Electric System Long Range Plan
2010-2030

December 2010
# Table of Contents

1.0 Executive Summary .......................................................................................................................... 7
   1.1 Overview......................................................................................................................................... 7
   1.2 Key Elements of the Plan............................................................................................................... 9
   1.3 Plan Performance.......................................................................................................................... 22
   1.4 Uncertainties and Signposts......................................................................................................... 24
   1.5 Summary ...................................................................................................................................... 26

2.0 Introduction ............................................................................................................................................... 27
   2.1 Vision, Mission and Plan Objectives .......................................................................................... 27
   2.2 Process of Developing the Electric system Long Range Plan .................................................. 30
       2.2.1 Electricity Forecasts ............................................................................................................. 31
       2.2.2 Stakeholder Input ................................................................................................................. 34
       2.2.3 Evaluation of Investments Based on Performance, Cost, and Risk ................................. 34
   2.3 Background on Con Edison .......................................................................................................... 35
       2.3.1 Service Territory .................................................................................................................... 35
       2.3.2 Electric System ..................................................................................................................... 36
       2.3.3 The Customer Bill ................................................................................................................. 43
       2.3.4 Performance, Cost, and Risk Trends ..................................................................................... 45

3.0 Managing Demand, Supply, and Environmental Profile ........................................................................... 57
   3.1 Overview ........................................................................................................................................ 57
       3.1.1 Supply Outlook ....................................................................................................................... 58
       3.1.2 Demand, Supply, and Environmental Objectives ............................................................... 60
   3.2 Energy Efficiency .......................................................................................................................... 65
       3.2.1 Objectives ............................................................................................................................. 65
       3.2.2 Implementation Plan ............................................................................................................. 66
       3.2.3 Cost Benefit Analysis ......................................................................................................... 69
       3.2.4 Signposts .............................................................................................................................. 72
   3.3 Demand Response .......................................................................................................................... 72
       3.3.1 Objectives ............................................................................................................................. 73
       3.3.2 Implementation Plan ............................................................................................................. 73
       3.3.3 Cost Benefit Analysis ......................................................................................................... 76
       3.3.4 Signposts .............................................................................................................................. 78
   3.4 Distributed Generation .................................................................................................................... 78
       3.4.1 Objectives ............................................................................................................................. 80
       3.4.2 Implementation Plan ............................................................................................................. 81
       3.4.3 Forecast ................................................................................................................................. 84
       3.4.4 Signposts .............................................................................................................................. 88
   3.5 Electric Vehicles ............................................................................................................................. 89
       3.5.1 Objectives ............................................................................................................................. 90
       3.5.2 Emerging Plan ....................................................................................................................... 91
       3.5.3 Forecasts ............................................................................................................................... 93
       3.5.4 Signposts .............................................................................................................................. 95
   3.6 Advanced Metering Infrastructure ................................................................................................. 96
       3.6.1 Objectives ............................................................................................................................. 98
       3.6.2 Implementation Plan ............................................................................................................. 100
       3.6.3 Cost Benefit Analysis ......................................................................................................... 101
       3.6.4 Signposts .............................................................................................................................. 102
   3.7 New Transmission .......................................................................................................................... 102
       3.7.1 Objectives ............................................................................................................................. 103
       3.7.2 Implementation Plan ............................................................................................................. 104
       3.7.3 Estimated Costs .................................................................................................................... 105
       3.7.4 Signposts .............................................................................................................................. 106
   3.8 Value Proposition of Steam ............................................................................................................ 106
   3.9 Sustainability Initiatives ................................................................................................................ 107
       3.9.1 Summary of Initiatives ......................................................................................................... 108
       3.9.2 Recognition of Accomplishments ......................................................................................... 113
4.0 Integrating Innovative System Design ................................................................. 114
  4.1 Introduction ......................................................................................................... 114
  4.2 Tailoring System Design ..................................................................................... 114
    4.2.1 Meeting Customers’ Demand for Electricity .................................................. 114
    4.2.2 Tailored Solution Approach .......................................................................... 117
  4.3 Innovative Designs ............................................................................................... 121
    4.3.1 Increasing Asset Utilization ......................................................................... 121
    4.3.2 Reducing Costs and Improving Overall System Performance ...................... 129
  4.4 Design Standards ................................................................................................. 131
  4.5 Research and Development ................................................................................ 134
  4.6 Signposts ........................................................................................................... 136
  4.7 Summary ........................................................................................................... 136

5.0 Improving Asset Management & Control ......................................................... 138
  5.1 Introduction to Asset Management ..................................................................... 138
    5.1.1 Background on Categories of Capital Expenditure ....................................... 139
    5.1.2 Overview of Equipment Replacement Strategies ........................................... 141
  5.2 Distribution Asset Management ......................................................................... 143
    5.2.1 Optimization Strategy ................................................................................. 143
    5.2.2 Management of Major Asset Classes ............................................................ 147
  5.3 Substation Asset Management ........................................................................... 157
  5.4 Transmission Asset Management ....................................................................... 161
  5.5 Enhancing Monitoring and Control of the Grid ................................................... 164
    5.5.1 Electric System Modeling, Monitoring, and Control ...................................... 164
    5.5.2 AMI and Smart Grid .................................................................................... 165
    5.5.3 Stimulus Grants ......................................................................................... 166
  5.6 Summary ........................................................................................................... 170
  5.7 Signposts ........................................................................................................... 171

6.0 Enhancing Customer Experience ................................................................. 172
  6.1 Overview ........................................................................................................... 172
  6.2 Customer Perspectives ....................................................................................... 173
    6.2.1 Objectives ..................................................................................................... 173
    6.2.2 Approach to Research for the Electric System Long Range Plan .................. 174
    6.2.3 Outreach Results ....................................................................................... 174
  6.3 Enhancing The Customer Relationship ............................................................... 179
    6.3.1 Objectives to Enhance Our Customers’ Experience ......................................... 180
    6.3.2 Implementation Plan ................................................................................... 184
  6.4 Electric System Long Range Plan Impact on Customer Bills ............................ 188
  6.5 Signposts ........................................................................................................... 190

7.0 Improving Processes and Skills ................................................................. 191
  7.1 Overview ........................................................................................................... 191
  7.2 Long Range Planning Process ........................................................................... 191
  7.3 Capital Optimization .......................................................................................... 195
  7.4 Continued Focus on Cost Management ............................................................... 198
  7.5 Enhancing Organizational Skills ......................................................................... 200
  7.6 Signposts ........................................................................................................... 207

8.0 Summary ........................................................................................................... 208
  8.1 Challenges .......................................................................................................... 208
  8.2 Continually Identifying Opportunities to Reduce Costs .................................... 210
  8.3 Customer Bills .................................................................................................... 212
  8.4 Summary ........................................................................................................... 213
# List of Figures

<table>
<thead>
<tr>
<th>Figure</th>
<th>Title</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>1-1</td>
<td>Peak Demand Forecasts</td>
<td>10</td>
</tr>
<tr>
<td>1-2</td>
<td>Elements of a Smart Grid</td>
<td>15</td>
</tr>
<tr>
<td>1-3</td>
<td>Con Edison Capital Expenditure (2010-2030)</td>
<td>17</td>
</tr>
<tr>
<td>1-4</td>
<td>Annual Capital Expenditure Plan by Category (2010-2030)</td>
<td>18</td>
</tr>
<tr>
<td>1-5</td>
<td>Residential Bill Impact</td>
<td>19</td>
</tr>
<tr>
<td>1-6</td>
<td>Customer Interruptions</td>
<td>22</td>
</tr>
<tr>
<td>1-7</td>
<td>Target Environmental Emissions (CO_{2e}) Reduction by 2030</td>
<td>23</td>
</tr>
<tr>
<td>2-1</td>
<td>Con Edison Vision, Mission, and Plan Themes</td>
<td>29</td>
</tr>
<tr>
<td>2-2</td>
<td>Process for Developing the Electric System Long Range Plan</td>
<td>30</td>
</tr>
<tr>
<td>2-3</td>
<td>Con Edison Organization Chart</td>
<td>31</td>
</tr>
<tr>
<td>2-4</td>
<td>Energy Forecasts</td>
<td>33</td>
</tr>
<tr>
<td>2-5</td>
<td>Demand Forecasts</td>
<td>33</td>
</tr>
<tr>
<td>2-6</td>
<td>Con Edison Service Territory</td>
<td>35</td>
</tr>
<tr>
<td>2-7</td>
<td>Illustration of Con Edison Electric System</td>
<td>36</td>
</tr>
<tr>
<td>2-8</td>
<td>Split Distribution Primary and Secondary System</td>
<td>38</td>
</tr>
<tr>
<td>2-9</td>
<td>Combined Distribution Primary and Secondary System</td>
<td>39</td>
</tr>
<tr>
<td>2-10</td>
<td>Typical Underground Electric System</td>
<td>40</td>
</tr>
<tr>
<td>2-11</td>
<td>4kV Unit Substation Grid Configuration</td>
<td>41</td>
</tr>
<tr>
<td>2-12</td>
<td>Overhead Autoloop System Configuration</td>
<td>42</td>
</tr>
<tr>
<td>2-13</td>
<td>Breakdown of Residential Bill in 2010</td>
<td>43</td>
</tr>
<tr>
<td>2-14</td>
<td>Customer Interruptions</td>
<td>46</td>
</tr>
<tr>
<td>2-15</td>
<td>Customer Average Interruption Duration Index (CAIDI), 2008</td>
<td>47</td>
</tr>
<tr>
<td>2-16</td>
<td>2008 Average Rates, Usage, and Bills for Con Edison Residential Customers</td>
<td>49</td>
</tr>
<tr>
<td>2-17</td>
<td>Risk Assessment Factors</td>
<td>51</td>
</tr>
<tr>
<td>2-18</td>
<td>Energized Equipment Incidents</td>
<td>53</td>
</tr>
<tr>
<td>2-19</td>
<td>Electric Shock Trends</td>
<td>54</td>
</tr>
<tr>
<td>2-20</td>
<td>Underground Network Transformer Failure Trends</td>
<td>55</td>
</tr>
<tr>
<td>3-1</td>
<td>Resource Mix 2010 Versus 2030</td>
<td>60</td>
</tr>
<tr>
<td>3-2</td>
<td>Con Edison Managing Peak Usage</td>
<td>61</td>
</tr>
<tr>
<td>3-3</td>
<td>Electric Power Research Institute’s Assessment of Mechanisms to Reduce CO_{2}</td>
<td>62</td>
</tr>
<tr>
<td>3-4</td>
<td>Achieving New York State’s “15 by 15” Goal</td>
<td>63</td>
</tr>
<tr>
<td>3-5</td>
<td>Implementation Plan: Energy Efficiency</td>
<td>68</td>
</tr>
<tr>
<td>3-6</td>
<td>Energy Savings from Energy Efficiency</td>
<td>70</td>
</tr>
<tr>
<td>3-7</td>
<td>Peak Demand Savings from Energy Efficiency</td>
<td>71</td>
</tr>
<tr>
<td>3-8</td>
<td>Implementation Plan: Demand Response</td>
<td>75</td>
</tr>
<tr>
<td>3-9</td>
<td>Peak Demand Savings from Demand Response</td>
<td>77</td>
</tr>
<tr>
<td>3-10</td>
<td>Implementation Plan: Distributed Generation</td>
<td>81</td>
</tr>
<tr>
<td>3-11</td>
<td>Distributed Generation Installation Trend by Technology</td>
<td>84</td>
</tr>
<tr>
<td>3-12</td>
<td>Distributed Generation Market Potential</td>
<td>87</td>
</tr>
<tr>
<td>3-13</td>
<td>Projected Demand Impact of Electric Vehicle Adoption in Con Edison Territory</td>
<td>94</td>
</tr>
<tr>
<td>3-14</td>
<td>Electric Vehicle Load Contribution by Service Territory</td>
<td>95</td>
</tr>
<tr>
<td>3-15</td>
<td>Targeted Deployment Costs and Benefits</td>
<td>101</td>
</tr>
<tr>
<td>3-16</td>
<td>Implementation Plan: New Transmission</td>
<td>104</td>
</tr>
<tr>
<td>3-17</td>
<td>Targeted Greenhouse Gas Emissions Reduction in 2030</td>
<td>108</td>
</tr>
<tr>
<td>4-1</td>
<td>Con Edison 20-Year Capital Spending Summary</td>
<td>115</td>
</tr>
<tr>
<td>4-2</td>
<td>Composition of System Expansion/Meet Customer Demand Investment (2010-2030)</td>
<td>116</td>
</tr>
<tr>
<td>4-3</td>
<td>Substation Construction (1948-2030)</td>
<td>117</td>
</tr>
<tr>
<td>4-4</td>
<td>System Expansion Planning Process</td>
<td>118</td>
</tr>
</tbody>
</table>
List of Tables

Table 2-1. Service Area Statistics.......................................................................................................... 35
Table 2-2. Taxes Reflected in Monthly Customer Bill Excluding Income Taxes ................................. 44
Table 2-3. Illustrative Electric Distribution Operational Risks ................................................................. 51
Table 3-1. Role of Energy Efficiency in Achieving Objectives ................................................................. 65
Table 3-2. Residential Programs ........................................................................................................... 67
Table 3-3. Commercial and Industrial Programs ...................................................................................... 67
Table 3-4. Role of Demand Response in Achieving Objectives ............................................................... 73
Table 3-5. Planned Demand Response Programs .................................................................................. 74
Table 3-6. Role of Distributed Generation in Achieving Objectives ....................................................... 80
Table 3-7. Con Edison Programs To Study Distributed Generation ..................................................... 82
Table 3-8. Con Edison Distributed Generation Pilot Programs ............................................................. 83
Table 3-9. Role of Electric Vehicles in Achieving Objectives .................................................................. 90
Table 3-10. Role of Advanced Metering Infrastructure in Achieving Objectives .................................. 98
Table 3-11. Role of New Transmission in Achieving Objectives .......................................................... 103
Table 4-1. Example Demand/Supply, Non-Traditional, and Traditional Load Relief Options .......... 120
Table 5-1. Scope of the Asset Optimization Initiative ........................................................................... 144
Table 5-2. Profile of Primary Distribution Cable Types ......................................................................... 152
Table 5-3. Elements of CECONY’s Smart Grid Project ......................................................................... 167
1.0 EXECUTIVE SUMMARY

1.1 OVERVIEW

For over 150 years, Consolidated Edison, Inc. (Con Edison or the Company) has had the privilege of providing power, light, heat, and cooling to the people of New York City and Westchester County through our electric, gas and steam systems. This Electric System Long Range Plan provides a road map for the electric system for the next two decades.

Our mission is to deliver safe and reliable electric service to customers in a cost effective, environmentally responsible, and innovative way. This mission entails building and maintaining the electric infrastructure necessary for the transmission and distribution of electricity, procuring energy supply, and providing meter reading, billing and other services to our customers. While we divested almost all of our electric generation plants when New York underwent electric utility restructuring in the late 1990s, we continue to purchase energy supply for our full service customers. Other customers purchase their energy supply directly from energy services companies, but we continue to deliver the electricity they purchase through our transmission and distribution systems.

The past decade has been a challenging one for the Company, as it has been for the nation. The next 20 years is expected to be even more challenging as it is reasonable to expect that the pace of technological and social change will accelerate. It is clear, however, that reliable and cost-effective electric service will continue to be necessary to fuel economic growth and that customer expectations of our performance will only increase. This dramatic pace of change combined with the ongoing challenge of modernizing our electric grid, attracting investors essential for maintaining a substantial investment program, and maintaining reasonable rate levels is why the time to develop an integrated long range plan is now.

Historically, Con Edison developed 10 and 20 year infrastructure plans for its electric distribution and transmission systems, separately. These plans allowed for the system to have sufficient capacity to meet customer energy requirements and were based on stringent design criteria aimed to produce a system that performed very reliably. This Electric System Long Range Plan is a holistic way to effectively integrate transmission and distribution system infrastructure plans with non-infrastructure related elements of our business, such as demand side solutions and renewable resources, into one comprehensive plan. We also initiated a comprehensive and quantitative approach to investment optimization for this plan. This enhanced process considers the impact of investments on the performance, cost, and risk profile of the electric system. The plan also provides a framework that links short and long term projects and programs to the Company’s goals and objectives.

The first step in this enhanced planning process is to develop forecasts for electricity demand. We made assumptions regarding potential environmental and regulatory requirements, economic trends, and included possible technological advances to develop three forecasts for potential customer demand: a High Case, Plan Case, and Low Case. To develop the infrastructure projects and programs in this plan we used the Plan Case demand forecast and identified signposts that we will monitor to test and adapt our plan in the future.
Over the next twenty years we will seek to integrate energy efficiency, distributed generation and demand response to further our goals of deferring new infrastructure investments and providing safe, reliable, and reasonably priced service that is environmentally responsible. We will provide various methods for customers to manage their energy consumption, expenditures, and to make green choices.

We will implement innovative designs to defer or minimize the investment requirements of new substations, increase asset utilization, and improve the performance of our electric system. These less asset intensive designs will be implemented on a targeted basis as we tailor our engineering and operational approaches to meet the specific needs of the customers we serve. Similarly, we will increase efforts to improve our asset management practices as we continue to move from time-based asset management to a condition-based approach. Advances in communications, such as Smart Grid technologies, have and will continue to give us greater visibility into the status of our system components, allowing us to increase system automation, improve the accuracy of our predictive system models, and direct us to those system components that need the most attention, all with the goal of reducing our total costs.

We conducted a number of outreach sessions with our residential and commercial customers. The feedback indicates that what matters most to our customers is reliability. They are interested in new technology and believe that demand for electricity will continue to grow, and they want to make sure that our infrastructure keeps up with their needs. The Company is committed to provide the appropriate systems and to have programs in place to enhance the overall customer experience, as well as to address key issues including cost and quality of service. We want to make sure our customers find it easy to do business with us. The long range plan will facilitate continued outreach and discussion with customers and other stakeholders, whose input will be used to enhance future plans.

Just as our business drivers are changing, so are our planning, engineering, and job based processes and skills. We will support our workforce by introducing new training that increases our capability to meet the needs of a rapidly changing energy economy.

In the next twenty years we expect to invest $28.6 billion in capital infrastructure in real 2010 dollars, or an average of $1.36 billion a year. At this level of expenditure, along with projected increases in the cost of supply, we expect that a typical New York City residential customers’ monthly bill for electricity, in real 2010 dollars would increase from $83.43 today to $121.66 in 2030, an average compound annual growth rate (CAGR) of 1.41% from the end of our current rate settlement in 2013 through 2030.¹

¹ For the full plan period from 2010 – 2030, inclusive of the current rate settlement, the average compound annual growth rate (CAGR) is 1.90%.
The projected bill reflects the impact of higher infrastructure replacement costs, higher energy costs, as well as rising service fees and taxes. Replacing components of our electric grid, which have a low average cost due to the vintage of equipment, with a much higher replacement cost will necessarily cause the cost of providing service to increase. We are sensitive to the impact of rate increases on our customers and we will work very hard to keep costs down. Concurrently we also need to address the needs of service reliability, system safety, and regulatory requirements to maintain the critical electric infrastructure that supports the economic viability and security of New York City and Westchester County.

Over the past twenty years, we have been successful in keeping the real price of electricity flat, on par with general inflation in the economy. Although there is no assurance that this pattern will continue, in the next twenty years we are determined to achieve the maximum efficiencies from operating our system to meet our commitments to our customers and investors. We will strive to achieve efficiency gains beyond the estimates in this long range plan.

Our plan outlines important opportunities to realize the potential for moderate cost increases, including potential regulatory, tax and related reforms and utility ratemaking approaches that would increase the relative value of electric service.

1.2 KEY ELEMENTS OF THE PLAN

Demand and Supply

We must ensure that our transmission and distribution systems have sufficient capacity to meet customers’ peak electricity demand and that we can procure adequate energy supply for our customers. We developed three potential forecasts to assess the impact of various economic, legislative, and technological drivers on customer demand for electricity.
The annual peak electricity demand in the Company’s service territory is shown in Figure 1-1 for three potential cases.

**Figure 1-1. Peak Demand Forecasts**

The Plan Case, which provides the basis for our Electric System Long Range Plan, assumes moderate economic growth, coupled with a continued increase in customers’ use of electricity, offset by moderate to high adoption of energy efficiency measures and improved codes and standards. This forecast is consistent with the New York Independent System Operator’s view of the future. Electricity demand in New York City and Westchester County rises at approximately 0.8% per year and represents almost a 20% increase in electricity demand over the 20-year planning horizon.

The High Case projects a swift upturn in the region’s economy, coupled with an increase in the number of customers served and in their use of electricity as we continue to use more electrically powered devices in our homes, businesses and for transportation. The High Case also assumes the same moderate to high levels of adoption of energy efficiency measures and improved building codes and standards as the Plan Case. This forecast is most like the historical pace of electric demand we have seen over the past thirty years and rises on average 1.7% per year. If this forecast is realized, we would see electricity demand in our service territory increase over the planning horizon by more than 40%.

The Low Case, like the Plan case, assumes that the local economy grows at a moderate pace, but there is a significant reduction in per-capita usage due to robust energy efficiency and demand response initiatives as well as widespread adoption of stringent codes and standards. Although there are localized increases in electricity demand in this forecast, the overall service territory demand is essentially flat over the planning horizon at less than 0.3% growth per year, and represents only a 6% increase in electricity demand over the next twenty years.
Peak demand, or the maximum electricity that our customers require at a single point in time, drives infrastructure investment because our system must be able to meet that demand even if it is a relatively infrequent occurrence. In our service territory, these peak demand periods occur only during the hottest periods of the summer, often for only several hours over the span of a few days. One goal embodied in the Electric System Long Range Plan is to implement customer-focused programs, such as demand side management, that can reduce the system peak, thus deferring infrastructure investments and lowering customer bills.

Supply costs are also a major component of our customers’ bills. Although Con Edison does not own significant sources of electric supply, we continue to procure electricity for our full service customers and those costs are part of their electric bill. Our assessment of the electricity supply market suggests that the cost of supply, in real 2010 dollars, will increase at an annual rate of 2.2% over the 20-year time horizon. On a per kilowatt-hour (kWh) basis that represents an increase from 9.4 cents per kWh in 2010 to 14.6 cents per kWh by 2030.

In order to keep our electric service reasonably priced while furthering our goals of safe, reliable and environmentally responsible service, we plan to work closely with our customers to actively manage both demand and supply. Demand side management, for example, may defer or eliminate the need for additional capital infrastructure, while at the same time reducing greenhouse gas emissions. Similarly, the integration of distributed supply solutions and the well planned off-peak integration of electric vehicles in our service territory may mitigate the need for large capacity upgrades, improve reliability, and reduce our reliance on fossil fuel resources.
Over the next twenty years we expect to deploy a full portfolio of programs to actively manage customer demand, diversify supply sources, and improve our overall environmental profile. The major initiatives we will offer in this portfolio are to:

- Expand our role as an energy advisor to customers to aid them in managing their energy expenditures through energy efficiency demand response programs.
- Facilitate and integrate distributed generation to provide choices for customers and increase the penetration of clean distributed generation, including renewables such as rooftop photovoltaics, through customer and utility owned applications with benefits for the electric system.
- Support new infrastructure to facilitate plug-in electric vehicle deployment (and other emerging end-use applications) and potential storage and vehicle-to-grid applications through a series of pilots, working with industry associations, manufacturers and customers. Our objective is to pace these infrastructure investments and initiatives in such a way that does not overbuild or create stranded assets.
- Invest in the cost-effective deployment of an advanced metering infrastructure (AMI) for the implementation, measurement, and dispatch of the aforementioned demand- and supply-side resources.
- Seek to incorporate renewable supply sources into the grid, including developing partnerships to investigate new technologies and building new transmission lines where necessary for reliability or which are the most cost-effective solutions (compared to generation or demand side management).
- Monitor and evaluate the impact of meeting demand requirements currently served by electricity produced from Con Edison’s steam generators.
- Continue to deploy a portfolio of environmental sustainability initiatives to improve Con Edison’s environmental impact in all aspects of our business.

**Transmission & Distribution Infrastructure**

Our electric system consists of over 1,100 miles of underground transmission cable and overhead transmission lines supported by 1,200 transmission towers. Our transmission system supplies power to 38 transmission substations which, in turn, supply 61 area substations. Approximately 1,340 primary distribution circuits come from these areas substations, feeding 26,000 underground distribution transformers in our 62 networks and 47,000 pole-mounted transformers in our overhead areas. These assets, among others, represent billions of dollars of investment requiring maintenance, repair, and replacement.
For each of the demand forecasts discussed in the previous section, we projected the work and capital infrastructure investment needed to assure the viability of our electric system. For all three cases, there is a significant investment that needs to be made to maintain our infrastructure. The major difference in work plans and capital expenditures between the three cases is in the expansion needed to meet new customer demand. The Plan Case demand forecast shows an increase in demand over the planning horizon of nearly 20%. To meet this demand, we would need to build six new substations at the transmission or sub-transmission level to accommodate six new distribution networks across our service area. In addition to this major substation work, we would need to implement associated equipment and cable transfers and expansions in local areas of the distribution system. The High Case would require double the number of new substations and networks as in the Plan Case in order to adequately support the 40% increase in projected demand. In the Low Case no new substations or networks would be needed, but there would still be a significant cost associated with maintaining existing components and infrastructure costs associated with local growth.

**Plan Initiatives**

It is imperative that we manage our existing infrastructure, and expand it as required, in a cost-effective manner. The 20-year plan details initiatives which challenge and fundamentally change key aspects of our current design criteria, moving us from a prescriptive and deterministic engineering design basis to one that is driven by a probabilistic approach. We actively integrate targeted demand and supply side management programs, innovative designs, advanced technologies, as well as traditional designs to implement tailored, “best fit” solutions. And, we enhance our asset management practices to optimize maintenance expenditures, effectively moving from a time-based to a condition-based approach.

Over the course of this plan, we intend to meet our service reliability objectives in less asset intensive ways through the implementation of innovative third generation (3G) designs. The first generation design, implemented during the initial construction of the electric system, was characterized by radial overhead construction. The second generation design moved much of the infrastructure underground and provided for more reliable service through multiple supply paths. Our newest generation of designs, or 3G, leverage asset sharing approaches and are enabled by enhanced system monitoring and advanced underground switching. 3G designs are a critical component of our strategy to defer or minimize the investment requirements of new substations, increase asset utilization, reduce cost and improve the performance of our system.

3G designs have the potential to result in significant savings in capital investment because they provide the ability to increase system capacity incrementally. This allows us to defer large capacity investments by closely matching relatively small increases in system capacity to customers’ growing demand for electricity as it occurs. The 3G designs also increase the utilization of our existing asset base, deferring a portion of the need for new infrastructure investment. We know our customers value high reliability and 3G design concepts were created with the goal of maintaining our reliability levels by considering the probabilities of simultaneous system component failures. Over the 20-year horizon, we plan to implement several 3G concepts, including the installation of transferrable feeder groups, virtual substations, intelligent underground autoloops, and automatic primary feeder switches. Each will serve to advance the achievement of our infrastructure investment objectives and will be used to further reduce customer cost increases.
In addition to implementing new design concepts, we will employ a more integrated approach to overall system investment. Various demand and supply management programs will reduce demand on the constrained parts of our system, thus reducing infrastructure expansion and reinforcement expenditures. When system expansion is required, however, our strategy is to pursue solutions to satisfy electric system goals. These solutions will apply targeted demand and supply side management programs, advanced technologies and innovative designs, as well as traditional infrastructure investments to specific load areas.

The need to maximize utilization and performance of our existing assets and to optimize maintenance expenditures makes strong and effective asset management essential. An effective asset management program affects maintenance patterns, repair and replacement decisions, as well as overall electric system planning and design. Greater precision in identification of the right time to add or replace an asset allows the best directed use of capital and operations and maintenance expenditures. In addition, information on operating conditions allows planners and operators to optimize system configurations when evaluating network reinforcements and replacements.

Our planned asset management programs and processes consider the performance, cost and risk profiles of components that, collectively, make up our electric transmission and distribution system. We use various methods and tools to monitor, analyze, assess and control our assets to obtain optimal performance of our electrical components, asset classes and overall system. The information we capture, trend, and analyze allows us to evaluate and compare the performance across various components or asset classes so that we are targeting our programs in the right places and, therefore, optimizing what we spend on our asset maintenance, repair, and replacement decisions.

As we add more advanced monitoring on our components we will be able to continue to move away from time-based to condition-based maintenance. By gathering and analyzing data from in-field sensors we are better able to understand performance trends on specific asset classes. This may allow us to alter maintenance cycles, increase the life of various components, improve the design of specific assets, and predict and prevent failures.
The effectiveness of our modeling capabilities is closely related to the quality and accuracy of the data and information we have about the performance of the electric system under a variety of customer demand conditions. We continue to develop and implement effective system monitoring to improve this information base. We are also implementing various Smart Grid technologies which may provide greatly enhanced control over the grid, more control of electricity use by our customers, and better system performance. Figure 1-2 illustrates the key elements of the Company’s planned Smart Grid implementation.

**Smart Grid**

Smart Grid puts information and communication technology into electricity generation, delivery, and consumption, making systems cleaner, safer, and more reliable and efficient.

**Smart Building Technology** including web portals and in-home displays will eventually allow customers to track their energy use and give them the tools to change their energy-using habits, including the ability to remotely control appliances.

**Greener Energy Sources** are more readily integrated into the smart distribution grid.

**Intelligent Underground Systems** use sophisticated communication technology to monitor, isolate, and correct problems and improve reliability.

**Plug-In Electric Cars** can connect to the grid to charge and one day may even provide power from their battery packs when the cars are not in use.

**Smart Motors** gather information about customers’ energy use so customers can use electricity more efficiently, and the meters may enable the utility to identify system problems.

**Customer Energy Generators** enhance system reliability.

Smart Grid is an industry term that generally describes how customers and the utility will have more information and control over various aspects of electricity usage and system performance through the application of advanced monitoring and technology.

Our Long Island City Pilot announced in July 2009, is the Company’s most comprehensive Smart Grid application and includes the installation of Advanced Metering Infrastructure devices, home area networks, solar panels, remotely controlled feeder switches on underground feeders, and transformer and network protection monitoring. In addition to the Long Island City Pilot, the Company filed two grant applications for Federal stimulus funding with the U.S. Department of Energy. Con Edison’s Smart Grid Investment Grant and Demonstration Project was approved for $173 million.
The Company expects a wide range of benefits to accrue from our Smart Grid initiatives, including the proof of concept of new wireless monitoring and control technologies, vast new data collection opportunities on distributed supply and customer demand patterns, and secondary model validation from the increased demand and power flow data. We anticipate that the change in information and telecommunication technologies will continue to help reduce the overall cost and improve the performance of our electric system. Our long term objective is to develop a smarter grid that will capture the full benefits of improved and additional monitoring, modeling, and control.

*Infrastructure Costs*

Each of the near and long term projects and programs discussed above was designed to help us achieve our goals to provide our customers with the consistent high reliability performance they have come to expect at a reasonable cost.

By investing in the promotion of energy efficiency and demand response and in the interconnection of distributed generation, we are able to reduce customer demand and to defer large scale capital investments. Over the course of the plan, we estimate that we can save $460 million in infrastructure investments from these demand and supply side initiatives. Improved asset management practices, often realized through enhanced monitoring and control, allows Con Edison to defer additional capital investment. We expect to realize about $1.9 billion in capital savings from these efforts. For certain substation investments that are required to meet system demand, Con Edison plans to adopt 3G design techniques which will reduce overall costs by an additional $659 million. The implementation of a new work management system will allow the Company to further optimize capital investments, achieving savings of $392 million. Additional opportunities for savings will be continually and aggressively pursued.
The Company’s overall capital investment profile, shown both gross and with the expected savings described above, is presented in Figure 1-3. The figure highlights that we estimate capital expenditures would have been more than $31.7 billion without the savings discussed above. Our forecasted expenditures are about $28.6 billion over the entire planning horizon, or an average of $1.36 billion per year in 2010 dollars.

Figure 1-3. Con Edison Capital Expenditure (2010-2030)
The total capital investment plan, which will be an ongoing focus for spending mitigation opportunities, is the aggregation of the expected expenditure levels across nine major functional areas. The individual spend patterns for each of these functional areas is highlighted in Figure 1-4.

**Figure 1-4. Annual Capital Expenditure Plan by Category (2010-2030)**

<table>
<thead>
<tr>
<th>Category</th>
<th>Cumulative Expenditure ($, million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Federal Stimulus</td>
<td>173</td>
</tr>
<tr>
<td>Information Technology (IT)</td>
<td>810</td>
</tr>
<tr>
<td>Advanced Metering Infrastructure (AMI)</td>
<td>400</td>
</tr>
<tr>
<td>Area Substation</td>
<td>5,880</td>
</tr>
<tr>
<td>Transmission</td>
<td>1,110</td>
</tr>
<tr>
<td>Network</td>
<td>13,700</td>
</tr>
<tr>
<td>Overhead</td>
<td>2,570</td>
</tr>
<tr>
<td>Generation</td>
<td>730</td>
</tr>
<tr>
<td>Common Capital</td>
<td>3,250</td>
</tr>
</tbody>
</table>

2 The spike in information technology expenditure between 2016 and 2019 (from $14 million in 2016 to a peak of $163 million in 2019) is due to the implementation of a new customer service system.

3 The implementation of the targeted AMI deployment is completed by 2020.

4 The Area Substation investment levels peak in 2021 and 2027 to account for new substation investments required to handle increases in customer demand in certain networks.

5 Common capital refers to a corporate allocation to the electric business unit to pay for items such as facilities, vehicles and equipment.
The savings in infrastructure costs described earlier are reflected in Figure 1-4. Network investments are $1.9 billion lower over the twenty years due to aggressive asset management enabled by improved monitoring and control capabilities. Area substation investments would have been greater by $1.1 billion due to $659 million in savings from the implementation of 3G substation designs and $459 million in savings from demand and supply management which defers the need for new substations. Finally, capital expenditures are expected to be reduced by $392 million as a result of work management savings.

An additional benefit of some of our investments to upgrade and enhance the system is the realization of reductions in future operations and maintenance expenditures. For example, the introduction of new equipment designs, manufactured with advanced materials will reduce required maintenance. From 2010 to 2030, Con Edison expects to realize a total of roughly $394 million in operations and maintenance savings over 20 years, or approximately 2.7% of transmission and distribution operation and maintenance costs.

**Customer Experience**

*Customer Bill*

We will continue to seek to help customers control their energy costs while maintaining the highest levels of service reliability and system safety. The estimated impact of our planned investments along with projected cost increases to the supply and tax portions of the bill is expected to increase annually from the end of our current rate settlement in 2013 to 2030 by approximately 1.41% on a real basis. The total increase broken out by bill component is illustrated in Figure 1-5.

**Figure 1-5. Residential Bill Impact**

![Image of Residential Bill Impact Chart]

19
This analysis incorporates a number of cost saving initiatives including $3.1 billion in capital savings and productivity improvements keeping O&M expenditures flat.

We fully recognize the importance of mitigating cost increases to our customers and have performed an evaluation to keep rate increases in line with inflation. To achieve this goal would require significant reductions in both capital and O&M programs as compared to the Plan Case. Specifically, it would require additional cuts to capital expenditures of approximately 50% over the course of the 20-year plan horizon. Alternatively, O&M expenditures would have to be cut significantly from 15% in year one followed by successively deeper cuts in each year thereafter, ultimately resulting in no O&M expenditures after approximately 8 years. These cuts will have corresponding short- and long-term safety, reliability, and environmental implications and these are described below.

In the short term for, example, we would expect:

- To fall out of compliance with regulatory and legislative mandates for key operating and performance criteria
- Increased backlogs
- Cuts to energy efficiency investments which would in turn increase long-term capital requirements

In the longer-term we would experience performance degradation, with increased likelihood of:

- Operational deficiencies
- Environmental non compliance
- Public or employee safety deterioration
- Security breaches (cyber or physical infrastructure)
- Inability to accommodate future load growth
- Higher O&M expenses with unpredictable capital costs

Notwithstanding the significant challenges of maintaining rate increases at inflationary levels, particularly in the absence of currently unforeseen innovations or cost avoidance measures, we are committed to keeping costs down. We are also committed to rigorously pursue regulatory and tax reforms.

Customer Service

Over the next 20 years, we expect that technology and industry innovation will lead to a significant change in our relationship with customers. We will collaborate with customers more closely as electric consumption levels and patterns are changed by new end-use devices such as electric vehicles. The widespread adoption of new technologies may call for investments in our transmission, distribution, and billing infrastructure to support activities such as remote charging, time-based pricing through “smart” appliances, and the integration of customer-owned distributed generation into the grid.
We are committed to ensure we have the right systems and skills in place to enhance the customer experience and address key issues including cost, quality of service, and the ease of doing business with us. We will leverage new media to offer customers an increased level of control of their energy through energy management tools. Customer service initiatives included in the plan are grouped into five categories:

- Provide a more efficient and effective customer service experience by introducing new and enhanced contact center technology
- Expand the ability for customers to access information on their own terms by implementing enhanced mobile and web interfaces and expanding mobile tools and notification options
- Empower customers with information and tools to manage their energy bills by expanding time-based pricing and offering more diverse energy efficiency programs
- Promote the option of customer choice in energy suppliers by enhancing systems and tools that facilitate customer enrollment with Energy Services Companies (ESCs)
- Support the integration of information and communication systems by streamlining customer access to information on any and all of our business units

**Our People and Processes**

To carry out our 20-year vision, we will need to develop new skill sets, processes, and systems to support their growth. We will concentrate on five areas (i) standardizing our integrated long range planning process, (ii) leveraging and expanding our capital optimization model, (iii) improving cost management, (iv) enhancing our skills, and (v) identifying and addressing gaps in our desired corporate culture.

Improving performance, cost-effectiveness, and risk mitigation are the main drivers behind our current planning process. Our goal is to have a planning process that is more integrated, interactive, and clearly linked to the corporate strategy. The Electric System Long Range Plan will be established and regularly reviewed under different forecasts for demand, commodity prices, and other aspects of the business environment.

To meet our financial, operational, regulatory, and strategic objectives, we will support planning with a comprehensive process and tool for capital optimization. These will allow the Company to evaluate projects across the system and make trade-offs across operating units through standardized analytical methods and guidelines. We will also build on the capabilities we have developed over time to effectively monitor expenditures. A number of cost and work management initiatives have been identified to further integration and collaboration between financial and field operations. Through enhancements to our technology, organizational structure, and processes we will drive toward better cost and performance management.

Every organization has its own culture, and critical cultural assessment is essential for continuing organizational effectiveness. Our cultural assessment efforts will identify gaps in desired cultural traits and we will take steps to achieve an environment of optimal effectiveness. Through our workforce strategy, we will adapt and enhance the skills needed to maintain the reliability of the system, satisfy the needs of our customers, and support the successful implementation of this plan. We will enhance these skills by training our people in areas such as advanced analytics; understanding new technologies; and integrating customer, regulatory, and governmental requirements into operational planning.
1.3 PLAN PERFORMANCE

The Electric System Long Range Plan includes major investments in our electric system, specific programs to maintain and upgrade it, and various initiatives to manage customer demand for the benefit of customers and the environment. To support the development of the plan we created a capital investment database and analytical model to evaluate the impact of programs and initiatives. Capital investment projects were evaluated for impacts on performance, risk, and cost characteristics of the electric system. This analysis is consistent with the Company’s asset management practices, annual capital expenditure prioritization process, and our focus on enterprise risk management.

Through our engineering designs, work practices, and system investment, we have placed a high priority on delivering power reliably. Figure 1-6 illustrates a relative comparison of Con Edison reliability vs. national and New York State levels.

![Figure 1-6. Customer Interruptions](image)

Our investment plan allows us to maintain our high level of service reliability as we continue to upgrade our systems and leverage new technologies, designs, and practices. As shown in Figure 1-6 our overhead system is more than twice as reliable as the rest of the state and nearly three times as reliable as the rest of the nation. On average, a customer served by our overhead system experiences an interruption less than once every two years. Our underground network system reliability performance is very strong, yielding superior day-to-day reliability. On average, a customer served by our underground network system experiences a service interruption nearly once every sixty years. Across the entire system, we expect customer interruptions to be no higher than the performance in 2008, which was 130 interruptions per 1,000 customers per year. Maintaining these levels of reliability is critically important to us as our customers consistently tell us that reliability is their number one priority.
In addition to maintaining these levels of day-to-day reliability, we seek to reduce the risk of a prolonged, large-scale network outage, and the resulting adverse impacts experienced by our customers. Con Edison has developed and utilizes analytical models to understand the performance of each of our networks based on their unique characteristics. The key output from these models, the Network Reliability Index (NRI), is a probabilistic measure of risk levels of each network. NRI is defined as the state where four or more feeders supplying power to one local portion of a network experience failure at the same time during periods of high electricity demand. NRI has become an important planning measure that the Company uses in a variety of design and investment decision-making processes.

Investment in three targeted capital programs directly reduces NRI risk: removal of PILC, the installation of sectionalizing switches on network feeders, and increasing the number of primary distribution feeders serving a network. Our goal is to apply focused program investment to decrease risk on networks where the investment will have the greatest impact. Based upon the application of these programs, at average annual investment of $38 million from 2010 through 2015, we estimate a 58% improvement across our relatively riskiest networks. In the 2015 time-frame, the three NRI programs described above will reach points of diminishing returns and as a result, a re-evaluation of our approach in this area will be required in 2016 to carefully weigh risk reduction benefit against the cost, and against new tools, programs, or innovations that may be available.

We measure the environmental impact of our plan by the reduction in greenhouse gases. Figure 1-7 summarizes the environmental improvements that result from the investments and sustainability initiatives in the Electric System Long Range Plan.

**Figure 1-7. Target Environmental Emissions (CO₂e) Reduction by 2030**
The largest contributor to greenhouse gas reductions from Direct CECONY Initiatives is our effort to continually reduce sulfur-hexafluoride (SF₆) emissions. SF₆ is used as to extinguish the arc of current present within a circuit breaker when it is opened under load, and as an insulating medium in different pieces of equipment such as in enclosed bus arrangements. As it has been identified by the Intergovernmental Panel on Climate Change as a potent greenhouse gas, the Company has committed to the Environmental Protection Agency to reduce SF₆ emissions annually by 5% from the 1996 baseline. Customer Reductions include the expanded availability and interconnection of renewable energy and the implementation of demand side management programs. Greenhouse gas reductions from New Generation are primarily from the Company’s efforts to support opportunities to generate renewable energy by participating in initiatives such as an offshore wind collaborative.

A factor of pivotal importance to us is the safety of the public we serve and of our employees that make these services possible. Over the past several years we have made improvements in our ability to maintain a safe environment for both the public and our employees. Our goal is to continue to improve in these critical areas. We recognize it is impossible to forecast the number of safety incidents that will occur in a particular year but our goal is to minimize incidents and to track and analyze those incidents that do occur in an effort to continuously improve. Our goal for employee safety is to reduce our OSHA (Occupational Safety and Health Administration) Incidence Rate to 1.5, or approximately 1.5 injuries and illnesses per 100 workers by 2015, from 3.22 in 2009, putting us in the top quartile among industry peers. As we continuously improve our culture to embrace learning from our experiences and achieving personal and organizational bests, we would seek to maintain or improve that performance over the entire planning horizon.

1.4 UNCERTAINTIES AND SIGNPOSTS

By definition uncertainties are difficult to predict. For the purposes of this plan, we describe two forces that we deem to be potential “game changers”: the pace of technology innovation and the nature of regulation and legislation. Of course, we recognize the uncertainty of the economy will add variability to forecasting.

Our plan was developed under considerable uncertainty including emerging technologies, energy and environmental regulations, customer demand, availability and cost of fuel supplies, economic conditions, availability of financing and utility regulation and ratemaking approaches. These uncertainties persist even though we have the significant benefit of the recent issuance of the New York State Energy Plan. This State Energy Plan, for the first time in many years, prescribes and affirms State energy policy and provides substantial policy guidance for utility companies, facilitating preparation of this Electric System Long Range Plan. We realize that with the passage of time, the nature of these uncertainties will change and new uncertainties will emerge. As such, the plan is intended to be a flexible, living document that will be monitored and reshaped as circumstances change.
**Technological Uncertainties**

Three areas of technological uncertainty that most affect our future are customer end-use, Smart Grid delivery and control technologies, and the cost of electricity supply. Innovations in lighting, air conditioning, motors, building controls and automation may decrease demand, but the sheer volume of new electric devices and new applications such as electric vehicles may increase demand. Smart Grid is predicted to bring advances in the delivery, control and availability of granular usage information that may be used to engage more customers in the efficient use of electricity and may lead to changes in our asset management practices. Clean distributed sources and distributed storage technologies may offset transmission and distribution infrastructure investments and reduce greenhouse gas emissions.

From a planning perspective, it is difficult to predict how quickly particular innovations will develop or whether they will experience widespread adoption. For the future, we will plan for both major breakthroughs as well as incremental advances in these three areas of uncertainty. The plan provides multiple “signposts” to signal when and where assumptions should be updated due to advances in technology.

**Regulatory and Legislative Uncertainties**

Energy issues are central to many of the current environmental, economic, and security debates occurring at all levels of government. Energy and environmental policies are under ongoing review and we cannot know with certainty what specific regulatory proposals will be adopted or what revisions will be made even in the near term.

This plan primarily incorporates and extrapolates the requirements in the New York State Energy Plan as well as pending Federal legislation and New York City plans. Since the plan describes multi-year, intensive capital investments on a vast network, rapid and large shifts in cost or revenue would be disruptive. Examples of the regulatory and legislative signposts related to such change are high taxes and imposition of more stringent environmental requirements. As such, regulatory reform, including tax reform is essential if the company is to succeed in moderating projected increases in the cost of electric service. For example, reforms that will facilitate off-peak charging for electric vehicles will be important to achieve the investment levels indicated in the plan, and not achieving that could result in increased needs if electric vehicles are widely adopted over the planning period.

**Economic Uncertainties**

The population and economy of the New York City metropolitan area are the primary drivers of our projections for energy use and demand. Increases in population, employment and overall economic growth drive increased energy usage and amplifies the pace of investment, while slower or negative growth has a contrary effect. The impacts are not symmetrical in that negative growth still would not eliminate the need to replace existing facilities serving the existing customer base.

Our goal is to provide safe and reliable energy at an affordable price to our customers. Our electric system is one of the most heavily relied upon in the world. Over three million customers depend on us every day for safe and reliable power. We are responsible for serving the financial and media capitals of the world, critical infrastructure including tunnels and subways, and more hospitals per square mile than any other city in the world. To meet these demands, we challenge ourselves to continually improve the design and operation of our electric system.
1.5 SUMMARY

Our Electric System Long Range Plan is a key step for serving our customers with safe and reliable power. It provides a strategic framework for implementing our plans to manage demand and supply, invest in our infrastructure, provide environmental stewardship, and to serve our customers at a reasonable cost. Over the planning horizon, some pilot programs will produce positive results, some uncertainties will be resolved, and other uncertainties will surface. It is because of this uncertainty that we must plan ahead.

General Eisenhower once said “plans are nothing; planning is everything.” In the process of developing a plan, a planning organization expresses desired outcomes, identifies unknowns, and enhances our corporate ability to address contingencies and to adjust to new and unforeseen developments when they inevitably arise. We have developed a long range planning process to monitor signposts and adjust the plan as needed.

We developed this long range plan to guide us into the future and provide us with a road map to progress for the next two decades. We have described the various uncertainties, identified key signposts and we expect to update the plan as fundamental changes occur in our operating environment. We will measure our performance, manage our costs and reduce the risks on our system. The way we will accomplish all of our goals is to work collaboratively with our customers, legislators, regulators, community leaders and others in order to implement our plan successfully.

This plan is consistent with our mission to deliver safe and reliable electric service to customers in an innovative, cost effective, and environmentally responsible way. “Safe” and “Reliable” energy service are words that are embraced by all of us at Con Edison. Our vision is to lead and support efficient electric energy practices in the communities we serve by continuously improving our electric systems and processes with smarter, high performing electric networks, better information management systems and highly qualified employees. Our commitment is to meet our customers’ expectations. We will do so by managing demand, supply and protecting our environment. We will integrate our system design to meet the needs of customers in specific areas and improve our asset management through optimal use of our assets. We will extend the life of our system if feasible and minimize capital investments. We will provide our customers with safe and reliable service, and train our workforce to be well positioned to serve today and in the future.

It is in these ways that we expect to successfully carry out our objectives and implement our long range electric plan.

***
2.0 INTRODUCTION

2.1 VISION, MISSION AND PLAN OBJECTIVES

A clear vision for our future and well-defined mission for our operations are necessary to guide our decisions for investments and programs in the 20-year planning period. The Con Edison Electric System vision statement is as follows:

We will meet New York City and Westchester County’s electric energy needs by continuously improving our electric systems and processes with smarter, high performing electric networks, better information management systems and highly qualified employees meeting customer expectations for safety, reliability and reasonably priced electric service.

New York City is already one of the most energy efficient cities in the world. With such a dense population in a small space, the average monthly use of electricity per customer in the city is amongst the lowest in the nation. A typical New York City apartment dweller uses only 3,600 kWh per year versus the national average of over 11,000 kWh. The New York metropolitan area also maintains the nation’s largest electric powered subway system and three major electric powered commuter railroads to neighboring communities.

Our service territory is a critical commercial center, making reliable electric service of utmost importance. Con Edison’s customers create about 9% of the United States’ Gross Domestic Product. Our economy is largely based on information-intensive enterprises which are highly dependent on power quality and reliability. Any significant decline in reliability would pose a high cost to our local businesses.

Our region is home to the headquarters of over 40 Fortune 500 companies. Some of our most famous customers include the New York Stock Exchange, the Federal Reserve, the United Nations, Rockefeller Center, and the Empire State Building. We serve world-renowned cultural and media institutions like Lincoln Center, the Metropolitan Museum of Art, the Museum of Modern Art, the Guggenheim, Carnegie Hall, Radio City Music Hall, and the Apollo Theater. We are home to two major league baseball teams that play at the new Yankee Stadium and Citi Field and house multiple sporting and cultural events at Madison Square Garden. Our Times Square neighborhood is home to thirty-nine Broadway theaters, 35 hotels with 15,000 guest rooms, too many restaurants to count, and hosts over 40 million tourists per year.

In our service territory alone, there are over seventy public and private hospitals, more than forty distinct emergency and relief services, and over one-hundred community care facilities for the elderly. There are one-hundred and twenty-five colleges and universities with over 500,000 students enrolled.

In addition to the largest subway infrastructure in the nation and commuter rail lines mentioned above, we serve three airports including two major international airports that serve over one-hundred million passengers each year on 1,400 domestic and 360 international flights daily.

---

6 Energy Information Administration. 2009.
On an individual basis, the lifestyle of this densely populated region is powered by electricity, which enables 24-hour and high-rise living, and promotes neighborhood safety. We serve over 6,000 buildings with greater than 12 floors. Our customers benefit from an extensive electrically powered, public transportation network that is distinguished from other major metropolitan systems by its size, 24-hour convenience, and widespread use. Perhaps no area in the world receives a greater financial and societal benefit from highly reliable electricity. And there may be no area which has higher expectations of reliability.

We know New York City and Westchester County will continue to grow and change. Con Edison will continue to power existing infrastructure and business while watching for what is to come for future generations. We envision a future where there is a continued and growing demand for electricity driven by an ever increasing proliferation of electricity powered appliances, communication devices, home controllers, and even transportation equipment such as electric vehicles. While appliance and building codes and standards will continuously improve the efficiency of electronic gadgets, the sheer increasing number and use of these devices will solidify the need for both the central plant and distributed utility grid model as well as the need to incorporate newer renewable and clean distributed resources to reduce our dependency on fossil fuels and additional, expensive infrastructure.

We see a future with increased need for integrated planning at the utility, local, state and federal levels, and even greater dependence on the sound engineering competencies that brought us to this time in our evolution. We support continued development of competitive markets where they make sense. Cleaner and more efficient technologies will drive demand, but will always need to be balanced by cost. When new technologies are the obvious low cost choice only then will they survive and consequently thrive in the marketplace. Our jobs in the future will entail a more integrated systems approach where more and more information will need to be collected, analyzed, and acted upon to keep the system operating at optimal levels.

To get us from here to there, Con Edison has further defined its strategic mission to align near-term objectives with our longer term vision. Our mission to deliver the benefits of safe and reliable electric service to customers in an innovative, cost effective and environmentally responsible way, serves as a touchstone for our planning and decision-making processes. The Company’s core commitment is to deliver safe, reliable, and cost-effective electric service to New York City and Westchester County and this is the foundation for all of our actions. Con Edison pursues these goals with the ultimate objective of positively contributing to the total living environment for all metropolitan New Yorkers, which includes the economic, security, and environmental well-being of the entire community.
We developed five objectives to guide the development of the Electric System Long Range Plan. These plan themes collectively carry out our mission and individually describe areas of Con Edison strategic intent by which individual programs and investments are categorized. Figure 2-1 illustrates how the objectives support the Con Edison vision and mission.

**Figure 2-1. Con Edison Vision, Mission, and Plan Themes**

**Managing Demand, Supply, and Environmental Profile**

Con Edison will take a proactive and integrated approach to managing demand, supply, and environmental impact. We will encourage demand side management to reduce peak demand and overall energy use and will support the development of highly efficient codes and standards. We will facilitate the interconnection of distributed generation and carefully plan for new circuit-level load from new technologies such as electric vehicles. Our plan includes the maintenance of a balanced, reasonable-cost supply portfolio and we will explore opportunities to efficiently connect additional renewable and other sources of affordable generation and transmission developed in the market. We expect to invest in cost-effective advanced metering where necessary to support these initiatives.

**Integrating Innovative System Design**

The deployment of a targeted approach to meeting electric system capacity, reliability, and replacement needs will improve asset utilization; reduce major risks; and lower costs. We will incorporate new designs and advanced technologies into our traditional capacity and reliability solutions at the network, feeder, and component level.

**Improving Asset Management and Control**

Con Edison will focus on efficient management of transmission and distribution assets. We will use innovative maintenance practices, monitoring tools, and control technologies. We will continue efforts to manage the costs of infrastructure construction and integrate new communications technologies such as Smart Grid applications into future asset management protocols as they evolve.
**Enhancing Customer Experience**

Con Edison will focus on customer needs and strive to make it easier for customers to interact with us through the use of new technology. We will incorporate feedback from customer outreach as we introduce new customer service options, communication channels, and information systems. Our plan is to broaden the ways in which we service, and communicate with customers.

**Improving Processes and Skills**

Our people are our key strength. We will build a culture emphasizing cost consciousness, stakeholder importance and trust. We will continue to improve our internal processes and skills training to make sure our people have the skill sets to provide excellent customer service and to perform work safely and efficiently. We intend to evolve our organizational structure, with increased focus on planning tools such as cost and work management, to successfully meet future challenges.

2.2 PROCESS OF DEVELOPING THE ELECTRIC SYSTEM LONG RANGE PLAN

Our process of developing this integrated Electric System Long Range Plan includes careful considerations for the questions listed below:

- What are the key drivers impacting the electricity marketplace?
- How will various elements of electricity consumption be impacted by the key drivers?
- What are the resultant electricity growth cases for our service territory?
- What do our customers want?
- How do we design our systems, build new infrastructure, and maintain existing assets to meet evolving customer needs?
- What are the implications of the various electricity forecasts on our customers’ bills, both from our transmission and distribution plan as well as other potential impacts on their bill such as the cost of supply?

As depicted in Figure 2-2 we developed hypotheses regarding the key drivers, projected the implications of various uncertainties on electricity demand, energy use and electricity supply, and developed three electricity growth cases. From here, we conducted a thorough review of our methods of system design and our plans to maintain and build assets. Plans were shared with stakeholders and tested for total customer bill impact.

---

**Figure 2-2. Process for Developing the Electric System Long Range Plan**

![Diagram of process](image)

<table>
<thead>
<tr>
<th>Drivers</th>
<th>Requirements</th>
<th>Forecasts</th>
<th>Customer Bill</th>
</tr>
</thead>
<tbody>
<tr>
<td>Economy</td>
<td>Electricity Demand</td>
<td>Low Case</td>
<td>Supply</td>
</tr>
<tr>
<td>Policies</td>
<td>Energy Use</td>
<td>Plan Case</td>
<td>Fees</td>
</tr>
<tr>
<td>Technology</td>
<td>Electricity Supply</td>
<td>High Case</td>
<td>Taxes</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>T &amp; D</td>
</tr>
</tbody>
</table>
To identify, assess, and prioritize business unit activity, we engaged in a comprehensive review of business unit plans and evaluated the merit of incorporating emerging ideas into the integrated plan. Throughout this planning process, plans were adjusted to ensure that collective organizational activities will fulfill our mission and optimize our performance against a framework that considers performance, costs and risks.

We expect that by 2030 the electric usage landscape will look very different than it does today. All potential initiatives were tested as to their relevance based on new transmission and distribution and end-use technologies, emerging legislative requirements like renewable portfolio standards, and continual changes in customer expectations. For example, several programs and technologies such as distributed generation, advanced metering infrastructure (AMI), and various Smart Grid applications were assessed in terms of their potential to increase performance, reduce costs, manage risks, and allow the Company to prepare for the electric needs of customers in the future.

In order to ensure the plan was truly integrated across all business units, the planning process required collaboration across the entire organization. Each of the organizations depicted in Figure 2-3 was integral to the process.

**Figure 2-3. Con Edison Organization Chart**

2.2.1 **Electricity Forecasts**

The electricity forecast drives the timing and magnitude of the required investment in transmission and distribution infrastructure. Con Edison currently develops 10-year load forecasts to ensure that transmission and distribution infrastructure is adequate to support the economic growth of New York City and Westchester County. To develop the 20-year forecast for the Electric System Long Range Plan, we extended the existing forecast based on a number of key driver sensitivities.
A standard forecast consists of two components: an energy forecast and a peak demand forecast. The energy forecast is a projection of electricity consumed throughout the year, measured in gigawatt-hours (GWh). The peak demand forecast is a projection of the maximum electricity requirements that Con Edison’s customers demand at a single point in time, measured in megawatts (MW). Peak demand, or the maximum electricity that our customers require at a single point in time, drives infrastructure investment because we must build to that demand even if it is a relatively infrequent occurrence. For the Con Edison electric system, peak demand occurs in summer when air conditioning loads are the highest.

The primary driver of energy demand is economic growth, which affects employment, construction and population growth in our service territory. Another important driver is environmental and energy policy and regulation, which influences customer rates and mandates certain utility programs. Innovations and price changes in end-use technology (e.g., flat screen televisions, electric vehicles) also affect customer energy use.

To facilitate the development of the plan, we developed a base Plan Case and two alternate bounding cases. These three forecasts for energy and demand are described in brief below and depicted graphically in Figures 2-4 and 2-5.

- **Plan Case**—Based on gradual economic recovery out of recession, with minimal load growth in 2010 followed by consistent annual energy growth of 1.1% and annual demand growth of 0.8%. The Plan Case is the basis for all initiatives and assumptions discussed in the plan. This case incorporates demand side management consistent with New York Independent System Operator assumptions which estimate that approximately 30% of New York State’s goal of 15% reduction in energy by 2015 is achieved.

- **High Case**—Assumes rapid economic recovery, leading to near-term load growth starting in 2010 and growing at an average rate of 2.1% for energy and 1.7% for demand over twenty years. This case is the most consistent with historical growth rates over the last 30 years.

- **Low Case**—Reflects reduced demand due to successful demand side management and improved codes and standards. This case starts with the Plan Case macro-economic demand forecast, but includes 100% of the energy reduction necessary meet the New York State target of 15% energy reduction by 2015. The resultant net 20-year average annual growth rate is 0.1% for energy and 0.3% for demand.
Figure 2-4. Energy Forecasts

Figure 2-5. Demand Forecasts
2.2.2 Stakeholder Input

During the development of the Electric System Long Range Plan, Con Edison met with a representative group of stakeholders, including New York City, and the New York State Governor’s office. We also had frequent discussions with the Public Service Commission Staff. In the future, we expect to continue to have discussions with key stakeholders about our plans.

We also engaged in a targeted customer outreach effort. We organized focus groups of residential and small commercial customers in New York City and Westchester County and conducted one-on-one interviews with large commercial customers. Outreach topics covered affordability, reliability, energy efficiency, renewable power, infrastructure upgrades, and the pace of adoption of new technologies. Customer feedback was considered and incorporated in the plan.

2.2.3 Evaluation of Investments Based on Performance, Cost, and Risk

The overall management challenge of effective planning is to manage the network in an optimal way to balance the often competing priorities of cost, performance, and risk. The Company’s strategic priorities and specific initiatives are designed to improve one or more of these attributes, and make informed trade-offs. For example, increasing reliability or reducing risk is desirable but could increase new capital expenditures or investment in additional operating programs. Consequently, the themes of performance, cost, and risk must be balanced in a systematic and appropriate manner.

As part of our effort to prepare this plan, we developed a capital investment database and custom analytic model to systematically evaluate the impact of specific programs and initiatives over the 20-year planning horizon. The forecasted capital investments were each evaluated in terms of their incremental impact on the performance, cost, and risk characteristics of the Con Edison electric system. Performance measures are contribution to system reliability and environmental impact. Cost measures are capital and operations and maintenance expenditures and savings when compared to existing or traditional solutions as well as the rate and bill impact of those investments. Risk reduction is measured within the model based on the network reliability index (NRI) and outside the model with various public and employee safety initiatives. These measures are consistent with the Company’s asset management practices, annual asset prioritization process, and Con Edison’s enterprise risk management (ERM) process. The Company believes the estimates in this plan are reasonable and their implications therefore warrant careful consideration and should be taken as indicative of an important need to develop strategies to mitigate the cost increases indicated by the plan. Each of these facets of the Company’s planning and prioritization methods will be described in more detail in subsequent chapters.
2.3 BACKGROUND ON CON EDISON

2.3.1 Service Territory

Our electric service territory is composed of over 600 square miles with 9.3 million residents located in the southernmost part of New York State and includes New York City (except the Rockaway Peninsula) and most of Westchester County, as shown in Figure 2-6.

![Figure 2-6. Con Edison Service Territory](image)

Table 2-1 shows the size of the areas we service in the five boroughs of New York City, as well as Westchester County, along with the number of customers in each of these areas.

Table 2-1. Service Area Statistics

<table>
<thead>
<tr>
<th>Service Area</th>
<th>Square Miles of Service Area</th>
<th>Customers</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bronx</td>
<td>41</td>
<td>418,000</td>
</tr>
<tr>
<td>Brooklyn</td>
<td>70</td>
<td>1,008,000</td>
</tr>
<tr>
<td>Manhattan</td>
<td>23</td>
<td>705,000</td>
</tr>
<tr>
<td>Queens</td>
<td>108</td>
<td>621,000</td>
</tr>
<tr>
<td>Staten Island</td>
<td>58</td>
<td>173,000</td>
</tr>
<tr>
<td>Westchester County</td>
<td>310</td>
<td>346,000</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>610</strong></td>
<td><strong>3,271,000</strong></td>
</tr>
</tbody>
</table>

Number of customers is determined based on number of electric meters.
2.3.2 Electric System

Electricity is produced at generating stations and then delivered to customers via a transmission and distribution network. Con Edison is primarily a transmission and distribution company. The infrastructure of a delivery system consists of the transmission system, substations, and the distribution system. These basic elements of the Company’s transmission and distribution system are illustrated in Figure 2-7.

Figure 2-7. Illustration of Con Edison Electric System

The CECONY Electric System

---

8 Con Edison owns less than 5% of the generation assets supplying its customers; the remaining 95% of generation assets is owned and operated by market suppliers.
**Generation**

Following restructuring in the 1990s, the majority of the electricity generated for supply to our customers is now owned and operated by other companies. We primarily purchase our customers' energy requirements through a combination of daily market transactions and longer-term contract arrangements. Con Edison, Inc. does operate a small number of electric generating facilities consisting of plants located in New York City with an aggregate capacity of 700 megawatts (MW).

**Transmission**

Con Edison’s transmission infrastructure consists of conductors that carry transmission voltage from generating sources or transmission lines to substations. Con Edison owns or jointly owns 438 circuit miles of overhead lines operating at 138, 230, 345 and 500 kilovolts (kV), or thousands of volts. The Company’s overhead transmission system is comprised of 1,212 towers that support “open-wire” type conductors.

We operate the largest underground transmission system in the United States: 727 circuit miles of underground cable operating at 69, 138 and 345 kV. The Company’s underground transmission feeders are either oil or solid-dielectric insulated. Oil-insulated cables are typically installed in steel pipes, whereas solid dielectric cables are typically installed in fiberglass reinforced epoxy conduit banks housed in concrete.


**Substations**

The Company’s 99 substations consist of components that transform the voltages and direct power in a safe and reliable manner. Con Edison owns and operates 38 interconnected transmission substations that route power to 61 individual area substations that, in turn, provide power to electrically independent distribution areas that serve our customers.
The transmission substations receive power, typically at the 345kV and 138kV levels, from generators, long-distance transmission lines, and connections to neighboring utilities, and transform it to the 138kV and 69kV levels typically used at the area stations, see figure 2-8. The area substations, in-turn, transform the power to the 33kV, 27kV, and 13kV levels typically used for distribution.

**Figure 2-8. Split Distribution Primary and Secondary System**

*Distribution*

Con Edison’s distribution infrastructure consists of about 95,000 miles of underground cable, which is about 3.6 times the circumference of the Earth, and about 37,000 miles of overhead cable, which is about 15 times the distance from New York to Los Angeles.
The Company’s distribution system consists of 62 secondary networks, which operate at low voltage (120/180V) and 20 non-network distribution load areas. We have the largest low voltage secondary network system in the world with about 260,000 underground structures, and 26,000 underground network transformers, see Figure 2-9.

Figure 2-9. Combined Distribution Primary and Secondary System
Each of our secondary networks is electrically and geographically isolated from every other secondary network. The components of a typical underground secondary network are illustrated in Figure 2-10.

**Figure 2-10. Typical Underground Electric System**

Secondary network designs are common in high density urban areas. They have multiple primary distribution feeders, network transformers, and secondary (or low voltage) mains serving power to a single customer. Consequently, the loss of a single feeder, transformer, or secondary main, in a secondary network design does not typically cause an interruption of power and thus the configuration meets high reliability requirements. The underground installation allows us to meet the space constraints of our urban service territory. There are 2.39 million customers supplied by our underground network system. This level of system redundancy is inherently more costly as the urban underground networks tend to be more expensive to construct and maintain than suburban and rural networks, which are typically based on radial network designs and overhead construction.

The Company’s 20 non-network distribution load areas deliver power to 886,000 customers via 37,000 miles of overhead wire and 46,650 transformers. These areas are serviced primarily by 4kV unit substation grid configurations and 13kV or 27kV autoloop configurations.
The feeders in the 4kV unit substation grid configuration, illustrated in Figure 2-11, connect to a series of distribution transformers that step down power to supply residential customers with house (or low voltage) service of 120/208V or 120/240V. 4kV primary grid feeders are tied together, allowing for continued service in the event one of the feeders is out of service.

Figure 2-11. 4kV Unit Substation Grid Configuration
The autoloop design of our overhead system, illustrated in Figure 2-12, integrates the electric system’s outage detection and protection equipment with automated feeder tie switches. This configuration enables fault isolation and automated switching of feeders and, under fault conditions, ensures power delivery to the maximum number of customers.

Figure 2-12. Overhead Autoloop System Configuration

---

**Design Specifications**

Much of the Company’s electric transmission and distribution system has been designed to satisfy a second contingency, or an “N minus 2” (N-2) standard, which means that, at various stages of electric transmission and delivery, the system is designed to withstand an outage to any two parallel devices, while still reliably serving customers.

Twenty seven of the Company’s area substations serve high-density load areas, defined as where customer load is dense and high-rise buildings are concentrated, and as such, are designed to the N-2 standard, whereas all of the Company’s 62 underground distribution networks are designed to the N-2 standard as well.9

The balance of the Company’s distribution load areas is of an N-1 or first contingency design. In these load areas, which are chiefly overhead systems, additional reliability is designed into the autoloop or 4 kV unit substation grid configurations to limit the number of customers affected by any given outage.

Application of these design standards, with contingency built into the system, results in a more expensive distribution system. Customers have benefited from the investment because of the resultant reliability.

---

9 N-2 design standard was applied to our distribution system for high density load areas prior to 1961 and mandated thereafter. See New York Commission Order dated July 19, 1961 concerning Con Edison.
2.3.3 The Customer Bill

The Con Edison customer bill reflects the Company's tariff charges for electricity delivery, charges for electricity supply, taxes, and regulated fees. As the operator of the delivery system, Con Edison collects all components in a single customer payment and remits payments as required to the appropriate parties. Our delivery charges constitute about a third of the typical residential bill; the remaining two thirds are attributable to costs of supply and costs to cover taxes and fees imposed by various electricity suppliers and government agencies. Figure 2-13 illustrates the breakdown of charges for a typical New York City residential customer in 2010.

Figure 2-13. Breakdown of Residential Bill in 2010

Delivery Rate

The delivery rate represents the cost of transporting energy from the point of supply to the Con Edison system to the customer and constitutes 29% of an average customer bill. This rate covers costs to build and maintain our transmission, substation, and distribution assets as well as to maintain and operate the customer billing and other operations platforms to service customers.

Delivery cost is influenced by three factors: system reinforcement, new business connection, and maintenance. System reinforcement is the cost of infrastructure upgrades to support growing demand.

Based on 292 kWh, residential customer usage in New York City. Average usage in Westchester County is 450 kWh; however the breakdown of bill components is consistent.

Supply rate varies with the market and is passed through to Con Edison customers. As of December 2009, the supply rate was about 44.4% of a typical NYC customer’s bill.
requirements of customers. Customer demand growth is the addition of new infrastructure and may require feeder upgrades, new transformers, or new substations. New business connection is the cost associated with serving new customers within our service territory. Maintenance costs include operations and maintenance costs for existing infrastructure, replacement of system components, installation of additional monitoring to reduce outages, and components required to achieve mandated environmental improvements.

**Delivery Tax and Fees**

The delivery taxes reflected in the customer bill are based on the total tax bill assessed to Con Edison. On average, delivery taxes represent 24% of the total customer bill, and 45% of the transmission and distribution portion of the bill. Con Edison delivery tax components are listed in Table 2-2.

**Table 2-2. Taxes Reflected in Monthly Customer Bill Excluding Income Taxes**

<table>
<thead>
<tr>
<th>Taxes</th>
<th>% of Tax Bill</th>
</tr>
</thead>
<tbody>
<tr>
<td>Property</td>
<td>74%</td>
</tr>
<tr>
<td>Revenue</td>
<td>19%</td>
</tr>
<tr>
<td>Payroll</td>
<td>5%</td>
</tr>
<tr>
<td>MTA Mobility</td>
<td>&lt;1%</td>
</tr>
<tr>
<td>Sales and Use</td>
<td>&lt;1%</td>
</tr>
<tr>
<td>Subsidiary Capital</td>
<td>&lt;1%</td>
</tr>
<tr>
<td>Receipts</td>
<td>2%</td>
</tr>
<tr>
<td>Miscellaneous/Other</td>
<td>&lt;1%</td>
</tr>
</tbody>
</table>

The customer bill also includes fees collected for external entities. The System Benefits Charge and Renewable Portfolio Standard surcharge are mandated fees that finance energy efficiency and renewable portfolio programs owned and operated by the New York State Energy Research and Development Authority (NYSERDA). The System Benefits Charge funds programs that have been determined by the Public Service Commission "to be inadequately addressed by New York’s competitive energy markets."12 Currently the charge is between 0.2 cents/kWh and 0.22 cents/kWh, which equates to roughly 60 cents per month for the typical residential customer.

The 18-a Assessment is an additional fee imposed by the New York State Legislature for the support of the State’s General Fund and is expected to represent 0.36 cents/kWh in 2011.

---

11 Con Edison 2009 Electric Rate Case. ‘Sales and Use’ tax is paid by the Con Edison; sales tax paid by the customer is not included here.

12 New York State Public Service Commission, 05-M-0090 System Benefits Charge, http://www.dps.state.ny.us/sbc.htm
Supply Rate and Supply Tax

As illustrated in Figure 2-11, the supply rate constitutes 44% of an average residential bill. Since customers purchase their electricity supply from a range of competitive suppliers, the supply rate is largely outside of our purview. We have largely divested our generating plants and primarily purchase our customers’ energy requirement through contracts and purchases from the energy markets. Customers who purchase their electricity supply from Con Edison are characterized as full service customers and are charged Con Edison’s cost for their electricity. In 2008, 42% of the electricity delivered on Con Edison’s system was to full service customers. The balance of our customers’ electricity supply was provided by a variety of competitive suppliers, the New York Power Authority (NYPA), and various municipal electric agencies.

As much as practical, Con Edison’s electricity supply is developed from the least cost options available to the Company and is typically a composite of short- and long-term firm supply contracts, Con Edison production\(^{13}\), and spot market purchases made by the Company. Con Edison’s cost of electricity and the allocation of these costs in customer rates are subject to regulation and review by the New York State Public Service Commission.

Consequently, the supply portion of our customer bill is directly related to the market price of electricity, which is itself highly dependent on regional fuel supply costs, fuel mix, environmental costs, and the supply/demand balance. Many of these core cost factors have been characterized by significant volatility in recent years. This volatility is expected to continue and potentially increase in the future as a result of rising and uncertain fuel cost, new technologies, and changing environmental regulation.

A supply tax, representing approximately 3% of an average residential customer’s bill, is imposed on each customer. The tax is based on a sales tax rate applied against purchased supply and a general receipts tax applied against Con Edison total revenues.

2.3.4 Performance, Cost, and Risk Trends

The Company will make business decisions related to operation, maintenance, and investment in the electric system in the context of their impact on the system’s performance, cost, and risk metrics. In this section we describe our historical performance on these dimensions our goals for the future.

Performance

Con Edison’s customers have come to expect a high level of electric system reliability, and our goal is to consistently meet that expectation. By doing so, we have frequently been cited by industry groups for our high reliability performance. Con Edison, for example, has received the ReliabilityOne award from PA Consulting six times since 2001.

---

\(^{13}\) Less than 5% of electricity delivered is generated by Con Edison.
Figure 2-14 compares customer interruptions per 1,000 customers per year for Con Edison to the national and New York State average. Con Edison experiences about 130 interruptions per 1,000 customers per year, which is significantly more reliable than the New York state average of 880 and the national average of 1,250. Under this metric, 1,000 interruptions per 1,000 customers represent approximately one interruption per customer per year.

Figure 2-14. Customer Interruptions
A second common measure of reliability is interruption duration. Figure 2-15 presents the Customer Average Interruption Duration Index, or the average outage duration experienced by those customers who experience an outage.

Figure 2-15. Customer Average Interruption Duration Index (CAIDI), 2008

The Company’s higher outage duration reflects the greater amount of time needed to identify and repair assets in our extensive and highly complex underground network system. In our underground system, many of the manholes and service boxes are not immediately accessible, which extends the time it takes to make repairs to service cables in the underground systems. Restoration time is significantly shorter for customers on our overhead system, which is more accessible. The Company places a high priority on minimizing overall outage times.

To continue high reliability performance, we set the following performance objectives for the Electric System Long Range Plan: to maintain system reliability at our current, industry-leading level, and to improve our customer restoration performance, as measured by outage duration and feeder restoration time.

Cost

The Company’s component of the overall “cost of service” is primarily for construction, operation, and maintenance costs for our transmission and distribution infrastructure and is a primary input into determining the Company’s electric rates.

---

Asset Intensity

The N-2 design standard, while highly reliable, results in a higher level of distribution assets per customer, as compared to the industry. From 1998 to 2008, Con Edison has maintained net distribution plant\textsuperscript{15} at levels approximately 40% to 100% greater than the median for New York utilities\textsuperscript{16}, due to both the N-2 design and the generally high cost of conducting business in the service territory. The Company’s transmission asset intensity, on the other hand, is in line with industry average.\textsuperscript{17}

Operations and Maintenance Cost Patterns

The Company’s operations and maintenance costs are also a critical component of our cost of service. From 1998 to 2008 our distribution operations and maintenance cost per customer was slightly higher than median for New York utilities. This pattern largely reflects the Company’s higher level of distribution asset intensity. Transmission operations and maintenance costs per customer are in line with the New York median.\textsuperscript{18}

The Company’s administrative and general costs on a per customer basis have historically been low relative to industry average. Even with the inclusion of recent high increases in fees and taxes, the resulting Con Edison administrative and general cost per customer is in line with the New York median.\textsuperscript{19}

\textsuperscript{15} Net plant is defined as the historic gross additions to plant accounts, net of accumulated depreciation.

\textsuperscript{16} FERC Form 1

\textsuperscript{17} Con Ed had $543 in net transmission plant per customer in 2008 vs. $520 for the New York median. Based on FERC Form 1 data.

\textsuperscript{18} From 1998 to 2008 Con Edison distribution operations and maintenance cost per customer was on average $143 per customer versus $135 for the NY median in 2008. Transmission O&M costs per customer are in line with the New York median, reaching $51 per customer in 2008 compared to $42 for the New York median. Based on FERC Form 1 data.

\textsuperscript{19} Con Edison administrative and general cost per customer was $121 in 2008 versus the New York median of $120. Based on FERC Form 1 data.
**Average Customer Rates, Energy Usage, and Bill**

Con Edison’s cost of service is higher than the industry average due primarily to the rigorous design standards we employ, and the higher cost of doing business in our service area. Nevertheless, Con Edison’s average residential customer bill was lower than the New York median in 2008. This is a result of the low usage patterns that are characteristic to dense, urban environments, where residential customers predominantly live in multi-family units with correspondingly lower lighting and space conditioning requirements. As such, New York City has been applauded for being the most energy efficient city in the nation.

**Figure 2-16. 2008 Average Rates, Usage, and Bills for Con Edison Residential Customers**

![Graph showing average monthly residential bill, average annual residential usage, and average residential rate for Con Edison and the New York median.]

Our cost objectives are to minimize expenses through a combined strategy of encouraging effective energy efficiency, improved processes and operations, reduced asset intensity and regulatory and tax reform, offsetting projected cost increases without sacrificing reliability.

**Risk**

Given the complexity of and critical dependency on our electric system, there are numerous inherent operational, financial, and safety risks that could potentially impact our customers, the communities we serve, our employees, and the public. The Company evaluates its risks and seeks to mitigate them to improve its performance. As a result, these risks drive many O&M programs and capital investments, and are considered within the project prioritization process when planning the budget.

We have developed an enterprise risk management (ERM) process by which the Company identifies, monitors, and mitigates risks. Below we highlight our ERM process and, as examples of some of the risks we manage, we describe our ongoing efforts to mitigate risks associated with wide-scale system reliability and employee and public safety.

---

20 CECONY refers to the total system (New York City and Westchester County). 2008 average bill higher than 2010 bill due to supply portion of the bill driven up by high case prices.
Enterprise Risk Management

The Company has always placed a priority on identifying and mitigating risk and, like many other companies, has implemented a formal ERM process. Con Edison's ERM program, initiated in 2005, is the subject of ongoing refinement to improve its usefulness. Through a collaborative process of risk assessment, ERM has become embedded into the planning and budgeting functions of all operating groups. As part of the annual ERM cycle, groups identify operational and administrative risks, and assess their severity, likelihood, and controllability. These assessments are reviewed and adjusted through the active participation of senior management.

ERM is a process to identify, analyze, integrate, evaluate, manage, monitor, and communicate risks across the Company. Our risk management program has three primary objectives:

- **Systematic risk mitigation**—Continually evaluate the likelihood, severity, and control mechanisms of risk categories and ensure proper risk mitigation and preparedness.
- **Proper allocation of resources**—Integrate ERM into the development and evaluation of business cases. Ensure that we utilize annual budgeting and longer-term program development to evaluate adequacy of resources for risk mitigation.
- **Enhanced communication and transparency**—Allow for greater transparency and collaboration by actively involving all levels and functions of the organization, up to and including the CEO. Establish accountability by assigning specific officers to each risk.

As shown in the Figure 2-17 and described below, ERM allows Con Edison to translate a broad concept such as “risk” into quantifiable measures of severity, likelihood, and controllability.

- **Severity**—Estimate of the event's potential impact on public perception, safety, finances
- **Likelihood**—Estimate of the likelihood that an event will occur within a set timeframe based on past experience and current probability
- **Controllability**—Estimate the likelihood that existing detection or control mechanisms could predict or prevent the event

For each identified risk, these three components are assigned a value from 2 to 10. These component factors are then multiplied to produce a risk priority number. The risk priority number quantifies the relative priority of risks across the Company. This value is a key input to the Capital Optimization process described in Chapter 7 of the Electric System Long Range Plan.
Figure 2-17. Risk Assessment Factors

<table>
<thead>
<tr>
<th>Severity Factor</th>
<th>Impact Category A</th>
<th>Impact Category B</th>
<th>Impact Category C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Insignificant</td>
<td>2</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Moderate</td>
<td>4</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Significant</td>
<td>6</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Severe</td>
<td>8</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Catastrophic</td>
<td>10</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Likelihood Factor

<table>
<thead>
<tr>
<th>Factor</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rarely</td>
<td>One incident in 10 years</td>
</tr>
<tr>
<td>Unlikely</td>
<td>One incident in 5 years</td>
</tr>
<tr>
<td>Likely</td>
<td>One incident in 3 years</td>
</tr>
<tr>
<td>Frequent</td>
<td>One incident in 1 year</td>
</tr>
<tr>
<td>Certain</td>
<td>Greater than one</td>
</tr>
</tbody>
</table>

Controllability Factor

<table>
<thead>
<tr>
<th>Factor</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Almost Certain</td>
<td>Excellent detection and control over the triggering event</td>
</tr>
<tr>
<td>High Probability</td>
<td>Highly predictable detection and control over the triggering event</td>
</tr>
<tr>
<td>Moderate</td>
<td>Detection and control are reasonably achievable</td>
</tr>
<tr>
<td>Low</td>
<td>Detection and control are very limited</td>
</tr>
<tr>
<td>Impossible</td>
<td>No ability to detect or control the triggering event</td>
</tr>
</tbody>
</table>

The output of the ERM process is detailed mitigation plans for each key risk. Illustrative examples of risks are set forth in Table 2-3.

Table 2-3. Illustrative Electric Distribution Operational Risks

<table>
<thead>
<tr>
<th>Event</th>
<th>Mitigation Programs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Distribution Low Voltage</td>
<td>- Secondary main replacement</td>
</tr>
<tr>
<td>Equipment Failure</td>
<td>- Secondary rebuilds</td>
</tr>
<tr>
<td></td>
<td>- Vented manhole covers</td>
</tr>
<tr>
<td></td>
<td>- Annual stray voltage testing</td>
</tr>
<tr>
<td></td>
<td>- Mobile stray voltage testing</td>
</tr>
<tr>
<td></td>
<td>- Facility inspections</td>
</tr>
<tr>
<td>Distribution Transformer</td>
<td>- Transformer replacement</td>
</tr>
<tr>
<td>Failure</td>
<td>- Remote monitoring system</td>
</tr>
<tr>
<td></td>
<td>- Network transformer inspections</td>
</tr>
<tr>
<td></td>
<td>- Transformer evaluation</td>
</tr>
<tr>
<td></td>
<td>- Failure detection and loss of life estimate</td>
</tr>
</tbody>
</table>
Risk of a Large-scale, Prolonged Network Outage

The Company has established a network reliability index (NRI) to measure the risk to each Con Edison network. NRI measures the probability that the four or more feeders supplying power to one portion of a network experience simultaneous failure under standard conditions. NRI therefore indicates the likelihood of experiencing cascading feeder failures that potentially result in overload conditions on nearby feeders and, in extreme cases, a network shutdown.\textsuperscript{21}

To improve our NRI performance and reduce the risk of a large-scale, prolonged network outage, we have made improvements in network feeder restoration, effectively reducing the feeder outage time from an average of 33 hours in 2004 to less than 14 hours in 2008. This performance improvement is not fully captured in average customer outage statistics (or CAIDI, the customer average interruption duration index) because most out-of-service feeders in the network system do not cause customer outages. However, this performance improvement lowers the risk of a large-scale, prolonged network outage and is therefore an important element of our risk mitigation efforts.

NRI is proving itself as a reliable and efficient planning tool; we believe it is a useful complement to our second contingency design criterion as a planning mechanism, helping to maintain overall reliability while reducing risk costs.

Public and Employee Safety

The Company operates several hundred thousand structures with energized equipment in the New York metropolitan area. We focus on the safety of the public in the surrounding areas, and on the safety of our employees who are working in and around these structures.

The Company has made a commitment to improving public safety by implementing a rigorous stray voltage detection and correction program using the newest technology. Stray voltage in Con Edison’s service territory is primarily a result of insulation breakdown on the low voltage cables or from defective neutral connections in streetlights and overhead wires. Some stray voltages inadvertently energize publicly accessible structures, although few are significant enough to cause bodily injury.

\textsuperscript{21} NRI is calculated based on failure rates for cable sections, joints, transformers, and other equipment based on their age, temperature range, voltage, and loading conditions to model specific network performance under various scenarios.
In 2005 Con Edison initiated an aggressive stray voltage detection and correction program. Our program uses 14 stray voltage detection vehicles to conduct comprehensive scans of the underground network electric system. When stray voltage is detected, repair crews respond promptly to remedy the cause. In 2009, the Company scanned the entire Con Edison underground system 12 times.

There has been a decline in the number of Energized Equipment Incidents as illustrated in Figure 2-18.

Figure 2-18. Energized Equipment Incidents
The results of Con Edison’s stray voltage detection program are also apparent in our Electric Shock Report performance. An electric shock report occurs when an employee or member of the public reports detecting a “shock” from stray voltage in our service territory. Figure 2-19 highlights that the number of ESR incidents is also declining. This is due to the Company’s stray voltage detection programs that are identifying stray voltage incidents much sooner, at much lower voltage, and correcting conditions immediately.

**Figure 2-19. Electric Shock Trends**

![Electric Shock Trends Chart]

The stray voltage initiatives have resulted in measurably improved public safety in this area. It is critical to economic efficiency to continue to evaluate programs and to focus scarce resources on the most effective programs. With that in mind, the Company believes that modifications can be made to the current stray voltage program that will maintain the progress achieved to date, freeing up resources to apply to other appropriate programs.

The reliability performance and risk characteristics of the Company’s 62 secondary networks are also linked to the performance and failure patterns of the underground distribution transformers that supply power to them. In-service failure of these underground network transformers can be a public safety issue.
The Company has fully implemented remote monitoring systems on all network transformers as well as enhanced transformer monitoring, inspection, and maintenance programs. As can be seen in Figure 2-20, the failure of these network transformers has dropped 70% since 2005.

**Figure 2-20. Underground Network Transformer Failure Trends**

Employee safety is a top priority for Con Edison. We have a number of programs and guidelines in place to achieve an injury-free workplace. The main performance metric in the area of employee safety is the OSHA incidence rate. The incidence rate is a normalizing indicator that captures the number of recordable injuries/illnesses per standard unit of 100 full-time equivalent employees (each working 2,000 hours per year). It is dependent upon the number of recordable injuries/illnesses experienced and the number of productive hours worked, which includes all straight time, compensable overtime, training hours, and restricted duty hours for both weekly and management employees.

Con Edison's current safety performance, as measured by the incidence rate, is at the midpoint of its industry peers. The 2009 company-wide incidence rate was 3.58, or approximately 4 injuries and illnesses per 100 workers. We believe there is significant opportunity for improvement, and have therefore established its reduction as a key objective for all operating groups. Our goal is to reduce this number by more than half, and achieve a rate of 1.50 or less by 2015.

---

22 The formula for calculating the incidence rate is: number of recordable incidences x 100 x 2000 / total number of productive hours worked.
Our Environment Health & Safety group is working closely with all operating groups to make sure we achieve our safety goals, including providing appropriate tools and resources to ensure compliance with safety rules, performing comprehensive job planning and briefings, documenting site safety observations, and more broadly, to promoting a culture of personal accountability.

Con Edison’s goals in this plan relating to the risks facing the company are to:

- Continue to utilize our ERM process to systematically identify and prioritize emerging risks, develop risk mitigation strategies, and mobilize resources to execute those strategies.
- Improve the NRI by approximately 60% across the 15 worst performing networks.
- Strive for continual improvement in employee and public safety by developing and executing innovative programs and processes.

In analyzing our historical performance on the dimensions of performance, cost, and risk we identified the following primary objectives.

- **Performance**—Maintain network reliability, while mitigating the risk of a large-scale, prolonged network outage. While these types of outages are infrequent events, their impact can cause significant hardship to our customers and can cause harm to property and public safety.  

- **Cost**—Improve the Company’s asset utilization while maintaining reliability.
- **Risk**—Continue to strive for improvements in all aspects of employee and public safety.

---

23 Long Island City Proceedings. New York State Public Service Commission 06-E-0894
3.0 MANAGING DEMAND, SUPPLY, AND ENVIRONMENTAL PROFILE

3.1 OVERVIEW

Our Plan Case forecasts 15,925 MW of electric peak demand in 2030, representing an approximately 20% increase over today. Along with the increase in demand for electricity, we expect there to be increases in the cost of the supply resources needed to meet that demand. Therefore we continue to seek to integrate well-proven methods to manage both demand and supply to further our mission of delivering safe, reliable, and affordable service while minimizing our environmental impact. For example, demand side management (in the forms of demand response, energy efficiency, and distributed generation) may defer or eliminate the need for building additional infrastructure, while at the same time reducing greenhouse gases and enhancing reliability. Similarly, the well-planned integration of more renewable resources, electric vehicles, and storage devices in our service territory may improve the reliability of the system and reduce reliance on fossil fuel resources.

Our goals for managing demand, supply, and our environmental footprint are to:

- Reduce transmission and delivery infrastructure investments and power purchase costs
- Help customers manage energy costs
- Improve the environmental profile and do our part to meet Federal, New York State and New York City energy and environmental targets
- Enhance reliability of our electric system
- Diversify the supply portfolio
To meet these goals we will develop a full portfolio of programs and initiatives; however we will deploy them selectively based on their benefit to customers. Our plan includes programs and initiatives to:

- Expand our role as an energy advisor to customers by aiding them in managing their energy expenditures through energy efficiency and demand response programs.
- Facilitate and integrate distributed generation to provide more choices for customers and increase the penetration of distributed renewables such as rooftop photovoltaics, through customer and utility owned applications with minimized constraints on the electric system.
- Support the expansion of infrastructure to facilitate plug-in electric vehicle (PEV) deployment (and other emerging end-use applications) and potential storage and vehicle-to-grid applications through a series of pilots, working with industry associations, manufacturers and customers.
- Invest in a cost-effective deployment of an advanced metering infrastructure (AMI) for the implementation, measurement, and dispatch of the aforementioned demand- and supply-side resources as well as to enhance our asset management and monitoring and control objectives.
- Consider the incorporation of new and renewable supply resources into the grid by developing partnerships to investigate new technologies and building new transmission lines (where necessary for reliability or where they are the most cost-effective solution compared to generation or demand side management).
- Monitor the impact of and evaluate options to use the electricity byproduct of Con Edison’s steam plants to meet electric demand.
- Continue to deploy a portfolio of environmental sustainability initiatives to improve Con Edison’s environmental impact in all aspects of our business.

3.1.1 Supply Outlook

The major balance of this document summarizes how Con Edison will optimize our transmission and distribution investments to meet our performance, cost, and risk objectives. While we will continue to make every effort to keep our transmission and distribution rates down, it is important to convey that market and policy will impact our customers’ bills. In particular, the composition, availability, and affordability of electricity supply may experience dramatic change over the 20-year planning horizon. Even assuming that fees and taxes remain consistent with 2011 estimates, we expect supply costs to rise steadily through 2030.

While we do not own significant sources of power generation we do procure energy for our full service customers, whose energy consumption in 2008 represented approximately 42% of all of our delivered energy. Con Edison works diligently to achieve the lowest reasonable supply costs for these customers. We accomplish this first by making informed and strategic purchase decisions, selecting a cost effective mix of power plants, long-term contracts, and direct purchases from the energy market. Second, we use financial hedging products to mitigate the volatility of our spot energy purchases with the objective of shielding our customers from supply market volatility.

24 Con Edison does not know if tax rates will remain constant over the planning horizon. We have made this simplifying assumption for the purposes of the Electric System Long Range Plan.
We have begun to take an even more proactive role in managing supply costs by leveraging energy efficiency and demand response programs to reduce electric demand, which in turn reduces supply purchases, particularly when the region is experiencing peak conditions and the cost of supply is at its highest. We are also facilitating the integration of distributed generation assets into the grid thus allowing our customers to identify additional cost-effective means of meeting their energy requirements, and further diversifying our overall supply portfolio. Our future plans regarding these initiatives are discussed in detail later in this chapter.

While we will continue to actively manage the supply costs for our customers, we still foresee that supply costs will rise over the 20-year planning horizon. For the Plan Case, our analysis suggests that the cost of supply will grow on a real 2009 dollar basis from 9.4 cents per kWh in 2010 to 14.6 cents per kWh by 2030, representing an average annual growth rate of 2.2%. For Con Edison customers, the primary driver of the cost of electricity is the price of natural gas used to generate that electricity by facilities in and around the service territory. The market price for electricity is determined by a market that is administered by the New York Independent System Operator. The NYISO gathers information from power plants and other resources in and around the Con Edison service territory to help match customer electricity demand to the lowest cost supply. At any point in time, the market price for energy is set by the highest bid generation unit that needs to be run to meet demand. And for Con Edison customers, that is usually a natural gas-fired unit. Over the 20-year life of this plan, it will likely continue to be a gas-fired plant, as expiring non utility generation contracts will be replaced by power from the New York Independent System Operator market. With gas-fired plant technology, since labor costs are low and it has low emissions compared to other fossil sources, most of the cost of running a unit is based simply on the input price of the natural gas burned. As the company studies a number of longer term demand forecasts, gas-fired units may not, on the margin, be exactly the same amount of hours in each case. But in general, gas will set the market price most of the time. Many gas-fired units are in the market, and more are proposed for development over the 20 years of this plan.

Con Edison customers also pay the cost of maintaining adequate generation supply through the New York Independent System Operator market. These capacity costs tend to vary inversely with market prices for power (i.e. they are low when energy prices are high and new supply is being developed.) Even though these can be a significant portion of the electric supply cost, it does tend to offset the cost increases associated with a rising natural gas scenario.

The continued operation of large central station power plants that produce electricity at relatively low prices in New York State is another key uncertainty. For example, the Indian Point facility in Westchester Country is a major source of supply of electricity for Westchester County and New York City. The current owner of the facility, Entergy, is facing a re-licensing process and a potential need to install cooling towers to meet environmental rules. If the Indian Point facility were unable to continue to operate, replacing it would be a major challenge.
Legislation and regulation are also significant drivers of supply cost increases. Proposed legislation includes a national Renewable Portfolio Standard and CO₂ cap and trade program. The Regional Greenhouse Gas Initiative is already in place for our region. Combined, the Regional Greenhouse Gas Initiative and a Federal CO₂ program will increase the unit cost of electricity for customers by applying a cost to CO₂ emissions associated with our supply portfolio. Also a large driver of supply cost growth is the cost associated with the additional transmission required to deliver the energy produced by additional renewable generation – both land based and offshore – to our service area. Figure 3-1 illustrates how we expect our resource mix to shift over twenty years in the Plan Case to meet these various requirements.

Figure 3-1. Resource Mix 2010 Versus 2030

Depending on the pace of adoption of distributed generation, particularly renewable and gas self-supply options, this supply mix could look very different.

3.1.2 Demand, Supply, and Environmental Objectives

Con Edison intends to provide customers an integrated offering of solutions for managing their environmental impact and their electric bills through both demand and supply side options. This service offering will include programs to shave and shift peak demand, programs that conserve energy, initiatives to improve access to renewable and affordable electric supply resources, as well as a comprehensive environmental sustainability plan relevant to all aspects of Con Edison operations. In this section we discuss the goals of our collective programs and initiatives.
Reduce Transmission and Distribution Infrastructure Investments and Power Purchase Costs

Our transmission and delivery system is constructed to meet the highest demand for electricity at a given point in time, which occurs in the summer for Con Edison. If our customers reduce their collective usage at that peak, we can reduce our transmission and distribution investments.

Active demand and supply side management will position us to better manage customer demand through peak shaving, peak shifting, and reducing overall energy usage. Lowering peak demand and energy use should allow the Company to defer or avoid infrastructure investments as well as reduce capacity and power purchases that would have been needed to meet higher peak demand. Figure 3-2 illustrates how demand and supply side initiatives help achieve these objectives.

Figure 3-2. Con Edison Managing Peak Usage

Cost effective deployment of these demand resources may allow us to postpone or permanently reduce the need for additional supply, transmission and distribution infrastructure, particularly when demand and supply side management programs are targeted to capacity constrained load areas. In addition, reducing demand can result in lower capacity prices, lower peak period energy, or both.
Help Customers Manage Energy Costs

Our plan initiatives will help customers manage their energy consumption and lower their bills by offering a comprehensive suite of energy efficiency, demand response, and distributed generation programs designed to meet the needs of all customer segments. In the near term we plan to continue to offer programs to promote energy efficient equipment, energy audits to identify opportunities to reduce usage, rate programs to encourage off-peak usage, and opportunities to install cost-effective, clean distributed generation. Customers will be empowered with these tools to both permanently reduce electricity consumption and to shift usage to off-peak hours. Longer term customer awareness and acceptance should evolve to the point where financial incentives for efficiency may no longer be needed as customers will move voluntarily toward these techniques or will be required to do so based on Federal and State mandates for building codes and appliance and equipment efficiency standards.

Improve Environmental Profile and Do Our Part to Meet Federal, New York State, and New York City Energy and Environmental Targets

As responsible corporate citizens, we are interested in environmental sustainability and we have actionable plans to reduce the environmental impact of our transmission and distribution operations, help our customers reduce their energy consumption, and reduce the carbon footprint from our day-to-day business activities.

The Electric Power Research Institute projects that multiple electricity production and consumption technologies will be required to measurably reduce national CO₂ emissions. Figure 3-3 illustrates the total potential CO₂ reduction from existing and emerging technology solutions. To that end, we are deploying a multi-pronged set of programs and initiatives: from energy efficiency (which reduces emissions) to demand response (which smoothes the interconnection of intermittent renewables). Together these programs can help meet our environmental objectives.

Figure 3-3. Electric Power Research Institute’s Assessment of Mechanisms to Reduce CO₂

![Graph showing percent reduction in CO₂ emissions from 2005 level to 2030.](image)

41% reduction in 2030 from 2005 level is technically feasible using a full portfolio of technologies

Our plan was designed to allow us to contribute to the achievement of the policy targets set at the Federal and State levels, as well as to support stated initiatives at various levels of the government, to the extent that such reductions are not already being provided by competitive market forces. At this point, New York State regulation establishes a strict standard for energy reduction and greenhouse gas regulation thus our plan is designed to meet New York State targets.

While no formal Federal guidelines existed coincident with the preparation of this plan, pending climate legislation could set mandates for CO2 reduction. Currently, draft bills require an 80% reduction by 2050 and an increase in the requirements for the percentage of energy supplied from renewable energy resources.26

New York State27 has established a state-wide energy efficiency target to reduce electricity usage by 15% by 2015.28 This is a state-wide goal whereby numerous entities, including electric utilities, are participating to reduce energy consumption, illustrated in Figure 3-4.29

**Figure 3-4. Achieving New York State’s “15 by 15” Goal**

![Graph showing the achievement of New York State's energy efficiency goal](image)

---

26 The climate bill under consideration, Waxman-Markey, in the U.S. Congress calls for up to 17% renewable and energy efficiency by 2020, with a 15% minimum to be met by qualified renewables, leading to renewables making up 12% of forecasted energy.

27 New York State Energy Plan Objectives and Strategies.

28 June 23rd 2008 EEPS order establishes baseline as energy sendout projections based on 2007 forecasts for 2015.

29 Reduction to be achieved by multiple entities including NYSERDA, NYPA, LIPA, utilities, and building codes & appliance standards.

The New York State Energy Plan also sets renewable portfolio standards and greenhouse gas reduction targets. The New York State has set objectives that 30% of electricity needs be met by renewables by 2015 and that 1990 levels of greenhouse gases be reduced by 80% by 2050. The Public Service Commission has recently adopted the 30% renewables goal predicated on successful achievement on the ‘15 by 15’ energy efficiency goal.31

Other initiatives outlined in the New York State Energy Plan that are relevant to our Electric System Long Range Plan include goals to:

- Maintain reliable energy and transportation systems in NYS
- Support energy and transportation systems to reduce greenhouse gas emissions
- Address affordability concerns of residents and businesses caused by rising energy bills
- Reduce health and environmental risks associated with the production and use of energy
- Improve energy independence and diversity by developing clean energy

New York City’s PlaNYC sets a goal to reduce energy consumption in New York City to 2005 levels by 2030. Although not a binding target, Con Edison plans to assist the City in meeting this objective.

**Enhance Reliability**

We believe continual enhancements across the system are necessary to maintain our best practice performance and reduce the risk of high-impact outages.

The deployment of an advanced metering infrastructure may improve reliability initially in targeted load areas. Real-time monitoring of the distribution network enables earlier outage detection and an enhanced ability to locate where an outage has occurred. This will reduce the amount of time to dispatch our repair crews directly to the location, and improve verification of customer service restoration.

The targeted integration of energy efficiency, demand response and distributed generation can result in increased reliability and stability of the distribution system during multiple contingencies by reducing peak demands on distribution equipment.

New transmission opportunities may offer the potential to enhance reliability in the case of a loss of a transmission line or the loss of a source of supply. These opportunities should be evaluated in comparison to developing local sources and other solutions.

**Diversify the Supply Portfolio**

The Company can incorporate diverse technologies and fuel sources by building transmission to connect to renewable sources of supply and by interconnecting and promoting cleaner distributed generation which reduces risk through small geographically dispersed projects.

31 New York State Public Service Commission Case-E-0188, Order Establishing New RPS Goals and Resolving Main Tier Issues (January 8, 2010)
3.2 ENERGY EFFICIENCY

Energy efficiency is generally associated with actions or technologies that provide permanent reductions in energy consumption, while maintaining equal or greater quality of service. Through our portfolio of programs, we will provide direct assistance and support the development of effective codes and standards and other tools to promote the efficient consumption of electricity.

Con Edison’s energy efficiency programs are part of an integrated demand side management strategy that coordinates energy efficiency, demand response and distributed generation, while leveraging an advanced metering infrastructure. This varied and integrated approach is expected to be the most cost-effective alternative for achieving demand side management objectives.

3.2.1 Objectives

Highlights of how our energy efficiency programs meet the five objectives introduced in this chapter are shown in Table 3-1.

<table>
<thead>
<tr>
<th>Objective</th>
<th>Role of Energy Efficiency in Achieving Objectives</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reduce Transmission &amp; Distribution Investments and Power Purchase Costs</td>
<td>Permanent reduction in energy consumption and peak demand achieved through efficiency programs sponsored by the utility and other agencies will reduce use of the transmission and delivery system, allowing for investment deferral or avoidance, and reduce power purchase requirements.</td>
</tr>
<tr>
<td>Help Customers Manage Energy Costs</td>
<td>Energy efficiency programs provide consumers with tools to better control their energy consumption. From rebates on the purchase of efficient lighting, to free removal and green disposal of inefficient refrigerators, to financial incentives to reduce the cost of highly efficient industrial equipment, these programs are designed to give Con Edison customers the power to reduce their energy usage and consequently their bills. System-wide reduction in peak capacity will lower capacity purchase costs, lowering the supply portion of customer bills.</td>
</tr>
<tr>
<td>Improve Environmental Profile and Meet Federal, New York State, and New York City Energy and Environmental Targets</td>
<td>Permanent energy conservation achieved through energy efficiency programs will help to meet New York State’s goal of 15% energy reduction of forecasted levels by 2015 and PlaNYC objectives to achieve 2005 consumption levels in 2030. Energy efficiency is also a clean and economical way to reduce the total amount of energy consumed thus helping to achieve renewable portfolio standard goals.</td>
</tr>
<tr>
<td>Enhance Reliability</td>
<td>Targeted energy efficiency can enhance reliability by lowering customer demand in capacity constrained areas of our system</td>
</tr>
<tr>
<td>Diversify Supply Portfolio</td>
<td>N/A</td>
</tr>
</tbody>
</table>
3.2.2 Implementation Plan

Con Edison’s energy efficiency plan, in the near term, is to actively work with customers to promote energy conservation and to develop, offer, and continually refine a suite of programs that drive efficient end-use technologies to provide permanent energy reduction.

Con Edison will continue to collaborate with the New York State Energy Research and Development Authority (NYSERDA) on statewide efficiency objectives. Currently, NYSERDA is funded by utility customers through the System Benefits Charge which was established on May 20, 1996, and received initial funding from July 1, 1998 to June 30, 2001. The System Benefits Charge has been extended several times, most recently until June 2011. The funds are allocated to energy-efficiency programs, research and development initiatives, low-income energy programs, and environmental disclosure activities across New York State. Part of this funding created New York Energy Smart SM which helps New York State’s efforts to develop competitive markets for energy efficiency, demand management, outreach and education services, research, development, and demonstration, low-income services, and to provide direct economic and environmental benefits to New Yorkers.

Because of our direct relationship with customers, we believe Con Edison is well positioned to partner with customers to reduce their energy usage. Therefore, we plan to expand our efficiency efforts to help achieve energy savings and emissions reductions. New York City and Westchester County are diverse communities comprised of customer segments that have distinct needs. Meeting their needs requires a tailored portfolio of energy efficiency programs that allow all customer segments to control their energy usage. We are expanding and revising existing programs, developing new programs, and seeking the Public Service Commission’s approval of these programs.

The Company’s existing Targeted Demand Side Management program, which launched in 2004 and is employed in 30 networks, runs through 2012 and will be extended if it continues to be successful. Under this program, the Company contracts with competitively selected contractors for load reductions achieved through the installation of permanent energy efficiency measures in customer facilities. This targeted program is unique as it was designed to directly reduce network peak demand via firm load reduction within specific geographic areas. The program is specifically targeted to load areas where transmission and distribution upgrades, including transmission lines, substations, network load transfers and distribution feeders, are proposed and can be deferred through firm load reductions. The targeted load reductions are set to defer near-term capacity investments.

---

33 In the Con Edison bill, the System Benefits Charge/Renewable Portfolio Standard charges fund New York State renewable energy, environmental and other related public policy programs. On April 2, 2010 the New York Public Service Commission (PSC) issued orders related to the programs administered by NYSERDA to implement the State’s Renewable Portfolio Standard (RPS) - Case 03-E-0188. The PSC approved a new collections schedule for the RPS programs, with higher collection amounts instituted on July 1, 2010 to continue through 2024.
New efficiency programs rolled out in 2009 and 2010 or under consideration are described in Tables 3-2 and 3-3.

Table 3-2. Residential Programs

<table>
<thead>
<tr>
<th>Program</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Direct Install</td>
<td>Provides low cost on-site energy surveys, direct installation of efficiency measures and recommendations for more extensive upgrades.</td>
</tr>
<tr>
<td>HVAC Rebates</td>
<td>Promotes the purchase and installation of new high-efficiency HVAC (central and room) equipment by providing customers with financial incentives to offset the higher purchase cost of energy efficient equipment and information on the features and benefits of energy efficient equipment. This program also includes a dealer incentive program for retailers who up-sell room air conditioners to a higher efficiency level.</td>
</tr>
<tr>
<td>Appliance Recycling</td>
<td>Provides rebates to participants and also provides free pick up and disposal of old appliances.</td>
</tr>
<tr>
<td>Multifamily Refrigerator Replacement</td>
<td>Promotes energy efficiency for gas and electric customers in the 5-50 unit multi-family buildings. This program will focus on energy surveys, recycling and replacement of inefficient refrigerators, rebates for high efficiency air conditioners and rebates for common area and building system measures.</td>
</tr>
<tr>
<td>New Targeted DSM</td>
<td>Encourages energy efficiency for residential customers in selected neighborhoods where transmission and delivery investment upgrades may be required.</td>
</tr>
<tr>
<td>Residential Room AC</td>
<td>Encourages the purchase of energy efficient room air conditioners for residential customers.</td>
</tr>
</tbody>
</table>

Table 3-3. Commercial and Industrial Programs

<table>
<thead>
<tr>
<th>Program</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Small Business Direct Install</td>
<td>Provides low-cost on-site energy surveys, direct installation of free efficiency measures and recommendations for more extensive energy efficiency upgrades.</td>
</tr>
<tr>
<td>Prescriptive Rebate Program</td>
<td>Offers rebates to install common, high-efficiency technologies to offset the higher purchase and installation cost.</td>
</tr>
<tr>
<td>Custom Rebate Program</td>
<td>Offers rebates to install complex systems and/or process improvements that are shown to be cost effective.</td>
</tr>
<tr>
<td>Steam Cooling</td>
<td>Encourages large buildings to use steam instead of electric air conditioning.</td>
</tr>
<tr>
<td>New Targeted DSM</td>
<td>Encourages energy efficiency for commercial customers in selected neighborhoods where transmission and delivery investment upgrades may be required.</td>
</tr>
</tbody>
</table>

33 Only available to customers in the Manhattan steam distribution area.
The implementation of Con Edison’s energy efficiency portfolio can generally be described in three phases over the next twenty years, as described in Figure 3-5. During Phase I, Con Edison will expand its offerings and test new programs. The efforts of Phase II will seek increased penetration and better integration with other demand and supply side resources and begin to test Smart Grid applications. Phase III will launch programs that benefit from available technology, focus on new end-use applications, and move away from incentive programs.

**Figure 3-5 Implementation Plan: Energy Efficiency**

<table>
<thead>
<tr>
<th>Phase I: 1-5 Years</th>
<th>Phase II: 5-10 years</th>
<th>Phase III: 10-20 Years</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Expand offering and test new programs</strong></td>
<td><strong>Drive penetration, better integrate with other demand and supply side resources, and enhance automation</strong></td>
<td><strong>Continue to drive penetration in key segments, expand linkage with “Smart Grid,” and move away from incentive models</strong></td>
</tr>
</tbody>
</table>

During Phase I, Con Edison will refine and expand its program portfolio. The Company will continue funding NYSERDA administered upstream programs through a System Benefits Charge. Periodically, Con Edison will identify the most load-constrained networks in the territory, and continue to target efficiency programs to those networks. Identification will promote programs that continue to deliver the most valuable cost-benefit proposition even as investments and demographic changes alter a network’s profile. Between 2009 and 2011, a robust portfolio of programs will be implemented with the most successful programs then expected to be expanded across the service territory.

In Phase II, Con Edison will continue to promote energy efficiency in customer segments that represent either high usage or have a high potential for reducing consumption using new practices or technologies. For example, there may be specialized efficiency solutions for data centers, financial services, building managers, government, or educational facilities. Programs will be tailored to produce a maximum reduction in consumption without compromising quality of service. In addition, we believe there will be increasing opportunities to tie programs focused on permanent conservation to other demand side solutions such as demand response and distributed generation to drive optimal improvements. We will continue to integrate energy efficiency with building automation and controls throughout our system. Automation will increase the certainty of demand reduction from energy efficiency resources. We will also continue to test integration with Smart Grid technologies such as voltage control and begin to phase out incentive programs as more energy efficiency becomes part of laws, codes, and standards.

We envision that Phase III will coincide with a time during which technologies that are now emerging may have become widespread in New York City and Westchester County. The Company will expand programs aimed at new end-use technologies such as electric vehicles and will benefit from the growing presence of home area networks, smart appliances, and customer-sited storage solutions to improve end-use efficiency. We expect that by this time, there will be no need for incentives as they are replaced by competitively-provided energy efficiency services and continually-improving building codes and appliance standards. We believe the role for the utility will still be significant in terms of working with developers, governments, manufacturers, and local stakeholders in developing effective codes and standards.
3.2.3 Cost Benefit Analysis

This energy efficiency plan has been designed using Con Edison's experience with energy efficiency, continued dialog with the Public Service Commission staff, and data provided by industry experts. As shown in Figures 3-6 and 3-7, Con Edison's energy efficiency programs are expected to deliver energy savings of 1.7 million MWh annually in 2030 and 452 MW of peak demand. Savings between 2010 and 2015 are based on current targets as defined during Energy Efficiency Portfolio Standard proceedings. The Company aspires to reach savings levels on par with top quartile performance of utilities with mature programs by 2016 and will continue to expand program offerings as long as they remain cost effective.34

Expenses associated with these programs, an average of $52 million per year, are based on Public Service Commission guidelines for costs of achieving the Energy Efficiency Portfolio Standard targets through 2015 and after that are projected to be consistent with the levelized cost of energy efficiency resources estimated by the Electric Power Research Institute35 adjusted to account for the higher cost of doing business in New York City.35 Energy efficiency, carried out effectively, is generally regarded as a highly efficient investment; this is due in large part to the fact that energy efficiency investments have an average life of about 10 years meaning that the savings from an investment in energy efficiency repeat throughout the life cycle, reducing marginal energy costs and other costs. For the individual consumer, energy efficiency can substantially reduce the energy bill.

34 Energy savings reaches 2.4% of sales; demand savings reaches 2.7% of peak demand in 2030.
36 Levelized cost of energy for energy efficiency is $0.06 per kWh compared to the national average of $0.04 per kWh.
Figure 3-6. Energy Savings from Energy Efficiency

Energy savings 2010-2015 based on current filings with the New York Public Service Commission. Savings for 2016-2030 are projected based on industry benchmarks for energy savings from mature programs. Energy savings represent energy sales, not energy sendout.

---

37 Energy savings 2010-2015 based on current filings with the New York Public Service Commission. Savings for 2016-2030 are projected based on industry benchmarks for energy savings from mature programs. Energy savings represent energy sales, not energy sendout.
While these are our best projections today, due to saturation of programs or innovations in program design or end use technologies, energy and peak demand savings may decrease or increase based on declining potential from efficiency.

This reduction in energy consumption and peak demand from our energy efficiency programs results in significant savings for the Company from the deferral of transmission and distribution investments into the future. By deferring investments in load-relief infrastructure, such as transmission lines, new or upgraded substations, network load transfers, and distribution feeders we could expect an estimated $171 million in deferred infrastructure investments over the planning horizon.  

---

38 Savings for Con Edison administered programs only. Peak demand savings 2010-2015 based on current filings with the NY Public Service Commission. Savings for 2016-2030 are based on best practice levels.

39 The introduction of our energy efficiency programs could allow the Company to defer the 24 identified large scale substation installations or upgrades by a total of 49 investment years, or an average of 2 years per investment. Based on the cost to the Company of acquiring the necessary capital to fund these projects, this results in an average savings of $9.5 million per project, based on approximations of load-triggers for transmission and delivery investments. Detail provided in the Assessment Document.
3.2.4 Signposts

The Company has identified signposts that will trigger the review and adjustment of its program portfolio at any point during implementation. Con Edison may have to increase expenditures or expected energy and demand savings from its programs as a result of any of the following:

- **Demand growth**—Higher than expected demand growth could create more cost-effective opportunities to leverage energy efficiency resources to offset load growth

- **Pending Federal legislation that is more aggressive than New York State targets**—Aggressive efficiency targets could require us to create additional programs resulting in incremental expenditures to meet policy goals

- **Achieving lower than expected energy efficiency**—If Con Edison or other agencies do not meet efficiency targets in the Con Edison service territory or codes and standards do not evolve as expected, utility targets could be increased to compensate

On the other hand, the Company may have to decrease expenditures or expected savings if any of the following occurs:

- **Achievable potential below national averages**—Today’s already low consumption of most residential city dwellers could limit achievable potential, prompting Con Edison to reduce our savings projections

- **Regulatory proceedings do not turn out as planned**—Disallowance of sufficient funding to achieve targeted savings levels may limit success of programs as outlined

- **Price of electricity drops**—Lower electricity prices may make efficiency measures less cost effective on a relative basis

Throughout the phases of implementation, Con Edison will monitor these conditions, and will adjust programs as necessary.

3.3 DEMAND RESPONSE

Demand response programs offer the utility control over the load shape by reducing demand during the system peak (peak shaving and shifting programs) or during system critical periods (reliability programs). Demand response programs can be counted on to allow the utility to manage demand by ensuring the system does not become overloaded. Such programs can also allow Con Edison to defer investments that would otherwise be necessary to increase the capacity of the system.

Demand response programs are designed to create incentives for customers to avoid using electricity during times of peak demand or system-critical situations on the electric system. Peak demand typically occurs on weekday afternoons for commercial networks and evenings for residential networks. When capacity demands on the electric system are high, customers taking part in demand response programs are notified to reduce or eliminate their demand. Con Edison offers two types of programs: incentive-based programs to encourage curtailment at peak or critical times and time-based energy pricing that offers different tariffs to encourage energy consumption during off-peak times of the year or day.
3.3.1 Objectives

Table 3-4 describes how demand response helps us achieve our objectives for managing demand and supply and our environmental profile.

Table 3-4. Role of Demand Response in Achieving Objectives

<table>
<thead>
<tr>
<th>Objective</th>
<th>Role of Demand Response in Achieving Objectives</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reduce Transmission &amp; Distribution Infrastructure Investments and Power Purchase Costs</td>
<td>Demand Response incentive programs to shift and shave peak as well as time-based pricing can be effective in reducing peak demand on the transmission and delivery system and can be targeted to load areas in need of load relief.</td>
</tr>
<tr>
<td>Help Customers Manage Energy Costs</td>
<td>Demand response helps customers manage their energy consumption and lower their bills by reducing peak demand charges, avoiding capacity purchase costs (which lower the supply portion of the bill), and allowing customers to earn incentives from the utility for changing their energy consumption behavior.</td>
</tr>
<tr>
<td>Improve Environmental Profile and Meet Federal, New York State, and New York City Energy and Environmental Targets</td>
<td>Curtailment programs and time-based pricing, which primarily impact peak demand, have shown to have some conservation results, importantly during system peaks which can result in reducing peaking generator emissions. Timely, dispatchable demand response can be used as a tool to allow the integration of intermittent renewables into the grid by smoothing consumption peaks and supply resources, thus demand response may be critical to help New York State achieve its renewables goals.</td>
</tr>
<tr>
<td>Enhance Reliability</td>
<td>Demand response deployed as a load relief mechanism may increase reliability and stability of the distribution network during contingencies by reducing loading of distribution system components.</td>
</tr>
<tr>
<td>Diversify Supply Portfolio</td>
<td>Timely, dispatchable demand response may be critical to reduce reliance on fossil fueled generation by assisting in the integration of intermittent renewables into the grid by smoothing consumption peaks.</td>
</tr>
</tbody>
</table>

3.3.2 Implementation Plan

Con Edison has begun to implement a number of demand response programs in its service territory. The Company plans to expand these, as well as introduce four new programs, including a critical peak rebate program, a type of time-based pricing. As part of our targeted approach to system investments, these programs will be implemented in the areas that have the most critical capacity, reliability and environmental needs. The targeted deployment of verifiable and measurable demand response ensures the strongest return on investment.
We currently manage three demand response programs, listed below:

- **Distribution Load Relief Program**—We pay customers to curtail their power use during emergency situations. The program offers a capacity payment to participants in the mandatory option and energy payments to all participants.

- **Direct Load Control**—This program targets residential and small business customers with a peak demand of less than 100 kW who have central air conditioning. Upon enrollment, we install a free programmable thermostat that allows the customer to adjust temperature manually or remotely via the Internet. Con Edison can communicate with the thermostat to cycle the compressor on and off to reduce demand on our electric system when needed.

- **Mandatory Hourly Pricing**—This program encourages large customers who take their supply from Con Edison to reduce electricity use during peak hours. Customers’ supply charges are based on the New York Independent System Operator day-ahead market price. Currently customers with demand in excess of 1000 kW are enrolled in the program. In May 2011, this program will be expanded to customers with demand in excess of 500 kW. This program is also available to small commercial customers on a voluntary basis.

Building on the experience acquired through the implementation of our current programs, we will introduce the next generation of demand response tools and incentives to our customers in 2010. New programs currently being rolled out or being considered are described in Table 3-5.

**Table 3-5. Planned Demand Response Programs**

<table>
<thead>
<tr>
<th>Program</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Commercial System Relief Program</td>
<td>Will include participants that can curtail load or bring on emergency generation to reduce their demand by a minimum of 50 kW individually, or 100 kW through aggregation, with a minimum of 24 hours notice before a planned event (a day ahead forecasted load level that is at least 92.5% of the forecasted summer system peak). Participants will receive capacity and energy payments.</td>
</tr>
<tr>
<td>Network Relief Program</td>
<td>Will target specific networks that are in need of system relief. An open enrollment and/or request for proposal process to demand response providers will be issued for load relief in certain hours and over a specific number of years to defer the need to build transmission and distribution infrastructure.</td>
</tr>
<tr>
<td>Residential Smart Appliance Program</td>
<td>Will initially target residential customers and allow utility control of the customers’ curtailable electric appliances. Participants will be given notification based on forecasted and emergency events. Participants will receive an initial rebate for each smart appliance or home area network purchased as well as a year-end bonus for verified participation.</td>
</tr>
<tr>
<td>Residential and Commercial Critical Peak Rebate</td>
<td>Customers that can reduce their demand by at least 1 kW during events will be eligible. Participants will be given notification based on forecasted and emergency events. Monthly payments will be made to participants based on actual energy reductions made during events.</td>
</tr>
</tbody>
</table>
We believe that the best way to deploy demand response in New York City and Westchester County is by coupling it with the right enabling technology. Integrating the right automation, monitoring, and verification infrastructure and processes will provide the full value of demand response for our customers. An Advanced Metering Infrastructure (AMI), a system which deploys end-use devices that are designed to communicate with the utility and a robust meter data management system, will expand the pool of eligible customers, provide valuable information on customer behavior, and facilitate accurate measurement and verification of program results. Time-based usage data or interval data – which is required for time of use pricing and other demand response programs – cannot be obtained from the traditional meters that are currently in service at small commercial and residential locations in our service territory. AMI will allow these two customer segments to participate in these types of programs.

To optimize the potential of measurable and verifiable demand response resources, Con Edison will seek to incent the purchase and installation of innovative utility-controllable technologies. More specifically, we will incent home area networks (HANs), auto demand response-enabled building management systems, load-controllable room and rooftop air conditioners, and other appliances. Home area networks, room air conditioners, and other appliances, will allow penetration of New York City residential customers that have been unable to participate in demand response. Rooftop air conditioners and auto demand response-enabled building management systems will allow Con Edison to offer demand response to an increased number of commercial customers. The combination of these technologies will provide demand response resources that are extremely reliable and verifiable.

The installation of advanced meters will significantly expand the amount of system data that will be collected by Con Edison. An expanded meter data management system solution will be required to aggregate this information. Electric system operators, demand response program managers, and energy services providers will be able to perform advanced analytics on customer use data across the territory, enhancing the use of demand response as a truly dispatchable resource and a resource that can be depended upon in our planning process.

The implementation of Con Edison’s demand response portfolio can generally be described in three phases, as described in Figure 3-8. During Phase I, Con Edison will expand some of its current programs, pilot new ones, and lay the infrastructure groundwork for dispatchable and verifiable demand resources. Programs that are integrated with other initiatives, and that rely on advanced pricing and dispatch will be launched during Phase II. Phase III will focus on evaluating new technologies and business models for achieving the Company’s load shape objectives.

Figure 3-8. Implementation Plan: Demand Response
Phase I will both expand current programs and launch new ones. More specifically, the Distribution Load Relief Program and the Direct Load Control Program will be expanded to a broader customer base. During this period, Con Edison will launch the Commercial System Relief Program, the Residential Smart Appliance Program, the Critical Peak Rebate Program, and the Network Relief Program.\footnote{New programs will automatically call on customers when the hourly demand reaches 92.5% of the forecasted annual peak demand.} We will also invest in a targeted rollout of AMI supported by competitively-provided home area networks and home energy displays. These initiatives, along with ongoing cooperation with competitive aggregators, will test the viability of mass-market demand response in our service territory.

During Phase II, Con Edison will pilot promising programs that can reach broader audiences and provide even greater dispatchability and verification. The Company will also expand our time-based pricing program. We will test additional pricing tariffs, potentially including real-time pricing in all customer segments. We will launch a new suite of programs to take advantage of the opportunities that distributed generation can provide when combined with energy efficiency and demand response initiatives. We will pursue greater coordination of demand response programs with demand response efforts targeted at generation supply. These integrated demand side management programs will be targeted to specific customer segments with high usage or with high potential for reduced consumption through new practices or technologies. Tailored solutions may be developed for customers such as data centers, financial services, building managers, government, and schools. To the extent that renewables become more widely available on our service territory, we will pilot the use of demand response to manage their intermittent availability. The portfolio of Phase II programs will focus on automated controls and tiered shedding, based on reliability and economic dispatch factors. These may include real-time end-use device controls and energy management systems. For example, we may promote the installation of devices such as thermostats and appliances that respond to price-based signals and voltage fluctuations. We will also continue to test the interactions of demand response programs with various Smart Grid applications.

New solutions and business models for managing growth in customer usage may be available during Phase III. Con Edison is committed to evaluating and integrating them as a cost-effective alternative to transmission and delivery investments. We expect to further expand eligibility for time-based pricing programs such as the Mandatory Hourly Pricing Program, as well as offer automatic dispatch of both demand and supply resources to intelligently respond to market pricing and reliability-based signals.

3.3.3 Cost Benefit Analysis

Con Edison’s demand response programs are deployed to meet system-wide and area-specific load shape objectives. The plan has been designed by leveraging Con Edison’s experience with demand response, continued dialog with the Public Service Commission staff, and data from industry experts such as the Electric Power Research Institute.
The dashed line in Figure 3-9 illustrates the theoretical potential from all programs. The solid line in Figure 3-9 shows that Con Edison’s demand response programs are expected to actually reduce our load forecast by 239 MW by 2030. As several of these programs are not triggered unless certain conditions—such as peak forecast or emergency situations—are present, we do not expect to realize 100% of the theoretically potential load reduction from our programs. We will re-evaluate our projections on an ongoing basis for how much of the potential load reduction is achievable, and thus should be included in our plan forecast.

Expenses associated with these demand response programs, on average $71 million annually, are based on Con Edison filings with the New York State Public Service Commission through 2015. Beginning in 2016, costs are projected to be consistent with the Electric Power Research Institute’s assessment of the levelized cost of energy for national demand response programs\(^41\), adjusted for doing business in New York City.\(^42\)

![Figure 3-9. Peak Demand Savings from Demand Response](image)

While these are our best projections today, peak demand savings may decrease or increase, depending on the levels of load growth that are seen over the next twenty years, the performance of these programs over time, emerging technologies, and rate design. Increased peak demand savings above those envisioned in our plan could result in greater cost savings than currently expected.


\(^{42}\) LCOE for energy efficiency is $139 per KW compared to the national average of $76 per KW
The reduction in peak demand enabled by our demand response programs results in savings for the Company from the deferral of transmission and distribution investments into the future. By deferring investments in load-relief infrastructure (such as transmission lines, new or upgraded substations, network load transfers, and distribution feeders) we could expect to save up to $9 million over the planning horizon. Savings would increase if we find that more of the demand response resources can be called upon and counted upon and thus included in our demand forecasts in coming years.

3.3.4 Signposts

This demand response plan is based on today’s technologies, current load growth assumptions, and today’s regulatory and legislative environment. The Company has identified signposts that will trigger the review and adjustment of its program portfolio at any point during implementation. More specifically, we will monitor changes in technology innovations, load growth, and legislation, and will change our plan accordingly.

- **Higher than expected load growth**—Greater load growth than projected in the plan case could create additional opportunities to leverage demand response to offset load in targeted areas.

- **Emergence of new technology**—Technological applications such as “smart” appliances and other end-use devices could become more widespread improving the cost effectiveness of verifiable and measurable demand response.

- **Rate of penetration of supply-side distributed resources**—Faster than expected adoption of distributed generation may increase customer adoption of demand response programs (customer has the ability to shift to back-up generation when called on to curtail), or on the other hand displace some of the demand-side potential (if distributed generation successfully lowers the peak in constrained networks).

- **Legislative restrictions**—Continued restrictions around mandatory time-based pricing in the residential and small commercial segments may limit potential of overall demand response portfolio.

3.4 DISTRIBUTED GENERATION

Distributed generation is an electricity generating apparatus located at the customer’s premises as opposed to a centralized station. Distributed generation is designed to serve some or all of the electricity needs of a customer using fuel sources that may include natural gas or renewable fuel sources such as solar or wind. Natural gas fueled technologies also offer the customer the extra benefit of using the heat byproduct of electricity generation for facility heating. Such technology is known as combined heat and power.

---

43 Total investment years deferred is approximately 5 and the average deferral per project is a fifth of a year resulting in an estimated average savings $400 thousand on each of the 24 large scale substation installations or upgrades.
Customers can choose to use their distributed generation for emergency use only, to offset thermal energy requirements, for peak shaving, for total energy offset, or to produce surplus energy to sell back to the grid. In most cases, customers do not choose distributed generation to allow them to disconnect from the grid; they choose it instead to offset or supplement some of the energy currently purchased or to provide emergency back-up power.

Distributed generation has the potential to be a future tool in managing both supply and demand in certain load areas, under specific conditions. In order to reach a state where the Company is able to fully incorporate distributed generation into its load management portfolio, we will help address the following factors:

- **Supporting infrastructure investments may be required**—To capture additional value from distributed generation, resources must be monitored at a minimum and preferably dispatchable and verifiable, which may require underlying equipment enhancements such as advanced metering infrastructure (AMI), or other appropriate technologies, and distribution system protection to support two-way power flow as well as communication between the distributed generation resource and the utility control center. The Company has commenced a pilot program in Long Island City that will assess the degree to which AMI can provide dispatchability.

- **Clear environmental regulations need to be adopted for fossil fuel distributed generation**—The health and environmental impacts of distributed generation facilities in urban areas should continue to be reviewed so that appropriate air emission regulations can be adopted and enforced.

- **Utility ownership of renewables should be permitted in order to support broad scale deployment**—On February 2010, the Company filed a proposal with the New York State Public Service Commission to support the development of solar energy resources in New York City. Our proposal included incentives to promote small solar projects through our service territory. These projects are targeted to areas where they provide direct benefit to the electric system, as well to areas with low-income residential customers in New York City. The issue of utility ownership of utility owned resources should continue to be considered.

- **Safety and reliability protocols must be addressed**—To ensure the safe operation of distributed generation, building codes are being reviewed to protect all stakeholders including: the Company’s employees, employees of other agencies (such as the Fire Department of New York), and the public at large. Con Edison is actively working with stakeholders on electric, gas and steam interconnections to clarify and streamline standards for distributed generation so that they are more easily understood.

- **The adequacy of the gas infrastructure should be evaluated**—Con Edison’s gas system long range planning effort is studying what enhancements or upgrades are required to the gas system to support the potential increased gas load from distributed generation.
### 3.4.1 Objectives

Table 3-6 highlights how distributed generation helps achieve our demand, supply, and environmental impact objectives.

#### Table 3-6. Role of Distributed Generation in Achieving Objectives

<table>
<thead>
<tr>
<th>Objective</th>
<th>Role of Distributed Generation in Achieving Objectives</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Reduce Transmission &amp; Delivery Infrastructure Investments and Power Purchase Costs</strong></td>
<td>Allowing customers to produce electricity with their own generation assets reduces electric peak demand in certain load areas, thus reducing the need for reinforcement of network and substation equipment. Currently, Con Edison provides standby energy to distributed generation customers; however, customers willing and able to give up partial standby service or that are willing to make themselves interruptible could allow Con Edison to defer future investment. In addition, highly efficient customer-sited generation lowers the amount of energy losses on the system, reducing energy and capacity purchases.</td>
</tr>
<tr>
<td><strong>Help Customers Manage Energy Costs</strong></td>
<td>For some customers, it will be more cost effective to site efficient and/or renewable generation on site rather than purchasing from the utility, particularly when financial incentives are available to lower the first-cost barrier of the generation asset. The associated reduction in line losses and deferred transmission and delivery investments would provide a benefit for all customers.</td>
</tr>
<tr>
<td><strong>Improve Environmental Profile and Meet Federal, New York State, and New York City Energy and Environmental Targets</strong></td>
<td>Utility promotion of renewable distributed generation such as photovoltaics and perhaps building mounted wind can potentially play a significant role in helping New York State to achieve its Renewable Portfolio Standards goals. In addition, co-located and/or efficient distributed resources realize less line loss than central supply, providing an opportunity to reduce the greenhouse gas impact of electric delivery.</td>
</tr>
<tr>
<td><strong>Enhance Reliability</strong></td>
<td>The proper integration of distributed generation into the secondary network could result in increased reliability of the distribution network by reducing peak loading of system components.</td>
</tr>
<tr>
<td><strong>Diversify Supply Portfolio</strong></td>
<td>The Company can incorporate diverse technologies and fuel sources by integrating distributed generation. Distributed supply also reduces financial risk through small, geographically dispersed projects. Additionally, as more customers adopt distributed generation, there will be an opportunity for Con Edison to enhance the network with sophisticated technologies, allowing customers to produce more energy than they need—energy which can be supplied to the grid and dispatched by Con Edison to offset other generation needs.</td>
</tr>
</tbody>
</table>
3.4.2 Implementation Plan

Con Edison’s distributed generation strategy can be generally characterized as falling into three phases, illustrated in Figure 3-10. In Phase I, Con Edison plans to continue partnering with customers and other stakeholders, including the New York State Department of Environmental Conservation, the New York City Department of Buildings, the Fire Department of New York, and distributed generation advocates, to facilitate the interconnection of distributed generation installations and examine the opportunity to pilot new projects and concepts. Based on the results of Phase I initiatives, Con Edison will be in a position in Phase II to promote adoption of distributed generation in areas of the service territory where it can be the most beneficial to meet customer and Company objectives, including: reducing cost, increasing reliability, improving air quality and lowering greenhouse gas emissions. Results of the first ten years will shape the subsequent strategy of the Company. Con Edison would hope to employ sophisticated technologies and policy enablers to take advantage of transformational opportunities.

Figure 3-10. Implementation Plan: Distributed Generation

During Phase I, Con Edison will continue to help customers and developers connect their distributed generation installations to Con Edison’s delivery system while improving our ability to communicate with our customers via an Online Customer Project Application Website and Tracker. In order to maintain a central source of distributed generation information and drive the overall strategy, we will continue and expand the role of the Distributed Generation Ombudsperson who can be used as an important resource by the public. From a technology perspective, we have also invested in programs to evaluate the long term efficacy of distributed generation in the service territory. Results of these programs will be evaluated and are expected to determine the future direction of the Company’s distributed generation strategy.
### Table 3-7. Con Edison Programs To Study Distributed Generation

<table>
<thead>
<tr>
<th>Program</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Distributed Generation Interconnection</td>
<td>Part of Con Edison’s application for funding under the American Recovery and Reinvestment Act (ARRA) is to install two-way communication to distributed generation units and network protectors to facilitate interconnection.</td>
</tr>
<tr>
<td>DOE/ Verizon/Infotility Project</td>
<td>Program to test interoperability with the Company’s control centers. The project’s objective is to integrate new hardware, software, and administrative protocols to create a virtual power plant that can safely distribute third party customer power into Con Edison’s network system during anticipated electric peak usage times. The study will review both conventional and renewable energy.</td>
</tr>
<tr>
<td>DC Link</td>
<td>Expands the DC link technology which allows synchronous distributed generation to interconnect with the distribution system even in areas with limited or no fault duty protection.</td>
</tr>
<tr>
<td>Substation Breaker Upgrade</td>
<td>Program to upgrade substation equipment to accommodate distributed generation.</td>
</tr>
<tr>
<td>Network Distributed Generation Penetration</td>
<td>Analyzes the impact of varying types and levels of distributed generation penetration.</td>
</tr>
<tr>
<td>Load Flow Electro-Magnetic Transient Program</td>
<td></td>
</tr>
</tbody>
</table>

In addition to these programs, Con Edison is also piloting technologies which can be used to support distributed generation. Four proposed initiatives (described in Table 3-8) the Company feels are important to developing a strong perspective on how to best use distributed resources are: the Solar Program (filed with the PSC), the Long Island City Smart Grid Pilot, the Grid Support Pilot, and the Distributed Generation Collaborative. Based on the results of interconnection and load flow studies as well as experience with these pilots, we will better understand the benefits, costs, and risks associated with distributed generation.

---

44 CECONY has received a total of $125M from the American Recovery and Reinvestment Act (ARRA) for programs aimed to deploy a wide-range of grid-related technologies, including automation, monitoring and two-way communications, to make the electric grid function more efficiently and enable the integration of renewable resources and energy efficient technologies.
Table 3-8. Con Edison Distributed Generation Pilot Programs

<table>
<thead>
<tr>
<th>Program</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Long Island City Smart Grid Pilot</td>
<td>Tests automated control technologies for solar resources, battery storage to manage the intermittent nature of solar as a fuel source, and new interconnection concepts.</td>
</tr>
<tr>
<td>Grid Support Pilot</td>
<td>Deploys smart communication technologies between distributed generation sites and regional controls rooms and distribution transformer network protectors (NWP) to coordinate the distributed generation output with NWP load flows in order to avoid excess strain on the network.</td>
</tr>
<tr>
<td>Distributed Generation Collaborative</td>
<td>Con Edison will chair a distributed generation collaborative sponsored by Building Owners and Managers Association (BOMA) and the Pace Energy and Climate Center with the goal of addressing distributed generation stakeholder issues.</td>
</tr>
<tr>
<td>Solar Program</td>
<td>Develop customer-sited rooftop solar projects to complement NYSERDA’s efforts to increase penetration of customer-sited renewables.</td>
</tr>
</tbody>
</table>

Phase II will bring the results of these pilots together, identify any gaps, and use the results to set implementation strategy. Ideally, Con Edison would like to be in a position to promote adoption of distributed generation in areas or network segments targeted due to cost, reliability or environmental implications. These target areas may be locations that have a high peak demand relative to their network capacity and where distributed generation is a cost-effective method for reinforcing the reliability of these network segments. To convince customers to adopt distributed generation on these specific networks, Con Edison may need to provide incentives that are equivalent to value provided. A structure for possible incentives has not been determined and will be evaluated at a later date. Also starting during this period, Con Edison expects to fully utilize its ability to dispatch and manage load flow coming from third party distributed generation locations to reduce peak and manage external generation costs.

It is expected that Phase III, in the ten to twenty year timeframe, will allow Con Edison to focus on more transformational opportunities through new policy and infrastructure enablers. By this time, technology standards should begin to emerge among the multitude of technologies being tested today. These standards will allow for simplified interconnection and management of disparate devices in the network as well as at utility and customer sited distributed generation locations, two-way communications between the distributed generation resource and the utility control room, and appropriate incentives or tariff structures to support interoperability. The DG may be considered reliable enough that customers with generation may only require an N-1 type connection. Also during this time, customers in close proximity, possibly with the assistance of the Company, may choose to link their distributed generation units together to form a microgrid, a structure in which individual distributed generation assets with excess capacity can serve as emergency backup generation for generation assets of other customers in the same microgrid in the event of an outage. In theory, if sized to meet these customers’ peak summer demand, microgrids could disconnect completely from the Con Edison grid.
3.4.3 Forecast

Historical Adoption

The adoption of distributed generation is nothing new to Con Edison customers, who had installed as much as 110 MW as early as 1989. Over the last twenty years, periods of increased distributed generation adoption occurred from 1989 to 1994 and from 2004 to the present resulting in the current 206 installed MW in the Con Edison service territory (see Figure 3-11).

In the first period, 1989-1994, the technology of choice for customers was reciprocating engines, which use a piston to produce energy and include the commonly known internal combustion engine, steam engine as well as the Sterling Engine. During this five year period, 27 of these sites came online, each with a sizeable capacity, typically in excess of 1.2 MW.

![Figure 3-11. Distributed Generation Installation Trend by Technology](image)

The second wave of distributed generation in the last twenty years started in 2004. Although there have been more distributed generation installations in the last five years than at any time previous, the trend has been for both smaller distributed generation installations focusing on renewable fuel sources and a growing number of larger CHP. During this time there have been 195 separate distributed generation sites to come online within the Con Edison service territory. Of those, 126 (65%) are photovoltaic solar technology. As previously stated, these solar installations tend to be smaller; the total installed capacity from all 126 sites is roughly 3 MW. It is important to note that because of the intermittent nature of solar as a generation fuel source; this 3 MW cannot be considered as coincident network or system peak capacity.
Projected Adoption

We developed preliminary forecasts for distributed generation adoption, including technical and market potential in the service territory. Technical potential measures the amount of adoption that is possible taking into account the physical availability of resources as well as any unique constraints of the service territory. Technical potential measures what is possible, but does not project actual adoption as it does not include any evaluation of cost. We use a preliminary estimate of technical potential as an upper bound and then make estimates about the cost of various technologies and fuel sources to arrive at an estimate of market potential, or what we could actually see in our service territory.

In estimating technical potential, the Company took into account constraints that exist in the Con Edison service territory, including geographic and space constraints, technology constraints, and the availability of fuel. Many customers do not have the extra space required for a generating unit and purchasing additional space is often not feasible. High population density requires strict safety guidelines, which limit many customers’ abilities to install distributed generation. Installation of technologies that include exhaust or emissions can only be installed by customers able to safely direct those emissions away from people living and working in the vicinity of the unit, something not possible for all customers. The permitting process currently in place is administratively burdensome, but required to ensure all generation assets are safe and will not inhibit the response actions of other agencies, such as the fire department.

Successful installation of distributed generation also requires addressing known problems of power quality and interconnectivity issues, which can cause varying output and system issues. Con Edison has currently identified solutions to many of these hurdles; however, each installation presents its own unique set of issues.

Most of the distributed generation facilities in the Company’s service territory will utilize natural gas, while a significant portion are expected to use renewable fuel sources in the future, such as solar and, to a lesser extent, building-mounted wind. Due to the intermittent nature of renewable fuels, these distributed generation installations will not be suitable for consistent base load generation in the absence of significant advancements in fuel storage technology.

Taking all of these factors into account, the Company has estimated a technical potential of 19,200 GWh of electric energy capable of being produced annually from distributed generation, 12,000 GWhs of which are from renewable fuels with the remaining from natural gas. Currently, Con Edison customers use 55,000 GWhs of energy per year, making the technical potential of distributed generation close to 34% of total sales. Although this is a significant number, the actual market potential is significantly lower due to the cost of equipment, installation, and fuel. In addition, as a significant portion of this technical potential is assumed to be from renewable sources, a large portion will not be coincident peak and only the coincident portion will translate into a reduction of demand on our system.
A customer’s willingness to pursue a natural gas distributed generation technology may depend on his expectations for the future level of commodity prices (specifically for natural gas) since the price of fuel often accounts for more than 50% of the total cost of distributed generation over its life. A customer’s evaluation of cost can be described using a levelized cost of energy methodology, which is an expression of the average price a customer would have to pay each year, over the life of the distributed generation asset, to install and operate a specific technology. Customers must also consider the additional costs of planning and executing a project to install or retrofit distributed generation since, depending on the size and type of the installation, the process can be time-consuming and technically challenging. Customers without technical expertise and without construction project planning experience will need to find partners in order to successfully pursue distributed generation, which in turn adds additional costs to such a project. Air pollution is also a significant concern for customers considering natural gas fired distributed generation, as well as for those customers living near an installation. Many natural gas-fired distributed generation units remain extremely noisy and odorous and will not be welcomed by residents in certain neighborhoods though new models have come a long way in addressing these problems. Companies concerned about neighborhood relations may hesitate to pursue distributed generation.

With these constraints in mind, as well as assumptions about the coincidence factor for renewable sources, Con Edison expects to see continued adoption of distributed generation in the service territory but at a tempered pace and consistent with forecasts made by New York State and city agencies. Estimated distributed generation penetration in terms of peak demand is illustrated in Figure 3-12.
Figure 3-12. Distributed Generation Market Potential

This market potential is based on initial estimates. Additional engineering analysis may be completed to refine estimates at a later date.
The New York City government has expressed interest in clean distributed generation in the city’s PlaNYC, and New York State recognizes the benefits of clean distributed generation in the New York State Energy Plan. The market potential forecasted by Con Edison is similar (800 MW for New York City and Westchester County), but lower than the 800 MW target set in the city’s plan for the city alone, although it would be reasonable to expect that most of the facilities will be located in New York City. Going forward, Con Edison will continue to work with the city, New York State and other agencies to fulfill its appropriate role in facilitating the adoption of clean distributed generation.

3.4.4 Signposts

Like many other issues the Company faces, the current strategy with regard to distributed generation does not exist in isolation and is open to the effects of external factors that will trigger the review and adjustment of the program, should that become necessary. These signposts will not affect Con Edison’s willingness to assist its customers in the interconnection of distributed generation, but may affect the strategic direction the Company desires to pursue. These signposts include:

- **Economic recovery**—If economic recovery is slow, the ability and appetite of many customers to pursue distributed generation is constrained due to reduced energy consumption and limited ability for customers to acquire the capital necessary to make large distributed generation investments.

- **New environmental regulation for local supply resources**—Regulation is likely to control the environmental impacts of distributed generating assets. This regulation is likely to change the economics of certain distributed generation technologies—particularly those powered by natural gas—and thus alter adoption patterns.

- **Enactment of Federal renewable portfolio standards and greenhouse gas legislation**—If Federal guidelines become stricter than New York State’s goals, there may be an increased focus on the adoption of renewable distributed generation in order to reach policy and any other goals.

- **Price of natural gas**—Natural gas prices are a major driver of the cost of distributed generation. As prices decline, distributed generation adoption could increase, specifically with regard to internal combustion engines, microturbines, gas turbines, and fuel cells.

- **Natural gas infrastructure**—Infrastructure upgrades may be required to provide sufficient capacity and throughput to enable natural gas-fueled distributed generation. The costs of these gas system reinforcements should be considered against benefits of deferred investments on the electric infrastructure.

- **Advancement in distributed generation and storage technologies**—Improved cost profiles of distributed generation technologies will increase the economic viability and therefore adoption of distributed generation.

- **Further net metering legislation**—Favorable economic incentives for selling power back to the grid may drive distributed generation adoption. Con Edison supports the use of transparent subsidies where subsidies are appropriate to encourage specific technology, or

---

46 Net metering, as a subsidy, is non-transparent, since the benefit provided to net metered customers cannot easily be calculated and determined. The Companies support use of transparent subsidies. There are also social issues in net metering because it departs from basic cost-causation principles. At most, the State should allow net metering up to the existing 1% caps only and then begin to explore other methods. The Companies are also concerned about the possible impact of oversized net metered resources on the system. Finally, fossil-fueled resources, even highly efficient CHP, should
paying DG customer-generators with the true avoided cost of energy particularly once “grid parity” has been realized.

3.5 ELECTRIC VEHICLES

Vehicles fueled by electricity can create an opportunity to reduce greenhouse gas emissions and reduce our reliance on fossil fuel.

The potential exists to drastically reduce our nation’s $CO_2$ emissions by making prudent investments in transportation fuel diversity. The United States Government, as part of its initiative to address climate change, has pledged to invest billions of dollars in cleaner and more efficient alternative-fuel vehicles. Further, the State of New York, in its 2009 Energy Plan, expressed the goal of supporting energy and transportation systems to reduce greenhouse gas emissions. And, PlaNYC published the City’s objective of increasing the electrification of fleet vehicles.

Electric vehicles offer an opportunity to move our nation’s transportation fuel source away from petroleum. Currently, the vehicle sector is almost completely dependent on liquid fuels. Expanding the diversity of fuels used in the transportation sector will increase flexibility in responding to any disruptions in the supply of petroleum-based fuels. Diversity should, in turn, protect the economy from the adverse impact of sudden changes in the availability and/or price of petroleum products.

Plug-in electric vehicles (PEVs) could have a sizable impact on electric utilities and the demand for power. Nearly every major auto manufacturer is preparing a PEV for introduction to the consumer market. With increased collaboration among auto manufacturers, utilities, government and businesses, PEVs appear to be a promising solution to the environmental consequences of dependence on vehicles with internal combustion engines. As more research and development is completed, designs will likely become more effective, energy efficient, and inexpensive. Plug-in hybrid electric vehicles will likely serve as a technology bridge to fully electric vehicles and a largely electrified transportation sector. Currently, dedicated electric vehicles are viable for niche applications, such as limited commercial delivery. If battery technology evolves and production increases, electric vehicles will likely become useful in other transportation applications.

While the future of electric vehicles is uncertain, the New York State Energy Research and Development Authority plans to examine the potential effect of these vehicles on the electric grid. This study will assess the energy, environmental, and wholesale market electricity price impacts of PEVs in New York. PEVs have the potential to improve our asset utilization but we need to keep a close watch on how usage patterns and market deployment evolve as unexpected concentrated load draws could cause a major additional strain on the existing grid if a sizeable portion of PEV’s plug in at local peaks.

---

1 See Comments of Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc. on the Draft 2009 New York State Energy Plan

47 Plug-in hybrid electric vehicles and electric vehicles, which do not have internal combustion engines, are both generally referred to as plug-in electric vehicles (PEVs).
3.5.1 Objectives

Table 3-9 summarizes how the carefully planned integration of PEVs into the grid will help us achieve our objectives for proactively managing demand, supply, and environmental emissions impact.

Table 3-9. Role of Electric Vehicles in Achieving Objectives

<table>
<thead>
<tr>
<th>Objective</th>
<th>Role of Electric Vehicles in Achieving Objectives</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reduce Transmission &amp; Distribution Infrastructure Investments and Power Purchase Costs</td>
<td>Circuit level planning and measured integration of PEV load into the grid will be important so as not to overload individual circuits. Potential to tap into PEVs as a storage option via vehicle-to-grid applications to offset demand growth and/or offset expensive peak-time power purchases. Use of this stored energy toward reserve margins may reduce transmission and delivery investments.</td>
</tr>
<tr>
<td>Help Customers Manage Energy Costs</td>
<td>Facilitation of PEVs will lower customers’ overall energy expenses by offsetting gasoline with lower cost electricity. Studies have shown that because of the lower cost of fuels consumed to produce electricity as compared to the cost of petroleum, consumers and businesses that use PEVs can reduce the total cost of fuel for their vehicles. Attractive time-based rates will be developed to encourage off-peak charging, limiting the increase in electric bills from PEVs. In addition, the potential of vehicle-to-grid power would allow owners to sell electricity back to the grid when their PEVs are plugged in at home.</td>
</tr>
<tr>
<td>Improve Environmental Profile and Meet Federal, New York State, and New York City Energy and Environmental Targets</td>
<td>Preparing the grid for PEVs helps meet Federal, state, and city objectives to increase the penetration of alternative fuel vehicles. An Electric Power Research Institute assessment suggests that PEVs can reduce greenhouse gas emissions from vehicles by approximately 200 million metric tons by 2030, which is equivalent to 40 million passenger cars.</td>
</tr>
<tr>
<td>Enhance Reliability</td>
<td>Proactively forecasting for PEVs down to the distribution circuit level will avoid any negative impacts on reliability caused by unforeseen load spikes from PEV adoption.</td>
</tr>
<tr>
<td>Diversify Supply Portfolio</td>
<td>Potential vehicle-to-grid applications, through the creation of new storage applications, can help diversify the supply portfolio and reduce financial risks and volatility from reliance on large-scale centralized resources.</td>
</tr>
</tbody>
</table>

---

3.5.2 Emerging Plan

While there is still a lot of uncertainty about the viability of PEVs, Con Edison is active in shaping the landscape in our service territory by helping influence standards and conducting pilots to understand the impact on our customers and our infrastructure.

The Company currently has two patent applications for mobile, wireless solutions for metering the power used to charge vehicles, as well as for scheduling vehicle charging. These metering systems will allow us to measure the power consumed for charging electric vehicles through our grid. These systems wirelessly transmit this information through the first available network (e.g., radio, satellite and various cellular networks). The charging system developed by Con Edison R&D manages vehicle charging time slots depending on system demand. Meters coupled to vehicle batteries respond to wireless signals sent by the Company, allowing charging to occur during time of reduced demands on the distribution system.

We are also actively engaged in a number of PEV related initiatives as described below:

- **Utility and original equipment manufacturer PEV stakeholder group**—Con Edison was instrumental in helping develop a utility/original equipment manufacturer PEV stakeholder group with the mission of discussing prevalent issues related to PEVs. The group consists of utilities, auto manufacturers, and PEV component suppliers (battery and controls manufacturers).

- **Ford Escape plug-in hybrid electric vehicle testing and demonstration**—Con Edison, along with Southern California Edison and the Electric Power Research Institute participated in a program to build, test, and demonstrate a fleet of Ford-engineered plug-in hybrid electric vehicles while conducting a set of detailed and comprehensive studies that will help define how to successfully commercialize the vehicles.

- **Electric Power Research Institute/General Motors plug-in hybrid electric vehicle Infrastructure Working Group**—The Electric Power Research Institute, General Motors, Con Edison, and numerous other participating utilities meet periodically to discuss topics related to market analysis, public education, technical features, customer experience, macro value analysis, and public policy.

- **NYSERDA/Electric Power Research Institute/Con Edison Grid Impact Study**—The project's goals are to assess the impact of increased penetration of plug-in hybrid electric vehicles on the electric grid and on air quality in New York State, with particular interest in New York City and Long Island. The project will address four items: 1) identification of the base case scenario of transmission/distribution capacity, 2) identification of several realistic plug-in hybrid electric vehicle penetration scenarios, including vehicle characteristics and required load support, 3) grid impacts of the various penetration scenarios, and 4) potential implications of vehicle-to-grid applications or utility aggregated load control.

- **Astoria Prius Fleet demonstration**—Con Edison has purchased three Toyota Prius vehicles and has converted them into plug-in hybrids. These vehicles have been integrated into our Con Edison fleet where their charging is metered and monitored.

- **BMW Electric Mini Pilot**—Con Edison has leased an all electric BMW Mini Cooper and is currently testing the vehicle.

- **Supporting New York City PlaNYC readiness study for Electric Vehicles**—Con Edison helped analyze the expected grid impact of projected electric vehicle adoption in the five boroughs of New York City.
Based on what we know today, we expect that the primary utility challenges from PEVs will include system and distribution charging levels and integration with distribution operations. Con Edison will continue to develop and revise plans to address these issues based on our R&D and collaboration with leading thought leaders and industry associations.

**System and Distribution Charging Levels**

PEVs may represent a significant new source of electricity use for Con Edison’s electric distribution system in the future. This use will affect total system requirements as measured by consumption, and even more importantly will affect the distribution grid because of the relative concentration of PEVs on specific circuits or at peak times. The impact of new customer use on Con Edison’s system peak will be influenced by the number of PEVs on the system and when they plug in. Charging may be concentrated during the early hours of the day and after arriving at home and the office. This could result in dual charging spikes.

Con Edison recognizes that PEVs may change load-area peaks. These localized (early on in the introduction of PEVs the impacts may be very “lumpy”) changes will be more important than system peaks. PEVs in specific neighborhoods are likely to concentrate loads differently than at the system level. The result will be local circuit loadings significantly different than average system loadings. The fact that the PEV load is mobile will also present new planning challenges.

Controlled charging, accomplished through rate incentives or “smart charging” has the potential to shift charging load to night hours, when electricity demand is at its lowest. While PEV loads are not likely to be shifted completely to the night time, it is possible to significantly alter customer usage patterns with smart charging capabilities. This in turn will reduce the need for new transmission and delivery assets.

In addition, demand response and other forms of load management can be deployed to smooth circuit-level load impacts. Demand response mechanisms would allow Con Edison to control loadings at specific times on specific circuits.

Con Edison’s residential networks, which typically peak between 8PM and 11PM, may require pricing incentives designed to promote charging after the peak or smart charging to avoid local area overloads. Additionally, the long commute times from counties surrounding New York City may also require more daytime charging in New York City than in other regions.

**Distribution Operations**

Increased peak load at night may reduce opportunities to perform maintenance, which is typically performed during periods of lower customer demand. In addition, the increased loading at night may change the thermal cycling of delivery assets and subsequently change our design specifications. These changes could lead to increased capital expenditures to reinforce our infrastructure. Further study is required to develop risk mitigation plans.

Our broader concern, however, is that PEVs must be integrated with the utility system at the distribution level. PEV charging interacts with metering, billing, system reinforcement, load control, and demand response management. Some functionality will require two-way communications for time-based pricing. Integration also requires coordination with utility information systems, as well as with operators. PEV integration is an example of a development that will benefit from Smart Grid technologies and AMI but does not require either for basic operation.
In order to prepare our system for these challenges, Con Edison supports a New York State Electric Fueling Collaborative, an organization created to centralize the analysis of the impact of electric fuel vehicles on the power grid. This collaborative will work with all stakeholders to analyze, through implementation of pilot programs, the impacts of PEVs on the bulk system and local distribution grid and should also assess the impact of emissions on air quality and the economic impact on New York State. The collaborative can also promote efforts to standardize payment and billing systems throughout New York State so that PEVs from anywhere in New York can seamlessly plug in and recharge in any part of the state. Such pilot programs should be implemented quickly in order to study system impacts, benefits, billing and tariff systems and consumer behavior.

As Smart Grid technologies and advanced metering will impact the way PEVs interact with the electric system including vehicle-to-grid capabilities, we will continue to study and implement Smart Grid technologies that can identify electric vehicles using the electric system. This can be the solution to universal access to the electric grid for PEVs, and remove the barrier of requiring each PEV to have its own account with every utility before recharging.

### 3.5.3 Forecasts

Initial analysis of PEV penetration in our service territory indicates a range of scenarios, with varying assumptions around penetration levels by load area and charging patterns. For our plan case we have assumed a system-level, peak-coincident impact of 54 MW in 2030, illustrated in Figure 3-13.

There are a number of different forecasts available for adoption rates for electric vehicles. Our forecast is based on background studies obtained from the Department of Energy and the Department of Transportation as well as data obtained from Electric Power Research Institute, the U.S. Census, and vehicle manufacturers. Using income and driving patterns as the primary factors influencing adoption, our Plan Case forecast is for 188,000 residential vehicles registered in New York City by the year 2030. This represents approximately 10.7% of the current vehicle registration. PEV adoption for Westchester County is also incorporated into the estimates in Figure 3-13. This demand impact assumes that 15% of vehicles will be charged at peak. The remaining vehicles will be charged either at off-peak hours or use smart charging equipment to charge at times predefined by the owner of the vehicle. In environments with time-based pricing, it is expected that many drivers will charge overnight to take advantage of lower cost of energy.

---

40 Based on Plug-In Hybrid Electric Vehicle Infrastructure Report – November 2008
Figure 3-13. Projected Demand Impact of Electric Vehicle Adoption in Con Edison Territory
As discussed earlier, our plans to facilitate and manage the integration of PEVs into the grid must be focused on specific load areas as penetration may vary dramatically across our service territory and system reinforcements will be specific to particular locations. The estimates in Figure 3-13 represent the aggregation of load-area specific estimates. Summarized by service territory, regional contribution to PEV load projections for 2030 is illustrated in Figure 3-14.

**Figure 3-14. Electric Vehicle Load Contribution by Service Territory**

3.5.4 Signposts

The overall pace of adoption of PEVs will be influenced by a few key factors:

- **Driving range**—A roadblock to widespread utilization for electric vehicles has been their limited driving range, which is entirely predicated on the design of the batteries. Battery development is constrained by inherent tradeoffs between five main battery attributes: power, energy, longevity, safety, and cost. Two leading battery designs rely on nickel-metal hydride and lithium-ion. Other battery technologies are in various stages of development and many different types of chemical combinations are currently being tested to achieve the energy storage density needed to increasing driving range and affordability, thus facilitating the widespread adoption of electric vehicles.

- **Interoperability**—Utility tariffs, which can be designed to accommodate not just local PEVs but also PEVs from other areas, will also drive adoption. The universality of fueling capability throughout the nation must be resolved; no one will buy a car that can’t be filled up outside of one’s own region. Billing becomes a technical issue that must be addressed through Smart Grid technology. This will require an integrated communications infrastructure and corresponding price signals. Smart chargers enabled by the Smart Grid will help manage the distribution infrastructure and allow for accurate billing.

- **Continued support for alternative fuel vehicles**—Government support will also be important to electric vehicle adoption, including current and proposed policies and plans such as Federal policy and pending greenhouse gas legislation.
3.6 ADVANCED METERING INFRASTRUCTURE

Advanced metering infrastructure (AMI) is the combination of digital interval meters, supporting telecommunications, and information technology systems. AMI gives customers greater control over their energy bills. AMI enables time-based pricing and demand response programs by facilitating two-way communication between the utility and the customer. These programs allow customers to adapt their behavior to lower their energy consumption and to shift their usage to less-expensive times of the day. Real-time information also allows consumers to better monitor their carbon footprint and enables them to curb behavior that has the highest environmental impact.

AMI can also facilitate a utility’s better control of its transmission and distribution system, and allows customers a more direct role in their electricity consumption. To support Con Edison’s mission to take an integrated approach to managing supply, demand, and environmental emissions impact, the Company plans to pilot and eventually deploy AMI in its service territory.

AMI enables bi-directional communication with customers and increases Con Edison’s control of its system. This is achieved through features embedded in the meters, as well as by integrating the right supporting technology.

One of the main components of AMI is the meters that will be installed by Con Edison. These have a number of capabilities that existing meters do not have, including:

- Bi-directional registration
- Ability to provide time-stamped interval data at hourly (or shorter) time intervals
- On-board memory capable of storing at least 60 days of readings
- Real-time (time lag of 5 minutes or less), remote read-only access to meter data for customers and/or competitive providers
- Two-way communication, including the capability to remotely read meters on demand
- Ability to send signals to customer equipment to trigger demand response functions and/or connect with a home area network (HAN)
- Positive notification of outage/restoration
- Self-diagnostics, including tamper flagging
- Interoperability with Smart Grid applications (e.g., distribution automation)
- Remote disconnection/reconnection
- Ability to remotely respond to underfrequency conditions by reducing system loading
- Improved billing options to customers
The functionality of advanced meters is enabled by the installation and integration of supporting information and telecommunication technology. These may include:

- Local area networks that enable meters and modules to convey data and receive information
- HAN controllers and devices that enable customers to view and manage energy use
- A data acquisition system that links meters with back-office components such as a meter data management system which collects meter information for billing and net metering
- Service relay technology for electric service connection/load limiting/disconnection
- The potential of incorporating meter data points into various analytical models used at the Company
- Compliance with cyber security standards

Con Edison views AMI as a key enabler of many of the initiatives outlined in this chapter and in the entire Electric System Long Range Plan. For example, demand response can only be relied upon as a firm resource if it is dispatchable, measurable, and verifiable, which can be implemented using AMI interval meters, data management applications, and bi-directional communications. Similarly, distributed generation cannot be fully integrated into the grid without the advanced metering functionality of AMI that tracks power sold back to the grid, and distributed generation cannot be relied on to lower peak capacity unless the utility can verify the load has shifted off of its system due to alternative generation sources. The integration of intermittent renewables is expected to have disruptive impacts on the grid unless the utility can quickly dispatch demand response and distributed generation resources. And, the expected conservation impacts of extending time-based pricing to the small commercial and residential segments cannot be achieved without interval meters and the supporting data management and telecommunications provided by AMI.
### 3.6.1 Objectives

Table 3-10 summarizes how AMI helps us achieve our objectives toward managing supply, demand, and our environmental emissions impact.

**Table 3-10. Role of Advanced Metering Infrastructure in Achieving Objectives**

<table>
<thead>
<tr>
<th>Objective</th>
<th>Role of Advanced Metering Infrastructure in Achieving Objectives</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reduce Transmission &amp; Distribution Infrastructure Investments and Power Purchase Costs</td>
<td>By enabling demand response and distributed generation, AMI will allow the Company to meet its load shape objectives of shaving and shifting peak in load constrained areas allowing for deferred transmission and distribution investments and reduced power purchased costs.</td>
</tr>
<tr>
<td>Help Customers Manage Energy Costs</td>
<td>AMI enables time-based pricing and demand response incentive programs to allow customers to adapt their behavior and lower their bills. System-wide reduction in peak capacity will lower capacity purchase costs, lowering the supply portion of customer bills. Commercial and industrial customers can leverage verifiable demand response and distributed generation (enabled by AMI) to avoid peak demand charges.</td>
</tr>
<tr>
<td>Improve Environmental Profile and Meet Federal, New York State, and New York City Targets</td>
<td>AMI is the backbone for time-based pricing, which has significant conservation potential. It enables demand response, which is critical to smooth demand peaks with the interconnection of intermittent renewables, and it facilitates the interconnection of supply-side distributed generation, which can offset central fossil fuel sources.</td>
</tr>
<tr>
<td>Enhance Reliability</td>
<td>AMI may improve reliability by reducing outage duration via real-time monitoring of the distribution network. Quicker outage detection and the enhanced ability to locate where an outage has occurred will allow the utility to dispatch repair crews directly to the location and improve verification of service restoration. AMI enables dispatchable and verifiable demand response, which when deployed as a load relief mechanism may increase reliability and stability of the distribution network during multiple contingencies or underfrequency conditions by reducing peak loading of distribution transformers. Absent AMI, which enables dispatching and measuring demand and supply resources, the use of intermittent renewables could impact service.</td>
</tr>
<tr>
<td>Diversify Supply Portfolio</td>
<td>AMI will be critical for Con Edison to integrate intermittent renewables into the grid, as it enables dispatch and measurement of demand and supply resources. The Company will be able to instantly deploy resources such as demand response and distributed generation, according to system needs.</td>
</tr>
</tbody>
</table>
There are two other core benefits of AMI:

First, AMI provides increased visibility and control, which are the foundation of Smart Grid. Much of the customer benefit of a Smart Grid infrastructure relies on the capture of detailed data that is timely enough to communicate the status of the utility distribution system to process-intelligent controls for the distribution equipment. AMI can potentially capture non-traditional data such as voltage and current information at the customer level for Smart Grid applications. In addition, the implementation of a meter data management system and integration of AMI data with distribution management systems, outage management systems, and other systems will provide the information and intelligent control necessary to facilitate the operation of the Smart Grid.

While Con Edison already has many elements of a Smart Grid, AMI will specifically help to enhance the visibility into and control of our distribution network by:

- Enhancing quantity and quality of data for monitoring and modeling for improved asset management
- Enriching data for distribution automation
- Integrating and monitoring new end-use devices, including electric vehicles
- Providing customer end-point data to enhance the value of Secure Interoperable Open Smart Grid Demonstration project
- Facilitating dispatchable demand and supply resources
- Enabling advanced building and appliance automation
Second, AMI enables a number of operating efficiencies. Operations and maintenance (O&M) and capital savings are expected from the following:

- Reduction of manual meter reading
- Improved meter accuracy
- Reduction of off-cycle reads
- Reduction of estimated reads
- Reduction of revenue losses from unoccupied premises
- Reduction of load research costs
- Reduction of call center inquiries and call resolution time
- Reduction of compensation and claims for meter reading
- Offset metering capital costs
- Interface to other projects
- Reduction of field service orders
- Reduction of outage restoration time
- Reduction of False Outage Dispatches
- Reduction of embedded-outage restoration time
- Reduction of call times related to power quality calls

3.6.2 Implementation Plan

Recognizing the importance of deploying the right technology in the right areas, Con Edison plans to precede AMI deployment with a pilot in a representative sample of its system. Once the pilot deployment is completed and its benefits are validated, AMI will be deployed across the system in a targeted fashion.

A pilot with 1,500 meters is expected to begin in 2010. During this period, Con Edison will test communication solutions, in-home devices, home area networks, and time-based rates in connection with energy efficiency and demand response. This pilot has been designed to better inform and validate the benefits of broader AMI deployment in New York City and Westchester County.

In accordance with Con Edison’s targeted approach to system investments, AMI deployment will focus on networks facing reliability or capacity constraints. By deploying AMI in these networks, Con Edison can be responsive to customer reliability needs and defer near-term transmission and delivery investment through verifiable and measurable demand response and distributed generation.

Thirty targeted networks (or load areas) were selected based on capacity and reliability constraints as determined by an evaluation of network reliability indices and expectations for the need to relieve future area substation and localized capacity constraints.

---

50 A number of initiatives and R&D projects may rely on the AMI communications network. The Company presently incurs costs for stand-alone, special data communications networks that are currently associated with some of these projects and initiatives. The use of the AMI infrastructure could potentially reduce the cost to gather data from various remote field devices. Specific projects include: Automation of 480V Vaults, High Tension Monitoring Data Acquisition System, Meters for Unmetered Services
If the pilots prove successful, a targeted deployment will begin in 2013 and will reach a total of 1.5 million meters (45% of total electric meters). Fifty percent of the meters would be installed in the first three years and implementation will be complete after six years (in tandem with gas meter replacement). The meter deployment schedule will also be aligned with the Company’s demand response programs.

3.6.3 Cost Benefit Analysis

After evaluating various alternatives, it was determined that the targeted deployment of AMI with 1.5 million meters would position Con Edison to leverage the functionality of AMI while continuing to test the benefits of broad scale deployment. As currently planned, targeted electric AMI in the Con Edison service territory will provide an 18-year\(^{51}\) net present value of $71 million. Rollout of this program is expected to begin in 2013; in the meantime, Con Edison will utilize the results of the pilot program to enhance this program as necessary. The targeted approach allows the flexibility to ramp up to a full deployment without all sunk costs being incurred. Figure 3-15 summarizes the breakdown of the cost and benefit categories that make up the AMI business case.

Figure 3-15. Targeted Deployment Costs and Benefits

Figure requires interpretation for proper understanding.

\(^{51}\) An 18-year Net Present Value represents the time from the initial rollout of the program, in 2013, to the end of the plan time horizon in 2030
3.6.4 Signposts

During the pilot, Con Edison will collect better cost and benefit information. The company will revisit its AMI implementation strategy based on the intelligence collected from the pilot, as well as from closely monitoring its business environment. The Company has developed signposts that will trigger the review and adjustment of its plan at any point during implementation. Some of the areas that will be monitored are:

- **Load Growth**—Low or negative load growth will limit the need to manage peak demand.

- **Linkages to Smart Grid and distributed generation strategy**—AMI as an enabler of operational savings and demand response is only part of the rationale for the investment. Depending on our Smart Grid strategy, AMI may be necessary to enable more advanced initiatives such as enhanced automation and modeling.

- **Regulatory/Legislative Guidance**—As in other states, the regulatory climate will be the largest driver of the pace of adoption of AMI.

- **Technology Obsolescence**—Over the 20-year planning horizon, there is a chance that traditional meters will no longer be commercially available.

- **Evolution of home area networks**—Breakthrough in home area networks could change the role of the meter relative to customer energy management.

- **Benchmarking**—The successes and challenges of other utility deployments.

3.7 NEW TRANSMISSION

Transmission projects offer another way to access renewable or less expensive sources of generation and to maintain or improve reliability. The Company recognizes and supports examining transmission projects that achieve these goals, but only to the extent that reliability is maintained and the transmission project is the most cost effective method, as compared to local generation or energy efficiency, for achieving those goals. The primary threshold for any transmission project is the project’s impact on system reliability. Each merchant generation or transmission project requesting to interconnect to the Con Edison grid must meet a strict set of publicly posted reliability standards. This review takes place under the supervision of the New York Independent System Operator (NYISO) through its interconnection process tariff, which include individual project studies, the system reliability impact study (SRIS), and the class year deliverability and cost allocation studies performed jointly for all projects in the class year. Con Edison is an active participant in those studies.

In order to study the transmission needs in New York State in the future, the Company is involved in the New York State Transmission Assessment and Reliability Study (STARS), a joint effort initiated by the transmission owners in New York State and supported by the NYISO, with the goal of studying the bulk power system throughout the state to assess its ability to meet the future needs of New York State residents through around 2028. Phase 1 of the study confirmed that transmission reliability needs depend on where generation is sited (i.e. none needed if generation locates close to load). Moreover, the current NYISO interconnection queue indicates a high probability of substantial new generation in New York City. Phase 2 will examine projects that may address longer-term reliability issues identified in Phase 1 as well as aging infrastructure and wind integration. Con Edison may invest in transmission for wind projects as a result of the potential projects that will be identified by this study, but at this time it appears that most of the projects needed will be local upstate projects.
3.7.1 Objectives

Table 3-11 explains how transmission projects, as part of a portfolio of solutions, may help achieve our objectives of managing demand, supply, and environmental emissions impact.

Table 3-11. Role of New Transmission in Achieving Objectives

<table>
<thead>
<tr>
<th>Objective</th>
<th>Role of New Transmission in Achieving Objectives</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reduce Transmission &amp; Distribution Infrastructure Investments and Power Purchase Costs</td>
<td>Building new transmission could enable integration of less expensive sources of supply, thus lowering purchase power costs.</td>
</tr>
<tr>
<td>Help Customers Manage Energy Costs</td>
<td>New transmission projects may be utilized to interconnect the Con Edison transmission system with more diverse supply sources, providing a hedge against risk from volatile commodity price changes. In addition, new transmission projects may offer a way to potentially reduce congestion costs.</td>
</tr>
<tr>
<td>Improve Environmental Profile and Meet Federal, New York State, and New York City Targets</td>
<td>Transmission projects can connect to cleaner and/or renewable fuel sources, including offshore wind, which in conjunction with local renewable energy supply sources may reduce greenhouse gas emissions and help both New York State and New York City meet their renewable energy targets.</td>
</tr>
<tr>
<td>Diversify Supply Portfolio</td>
<td>New transmission projects, if they provide access to renewable resources, may also help to diversify our supply portfolio.</td>
</tr>
</tbody>
</table>
3.7.2 Implementation Plan

As noted above, there are no transmission projects that currently appear to be needed for reliability or economic reasons. In the longer term there may be an opportunity to build new transmission to integrate bulk renewables into the overall generation mix. The combined costs of transmission projects with remote generation, however, must continue to be compared against the cost of adding new local generation and against the cost of demand side management programs to offset additional load growth. Figure 3-16 illustrates that Con Edison's transmission projects generally fall into three phases.

Figure 3-16. Implementation Plan: New Transmission

Three generation/transmission projects, occurring during Phase I, which highlight CECONY’s goal of integrating bulk renewables and/or affordable supply, are the Long Island Offshore Wind Project, the Astoria Energy II Project and NRG Berrians III.

The Joint Con Edison-Long Island Power Authority Offshore Wind Power Project aims to create the largest offshore wind project in the United States. A goal such as this cannot be achieved alone, and therefore a joint venture was created between Consolidated Edison, the Long Island Power Authority, the Port Authority of New York & New Jersey, the Metropolitan Transit Authority, the New York State Department of Environmental Conservation, the New York Power Authority, and the New York State Energy Research and Development Authority. Successful implementation of this offshore wind project, which is expected to reduce CO₂ emissions by 40,000 tons annually, will significantly enhance New York’s downstate renewable supply portfolio when the project is placed in service (currently scheduled for 2015). In addition to its environmental benefits, this initiative would add 700 MW of intermittent power to the combined service territories of Con Edison and the Long Island Power Authority. The proximity of these wind resources offers a significantly lower transmission cost than other potential projects to interconnect renewables which is an additional benefit to our customers.

The first Astoria Energy unit, online since 2005, is one example of a new clean natural gas plant that has been built in New York City over the last 10 years and uses combined-cycle natural gas technology. This process utilizes exhaust gas normally lost in the combustion process to produce additional electricity, therefore reducing fuel consumption by the plant by 30% per unit of electricity generated over conventional power plants. The second unit is the same kind of generating plant as Astoria I. It is anticipated that this facility will be interconnected where the retired Charles Poletti Power Project in Astoria, Queens once interconnected, the new generation facility, strongly supported by state and city government officials is expected to be online in May 2011 and will supply an additional 550 MW to New York City.

The NRG Berrians III project is aimed at injecting 789 MW of generation at the point of the retired Poletti site.
It is possible that within the near term technology changes will occur that will add to the affordability and availability of renewable sources of generation. As such, the Company will seek to identify opportunities to connect to these resources to help meet any Federal renewable portfolio standard targets and greenhouse gas objectives, as long as the connection of these sources does not include an unwarranted cost burden on our customers for transmission lines that have not been deemed necessary for reliability.

During Phase III Con Edison expects to be involved with transformational opportunities that will enhance the capabilities of the business. These transformation drivers should come from both policy initiatives as well as technological advancements, and Con Edison is committed to utilizing any and all measures that will have significant cost and environmental benefits for customers.

### 3.7.3 Estimated Costs

Building new large transmission projects is an extremely capital intensive endeavor, and several business models exist for the ownership and operation of transmission assets. The two most common models are for transmission assets to be owned by utilities, generators and municipalities or for the assets to be owned by independent transmission companies. Con Edison’s position is that joint ownership of transmission assets by New York State’s utilities should be encouraged as an effective and equitable way to finance any new transmission that would, for example, reduce congestion or achieve societal goals like greenhouse gas reduction.

The New York Independent System Operator operates a competitive wholesale market and accordingly maintains a market-based philosophy with regard to the need for transmission and generation assets. Only in situations where market based proposals are insufficient to meet identified reliability needs will regulated solutions be required to maintain reliability. Costs of regulated transmission projects necessary to maintain system reliability are recovered consistent with rules specified in the New York Independent System Operator’s tariffs on file with the Federal Energy Regulatory Commission (generation and demand-side management projects are subject to the PSC’s jurisdiction). Further, costs of regulated transmission projects that reduce congestion and provide statewide economic benefits may be passed through to customers via economic planning rules (also outlined in the New York Independent System Operator tariff) if the project receives 80% or more approval from the project's intended beneficiaries.

The Federal Energy Regulatory Commission (FERC) has ultimate jurisdiction over transmission projects. To promote transmission investment, the FERC has defined several incentives, including ROE adders on new investments that owners of transmission assets that meet certain requirements are allowed to earn. Projects, which are approved in a regional planning process, generally qualify for these returns.

With regard to the overall cost of transmission projects, the Long Island Offshore Wind Project is currently budgeted at $821 million for the on-shore transmission infrastructure, to be spread out over two phases -- $415 million for Phase I and $406 million for Phase II. This cost only applies to the transmission lines needed to interconnect the wind farm to both the Con Edison and Long Island Power Authority systems and does not include the cost to build the wind farm itself.
3.7.4 Signposts

In order to be adaptable to the marketplace, Con Edison has defined a number of signposts that will identify changing needs and sentiments of the market and that could require modification of the overall strategy.

- **Enactment of more stringent Federal renewable portfolio standards and greenhouse gas laws**—Federal targets that are more aggressive than New York State targets may provide increased impetus for the interconnection of renewable sources of generation.

- **Dramatic changes in the sources or amount of supply available**—Dramatic changes in supply availability could affect the need for additional transmission assets, for example, Entergy failing to renew the operating licenses of the Indian Point Units 2 and 3, which would result in their retirement at the end of September 2013 and December 2015, respectively.

- **Increased proliferation of storage technology**—Proliferation of new storage technologies may alter the need for additional transmission assets.

- **Changes in federal regulation and oversight**—Policy regarding Independent System Operators, Regional Transmission Operators, and Interconnection-Wide Planning Requirements can have a significant impact on the entire transmission industry.

- **Results of New York State Transmission Assessment and Reliability Study**—Results could call for changes to be implemented by various New York State transmission entities in order to meet the needs of customers and ensure reliability (but does not appear likely at this time).

- **Changes in customer demand for cheaper or cleaner sources of energy**—Dramatic changes in customer requirements including conservation measures could impact the pursuit of additional transmission projects.

Throughout the three phases of implementation, Con Edison will continuously monitor these conditions, and adjust programs as necessary. As the internal and external environments change, additional signposts may be identified and added to this list.

3.8 VALUE PROPOSITION OF STEAM

As part of our efforts to proactively manage both demand and supply, we continually monitor the role of the steam byproduct in our supply portfolio as well as the offset in our electric demand from steam powered air conditioners. If we were to lose this relatively affordable and clean resource there would be a significant impact to both electric and gas customers due to the infrastructure and capacity that would likely be needed to be built to replace the steam system. Therefore, decisions related to the steam business must be integrated into the electric system long range planning process.

Currently, the company uses the electricity byproduct produced by our company-owned in-city steam generating plants during peak summer days. If the steam system were no longer available, there would be significant impacts on customers, the environment, New York City, and the gas and electric systems. This change in the composition of our supply resources would affect the operation of our system as it stands today, and would require significant investments in our electric and gas infrastructure. A number of projects would have to be accelerated and included in Con Edison’s capital plans. In addition, 350 MW of peak electric demand would need to be procured through the marketplace, ultimately increasing the cost of supply.
In addition to using steam byproduct, the use of steam air conditioning in lieu of electric air conditioning offsets peak load requirements on critical electric networks. There are approximately 580,000 tons of installed steam air conditioning. Conversion to electric air conditioning would add 350 MW of incremental demand to Con Edison’s electric system. Our analysis shows that, over a 20-year period, steam air conditioning averts approximately $180 million per year in annual electric transmission and distribution costs.

In Con Edison’s current steam rate case, the Company pointed to the related aspects of the steam and electric and natural gas systems. The Company indicated that the prospect of financial support from electric customers, which may be based on marginal cost principles, would warrant considerations if the steam system were unable to separately maintain its financial viability.

3.9 SUSTAINABILITY INITIATIVES

Con Edison has a long standing commitment to protect the environment. Our Sustainability Strategy is a plan to reduce the Company’s environmental impact, encourage and assist customers in managing energy use, build partnerships with stakeholders to support our vision, and develop infrastructure for clean energy alternatives. Long-term objectives of this strategy include: integrating more sustainable choices in the Company’s decision making, enhancing our role in policymaking, and improving stakeholder relations. This strategy is constructed of six key principles incorporating environmental, social, and financial considerations:

- Model green behavior internally
- Promote green behavior to external stakeholders
- Innovate to meet customer preferences for a greener lifestyle
- Partner with government to shape policies and standards consistent with sustainability vision
- Develop infrastructure to advance the use and delivery of value-creating clean energy alternatives
- Incorporate environmental and societal value into our decision making
Sustainability is a business imperative, as well as a global imperative. We will continue to refine and expand our efforts so that the way we conduct business contributes to a more sustainable future. Figure 3-17 summarizes the greenhouse gas reduction goals for our environmental sustainability initiatives and the Electric System Long Range Plan through 2030\textsuperscript{52}.

![Figure 3-17. Targeted Greenhouse Gas Emissions Reduction in 2030\textsuperscript{53}](image)

3.9.1 Summary of Initiatives

**Model Green Behavior Internally**

Con Edison is a user of energy as well as a provider, so we continue to examine our own consumption patterns. The primary greenhouse gas emissions generated by the company include carbon dioxide, sulfur-hexafluoride (SF\textsubscript{6}), and methane. Greenhouse gases are reported using carbon dioxide equivalence, or CO\textsubscript{2}e, a standardized unit that accounts for the differing warming potentials of the various greenhouse gases. The Company is continually focused on lowering greenhouse gas emissions and has reduced the Company’s carbon footprint by more than 36\% between 2005 and 2009.

\textsuperscript{52} Direct and New Generation emission reductions are estimated based on anticipated project completion by 2020; Customer Reductions are estimated based on approved EEPS projects as of January 2010.

\textsuperscript{53} Based on 2008 baseline. New generation is based on CECONY’s interconnection to bulk renewables, primarily as off-shore wind.
Greening Our Premises

New York City’s skyline grew greener when we installed energy efficient lighting in the tower of our corporate headquarters. At night, the tower uses 63% less energy than conventional lighting, lowering carbon emissions by roughly 19 tons a year. Another goal for the company is to reduce employee electricity consumption at company office locations 15% from 2005 levels by 2015. Meeting this goal will conserve an estimated 6,600 MWh of electric consumption annually.

In 2008, we installed our first green roof at our training facility in Long Island City, in cooperation with Columbia University’s Center for Climate Systems Research. Thousands of plants are keeping the building cooler in summer and warmer in winter. We will be evaluating all new company construction and renovation projects, as well as operation and maintenance of our existing buildings, to conform to reduce the impacts of our buildings.

A green awareness campaign, and improved waste segregation, and additional recycling vendors will assist in achieving a recycling rate at our facilities that is greater than or equal to industry-leading standards. The Company currently recycles 90% of the solid non-hazardous waste generated in its operations throughout NYC and Westchester County. We will continue to identify new opportunities for recycling, and will work with vendors on meeting sustainability criteria and performance.

SF₆ Emission Reductions

Sulfur hexafluoride (SF₆) is used as a dielectric to extinguish the circuit breaker arc and as an insulating medium in different pieces of equipment, such as enclosed bus arrangements. As it has been identified by the Intergovernmental Panel on Climate Change as a potent greenhouse gas, the Company has committed to the Environmental Protection Agency (EPA) to reduce SF₆ emissions annually by 5% from a 1996 baseline.

To reduce SF₆ emissions, the company has accelerated equipment replacements and improved its ability to identify and repair leaks. Specific initiatives include:

- Establishing SF₆ reclamation centers and the use of “gas carts” (recycling units) that enable the Company to recover, purify, and reuse SF₆.
- A laser imaging camera that displays leaking SF₆ on a video monitor. This allows users to pinpoint the precise location of the leak and take corrective measures. This also greatly reduces the time it takes to locate leaks, resulting in fewer outages.
- Regular periodic internal inspection of SF₆ equipment.

Transformer Oil Recycling

A typical network system distribution transformer holds 350 gallons of oil, which is used to insulate, suppress arcing, and serve as a coolant. In 2008, the company signed an agreement with a recycling vendor that cleans and filters the used oil for reuse in electrical equipment. The reconditioned oil eases the burden on natural resources because it eliminates the need for refining fresh oil from petroleum feed stock. It also eliminates the carbon emissions associated with burning it as fuel. Overall, the company plans to recycle approximately 450,000 gallons of dielectric oil every year.
Leak Detection, Location, and Prevention (Dielectric Feeder Oil)

In addition to conventional leak detection methods (i.e., low-reservoir-level alarm, frequent-pumping alarm, low-pressure alarm), we employ innovative On-Line Leak Detection. This system remotely monitors cable systems, and detects small differences between the predicted and actual fluid entering the system. Data is monitored and transmitted to our control center in real-time. The solution enables more accurate leak detection by analyzing the relationship between pipe and soil temperatures, fluid pressure, and conductor current.

In collaboration with Electric Power Research Institute and the Brookhaven National Laboratory, we have tested a variety of methods to pinpoint leaks. The most advanced of these is the PFT Leak Location Method. This involves injecting the affected cable systems with a perfluorocarbon tracer (PFT), allowing it to run through the cable system, and then detecting its vapors with our PFT Leakmobile.

Our crews employ leak prevention methods, such as maintaining cathodic protection systems, isolating termination ruptures, replacing leak-prone sections, inspecting manholes, and detecting corrosion and coating disbonding.

Con Edison Fleets

More than 45% of Con Edison’s fleet uses alternative fuel technology, including biodiesel, hybrids, and compressed natural gas. Since January 2008, diesel vehicles have been using cleaner-burning B-20 biodiesel fuel. By volume, 20% of this fuel is derived from soybeans. The soy-based portion of the fuel is a renewable resource that will help the company offset almost 400,000 gallons of petroleum per year. Newer diesel vehicles also will be equipped with special exhaust filters for even cleaner tailpipe emissions. All vehicle operators have strict guidelines for limiting vehicle idling when it is not an operational requirement. We replace about 80 vehicles a year with alternative fuel vehicles, making our fleet even greener.

Mitigating Past Harm

The Company also manages environmental-related issues and risks that resulted from historical operations. The Company’s mitigation activities are currently focused on the following:

- Monitoring and managing various Superfund sites
- Investigating, and if necessary remediating old oil and dielectric fluid spills at various locations
- Performing corrective actions related to the Company’s Astoria site\(^\text{54}\)
- Investigating or remediating if necessary, the contamination that resulted from underground storage tanks (USTs)\(^\text{55}\)
- Investigation and remediation, if necessary, of Manufactured Gas Plants (MGPs), which were part of the Company’s original gas business

\(^{54}\) Under the Company’s agreement with the Department of Environmental Conservation (DEC) and in compliance with the Resource Conservation and Recovery Act (RCRA).

\(^{55}\) These USTs are subject to EPA and DEC standards and the Company currently has 9 sites where it is actively pursuing investigation or remediation activities. Typically, Con Edison owned or operated these sites as part of service centers and other facilities that were used to support operations. Its investigation efforts often involve groundwater and soil testing.
Promote Green Behavior to External Stakeholders

Con Edison encourages our customers and the public to make sustainable choices. Education of the general public can be accomplished through use of a broad communications program that includes advertising, the web, and public speaking appearances. New Power of Green web pages offer more than 100 energy-savings tips. Energy efficiency tips are also posted on subways, broadcast on local radio stations, and published in brochures and newsletters.

We extended green communications to one of our most important stakeholder groups—our employees. A new Greening House campaign delivers messages about how the company is greening the way it does business, one story at a time. Through electronic messages, the company newsletter intranet video, and posters, Greening House also encourages employees to do their part for a more sustainable future.

The Company also promotes energy pricing that allows consumers to make environmentally appropriate decisions. The Company supports an economy-wide cap and trade system as a means to regulate greenhouse gas reduction. Furthermore, as Federal and state agencies establish rules for the implementation and cost accounting for these programs, the Company will maintain a position toward redistribution of electric generation carbon funds to utility-run energy efficiency and renewable energy programs. Concurrently, we support real time pricing for all customer classes and support the adoption of AMI to facilitate variable pricing and to provide associated information to help customers better manage their energy consumption.

The Company enjoys close relationships with 150 local community groups. We support green education programs in local schools, and contribute to nonprofit organizations that help create green spaces and community gardens. We are proud to be a leading benefactor of the New York Botanical Garden and a sponsor of its Greening the Garden program.

The Company also supports hundreds of local organizations whose activities advance strong and vibrant communities. The company carefully chooses these groups based on their ability to develop education initiatives, training, and other programs and events to enrich the quality of life for all New Yorkers.

Innovate to Meet Customer’s Preferences for a Greener Lifestyle

As described earlier in this chapter, the Company supports the New York State Energy Efficiency Portfolio Standard and Renewable Portfolio Standard, and seeks greater participation by utility companies in interfacing with customers on incentive programs devised to reduce customer demand. The Company has filed and may seek to file additional proposals with the Public Service Commission to expand program capacity for installation of energy efficiency, demand response, and distributed generation measures in residential, small commercial and industrial facilities. Accordingly, the Company will also consider the adoption of advanced metering infrastructure (AMI) for electric service to allow customers to make decisions on when to use energy and to enhance operational reliability and energy response.

More trees are growing as a result of the 10 million electronic customer payments processed in 2007 alone. Con Edison contributes $1 to the planting of trees for each customer that chooses electronic billing. In addition to saving trees through increased electronic transactions, we have planted 7,000 new trees thanks to customers who signed up for paperless billing.
Most recently, Con Edison employees joined MillionTreesNYC, a PlaNYC initiative launched by Mayor Mike Bloomberg and the entertainer Bette Midler with the goal of planting one million trees across the city’s five boroughs by 2017.

**Partner with Government to Shape Policies and Standards Consistent with Sustainability Vision**

Con Edison will continue to build coalitions with stakeholders to implement policies and programs that support our vision. We will maintain transparency with stakeholders. A key component of a government partnership will be Public Service Commission endorsement of our Sustainability Strategy. This partnership would include broadening our energy advocacy to support public transportation infrastructure that uses energy efficiently and improves sustainability. Federal agencies have developed a significant number of voluntary and partnership programs, and the path to implement fully the Sustainability Strategy will include recognition of the Company’s efforts by Federal regulators. All of the other stakeholders noted above will be cognizant of the Company’s efforts, and the Company will be considered a resource for input to responsible policy development in efforts to advance the principles of sustainability.

**Develop Infrastructure to Advance the use and Delivery of Value-Creating Clean Energy Alternatives**

As described earlier in this chapter, Con Edison is committed to advancing cost-effective and responsible use of renewable and distributed generation. We will do this by facilitating and incenting customer use of distributed and renewable energy and by promoting the development of an advanced metering infrastructure which will facilitate the sharing of customer-sited energy back on to the grid.

We will also work to expand our options for delivery of cleaner and renewable energy. Con Edison will evaluate building new transmission lines to integrate renewable resources such as offshore wind. The Company will also work in concert with The Electric Power Research Institute and other utilities to support the adoption of electric vehicle technologies with an aggressive R&D initiative and company fleet initiative.

Where applicable on our system, Con Edison will promote the development of a “smarter grid” to allow for the integration of intermittent renewable generation and to improve the overall efficiency of energy distributed on our network. The following initiatives are being deployed or tested:

- Demand response to absorb short-term load shortfalls due to the intermittency of wind and solar
- Storage to accompany intermittent distributed and renewable energy resources
- Voltage management to allow for the safe integration of solar resources
- Automated metering to allow for effective dispatch of distributed energy and demand response resources
Incorporate Environmental and Societal Value into Our Decision Making

Con Edison will consider the potential environmental and societal impacts of our business decisions. To this end, we will evaluate and measure opportunities to enhance sustainability characteristics within individual and enterprise wide projects.

The Company is also committed to working together with other stakeholders to develop appropriate frameworks for the State’s Climate Action Plan. The Company has representatives on two Technical Work Groups: (1) Power Supply and Delivery and (2) Adaptation, as well as the higher-level Integration Advisory Panel.

We will monitor any developments from the State’s Climate Action Plan as a signpost for the Electric System Long Range Plan.

3.9.2 Recognition of Accomplishments

We strive to be a leader in the industry in terms of managing our environmental impact and have been recognized by several external entities, including the acknowledgements listed below:

- Received a 2009 EPA award for SF$_6$ emission reduction by replacing equipment, thereby preventing 670,000 lbs of SF$_6$ from entering the atmosphere between 1999 and 2009
- Ranked highly in the Carbon Disclosure Project's Leadership Index for actions helping to mitigate the Company's impact on climate change
- Named in 2009 to the Dow Jones Sustainability Index (DJSI), which recognizes corporations for economic, environmental and social excellence
- Became a founding member of the Climate Registry in 2008 to voluntarily report greenhouse gas emissions, and have emission statements verified by an accredited 3rd party verifier
- Recognized by the United States Environmental Protection Agency for replacing paper insulated lead-covered cable with nonleaded solid dielectric cable
- Received the 2007 Financial Times/Citi Private Bank Environmental Award for the greatest improvement in carbon efficiency by any large corporation in the Americas
4.0 INTEGRATING INNOVATIVE SYSTEM DESIGN

4.1 INTRODUCTION

We design our electric system to meet customers’ growing demand for electricity and to maintain reliability. A core principle of Con Edison’s system design approach is the use of tailored solutions to fulfill these requirements. Tailored solutions apply targeted demand and supply side management programs, advanced technologies and innovative designs, as well as traditional infrastructure investments to specific load areas. Our tailored approach will result in the application of solutions where they can provide maximum benefit for our customers.

The expectation for world class reliability in New York City and Westchester County has led our system design to be robust and necessarily redundant. Due to this redundancy we have more distribution components per customer than other utilities. The sheer number of any given type of component on our system means that implementation of any wide scale investment program is higher in cost, even on a per customer basis. Our strategy, outlined in this chapter, is to invest in infrastructure enhancements only when less expensive alternative solutions are not available to sustain existing reliability levels, provide for localized delivery capacity needs, and ensure employee and public safety.

In section 4.2 we describe how we design our system and emphasize the steps we have taken to improve the cost effectiveness of our network by systematically incorporating alternative solutions to meet customers’ growing demand for electricity. In section 4.3 we introduce some of the specific innovative designs and advanced technology that we deploy to meet system requirements at a lower cost than traditional infrastructure enhancements without sacrificing reliability. In section 4.4 we discuss our ongoing exploration of changes to our rigorous design standard that would address our high asset intensity. And, in section 4.5 we introduce our research and development function tasked with continually developing advanced technology and design solutions to serve the unique needs of our customers. In sections 4.6 and 4.7 we provide signposts upon which to re-evaluate the strategy presented here and summarize the conclusions from this chapter.

4.2 TAILORING SYSTEM DESIGN

4.2.1 Meeting Customers’ Demand for Electricity

The Company’s obligation to meet the electricity delivery demands of our customers requires us to expand and reinforce our electric delivery system based on customer usage. Chapter 3 of this report highlighted the Company’s specific efforts and processes to manage our customers’ supply and demand in order to reduce the need for capital expenditure. However, even with a host of demand and supply side management programs, certain portions of the system will grow and require capacity replacement or expansion.
Expenditures for Meeting Customers’ Electricity Demand

Figure 4-1 presents a summary of the Company's capital expenditures over the plan horizon, 2010 to 2030.

Figure 4-1. Con Edison 20-Year Capital Spending Summary

As seen in Figure 4-1, ‘Asset Management/Equipment Replacement’ expenditures, which are for maintaining the safety and reliability of the existing electric system, represents the majority of expenditures, or 60% of the total. Our approach to managing this category is described in detail in Chapter 5.

Chapter 4 describes the initiatives we employ to ensure our system meets customer demand, referred to as ‘System Expansion/Meet Customer Demand’ in Figure 4-1, which represents approximately 30% of the Company's total capital plan. This mix of spending is consistent with spending at other large U.S. investor owned electric utilities.

---

96 ‘Other’ expenditure includes general or supporting investments such as information technology, common plant, and small investments in our few remaining power production plants.
Figure 4-2 provides a further breakdown of this ‘System Expansion/Meet Customer Demand’ expenditure and reveals that a vast majority of the Company’s investments in this area consist of distribution and area substation expenditures. While total demand for energy may remain flat, specific networks or customer load areas could still experience local growth and necessitate capacity-related expenditures.

**Figure 4-2. Composition of System Expansion/Meet Customer Demand Investment (2010-2030)**

![Diagram showing composition of System Expansion/Meet Customer Demand investment]

_**Nature of System Expansion Planning**_

It takes several years to plan, site, and construct major new assets like substations and transmission lines, especially in urban environments like metropolitan New York. Consequently, the Company maintains a long term perspective with regard to its planning and forecasting activities. It is not possible to precisely predict customer demand 5, 10, or 20 years in the future. This is especially true in an era characterized by evolving technologies and policies, volatile and uncertain prices, and changing economic patterns. We must therefore develop flexible plans that prepare for but not over-commit to capacity related initiatives.

---

57 Totals do not add precisely due to rounding.
Figure 4-3 illustrates the Company’s historic and projected transmission and distribution substation investment from 1948-2030. Capacity planning (i.e., load relief) occurs at both the transmission and the distribution levels of the Con Edison System. The Company’s transmission planning is conducted in concert with the New York Independent System Operator, which incorporates our local transmission plans into its statewide bulk transmission planning process.

Balance and flexibility are critical attributes of the Company’s load relief planning and implementation. Committing to major capacity expansions well in advance of need may result in excess capacity, add additional infrastructure cost, and add to the Company’s asset intensity challenge. Conversely, delaying capacity-related initiatives can increase cost as the availability of land decreases and the price of property increases. Our capital planning process seeks to optimize the timing of investment in order to take advantage of opportunities to minimize cost.

4.2.2 Tailored Solution Approach

In the past several years, the company has adopted and intends to continue to develop and improve its integrated and tailored approach to meeting customer demand. This tailored approach is designed to move the Company beyond traditional capacity expansion methods (i.e., construct additional assets to serve load) to create a tailored solution to each specific need.
Figure 4-4 illustrates the generalized steps in the load relief planning process. It commences with independent forecasts of customer demand that integrate various assumptions and planning horizons (Step 1). In concert with the system capabilities (Step 2), specific local system needs are identified and potential solutions or options are defined (Step 3). These options are evaluated (Step 4) and the optimal solution is defined. The Company’s selected plans are combined into a comprehensive plan (Step 5) to initiate various planning, budgeting, and engineering activities.

The Company’s traditional solutions for meeting customer demand – adding equipment to increase capacity, constructing new area substations and transmission lines, splitting or shifting of load among networks, etc. – are typical across utilities. This approach has been relied upon for decades and will necessarily continue to be employed. It has provided the necessary capacity for the growing electricity needs of our customers. This approach could lead to large units of incremental capacity expansion, thus initially lowering the overall system asset utilization until load growth catches up. In the past this approach was dependent on incorporating demand and supply side measures on a system-wide level. Figure 4-5 illustrates this traditional approach to capacity expansion planning. This does not lend itself to the detailed load area planning we need to do at the area substation and network or load area level.
We now rely to a greater extent on contributions from energy efficiency and demand response and have incorporated these measures into our load area level forecasts. Advancement in measurement and verification, once implemented, will facilitate this process. This ability to identify area-specific demand reductions from demand management, as well as new infrastructure investment has led us to develop our tailored design approach as a more effective way to serve the energy requirements of our customers.

Under this integrated approach, each load relief opportunity is evaluated separately but in conjunction with other needs. Both traditional and new design options are evaluated and an integrated, lowest overall cost solution is chosen for implementation. The solution may include demand and supply side solutions, new technologies, and traditional or non-traditional capacity expansion and reliability approaches.

Step 3 from Figure 4-4 above highlights the key step of identifying system expansion opportunities and identifying the specific options available to satisfy them. Under Step 3, each area substation and its corresponding load areas are evaluated to identify and prioritize the greatest near-term challenges.

The Company then builds a specific or tailored load relief plan for the pertinent load areas. This load relief plan incorporates the entire range of solutions, including usage related solutions (demand and supply), non-traditional design solutions, and traditional load relief initiatives. Elements of a conceptual plan for system expansion are illustrated in Figure 4-6. In this figure, various traditional, non-traditional, and demand/supply solutions are weighed against the criteria of cost, performance, and risk. The system expansion plan will then balance these criteria to result in an integrated and tailored solution for the area in need of reinforcement.
The range of the potential system expansion options under the tailored approach are presented in Table 4-1. They include supply and demand related options as outlined in Chapter 3 and non-traditional design options that are described later in this chapter.

**Table 4-1. Example Demand/Supply, Non-Traditional, and Traditional Load Relief Options**

<table>
<thead>
<tr>
<th>Demand/Supply Options</th>
<th>Innovative/Non-Traditional Design Options</th>
<th>Traditional Options</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy efficiency</td>
<td>Virtual substations</td>
<td>Split networks / add new substations</td>
</tr>
<tr>
<td>Demand response</td>
<td>Substation asset sharing</td>
<td>Add transformers or feeders</td>
</tr>
<tr>
<td>Distributed generation – solar, combined heat</td>
<td>Transferrable feeder groups (switchable load transfer)</td>
<td>Add capacitors or voltage regulators</td>
</tr>
<tr>
<td>and power (CHP), and fuel cells</td>
<td>Automatic primary switching</td>
<td>Permanent load transfers, load balancing</td>
</tr>
<tr>
<td>New transmission</td>
<td>Intelligent underground autoloop</td>
<td>System reconfiguration (add switches/ties, feeder de-bifurcation)</td>
</tr>
</tbody>
</table>

In summary, the expected benefits of the Company's integrated and tailored approach are as follows:
• **Reduce infrastructure cost**—Reduction and deferral of capital investments, achieved through supply and demand management and innovative designs, reduces customer bill impact.

• **Advance system design**—While maintaining or improving reliability, a directed effort to implement new, non-traditional design solutions wherever practical supports our intent to drive to a cleaner, smarter, safer, more asset utilized, and more automated electric system.

4.3 INNOVATIVE DESIGNS

4.3.1 Increasing Asset Utilization

Central to the integrated and tailored approach is the availability of a full menu of system expansion solutions. Over the course of this plan, we intend to meet our service reliability objectives in less asset intensive ways through the implementation of innovative third generation (3G) designs. The first generation design, implemented during the initial construction of the electric system, was characterized by radial overhead construction. The second generation design moved much of the infrastructure underground and provided for more reliable service through multiple supply paths. The Company’s innovative or third-generation (3G) designs can be used for system expansion, without sacrificing reliability while also increasing operational flexibility and asset utilization. They are the result of years of research and development efforts and they are now fully integrated into Con Edison’s design process. 3G design concepts to address system expansion include:

• Asset Sharing

• Transferrable Feeder Groups

• Virtual Substations
**Asset Sharing**

Our asset sharing approach achieves comparable reliability to our existing standards at lower cost than traditional infrastructure investments. In this approach, spare substation transformers in distribution area substations are shared among multiple substations. This design is conceptually illustrated in Figure 4-7.

![Figure 4-7. Asset Sharing Design](image)

Under a traditional second contingency (N-2) design, a typical 5-transformer area substation is designed to satisfy a peak customer demand that is equivalent to the capacity of 3 transformers with two of the transformers serving as back-up or spare transformers. In most cases, two neighboring substations on the same property, identified as ‘Substation A and Substation B’ in the figure above, would be served by the same five transmission feeders. Therefore, the redundancy of the traditional design is in the transformer assets.\(^{58}\)

Using asset sharing, the same spare or back-up transformers are shared by two nearby substations through feeder ties at primary distribution voltages, thereby eliminating the need for separate spare transformers in both area substations. Thus the N-2 design standard is shared across both substations. Since a typical area substation transformer is valued at $2.5 million, the resultant savings, due to the installation of fewer transformers and associated transmission lines, can be substantial. Since substation transformers have an extremely low failure rate, reliability is not adversely affected. The second contingency design criterion has protected customers but new

\(^{58}\) Without supply feeder diversity of sources, which is usually available for substations not on the same property, the asset sharing connections are not viable.
planning tools and analytical techniques appear poised to provide customers with commensurate reliability at lower costs.

**Transferrable Feeder Groups**

Typically our secondary networks are served from a single area substation, although a substation may serve more than one load area or secondary network. A transferrable feeder group ties feeders across two substations with an advanced, automated, normally open switch to provide possible power supply to the primary circuits from two locations. Where applicable and cost effective, a transferrable feeder group is established between existing substations to support initial incremental load growth in a neighboring area. This enables automatic load transfers between substations to provide interim load relief and defers the immediate implementation of new area substations. The transferrable feeder group requires additional fast switches and feeder cable.

Figure 4-8 illustrates the transferrable feeder group design.

![Illustrative Transferrable Feeder Group Design](image)

The transferrable feeder group provides numerous advantages, including the potential for temporary supply sources from feeders in supporting substations and lower overall risk levels. This is a promising new design but not universally applicable, as it requires additional substation and distribution level switches and cable sections. Some of our existing substations may not have the space or the capability to accommodate these new designs. At each individual substation with the potential for transferrable feeder groups, feasibility, practicality, and cost must be considered.
**Virtual Substation**

Presuming a growing load area, asset sharing approaches could defer but would not eliminate the need for a new area substation. The virtual substation is an innovative, responsive capacity expansion process that can be used to better match investment with needs to meet system expansion requirements. Figure 4-9 illustrates the format of a virtual substation.

![Figure 4-9. Illustrative Virtual Substation Design](image)

In a virtual substation design, the new substation is constructed with the requisite switchgear and protection equipment but without substation transformers. It is supplied via feeder ties from two nearby substations. The necessary ducting and feeders are built with the ability to supply 138kV or 345kV transmission to future substation transformers. Once demand growth is sufficient to properly utilize substation transformers, the transformers are installed and the virtual substation becomes a traditional substation. This approach lowers the overall size and cost of incremental capacity expansion, thereby lowering customer costs and improving asset utilization.

The virtual substation is an alternative to the traditional 5-transformer area substation. When demand exceeds the capacity of the virtual substation, the substation is completed to traditional or compact (1 or 2 bank) design specifications.
**3G Case Studies**

The 20 year system expansion planning process identified a number of situations that will potentially result in the construction of new transmission and distribution area substations. The following case studies apply the virtual substation and transferable feeder group concepts to illustrate how it can meet expected growth in customer demand and minimize the associated infrastructure investment.

**Queens Case Study**

The previous system expansion forecast projected that demand growth in eastern Queens would necessitate the construction of an additional switching station and two area substations. Following the traditional approach, we would build all three stations and install ten substation transformers to support the constrained areas. However, if we use the virtual substation approach, we can build just the switching station to supply eastern Queens via 27kV distribution feeders connected to two neighboring area substations with excess transformer capacity. The 27 kV connection will be built in a way to be readily converted in the future to supply 345kV transmission to the two future area substations, where transformers are brought online as they are needed.

We anticipate numerous benefits from this virtual substation design, including:

- The deferral of construction of complete new switching and area substations by at least ten years. Our initial estimate of the net present value of this savings is estimated to be $384M.
- The incremental unit of capacity expansion (e.g. the required infrastructure investment needed to meet an increase in demand) has been reduced significantly in comparison to a traditional substation design and construction. This will have the impact of reducing the sharp impact of load relief investment levels and will result in smoother, less volatile capital investment.

Due to downward revisions in the 2009 forecast, the virtual substation discussed in the Queens Case Study is not included in the Plan Case.

**Brooklyn Case Study**

Expected growth in customer demand in Brooklyn by 2020 would require the expansion of a switching station and the construction of two area substations. The alternative 3G plan is to construct two virtual substations connecting to spare transformers at neighboring substations. This design will require the installation of transmission class feeder cable and would defer the construction of the traditional area substation and the switching station up to eight years resulting in cost savings. The proposed 3G alternative is based on preliminary design, requiring detailed engineering evaluation including load flow, short circuit, reliability, and transmission system impact analysis before implementation.

**Manhattan Case Study**

Significant projected demand growth on the west side of Manhattan will result in the construction of a new transmission substation by 2025 and a new area substation in 2026. These two substations would require a combined investment of over $1 billion.\(^5^9\)

---

\(^5^9\) West Side Switching Station and Hudson Yards
We are currently evaluating the potential to apply 3G methods to these new substations to reduce the overall capital expenditures and still meet the overall capacity and reliability needs of this part of our system. This design includes two transferrable feeder groups to be established between neighboring substations. This approach has the potential to defer the construction of both the traditional area substation and transmission substation up to 3 years.

Figure 4-10 summarizes the timing of specific capital expenditures in the Manhattan and Brooklyn case studies using a virtual 3G substation versus the traditional substation design approach.

![Figure 4-10. Traditional vs. 3G Capital Expenditure](image-url)
Figure 4-11 summarizes the total capital expenditure associated with each approach.

**Figure 4-11. Traditional vs. 3G Designs**

New Substation Capital Expenditures
Traditional vs. 3G Design (2016-2030)

[Bar chart showing capital expenditure for Traditional and 3G designs from 2010 to 2030]
Figure 4-12 summarizes the net impact on capital expenditures by adopting the 3G design approach in lieu of the traditional designs. It results in a deferral of well over $800 million for nearly half a decade.

**Figure 4-12. Annual Change in Capital Expenditure with 3G Substation Design**

Deferred Capital Expenditures from 3G
Negative is reduction or deferral of Capex (2010-2030)
The capital deferrals realized via these 3G designs result in savings to customers. The deferred capital expenditures illustrated in Figure 4-11 and 4-12 lead to a peak average residential customer savings of $1.82 per customer per month in 2025. The savings reduce over time commensurate with the virtual substation concept; when customer demand increases the substation is eventually built to traditional specifications (Figure 4-13).

4.3.2 Reducing Costs and Improving Overall System Performance

Our asset sharing, transferrable feeder group, and virtual substation designs described above are focused on increasing the asset utilization of our system. They are especially targeted at deferring or minimizing the investment requirements of implementing expensive new substations. We are also focused on developing other transmission and distribution applications of 3G designs to reduce the cost and improve the performance of the Con Edison system. Our most recent and advanced applications of these designs include:

- Automatic Primary Switching
- Intelligent Underground Autoloop

Each of these 3G designs is currently in various stages of the development and testing phase. Their implementation should take place, on a case by case basis, during the first ten years of this plan.

Automatic Primary Switching
The Company’s networks are supplied from area substations by radial primary feeders that supply network transformers that convert power from primary voltages (13kV or 27kV) to low voltage (120/208V) as typically used in a home. The installation of automated switches tying these radial feeders together would enable us to switch portions of a feeder to an alternative supply feeder.

The ability to remotely switch sources of supply among various operating primary feeders would introduce a highly valuable level of automation and flexibility to the Con Edison network system. This flexibility would enable numerous benefits, including new temporary or interim load transfer capability and improved sectionalizing and reconfiguration under planned and emergency conditions.

The key new equipment needed to achieve this is a submersible remote switch capable of closing quickly (in hundredths of a second) for the 13kV and 27kV systems. In response to this need, we have researched, specified, designed, developed, and tested a new switch. A pilot application of the automatic primary switch was placed in service in Westchester in 2009.

This automatic primary switching design will be tested throughout 2009-2010 and will be a part of the Long Island City Smart Grid pilot.

**Intelligent Underground Autoloop**

In the Company’s highly reliable underground system, the distribution feeders represent the system’s point of highest vulnerability. Multiple feeder failures increase the risk of an infrequent but potentially large-scale network shutdown event. While feeder restoration times have been reduced to an all-time low as part of our effort to continuously improve operations, we are also testing higher reliability designs on these circuits. One such design is known as the intelligent underground autoloop illustrated in Figure 4-14.

*Figure 4-14. Illustration of Intelligent Underground Autoloop Configuration*
The design has been effectively used in the overhead system. The overhead autoloop system integrates the electric system’s outage detection and protection equipment with automated feeder tie switches, enabling near instantaneous fault isolation and automated switching of feeders and ensuring uninterrupted power supply to the maximum number customers possible. Con Edison has been an industry leader in deploying this technology, which has enabled the Company to sustain an exceptionally high level of reliability in its overhead system.

We have sought to develop an analogous automated 3-way switch to support an equivalent configuration in our underground system. This switch, operating in conjunction with detection and protective devices, could automatically switch among feeder options to ensure supply in the event of planned or unplanned interruption. In response to this need, Con Edison has performed a pilot implementation of this 3G approach at Randall’s Island.

4.4 DESIGN STANDARDS

The Company’s network electric system is most commonly designed to satisfy an “N minus 2” (also denoted N-2 or referred to as second contingency) standard, meaning that at various stages of electric delivery the system is designed to withstand the loss or failure of any two parallel devices. Specifically, at the distribution level we operate 62 second contingency networks; the balance of the Company’s load areas (20) are N-1 or first contingency design. This N-2 standard is generally much more rigorous than the typical electric distribution system design standard, and yields very high reliability. Even as we consistently apply this N-2 design standard to each of our distribution networks and derive excellent day-to-day reliability, the likelihood of a large-scale, prolonged network outage varies from network-to-network. This variation is the result of differences in network characteristics, including relative geographic size, number and type of components, and length and number of feeders within each network.

Con Edison has developed and utilizes sophisticated models to understand the performance behaviors of each of these networks based on their unique characteristics. The key output from these models, the Network Reliability Index (NRI), is a probabilistic measure of risk levels in each of our networks. NRI is defined as the state where four or more feeders supplying power to one local portion of a network experience failure at the same time under standard peak load operating conditions.  

Through the use of NRI, the Company is enhancing its design and planning criteria to ensure that infrastructure investments minimize the level of risk for all networks.

---

Our objective in this area is to apply focused program investment to decrease risk on networks where the investment will have the greatest impact. While all capital investment in our networks has some impact on reducing risk, the investment in three targeted capital programs directly and most significantly reduces the risk of the loss of a network as measured by NRI:

- Removal of PILC
- Installation of sectionalizing switches on network feeders
- Increasing the number of primary distribution feeders serving a network.

While large-scale, prolonged network outages do not occur frequently, such events have tremendous impact on the customers we serve and the region as a whole. Our densely populated urban environment is critically dependent upon reliable service to power public transportation systems, elevators in high rise buildings, hospitals, and major business centers. This dependency makes reducing the risk of such an event a key objective.
Figure 4-15 illustrates the ranked NRI measures of the Company's 62 networks. Of particular note is the annual improvement in total system NRI in each year from 2007 through 2010 and expected improvements based on planned investments through 2015. The planned investments through 2015 were determined by weighing the benefits of reducing the risk of a large-scale, prolonged network outage in our urban service territory versus the cost of implementing the programs. In this specific case, we estimate a 58% improvement across our highest risk networks based on an average annual investment of $38 million from 2010 to 2015.

In the 2015 time-frame, the three NRI programs described above will reach points of diminishing returns. These diminishing returns result from the fact that system constraints will begin to present a limitation, as existing infrastructure (available cubicles at substations, etc.) will no longer be as available. Because the marginal benefits of these existing NRI improvement programs will begin to diminish, the effective lifecycles of these programs will begin to fade.

Consequently, a re-evaluation of our approach in this area will be required in 2016 to carefully weigh risk reduction benefit against the cost, and against new tools, programs, or innovations that may be available. These new tools may include modification or application of demand side management or other advanced methods. We are already starting to evaluate these future options, and will do so on a continual basis.
The Plan is designed to manage the operational, financial, and safety risks as identified and prioritized by Con Edison’s Enterprise Risk Management program. As it is a priority to provide safe, reliable service, our plan initiatives seek to mitigate the risk of a prolonged, large-scale network outage. We consider NRI to primarily be a measure of risk.

In summary, our “N-2” planning criterion served to build a reliable system, but its strict application can result in inconsistent levels of operational risk in different networks. Through the use of NRI, the Company is enhancing its design and planning criteria to ensure that infrastructure investments are targeted in such a way as to have the most significant impact on mitigating risk. As the risk mitigating impacts of existing programs begin to diminish, we plan evolve to new, more impactful programs.

**Long Term Design Changes**

The Company is undergoing an analysis of our long term (20- to 50-year) system design strategy with a special focus on the continued viability and fitness of our secondary networks to sustain their widespread role in the electricity delivery system in metropolitan New York. Maintaining and continuously refurbishing our vast secondary system entails significant ongoing investment commitment for the Company. New electric system and end-use technologies have the potential to require significant changes in how all electric delivery systems are utilized.

The long term system strategy initiative will focus on such topics as:

- Is widespread conversion of our secondary networks to higher distribution voltages desirable, feasible, and cost effective?
- Can the existing infrastructure support significant implementation of distributed generation, distributed electricity storage, or significant new electricity end uses?
- What is the ideal, long term network design to support New York’s energy needs?
- What are the technical and economic barriers to any widespread conversion?

As we progress through this planning cycle, piloting new technologies, designs and systems like 3G and Smart Grid, we will gain greater insight into the feasibility of changing the fundamental design concepts that have supported and guided our infrastructure planning over the last half century. We will evaluate new information and performance of our new projects and programs to adopt the most suitable solutions. We will continue to rely on our strong research and development processes and our partnerships with industry associations and government to optimize the cost, performance, and risk of our infrastructure.

4.5 **RESEARCH AND DEVELOPMENT**

The Company’s effort to implement new system designs frequently relies on innovations in new materials, equipment, and methods. The source of these innovations is widespread, including the Company’s own operations, industry suppliers, other utilities, and various government and university sponsored research. Con Edison’s Research & Development (R&D) department plays a leadership role in integrating these new innovations.
The Company’s R&D department was formed in 1970 and has a distinguished 40-year record of leading Con Edison’s efforts to keep pace with the changing electric utility industry. The R&D department ensures that the Company identifies and sets research and development priorities that will improve service, reduce consumer costs, and minimize the environmental impact of delivering electric power.

Prior to industry restructuring in the late 1990s, the scope of Con Edison’s overall R&D program was wider, incorporating non-transmission and distribution research in generation, emissions control, electric vehicles, and energy efficiency. In the past decade, the Company’s R&D efforts have focused substantially on transmission and distribution related initiatives. Con Edison’s long term vision and goals as well as regional, state, and city plans play an integral role in setting the Company’s overall R&D priorities.

Con Edison’s R&D efforts are commonly conducted in collaboration with other utilities, with industry groups, and other entities. In recent years we have collaborated with:

- Electric Power Research Institute
- U.S. Department of Energy
- New York State Energy Research and Development Authority
- U. S. Department of Homeland Security
- National Electric Energy Testing Research & Application Center
- Smart Grid initiatives

R&D programs are categorized as General R&D Support, Internal and Contractor Research, and Development and Demonstration programs. The Internal and Contractor RD&D program is further segregated into five sub programs:

- Transmission
- Distribution
- Substations and system operations
- Customer operations
- Advanced technologies
Recent Developments

The Company’s R&D initiatives led to specific improvements in how we plan, design, construct, and operate the electric system. For example, stray voltage detection is an important customer and system safety topic and a high priority among the Company’s R&D initiatives. In the past few years we have developed mobile stray voltage detection methods that have vastly improved our detection capabilities. Similarly, in collaboration with the Electric Power Research Institute, we have developed and implemented handheld stray voltage detection tools and methods.

Our asset management and control initiatives (described in detail in Chapter 5) have also been a focus of our R&D efforts. In collaboration with the Electric Power Research Institute, we have implemented a dissolved gas in oil online analysis that has substantially improved our remote monitoring of transformer conditions. Similarly, our underground autoloop switch and fast switch (discussed above) are the result of the Company’s other R&D efforts. Our long term system monitoring and control initiative is a collaboration with multiple partners and will lead to our Secure Interoperable Open Smart Grid Demonstration vision.

Some other recent R&D initiatives include:

- Enhanced 4 kV Grid Substation Monitoring
- 4 kV Grid Power Flow Optimization using Advanced Controllers
- New Commissioning Test for Transmission Feeders Joints
- Reactance to Fault (RTF) Locating Tool
- Major Customer Service Work Management System

4.6 SIGNPOSTS

We have identified two signposts that will trigger the review and adjustment of our design strategies at any point during implementation of this plan. These signposts include:

- **Growth in electricity demand**—3G deployment can occur more rapidly in areas of system expansion or major construction. We will continuously monitor growth in our service territory and adjust implementation plans as necessary.
- **Technology innovation**—Significant breakthroughs in materials, communications, computing, energy storage, and other energy-related technologies could significantly alter the scope and pace of 3G implementation and the wider role and function of the Con Edison network.

4.7 SUMMARY

Due to the many unique characteristics of the Con Edison system, system design will always play a prominent role in our efforts to make continuous improvement in the cost, performance, and risk characteristics of our system. Design requirements need to be re-assessed in light of new analytic techniques that point to the ability to deliver value and reliability for customers. We believe an integrated and tailored approach to system design will lead to solutions that minimize costs while maximizing the performance and risk benefits of new investments.
As noted in Figure 4-1, growing customer demand requires us to expand system capacity. System expansion investments comprise 32% of the total capital expenditures in this twenty year plan. Our updated system expansion planning process focuses on integrating demand and supply side management as well as innovative or 3G designs with traditional capacity expansion investments.

The cost to replace aging equipment on our system is a major source of required capital investment. These costs will point to continual required increases in revenue requirement over an extended horizon in the absence of steps to offset their impact. Such potential measures include regulatory and tax reform, improvements in company operating effectiveness, and changes in the ratemaking process including accelerated depreciation.

To maximize the impact of our R&D efforts, we have focused on identification and development of system design innovations. This focus has led to 3G innovations such as asset sharing, transferrable feeder groups, and virtual substations, all of which will have significant and measurable positive impact on customer rates throughout the life of this plan.

Our integrated and tailored system design approach and innovations support our efforts to sustain high reliability levels. Our tailored design philosophy drives continuous improvement of NRI on our network. While this chapter of the Electric System Long Range Plan focused on our system design initiatives, the next chapter of this report will focus on our asset management and control initiatives.
5.0 IMPROVING ASSET MANAGEMENT & CONTROL

5.1 INTRODUCTION TO ASSET MANAGEMENT

An effective asset management program should provide structure for maintenance and asset replacement activities. Our asset management programs and processes evaluate the performance, cost and risk characteristics of the components that, collectively, make up our electric transmission and distribution system. We use various methods and tools to monitor, analyze, and control our assets to produce our best estimate of optimal performance of our electrical components, asset classes and overall system. The information we capture and analyze provides the basis to evaluate and compare the performance across various components or asset classes to assure that we are targeting our programs properly and therefore optimizing the money we spend on asset maintenance, repair, and replacement.

As we have added more sophisticated monitoring on our components we have been able to continue our progress from time-based maintenance to real-time and condition-based maintenance. By gathering and analyzing data from in-field sensors we are better able to understand performance trends of specific asset classes. Additional monitoring may allow us to alter maintenance cycles, improve the design of specific assets, and predict and prevent component failures.

Our electric system consists of over 1,100 miles of underground transmission cable and 438 miles of overhead transmission lines supported by 1,212 transmission towers. This transmission system supplies power to 38 transmission substations and 61 area distribution substations. The distribution system is composed of 62 underground networks which are supplied by 2,200 primary distribution cable circuits and 26,000 underground transformers. These assets are connected through 450,000 secondary cable mains that make-up the meshed grid. In addition, there are 46,650 transformers in the overhead distribution system, which are mounted on 207,500 poles. These assets, among others, represent billions of dollars of capital investment, and many are starting to reach the end of their expected life.

We expect to spend an average of $710 million per year (in real 2009 dollars) to maintain our existing electric infrastructure and an additional $350 million to add new infrastructure to meet demand growth. As the majority of our annual capital expenditure is dedicated to our existing infrastructure, our optimization of these expenditures for maintenance, repair, and replacement is critically important to meet electricity needs safely, reliability, and cost effectively.

We address examples of the programs discussed above in the various sections that follow. We have organized our discussion by Distribution, Substations and Transmission and will end with a discussion about our Smart Grid project, which pilots the application of the newest monitoring and customer interface technologies.
5.1.1 Background on Categories of Capital Expenditure

More than one-half of the Company’s capital expenditure over the next twenty years will be dedicated to replacing our existing infrastructure (Figure 5-1). This portfolio of investment is consistent with spending at other large U.S. utilities. A sound asset management approach is necessary to optimize our maintain-repair-replace decisions on each of our asset classes.

Figure 5-1. CECONY 20-Year Capital Spending Summary

Expenditures in the ‘Asset Management/Equipment Replacement’ category constitute the replacement of existing equipment and cable either due to failure or after inspection. This investment category accounts for 55-65% of annual capital expenditures in any particular year and 60% of the total 20-year plan. Annual expenditure ranges from $700 million to $800 million. Much of the equipment replacement investment is part of continuing programs that are more fully described in the following subsections of this report.

As we expand our infrastructure and invest $7.4 billion over the next 20 years to meet growing customer energy requirements, we will leverage some of the same efficient practices we employ in managing our existing assets to implement better designs, make better purchase decisions, and better manage our inventory.
Figure 5-2 shows total capital expenditures categorized by stage of delivery as well as our Information Technology and support investments. This functional breakdown is consistent with how we design and implement our asset management programs.

**Figure 5-2. Composition of CECONY’s Capital Investment Plan**

The distribution elements of the plan are categorized as network and overhead. Network expenditures are the costs of repair, maintenance, and replacement in our underground secondary network system. These costs represent the largest portion of our planned investment, proportional to the density and scale of assets in our underground networks. We expect these network expenditures to decline 19% (from $727 million to $592 million) over the plan horizon through implementation of advanced asset management practices and integration of new, innovative designs. Overhead electric system expenditures, which we expect will be fairly constant over the plan horizon, represent the costs of repair, maintenance, and replacement in our overhead system.

The transmission and area substation components of the investment plan are primarily a function of construction patterns coincident with customer demand growth. Area Substation investment levels peak in 2021 and 2027 to account for new substation investments required to handle increases in customer demand in certain networks. Application of innovative 3G designs to six substations are expected to lower substation expenditure for the 20-year period by $659 million as compared to what traditional substation designs would have cost.

The Information Technology, Advanced Metering Infrastructure (AMI), and Federal Stimulus elements are a relatively small portion of the overall plan and vary significantly with the annual funding level of key projects.
The Company’s generation-related investment is a small portion of our total spending. Since the
divestiture of the vast majority of our central generation power plants in the late 1990’s, our
generation-related investment has been a small fraction of total expenditures and remains so throughout the planning period.

In the following pages we discuss major recent initiatives, near-term plans, and the long-term direction of the Company’s approach to managing the assets that comprise our transmission system, area substations, and distribution system.

5.1.2 Overview of Equipment Replacement Strategies

Like virtually all U.S. utilities, we face the challenges of maintaining a very large infrastructure of equipment, cable and structures. The Company’s capital maintenance expenditures replace equipment after failure and programmatically upgrade or replace system components prior to failure or obsolescence.

Figure 5-3 highlights that the Company’s investments related to distribution (e.g., network primary circuits, network transformers, secondary circuits, etc.) represent more than half of total electric equipment replacement expenditure. This proportion of investment is generally consistent with the value of the assets in each category described therein.

Figure 5-3. Equipment Replacement Investment
Primary distribution cable, network transformers, and secondary cable are the largest classes of assets installed in the electric delivery system. In general, the Company’s expenditures for cable and equipment are more consistent year to year than system expansion expenditures. This is because long-term programs have been developed to address the repair, maintenance, and replacement of various asset classes. In contrast, system expansion expenditure is driven by relatively variable local usage patterns and economic conditions.

Over the last few years, efforts have led to improvements in two vital and interrelated areas of analysis: component analysis and electric system analysis. Improved component analysis allows us to now identify potential problems within an asset category such as manufacturing flaws or life cycle fatigue. These problems may pose possible challenges to performance and hence operating risk. Our efforts to improve electric component analysis acknowledge the reality that because the electric system operates as a network of electrical devices (i.e., components) – each with different performance characteristics – system reliability is the product of the performance of each of the components in the system. The Company’s electric system analysis monitors these relationships and performance among components as they are configured in the electric system.

The Company has realized, and will continue to realize, significant benefits from its targeted efforts to identify and implement the best mix of replacements, maintenance, and repair. The types of benefits realized include:

- **Reduction in replacement volume**—Equivalent or improved electric system reliability at a reduced level of replacement investment due to monitoring that can pinpoint small problems so that they are addressed before they become more widespread.

- **Reduction in replacement unit cost**—Reduced unit replacement costs as more replacement events occur according to schedule and prior to failure. Replacement of failed components is generally more expensive as it disrupts planned work, causes overtime labor costs, and typically takes longer to accomplish.

- **Reduction in operations and maintenance cost**—While we expect to realize increases in some operations and maintenance categories due to the broader deployment of monitoring technologies, we expect lower overall maintenance requirements due to the replacement of obsolete components with improved materials and designs.

- **Reduction of system and public safety risks**—Prevention of emergency failures, which have unpredictable consequences.

Improvements to our asset management practices have resulted in better decision-making capabilities and processes. Our practices have been enabled by enhanced monitoring of assets’ condition and improved data collection systems, and advanced decision-analysis and modeling capabilities. We continue to define preferred design standards, data collection and analysis needs, and maintenance practices incorporating the best available industry knowledge and technology.
5.2 DISTRIBUTION ASSET MANAGEMENT

5.2.1 Optimization Strategy

Electric Operations has adopted an improved prioritization process to ensure infrastructure investments and longer-term reliability projects are systematically addressed in capital investment plans. In early 2009, CECONY began detailed analysis of various programs to ensure investment is prioritized to meet system performance needs. This approach results in a quantified cost-benefit analysis to target investment to those programs yielding the greatest projected benefit. These cost-benefit relationships provide an effective means of gauging program effectiveness across investments and at varying levels of investment.

Cost-benefit curves as well as performance targets are used to determine optimal program investment levels. Calculated benefits of a program’s contribution to risk reduction and achievement of strategic objectives are used to prioritize programs and to dictate program investment across programs. Our engineering planning organizations utilize a tiering process to evaluate relative ranking of benefits, to identify and rank programs that yield different levels of benefit for dollars spent, and to determine the extent to which a program should be expanded or contracted.

In support of the 2010 Capital Budget Process, several electric distribution capital reliability programs have been targeted for the development of cost-benefit analyses. These programs total approximately $264 million and represent over 75% of the total 2010 System Relief and Reliability planned expenditures. In addition to representing a significant proportion of the 2010 budget, these programs were selected based on a net benefit index. The net benefit index is comprised of a combination of the Risk Priority Number (RPN) and Corporate Strategic Objectives (CSO). The RPN metrics, supplied through the Enterprise Risk Management committee, and CSO categories provide high level guidelines to assist in the prioritization of programs. For each program these guidelines quantify the program’s relative impact on the likelihood, severity, and controllability of specific system events.

Additionally, an overall portfolio analysis of the electric distribution programs completed under this initiative is currently being undertaken and refined. The results of this analysis, coupled with engineering review and judgment, should quantify the distribution of capital expenditures across targeted programs to ensure that the benefits from capital investments yield the greatest overall benefit for the dollars spent.
Table 5-1 lists the programs currently being evaluated. We discuss a few of these programs in detail as examples to illustrate how they benefit overall system performance, cost, and risk.

Table 5-1. Scope of the Asset Optimization Initiative

<table>
<thead>
<tr>
<th>Program</th>
<th>Status of Cost Benefit Curves</th>
</tr>
</thead>
<tbody>
<tr>
<td>#4, #6 Copper Wire and Self-supporting aerial cable</td>
<td>Complete</td>
</tr>
<tr>
<td>Dissolved Gas in Oil (DGOA)</td>
<td>Complete</td>
</tr>
<tr>
<td>Network Reliability</td>
<td>Complete</td>
</tr>
<tr>
<td>Paper Insulated Lead Covered (PILC) Cable Replacement</td>
<td>Complete</td>
</tr>
<tr>
<td>Pressure Temperature Oil (PTO) Sensors</td>
<td>Complete</td>
</tr>
<tr>
<td>Remote Monitoring System (RMS) 3rd Generation</td>
<td>Complete</td>
</tr>
<tr>
<td>Secondary Open Mains</td>
<td>Complete</td>
</tr>
<tr>
<td>Shunt Reactors</td>
<td>Complete</td>
</tr>
<tr>
<td>Streetlights Service Reliability</td>
<td>Complete</td>
</tr>
<tr>
<td>Underground Sectionalizing Switches</td>
<td>Complete</td>
</tr>
<tr>
<td>Vented Manhole Cover</td>
<td>Complete</td>
</tr>
<tr>
<td>Vented Service Box Cover</td>
<td>Complete</td>
</tr>
</tbody>
</table>

*Optimization Program Examples: Paper-Insulated Lead Covered Cable Replacement and Underground Sectionalizing Switch Installation*

As an example, we compare the effectiveness of two of the programs listed in Table 5-1, Paper-Insulated Lead Covered (PILC) Cable replacement and the installation of underground sectionalizing switches. We have analyzed the cost and performance of each of these programs and produced cost versus benefit curves to facilitate comparison and to determine investment levels across various programs.

The PILC cable replacement program encompasses our ongoing effort to replace sections of primary underground 13kV and 27kV PILC cable. PILC cable is lead jacketed and uses oil-impregnated paper as its insulating medium. We no longer install PILC cable; we are now using Ethylene propylene rubber (EPR) insulated cable. EPR cable is more environmentally friendly since it contains neither oil nor a lead jacket. It also provides higher reliability, due to its superior mechanical and insulating properties.

Our effort to replace PILC cable has been underway for over a decade. It has had the operations benefit of reducing the failure rate of our feeders and therefore the risk of a large-scale, prolonged network outage, especially in high customer usage periods (e.g. hot days). The cost to replace a section of PILC cable, typically several hundred feet long, is approximately $20,000 and provides measurable reliability improvement. These activities have contributed to a declining number of cable failures and their associated outages.
While replacing PILC cable reduces the incidence of feeder failures, many other programs also positively impact feeder and network reliability. One such program is the installation of underground sectionalizing switches at strategic points on our 13kV and 27kV network feeders. Sectionalizing switches are typically installed either very near the area substation on two separate parallel outbound cables, which essentially create two feeders out of one, or by placing a switch midway along the single feeder path, which provides quicker restoration of half of the feeder when a component fails. Both of these approaches help us to restore the feeder to service quickly and therefore reduce the probability of cascading feeder failures and a prolonged, large-scale outage in the network. Installation of a sectionalizing switch costs approximately $200,000 and provides a measurable network reliability benefit.

PILC cable replacement and the installation of underground sectionalizing switches each provide a measurable reliability benefit. Our asset prioritization process measures and compares marginal reliability improvement, using NRI, at various levels of investment. We use this comparison to analyze the incremental benefit and cost of each program and identify the most efficient investment across a mix of reliability programs. Figures 5-4 and 5-5 compare NRI improvements at cumulative investment levels for replacement of PILC cable and installation of underground sectionalizing switches.

Figure 5-4. NRI Improvement from PILC Replacement

![Graph showing NRI Improvement from PILC Replacement](image)
Analysis of these two figures reveals that the same 20% increase in NRI that is achieved from $120 million in PILC cable replacement can be achieved by spending approximately $6 million for underground sectionalizing switch installations. Thus, equivalent NRI improvement can be realized by installing sectionalizing switches at 1/20th of the investment required for PILC cable replacement. Comprehensive analysis across all major programs enables the Company to adjust its reliability programs periodically to ensure the effective investment of capital.

While this analysis would lead one to believe we should only install switches and not replace PILC cable to gain benefits in NRI, the density of our underground system in some areas inhibits our ability to install underground sectionalizing switches on a large scale. Replacing sections of cable typically does not require new infrastructure as it can be installed in the existing conduit. Also, installing switches optimizes capital spend in selected networks, while replacing PILC cable addresses the root problem. Thus, both engineering and construction feasibility must be taken into account when considering individual reliability improvement projects. Therefore, a mix of projects typically yields the best overall reliability benefit.

Cost-benefit curves can also be used to identify the optimal levels of spending within specific component replacement programs. Figure 5-5 shows a “flattening” of the benefit curve, which signals diminishing incremental impact of increased spending on underground sectionalizing switches. This suggests a logical upper limit to the benefits from increased investment.
5.2.2 Management of Major Asset Classes

As noted above, the Company’s asset management initiative is designed to facilitate the optimization of ‘maintain-repair-replace’ decisions among all asset classes and asset-related programs. Asset condition, which is a function of many factors including manufacturer, usage, and age, impacts system performance and risk characteristics. The following subsections of this chapter explain how we incorporate component condition and current performance into our system analyses.

Low Voltage Network Cables

Our secondary cable networks, composed of approximately 70,000 miles of underground low voltage cable, constitute our largest asset class. Our network grids are comprised of almost a half million secondary conductor sections, or “mains”. A secondary main ranges from one hundred to several hundred feet in length. Together, 450,000 of these interconnected mains make up our low voltage network grids. By design, these systems of secondary mains provide excellent reliability to the customers served by our networks. The grids are built to provide multiple paths from the source transformers to the customers through secondary cables. All of the cables in these grids are located underground and housed mainly in concrete conduits which provide a relatively ‘safe’ environment for the bulk of the cable. Due primarily to the protected environment of these cables, the average age of the asset class is just over forty years. The connection points for these cables are housed in manholes, vaults and service boxes. These underground structures may be subject to a harsher environment including water, mud, salt and other materials that wash in from street level.

From these grids we feed millions of service cables that provide electricity directly to homes and buildings, and an additional several hundred thousand smaller service cables that provide electricity to streetlights. A service to a home, building or streetlight is typically no more than one hundred feet.

At an annual expenditure of approximately $150 million, we replace about 7,700 sections of mains each year, which is just over 1% of the total population of mains. Damaged sections are replaced after failure or inspection. The cause for replacement is due mainly to compromised insulation. We replace approximately 4,400 services per year to homes and buildings and 3,800 services to streetlights. This replacement level of services requires approximately $50 million of capital investment annually.

Unlike our network distribution and transmission transformers, and many of our medium and high voltage switches and cables, our low voltage secondary cables are not equipped with monitoring nor communications technology. As such, we rely on our inspection programs and known failures to trigger replacement activities. The overwhelming size of this asset class and its relative inaccessibility underground, present significant challenges to systematically optimize replacement activities.

The redundancy of our secondary low voltage grids, while contributing to the very high reliability of the low voltage networks, makes it difficult to identify failures as they occur. A cable may no longer be carrying power, but the power normally flowing through it automatically reroutes to another section to serve the customer. This hides the presence of low voltage cables that are no longer functioning, and as a result, failed sections can go unnoticed on our system. A breech in insulation, however, does not automatically cause a known problem. The power in the conductor will still flow and serve the customer so long as that cable’s insulation is in a relatively dry environment and not touching another conductor directly or any other metallic or conductive material.
Low voltage cables are located underground, in manholes and in ducts (conduit), making sections of cable difficult to access and expensive to repair. The predominant failure season is during winter snow storms. During these storms, salt is spread to melt the snow and it washes into our underground structures, sometimes reaching the conductors of the cable through damaged insulation. Salt water is very conductive and can cause short circuits. The number of failures during this season is magnified and the access problems normally encountered become exacerbated with the presence of snow and ice. While winter can be a particularly difficult time to address this system, we experience failures, and make replacements, all year round.

The failure of a low voltage cable may cause a localized service interruption or outage. Because there is no monitoring on these cables, when an underground network customer experiences a partial or full service outage, typically the first notification we receive is when they call our customer service representatives to inquire about restoration. While we have developed computer algorithms to give us an early warning for a potentially wider-scale customer outage in our network, for individual outages we rely on the customers call to alert us to the service interruption.

The failure of a low voltage cable may also contribute to public safety hazards like stray voltage or a smoke condition in a manhole that could cause carbon monoxide to migrate to an adjacent dwelling. Public and employee safety is important to us. Recent trends indicate that public safety conditions caused by our secondary cable assets are decreasing due to a number of programs and initiatives we employ.

Even as we add advanced modeling to these systems, we are held back by a lack of monitoring to validate these models and assess real-time conditions. Equipping this system with monitoring has been extremely challenging in the past due to the need for hundreds of thousands of monitors (potentially millions if employed for each customer) that must be able to function in and communicate from an underground environment, and robust computer modeling systems to analyze the data. We have managed our secondary cable system through technology changes in materials and designs, inspections, and a ‘replace after failure’ mode.

To harden our low voltage grids against risk of insulation breakdown, since 2001 we have been installing a low-voltage cable that incorporates dual-layer insulation. This insulation is physically tougher than past materials and provides superior protection against mechanical and environmental damage. It has a fire resistant, low-smoke outer jacket that produces less harmful fumes if the cable is ever involved in a fire. This new cable benefits both reliability and system safety.

To reduce risk from potential smoke conditions, we have replaced all of our solid manhole covers with vented ones so that we recognize these hazards more quickly, mitigate the severity of explosive gasses and keep potentially harmful smoke out of customers’ dwellings. We are moving to a similar program with our smaller service boxes. In addition we seal the ducts that feed a customer’s service point in our structures and in the customer’s premise (on new installations) to prevent carbon monoxide from entering customer dwellings.

To reduce instances of stray voltage emanating from our low voltage cable infrastructure, our research and development department partnered with a technology company to manufacture a mobile stray voltage detector as discussed in chapter four. We now scan our entire underground system once per month and find very low levels of stray voltage (down to one volt). When we find an incidence of stray voltage we eliminate the condition through isolation, replacement, and/or repair. These scans are the best targeting effort we have employed to date on this asset class to find and replace sections with damaged insulation before they become larger issues.
At the end of 2009 we completed the first five year inspection program of underground structures. Through this program, we inspect the condition of every manhole and service box in our network underground system, and as a result of this program and our findings we have replaced a number of low voltage cables, and made completely new connections to existing cables in our structures when needed. Essentially this renews the system in a local area. We are developing a secondary risk model that will assist in ranking our underground structures. This will allow us to migrate away from the five year inspection program that treats each asset equally, and allow us to prioritize our inspection, repair, and replacement efforts on this vast system. The use of a risk model coupled with the advanced technology of the mobile stray voltage detection will optimize our efforts to improve underground secondary performance.

The success of the Company's structure inspection, stray voltage detection, and vented manhole cover replacement programs can be measured by trend in manhole events. Figure 5-6 depicts the decline in annual manhole events of 45% since 2004.

Since this is one of our most cost intensive asset classes and one of the last on our system with little detailed modeling, nor effective real-time monitoring, we set out to explore various options. For the past decade or so, we have been working to develop and deploy secondary models of our network systems. We have been limited by the scarcity of monitoring data and a need for tremendous resources to code the many cables in our network systems into an accurate connected grid in a computer model. However, we are on the verge of deploying effective secondary models that will help us more efficiently plan for our secondary network grid systems.
We currently have a number of research projects underway to identify impending secondary cable failures so they can be repaired before they develop into safety hazards such as stray voltage or manhole events. These projects are developing the technology to recognize the electrical signatures created by defects in secondary cables using sensors installed on primary feeders, in network protector relays on secondary cables. Initial results indicate that these electrical signatures are detectable in advance of cable failures but more work needs to be done to implement a practical system.

In addition, new monitoring and control technologies such as an automated metering infrastructure (AMI) and Smart Grid implementation, discussed later in this chapter, are introducing opportunities to greatly influence how we manage this asset class in the future. Data points at the customer level provided by AMI would give our engineers the information necessary to perform customer demand analysis across our secondary mains and services. It would yield the data necessary to validate our models in real time and provide intelligence on local secondary disturbances signaling timely operational response for repair. As programming and computer technologies improve, data collection and modeling could become so robust that it could be employed operationally to give our operators eyes into the secondary cable grids they have not had before. This access to and understanding of information would lead to a revolution in how we design, reinforce and manage our low voltage cable assets.

We are reviewing the potential to migrate away from asset intensive secondary networks while maintaining comparable levels of reliability for the customer. As a first step in this effort, we are installing “spot networks” for large customers at lower demand thresholds than in the past. A spot network is an electrically isolated high voltage service that feeds directly from the Company’s primary system to a customer. Voltage is then transformed at the customer site to provide low voltage (120/208V or 277/480V).

In addition to reducing the risks associated with secondary cable systems, the implementation of spot networks reduces the reliance on the adjacent secondary network, enabling incremental load growth from other customers without expansion of secondary network capacity.

Over the course of the plan, initiatives such as distributed generation integrated as dispersed supply sources in the network, could result in additional opportunities to migrate away from the secondary low voltage grids.

**Network Transformers**

The secondary network system contains over 26,000 transformers, which are characterized by an average age of 19 years. The transformers are filled with oil for insulation and cooling. The reliability of these transformers is critical to overall network performance, and if a transformer ruptures and fails, it can present a public safety issue.

To improve the performance of our underground network transformer population, we have implemented a remote monitoring system (RMS) and combined it with enhanced routines for monitoring, inspection, and maintenance. Enhanced remote monitoring systems provide information about the health of the transformer and enables preventive replacement before failure.
Our remote monitoring system has been improving for decades. The first generation of this system reported only electric loading and several status or “trouble” indicators. A second generation of technology added voltage monitoring. Over time, the transmitter technology migrated from solid state to microprocessors. Current third-generation measurement technology has the added capability to monitor transformer pressure, temperature, and oil level readings (PTO), and near real-time reporting over existing power lines, enabling online, remote diagnostics. As of December 2009, we had deployed 5,200 PTO transmitters throughout the system. All new transformers are equipped with the latest generation of RMS upon installation. Continued PTO deployment will enable transition from a time-based to a condition-based transformer protocol for managing our transformers.

We analyze all transformer failures that cause a feeder to open automatically at our Distribution Engineering Equipment Analysis Center (DEEAC). In-service failure rates for network transformers have decreased due to an aggressive program of testing our transformers through dissolved-gas-in-oil-analysis (DGOA). We have made further improvements through transformer design changes in the transformer tank precipitated by recent DEEAC findings.

Figure 5-7 portrays multi-year in-service failures for underground network transformers. Failures have decreased 80% since 2005. Reduction in transformer failure rates results in a significant reduction in overall operating and safety risk and improves feeder reliability. Over the course of the plan, as we learn even more about these assets, we will continue to seek ways to employ new technologies and devices to improve the performance of this asset.

Figure 5-7. Underground Network Transformer Failure Trends
**Primary Distribution Cables**

Our primary distribution cables supply power, through over 2,200 feeder circuits, from our Area or Unit Substations to distribution transformers that further reduce the voltage to the level intended to meet the customer’s demand. Our distribution system consists of over 20,000 miles of primary circuits operating at 4kV, 13kV, 27kV or 33kV with an average age of 24 years. The medium voltage cables used on our primary distribution feeders employ a shielded design with either oil impregnated paper (Paper Insulated Lead Covered, PILC, cable), cross-linked Polyethylene (XLP) or Ethylene Propylene Rubber (EPR) insulations. The PILC cable was installed from the 1920s through the mid 1980s with XLP cable installed from 1970 through the early 1990s. The Company, since 1995, has only installed EPR cable on its primary distribution feeders.

The table below shows the three principal primary distribution cable types by insulation class, reported population and failure rate.

<table>
<thead>
<tr>
<th>Cable Type</th>
<th>Population in Miles</th>
<th>Population in Cable Sections</th>
<th>Percent of System</th>
<th>Failure Rate (Failure/Mile of Cable)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PILC</td>
<td>3,300</td>
<td>23,000</td>
<td>16%</td>
<td>0.033</td>
</tr>
<tr>
<td>XLP</td>
<td>7,500</td>
<td>53,000</td>
<td>36%</td>
<td>0.029</td>
</tr>
<tr>
<td>EPR</td>
<td>10,000</td>
<td>71,000</td>
<td>48%</td>
<td>0.012</td>
</tr>
</tbody>
</table>

The 20,000 miles of primary distribution cable is connected through 140,000 medium voltage splices. These splices consist of: lead-sleeve splices that connect PILC cable to PILC cable, solid dielectric splices that connect XLP and EPR cable, and transition or stop-joints that connect XLP/EPR cable to PILC cable. The solid dielectric splices make up almost 80% of the splices used on the primary distribution system and they are the most reliable of all splices.

Figure 5-8 shows the relative failure rate trends of the three types of primary distribution cable and splices. The cables show a very stable performance over time with the EPR cable clearly out performing both the XLP and PILC cables. The chart also demonstrates the superior performance of the solid dielectric splice against the performance of the predominant type of transition, or stop-joint, splice. Maintenance programs have been developed, and implemented, to reduce these transition splice failures.
We currently manage our primary cable assets through a variety of system modeling, preventive maintenance, and cable replacement programs. Each is described below:

- A load-flow program has been developed to model the entire primary and secondary distribution systems. The primary distribution models are used to detect overloaded cable sections and plan for the subsequent feeder reinforcement work.

- We employ a preventative maintenance program on our primary feeder asset class through the use of high-voltage withstand tests (HiPot Test). The test applies high voltage to a de-energized feeder in an attempt to “weed” out components with incipient faults that could fail during the high-load summer period.

- A PILC cable replacement program was implemented in the late 1990s to remove high failure rate components from the primary distribution system. The program targets PILC cable and high failure rate transition splices that have been known to compromise the system during the high-load summer period. We remove, on average, about 1,000 compromised cables, splices and terminations from the system each year before a failure.
Figure 5-9 shows the feeder component failures over the past five years. The data shows that our asset management programs have, in part, resulted in a 41% reduction in primary feeder component failures.

Figure 5-9. Feeder Component Failure Trends
During the next two decades we will improve the performance of our primary distribution cable assets through:

- The development of a more refined network model that will better represent the actual power flows on the primary and secondary distribution systems. A more accurate representation of the load flow will allow us to better assess the need for system reinforcement.

- Refinement of methods to identify “incipient” faults on primary cables so that they can be addressed before they develop into feeder failures. Our work to date shows that primary feeders exhibit short duration events days or weeks before actually failing. We are developing algorithms to allow our substation relays to detect and identify such events to allow us to direct our diagnostic efforts toward those feeders to repair any defects and improve feeder reliability.

- The development of a cable rating program that more accurately models the thermal environment and works directly with the load-flow program. These enhancements will also allow us to better assess the need for system reinforcement.

- An enhanced HiPot indexing model will be developed to better target feeders for Hipot testing. The Company is working with NEETRAC (National Electric Energy Testing, Research and Applications Center) on the enhanced HiPot indexing model.

- Development and implementation of an enhanced PILC cable replacement program to better target program investments.

- Develop better designs for medium and low voltage cables through our work with our principal cable supplier and EPRI (Electric Power Research Institute). We are developing the next generation of cable insulation through “nano” technologies and enhanced material design. The new cable will be smaller in diameter, more flexible and carry a higher thermal rating.

- Continue our work at our state-of-the-art Cable Center of Excellence facility. Among the projects under development are improved diagnostics for our primary feeders including infra-red scanning to identify defective components operating at higher than normal temperatures, partial discharge technology to identify defects in operating primary feeders and splices and arc fault detection technology to identify arcing faults on secondary cables which can contribute to manhole events and customer outages.

**Overhead Distribution System**

Our overhead distribution system is substantial in its own right. It supplies power to 886,000 customers, or approximately 27% of our total customer base. The system, which operates at 4kV, 13kV, 27kV, and 33kV, consists of 206,500 poles, 47,000 pole mounted transformers and 33,700 miles of overhead wires.

Over the plan horizon, we’ll continue to implement capital and maintenance programs needed to maintain reliability, employing the asset optimization process discussed above. Some of the specific programs for the overhead system include:
#4 and #6 Copper Wire and Self-supporting Aerial Cable (SSC) Replacement

The protective outer jacketed layers on some older vintage overhead conductors and the insulation of self-supporting aerial cable are weathered and degraded to a level that has a negative impact on system reliability. The Company has an ongoing program to replace the existing deteriorated #4 and #6 copper wire and self-supporting aerial cable with new conductors, poles and associated hardware installed to the Company’s latest construction standards and specifications. These upgrades will reduce the frequency and duration of customer interruptions. The investments in this program are prioritized through engineering analysis to achieve the greatest reliability improvements.

Wood Pole Inspection and Treatment

The integrity of the 206,500 poles on the overhead system is critical to system performance. Pole inspections are performed to ensure the reliability of installed poles and the safety of the public. As part of the Company’s asset management strategy the majority of the inspected poles (approximately 80%) are subsequently treated in order to preserve the pole’s acceptable working condition and thereby extend pole life. Inspection and treatment involves “sounding” the pole, taking bore samples, internal treatment, and the installation of a wrap around the base of the pole. In addition to these inspection and treatment programs, some poles are restored to full strength and functionality by way of C-Trussing, which reinforces the base of the pole by installing a metal “C” shaped truss along its side. The installation of C-trusses defers the need to replace the pole, resulting in savings. The Company’s multi-faceted pole maintenance program ensures that our investments on this asset class are optimized.

Line Clearance (Tree Trimming) Program

Trees limbs and branches coming in contact with overhead wires represent a critical threat to overhead system reliability, causing approximately 16% of interruptions on the overhead system. In 2007, in an effort to improve reliability, the company developed an enhanced line clearance program encompassing appropriate risk prevention and mitigation strategies. By increasing clearances between tree limbs and the overhead conductors, targeting the work to those feeders most impacted by tree-related interruptions, and addressing unhealthy trees along the utility right-of-way, the program has proven effective. A major component of the program is an aggressive communications strategy focusing on information sharing and customer outreach.

This constantly evolving program has already resulted in significant increases in customer reliability, particularly during adverse weather. Over the course of the 20-year plan, we will continue to adjust the program, leveraging benchmarking efforts and lessons learned to ensure we optimize the impact of this critical program.

Installation of 4kV and 13kV Open Wire Automatic Sectionalizing Switches

The deployment of new, technologically advanced devices over the 20-year planning horizon will allow us to efficiently meet reliability objectives on our overhead system. We plan to install automatic sectionalizing switches throughout the 4kV overhead system. These automatic switches, with microprocessor technologies, provide superior coordination with other protective devices and higher fault interrupting capabilities than earlier vintage switches. They will also reduce service interruptions as they are capable of isolating faulted sections in a more targeted fashion (i.e. providing single-phase isolation of faults as opposed to three-phase isolation of existing switches). Over the next 20-years,
we’ll also implement a program to provide improved fault isolating capabilities on our 13kV autoloops. The installation of additional switches with enhance interrupting capabilities will yield reliability gains similar to those stated above. These automatic switches will be fitted with Supervisory Control and Data Acquisition (SCADA) equipment to remotely monitor and control these devices.

5.3 SUBSTATION ASSET MANAGEMENT

During the past decade, the electric utility industry has been moving from period-based maintenance practices to condition-based maintenance practices. We have been an early and aggressive adopter of condition-based asset maintenance. With regard to our Substation assets, we have focused on the following:

- Substation transformers
- High voltage circuit breakers
- Low voltage circuit breakers
- Capacitor banks

The following subsections of this chapter summarize some of the Company’s recent advances in asset management methods for the largest classes of assets.

Substation Transformers

Substation transformers are used in area substations to transform power from transmission voltages (138 kV and 345kV) to distribution voltages (13kV, 27kV, and 33kV). Our system includes 411 substation transformers with an average age of 29 years. Thirty six percent of these transformers are over 40 years old. Like network distribution transformers, the substation transformers are filled with oil to provide insulation and cooling.
As can be seen in Figure 5-10, for substation transformers there is no discernable rising trend of failure with age. Since age is not a reliable indicator of transformer health, alternate measures must be utilized.

Figure 5-10. Substation Transformer Failure Rates, by Vintage, Since 1990

While most transformer failures have a modest localized cost with no safety implications, they can result in unplanned outages and do have the potential to become major events. Major events occur with low frequency but could result in significant environmental or personnel safety consequences.
Over the past five years, the failure rate of our substation transformer fleet has been about 0.5%, or approximately two failures per year. To prevent their failure, high-risk transformers are identified and either repaired or replaced. Our internally-developed methodology employs an algorithm that considers the transformer condition parameters listed below.

- Transformer manufacturer and other nameplate information
- Dissolved gas in oil history
- Oil quality
- Furan analysis
- Environmental condition (oil leaks)
- Type of load tap changer (LTC)
- Controls and wiring issues
- Operating history
- Maintenance history
- Loading history
- Teardown inspection results from similar transformers
- Availability of spare parts

Each condition parameter is assigned a score, ranging from zero to five, which is then multiplied by a weighting factor that takes into account the importance of each condition parameter in determining the overall health of the transformer. For example, as part of the assessment, we externally inspect each transformer to determine its general condition and identify environmental concerns (oil leaks). A rating of 0-5 is assigned for the environmental condition of each transformer and recorded in a master file.

The algorithm produces a transformer health index on a score that is normalized to 100. Approximately 150 transformers have been evaluated using this program. We will evaluate and prioritize the remainder of our transformers to develop a complete assessment of the health of our transformer fleet.

To further enhance this effort, we have an ongoing research and development collaboration with Electric Power Research Institute (EPRI) to develop a Predictive Reliability and Risk Assessment program for our transformer fleet. The Predictive Reliability and Risk Assessment program will assess transformers and assign individual risk rankings, which can be used for transformer life-cycle asset management. This program will combine transformer health and impact of failure to determine the overall evaluation.

Replacement Philosophy

The decision to replace a transformer is based upon its risk of failure, the potential consequence of failure, economic constraints, and substation construction and maintenance schedules. Before we decide to replace a transformer, we consider the costs and probable outcome of transformer repair.
High Voltage (345 and 138kV) Circuit Breakers

We have 456 high voltage circuit breakers on our transmission system. These circuit breakers provide proper isolation and protection when a fault occurs on a cable. Historically, the maintenance plan for circuit breakers was based primarily on time and to a lesser extent the number of operations of a particular circuit breaker. This was due to the limited ability to economically collect and maintain condition-based data for individual circuit breakers. Recent advances in data collection methodologies as well as newly-developed software analysis tools have enabled us to adopt condition-based circuit breaker maintenance programs.

The move to condition-based maintenance for circuit breakers allows for better allocation of maintenance resources directed at the circuit breakers most in need of attention. There are three different approaches to determine the need for maintenance or replacement of a circuit breaker or class of circuit breakers. The first approach uses in-service monitoring and out-of-service diagnostic tools. The testing (in-service or out-of-service) provides critical data to determine the health of a circuit breaker. The second approach uses a ranking software program developed by EPRI to rank circuit breaker performance. This software uses data from various sources to calculate a health index for each circuit breaker. The data includes maintenance and operation history, past history of similar breakers as well as risk factors such as system position, safety and environmental. The third approach uses data collected during the teardown, overhaul, or inspection of circuit breakers to predict the condition of other circuit breakers of the same type. Together, these three methods allow a team of subject matter experts to determine when a circuit breaker is most likely to need major maintenance to keep it in an acceptable operating condition. When a circuit breaker requires major maintenance it is then evaluated to determine whether the breaker should undergo targeted maintenance to resolve a specific problem, a complete overhaul to return the breaker to a like-new condition, or replacement. The decision to overhaul or replace is based on various factors including cost, future maintenance costs, environmental, safety, and obsolescence.

The annual cost savings estimated from our effort to optimize circuit breaker asset lives is approximately $3 million

Medium Voltage (13, 27 and 33 kV) Circuit Breakers

The CECONY electric distribution system has over 3,200 medium voltage (13kV/27kV/33kV) circuit breakers. These circuit breakers provide proper isolation and protection when a fault occurs on a cable. We recently reviewed our approach to circuit breaker maintenance together with historic performance data to determine if improvements could be made to the scope and frequency for our preventive maintenance activities. As a result of this review, we are implementing several major changes, outlined below:

- The frequency of visits for inspecting vacuum and sulfur-hexafluoride (SF6) medium voltage circuit breakers was extended from six years to ten years.
- The frequency for inspection of circuit breakers installed in conjunction with our metal-enclosed capacitor banks was extended from one year to ten years to align with the requirements for similar feeder breakers.
- The insulation resistance testing of control wiring during circuit breaker preventive maintenance inspections is no longer required. The control circuits are now monitored with ground detection relays, which are more effective.
We will continue to monitor the performance of all medium voltage circuit breakers to affirm these changes positively impact performance. We believe that the changes to medium voltage breaker maintenance activities will result in a total savings of approximately $3.6 million dollars over the life of the ELRP.

**Outdoor (13 and 27 kV) Capacitor Banks**

The CECONY electric distribution system has 132 outdoor 13/27 kV capacitor banks. A recent review of our maintenance procedures and performance data for standard 13/27 kV capacitor banks led to changes to our maintenance and testing cycle. We developed a targeted maintenance program assuring that the frequency of maintenance inspection is closely correlated to the risk of equipment failure.

The annual maintenance plan includes: infrared inspection of the capacitor bank while in service; visual inspection of all fuses, capacitor cans, and cap bank area; and inspection of the protective fencing. These activities were chosen based on a review of past capacitor bank outages. Performing annual inspections that concentrate on the items that most often cause outages is expected to reduce outages. However, some inspections conducted on an annual basis proved to be more cost effective on an elongated cycle of five or ten years based on risk profiles.

These changes to our capacitor bank maintenance routine should result in total savings of approximately $4.6 million over the planning horizon. Going forward the performance of the capacitor banks will be monitored to confirm that the new targeted maintenance keeps the capacitor banks in an acceptable condition. If required the maintenance plan will be altered based on the results.

### 5.4 TRANSMISSION ASSET MANAGEMENT

Con Edison’s transmission infrastructure consists of conductors that carry transmission voltage from generating sources or transmission lines to substations. Con Edison owns or jointly owns 438 circuit miles of overhead lines operating at 138, 230, 345 and 500 kV. The Company’s overhead transmission system is comprised of 1,212 towers that support “open-wire” type conductors.

We also operate the largest underground transmission system in the United States: 727 circuit miles of underground cable operating at 69, 138 and 345 kV. The Company’s underground transmission feeders are either oil or solid-dielectric insulated. Oil-insulated cables are typically installed in steel pipes, whereas solid dielectric cables are typically installed in fiberglass reinforced epoxy conduit banks housed in concrete.

Our pipe-type transmission system was one of the first of its kind and today it is one of the oldest and largest in the world. Despite its age, system performance is exemplary. Only 55 electrical cable failures have been experienced since 1955. Furthermore, the rate of failure has generally not increased with cables’ age, as evidenced by Figure 5-11.

Figure 5-11. Cable Failure Trends Since 1955

Transmission Dielectric System Leaks

The system’s steel pipes which house the transmission feeders are an important focus of our asset management activities, as they are essential in the reliability of the system. Several programs have been implemented to protect these pipes from corrosion or other damage, including:

- A state-of-the-art cathodic protection system
- A system of drain-bonds for mitigation of DC stray current from subways
- A program to refurbish pipes within manholes that cannot be protected cathodically
- A coating refurbishment program to address areas of coating disbondment
- An active participation in a program to minimize contractor damage (code 753)

As a result of these efforts, these pipes are expected to continue to provide reliable service as part of the underground electric transmission system. In addition, we are developing plans to re-use these pipes as conduits for future solid dielectric cable installations.
When leaks do occur, we employ a sophisticated leak detection system with the ability to detect leaks at rates of one gallon per hour. The online leak detection system continuously performs a dynamic mass balance everywhere along the cable system. Leak detection is accomplished when there is a deficit between the predicted fluid entering the cable system and the corresponding measured quantity.

**Dynamic Feeder Ratings of Transmission Feeders**

The current-carrying capacity of transmission feeders, or feeder rating, is determined based upon a number of factors, including conductor size and the temperature and moisture of the earth surrounding the feeder. Traditionally, earth temperature and moisture data used in the rating process were taken as constants. Dynamic Feeder Rating (DFR) Systems use real time data to improve the accuracy of these ratings. For example, the temperature of the earth varies throughout the year, peaking in the late summer. By measuring and analyzing data on a real time basis, more accurate and often increased ratings are determined, providing operators with actionable data to manage the system.

Through the use of real-time data and analytical modeling, DFR Systems allow us to maximize asset utilization. Over the course of the plan, we intend to implement similar initiatives to leverage information through monitoring and control.

**Solid Dielectric Cables**

Con Edison will continue to expand the use of solid dielectric cables to install new transmission facilities or when replacing existing transmission feeders. Although oil filled pipe-type cable and solid dielectric cables have comparable installation costs, solid dielectric cables are preferred whenever possible because they offer two distinct advantages over high pressure pipe type cables.

First, they eliminate the environmental issues associated with oil leaks from pipe-type cables. In addition, they require less maintenance than do pipe-type cables because they don’t require associated systems such as pressurizing, circulating and cooling plants, pressure alarms, motor operated valves, and cathodic protection systems.

In addition, solid dielectric cables are generally easier to install and repair because they do not require the extensive pressurization procedures that are necessary before oil filled systems can be placed in or be restored to service.

To further increase the use of these cables, Con Edison is undertaking a research project to evaluate the feasibility of re-using not only existing piping as conduits for new solid dielectric cables but existing manholes to house their new splices. There are various technical challenges associated with this project having to do with the expansion and contraction of these cables as their load cycles. Resolving these issues will greatly reduce costs, most of which is presently associated with trenching, duct and manhole installation.
5.5 ENHANCING MONITORING AND CONTROL OF THE GRID

5.5.1 Electric System Modeling, Monitoring, and Control

A fundamental characteristic of electric transmission and distribution systems is that they deliver electric power through a network of mutually interdependent transmission and distribution components or assets. Consequently, and especially because of the sheer size of these systems, the Company’s electric system replacement and maintenance strategies as outlined above must embody more than merely a component focus; rather, they must be based on how these electric system components operate in concert with one another.

Consequently, the Company has a number of initiatives that are related to improving how we model, monitor, and control our electric system. These initiatives are designed to reduce operating costs, minimize (or optimize) investment requirements, maintain system reliability, improve safety, and reduce risks.

At the transmission, sub-transmission, substation, and primary distribution stages of delivery the Company has detailed, real-time operating and long-term system planning models. Although these resources are subject to continuous innovation, our current priority has been on improving our modeling capabilities related to the Company’s 62 low voltage networks. In 2008 the Company began an initiative to improve secondary network modeling by utilizing existing company modeling programs, map records, and telemetry along with new data validation methods to simulate load flows across the low voltage cables of secondary network grids. This more accurate secondary modeling will help us to understand the needs of our low voltage networks, will improve primary and transformer load modeling, and enable better prioritization of our asset-related activities on the Company’s secondary networks. This modeling will also be enhanced by leveraging customer use information available from the Company’s future advanced metering infrastructure (AMI) initiative which will provide detailed data at the customer level.

This enhanced secondary modeling, as it is implemented in the next several years, has the potential to:

- Prioritize and reduce investment requirements in the secondary network so that the investment resources are targeted at the most critical secondary system replacement needs,
- Reduce the unit costs of some of our repair and replacement activities by performing more of them under normal, rather than emergency (and thus potentially more costly), conditions,
- Lower the overall risk in the system by improved modeling of real-time operations.

The effectiveness of our modeling capabilities are closely related to the quality and accuracy of the data and information we have about how the electric system actually performs under a variety of loading conditions. Consequently, we are making continuous efforts to develop and implement cost-effective system monitoring to improve this information base. For example, all of the Company’s network transformers are monitored for loading and some are equipped to monitor oil pressure, voltage, and temperature conditions. While these monitoring resources play a key role in our real-time system operation and maintenance procedures, they also have an important role in supporting and improving our system modeling.
In the long run, the Company’s AMI initiatives are expected to provide an expansive new level of system monitoring and performance data to improve the quality and accuracy of the Company’s modeling and support efforts to further realize the benefits outlined above. The AMI initiative will be the first time near or real-time customer-level loading data will be available to support our network models.

5.5.2 AMI and Smart Grid

In an effort to begin evaluation of the Smart Grid concept, the Company is developing network- and customer-focused pilot implementations of various Smart Grid technologies. The Company’s Long Island City (LIC) Pilot, which was announced in July 2009, is the Company’s most comprehensive effort yet. The LIC pilot incorporates completely wireless data collection and control technologies and includes:

- Installation of approximately 1,500 AMI meters\(^{61}\) at customer premises. Smart meters provide real-time voltage monitoring, remote turn-on/turn-off capability, power quality/power harmonics monitoring
- Home Area Networks (HAN) at 200-300 customer locations
- Interaction with a customer-owned solar application at a local university
- Remote controlled feeder switches on two underground feeders that enable remote reconfiguration of the LIC network
- Transformer and network protection monitoring
- Evaluate the integration of multiple distributed generation (DG) applications

\(^{61}\) Includes gas meters
Figure 5-12 illustrates the key elements of the Company’s Smart Grid implementation.

**Figure 5-12. Elements of a Smart Grid**

### Smart Grid
Smart Grid puts information and communication technology into electricity generation, delivery, and consumption, making systems cleaner, safer, and more reliable and efficient.

- **Smart Building Technology** including web portals and in-home displays will eventually allow customers to track their energy use and give them the tools to change their energy-using habits, including the ability to remotely control appliances.
- **Intelligent Underground Systems** use sophisticated communication technology to monitor, isolate, and correct problems and improve reliability.
- **Greener Energy Sources** are more readily integrated into the smart distribution grid.
- **Plug-In Electric Cars** can connect to the grid to charge and one day may even provide power from their battery packs when the cars are not in use.
- **Smart Motors** gather information about customers’ energy use so customers can use electricity more efficiently, and the meters may enable the utility to identify system problems.
- **Customer Energy Generators** enhance system reliability.

The Company anticipates the following benefits from the LIC Smart Grid initiative, including:

- Proof of concept for new wireless monitoring and control technologies
- New data collection opportunities on distributed supply and customer demand patterns
- Secondary model validation from the increased demand and power flow data
- Expanded system monitoring
- Further implementation of 3G applications
- Increased ability to support the interconnection to new renewable power supplies

### 5.5.3 Stimulus Grants

**Investment Grants**

The Company filed grant applications for stimulus funding in June 2009 with the U.S. Department of Energy. Our Smart Grid Stimulus Award was approved and announced on October 25, 2009. Grant funding includes distribution initiatives led by Con Edison and transmission initiatives led by NYISO.
Table 5-3 summarizes the specific scope and value of the Smart Grid project.

**Table 5-3. Elements of CECONY’s Smart Grid Project**

<table>
<thead>
<tr>
<th>Application Focus</th>
<th>Project Components</th>
<th>Total Cost</th>
<th>DOE Funding Requested</th>
</tr>
</thead>
<tbody>
<tr>
<td>Distribution</td>
<td>Dynamic Modeling &amp; Visualization</td>
<td>$19.0</td>
<td>$9.5</td>
</tr>
<tr>
<td></td>
<td>UG Sectionalizing Switches</td>
<td>$40.0</td>
<td>$20.0</td>
</tr>
<tr>
<td></td>
<td>4 kV Grid Modernization</td>
<td>$21.0</td>
<td>$10.5</td>
</tr>
<tr>
<td></td>
<td>OH Sectionalizing Switches</td>
<td>$45.8</td>
<td>$22.9</td>
</tr>
<tr>
<td></td>
<td>Remote Monitoring System</td>
<td>$47.5</td>
<td>$23.8</td>
</tr>
<tr>
<td></td>
<td>High Tension Monitoring</td>
<td>$2.0</td>
<td>$1.0</td>
</tr>
<tr>
<td></td>
<td>UG Automatic Loop</td>
<td>$71.6</td>
<td>$35.8</td>
</tr>
<tr>
<td></td>
<td>DG Interconnection</td>
<td>$4.0</td>
<td>$2.0</td>
</tr>
<tr>
<td></td>
<td><strong>Sub-Total</strong></td>
<td><strong>$250.9</strong></td>
<td><strong>$125.4</strong></td>
</tr>
<tr>
<td>Transmission</td>
<td>CECONY Phasors</td>
<td>$5.2</td>
<td>$2.6</td>
</tr>
</tbody>
</table>

The project includes Distribution Automation, Dynamic Modeling and Simulation, and Energy Efficiency initiatives which address Con Edison’s ongoing challenges of maintaining reliability of service and satisfying the increasing demand on resources. By implementing advanced system capabilities like rapid restoration and grid reconfiguration, achieving efficient delivery through system losses reduction, enhancing data visualization, and integrating smart grid technologies, the project attains new capabilities for the Company’s electric system and its customers.

Distribution Automation component includes strategic programs that put Con Edison’s electric distribution system on the road to the future. The programs include:

- Installing intelligent SCADA-controlled sectionalizing switches
- Expanding secure monitoring and communication systems
- Implementing advanced computational intelligence for automated system restoration; and
- Establishing a distribution smart grid

Dynamic Modeling and Simulation component integrates data from diverse systems to generate predict and visualize information on the secondary grid through dynamic modeling and developing a distribution simulator. This will enable interoperability, enhanced visualization of information and automation.
The System Efficiency component accommodates distributed generation, increases energy efficiency and reduces system losses. The major project objectives are:

- Expand distribution automation to advance self-healing grid operations
- Provide greater visibility and expand automation and control of one of the world’s most complex distribution systems
- Establish cyber-secure and scalable communication platforms
- Augment decision support systems with sensor feedback to provide improvements to the predictive models that identify, isolate and rectify system vulnerabilities
- Expand monitoring and control elements necessary to adapt to dynamic conditions of the service area
- Provide for future renewable energy capabilities in the service area

**Secure Interoperable Open Smart Grid Demonstration Project**

We anticipate that the continual evolution of information and telecommunication technologies will reduce the overall cost and improve the performance of our electric system. Our long-term objective is to develop a smarter grid that will capture the full benefits of improved and additional monitoring, modeling and control. The long-term end state is to completely implement our Secure Interoperable Open Smart Grid Demonstration Project initiative. This initiative will consolidate CECONY’s Smart Grid initiatives under a single, integrated master information system and control technology:

Some of the long-term objectives of the Secure Interoperable Open Smart Grid Demonstration Project are to:

- Manage and adapt to new distributed generation supplies such as solar and EV recharging
- Control distributed energy storage (when it is available)
- Minimize or eliminate load pockets and circulating currents
- Migrate to preventive maintenance as enabled by improved data and information systems
- Maintain cyber security over T&D network operations and energy usage

We will leverage the American Recovery and Reinvestment Act (ARRA) Smart Grid funding as practical and admissible to support the Secure Interoperable Open Smart Grid Demonstration Project. We will be receiving an additional $45 million in funding and working with 12 companies in industries including manufacturing, utilities and higher education.
Figure 5-13 introduces our three phase approach to Smart Grid.

**Figure 5-13. Smart Grid Implementation Plan**

- **Phase I: 1-5 Years**
  - Develop and evaluate monitoring, control, modeling, and visualization technologies
  - Establish widespread system control and automation under AMI and the Secure Interoperable Open Smart Grid Demonstration Project

- **Phase II: 5-10 years**
  - Integrate innovative technologies to enhance end use and minimize T&D investments

- **Phase III: 10-20 Years**

Phase I of this effort consists of a series of key technology ‘proof of concept’ implementations, including:

- Advanced secondary remote monitoring supported by AMI
- Distribution primary automation and control
- 3G /asset sharing applications
- Advanced Metering Infrastructure
- Home/building automation for all classes of customers
- Integration of distributed generation (DG) technologies
- Comprehensive secondary modeling, analysis, and visualization

Phase II of the Company’s Smart Grid Strategy will build on the results of Phase I and incorporates widespread implementation of Smart Grid technologies, including:

- Secondary monitoring and control
- Distributed Generation
- Advanced Metering Infrastructure
- Emerging materials and energy storage technologies
- Home and building automation to improve efficiency and control
- Integrated control

Phase III of the Company’s Smart Grid Strategy will build on the results of Phase II and may include:

- Implementation of new materials and storage technologies, including high temperature super conductors and batteries
- Enablement and promotion of new end-use technologies (PHEVs, EVs).
5.6 SUMMARY

Approximately 60% of the total ELRP capital expenditure is allocated to the Company’s asset management and equipment replacement. Therefore, developing the optimal approach to management of component maintenance, repair, and replacement decisions is critically important to the Company and its customers. An additional 31% of capital investment, for system build out to meet customer demand, can also be impacted via better system design to optimize asset utilization.

Our asset management initiatives encompass all asset classes involved in every stage of delivery. Over the life of this plan, they will produce about $1.9 billion in avoided capital expenditures by identifying optimal maintenance cycles, determining replacement strategies, and analyzing the system performance, cost, and risk trade-offs.

Enhanced monitoring and control will produce long-term improvements in system performance and lower costs. Increasingly granular asset health and performance information will ultimately enable us to optimize future system investment. We are actively pursuing a variety of Smart Grid pilot initiatives to improve the monitoring and control of our system. Should we see promising results from these pilots we will explore opportunities for extending Smart Grid applications throughout our service territory.
5.7 SIGNPOSTS

Our asset management initiatives are actively managed in all areas of the Company and they are continuously monitored, analyzed, and improved to ensure their effectiveness. While the effectiveness of individual programs is continuously monitored, our overall asset management strategy and approach will also be monitored and evaluated and adapted as needed. Some of the signposts that we will monitor (some internal and some external) to make our assessment of the overall asset management strategy will include:

- **Realized Efficiency**—Our overall goal is to minimize total system investment while sustaining our world-class reliability performance and minimizing system risk. While we may not observe that our total system replacement/reinvestment spending levels decline in nominal terms, we do expect to see continuous improvement in the relative efficiency of our investments (e.g. nominal improvement in NRI per dollar investment) as we continuously improve our investment targeting strategies.

- **Realized NRI**—Our asset management initiatives are highly focused on sustaining reliability and reducing risk at minimal practical cost. We have seen and continue to expect that the network-level and system-wide NRI will improve and this improvement should be directly attributable to specific decisions made from asset management processes. We also believe that the accuracy of forecasted NRI and actual results will improve over time.

- **Asset Management Strategies and Resulting Performance**—Our asset management strategies will optimize our repair-maintain-replace decisions as a result of more selective component replacement and improved condition-based maintenance actions. We will actively monitor and assess the effects of our decisions to ensure that performance objectives are met.

- **Regulatory Approval**—Some of our replacement, inspection and maintenance practices and policies are subject to regulatory approval or directed by regulatory mandates. We will actively monitor these requirements and adapt our strategies and plans accordingly.

- **Availability of External Funding Sources**—The national and regional energy industry is the focus of substantial government attention and, more recently, active investment incentives and government funding. Several of our major monitoring and control and renewable portfolio-related investments are dependent on these external incentives and funding and we will monitor these initiatives to seek to maximize the benefits achievable.
6.0 ENHANCING CUSTOMER EXPERIENCE

6.1 OVERVIEW

Over the next twenty years, customers are expected to change how they use electricity, and consequently may require different types of customer service. Technological innovation will continue to drive the creation of new products, such as electric vehicles (EVs), which rely more heavily on electricity. Increased usage is expected to offset increased efficiency, supporting the view that over time the value of electric service for customers will also grow. Innovation and technology will likely greatly change how much, where, and when our customers consume energy. To facilitate these changes in the patterns of consumer usage, we will require the support of enhanced infrastructure and billing systems.

Customers generally expect that we will no longer be just providers of electricity and that they will no longer be just consumers. They want an interactive relationship whereby information will flow both ways and usage will depend on price, time of day, and local system characteristics. The greater integration of “smart” appliances, that help customers manage energy consumption based on pre-programmed schedules and responses to real-time price signals, will help create a closer, more interactive relationship between our customers and us. Another component of our changing relationship may be that some customers may choose to become suppliers to the grid by leveraging distributed generation (DG), which may become cost effective for an increasing number of customers over this time period.

We view the rapidly changing environment as a call to action to ensure that we are prepared to put systems in place to meet the operational challenges ahead. We know customers do not seek or want rate increases, and they will not accept them, unless there is an underlying premise that the value proposition increases or remains intact. The Company needs to exercise care that it is spending money wisely, and that it is neither falling too far behind, nor getting too far ahead of what customers genuinely see as reasonable and appropriate service enhancements. This is a difficult balance for the Company to achieve given the diversity of its customer base. Nevertheless, it is one that the Company must successfully accomplish. This plan defines our roadmap to get there by focusing our efforts on five plan objectives, re-stated below:

- Managing Demand, Supply and Environmental Profile
- Integrating Innovative System Design
- Improving Asset Management and Control
- Enhancing Customer Experience
- Improving Processes and Skills

Our customers’ needs are a critical factor in the design of our systems and the training of our people. We performed research to better understand our customers’ perspectives on service, reliability, and the cost of energy. The results of our research are described in section 6.2. In section 6.3 we present our strategy and investment plans to enhance organizations that work directly with customers to make sure we live up to their expectations. We conclude this chapter with a projection of the customer bill in 2030, reflecting these customer initiatives and all preceding infrastructure programs discussed in this plan.
6.2 CUSTOMER PERSPECTIVES

The energy we provide affects the lives of our customers every day. So, we expect that our customers will look to us to address their concerns about their energy needs. We already have numerous customer interactions and we expect an even broader range of topics in the future. Some examples are noted below:

- Participation in energy efficiency or demand response programs
- Energy conservation advice
- Interconnection of distributed generation
- Power quality reporting and inquiries
- Bill and credit payment and inquiries
- Outage notification and restoration inquiries
- New service or service upgrade requests
- Special services regarding elderly, blind, disabled, direct debit, electronic billing, voluntary time of use
- Community and government stakeholder issues

We receive feedback from customers and other members of the public, community-based organizations, and public officials throughout the year in various forums. Our customer service representatives handle close to 7 million calls every year. Our public affairs staff interacts with homeowners, renters, small business owners, and community leaders at over 100 events, including community and employer events, environmental fairs and senior events. We conduct two conferences for community-based and social service organizations and we interact with countless numbers of elected officials and community boards. We participate in JD Power surveys of residential and business customers for electric and gas utilities. In addition, we conduct surveys on customer satisfaction, as well as on our own information and education programs to identify their effectiveness. We actively use the feedback we receive from each of these areas about customer concerns, information requirements, and expectations. We also utilize professional facilitators to conduct focus groups related to key topics such as bill design, reliability, and affordability.

6.2.1 Objectives

Success in defining and executing this plan is dependent on a strong partnership with our customers. Gathering feedback on key issues directly from our customers allowed us to build on our daily interactions with them and better understand customers’ energy needs and priorities around a few key issues.

What we learned helped refine the five objectives of this plan and confirmed our belief that customers value reliability, prefer that we are proactive with our investment programs rather than reactive, and understand that there is a cost associated with maintaining a system as reliable as ours.
6.2.2 Approach to Research for the Electric System Long Range Plan

We conducted qualitative research with three groups of customers:

- Residential customers (both homeowners and renters)
- Small business customers
- Large business customers

For residential customers, we conducted focus groups in New York City, including participants from all boroughs, across a range of ages and incomes; and in Westchester County, similarly diverse.

For small business customers, we likewise conducted focus groups in New York City and Westchester County, in both cases including a very diverse set of business categories and business sizes.

For large business customers, we conducted a series of telephone interviews with top executives and managers at some of our largest accounts.

In these focus groups and interviews, we sought input on a range of issues including the:

- Value of reliability
- Perceptions of our current infrastructure and future electricity needs
- Support for infrastructure projects and the investments associated with them
- Perception of the size of electric bills relative to other monthly expenses
- Understanding of the delivery, tax, and supply components of the bill
- Interest in energy conservation and efficiency
- Interest in future technology, such as Smart Grid and electric vehicles

6.2.3 Outreach Results

The input from our customers helped us refine our plan. The research provided valuable insight on how customers view the nature of “affordable electric service”.

A summary of the comments we received from the residential and small commercial customers who participated in our focus groups follows:62

- On reliability and infrastructure investment:
  Everything in our lives depends on electricity – it is not a luxury but a necessity
  Reliability is the single most important issue. The bar is set high for reliability, and Con Edison normally delivers it
  Customers do not usually think about reliability – unless the power goes out
  The participants were willing to pay more for upgraded infrastructure to keep up reliability. They felt it is much better to undertake improvements proactively, rather than suffer power disruptions
  The participants expressed how important it is that Con Edison clearly explains what its plans are in a way that they can understand. They want to see how these plans would connect with the reliability they need

- On energy usage and conservation:
  Most participants thought they would use more electrical devices, even more efficient ones, and consume even more power in the future
  Many participants have already taken steps to conserve energy – most notably, the installation of low energy light bulbs, and shutting off electric lights and appliances at night
  Most participants like the idea of energy efficient appliances, but will not buy new ones until their current appliances need to be replaced
  There is a limit to conservation, especially at home, since people do not want to cut back on comfort and convenience

- On the future:
  While participants acknowledged that smart grid looked ‘hi-tech’ and ‘neat’ and liked that it could give them more control over their usage and bill, there was some skepticism over how much it would cost
  Participants anticipated owning electric vehicles in the future, but weren’t sure when, and at least one participant said he would like to see those charges separately

- On the bill:
  They do not know how to predict their bills, and even when they try to reduce their consumption, it has only a minimal impact
  They do not understand the concept of a ‘pass-through’ on the energy supply charge
  For most participants the size of their bill was in the mid- to low-range of monthly expenses
  The participants felt an increase of 5% is reasonable. Customers consider the whole bill, not just the delivery portion when they express acceptance of bill increases
  The participants expressed that taxes and fees are much too high. When compared to the tax charged on goods bought at stores, it seems they pay a much higher rate on their energy service

A summary of the comments we received from the interviews conducted with large commercial customers follows:

- Reliable power is the bottom line
- The consensus was that energy usage would continue to increase, despite efficiency programs and new more efficient equipment and devices
- Every customer we interviewed is already engaged in some form of energy management and looking for ways to reduce, or at least stabilize electric consumption
- Because of the increasing demand for power that most of these customers anticipated in the years ahead, they wanted the needs of the system to be addressed proactively, even if it meant slightly higher rates
- Although the electric infrastructure was adequate for today, the range of tasks and equipment requiring electric power in the future would continue to increase, and the system and system capacity would need to continue to increase to meet future needs
- None of them saw getting off the grid as a realistic or desirable option in the foreseeable future
- Although there is interest in distributed renewable resources, solar, in particular was hard to implement in older buildings in a highly built-up urban environment.

The feedback we received reinforced and helped refine the objectives of our plan, as discussed below.

**Managing Demand, Supply, and Environmental Profile**

Many of the residential and small business customers we spoke with are experimenting with energy conservation and efficiency themselves (e.g., installing efficient light bulbs). Most large commercial customers have sophisticated efficiency and demand response programs well underway – many use interval metering, others distributed generation. One said, “I’ve been looking at the numbers pretty closely. We are very proactive in making changes and moving to much more efficient energy everything.” Another said, “We do try to modify our usage.” A third said, “I saw a difference in the bill when we started shutting off everything at night two years ago – maybe 20%.”

Nevertheless, the consensus was that energy demand will continue to increase. Although there is interest in renewable energy (e.g., rooftop solar) and electric vehicles, our customers recognize the practical difficulties of cost, and the physical constraints of implementing new technologies and equipment in existing, already built-up dense urban areas.

When discussing efforts to reduce environmental impact, customers say they are consciously looking for opportunities but that they need to be cost effective. One large commercial customer had a “greening department” responsible for managing their environmental impact and energy efficiency measures. Another said, “We’d really have to consider cost a major issue before we’d look at renewable, unless we had funding that would help to compensate for it.”

The initiatives we described in our plan to manage our demand, supply, and environmental profile fall in line with the philosophy voiced by the participants in our research effort. We are seeking to lower our costs in the long run by reducing the overall system demand and by managing the load shape through energy efficiency, demand-shaping initiatives, and advanced metering.
Integrating Innovative System Design and Improving Asset Management and Control

These two objectives focus on various methods of improving the cost effectiveness of our transmission and distribution infrastructure, while maintaining our industry-leading levels of reliability.

As to the importance of reliability, one large commercial customer said, "In this day and age, we’re so totally dependent on electric power, that reliability is critical." A small business customer said, "It’s not a luxury, it’s a necessity." A residential customer said that when the power goes out, "My life stops. Everything, it just stops."

For all three types of customers, reliability is definitely the single most important issue, and generally, they feel we deliver it. A residential customer called us "very reliable." A small business customer expressed his satisfaction saying "If things are going wrong, they get on the problems, which is good."

Customers understand the important role of Con Edison in their lives. Most customers we spoke to felt that it is much better for us to build infrastructure proactively, than to risk power disruptions. The most important thing, they said, is for us to explain clearly what our plans are, and how these plans connect with reliability. One said, "I wouldn’t mind paying a premium if the stuff is done in the most efficient way as possible – or if it doesn’t get wasted." Another said, "I don’t….want to just pay [Con Edison] more money without a promise they know how to spend it." Another said, "Show the customers respect and let us know what you’re going to do with the money." A fourth said, "I would like to see their 5 or 10-year plan."

None of the large commercial customers saw getting off the Con Edison grid as a realistic or desirable option in the foreseeable future – and residential/small commercial customers do not even think about it.

Our plan initiatives to meet customers’ demand for electricity, leverage less asset-intensive designs, expand asset management practices, and increase automation and control of the grid all work toward the objective of maintaining and expanding our infrastructure to provide the highest level of reliability at a reasonable cost.

Enhancing the Customer Experience

Most customers are interested in having more visibility into, and control over, their electricity usage. They would like to be able to know what behavior has an effect on their bill, and to be able to predict and control it. One said, "If people could understand exactly…at this time of day, you’re using this much energy. Then you have a graph, a visual that could tell you, okay, now I know where I need to cut it down so it would actually be lower."

Across all three customer types, many of them have heard of the smart grid, and in general have modestly positive reactions. One said, "We’re very excited about the shift to smart meters." Some, especially large commercial customers, understand that it can put them in control of their energy usage, but most are not as clear on how exactly they will use them. However, one residential customer said, "Now I’m in the loop. You feel like you have some sort of control over what you’re using." In spite of this, some customers are skeptical of the costs associated with this new technology. One said, "I have a question. How much is this going to cost me?"
This is in line with our use of pilots to test new technologies before implementing them system-wide. In doing so, we will be able to gauge the customer interaction in systems like smart grid, and understand the trade-offs between cost and performance for these systems.

Our planned customer initiatives to expand energy efficiency and demand response programs, expand time-based pricing, and pilot various smart grid applications will support customers’ expressed desire for greater visibility and control over their energy usage.

**Improving Processes and Skills**

The research provided information on how we can improve our processes, most notably on how we communicate our priorities, objectives, and plans to our customers. In addition to the many outreach efforts we already conduct, this Electric System Long Range Plan will help us communicate better. Although the research conducted did not address employee skills directly, as customers change electricity usage patterns they will also require more and different products and services, and we will have to train our employees to provide these services. For example, to support Smart Grid applications such as home energy displays, we will have to develop new skill sets.

**Important Commentary on Affordability**

The participants in our focus groups felt that for the most part their bill is fair. Some were concerned about the supply and tax components. Despite efficiency efforts, some residential customers did not feel they can do much to control their bills. Naturally, every customer would like to see their bills decrease, but there was widespread understanding that the electric system needs continuous investment to provide reliable service.

When presented a graphic representation of the components of the bill: delivery, supply, and taxes and fees, customers stated that, in general, the taxes and fees included in the bill are too high. One said, “I don’t know why I have to be taxed on that. When you go to the store and you pay a sales tax, you’re at 8.25%; this is more than four times that”; and, interestingly, many residential/small commercial customers were skeptical that Con Edison passes through the energy supply charge with no added margin. One small commercial customer said, “They are not charging anything on what they pass on to you? I don’t believe it.”

There were a few customers that expressed that rates should not go up. One residential customer said, “I think we are paying a lot more than we all paid 5-10 years ago...You want to give us another increase. That is not acceptable...It should go down.” A large commercial customer said, “I don’t feel comfortable that Con Edison is a utility that does the job right. So I’m not certain I want to just pay them more without a promise they know how to spend it.”

We recognize that our customers have very high expectations of how we deliver energy and conduct business in New York City and Westchester County. We need to understand how customers feel about us and do our best to address their needs. Every day, in our plans and operations, we balance what it takes to provide high reliability with the need to keep costs down. While some customers are very skeptical, most participants in our focus groups understood there is a cost associated with maintaining the benefits of service they receive. When asked if a 5 to 10% increase on their bill was acceptable, the consensus among participants was that an increase of 5% of the total bill on an annual basis is reasonable, but increases of a great deal more than that would not be. Most also
acknowledged that they would expect any increases to go hand in hand with future conditions that include steady reliable service and few, if any, power disruptions.

Large commercial customers were less definitive about the tolerable percentage of future rate increases, but still generally acknowledged the need for them. One remarked, “If I said, no, I don’t want my rates ever to go up, but I want my power to stay consistent, I don’t think that’d be realistic.” In terms of affordability, one large customer stated, “…it’s always about you get what you pay for. We always like to pay less, but…we’re in the infrastructure business as well and we realize…what it takes to…provide that service in a big city…we’d love to figure out ways to pay less, but we also don’t want Con Edison to go away.”

All of our infrastructure investments in this plan, and the customer initiatives discussed in this chapter are reflected in our projection of the customer bill in 2030, shown at the end of this chapter.

6.3  ENHANCING THE CUSTOMER RELATIONSHIP

We expect a rapidly changing environment in our industry over the next two decades, and have to be prepared for that. We have several objectives pertaining to our relationship with our customers and are building systems and processes to support these objectives. We plan to use new media, when appropriate, to expand our communication and customer service programs. We will also use new technology, including improvements to our internal systems, to make it easier for customers to do business with us.

We intend to expand options for time-based pricing programs in order to give customers greater control over their energy costs. Consistent with our environmental goals, we will increase customers’ attention to energy efficiency via energy management tools, incentives, and education.

Our objectives are as follows:

- Provide a more efficient and effective, customer service experience
- Expand ability for customers to access information on their own terms
- Empower customers with information and tools to manage their energy bills
- Educate customers about the customer choice option for energy supply
- Support integration of information and communication systems

The next section shows the key initiatives that we will pursue, within the context of the objectives for enhancing the customer relationship.
6.3.1 Objectives to Enhance Our Customers’ Experience

Provide a More Efficient and Effective, Customer Service Experience

Our contact center allows customers to access information through streamlined automated options and, when necessary, gain easy access to employees with specialized knowledge. We interact with customers through an adaptable and responsive call distribution system that provides them with specialized service. We route calls for customized, vital messaging in emergency and non-emergency situations, and provide improved self-service options. Through the implementation of enhanced contact center technology and workflow improvements, we will make it easier for customers to communicate with us. We will provide enhanced speech-enabled interactive voice response (IVR) in the near future, which will give customers more control over their inquiries. We will also hire additional multi-lingual representatives to support the many languages that we serve in New York City and Westchester County.

Expand Ability for Customers to Access Information on Their Own Terms

Customers communicate with us in person at our service centers, via the Internet, mobile devices, interactive voice response, and by phone with our customer service representatives. We continue to provide an expanding menu of services in various mediums. For example, over 195,000 customers receive their bills electronically.
Web Services

More of our customers want to conduct their business online. In response, we must expand our web services and communication links via mobile devices. Today, for example, we provide customized outage information and estimated restoration times on our website (Figure 6-1).

Figure 6-1. Web-Based Outage Information

We plan to further enhance our customer web interfaces. Upgraded technology will be implemented to transform the site into an expansive electronic communication platform for customers. In addition to paying their bills, customers will be able to conduct a home energy audit and get energy savings tips.
While many internet applications work poorly on cell phones, mobile smart phones can be a useful way to report an outage, make a payment, and get account balances. It was with these limitations and opportunities in mind that Con Edison partnered with Usablenet, Inc. to develop a mobile version of our website. Customers are now able to use their mobile devices to:

- Report and check the status of electric service problems
- Pay their bills
- Enter meter readings
- View gas emergency instructions
- View carbon monoxide emergency instructions
- View their current account balances
- View their payment histories
- View their billing histories
- View/update their account information
- Obtain payment extensions

In storm and emergency situations, we will continue to build on our current practices of seeking out advanced methods for customers to report electric service problems. We will examine new communication techniques and mediums to provide customers with updated information in a more efficient, effective manner.

**New Service Connections**

We also plan to improve the experience of customers and developers setting up new accounts. In recent years, Con Edison has made improvements to this process by streamlining business processes and launching an Internet-based project center, which provides a self-service facility for contractors, developers, and customers to process and track new service requests. Although this web-based front end interface is a step in the right direction, it is somewhat constrained by the mainframe from which it obtains its data. We plan to replace the existing mainframe with an information system that, using new technology, will streamline case workflow and provide enhanced updates to contractors, developers and customers. The new and improved project center will subsequently provide information specific to new service requests. The web portal and interactive voice response (IVR) will be tied to this new system, allowing for expanded self-service options, as well as access to case-specific information twenty-four hours a day, seven days a week. Con Edison is committed to meeting customer needs by automating processes and improving the information systems.
Empower Customers with Information and Tools to Manage Their Energy Bills

Pricing and Incentive Programs

We strive to provide customers with information, billing options, and tools to help them manage their bills. Time-based pricing provides customers with granular information on the price of energy at different times of the day in order to help customers align their usage with the actual price of supply resources. Under these programs, customers able to reduce their consumption of electricity during peak daily hours will receive rates during off-peak hours which can be significantly less than the current average rate. These savings are based on the customer’s ability to reduce peak energy usage through conservation, or shifting that usage to a different time of day. Given the success of these programs with larger customers, we expect to offer more time-based pricing options to more customer classes.

When supported by information and programs to align incentives, the way our customers consume energy can change. For example, running the dishwasher and using the clothes dryer are energy-intensive activities which can be shifted to nighttime hours. To make these changes as seamless as possible, customers could take advantage of automated controls to remotely manage their appliances and therefore better manage their energy bills. This type of control would be built into the newest generation of appliances.

Towards the objective of enabling customers to have more control of their energy costs, we will also continue to pursue a variety of energy efficiency and demand response programs. These include direct load control and programs that offer annual payments for agreements to curtail when peak forecasts are reached. Some of these programs, along with time-based pricing, discussed above, may be supported by the deployment of an advanced metering infrastructure (AMI). AMI will allow the measurement of interval usage information, and will support energy management tools. Details on these programs and the enabling metering infrastructure can be found in Chapter 3.

Customer Education

Customer and community education is an ongoing effort and the Company actively conducts seasonal and topical education programs. Our goal is to engage and educate customers while collecting their feedback regarding issues that matter most to our stakeholders.

We are always evaluating how and where we communicate with customers. We are currently working to make it easier for customers to do business with us on our corporate website. To reach our customers in new venues, we recently launched a Facebook site, “The Power of Green”, and are using Twitter to advise customers about outages, energy efficiency programs, and conservation tips. We continue to evaluate new media opportunities and new technology as potential communication outlets.

---

63 Time-based pricing is a type of demand response
**Educate Customers About the Option of Customer Choice in Energy Supply**

Education about the competitive market for electricity supply will continue to be of importance to the Company and our customers. Energy Services Companies (ESCO) provide offerings such as renewable supply and diverse pricing options. Enhanced customer communication programs will be provided to make a customer’s enrollment with these ESCO’s faster and easier. The PowerMove program will be offered whenever a customer requests new service with an ESCO. The associated retail access billing and information systems will be upgraded to offer increased interoperability with competitive suppliers. Likewise, these systems will provide customers with easily accessible information about their account with respect to the ESCO that provides their supply. It is worth noting that regardless of the provider of supply, the distribution comes from Con Edison, and with combined utility billing, customers can receive their total bill from CECONY.

**Support Integration of Information and Communication Systems**

It is important to point out that our customers interact with the Company for more than just electricity. Many of our electric customers are also customers of the gas and/or steam businesses, and it is our objective to streamline the communication required to receive information about our other service offerings.

**6.3.2 Implementation Plan**

We plan to implement our programs in three phases. In Phase I, we will continue to improve customers’ interactions with Con Edison and begin to develop our employees to become energy advisors. In Phase II we begin needed upgrades to back-office systems to support capabilities including new pricing structures in the capture and management of interval usage data. In Phase III we aim to be able to support full, rich, automated information flow between Con Edison and our customers in order to enable new technologies aimed at the “smart home”, and at other energy management initiatives.

**Figure 6-2. Customer Operations’ Implementation Plan**
Phase I

We have a number of initiatives under way or planned for the near future to improve the effectiveness and efficiency of customer interactions. These enhancements will provide customers with additional information and more self-service options.

Using new technology, we will make it easier for customers to do business with us on the Web. Customers will be able to obtain instant and complete answers to routine inquiries. Transactions will be simplified. Advanced self-service options will facilitate the resolution of customer bill inquiries, and will give access to energy use analysis (i.e., on-line energy audit). This web interface will actively guide the customer in identifying conservation and efficiency measures that could reduce energy use and bills. The easy-to-access services and information on the website will also be made available to mobile devices, such as PDAs and cellular phones. Overall, we will continue to pursue initiatives to promote customers’ use of web connections as new technologies emerge.

Upgrades to the contact center are expected to allow Company staff to answer customer calls faster. This will create a more flexible, responsive phone system and contact center to meet customers’ changing demands for information and heightened service. This will be accomplished through the replacement of the Company’s automatic call distribution phone system, and other enhancements to the call center.

The Company’s Interactive Voice Response (IVR) system will be upgraded to a speech-enabled IVR platform. This upgraded IVR should streamline the experience for customers. This new system will provide “virtual hold technology”, which offers customers the opportunity of a returned phone call, instead of holding for a representative.

Expanded customer education programs will provide progressive efforts to educate, inform, and guide customers in the management of their energy use and bills. We will address the need for increased education and information on energy efficiency, conservation, and green initiatives including green power. Future outreach and education initiatives will focus on more customized educational campaigns. The Company will also continue to develop alternate forms of education and outreach via web-based systems and smart phone communications. This outreach will be conducted in coordination with our expanded energy efficiency and demand response portfolio, which offers customized programs for each customer segment to better control their energy costs. We will train our employees to become energy advisors to facilitate the implementation of demand side management applications as an option for customers.

We will also pursue additional communication channels for customers to report electric service problems. Potential upgrades being considered include additional storm and emergency response measures that will increase communication through the use of text messaging, e-mails, and website outage reporting. New communication tools are being studied to improve our interactions and warning notifications to our Life Sustaining Equipment and special needs customers.

It is important to maintain a billing system with the required flexibility to support the current and future operating environment. Upgraded programming will facilitate integration and interface with other systems. These upgrades will enable new and emerging rate structures, such as the extension of time-based pricing, and the expansion of customer enrollments with competitive suppliers.
Promotion of a competitive market, including retail access programs such as, PowerMove, Market Match, and Purchase of Receivables, were created in support of a competitive market in the New York area. We will study the potential expansion of the PowerMove Program to encourage more customer enrollments with competitive suppliers. Enhanced customer communication tools will be provided to make a customer’s enrollment with these suppliers a seamless, more expedient process.

**Phase II**

Instead of responding to customer inquiries, our customer operations team will analyze data and actively contact customers about issues, or opportunities for customers to benefit from additional programs or changes in consumption behavior. The installation and build-out of a new Customer Service System (CSS) is expected to be a multi-year effort starting in 2017 and lasting three to four years. With the new CSS, we will be able to manage real-time customer data, and aggregate it with other customer data repositories. We will make our customer service effort more active by using the vast amount of available data.

In Phase II, we expect to have rolled out AMI, as discussed in Chapter 3, and will thus be able to offer time-of-use pricing and other demand response programs to a broad set of customers. This will be achieved through the installation of digital meters which capture and transmit interval usage data, and receive pricing signals and other information which enables time-based pricing. Most customers will have to actively turn off the dish washer, shut off the lights, or program each device in the home through built-in timers. We have designed the Residential Smart Appliance Program where communication from the utility will automate the curtailed operation of certain devices to improve customer efficiencies. It is also expected that as time goes by, more homes will include smart end-use devices which can respond to price signals from Con Edison. Devices will be programmed through a central home controller that will be automatically accessible not only in the home, but also via the Internet.

In addition to home appliances, we expect that during Phase II, customer use of electric vehicles will rise beyond hobbyists and car enthusiasts to the mainstream. Moving from a network of gas stations to electric charging stations will dramatically change how customers’ rely on the Company, and thus change the way we operate our business. We plan to work with customers, manufacturers, regulators, and industry associations to design mutually-beneficial programs for recharging these devices. We will start by proactively working with commercial fleets proactively, where charging can be centralized and the implications to our system utilization are isolated in one area.

Finally, it is expected that the forecasted increased cost of energy will push some customers to consider and adopt distributed generation technologies in order to supply their own source of electricity. Distributed generation offers a wealth of benefits for those customers with the knowledge and interest in installing them, and we will continue to support those customers as technology evolves.
Phase III

By the end of the planning horizon, we expect more widespread adoption of smart grid applications for homes and businesses. A key uncertainty is when customers will adopt electric vehicles and smart grid technologies. When they do, customers will desire an increased level of interoperability and control with respect to their energy-use devices. Device proliferation from high-definition TVs, home computing devices, and electric vehicles will only increase customer usage of energy. Customers will seek automated ways to take advantage of the increase in information available from time-based pricing signals, as well as ways to analyze their own energy use in order to find efficiencies and cost savings. We are committed to partnering with customers by providing information and answering customer inquiries.

Although some of the technologies we discuss here are only just being piloted and tested today, we believe the future of the “smart home” will occur in the planning horizon. The following description provides a glimpse of what may lie ahead.

The term “smart home” refers to a residence that, among other things, may use a home area network to manage and communicate with a number of different systems (e.g., home security, data transfer) and components (e.g., air conditioner, washer/dryer) of the residence. Through the use of a home controller, a customer will be able to set preferences for the operation of components within his or her home, as well as create scenarios for how all components should behave at specific times (e.g., when at home alone vs. having a party vs. on vacation). In current designs, all components in the home use a home area network to talk to each other through the use of the existing electric wiring, a protocol known as X10, or using wireless interfaces such as ZigBee and Z-Wave.
Specific systems within the residence may use central communication in different ways.

- **Climate control system**—Offers the user fine-grained customization and control over the temperature of the home, and provides increased information about, and control of, the devices that heat and cool the home (e.g., boiler and air conditioner). Additional control will allow customers to respond to signals from the utility letting them know when electricity supply prices are high and it may be desirable to reduce electricity consumption.

- **Home monitoring**—Allows customers to monitor the security of both the inside and outside of the home through the use of security cameras which are managed by the home area network. In addition to the home security systems of today, which identify when entrances to the home are compromised, these security devices will capture video data, which will be available real-time to the user both in the home and via the web. This video data will be configurable to scan in real time for certain images including unrecognized persons, or malfunctions in the home. In addition to external security, these security systems will be useful inside the residence to monitor various rooms of the house, such as a nursery.

- **Electric vehicle (EV)**—Allows home owners to centrally manage the charging of their electric vehicles. Electric vehicles being developed today include technology allowing a user to customize the time of day when charging should occur, as well as the characteristics of an individual charge; however, the smart home will centralize this functionality via the home controller, and allow the user to set and modify charging characteristics of all the electric vehicles in the home via a single interface.

- **Home area network**—Enables the home owner to manage the communication between devices in the home. In addition, users will be able to access their local network, and configure devices and the home controller from any location via the Internet.

- **Data exchange**—Enables the customer to share some of the data collected by their devices with the Company so that it can construct optimal usage profiles. The utility will also be able to aggregate information from many users to identify opportunities for efficiencies, and ultimately customer bill reductions.

- **Distributed generation**—Offers customers the opportunity to manage and control their distributed generation assets through the central controller. In this scenario, distributed generation is monitored by the home, which alerts home owners of issues that arise, or when distributed generation is not being optimally utilized.

Some of these technologies, including home area networks and distributed generation technologies, are being tested as part of the Company’s Long Island City Pilot, as discussed in Chapter 5.

The above description includes only a small sampling of potential devices and complexities of the smart home, and does not include any mention of the broad range of emerging commercial and industrial applications of energy management and building automation. We will be prepared to support our customers’ changing energy management needs and we expect to work with customers in developing solutions, analyzing data, and providing knowledgeable support to realize their objectives.

### 6.4 ELECTRIC SYSTEM LONG RANGE PLAN IMPACT ON CUSTOMER BILLS

All of the programs discussed in section 6.3 will help us to enhance the customer experience over the planning horizon. Much of this plan has illustrated our infrastructure investment projects and programs. These programs will minimize risk and provide the high reliability our customers have come to expect. The investment plan that supports these projects and programs leads to the following projections for the customer bill.
We strive to minimize customer bills and have outlined in this document several programs and initiatives to manage our infrastructure costs as well as to work directly with customers to manage their energy expenditures. While we will continue to make every effort to keep our transmission and distribution rates down, it is important to convey that market and policy forces outside of our control will impact our customers’ bill. In particular, the composition, availability, and affordability of electricity supply may experience dramatic change over the 20-year planning horizon.

The estimated impact of all of our planned investments, along with projected cost increases to the supply and tax portions of the bill, is expected to be an average annual increase of approximately 1.90% on a real basis. The total increase broken out by component of the bill is illustrated in Figure 6-3.

Figure 6-3. Forecasted Residential Bill Breakdown in 2030
6.5 SIGNPOSTS

Concern about global climate change and the environment, combined with commodity price increases in a weakened economy has brought the issue of energy demand front and center. The rate at which the broader economy recovers will drive not only energy demand, but significantly affect energy prices and drive the adoption of new technologies. In turn, these actions will drive the changes needed by the Company to be responsive to customers. We will monitor the following signposts to determine if and when adjustments to the previously outlined plan need to be made.

- **Customer needs**—Customers’ energy needs tend to fluctuate given changes in their lifestyles, work situations, personal circumstances, and as a result of innovations in technology, fluctuations in the economy, and changing energy prices. Continual dialog with our customers, whether via outreach or customer research, will ensure we continue to be aware of our customers’ priorities.

- **Adoption of new technologies**—Integration of new technologies into the lives of our customers drives the speed at which we need to make the necessary upgrades to the electric system. Specific markers to look for include requests for DG, proliferation of residential LED lighting, adoption of in-home battery storage technology, and the penetration of electric vehicles.

- **Growth of new media**—Our adoption of new media, offers additional opportunities for us to converse with customers. Continuous customer feedback helps us understand emerging issues within our stakeholder groups, as well as identify gaps that may exist between stakeholder expectations and company actions.

As uses of and needs for electricity change over the next twenty years, so too will the ways in which we interact with our customers. Throughout this evolution we will remain committed to balancing affordability and reliability with the need to make the necessary electric infrastructure investments. In addition, we will provide our customers with the tools to better manage their energy use. To carry out these objectives, we will take advantage of innovative technologies and provide our employees with the necessary skill sets, as explained in the next chapter.
7.0 IMPROVING PROCESSES AND SKILLS

7.1 OVERVIEW

To facilitate the successful implementation of the Electric System Long Range Plan, we will develop new skill sets, processes, and systems. We will focus on the following four key areas:

- Developing an Integrated Long-Term Planning Process
- Leveraging and Expanding our Capital Optimization Model
- Improving our Focus on Cost Management
- Enhancing Organizational Skills

7.2 LONG RANGE PLANNING PROCESS

We plan, manage and maintain a complex electric system and strive to do so in a consistently safe, reliable and cost-effective manner. We collaborate with stakeholders and experts to ensure we deliver high quality electric service to our customers in New York City and Westchester County.

In developing the Electric System Long Range Plan, we performed an assessment of our current transmission and distribution (T&D) system planning process. The initiatives that are identified for process improvement are grouped into three key categories which are described below:

Figure 7-1. Planning Process Areas of Focus

- Linkages and integration across the company
  Integration and communication between groups improves by establishing central accountability over the planning process

- Approach to investment evaluation and trade-offs
  A standardized methodology for building and evaluating business cases enables effective prioritization of investments across the Company

- Alignment with corporate budgeting cycle
  A strategic management process aligns all corporate and operational functions related to planning and budgeting into one annual cycle with a long term vision
**Strengthen Linkages and Integration Across the Company**

We have historically developed 10 and 20 year plans for electric system projects. Our planning process is built on standardized and tested methods of design and has produced a system that performs to high levels of reliability. We evaluate individual investment projects based upon several key factors. There are opportunities to improve project evaluation by prioritizing and aggregating programs in a way that allows us to better determine their collective impact on the performance, cost structure, and risk profile of the electric system.

Integration and communication among groups will be accomplished by establishing clear oversight and responsibility for the planning process. Before divestiture of the Company’s generation assets, a central planning group guided an integrated planning process. While many elements of that group still exist within the Company, they are less centralized today. We will reexamine the organizational structure and determine what will be the appropriate structure for the Company going forward.

The Electric System Long Range Plan will be regularly reviewed under different scenarios for demand, commodity prices, and other aspects of the business environment. Scenario planning will be supported by the identification, development, and maintenance of “information platforms.” Information platforms are a set of processes that allow the Company to better track internal and external information that is critical to both short- and long-term planning. Ultimately, information platforms are meant to provide the Company with the information necessary to perform effective strategic planning. Some of the data tracked are market trends, regulatory developments, technology development, commodity prices, and knowledge developed through Con Edison pilot projects. Scenario planning, supported by these information platforms, will allow the Company to operate under a common set of assumptions regarding our business environment. Some of the major planning activities that will be better integrated are long-term demand forecasting, long-term integrated resource planning including demand and supply side solutions, the coordination of budgeting decisions, and the regular assessment of project performance.

**Implement a More Systematic Approach to Investment Evaluation and Trade-Offs**

A standardized methodology for evaluating business cases will enable effective prioritization of investments across the Company. It will include the ability to make trade-offs to reach the right balance of cost, performance and risk. Performance management will be refined by centrally-tracking projects throughout their lifecycle, and by regularly reviewing them against strategic, financial, and operational goals.

We have made progress in piloting a Capital Optimization process that enables the collaborative evaluation of project plans. The process is driven by recently refined corporate strategic drivers. We developed a quantitative weighting system for prioritizing projects based on their support of each driver. This was done using an objective and well-defined guide for quantifying the impact of each project on the strategic drivers. Projects are prioritized based on their cost, benefits, and weighted strategic value. This process allows the Company to make trade-offs across projects, in order to build an investment portfolio that reflects the strategic, budgetary, regulatory, and technical priorities of the Company.
We are currently implementing the Capital Optimization process within Electric, Gas, and Steam departments. The ultimate goal is to refine and deploy the process across the Company, and determine the overall capital budget with clearly-identified short- and long-term costs and benefits. In time, we plan to evaluate the maintenance programs using this process.

A more detailed description of the software tool and process is provided in section 7.3.

**Align Strategy Development with Corporate Budgeting Cycle**

The strategic management process will leverage the Electric System Long Range Plan and the Capital Optimization tool to link transmission and distribution planning and investments to the corporate strategy. The main steps of this process are outlined below:

- Strategy is developed based on scenarios for market conditions, internal competencies, and assets
- Project plans and budgets are developed and adjusted based on quantitative analysis of performance, cost, and risk indicators identified for the short- and long-term
- Initiatives are implemented and monitored against our Key Performance Indicators (KPIs)
- Performance data and other information of strategic importance (information platforms) are continually analyzed and aggregated for strategy development

Figure 7-2 shows the flow of this annual process.
Step One: Develop strategy and assess operational needs:

- Essential strategic information, or “information platforms”, are identified, developed, and maintained in order to better track market trends, regulatory developments, intellectual capital, etc.
- The Electric System Long Range Plan is regularly reviewed under evolving real conditions and different hypothetical or probable scenarios for demand, commodity prices, new technology implementation and adaptation, and other aspects of the business environment.
- Energy efficiency and demand response programs are included in load forecasts with increased network-level certainty, based on scenario planning and real performance.
- Central and regional groups determine their business requirements (shared services and system needs) based on the load forecast, current infrastructure capability, safety and reliability goals, ongoing maintenance, regulatory requirements, and customer interconnections.
- Management provides budget guidance to groups based on scenario planning and corporate targets.

Step Two: Evaluate alternatives:

- Business groups build business cases using standardized templates with all the cost, benefit, timing, and operational considerations clearly outlined for prioritization and evaluation.
- Project business cases are prioritized and evaluated through a collaborative process called the Capital Optimization process, which includes both corporate and operational stakeholders. As these processes are improved, this would include O&M programs as well as they will work in an integrated fashion to improve system performance over time.
- Once projects are adjusted to reflect the strategic, budgetary, regulatory, and technical priorities of the Company, the resulting Business group budgets are submitted for approval.

Step Three: Build work plans and budgets:

- Business groups review work plans and budgets based on the Company’s investment decisions.
- Budgets are finalized and set.

Step Four: Implement plans and review performance:

- Work plans are implemented.
- Improved specifications and other solutions resulting from the Company’s initiatives are tracked and integrated into the strategy and operational protocols through internal information platforms.
- Initiatives are centrally tracked and regularly reviewed against strategic, financial, and operational goals.
- Performance feedback loops are established to provide new inputs to existing program evaluation or to confirm expected outcomes and to assure optimal performance of annual and long-term initiatives.
- Budgets are adjusted internally as real-time conditions unfold to assure we are supporting our vision, mission, corporate strategic objectives, and plan themes.
One of the strategic implementation enablers will be the improvements to our cost management practices, which will monitor performance against financial objectives. We are working to improve the tracking of project financial performance to provide greater transparency at more granular levels. Section 7.4 of this chapter explains the planned improvements to this process in further detail.

7.3 CAPITAL OPTIMIZATION

In our ongoing efforts to refine our decision making process for allocating funds between various investment opportunities, the Company has developed a comprehensive Capital Optimization process using a software tool. This process is implemented within the overall planning process and allows us to develop business cases and to evaluate alternatives in the development of our plan. Capital Optimization allows us to attain objectives by helping us evaluate projects system wide, and make trade-offs across operating units through standardized analytical methods and guidelines.

Through this Capital Optimization process the Company will ensure that resources are efficiently used to reduce risks and meet strategic objectives.

The process has the following objectives:

- Provide a consistent set of evaluation guidelines and tools for all business units
- Develop an optimized work plan with the appropriate balance of performance, cost, and risk
- Leverage a more analytical approach for project/program initiation, evaluation, and closeout
- Create “what if” scenarios to improve decision-making for long and short term plans
- Improve monitoring and tracking of project/program performance
- Provide valuable and comprehensive information to regulators

The main steps of our Capital Optimization process are shown below:

Figure 7-3. Capital Optimization Process
**Corporate Drivers**

The Company employs a streamlined cost management process to develop its capital investment and annual operating expense needs. Each group develops a forecast of its needs, identifies necessary projects, and develops a budget and work plans for the coming year. In developing these plans we focus on ensuring the system has sufficient capacity to meet customer needs and on maintaining our existing infrastructure. Our corporate strategic objectives, or drivers, listed below, are incorporated into budget development to determine the appropriate level of Capital and O&M expenditures.

- Provide reliable service
- Reduce costs to the customer
- Satisfy customer needs
- Increase energy efficiency
- Be responsible stewards of the environment
- Enhance external relationships
- Strengthen the company’s support activities
- Strengthen the company’s human resources
- Reduce and manage risk
- Improve public and employee safety
- Grow through regulated expansion
- Build on successes of the competitive energy businesses

**Driver Prioritization**

These objectives are given a weighting by executive management from across the organization. The result was a quantitative weighting system for prioritizing projects based on their support of each corporate driver.

**Impact Statement Definition**

To quantitatively evaluate each project’s strategic value, a working group of subject matter experts writes “impact statements” for each of the corporate drivers. These serve as an objective and well-defined guide for quantifying the impact of each project on the corporate drivers. For example:

- Cost impact is measured in terms of dollar savings within five years of project implementation.
- Reliability for projects related to the electric system is measured in terms of the impact on the potential duration and frequency of customer interruptions.
- Risk mitigation is measured by the project’s Risk Priority Number (RPN), which is based on three factors; severity, likelihood, and controllability. An asset optimization committee rates the program within 5 levels; None, Low, Moderate, Strong, and Extreme, based on program impact to mitigating that risk. Historical performance data and risk simulations are used to assist in assigning the levels.
**Project Assessment**

The optimization process starts with the assessment of projects or programs. We developed a formal template to standardize the information gathered to facilitate a comparative analysis of programs within the portfolio.

Key attributes in the template are:

- Work description
- Justification
- Alternative designs
- Risk of no action
- Financial and non-financial benefits
- Technical analysis
- Sensitivity analysis
- Project relationships
- Estimated completion dates
- Current status
- Current working estimate

This allows a consistent set of guidelines for program owners to review, and ensures the process is timely during the budget cycle. A software application was developed to allow for ease of submittal and tracking among many program owners and business units.

**Project Prioritization**

With all business case components properly captured, the Company can measure the portfolio’s cost, benefits and weighted strategic value. These allow the Company to analyze all projects as an integrated portfolio, with total cost, savings, and return on investment. Other filters specific to each group can also be applied. For example, within Electric Operations, projects can be analyzed in terms of network and overhead investment, or both.

The Capital Optimization software can analyze all programs, and produce a graphical depiction of the portfolio with multiple combinations of the above criteria in up to 4 axes. For example, a graph can compare programs in terms of their strategic value, benefit, cost, and system type (network vs. overhead).

**Portfolio Optimization and Final Recommendation**

A holistic approach to cost management leverages an asset optimization process that can optimize T&D investments against multiple constraints to reach goals and objectives.

This process provides for system-wide program comparisons through standardized analytical methods and guidelines, governed by a centralized group of subject matter experts. A rigorous benefit analysis methodology enables timely, informed decisions with increased transparency, and improves alignment in project and program management.
**Benefits of Capital Optimization**

Our capital optimization process has three key benefits: enhanced analytics, lower life cycle costs per asset, and centralized asset management. The emphasis on improved data collection, the conversion of data into useful information, monitoring of performance metrics, modeling, and scenario planning will ensure an appropriate balance of short- and long-term initiatives. The formal evaluation of programs will result in more regular reviews of specifications and procedures. This will encourage the leveraging of technology, systems, and modeling to shift from a time-based approach to asset management to a condition-based approach. This is expected to result in lower life cycle costs per asset. The decision making process will shift from a decentralized approach to a more centralized approach. We have begun forming centralized asset management committees that will oversee the process from program initiation, prioritization, monitoring, evaluation, and close-out.

**7.4 CONTINUED FOCUS ON COST MANAGEMENT**

We have made significant investments in time and resources to provide our people with the skills and tools necessary to effectively track and manage costs. Costs are monitored against a set of key performance indicators (KPIs) that are used not just to highlight strengths and identify opportunities for improvement, but also to promote a culture of accountability. For example, these KPIs are used to ensure safe and reliable performance which is a benefit to our customers and to align management employee salaries to the Company’s performance. The periodic monitoring of these indicators helps us make mid-course corrections, as necessary.

A key theme of this plan is to assure our electric service is and remains reasonably priced for the people of New York City and Westchester County. We have reviewed our cost management processes to accomplish this goal.

In early 2009, we began assessing current cost management practices in a three-pronged approach using internal surveys, industry benchmarking, and third-party evaluations. The Company surveyed 270 finance and operations employees, and performed follow-up focus groups and interviews with subject matter experts. To better understand the Company’s performance against industry peers, we surveyed the cost management practices of leading utility and non-utility companies across the country. We identified opportunities to define, communicate, and institutionalize a formalized corporate approach to cost management. The changes we will make conform to the following objectives:

- Integrate planning, management, and review processes to integrate financial and field operations and establish the aligned priority for cost management
- Enable an action- and deliverable-oriented approach by defining and building skills of and developmental career paths for cost management personnel
- Identify and implement an organizational structure that balances consistency in policies and practices, alignment of activities to priorities and goals, oversight and direction, partnership with stakeholders, independence of cost management personnel and opportunity for employee development
- Better integrate project management concepts into work practices and procedures
Components and Implementation Plan

We will improve our cost management practices in the following four key areas: jobs, skills, and organization; information technology; culture and values; and management systems. Ultimately, the process will allow tracking financial performance from planning to project execution. The appropriate information technology systems will provide end-to-end performance monitoring and transparent reporting tools.

Figure 7-4. Four-Point Implementation Program for Cost Management Improvement
The main components of the cost management initiative are grouped within these areas:

1. Jobs, Skills & Organization
   - **Strengthen Financial Analysis Capabilities**—Strengthen analytical skills across the Company, combined with an understanding of operations. Establish and coordinate training programs throughout all organizations to ensure consistency and minimize the loss of knowledge due to attrition. Establish career paths for financial personnel, and include job rotations to broaden employee exposure to field operations.
   - **Launch a Program on Utility Economics and Key Financials**—Develop programs on utility economics and key financial management principles for all new management employees. Include this program in the supervisor training and development curriculum. Make an online version of the program available to all employees.

2. Information Technology
   - **Improve the Estimating Process**—In parallel with developing the reporting tool, improve work management systems to enhance estimating accuracy.

3. Culture & Values
   - **Align Key Players**—The roles and responsibilities of all professionals will be more clearly defined across the entire process, with an emphasis on creating a deliverable- and action-oriented culture. Establish clear accountabilities for estimating accuracy, tracking of results, analyzing variances, and implementing corrective actions.
   - **Enhance Cost Awareness**—Promote cost-awareness as a core value across corporate and operational functions. Institute processes that support the careful balancing of key priorities such as cost, reliability, and risk. Successful prioritization of expenditures will require that employees have a solid understanding of field operations. This will facilitate inter-organizational communication and enhance the effectiveness of financial analysis.

4. Management Systems
   - **Standardize Project Management**—Standardize the project management function across the Company.
   - **Establish KPIs for Capital**—KPIs are heavily weighted toward O&M performance. Establish a significant weighting for the performance of capital projects.

### 7.5 ENHANCING ORGANIZATIONAL SKILLS

**Skill Evolution**

Our workforce of 2030 will look very different from today’s workforce. In looking out over the period of the next 20 years, our workforce – at all levels - will need stronger analytical skills. This is because each of the plan themes outlined in this report will require significantly enhanced analytical work. The integrated management of new demand and supply resources, often smaller in size and more dispersed geographically, will require a new, more complex level of planning and dispatching that is more complex. Tailoring system design will require quantitative evaluation of several options to meet customer demand and reliability constraints. Improving asset management and increasing monitoring and control of the system will require the processing and analysis of large volumes of data, from load flow analysis to condition-based maintenance. Managing the customer experience will be transformed by the availability of new information and data and the exponential increase in customer service requirements to explain and make the data easily understood and actionable by customers. Jobs throughout the organization will become more complex and we expect that new jobs will be created to meet the great demand for analytical skills.
We will seek other opportunities for improving our skill sets in order to successfully execute the Electric System Long Range Plan:

- **Advanced understanding of technology and power systems**—The equipment and systems which we plan to deploy over the next twenty years will have more capabilities and will be much more technologically complex than much of what we have in our system today. We will replace our current equipment gradually, not all at once. But as we shift gradually to a more complex system, we need to have a parallel shift in our people’s technical skills, from planners to engineers to operators and line mechanics.

- **Improved planning and problem solving**—Utilities rely on standards for good reason: so that capable engineers can determine the best way to ensure desired results and operators can implement them systematically. As equipment, systems, and approaches offer changes at an increased pace, however, we need to be able to problem-solve more quickly and incorporate new solutions into our plans more readily.

- **Ability to utilize real-time data in the field**—The salient characteristic of all the technologies associated with Smart Grid is a higher, and more real-time, volume of information about customers, equipment condition, failures, etc. The highest value of this information is that our people in the field will be able to receive, digest, and use it in real time, which involves both equipment (mobile computing devices) and the skill to know how to make the information actionable.

- **Improved communications for customer service activities that advise customers on demand side management options**—We have an important educational role to play, and advising and educating residential and small commercial customers about demand side management issues is a skill that will needed by more of our employees.

- **The ability to adapt to change both individually and as an organization**—Flexible and adaptable organizations and employees can perform much more effectively in ever-changing business environments.

- **Focus on creating a tighter linkage between strategic planning and operational planning**—We need to greatly strengthen the degree to which our operating unit planning is ultimately driven by our strategic planning. Strategic planning, in turn, needs a stronger focus on improving value for our shareholders. Only in this way will we be able to secure, over the long run, the financing needed to provide our customers with the quality of electric service they require, and drive the resulting priorities through to execution.

- **Systematically incorporate customer and regulatory/governmental needs into operational planning**—While we seek in good faith to accommodate changing needs of our customers and public policymakers, we need to include them more systematically among the considerations which are driving our strategic and high-level operational planning.

- **More quickly and more thoroughly incorporate learnings from R&D into operational planning**—Con Edison has among the most advanced R&D activity sets of any utility in America. We need to develop systems and habits that will drive us to incorporate their results much more quickly and thoroughly into our strategic and operating plans, and into future revisions of the Electric System Long Range Plan.

- **Leadership skills should complement technical skills**—Con Edison should ensure its next generation of leaders possesses the leadership and communications skills needed to enhance relationships with its customers and other stakeholders. Resources should be committed to develop these skills at all levels.
We recognize that we are one of many influencers in the energy market. There are areas, such as demand side management, where our efforts in customer outreach and education will be complementary to those of other players in the market. For example, load aggregators, which provide assistance to customers with demand response programs, play an active role in educating and promoting the transformation of our market. This means that energy efficiency and demand response initiatives, and more broadly, a conservation mindset, will develop as a result of both our efforts and those of other market players. The Company remains committed to developing the skills needed to enhance our relationship with customers in a changing business environment, and will continue planning (as we do today with our load forecasts) for internal and external factors that shape this relationship.

**Strategic Workforce Planning**

We are working on plans to assure we fill the work force gaps that could exist in the future.
We have identified two major workforce issues common to electric utilities across the country and relevant to the Electric System Long Range Plan. First, workforce demographics are a concern, with a growing number of workers close to retirement and an influx of young, inexperienced workers. Based on the demographics of our workforce, and the structure of our retirement plan, we project that over the next five years, an average of 5% of our workforce will retire annually. This means that we expect that about 25% of our employees will retire between 2010 and 2014.

**Figure 7-5. Retirement Eligibility**

Projected Annual Retirees Based on Eligibility for the Con Edison Retirement Plan

---

64 Employee retirement eligibility and benefits at Con Edison are determined through a point system. The point system works by combining the age of the employee with their years of service. Employees are eligible to retire once they have 75 points.

At the other end of the spectrum, 50% of our workforce has been employed at Con Edison for less than ten years, and 31% for less than five years, as shown in Figure 7-6. This demonstrates that a large number of new employees that require comprehensive training programs are coming into the organization. Training objectives must address the steep learning curve to enable new employees to quickly develop functional knowledge and be effective on the job. Field personnel, for example, participate in apprenticeship programs coupled with formal hands-on training, to provide them with the necessary skill sets to qualify for promotions and increasing responsibilities.

We will address these demographic issues via the following strategies.

- Systematic knowledge management and transfer to ensure we do not lose critical organizational capabilities as this workforce retires
- Systematic and thorough training for critical job categories
- Supplementing the first two initiatives with experienced external candidates as required

---

The second workforce issue identified is that the skills, jobs, careers and majors that will be in demand tomorrow may not exist today. Field personnel and customer service representatives will require new skills to work with innovative technology. These skill gaps have been identified and are being addressed by building strategic partnerships with local high schools, community colleges, and universities.

We are currently developing capabilities to perform ongoing strategic workforce planning, which will help us proactively manage our workforce into the immediate and longer term future. The information platforms discussed in section 7.2 will enable monitoring of the internal and external business environment as a key element of strategic planning. In the short-term, this involves identifying key skill gaps 3 to 5 years out, and developing and updating an ongoing strategy to fill those gaps – through hiring, developing internally, or a mix of both. We expect to manage the longer term implications on skill gaps by carefully monitoring the relationship between industry trends, Con Edison strategic direction, and internal capabilities. This will ensure we are well positioned for the future. Going forward, this skill gap analysis will be a standard activity in our workforce planning initiatives.

**Highest Commitment to Employee Training**

Training is the most significant investment we can make. The Learning Center is a corporate education facility where we train and test employees in the skills they need to safely and productively perform their work. The Learning Center includes classrooms and hands-on labs for real-life learning. Instructors are a combination of former field, office and line personnel. The courses available at The Learning Center fall into two general categories: Skills and Leadership.

Training employees in ‘hands-on’ skills for new positions is a high priority at The Learning Center. But the type of employee we are training today and the organizational needs differ from the past. We have shifted from providing veteran employees with new skills for different jobs to providing new employees with new and enhanced skills for more complex jobs. All of our newly hired employees require basic training and then skill-enhancement training as they move through their career paths. We also provide refresher training for existing employees. This increase in training demand has compelled us to look at new instructional methods, such as eLearning, simulation training, and self-study courses.

It has become increasingly important to look toward recruiting the company's future leaders into programs such as the Growth Opportunities for Leadership Development (GOLD) program, an intensive, 18-month entry-level rotational program for recent college graduates. We have adapted our training curriculum to provide leadership and analytical skills, as well as career advice, to develop and prepare employees to manage the Con Edison of tomorrow.

An additional priority of both The Learning Center and Talent Management is to develop employees with a greater sense of business acumen. This involves classroom discussions of such topics as ethics, open communications, lessons learned from incidents and audits, and continuous improvement.
There are four key principles that guide us:

- We will incorporate our values and the principles into all our programs.
- We will provide employees with the right skills, for the right job, at the right time. Since 2001, Con Edison has lost many highly skilled, experienced employees through retirement. To continue to operate and maintain the most complex energy system in the world, we must train and develop employees with the highest technical and managerial skills.
- All of our training programs will be tied directly to performance on the job. We work in partnership with line organizations to ensure that students are exposed to the skills, procedures, and equipment needed to do their job efficiently and safely. The key to effective "performance-based" training is alignment with operating organizations. Our courses must be linked to "real world" tasks and experiences. Many training facilities and laboratories were designed to simulate conditions in the field.
- We will maintain a team of experienced, professional instructors and managers who are subject-matter experts from line organizations. We provide new instructors with training in such topics as presentation skills, curriculum development, and innovative instructional techniques; however, there are no "lifetime" teachers at The Learning Center. In order to stay familiar with the realities of the field, our instructors are expected to rotate back to operating organizations after a three to five-year assignment at The Learning Center.

**Strong Linkages Between Human Resources and the Operating Companies**

We recognize that a strong human resources organization, with a clear vision and set of tools, is needed in order to prepare for the changing skill sets needed to manage the business.

In 2007, an enhanced human resource strategy was introduced to the corporation. This strategy resulted from the work of a team of leaders both from line and human resource positions. The objectives of the human resource strategy are to achieve superior business performance through talented employees, engaging work and continuous learning. The strategy consists of four key components: attraction, development, retention, and our corporate values. Each of the components consists of various programs that support them.

Figure 7-7 outlines our human resource strategy map, which shows the linkage between corporate strategy (including the Electric System Long Range Plan), corporate strategic objectives such as reliability and energy efficiency, and the core functions of the Human Resources organization.

**Figure 7-7. Human Resources Strategy Map**

---

206
7.6 SIGNPOSTS

Changes in the skills of our workforce will impact our ability to operate with the efficiency and consistency we value. Through strategic workforce planning, we will monitor and identify potential skill gaps and address them through resources such as training (e.g., The Learning Center), systematic knowledge management, career management, and hiring.

One of the goals of our new vision for planning is that all functions are aligned to maximize planning effectiveness, and to ensure ease of communication and collaboration with stakeholders such as regulatory bodies.

As the economy evolves, the elements of our business environment that affect our finances and operations may shift. We will closely monitor our business environment through established information platforms. This will ensure that our Enterprise Risk Management, Scenario Planning, and Capital Optimization processes reflect any shifts in the relative impact and importance of external factors on planning, cost management, and skill gaps.
8.0 SUMMARY

8.1 CHALLENGES

Planning for this more responsible energy future begins with understanding our internal and external challenges.

Internal Challenges

In the next twenty years, variables that will challenge and redefine the basic assumptions of electricity delivery, from economic drivers to technological innovations and customers’ increasing ability to control their usage, will change the landscape upon which Con Edison and other utilities operate. As we have been for the past 150 years, we continue our commitment to provide reliable electric service at an affordable cost to customers for years to come. Reliability and affordability: these are the two guiding principles of our long range plan. We hold ourselves as responsible for the quality of service we provide as we do for the financial impact it has on our customers.

To address internal challenges, we need to adapt our planning, design, and operational practices. As in the past, we will continue to build and maintain the necessary electric delivery infrastructure. To achieve excellence in this pursuit, we will introduce and implement innovative approaches as compared to what were previously standard practices. We will establish improved planning processes that leverage quantitative measures to optimize our project and program investment portfolio, and further to continuously prioritize and incorporate feedback into that process. We will continue to reevaluate our traditional design standards to find lesser-cost solutions to meeting our customers’ growing and changing needs, and furthermore our designs will need to provide greater flexibility than ever before. To reduce our overall cost structure, we need to continue to reevaluate our operational practices and continue to enhance our cost management practices. We will incorporate probabilistic analyses into our infrastructure designs to increase the asset utilization in our infrastructure. In short, will plan for change, implement design and operational practices that support those changes, and meet the changing needs of our customers, while providing safe, reliable service in a cost effective manner.

We are as proud to serve the New York metropolitan area as we are to be one of its citizens; being one of its oldest citizens, however, has its impacts. We operate some of the largest and most complex infrastructure systems in New York’s metropolitan area. To meet our customers’ needs, we utilize a tremendous amount of assets, whether wires, manholes, or poles, and after they are built, they must be maintained. The majority of our annual capital investment portfolio over the next twenty years will be dedicated to replacement of this infrastructure. Our focus will be on maintaining a sound infrastructure at the lowest cost possible. Past industry practices have focused on a time-based approach to asset management and to increase our efficiency we are using analysis to adopt a condition-based approach. To further reduce the impact of these assets on our customers’ bills, we need to focus on increasing our asset utilization.

We will need to implement both traditional and innovative design solutions. Advances in communications, such as Smart Grid technologies, have and continue to give us greater visibility into the status of our transmission and distribution systems. We need to leverage this in the future by installing more monitoring and control equipment that will allow us to increase system automation and the accuracy of our predictive system models, and will help us to focus on those system components that need the most attention. A core principle of Con Edison’s system design approach is the use of
tailored solutions to fulfill these requirements. Tailored solutions apply targeted demand and supply side management programs, advanced technologies and innovative designs, as well as traditional infrastructure investments to specific load areas. Our tailored approach will result in the application of solutions where they can provide maximum benefit for our customers.

Excellence demands that these challenges are addressed with a keen awareness of the impact we have on our customers; for this reason, our standing responsibility to provide safe and reliable service to our customers will be balanced by efforts to mitigate bill and rate increases. Reliable and safe service is an expectation of our customers, and we consider it a mighty challenge to balance these expectations with lower and reduced costs, but it is a balance we will aggressively pursue. By implementing aggressive demand side management programs, new designs, switching to condition based asset management by installing more monitoring and control, and driving efficiencies in the business by implementing programs like enhanced work and cost management practices, we can lower our cost structure. Addressing these challenges will give customers the same levels of reliability they have today with less risk of large scale prolonged disruptions to natural flows of everyday business and life, whether they be as a result of transformer failures or instances of stray voltage. To our customers, outages mean lost business and financial impact, not to mention public safety concerns in high-rise and densely populated areas reliant upon elevators, subways, and other electrically supplied public services.

External Challenges

Our delivery charges constitute about one-third of our typical residential bill. The supply rate constitutes about 44% of an average residential bill. Since customers purchase their electricity supply from a range of competitive suppliers, the supply rate is largely outside of Con Edison’s purview. As much as practical, Con Edison’s electricity supply for its full service customers is developed from the least cost options available to the Company. The supply portion of our customer bill is directly related to the market price of electricity, which is itself highly dependent on regional fuel supply costs, fuel mix, environmental costs, and the supply/demand balance. Many of these core cost factors have been characterized by significant volatility in recent years. In addition, a supply tax, representing approximately 3% of an average residential customer’s bill, is imposed on each customer. The tax is based on a sales tax rate applied against purchased supply and a general receipts tax applied against Con Edison total revenues.

More than 22% of the total bill and 36% of the delivery portion of the bill is due to taxes and fees (see Figure 2-13, Chapter 2). These are largely out of the control of the Company yet contribute to the upward pressure on bills. We will continue our dialog with government and tax authorities to ensure full transparency of all components of the bill and to work toward minimizing upward pressure on our customers’ bills. We have consistently advocated on behalf of our customers that New York’s state and local governments reform utility taxation because of the regressive nature of utility taxes. In the current economic climate where large business users of electricity are aggressively seeking to reduce their energy costs, high taxes and fees imposed on a utility drive the cost of energy up, providing an incentive to explore other options. Loss of business customers would leave Con Edison’s residential customers to bear even higher costs to the detriment of New York’s economic viability. Taxes for CECONY, and therefore for our customers, are principally comprised of four components: property taxes, income taxes, revenue taxes, and sales taxes charged to customers. For the purposes of this plan, the tax rates were held steady for the duration of the plan horizon. However, the assessed value of property taxes, the largest contributor to the tax portion of our customer’s bill, increases over time with new capital infrastructure expenditures. The customer bill also includes fees collected for
governmental entities. The System Benefits Charge and Renewable Portfolio Standard surcharge are mandated fees that finance energy efficiency and renewable portfolio programs administered by the New York State Energy Research and Development Authority (NYSERDA). The System Benefits Charge funds programs that have been determined by the Public Service Commission to be inadequately addressed by New York’s competitive energy markets. In addition, the 18-a assessment fee is imposed by the New York State Legislature for the support of the State’s General Fund. Our plan reflects the current expiration dates of these fees, with the System Benefits Charge expiring in 2013, and the 18-a assessment fee due to expire in 2014.

It should be expected that this challenge will continue during the 20-year term of this plan, i.e., there will be a continuing tendency to raise taxes through the utility bill and use the utility bill to fund worthy social-environmental goals that would be more appropriately funded from general taxation revenues.

8.2 CONTINUALLY IDENTIFYING OPPORTUNITIES TO REDUCE COSTS

Savings Achieved through Planning Process

Of the total 20-year ESLRP capital expenditure illustrated in Figure 5-1 of Chapter 5, 60% is allocated to the Company’s asset management and equipment replacement, while 30% is used for system expansion to meet customer demand. This means that the majority of the Company’s spending is required for maintaining the safety and reliability of the existing electric infrastructure. It is therefore critically important to us that we optimize the management of component maintenance, repair, and replacement decisions to minimize cost impact to our customers.

Cost considerations are a major part of our planning process, and we’re continuously looking for ways to do things better. Our strategy is to invest in infrastructure enhancements only when less expensive alternative solutions are not available to sustain existing reliability levels, provide for localized delivery capacity needs, and ensure employee and public safety. Through the efforts of this long range planning process, we have been able to identify $3.1 billion in estimated savings over the twenty year horizon.

Major savings have come from our efforts in managing system expansion, using tailored and innovative approaches to system design and better managing our existing assets (explained in greater detail in Chapters 4 and 5). Managing system expansion allows for the deferral of capital-intensive infrastructure investments, which has substantial cost savings. Demand Side Management initiatives assure that we have the capacity necessary to support growing customer demand and support our ability to provide safe, reliable, and reasonably priced service that is environmentally responsible. The total savings realized from these programs is $459 million.

The Company intends to continue to develop and improve its integrated and tailored approach to meet customer demand. We have looked to 3G designs as an innovative approach to meet capacity needs at the least possible cost. 3G provides not only less asset intensive designs but also the capability to optimize on the asset utilization of what we currently own, allowing us to defer some of the large capital expenditures that would be required by implementing a traditional design. This is another example of how the Company strives to meet the needs of the customers in a more cost-effective way. The 3G savings are forecasted to be $659 million over the twenty year planning horizon.
The Company has also made great strides in determining ways in which we can better perform our asset management and equipment replacement programs. We are moving from time-based to condition-based maintenance, which drives towards better cost and performance management, and we have and will continue to develop planning tools like enhanced work management systems to help accomplish this. The Company has in fact realized, and will continue to realize, significant benefits from its targeted efforts to identify and implement the best mix of replacements, maintenance, and repair. The total savings realized from these targeted efforts is $2.3 billion.

As we expand and invest in our infrastructure over the next 20 years to meet the expected growing customer energy requirements, we will continue to manage our existing assets to implement better designs, make better purchase decisions, and better manage our inventory so that we can provide maximum benefit for our customers at the most reasonable price possible.

**Con Edison Supported Reforms to Reduce Customer Costs**

There are a number of governmental and policy reforms that the Company could pursue to reduce its electricity costs for its customers. They can be divided into: (1) tax reforms; (2) financing reforms; (3) supply reforms; (4) ratemaking reforms; (5) operational reforms; (6) customer service reforms; and (7) social policy reforms. Examples of each are set forth below.

**Tax Reforms**

- **Property Taxes**—The property tax classification system in New York City is outmoded and should be examined from the point of view of modernizing the tax system and achieving a more equitable approach to property taxation. These taxes are beyond the Company’s direct control. By reducing these taxes, we can reduce our customers’ bills, thereby increasing the affordability of the services we provide.

**Financing reforms**

Con Edison customers would benefit from low cost financing. For example, at one time, Con Edison had access to tax-exempt financing from the New York State Environmental and Research Development Authority (NYSERDA). Savings from tax-exempt debt are available to lower electric rates. Con Edison has been unable to issue tax-exempt debt since 1994. Among other things, Con Edison’s bond rating is not at a level that would make the Company eligible for the NYSERDA program without costly and difficult to get credit support.

- **Capital Recovery**—Faster capital recovery of utility investments, while potentially increasing bills in the short terms, would reduce long term rate pressure, and over time lead to lower bills.

**Supply reforms**

- **ISO Pricing Reforms**—Investigate changes required to lower energy costs through initiatives intended to improve market efficiency such as the NYISO’s broader regional markets initiative.

- **Upstate Hydropower**—Seek geographically equitable distribution of State-owned hydroelectric resources. New York’s upstate hydroelectric resources are a state resource and the benefits of these resources should be more equitably spread throughout the State.
Ratemaking reforms

- **Performance-Based Ratemaking (PBR)**—The Public Service Commission’s implementation of PBR could align investors’ and customers’ interests in more efficient operations by modifying rate plan frameworks to provide utilities with stronger incentives for achieving efficiencies.

Operational reforms

- **Equipment Inspection Program**—Currently-required equipment inspection cycles may be capable of reform to achieve operating goals more efficiently (e.g., extension of required inspection cycle from 5 years to 10 years may be feasible and would significantly reduce maintenance costs).

Customer service reforms

- **Customer Service Centers**—Customer service centers were once common in many industries, but they have been phased out. The current requirement for availability of face-to-face customer service in each borough or county may be an unnecessary cost.

- **Call Center Staffing**—With the growth in other methods of communication, call center requirements can be reviewed from the standpoint of cost, e.g., reduction in the service hours for non-emergency calls and requirements for toll-free telephone service.

Social policy reforms

- **Low-Income Customer Rate Program**—Seek additional governmental funding of the low-income program so as to reduce or eliminate subsidy by other customers.

- **Madison Square Garden (MSG) Discount**—Eliminate subsidy of MSG by other customers that is being provided pursuant to special interest legislation.

- **Joint Bidding**—Expand joint bidding on interference work (currently applicable only in limited areas of Manhattan) that would make public improvement work more efficient and less costly.

8.3 CUSTOMER BILLS

As a Company, our goal is to provide the best option for our customers’ energy service needs, and our customers have come to expect the highest service reliability from us. We want to be easy to work with, effective in our services, and an important supporting player in the local economy and our customers’ lives. We want to enable the next evolution in energy delivery infrastructure and operate a safe, sustainable and reliable system. We also will continue to plan, design, and manage our system in a cost effective manner, and to seek ways to advance the performance of our people and our infrastructure.

We will continue to do everything we can to keep our costs down and to help customers control their energy costs while maintaining the highest levels of service reliability and system safety. The delivery rate covers costs to build and maintain our transmission, substation, and distribution assets as well as to maintain and operate the customer billing and other operations platforms to service customers. Other components of the bill include supply costs and taxes and fees. Over the past twenty years we were able to keep delivery rates in-line with inflation, and we will try to keep our costs down as much as possible.
From our efforts to implement the plan initiatives, we project a bill increase slightly above the rate of inflation. Planned investment levels along with projected increases in the cost of supply will increase a typical New York City residential customers’ monthly bill from $83.43 today to $121.66 in 2030, an average compound annual growth rate (CAGR) of 1.41% from the end of our current rate settlement in 2013 through 2030. Our delivery charges, representing the cost of transporting energy from the point of supply to the Con Edison system to the customer, constitute about a third of the typical residential bill; the remaining two thirds are attributable to costs of supply and costs to cover taxes and fees imposed by various government agencies and electricity suppliers.

We strive to minimize customer bills and have outlined in this document several programs and initiatives to manage our infrastructure costs as well as to work directly with customers to manage their energy expenditures. We will continue to make every effort to keep our transmission and distribution rates down, nevertheless, as described above, market and policy forces outside of our control will continue to affect our customers’ bills.

As discussed throughout this plan, we see the objective to better manage costs to our customers as an imposing challenge, but one which we intend to pursue and achieve. We will continue to explore and implement ways to reduce rate and bill costs for our customers and operate our system in the most cost efficient way possible, while delivering the benefits of safe and reliable electric service to customers in an innovative and environmentally responsible way.

8.4 SUMMARY

The Electric System Long Range Plan provides us with a roadmap for our electric system for the next twenty years. This plan guides us toward a responsible energy future for our customers, with safe, reliable energy sources that are both environmentally responsible and affordably priced. Building that future will require that we meet the challenges described in this plan by maintaining the electric infrastructure necessary for the transmission and distribution of electricity and evaluating the role of advanced metering and smart grid technologies in modernizing the electric grid. This comprehensive plan is a holistic way to effectively integrate our electric system infrastructure plans with non-infrastructure related elements of our business, such as demand side solutions and renewable resources. The plan considers ongoing improved asset management for existing infrastructure and a tailored approach to design that includes alternatives and innovative technologies. The plan also provides a framework that links short-term projects and long-term actions to our goals and objectives.

To develop the forecasts for electricity demand and a supply outlook, we made assumptions regarding potential environmental and regulatory requirements, economic trends, and included possible technological advances to develop three forecasts for potential customer demand. We used the Plan Case demand forecast to develop the infrastructure projects and programs in this plan. Our plan was developed under considerable uncertainty (i.e., technological, regulatory, and economic) and as a result we identified key signposts that we will monitor and use to adapt our plan as changes occur. This first long range plan is intended to be a living document, with assumptions that will be refined in future versions.

Throughout development of the plan, we measured our performance by showing the expected benefits of our projects over the long-term, managed our costs to keep in mind rate and customer bill impacts, and sought to maintain electric system reliability while reducing the risk of a prolonged network shutdown or public safety issues.
We discuss a phased implementation plan that will put the Company on track to meet the challenges we foresee today and position us to deal nimbly with new challenges as they emerge. In the next twenty years, our plan calls for investments of nearly $28.6 billion in capital investments (in real 2010 dollars) in our electric delivery system, or an average of $1.36 billion a year. Ongoing investment in our electric infrastructure is necessary in order for the Company to be able to continue to meet the energy demands of our customers in a safe and reliable manner. This level of investment along with expected increases in the price of supply results in an average annual increase in rates of 1.41% from the end of our current rate settlement in 2013 to 2030.

We remain sensitive that any rate increases impact our customers and we strive to keep rates as flat as possible. We have been successful in keeping the real price of electricity flat, on par with general inflation in the economy over the past 20 years. We fully recognize the importance of mitigating cost increases to our customers, and we are committed to keeping costs down as much as possible through continued cost management, efficiencies and innovations. We are committed to rigorously pursue regulatory and tax reforms as well. We are also mindful of the Company’s need to continue to attract large amounts of capital on reasonable terms.

We also recognize that utilities can play a key role in helping the federal, state and local governments meet their energy policy objectives. We are committed to working with various stakeholders (our customers, the community, legislators, regulators, and others) in order to implement our plan successfully.