

Notes: Number of employees is expressed in "Full-time equivalent" or FTE.
Functions are do not appear to add to totals due to rounding

Appendix B LIPA T&D O&M

	2009 Costs (\$000)	2010 Costs (Estimated) (\$000)
National Grid Fee + Pass-Through Costs	\$803,196	\$881,900
<u>Cost Areas</u>		
EE/DR/Renewables	\$5,185	\$6,150
Environmental Regulation	\$1,637	\$1,942
Regulatory, Rates, & Pricing	\$2,360	\$2,800
Customer Accounts & Services	\$49,510	\$58,721
Marketing & Sales	\$2,364	\$2,803
Media/Government Relations	\$632	\$750
Accounting & Finance	\$8,915	\$10,573
Finance: Risk	\$1,047	\$1,242
Legal	\$4,647	\$5,511
T&D Operations & Maintenance - Lines & Subs	\$43,366	\$45,729
T&D Maintenance - Veg Mgmt	\$10,299	\$12,215
T&D Operations - Service	\$25,610	\$29,809
T&D Operations - Systems	\$2,908	\$3,449
T&D Operations - Engineering	\$13,103	\$13,469
T&D Operations - Planning/Management	\$13,833	\$16,406
T&D Operations - General/Other	\$31,298	\$33,468
Power Markets	\$4,423	\$5,246
Facilities/procurement	\$15,680	\$18,597
IT	\$17,147	\$20,337
HR	\$21,773	\$25,824
Other/corporate	\$77,652	\$92,099
PSA-related	\$425,243	\$445,626
Total Cost Areas	\$778,632	\$852,765
Residual = Estimated MSA profit/loss	\$24,565	\$29,135

Appendix C **Pensions & Benefits Analysis** 2009 – 2010 Baseline Pensions & Benefits Expenses

Functional Area	National Grid (2009)			LIPA (2009)			LIPA (2010)			2009	2010
										Total	Total
	Non-Pension Benefits	Pensions + OPEBs	Total P + B	Non-Pension Benefits	Pensions + OPEBs	Total P + B	Non-Pension Benefits	Pensions + OPEBs	Total P + B	Total P + B	Total P + B
	(\$000)	(\$000)	(\$000)	(\$000)	(\$000)	(\$000)	(\$000)	(\$000)	(\$000)	(\$000)	(\$000)
EE/DR/Renewables	\$423	\$1	\$424	\$354	\$271	\$625				\$1,049	\$1,244
Environmental Regulation	\$299	\$184	\$484	\$77	\$59	\$136				\$620	\$735
Regulatory, Rates, & Pricing	\$430	\$213	\$643	\$113	\$86	\$199				\$842	\$999
Customer Accounts & Services	\$9,552	\$5,981	\$15,533	\$175	\$133	\$308				\$15,841	\$18,788
Marketing & Sales	\$499	\$328	\$826	\$144	\$110	\$254				\$1,080	\$1,281
Media/Government Relations	\$81	\$49	\$130	\$216	\$165	\$381				\$511	\$606
Accounting & Finance	\$1,019	\$650	\$1,669	\$585	\$448	\$1,033				\$2,702	\$3,205
Finance: Risk	\$237	\$113	\$350	\$31	\$24	\$54				\$404	\$479
Legal	\$542	\$332	\$874	\$339	\$259	\$598				\$1,472	\$1,746
Power Markets	\$692	\$380	\$1,072	\$401	\$306	\$707				\$1,779	\$2,110
Facilities/procurement	\$1,698	\$1,061	\$2,759	\$103	\$79	\$181				\$2,940	\$3,487
IT	\$1,918	\$1,196	\$3,114	\$164	\$126	\$290				\$3,404	\$4,037
HR	\$15,065	\$1,156	\$16,221	\$195	\$149	\$344				\$16,565	\$19,647
Other/corporate	(\$6,014)	\$49,158	\$43,144	\$92	\$71	\$163				\$43,307	\$51,364
T&D Operations & Maintenance - Lines & Subs	\$6,512	\$2,317	\$8,829	\$0	\$0	\$0				\$8,829	\$10,472
T&D Maintenance - Veg Mgmt	\$82	\$0	\$82	\$0	\$0	\$0				\$82	\$97
T&D Operations - Service	\$1,490	\$41	\$1,530	\$0	\$0	\$0				\$1,530	\$1,815
T&D Operations - General/Other	\$4,065	\$912	\$4,977	\$216	\$165	\$381				\$5,357	\$6,354
T&D Operations - Systems	\$381	\$46	\$427	\$0	\$0	\$0				\$427	\$506
T&D Operations - Engineering	\$2,560	\$941	\$3,501	\$0	\$0	\$0				\$3,501	\$4,153
T&D Operations - Planning/Management	\$2,662	\$1,105	\$3,768	\$0	\$0	\$0				\$3,768	\$4,469
Total	\$44,192	\$66,164	\$110,356	\$3,204	\$2,450	\$5,654	\$3,822	\$3,104	\$6,926	\$116,010	\$137,594
National Grid FTEs	1,913										
LIPA FTEs	104										
Cost Per FTE	\$23,103	\$34,589	\$57,691	\$30,808	\$23,558	\$54,365	\$36,750	\$29,846	\$66,596	\$57,520	\$68,222

Appendix C (cont.)
Pensions & Benefits Analysis
2009 – 2010 Baseline Direct Labor Expenses

	National Grid Direct Labor Costs (2009) (\$000)	LIPA Direct Labor Costs (2009) (\$000)	LIPA Direct Labor Costs (2010) (\$000)	2009 Total Direct Labor (\$000)	2010 Total Direct Labor (\$000)
EE/DR/Renewables	\$3,575	\$1,079		\$4,654	\$5,519
Environmental Regulation	\$724	\$235		\$959	\$1,137
Regulatory, Rates, & Pricing	\$1,372	\$344		\$1,716	\$2,035
Customer Accounts & Services	\$23,891	\$532		\$24,423	\$28,967
Marketing & Sales	\$1,130	\$438		\$1,568	\$1,860
Media/Government Relations	\$213	\$657		\$870	\$1,032
Accounting & Finance	\$3,064	\$1,783		\$4,846	\$5,748
Finance: Risk	\$500	\$94		\$594	\$704
Legal	\$1,355	\$1,032		\$2,387	\$2,831
Power Markets	\$2,300	\$1,220		\$3,520	\$4,174
Facilities/procurement	\$3,976	\$313		\$4,289	\$5,087
IT	\$4,565	\$500		\$5,065	\$6,007
HR	\$2,713	\$594		\$3,307	\$3,923
Other/corporate	\$4,505	\$281		\$4,787	\$5,677
T&D Operations & Maintenance - Lines & Subs	\$20,601	\$0		\$20,601	\$24,434
T&D Maintenance - Veg Mgmt	\$702	\$0		\$702	\$833
T&D Operations - Service	\$12,195	\$0		\$12,195	\$14,464
T&D Operations - General/Other	\$19,166	\$657		\$19,823	\$23,511
T&D Operations - Systems	\$2,601	\$0		\$2,601	\$3,084
T&D Operations - Engineering	\$8,076	\$0		\$8,076	\$9,579
T&D Operations - Planning/Management	\$6,464	\$0		\$6,464	\$7,667
Total	\$123,690	\$9,757	\$10,127	\$133,447	\$158,274

Appendix C (cont.)

Pensions & Benefits Analysis

Pensions & Benefits / Labor Ratios

	National Grid (2009)			LIPA (2009)			LIPA (2010)			2009 Total	2010 Total
	Ratio: Non- Pension Benefits	Ratio: Pensions & OPEBs	Ratio: Total P + B	Ratio: Non- Pension Benefits	Ratio: Pensions & OPEBs	Ratio: Total P + B				Ratio: Total P + B	Ratio: Total P + B
	To Direct Labor	To Direct Labor	To Direct Labor	To Direct Labor	To Direct Labor	To Direct Labor				To Direct Labor	To Direct Labor
EE/DR/Renewables	12%	0%	12%	33%	25%	58%				23%	23%
Environmental Regulation	41%	25%	67%	33%	25%	58%				65%	65%
Regulatory, Rates, & Pricing	31%	16%	47%	33%	25%	58%				49%	49%
Customer Accounts & Services	40%	25%	65%	33%	25%	58%				65%	65%
Marketing & Sales	44%	29%	73%	33%	25%	58%				69%	69%
Media/Government Relations	38%	23%	61%	33%	25%	58%				59%	59%
Accounting & Finance	33%	21%	54%	33%	25%	58%				56%	56%
Finance: Risk	47%	23%	70%	33%	25%	58%				68%	68%
Legal	40%	25%	65%	33%	25%	58%				62%	62%
Power Markets	30%	17%	47%	33%	25%	58%				51%	51%
Facilities/procurement	43%	27%	69%	33%	25%	58%				69%	69%
IT	42%	26%	68%	33%	25%	58%				67%	67%
HR	555%	43%	598%	33%	25%	58%				501%	501%
Other/corporate	-133%	1091%	958%	33%	25%	58%				905%	905%
T&D Operations & Maintenance - Lines & Subs	32%	11%	43%							43%	43%
T&D Maintenance - Veg Mgmt	12%	0%	12%							12%	12%
T&D Operations - Service	12%	0%	13%							13%	13%
T&D Operations - General/Other	21%	5%	26%	33%	25%	58%				27%	27%
T&D Operations - Systems	15%	2%	16%							16%	16%
T&D Operations - Engineering	32%	12%	43%							43%	43%
T&D Operations - Planning/Management	41%	17%	58%							58%	58%
Total Ratio	36%	53%	89%	33%	25%	58%	38%	31%	68%	87%	87%
Direct Labor / Total L + B			53%			63%			59%	53%	53%
P + B / Direct Labor + P + B			47%			37%			41%	47%	47%
Excluding Benefits "Catch Up"											
Catch Up Charge	\$6,017	\$48,423	\$54,440							\$54,440	\$64,569
Adjusted Total P + B	\$38,175	\$17,741	\$55,916	\$3,204	\$2,450	\$5,654	\$3,822	\$3,104	\$6,926	\$61,570	\$73,025
Ratios To Direct Labor	31%	14%	45%	33%	25%	58%	38%	31%	68%	46%	46%

Appendix D
Non-Labor O&M Expenses Baseline Analysis
National Grid

2009 NATIONAL GRID									2010 Total (Labor + Non-Labor) O&M (\$000)
	Materials / expenses (\$000)	Outside services / contractors (\$000)	Systems (\$000)	Rents / leases (\$000)	Fleet leases (\$000)	Tax (\$000)	Other costs (\$000)	2009 TOTAL Non-Labor (\$000)	
EE/DR/Renewables	\$177	\$951	\$0	\$4	\$3	\$6	\$46	\$1,187	\$6,150
Environmental Regulation	\$251	\$56	\$0	\$0	\$22	\$72	\$28	\$429	\$1,942
Regulatory, Rates, & Pricing	\$41	\$197	\$1	\$10	\$13	\$79	\$6	\$346	\$2,800
Customer Accounts & Services	\$2,857	\$3,360	\$68	\$52	\$657	\$1,966	\$1,126	\$10,085	\$58,721
Marketing & Sales	\$48	\$139	\$1	\$24	\$1	\$113	\$81	\$407	\$2,803
Media/Government Relations	\$218	\$30	\$0	\$0	\$6	\$18	\$16	\$289	\$750
Accounting & Finance	\$430	\$2,907	\$27	\$0	\$0	\$282	\$536	\$4,182	\$10,573
Finance: Risk	\$46	\$108	\$0	\$0	\$0	\$42	\$2	\$197	\$1,242
Legal	\$345	\$754	\$4	\$0	\$20	\$133	\$1,162	\$2,418	\$5,511
Power Markets	\$192	\$409	\$45	\$5	\$0	\$135	\$264	\$1,051	\$5,246
Facilities/procurement	\$99	\$1,428	\$0	\$842	\$168	\$497	\$5,911	\$8,945	\$18,597
IT	\$1,161	\$2,561	\$3,611	\$0	\$4	\$705	\$1,427	\$9,468	\$20,337
HR	\$517	\$1,784	\$2	\$6	\$26	\$486	\$18	\$2,839	\$25,824
Other/corporate	\$1,734	\$4,047	\$61	\$10	\$2	\$341	\$23,809	\$30,003	\$92,099
T&D Operations & Maintenance - Lines & Subs	\$3,700	\$2,356	\$167	\$1,313	\$4,970	\$1,168	\$262	\$13,936	\$45,729
T&D Maintenance - Veg Mgmt	\$42	\$9,102	\$0	\$5	\$36	\$602	(\$271)	\$9,515	\$12,215
T&D Operations - Service	\$2,992	\$6,430	\$2	\$18	\$1,146	\$772	\$523	\$11,885	\$29,809
T&D Operations - General/Other	\$1,361	\$2,721	\$8	\$33	\$285	\$515	\$2,231	\$7,155	\$33,468
T&D Operations - Systems	\$212	\$7	\$1	\$1	\$110	\$35	(\$487)	(\$119)	\$3,449
T&D Operations - Engineering	\$449	\$208	\$151	\$4	\$243	\$440	\$30	\$1,526	\$13,469
T&D Operations - Planning/Management	\$483	\$2,785	\$41	\$5	\$35	\$476	(\$224)	\$3,601	\$16,406
Total	\$17,354 15%	\$42,340 35%	\$4,191 4%	\$2,329 2%	\$7,747 6%	\$8,886 7%	\$36,496 31%	\$119,343	\$407,139

Appendix D (cont.)
Non-Labor O&M Expenses Baseline Analysis
LIPA

	2009 LIPA								
	Materials / expenses (\$000)	Outside services / contractors (\$000)	Systems (\$000)	Rents / leases (\$000)	Fleet leases (\$000)	Tax (\$000)	Other costs (\$000)	2009 TOTAL Non-Labor (\$000)	2010 Total (Labor + Non- Labor) O&M (\$000)
EE/DR/Renewables	\$58,918	\$0	\$0	\$192		\$0	\$166	\$59,277	\$72,327
Environmental Regulation	\$0	\$0	\$0	\$42		\$0	\$36	\$78	\$532
Regulatory, Rates, & Pricing	\$0	\$0	\$0	\$61		\$0	\$53	\$114	\$780
Customer Accounts & Services	\$0	\$0	\$235	\$95		\$0	\$82	\$412	\$1,484
Marketing & Sales	\$0	\$0	\$0	\$78		\$0	\$67	\$145	\$993
Media/Government Relations	\$0	\$0	\$0	\$117		\$0	\$1,034	\$1,151	\$2,596
Accounting & Finance	\$0	\$2,400	\$0	\$318		\$0	\$275	\$2,992	\$6,888
Finance: Risk	\$0	\$0	\$0	\$17		\$0	\$14	\$31	\$213
Legal	\$0	\$0	\$0	\$184		\$0	\$1,944	\$2,128	\$4,457
Power Markets	\$0	\$0	\$0	\$217		\$0	\$188	\$405	\$2,765
Facilities/procurement	\$0	\$0	\$0	\$56		\$0	\$48	\$104	\$709
IT	\$0	\$0	\$0	\$89		\$0	\$77	\$166	\$1,135
HR	\$0	\$0	\$0	\$106		\$0	\$92	\$197	\$1,347
Other/corporate	\$4,739	\$11,289	\$0	\$50		\$0	\$196	\$16,274	\$19,829
T&D Operations & Maintenance - Lines & Subs	\$0	\$0	\$0	\$0		\$0	\$0	\$0	\$0
T&D Maintenance - Veg Mgmt	\$0	\$0	\$0	\$0		\$0	\$0	\$0	\$0
T&D Operations - Service	\$0	\$0	\$0	\$0		\$0	\$0	\$0	\$0
T&D Operations - General/Other	\$0	\$0	\$0	\$117		\$0	\$101	\$218	\$1,489
T&D Operations - Systems	\$0	\$0	\$0	\$0		\$0	\$0	\$0	\$0
T&D Operations - Engineering	\$0	\$0	\$0	\$0		\$0	\$0	\$0	\$0
T&D Operations - Planning/Management	\$0	\$2,400	\$0	\$0		\$0	\$0	\$2,400	\$2,847
Total	\$63,657 74%	\$16,089 19%	\$235 0%	\$1,738 2%	\$0 0%	\$0 0%	\$4,374 5%	\$86,094	\$120,390

Appendix D (cont.)
Non-Labor O&M Expenses Baseline Analysis
Total (National Grid and LIPA)

2009 TOTAL (LIPA AND NATIONAL GRID)										
	Materials / expenses (\$000)	Outside services / contractors (\$000)	Systems (\$000)	Rents / leases (\$000)	Fleet leases (\$000)	Tax (\$000)	Other costs (\$000)	2009 TOTAL Non-Labor (\$000)	2010 Total Non- Labor O&M (\$000)	2010 Total (Labor + Non- Labor) O&M (\$000)
EE/DR/Renewables	\$59,095	\$951	\$0	\$196	\$3	\$6	\$212	\$60,464	\$71,713	\$78,476
Environmental Regulation	\$251	\$56	\$0	\$42	\$22	\$72	\$65	\$507	\$601	\$2,473
Regulatory, Rates, & Pricing	\$41	\$197	\$1	\$71	\$13	\$79	\$59	\$460	\$546	\$3,580
Customer Accounts & Services	\$2,857	\$3,360	\$303	\$146	\$657	\$1,966	\$1,208	\$10,497	\$12,450	\$60,205
Marketing & Sales	\$48	\$139	\$1	\$102	\$1	\$113	\$149	\$552	\$655	\$3,796
Media/Government Relations	\$218	\$30	\$0	\$117	\$6	\$18	\$1,050	\$1,440	\$1,708	\$3,345
Accounting & Finance	\$430	\$5,307	\$27	\$318	\$0	\$282	\$811	\$7,174	\$8,509	\$17,462
Finance: Risk	\$46	\$108	\$0	\$17	\$0	\$42	\$16	\$229	\$271	\$1,455
Legal	\$345	\$754	\$4	\$184	\$20	\$133	\$3,106	\$4,546	\$5,391	\$9,969
Power Markets	\$192	\$409	\$45	\$222	\$0	\$135	\$452	\$1,456	\$1,727	\$8,011
Facilities/procurement	\$99	\$1,428	\$0	\$897	\$168	\$497	\$5,959	\$9,049	\$10,732	\$19,306
IT	\$1,161	\$2,561	\$3,611	\$89	\$4	\$705	\$1,504	\$9,634	\$11,427	\$21,471
HR	\$517	\$1,784	\$2	\$112	\$26	\$486	\$109	\$3,036	\$3,601	\$27,171
Other/corporate	\$6,473	\$15,336	\$61	\$60	\$2	\$341	\$24,004	\$46,277	\$54,886	\$111,928
T&D Operations & Maintenance - Lines & Subs	\$3,700	\$2,356	\$167	\$1,313	\$4,970	\$1,168	\$262	\$13,936	\$10,822	\$45,729
T&D Maintenance - Veg Mgmt	\$42	\$9,102	\$0	\$5	\$36	\$602	(\$271)	\$9,515	\$11,285	\$12,215
T&D Operations - Service	\$2,992	\$6,430	\$2	\$18	\$1,146	\$772	\$523	\$11,885	\$13,530	\$29,809
T&D Operations - General/Other	\$1,361	\$2,721	\$8	\$150	\$285	\$515	\$2,333	\$7,373	\$5,091	\$34,957
T&D Operations - Systems	\$212	\$7	\$1	\$1	\$110	\$35	(\$487)	(\$119)	(\$142)	\$3,449
T&D Operations - Engineering	\$449	\$208	\$151	\$4	\$243	\$440	\$30	\$1,526	(\$263)	\$13,469
T&D Operations - Planning/Management	\$483	\$5,185	\$41	\$5	\$35	\$476	(\$224)	\$6,001	\$7,118	\$19,253
Total	\$81,012	\$58,429	\$4,426	\$4,067	\$7,747	\$8,886	\$40,871	\$205,437	\$231,661	\$527,529
T&D only	\$9,239	\$26,009	\$371	\$1,496	\$6,826	\$4,010	\$2,166			
	39%	28%	2%	2%	4%	4%	20%		MSA Profit	\$29,135
									Total O&M	\$556,664

Appendix E

Cost Benchmarking Peer Panels

Utility	Peer Panel = 1				Utility	Peer Panel = 1			
	National	NY	Neighbors	Similar		National	NY	Neighbors	Similar
Orange & Rockland Utilities Inc	1	1		1	Empire District Electric Co (The)	1			
Central Hudson Gas & Electric Corp	1	1			Entergy Arkansas Inc	1			
Consolidated Edison Co of New York Inc	1	1			Entergy Gulf States Louisiana LLC	1			
New York State Electric & Gas Corp	1	1			Entergy Louisiana Inc	1			
Niagara Mohawk Power Corp	1	1			Green Mountain Power Corp	1			
Rochester Gas & Electric Corp	1	1			Idaho Power Co	1			
Baltimore Gas & Electric Co	1		1	1	Indiana Michigan Power Co	1			
Connecticut Light & Power Co (The)	1		1	1	Indianapolis Power & Light	1			
Jersey Central Power & Light Co	1		1	1	Interstate Power & Light Co	1			
NSTAR Electric Co	1		1	1	Kansas City Power & Light Co	1			
Potomac Edison Co (The)	1		1	1	Kansas Gas & Electric Co	1			
Atlantic City Electric Co	1		1	1	KCP&L Greater Missouri Operations Co	1			
Delmarva Power & Light Co	1		1	1	Kentucky Power Co	1			
United Illuminating Co (The)	1		1	1	Kentucky Utilities Co	1			
Potomac Electric Power Co	1		1	1	Kingsport Power Co	1			
Massachusetts Electric Co	1		1		Louisville Gas & Electric Co	1			
Public Service Electric & Gas Co	1		1		Madison Gas & Electric Co	1			
Fitchburg Gas & Electric Light Co	1		1		Metropolitan Edison Co	1			
Western Massachusetts Electric Co	1		1		MidAmerican Energy Co	1			
Florida Power & Light Co	1			1	Midwest Energy Inc	1			
Gulf Power Co	1			1	Mississippi Power Co	1			
Tampa Electric Co	1			1	Monongahela Power Co	1			
CLECO Power LLC	1			1	Nantucket Electric Co	1			
Entergy Mississippi Inc	1			1	Nevada Power Co	1			
Entergy New Orleans Inc	1			1	Northern Indiana Public Service Co	1			
Entergy Texas Inc	1			1	Northern States Power Co (Minnesota)	1			
Narragansett Electric Co	1			1	Northern States Power Co (Wisconsin)	1			
Portland General Electric Co	1			1	NorthWestern Corp	1			
Public Service Co of New Hampshire	1			1	Ohio Edison Co	1			
Puget Sound Energy Inc	1			1	Ohio Power Co	1			
Southwestern Electric Power Co	1			1	Oklahoma Gas & Electric Co	1			
Alabama Power Co	1			1	Otter Tail Power Co	1			
Granite State Electric Co	1				Pacific Gas & Electric Co	1			
Appalachian Power Co	1				PacifiCorp	1			
Duke Energy Carolinas	1				PECO Energy Co	1			
Georgia Power Co	1				Pennsylvania Electric Co	1			
Progress Energy Carolinas	1				Pennsylvania Power Co	1			
Progress Energy Florida	1				PPL Electric Utilities Corp	1			
Virginia Electric & Power Co	1				Public Service Co of Colorado	1			
Pike County Light & Power Co	1				Public Service Co of New Mexico	1			
Rockland Electric Co	1				Public Service Co of Oklahoma	1			
ALLETE Inc	1				San Diego Gas & Electric Co	1			
AmerenCIPS	1				Sierra Pacific Power Co	1			
AmerenIP	1				South Carolina Electric & Gas Co	1			
Arizona Public Service Co	1				Southern California Edison Co	1			
Avista Corp	1				Southern Indiana Gas & Electric Co	1			
Bangor Hydro Electric Co	1				Southwestern Public Service Co	1			
Black Hills Power Inc	1				Superior Water Light & Power Co	1			
Central Maine Power Co	1				SWG Colorado LLC	1			
Central Vermont Public Service Corp	1				Toledo Edison Co (The)	1			
Cheyenne Light Fuel & Power Co	1				Tucson Electric Power Co	1			
Cleveland Electric Illuminating Co (The)	1				UGI Utilities Inc	1			
Columbus Southern Power Co	1				Unitil Energy Systems	1			
Commonwealth Edison Co	1				UNS Electric Inc	1			
Consumers Energy Co	1				Upper Peninsula Power Co	1			
Dayton Power & Light Co (The)	1				West Penn Power Co	1			
Detroit Edison Co (The)	1				Westar Energy Inc	1			
Duke Energy Indiana	1				Wheeling Power Co	1			
Duke Energy Kentucky	1				Wisconsin Electric Power Co	1			
Duke Energy Ohio	1				Wisconsin Power & Light Co	1			
Duquesne Light Co	1				Wisconsin Public Service Corp	1			
El Paso Electric Co	1								
					Total	123	6	13	23

Appendix F

LIPA Property Tax Payments under Different Options

	2009 (\$000)	2010 (\$000)
Revenue Taxes	\$55,308	\$64,247
Long Island and New York City	\$180,308	\$203,444
Nine Mile PILOTs	\$3,619	\$3,619
Merchant Power Plants	\$10,417	\$10,300
Other	\$0	\$0
Metropolitan Commuter Transportation Tax	\$28	\$34
Total PILOTs	\$194,372	\$217,397
Property Taxes on NGrid Power Plants (PSA)	\$176,282	\$183,333
Property Taxes on other Purchased Power Agreements	\$6,090	\$3,275
NYS Temporary Conservation Assessment	\$0	\$44,973
Petroleum Business Tax and Motor Fuels Tax	\$6,090	\$4,537
Sales and Use Tax on Purchases	\$9,081	\$17,936
Total Other Taxes, PILOTs and Assessments	\$197,543	\$254,054
Total State and Local Taxes, PILOTs and Assessments	\$447,223	\$535,698

Source: LIPA budgets.

Potential For Reduction In 2010 LI/NYC Property Tax / PILOT Expenses

ServCo Option	20%
Municipalization Option	15%
Privatization Option	30%

ServCo Option	(\$000)	(\$40,689)
Municipalization Option	(\$000)	(\$30,517)
Privatization Option	(\$000)	(\$61,033)

Adjustments To Revenue Taxes

ServCo Option	(\$000)	(\$296)
Municipalization Option	(\$000)	\$1,208
Privatization Option	(\$000)	\$5,657

Appendix G
Summary of Operations Cost Analysis
Privatization

	Adjustments to 2010 Baseline			2010 Baseline	
	Operating Costs			Rate Impact	Adjusted Rate
	Low Case (\$000)	Mid Case (\$000)	High Case (\$000)	(¢/kWh)	(¢/kWh)
Direct Labor	(\$13,987)	(\$11,656)	(\$9,324)	-0.056	18.117
Benefits & Pensions	(\$6,453)	(\$5,378)	(\$4,302)	-0.026	18.147
Profits	(\$29,135)	(\$29,135)	(\$29,135)	-0.140	18.033
Non-Labor O&M	(\$14,424)	(\$12,020)	(\$9,616)	-0.058	18.115
Facilities	\$10,000	\$10,000	\$10,000	0.048	18.221
PILOTs / Property Taxes	(\$61,033)	(\$61,033)	(\$61,033)	-0.294	17.879
Depreciation & Amortization	\$8,190	\$10,237	\$12,284	0.049	18.222
Revenue Taxes	\$5,657	\$5,657	\$5,657	0.027	18.200
Total (Including PILOTs Impact)	(\$101,186)	(\$93,328)	(\$85,470)	-0.449	17.724
<u>Rate Impact</u>					
Cents Per kWh	-0.487	-0.449	-0.411		
Adjusted Rate	17.686	17.724	17.762		
% of 2010 Baseline Rate	-2.68%	-2.47%	-2.26%		
Total (Excluding PILOTs Impact)	(\$40,153)	(\$32,295)	(\$24,437)		
<u>Rate Impact</u>					
Cents Per kWh	-0.193	-0.155	-0.118		
Adjusted Rate	17.980	18.018	18.056		
% of 2010 Baseline Rate	-1.06%	-0.85%	-0.65%		
2010 Baseline Rate (Cents per kWh)					18.173

Appendix G (cont.)
Summary of Operations Cost Analysis
ServCo

	Adjustments to 2010 Baseline			2010 Baseline	
	Operating Costs			Rate Impact	Adjusted Rate
	Low Case (\$000)	Mid Case (\$000)	High Case (\$000)	(¢/kWh)	(¢/kWh)
Direct Labor	(\$1,400)	\$75	\$1,550	0.000	18.173
Benefits & Pensions	(\$646)	\$35	\$715	0.000	18.173
Profits	\$865	\$865	\$25,865	0.004	18.177
Non-Labor O&M	(\$1,444)	\$78	\$1,599	0.000	18.174
Facilities	\$10,000	\$10,000	\$10,000	0.048	18.221
PILOTs / Property Taxes	(\$40,689)	(\$40,689)	(\$40,689)	-0.196	17.977
Depreciation & Amortization	\$4,061	\$5,076	\$6,092	0.024	18.198
Revenue Taxes	(\$296)	(\$296)	(\$296)	-0.001	18.172
Total (Including PILOTs Impact)	(\$29,548)	(\$24,856)	\$4,837	-0.120	18.054
<u>Rate Impact</u>					
Cents Per kWh	-0.142	-0.120	0.023		
Adjusted Rate	18.031	18.054	18.196		
% of 2010 Baseline Rate	-0.78%	-0.66%	0.13%		
Total (Excluding PILOTs Impact)	\$11,141	\$15,833	\$45,525		
<u>Rate Impact</u>					
Cents Per kWh	0.054	0.076	0.219		
Adjusted Rate	18.227	18.249	18.392		
% of 2010 Baseline Rate	0.29%	0.42%	1.21%		
2010 Baseline Rate (Cents per kWh)					18.173

Appendix G (cont.)
Summary of Operations Cost Analysis
Municipalization

	Adjustments to 2010 Baseline			2010 Baseline	
	Operating Costs			Rate Impact	Adjusted Rate
	Low Case (\$000)	Mid Case (\$000)	High Case (\$000)	(¢/kWh)	(¢/kWh)
Direct Labor	\$4,471	\$6,411	\$8,352	0.031	18.204
Benefits & Pensions	\$2,063	\$22,407	\$40,933	0.108	18.281
Profits	(\$29,135)	(\$29,135)	(\$29,135)	-0.140	18.033
Non-Labor O&M	\$4,611	\$6,612	\$8,613	0.032	18.205
Facilities	\$10,000	\$10,000	\$10,000	0.048	18.221
PILOTs / Property Taxes	(\$40,689)	(\$30,517)	(\$30,517)	-0.147	18.026
Depreciation & Amortization	\$6,626	\$7,362	\$9,571	0.035	18.209
Revenue Taxes	\$1,208	\$1,208	\$1,208	0.006	18.179
Total (Including PILOTs Impact)	(\$40,845)	(\$5,651)	\$19,025	-0.027	18.146
<u>Rate Impact</u>					
Cents Per kWh	-0.197	-0.027	0.092		
Adjusted Rate	17.977	18.146	18.265		
% of 2010 Baseline Rate	-1.08%	-0.15%	0.50%		
Total (Excluding PILOTs Impact)	(\$157)	\$24,865	\$49,541		
<u>Rate Impact</u>					
Cents Per kWh	-0.001	0.120	0.238		
Adjusted Rate	18.172	18.293	18.411		
% of 2010 Baseline Rate	0.00%	0.66%	1.31%		
2010 Baseline Rate (Cents per kWh)					18.173

Appendix G (cont.)
Summary of Operations Cost Analysis
Low Case Comparisons

	Privatization Option (\$000)	ServCo Option (\$000)	Municipalization Option (\$000)
Direct Labor	(\$13,987)	(\$1,400)	\$4,471
Benefits & Pensions	(\$6,453)	(\$646)	\$2,063
Profits	(\$29,135)	\$865	(\$29,135)
Non-Labor O&M	(\$14,424)	(\$1,444)	\$4,611
Facilities	\$10,000	\$10,000	\$10,000
PILOTs / Property Taxes	(\$61,033)	(\$40,689)	(\$40,689)
Depreciation & Amortization	\$8,190	\$4,061	\$6,626
Revenue Taxes	\$5,657	(\$296)	\$1,208
Total (Including PILOTs Impact)	(\$101,186)	(\$29,548)	(\$40,845)
<u>Rate Impact</u>			
Cents Per kWh	-0.487	-0.142	-0.197
Adjusted Rate (Cents Per kWh)	17.686	18.031	17.977
% of 2010 Baseline Rate	-2.68%	-0.78%	-1.08%
Total (Excluding PILOTs Impact)	(\$40,153)	\$11,141	(\$157)
<u>Rate Impact</u>			
Cents Per kWh	-0.193	0.054	-0.001
Adjusted Rate (Excluding PILOTs)	17.980	18.227	18.172
% of 2010 Baseline Rate	-1.06%	0.29%	0.00%

Appendix G (cont.)
Summary of Operations Cost Analysis
Mid Case Comparisons

	Operating Costs Adjusted From 2010 Baseline		
	Privatization Option (\$000)	ServCo Option (\$000)	Municipalization Option (\$000)
Direct Labor	(\$11,656)	\$75	\$6,411
Benefits & Pensions	(\$5,378)	\$35	\$22,407
Profits	(\$29,135)	\$865	(\$29,135)
Non-Labor O&M	(\$12,020)	\$78	\$6,612
Facilities	\$10,000	\$10,000	\$10,000
PILOTs / Property Taxes	(\$61,033)	(\$40,689)	(\$30,517)
Depreciation & Amortization	\$10,237	\$5,076	\$7,362
Revenue Taxes	\$5,657	(\$296)	\$1,208
Total (Including PILOTs Impact)	(\$93,328)	(\$24,856)	(\$5,651)
<u>Rate Impact</u>			
Cents Per kWh	-0.449	-0.120	-0.027
Adjusted Rate (Cents Per kWh)	17.724	18.054	18.146
% of 2010 Baseline Rate	-2.47%	-0.66%	-0.15%
Total (Excluding PILOTs Impact)	(\$32,295)	\$15,833	\$24,865
<u>Rate Impact</u>			
Cents Per kWh	-0.155	0.076	0.120
Adjusted Rate (Excluding PILOTs)	18.018	18.249	18.293
% of 2010 Baseline Rate	-0.85%	0.42%	0.66%

Appendix G (cont.)
Summary of Operations Cost Analysis
High Case Comparisons

	Operating Costs Adjusted From 2010 Baseline		
	Privatization Option (\$000)	ServCo Option (\$000)	Municipalization Option (\$000)
Direct Labor	(\$9,324)	\$1,550	\$8,352
Benefits & Pensions	(\$4,302)	\$715	\$40,933
Profits	(\$29,135)	\$25,865	(\$29,135)
Non-Labor O&M	(\$9,616)	\$1,599	\$8,613
Facilities	\$10,000	\$10,000	\$10,000
PILOTs / Property Taxes	(\$61,033)	(\$40,689)	(\$30,517)
Depreciation & Amortization	\$12,284	\$6,092	\$9,571
Revenue Taxes	\$5,657	(\$296)	\$1,208
Total (Including PILOTs Impact)	(\$85,470)	\$4,837	\$19,025
<u>Rate Impact</u>			
Cents Per kWh	-0.411	0.023	0.092
Adjusted Rate (Cents Per kWh)	17.762	18.196	18.265
% of 2010 Baseline Rate	-2.26%	0.13%	0.50%
Total (Excluding PILOTs Impact)	(\$24,437)	\$45,525	\$49,541
<u>Rate Impact</u>			
Cents Per kWh	-0.118	0.219	0.238
Adjusted Rate (Excluding PILOTs)	18.056	18.392	18.411
% of 2010 Baseline Rate	-0.65%	1.21%	1.31%