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VIA ELECTRONIC DELIVERY

September 5, 2014

Hon. Kathleen H. Burgess, Secretary
New York State Department of Public Service
3 Empire State Plaza, 19th Floor
Albany, New York 12223-1350

Re: Case 08-E-0827, Comprehensive Management Audit of Niagara Mohawk Power Corporation d/b/a National Grid's Electric Business

Case 12-E-0201, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service

Electric Transmission and Distribution System Fifteen-Year Plan

Dear Secretary Burgess:

Pursuant to the Commission's *Order Directing the Submission of an Implementation Plan* in Case 08-E-0827 (issued and effective December 18, 2009), and *Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal* in Case 12-E-0201 (issued and effective March 15, 2013), Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid" or the "Company") submits the attached Electric Transmission and Distribution System Fifteen-Year Plan ("Fifteen-Year Plan" or "the Plan"). The Fifteen-Year Plan covers the Company's fiscal years 2015 to 2029 (FY15 - FY29) and reflects the Company's current assessment of its electric system needs over a fifteen-year horizon. The Plan is a result of the management audit of National Grid's electric business performed in Case 08-E-0827, and implements several of the recommendations contained in the final audit report adopted by the Commission) in that case.

Please contact me if you have any questions regarding this filing. Thank you for your attention to this matter.

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Respectfully submitted,

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NY Fifteen-Year Plan

Electric Transmission & Distribution System

PREPARED FOR:

THE STATE OF NEW YORK PUBLIC SERVICE COMMISSION

THREE EMPIRE STATE PLAZA

ALBANY, NY 12223

SEPTEMBER, 2014

nationalgrid

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Chapter 1. Executive Summary

1. A. Overview

Niagara Mohawk Power Corporation d/b/a National Grid (National Grid or the Company) presents this Fifteen-Year Electric Transmission & Distribution System Plan (Fifteen-Year Plan or Plan), reflecting the Company's current assessment of its electric system needs over a fifteen-year horizon. The Fifteen-Year Plan is a result of the management audit of Niagara Mohawk's electric business performed in Case 08-E-0827, and implements several of the recommendations contained in the final audit report adopted by the Public Service Commission (Commission) in that case.[1]

On April 25, 2014, the Commission launched its Reforming the Energy Vision ("REV") initiative.[2] The REV proceeding is aimed at reshaping the electric industry to meet the needs and expectations of customers in the 21st century, while also addressing some of the most pressing challenges facing our society. The REV proceeding, among other things, will examine the role of utilities in enabling system-wide efficiency and market-based deployment of distributed energy resources ("DER") and load management, and will look at regulatory and market changes that might be implemented to achieve desired outcomes. Key to achieving the REV goals is revising the utility's planning process to more readily integrate customer-sited generation, micro-grids, and other DER and enable more direct customer participation in energy markets. The new planning processes contemplated by REV would also rely more on DER to meet system needs in a way that protects operational resiliency and information security needs, while still addressing aging infrastructure. In addition to the REV proceeding, a number of other significant efforts since the Company's first Fifteen-Year Plan filing on February 29, 2012 also influence the Company's future investment plans. The recommendations of the Moreland Commission, the State Energy Plan, and the Energy Highway Initiative all will affect investments going forward.

[1] Case 08-E-0827, Comprehensive Management Audit of Niagara Mohawk Power Corporation d/b/a National Grid's Electric Business, *Order Directing the Submission of an Implementation Plan* (issued and effective December 18, 2009).

[2] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, *Order Instituting Proceeding* (issued and effective April 25, 2014) ("REV Proceeding").

The Company's Fifteen-Year Plan is based on its vision for the electric system of the future, which includes creating a more resilient electric backbone for reliable service that is also flexible enough to recover quickly from more frequent and severe weather events. The electric system of the future will also enable greater customer-side participation, and system investments should be consistent with fostering more transparent and dynamic markets, while also increasing opportunities to engage with customers and other stakeholders on tailored solutions to address identified needs more effectively and efficiently. This version of the Company's Fifteen-Year Plan further progresses towards that future vision.

The Fifteen-Year Plan is that it brings together traditional transmission and distribution planning, non-infrastructure considerations, technological developments and other factors in a single place. The Plan builds upon information in the Company's other major electric system planning and assessment reports: the Asset Condition Report,[3] the Capital Investment Plan ("CIP"),[4] and the Electric Service Reliability Report,[5] and goes beyond the timeframes considered in those other reports. The ultimate objective of the Fifteen-Year Plan is to develop an integrated system plan to provide customers with safe, reliable and reasonably-priced service to meet their needs over the long term.

The Fifteen-Year Plan also provides a forum for the Company to consider how potentially significant social, environmental, economic, technological and regulatory changes may influence the future electric system and investment plans. Clearly the REV proceeding is focusing on these same issues and future Company plans will be highly influenced by policy directives in the REV proceeding orders. Because the REV proceeding is on-going, the Company's current Fifteen-Year Plan reflects its best attempt to describe anticipated long-term investment levels based on information known today. With the understanding that the REV proceeding could significantly alter the Company's system and investment plan going forward and could continually evolve over time.

The Company's capital spending plan is categorized by Spending Rationale (i.e., Customer Requests/Public Requirements; Damage/Failure; System Capacity and Performance; Asset Condition; and Non-infrastructure), and also by system (i.e., transmission, sub-transmission and distribution). Table 1-1 and Figure 1-1 summarize the Fifteen-Year Plan forecasted spending by system for the period FY15 - FY29.

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[3] Case 06-M-0878, Joint Petition of National Grid PLC and KeySpan Corporation for Approval of Stock Acquisition and Other Regulatory Authorizations ("National Grid-KeySpan Merger"), *Report on the Condition of Physical Elements of Transmission and Distribution Systems* (most recently submitted October 1, 2013).

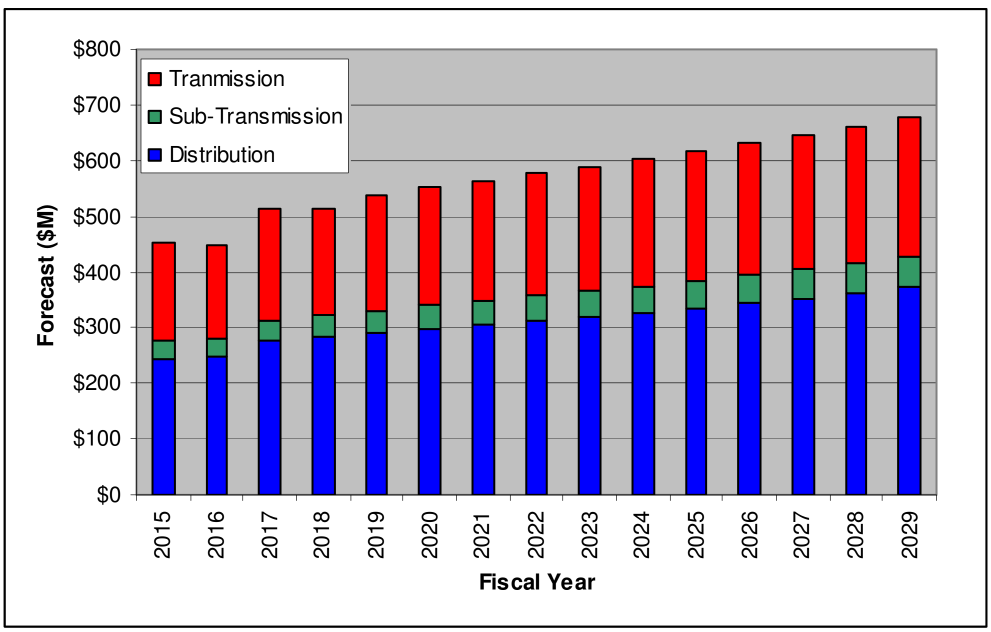
[4] Case 10-E-0050, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation for Electric Service, *Transmission and Distribution Capital Investment Plan* (most recently submitted January 31, 2014).

[5] Case 02-E-1240, Proceeding on Motion of the Commission to Examine Electric Service Standards and Methodologies, *Annual Reliability Report* (most recently submitted March 31, 2014).

Table 1-1
Fifteen-Year Plan Forecasted Spending By System ($M)

System	Fiscal Year														
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Tranmission	176	167	199	189	206	210	214	218	223	227	232	236	241	246	251
Sub-Transmission	33	33	37	40	42	45	45	46	47	48	49	50	51	53	54
Distribution	243	248	276	284	289	297	304	312	318	326	335	344	353	362	372
Total	452	448	512	513	537	551	564	576	588	602	616	630	645	661	676

Figure 1-1
Fifteen-Year Plan Forecasted Spending By System ($M)



Based on the capital investment projections in this Fifteen-Year Plan, the Company prepared a simplified analysis to estimate revenue requirement effects and anticipated customer bill impacts in 2029 for both the Base Case, as well as an Advanced Grid Case. The Base Case reflects the base level of investment described in this Fifteen-Year Plan, while the Advanced Grid Case reflects the base level of spending in the Plan, *plus* incremental spending associated with investments designed to modernize the electric system, as described in Chapter 7, Section 7.C.6.

Figure 1-2 shows the bill impacts on a nominal basis (2029 dollars) from 2014 to 2029 under the Base Case for a 600 kWh per month residential customer. The Company estimates that this investment plan, and inflation on operating expenses, would raise a typical customer's delivery bill on a nominal basis by 27% or $11.71; a 1.8% per year increase over the period of the Fifteen-Year Plan.

Figure 1-2
Typical Residential Bill – Nominal (Base Case)
(600 kWh Monthly Usage)

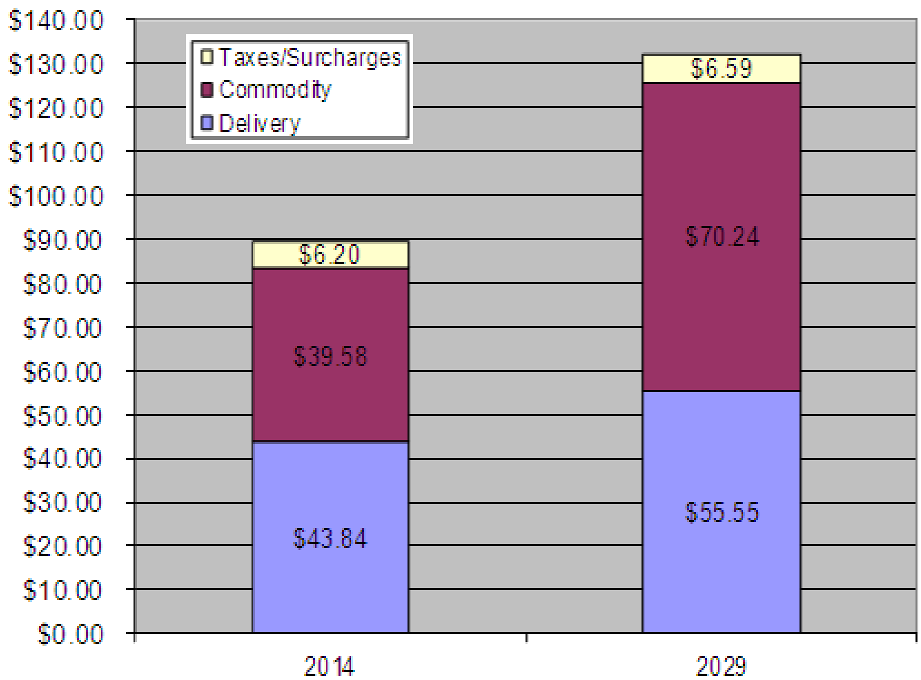
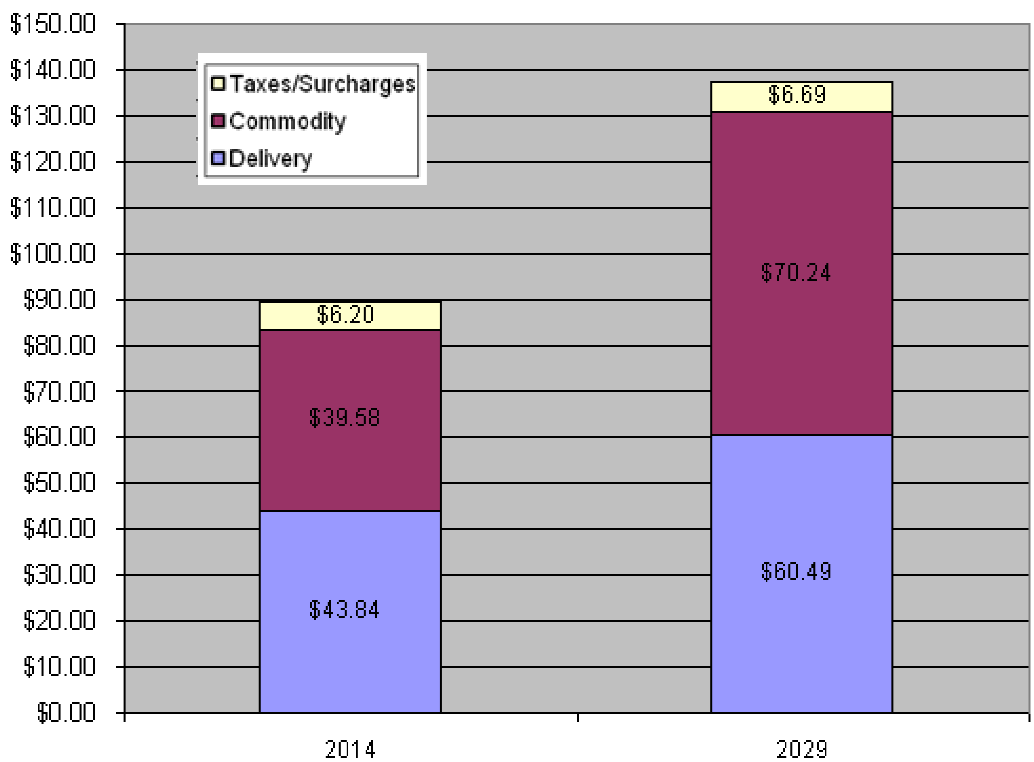


Figure 1-3 shows the bill impacts on a nominal basis (2029 dollars) from 2014 to 2029 under the Advanced Grid Case for a 600 kWh per month residential customer. Under the Advanced Grid Case, the Company estimates that a typical residential customer's delivery bill would increase on a nominal basis by approximately 38% or $16.65; approximately 2.5% per year increase over the period of the Fifteen-Year Plan.

Figure 1-3
Typical Residential Bill – Nominal (Advanced Grid Case)
(600kWh Monthly Usage)



Details of the simplified analysis for each rate class for the Base and Advanced Grid cases, including assumptions, are provided in Chapter 8.

1. B. Key Elements of the Fifteen-Year Plan

1. B. 1. Planning Approach and Focus on the Customer

To create the Fifteen-Year Plan, the Company reviews past performance of the system and forecasts future needs against a wide array of criteria and information. Such information includes projected customer demand and requirements, reliability performance, asset condition issues, and requirements imposed by external authorities. The Company also evaluates the impact of proposed developments in areas outside of the Niagara Mohawk service territory and what impacts these developments could have locally. The Company also considers potential future drivers that may influence needs later in the plan timeframe.[6] Based on this information, the Company evaluates the needs, risks, costs, and available alternatives to develop comprehensive project plans to meet projected customer and system needs in a reasonable manner.

The Company developed its Fifteen-Year Plan in the following manner. First, the Company reviewed the existing Five-Year Capital Investment Plan (CIP) to assess the potential for significant load additions in years six through fifteen. The Company also considered whether asset condition issues involving equipment no longer economical to repair or adversely affecting the ability to provide safe and reliable service could become prevalent during that period. Solutions to address these issues form a set of required actions in the Plan.

As a second step, the Company evaluated the evolving energy market, regulatory requirements and customer needs. As mentioned in the context of the REV proceeding, the Commission is examining ways to reshape energy markets and alter the regulatory paradigm, and the results of such efforts are unknown at this time and therefore not reflected in this Plan. However, the Company is working with customers and other stakeholders to forge collaborative partnerships to develop cost-effective, innovative energy solutions tailored to local community needs that support local economic growth and development. For example, the Company has been working with the Buffalo Niagara Medical Campus (“BNMC”) to help the customer plan for and manage expected growth in the Buffalo-Niagara region. Elements of this effort include, among other things, the SmartHome program, an advanced buildings program, and a smart grid study. The Company also has been coordinating with BNMC to implement electric vehicle charging stations, renewably-powered parking lot lighting, and alternative transportation programs. Key to the success of the partnership with BNMC is listening and responding to the customer’s needs to provide more tailored, holistic, and innovative energy solutions.

[6] Although premature for this edition, the Company anticipates that the REV proceeding will strongly influence all future versions of the Fifteen-Year Plan.

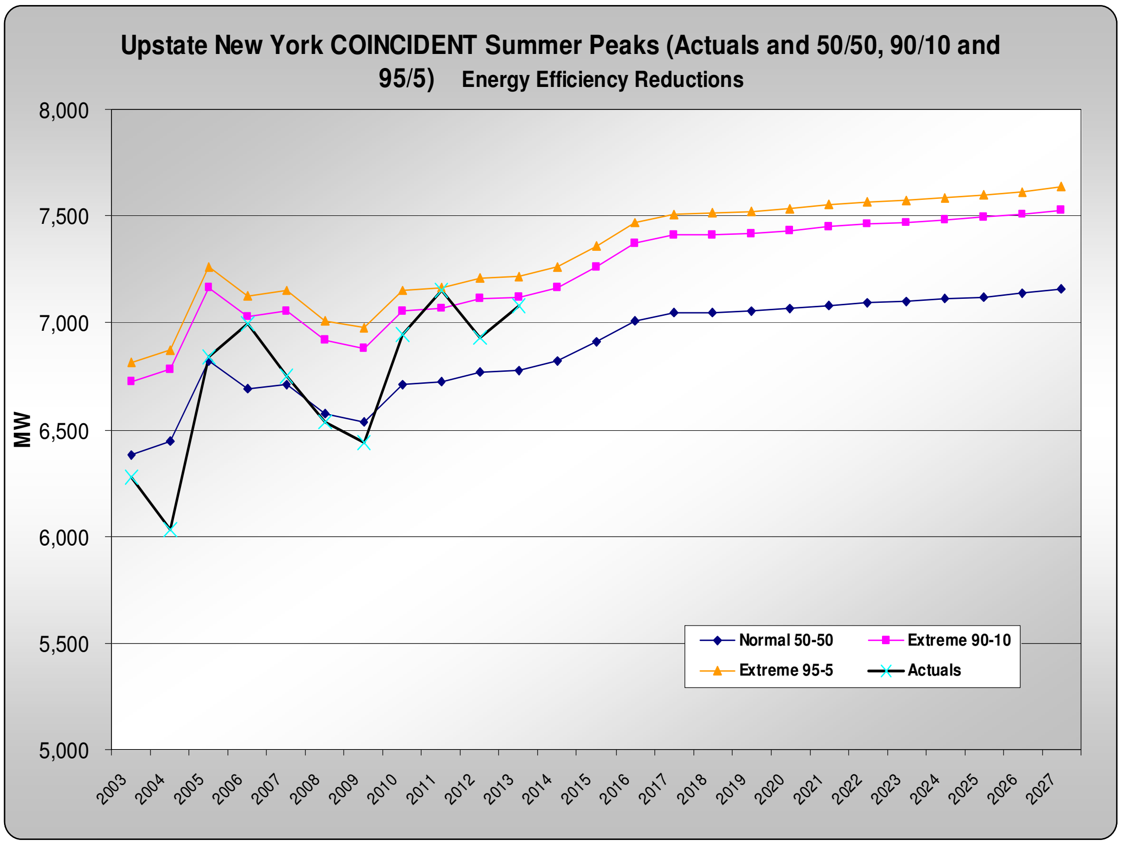
The Company continues to further develop its non-wires alternatives framework. To date, the Company has not implemented a non-wires alternative project, but is actively evaluating the potential for a project in the Brockport area. The Company expects to complete its evaluation of the feasibility of the Brockport project by the end of calendar 2014. The Company anticipates incorporating lessons learned from the Brockport experience into future non-wires alternative evaluations and capital project assessments.

1. B. 2. Long-Range Demand Forecast

The Fifteen-Year Plan starts with development of a long-range demand forecast. Improvements in forecasting methodology provide for more accurate regional assessments, allowing planners to develop better system models, which in turn can lead to more tailored system plans, and ultimately improved solutions for the benefit of customers. The effects of how the Company might implement policy directives from the REV proceeding obviously cannot be reflected in the forecast in this Fifteen-Year Plan; however, the long-term forecast does account for the effects of energy efficiency initiatives approved through 2015, as well as technological developments such as electric vehicles ("EVs"). As the electric system is modernized with new technology, there will be greater potential to deliver significant benefits to customers. There will be a need for further consumer outreach and education on available technology and benefits in managing electricity usage. Targeted deployment of advanced grid applications will likely be useful in meeting existing and future planning guidelines and regulatory performance requirements. These factors are important signposts that will influence the Company's future system plans, and are addressed within the Fifteen-Year Plan.

With respect to currently available forecasts, the Company anticipates an average growth of 0.8% per year over the next five years. Over the fifteen-year planning horizon, long-term growth is expected to average 0.5% per year versus 2013 weather normalized peak of 6,788 MW and the Company must plan to meet expected demand. The Company's actual peak demand in 2013 was 7,078MW, on Friday July 19th and became the Company's second highest all-time peak. This value includes the impacts of Demand Response (DR) programs activated by the New York Independent System Operator (NYISO). It was 1% below the Company's all-time high of 7,150 MW reached on Thursday, July 21, 2011. Figure 1-4 shows the Company's actual coincident peaks through 2013, as well as projected coincident peaks for the following weather cases: 50/50 normal; 90/10 extreme weather; and 95/5 extreme weather.

Figure 1-4
National Grid Actuals/Weather Normal and Extremes Forecast Summer Peak (MW Before EE Reductions) [7]



Forecasting peak electric load enables the Company to assess the availability of electrical infrastructure, enables timely procurement and installation of required facilities, and provides system planning with information to prioritize and focus action plans. The peak forecast is also used by the NYISO to determine how much installed capacity (ICAP) will need to be procured by the Company for its customers.

Based on peak demand projections provided in the Upstate NY coincident summer peak forecast the Company does not project a notable increase in infrastructure spending to address thermal performance concerns when viewed at the full system level. However, spot load developments (possibly significant) may occur, requiring

[7] National Grid - Upstate New York Peak (Summer & Winter) MW Forecast By Region, Customer Organization, October 2013, Revision 0, Page 6.

targeted projects to provide service. This could result in regional spending variations which would be reflected in future Plans. It should also be noted that the Company modified its distribution planning criteria in 2011, which reduced acceptable outage exposure from single contingency events. The cost of complying with these criteria was not reflected in the Company's previous Fifteen-Year Plan (2012). Projects reflecting the cost to achieve the updated criteria are now in the Company's portfolio, and contribute in part to increased capital spend beginning in FY17.

Supporting detail for the fifteen-year load plan is covered in Chapter 3.

1. B. 3. Asset Condition

Investment due to Asset Condition represents a substantial proportion of the planned investment over the Fifteen-Year Plan. The deterioration of transmission and distribution assets caused by exposure to the environment and typical usage is managed through routine preventive and corrective maintenance actions. Where deterioration cannot be corrected through maintenance, refurbishment or replacement is necessary. This may take the form of a full replacement or a partial refurbishment where cost effective. The principal asset condition programs affecting the Company's system plan over the next fifteen years are described in the annual Asset Condition Report. The pace of asset condition program development and execution has not slowed and in fact increased since Company's submittal of the previous Fifteen-Year Plan (2012). Projects reflecting the cost to deliver these programs are now in the Company's portfolio, and contribute in part to increased capital spend beginning in FY17.

1. B. 4. Future Influences and Key Drivers

The near-term portion of the Fifteen-Year Plan reflects the Company's view of what is needed to maintain safe, reliable and reasonably priced service for customers today. However, the medium-term and long-term portions of the Plan are likely to be influenced by external drivers the Company cannot accurately predict. Developments to harden and increase the resilience of the electric system will affect the Company's near-term and long-term investment plans. In addition, changes in the generation market (including retirement of existing generation capacity), changes in the regulatory paradigm, significant increases in distributed generation, utility-scale renewable resources, widespread adoption of EVs, and domestic natural gas production, all could affect future investment needs in unpredictable ways. Some of these external factors are discussed below.

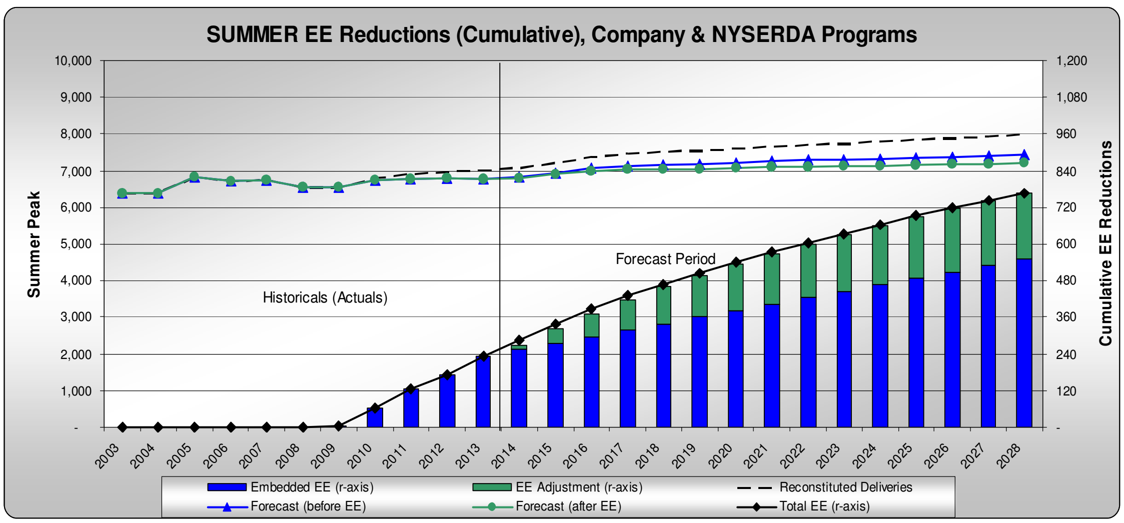
1. B. 4. 1. Energy Efficiency

The Commission's Energy Efficiency Portfolio Standard ("EEPS") Order specifies a goal of 15% savings by the year 2015 (or "15 x 15"). To meet this goal, the Company began implementation of a portfolio of EEPS programs in 2009. These programs have significantly ramped up and as of 2014 are delivering substantial savings.

For this forecast the currently approved program targets through 2015 are incorporated. EEPS program goals through 2015 are assumed at 75% of the target to account for uncertainty. Post 2015 energy efficiency reductions are assumed to continue, but at a declining rate of 95% of each prior year to account for increasing costs and uncertainty to obtain similar additional savings longer term.

Figure 1-5 shows the reductions to the forecast to capture energy efficiency reductions.

Figure 1-5
Company Sponsored and NYSERDA Energy Efficiency Cumulative (MW) [8]



The REV proceeding contemplates that utilities will more fully integrate energy efficiency and engage customers in the goal of bill reduction as well as targeted system needs. The New York State Energy Research and Development Authority ("NYSERDA") is also expected to refocus on energy efficiency market transformation strategies to strengthen and expand the impact of energy efficiency going forward.

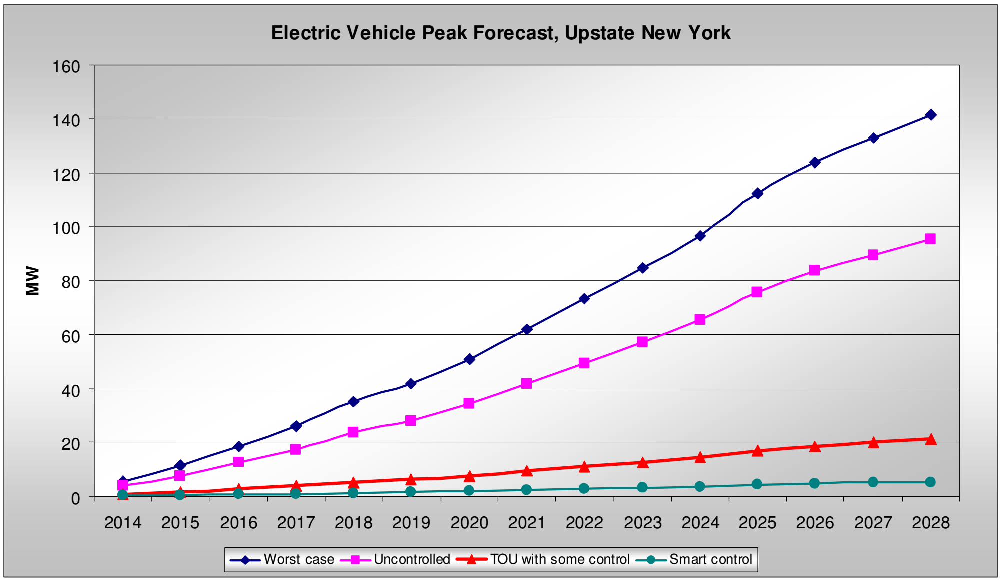
1. B. 4. 2. Electric Vehicles

The peak forecast for Niagara Mohawk may also be adjusted for various EV scenarios. National Grid has developed estimates of the future impact of EVs on peak demand on residential feeders under several penetration scenarios.

Figure 1-6

[8] National Grid - Upstate New York Peak (Summer & Winter) MW Forecast By Region, Customer Organization, October 2013, Revision 0, Page 8.

Electric Vehicles Peak Impact in Niagara Mohawk Service Area (MW) [9]



Under the "Uncontrolled" charging case, the impact of EVs on the Company's residential peak could reach approximately 24 MW by 2018. As a point of reference, in its prior Fifteen-Year Plan, the Company estimated the "Uncontrolled" impact of EVs by 2016 would be 46MW. Moving forward it is likely that "Time of Use (TOU)" rates will be implemented and the TOU charging case will become representative of grid impacts. In this case, the EV impact on the residential peak could reach 23 MW (0.3% of peak) by 2028.[10]

The scenarios reviewed are discussed in Chapter 3.

1. B. 4. 3. Demand Response

Demand Response ("DR") programs actively target reductions to peak demand during hours of high expected demand and/or reliability problems. These are in contrast to the more passive energy efficiency savings discussed above that provide savings throughout the year. The DR programs enable the NYISO to take action in response to a system reliability concern or economic (pricing) signal. During these events customers can actively participate by either reducing their load ("Emergency Demand Response Programs", or "EDRPs") or by turning on a generator (or "Special Case Resources" or "SCRs") to displace load from behind the customer's meter. DR

[9] National Grid - Upstate New York Peak (Summer & Winter) MW Forecast By Region, Customer Organization, October 2013, Revision 0, Page 14.
[10] Forecast combines latest monthly sales trended for two years (to 2015) and AEO 2013 long-term projections for the Northeast, proportioned by load to National Grid's territory.

currently is initiated by the NYISO, primarily during times when the system is at peak conditions, or for "Peak Clipping." Because the Company is unable to control or consistently rely on DR to reduce peak loads, it must plan its system in the event that they are not called. A recent decision of the U.S. Court of Appeals for the District of Columbia calls into question whether DR programs will continue to be administered by the NYSIO. Although the Company does not offer specific DR programs at this time, the REV proceeding contemplates that the local distribution utility—serving as a Distributed System Platform Provider ("DSPP")—will implement and play an active role in a future DR market and DR products.

Table 1-2 shows the total MW of demand reductions that were enrolled in New York (of which the Company is only a part) during last summer's peak month.

Table 1-2

SCR Enrollment – July 2013

Special Case Resources

UCAP Available for ICAP Auction

Zone	MWs (UCAP)
A	303.6
B	58.7
C	105.2
D	4.9
E	28.4
F	95.2
G	25.4
H	4.2
I	21.3
J	341.5
K	77.8
Total	1066.2

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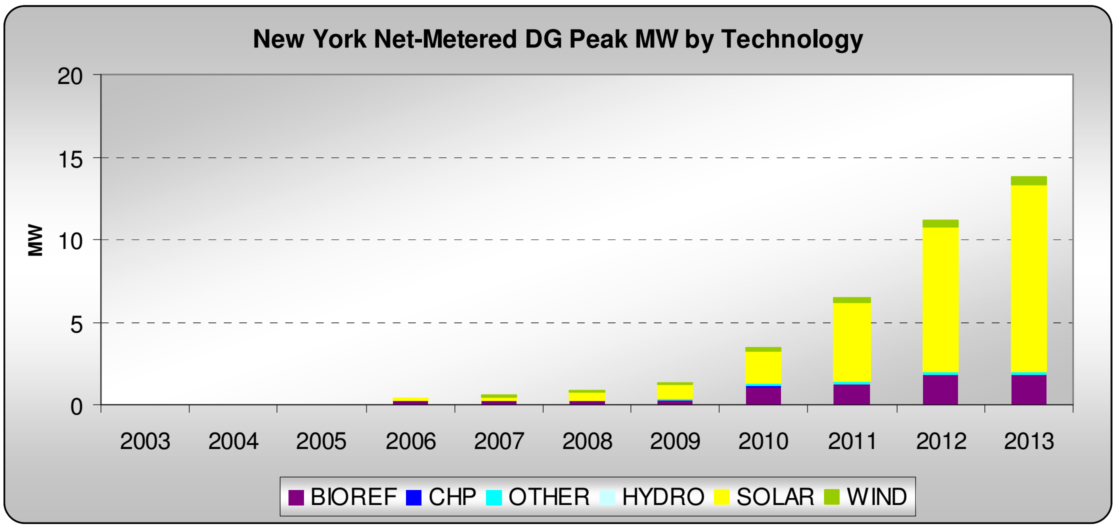
1. B. 4. 4. Distributed Generation

Distributed Generation (DG) includes installations that can inject power beyond that of the larger centralized plants and/or lower customer use of energy from the grid via "behind the meter" installations. The types of DG that lower customer demand and are growing the most in recent years include solar and wind. Of particular interest and impact to the load forecasting process are these "behind the meter" or "net metered" installations because of their direct load lowering impact at the customer level.

A customer's decision to install and run a DG system is made based on regulatory, economic and operational drivers. These technologies are installed primarily for their energy savings to the customer but they also have impacts that reduce the peak demand loads.

Figure 1-7 indicates that in 2013 there were approximately 14 MW (33 MW nameplate) of DG installations coincident with peak in the Company's service territory.[11]

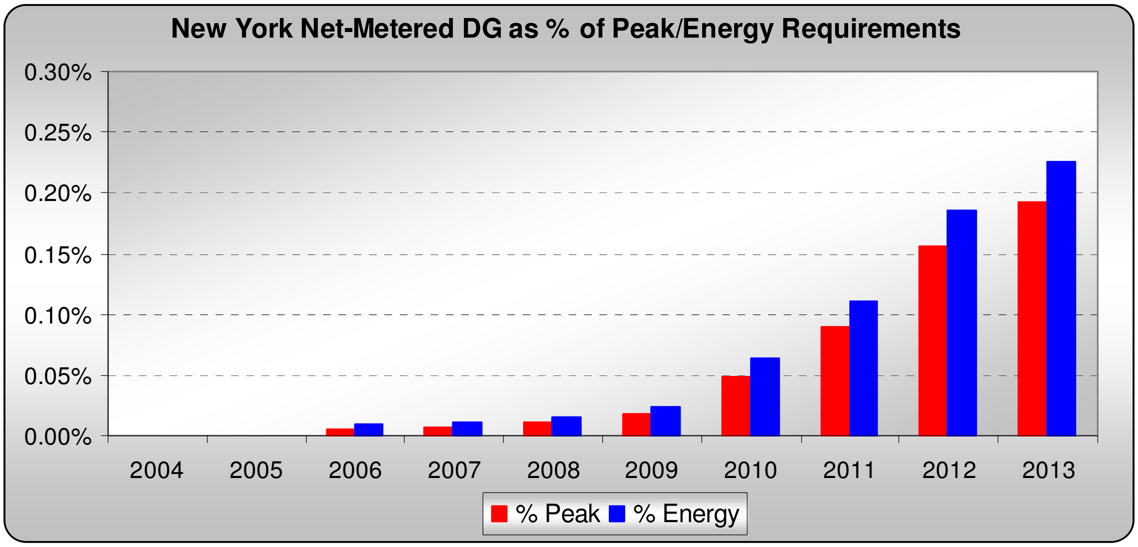
Figure 1-7



[11] Because not all nameplate installed MWs are coincident with the Company's summer peaks, a conversion is made to derive estimated coincident values as follows: Wind: 25%; Solar: 40%; CHP: 95%; and Other: 30%.

Figure 1-8 shows what the estimated historical net metered impacts have been as a percent of Company load. The current level is about 0.2%.

Figure 1-8



The impact of DG installations on the peak is considered already embedded in the historical values and no additional adjustments were made to the forecast. At this time, the impact on total load is small and, therefore, not significantly impacting the overall load forecast; however, realization of the REV objectives will significantly affect the impact of DG on system loading in the future.

1. B. 5. Customer Needs and Market Information

As the REV proceeding highlights, customers will be the key participants affecting the development of EV, DER (i.e., DG, EE, and DR), and other major electric industry drivers. How the Company engages with its customers will play a critical role in the manner and rate of customer participation and impact. National Grid is implementing programs to better engage customers and provide an improved customer experience. The Company's new E-Zone strategy exemplifies this transition to a more customer-focused organization. The goal of the E-Zone initiative is to forge collaborative partnerships with our stakeholders to develop innovative energy solutions tailored to the local community needs, and support local economic growth and development. Our first E-Zones are currently being developed with the Buffalo Niagara Medical Campus (energize BNMC), with other potential E-Zones under consideration. The Company will continue to work with the Commission and key stakeholders to develop this strategy.

1. B. 6. Long-Term Supply Outlook

Over the period addressed in the Fifteen-Year Plan, the composition, availability, and affordability of electric supply may be subject to dramatic change. Based on projections by the U.S. Energy Information Administration (EIA), the Company expects supply costs to rise through the period of the plan, placing upward pressure on customer bills.

The Company procures energy for its full service customers (i.e., those customers that do not procure their energy from electric service companies or other third-party providers), whose consumption in 2013 represented approximately 46% of all of the Company's delivered energy. The Company's procurement strategy follows the Commission's policy on electric commodity portfolios. That policy requires that supply for larger commercial and industrial customers be procured through the NYISO markets without any additional hedges provided on their behalf. The policy also requires that supply for the mass market customers (residential and small non-demand commercial) be procured through a managed program to mitigate supply cost volatility. The Company continues to explore and discuss with Staff appropriate supply-side opportunities and activities that may benefit customers.[12]

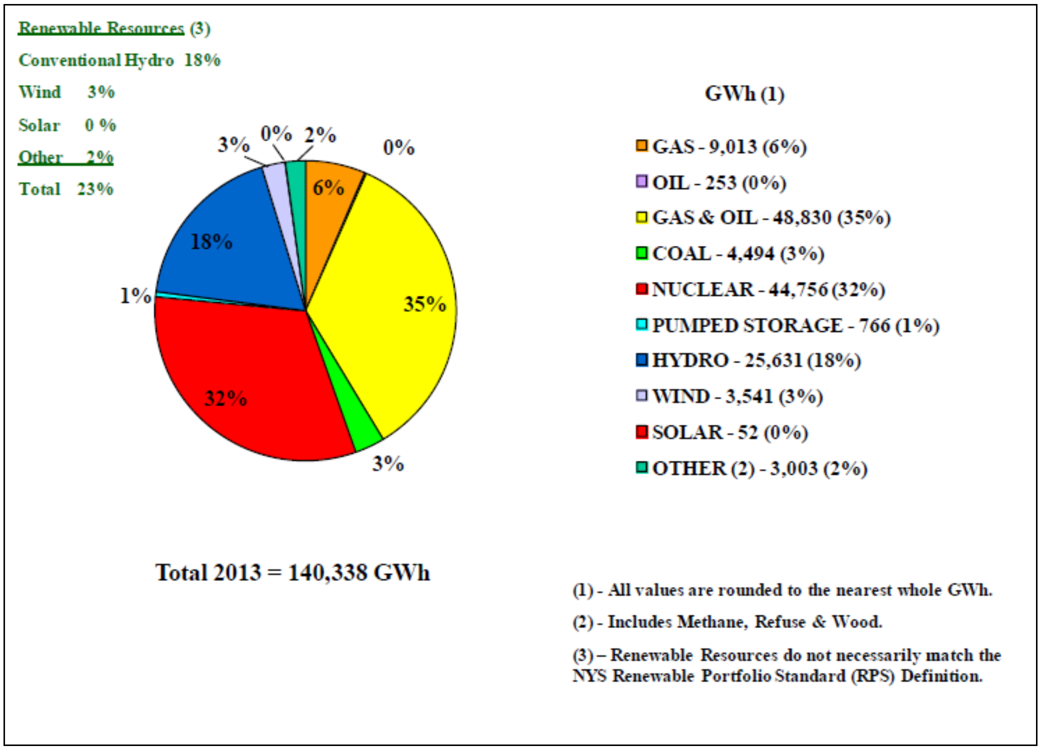
The outcome of the REV proceeding is anticipated to significantly affect the operation of New York's retail and wholesale electric markets, including the Company's role in providing electric supply to customers. Nevertheless, for purposes of the estimates reflected in this Fifteen-Year Plan, the Company used the publicly available electric supply cost estimates.

Projections from the EIA's Annual Energy Outlook[13] suggest that the cost of supply will grow on a real dollar basis from 6.1 cents per kWh in 2014 to 8.2 cents per kWh by 2029, an increase of 34%. This represents an average annual (compound) growth rate of 2.0%. On a nominal basis, the cost of supply will grow to 10.8 cents per kWh in 2029, an increase of 76%, or an annual growth rate of 3.9%.

The cost of supply is directly affected by additions or retirements to the generation resource mix supplying customers in the Company's service territory. Figure 1-10 shows the resource mix in New York State as of 2013. The total output from generators that use natural gas as their primary fuel in New York has increased 3% from 2010 levels to become 41% of the total generation production in 2012.

[12] The Company has also undertaken a proactive role in energy efficiency and demand response programs to reduce electric demand, as discussed above.
[13] Based on EIA AEO 2014 report, NPCC Upstate New York EMM region, reference case, vintage Dec. 2013

Figure 1-9
New York State Fuel Mix
2013 NYCA Generation by Fuel Type[14]



Potential legislative and regulatory changes over the planning period that also could affect supply prices include possible national Renewable Portfolio Standard ("RPS") and Clean Energy Standard programs, a national CO2 cap and trade program, the EPA's recently proposed its Clean Power Plan, and the Regional Greenhouse Gas Initiative ("RGGI"), which is already in place for the Northeast United States. Individually or combined, such programs would likely increase the unit cost of centrally-generated electricity for customers by valuing the cost of CO2 emissions.

1. B. 7. Other Factors Affecting the Fifteen-Year Plan

The REV proceeding has the potential to greatly affect the structure and operation of the electric industry over the time horizon of the Plan. Although some investment areas may not be significantly impacted (*e.g.*, asset condition spending on transmission backbone facilities), National Grid expects that policy changes resulting

[14] NYISO "Gold Book," 2013 Load and Capacity Data (April 2013), p. 51.

from the REV proceeding could significantly alter the Company's system and investment plans going forward. In addition to the REV proceeding, other external factors also have the potential for affecting customer demand, costs, and system development over the fifteen-year timeframe of this plan, including:

- Sustained economic expansions or downturns.
- Significant changes in the price or availability of fossil fuels (e.g., gasoline, natural gas, shale gas development, etc.).
- Changing regulatory or compliance requirements requiring increased or different investments (*e.g.*, the July 2016 implementation of Bulk Electric System requirements may result in increased investment, or accelerated remediation requirements from North American Electric Reliability Corporation (NERC) actions). Examples include updated planning standards, physical security, Critical Infrastructure Protection (CIP) standards in substations, and disturbance monitoring.
- Increased penetration of large-scale renewable resources and the transmission infrastructure needed to deliver those resources.
- Generation resource retirements resulting in the need for significant transmission system expansion or reinforcement in order to maintain reliable service.

The Fifteen-Year Plan reflects the Company's projection of system investment needs given available information at this time, adjusted to account for a probabilistically occurring variation in the actual demand driver. The Company's approach to the uncertainty inherent in longer-term planning is to establish tools and processes that enable flexibility and promote efficient system development to respond to needs as they emerge and their impacts are better understood. In developing and implementing the Fifteen-Year Plan, the Company has made and will continue to make adjustments to reduce costs and maximize opportunities for greater efficiency, consistent with the provision of safe, reliable and reasonably priced service to customers.

The remainder of this document provides detail on the processes and programs that comprise the Fifteen-Year Plan as well as greater detail on influences and key drivers that will affect the future evolution of the Plan.

1 C. Fifteen-Year Plan Development

Chapter 2 includes a description of how the Fifteen-Year plan is developed and maintained, and summaries of the spending categories. Chapter 9 - Exhibit A contains the projected investment levels in the Plan by spending category.

1 D. Planning and Driver Considerations

Chapter 3 provides detail on how the long-term term load forecast is developed and used in preparing the Fifteen-Year Plan. This chapter also describes several of the drivers the Company anticipates will influence its capital investments over the next fifteen years.

1 E. Evaluating Effectiveness of the Fifteen-Year Plan

Recommendation VII-3 of the Company's management audit implementation plan in Case 08-E-0827 requires evaluation of the effectiveness of the system plan to determine how it is achieving objectives. Chapter 4 describes factors the Company considered in evaluating the Plan and presents the results of that evaluation. The Company will continue to consider factors and measures that could be assessed to evaluate the effectiveness of the Fifteen-Year Plan and apply lessons learned from that process to improve future plans.

1 F. System Level Discussions by Spending Category

Chapters 5, 6 and 7 provide a more detailed description of the Plan for the transmission, sub-transmission and distribution systems, respectively. The chapters are further broken down by spending category based on the primary investment driver: Customer Requests/Public Requirements; Damage/Failure; System Capacity and Performance; Asset Condition; and Non-Infrastructure. The major programs and projects described in the annual Capital Investment Plan ("CIP") for Plan years FY15 to FY19 are discussed; however, the level of detail provided in the Fifteen-Year Plan for such programs and projects is less than included in the CIP, and readers are referred to the CIP for additional detail. Chapters 5, 6, and 7 also describe anticipated impacts of factors outlined in Chapter 3 on the various spending categories. Major project and program work beyond FY19, if known, is also described.

1 G. Rate Impacts by Service Class and Voltage

Chapter 8 presents a simplified rate and customer bill impact analysis based on projected investment levels in the Fifteen-Year Plan.

1 H. Exhibits

Chapter 9 - Exhibit A includes forecasted investment levels in Exhibit A. The forecast is broken down by spending category and programs and projects within the spending categories.

Chapter 10 - Exhibit B includes bill comparison in Exhibit B. The bill is broken down by typical customers by service class and voltage.

Chapter 2. Fifteen-Year Plan Development

2. A Context and Purpose of the Plan

National Grid serves approximately 1.6 million electric customers in upstate New York. The Company's service territory covers over 25,000 square miles, and includes everything from densely populated urban areas in Buffalo, Syracuse, and Albany, to remote and sparsely populated rural areas throughout upstate New York. The system includes over 1,200,000 distribution poles, 55,000 transmission structures, nearly 36,000 miles of distribution overhead primary conductor, 420 distribution substations, and 323 transmission substations; all of which may be subject to extreme weather conditions. Residential and commercial customers alike depend on National Grid to provide safe, reliable, and efficient electric service.

This Fifteen-Year Plan is designed to align with the Company's electric business plan priorities, which support the Company's objective of delivering electric service safely, reliably and securely, with high levels of customer service and environmental performance. The Fifteen-Year Plan also complements the Capital Investment Plan ("CIP"), is consistent with National Grid's vision for the electric system of the future, and attempts to identify drivers and challenges that could affect planning, infrastructure, and capital expenditures over the fifteen-year period.

The Fifteen-Year Plan considers forecast demands, potential growth, reliability performance, asset condition, and regulatory/governmental requirements, as well as the impact of many other drivers. The five-year CIP provides the foundation for this document. The CIP is an actively managed work plan based on current rate agreements and provides near term planning for future rate plan discussions. The Company experiences some movement of work into and out of the nearer term CIP for various reasons, but the CIP is well established, detailed and generally stable for the five year period. Work beyond the current CIP, and specifically work in years 6-10 and years 11-15, involves progressively greater uncertainty. The Commission's REV proceeding—which is specifically intended to change how the electric system operates and how customers use the system—further increases the uncertainty regarding the nature and level of investment the Company may be making in the later years of the Fifteen-Year Plan. For purposes of this Plan, the Company did not try to predict how the REV proceeding might affect investments further out in time; but, rather, applied an approach similar to what it used in the previous Fifteen-Year Plan for projecting later year spending levels.

The investments covered in years 6-10 include known large projects anticipated to be active in this timeframe. Additionally, program spending in years 6-10 (typically based on historic information) is described. Drivers affecting system needs 6-10 years in the future will evolve in unanticipated ways, which will require adjustment in the Company's spending levels. Changes in growth, regulation, technology, customer needs, etc., are more likely to affect the plan in years 6-10, as well as in years 11-15, than in the first five years. Project plans may become outdated as time goes on and additional review and detailed design take place. As the REV proceeding highlights, the scope or even the need for projects can completely change based on future conditions, systems needs, regulatory changes, technology, or customer requirements – and it is expected that the later years of the plan (years 6-15) will face numerous changes as a result of such evolving conditions. Long range forecasts are necessary and required for business planning, but also must be scalable and adaptable to meet anticipated and unanticipated changes. Various drivers impacting the plan are expected to change dramatically in the course of fifteen years, and thus, the accuracy of the Fifteen-Year Plan should be viewed in context, reflecting the uncertainty associated with any long range plan or forecast.

The Company's planning process is designed to ensure that programs and projects in the plan provide customer value, not only for safety and reliability, but for affordability as well. The Fifteen-Year Plan includes discussion of the projected impact on ratepayers' bills. The Fifteen-Year Plan will evolve and change over the next fifteen years as technology, customer expectations, and regulatory and market changes lead the way.

2. B Fifteen-Year Plan - Spending Rationale

The Company classifies its capital projects into five main spending rationales based on the primary investment driver: (1) Customer Requests/Public Requirements; (2) Damage/Failure; (3) System Capacity and Performance; (4) Asset Condition; and (5) Non-infrastructure. Although a project may be scoped to address multiple issues, the project will be categorized by a single spending rationale that best defines the primary driver for the project. The spending rationales are described in detail in the Five-Year CIP; therefore, they are described here in an abbreviated manner. The reader is referred to the most recently filed Five-Year CIP for a fuller description of the spending rationales.

2. B.1 Customer Requests / Public Requirements

Customer Requests/Public Requirements projects are required to respond to, or comply with Customer Requests/Public Requirements mandates.

2. B.2 Damage/Failure

Damage/Failure projects are those capital investments required to replace failed or damaged equipment and to restore the electric system to its original configuration and capability.

2. B.3 System Capacity and Performance

System Capacity and Performance projects are required to ensure the electric network has sufficient capacity to meet the growing and/or shifting customer demands and reliability and voltage performance are at acceptable levels.

2. B.4 Asset Condition

Projects in the Asset Condition category are those investments required to reduce the risk and consequences of unplanned failures of transmission and distribution assets.

2. B.5 Non-Infrastructure

The “non infrastructure” category is for capital investments that do not fit into one of the foregoing categories, but which are necessary to run the electric system.

2. C Fifteen-Year Plan – Development Methodology

Years FY15 to FY19 of the Plan are based on the 2014 CIP. Years six (FY2020) through fifteen (FY2029) of the Distribution and Sub-Transmission plans are projected at a budget classification level using year five as the “base year.” Year five had no large “one-time” items that had to be normalized out to achieve a reasonable base year

Years six (FY2020) through fifteen (FY2029) of the Transmission plan are based on a combination of known asset condition projects that were either already planned for this timeframe or deferred from FY2015 through FY2019 - the five year period of the Company's most recent CIP filing. In addition to these known asset condition projects are some predicted volume replacements of circuit breakers, transformers and protection and control devices based on drivers identified in their respective replacement strategies discussed in the Company's report on the Condition of Physical Elements of Transmission and Distribution Systems Dated October 1, 2013 (Cases 06-M-0878 and 10-E-0050).

2. D Plan Development Assumptions

As stated above, the Company did not make any specific adjustments to try to predict the effects of the REV proceeding on its long-term system plan. Some of the assumptions the Company did use are noted below.

2. D.1 Inflation Factor

A 2% inflation factor was applied to each year as a means to keep levels of work consistent while taking into account anticipated increasing costs over time. The 2% figure was based on the Congressional Budget Office's economic projection for CPI through 2020.

2. D.2 Growth Factor

Most budget classification categories were given 0% growth factors over the course of the plan years. In lieu of any known reasons why this work would increase, the Company believes using a conservative factor of 0% is reasonable. Categories not using 0% are listed below with factors used and reasoning for the factor:

2. D.3 Customer Requests/Public Requirements: Meters – Dist, New Business – Commercial, New Business – Residential & Public Requirements

The more economic-based categories listed above were given a factor of 2% growth per annum over the course of the plan years. This is a conservative estimate consistent with average historic US GDP growth of between 2 to 3% over the past several years.

2. D.4 Damage/Failure

The distribution and sub-transmission Damage/Failure category was given a factor of approximately -1% per annum over the course of the plan years. This takes in account the expectation that damage/failure situations will remain flat or decrease slightly over the course of time due to capital expenditures in many other areas including Load Relief, Reliability and Inspection and Maintenance and a factor of 2% inflation.

2. E Non-Wire Alternatives to Transmission and Distribution Investments

The Company has implemented a process for evaluating non-wire alternatives (NWA) to traditional T&D system expansion projects. Implementation of potential NWA solutions will require new business roles and rules. The Company has developed initial processes appropriate for a transitional period during which it will gain experience with planning issues related to NWAs. In every transmission and distribution planning study that identifies the need for a capital project, the Company reviews the need against screening criteria for NWAs.

The Company's NWA review process has resulted in a Non-Wires Alternative being explored in detail for the Brockport Relief via West Sweden Station and feeders projects. The area of need is essentially the Village of Brockport and the Town of Sweden. The required amount of NWA, the traditional project estimates, customer base have been identified and the Energy Efficiency and Account Development groups have been targeting energy efficiency measures to commercial and industrial customers in the area. The Company will continue to screen other potential capital projects and remain alert to opportunities for NWAs. The Company will review any such pilot project with Staff and interested stakeholders, prior to seeking PSC approval to proceed with implementation.

Chapter 3. Planning and Driver Considerations

The Company develops coordinated T&D system plans to ensure provision of safe and reliable service that meets expectations of customers and other stakeholders (i.e., the NYPSC, FERC, NERC, NYISO, etc). Among the Company's key considerations in developing its system plan are historic system performance and assessments of future performance based on a forecasted demand. In addition to the traditional considerations of T&D planning such as capacity, reliability and asset condition issues, this chapter will discuss the Company's expectations as to how several developing initiatives and technologies may impact the plan going forward.

3. A. Fifteen-Year Load Forecast

The Company continues to improve the development of its fifteen-year peak load forecast. These improvements reflect the recommendations in the management audit report adopted by the Commission in Case 08-E-0827, and include the use of industry standard planning techniques that base our plans on peak load forecasts. In addition, the peak load forecasts now incorporate energy efficiency projections and estimates of the impact of electric transportation that may be used to further adjust the forecast. Specific area peak forecasts may also be adjusted for large customer additions/reductions ("spot load changes") considering customer needs and market information and active peak reduction measures such as demand response and distributed generation. The greater specificity afforded by these forecast enhancements allows T&D planners to develop more accurate system models which allow for more tailored system plans, and ultimately improved solutions for the benefit of customers.

As technology, systems and processes improve, the Company will continue to revise and improve its forecast. The vision articulated in the REV proceeding has the potential to dramatically influence future forecasts and how the Company, customers and the market address evolving needs. The forecast information described below is based on recent and relevant information available to the Company, but does not reflect any anticipated effects specifically from the REV process.

Forecasting peak electric load is important to the Company's capital planning process because it enables the Company to assess the reliability of its electrical infrastructure, enables timely procurement and installation of required facilities, and it provides system planning with information to prioritize and focus their efforts. In addition to these internal reliability and capital planning internal uses, the peak forecast in New York is also used to support regulatory requirements with state, federal, and other agencies.

The Company's peak demand in 2013 was 7,078,[1] on Friday, July 19, and became the Company's second highest all-time peak. This value includes the impacts of Demand Response (DR) programs activated by the NYISO.[2] It was 1% below the Company's all-time high of 7,150 MW reached on Thursday, July 21, 2011. Based on the forecast, the area will experience an average growth of 0.8% per year over the next five years. Over the fifteen-year planning horizon, long-term growth is expected to average 0.5% per year versus 2013.

The 2013 summer peak was generally between a "50/50", or normal level and a "90/10" extreme weather level. It was 290 MW *more* than if the peak had been at the "50/50" level and 83 MW *less than* the "90/10" peak. On a weather-adjusted "normal" basis the peak was estimated to be 6,788 MW, a small increase of 0.1% over last year's weather-adjusted peak.

[1] Meter Data Service's system level preliminary peak information, which is subject to change. This peak load includes Corporate Load plus wholesale NYPA and NYMPAs, but does not include NYISO bulk system losses of load modifiers.

[2]The highest recorded Company peak without the impacts of DR was 6,984 MW and occurred Wednesday, July 17, 2013.

Table 3-1 below shows historic and forecast summer peaks for the Company.

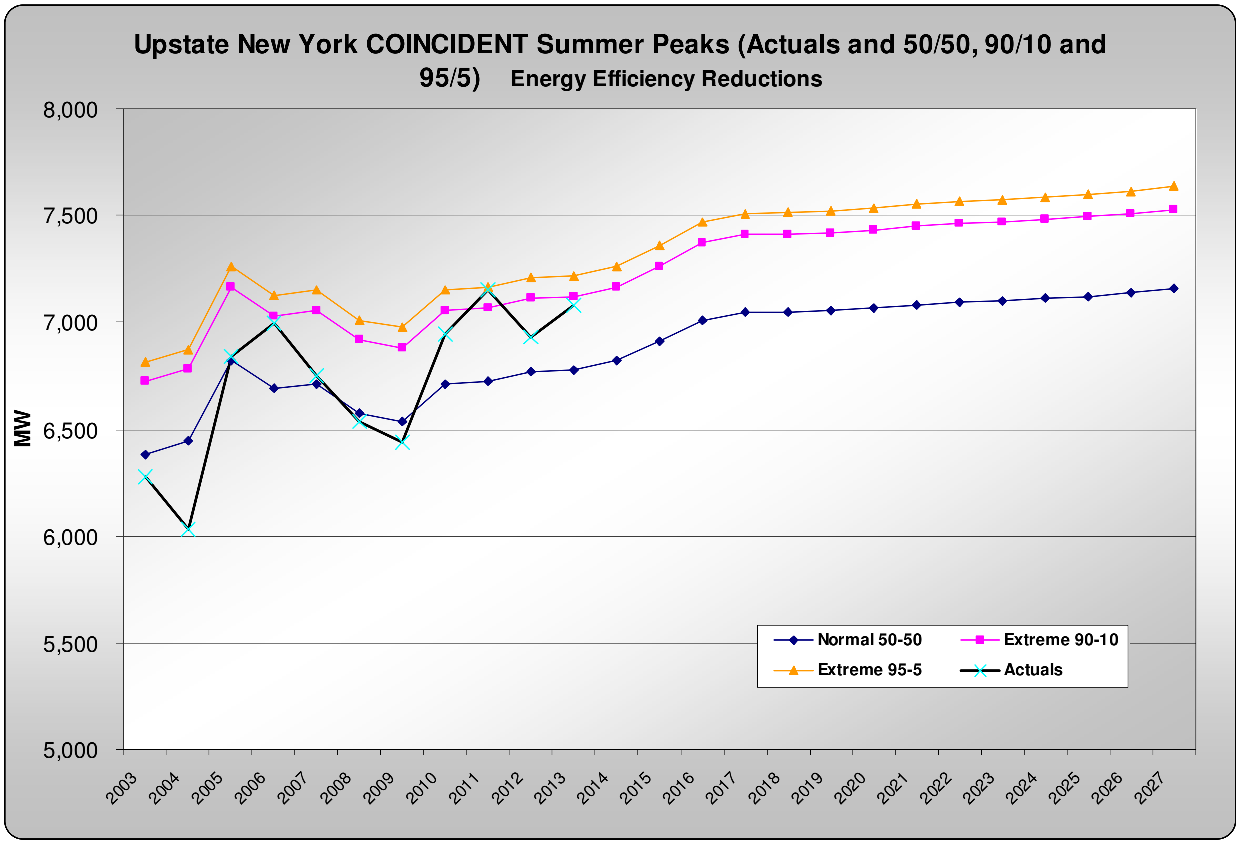
Upstate New York COINCIDENT Summer Peaks (Actuals and 50/50, 90/10, & 95/5 Weather-Adjusted Cases)
after Energy Efficiency Reductions

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (% Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (% Grwth)	Weighted Temperature-Humidity Index (WTHI) ACTUAL	NORMAL	EXT 90/10	EXT 95/5
2003	6,274		6,391		6,762		6,868		79.6	80.4	82.9	83.5
2004	6,032	-3.9%	6,455	1.0%	6,820	0.9%	6,924	0.8%	77.5	80.4	82.9	83.5
2005	6,838	13.4%	6,831	5.8%	7,205	5.6%	7,310	5.6%	80.5	80.4	82.9	83.5
2006	6,996	2.3%	6,699	-1.9%	7,070	-1.9%	7,175	-1.9%	82.3	80.4	82.9	83.5
2007	6,751	-3.5%	6,719	0.3%	7,094	0.3%	7,200	0.3%	80.7	80.4	82.9	83.5
2008	6,536	-3.2%	6,588	-2.0%	6,957	-1.9%	7,062	-1.9%	80.0	80.4	82.9	83.5
2009	6,437	-1.5%	6,544	-0.7%	6,919	-0.6%	7,025	-0.5%	79.7	80.4	82.9	83.5
2010	6,943	7.9%	6,720	2.7%	7,096	2.6%	7,202	2.5%	81.9	80.4	82.9	83.5
2011	7,150	3.0%	6,738	0.3%	7,113	0.2%	7,219	0.2%	83.1	80.4	82.9	83.5
2012	6,932	-3.1%	6,782	0.7%	7,155	0.6%	7,261	0.6%	81.4	80.4	82.9	83.5
2013	7,078	2.1%	6,788	0.1%	7,161	0.1%	7,266	0.1%	82.3	80.4	82.9	83.5
2014			6,832	0.7%	7,208	0.7%	7,315	0.7%		80.4	82.9	83.5
2015			6,926	1.4%	7,310	1.4%	7,418	1.4%		80.4	82.9	83.5
2016			7,032	1.5%	7,422	1.5%	7,533	1.5%		80.4	82.9	83.5
2017			7,072	0.6%	7,467	0.6%	7,578	0.6%		80.4	82.9	83.5
2018			7,081	0.1%	7,476	0.1%	7,588	0.1%		80.4	82.9	83.5
2019			7,092	0.2%	7,489	0.2%	7,601	0.2%		80.4	82.9	83.5
2020			7,106	0.2%	7,505	0.2%	7,618	0.2%		80.4	82.9	83.5
2021			7,127	0.3%	7,528	0.3%	7,641	0.3%		80.4	82.9	83.5
2022			7,145	0.2%	7,547	0.3%	7,661	0.3%		80.4	82.9	83.5
2023			7,159	0.2%	7,562	0.2%	7,676	0.2%		80.4	82.9	83.5
2024			7,175	0.2%	7,580	0.2%	7,694	0.2%		80.4	82.9	83.5
2025			7,192	0.2%	7,598	0.2%	7,713	0.2%		80.4	82.9	83.5
2026			7,213	0.3%	7,621	0.3%	7,736	0.3%		80.4	82.9	83.5
2027			7,238	0.3%	7,647	0.3%	7,763	0.3%		80.4	82.9	83.5
2028			7,263	0.3%	7,674	0.3%	7,790	0.3%		80.4	82.9	83.5

	Actuals	Normal 50-50	Extreme 90-10	Extreme 95-5
Compound Avg. 10 yr ('03 to '13)	1.2%	0.6%	0.6%	0.6%
Compound Avg. 5 yr ('08 to '13)	1.6%	0.6%	0.6%	0.6%
Compound Avg. 5 yr ('13 to '18)		0.8%	0.9%	0.9%
Compound Avg. 10 yr ('13 to '23)		0.5%	0.5%	0.6%
Compound Avg. 15 yr ('13 to '28)		0.5%	0.5%	0.5%

Figure 3-1 shows the forecast graphically.

Figure 3-1



3. A. 1. Energy Efficiency

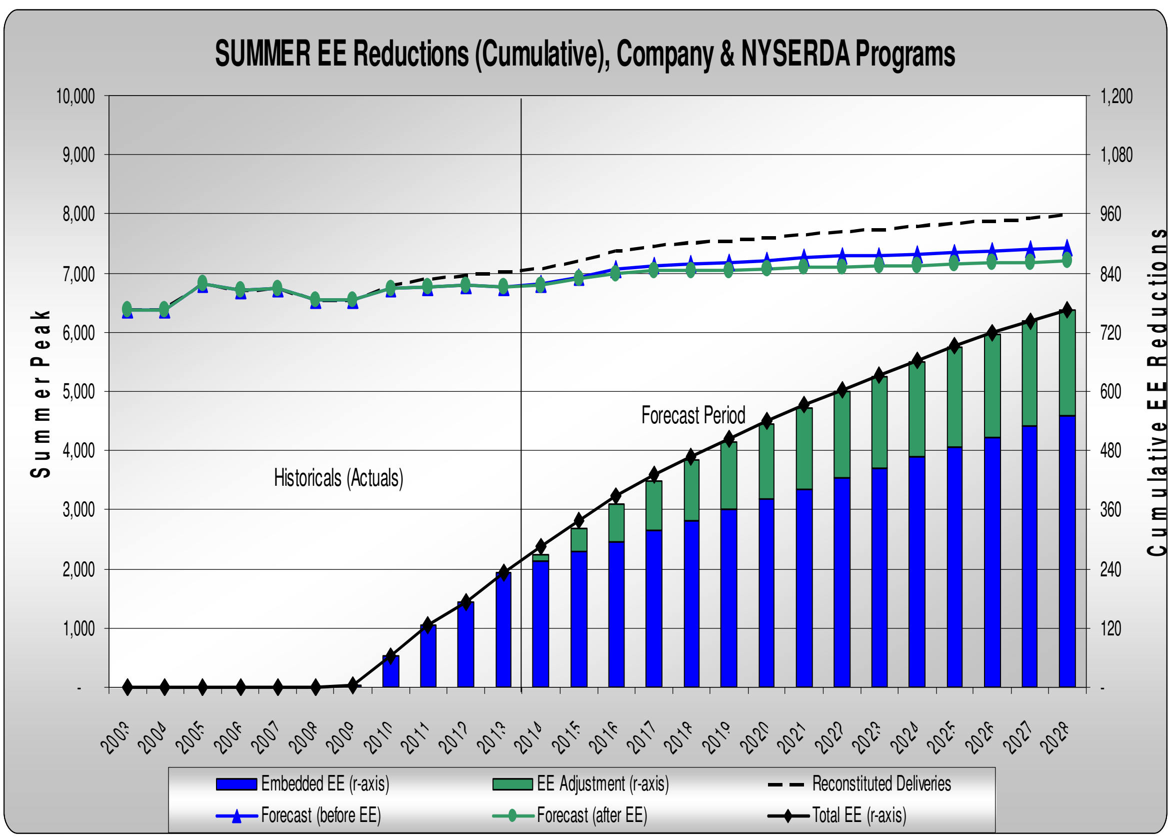
The Company and NYSERDA have been implementing EE programs in New York for several years. These programs have produced sizeable savings and have been fully incorporated into the forecast process. Since 2008 the Company and NYSERDA have implemented programs that targeted about 3.3% lower peaks than if there were no EE programs. These savings are considered fully embedded in the historical data and thus in the model produced results. Therefore, only additional EE program savings above and beyond the historical program trend are subtracted from the econometric model projections. For example, if the historical EE rate was 10 MW per year and the future EE programs were estimated at 15 MW per year, then 5 MW per year would be subtracted from the econometric model results. The original 10 MW is assumed to be already accounted for in the model projections.

The Company does not reflect any specific EE program changes anticipated from REV in its forecast. For the forecast in this Plan, the Company incorporates the currently approved program targets through 2015. Program goals through 2015 are assumed at 75% of the target to account for uncertainty. Post-2015 efficiency reductions are assumed to continue, but at a declining rate of 95% of each prior year to account for increasing costs and uncertainty to obtain similar additional savings longer term.

In New York State there are also a number of state run EE programs implemented by NYSERDA. There is assumed to be a substantial allocation of NYSERDA program targets to the Company's service territory. Since there are no specific reduction targets by service territory detailed by NYSERDA, it is assumed that EE-related reductions in the Company's service territory are roughly equal to its share of System Benefit Charges (SBC) collections allocated by the state (about 23%). The assumptions for NYSERDA EE used in this report are generally consistent with what the NYISO has published in its 2013 Load & Capacity "Gold Book" report.

Figure 3-2 shows the reductions to the forecast to capture energy efficiency reductions. Since 2008, approximately 233 MW have been targeted for implementation in the Company's service territory. Five years from now, or by 2018, up to 468 MW will have been targeted annually; 339 MW of which will have been embedded in the models and another 120 MW of additional EE not embedded due to the expanded EE programs that are planned. By the end of the 15-year planning horizon, up to 767 MW, or almost 10% of peak, will have been targeted. This will have the effect of reducing an estimated pre-EE growth rate of 0.6 % annually over 15-years to 0.5% per year.

Figure 3-2



nationalgrid

3. A. 2. Electric Vehicles

Electric Vehicles may also impact future peak forecasts. Plug-in types use electricity that can contribute to demand. Presently, the impact of electric vehicles is minimal; however, the Company continues to track and monitor EV adoption rates for future impact on its system.

The Company has developed estimates of the future impact of EVs on peak demand on residential feeders under several penetration scenarios and four charging cases summarized on **Table 3-2**.

Table 3-2

Charging Case	Description	Diversity factor	Coincidence with peak demand	Net Peak Contribution (% of gross PEV charging requirement)
Worst case	*** All vehicles are plugged in and charging at the same time * Charging is uncontolled and occurs on peak**	100%	100%	100%
Uncontrolled	* Charging is uncontrolled * Charging load is based on "likely" conditions in terms of how many vehicles will be plugged in at any given time and charging while plugged in	75%	90%	68%
TOU with some control	* Charging is subject to simple controls and time-of-use tariffs to encourage (but not require) off-peak charging	75%	20%	15%
Smart control	* Charging is subject to smart controls and related tariffs to manage peak demand impacts	75%	5%	4%

Notes:

* These are preliminary estimates

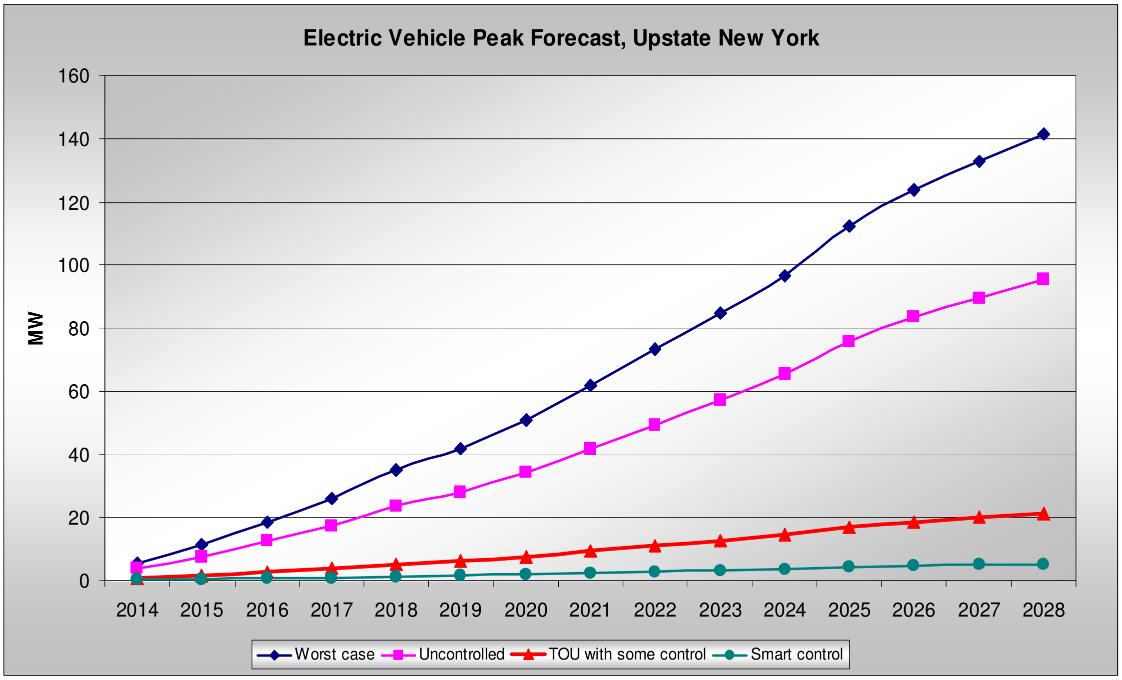
* The "diversity factor" is based on commuting habits, which are assumed to be the same in all cases, except the Worst Ca

* Coincidence with peak demand is never zero because some customers will overrided control. The availability and use of public charging could also impact the coincidence with peak demand.

In the near term (five years), the most representative charging case is “Uncontrolled”. Under this case the impact of EVs on the Company’s residential peak could reach approximately 24 MW by 2018. The Company recently filed a voluntary “Time of Use” (TOU) rate aimed at serving the residential EV market, and that rate is currently scheduled to go into effect later this year. As TOU rates expand, the TOU charging case will become representative of grid impacts, which the Company estimates would result in an EV impact on the residential peak of approximately 23 MW (0.3% of peak) by 2028[3].

[3] Forecast combines latest monthly sales trended for two years (to 2015) and AEO 2013 long-term projections for the Northeast, proportioned by load to National Grid’s territory.

Figure 3-3



Under the "Worst" case charging scenario, all EVs would be plugged in at the same time and during the residential peak, and impacts from such a scenario are estimated at 141 MW by 2028. Under the "Smart Control" case, EVs would have no significant impact (5 MW) on the total residential peak in 2028.

These estimated EV impacts are not included in the forecasted peaks published in the body of this report. However, planners can add estimated EV load impacts to the base line load forecast. Before adding EV-related impacts, an appropriate coincidence factor would have to be applied since the impacts shown are on the residential peak, which usually occurs during a weekday evening; rather than the system peak, which usually occurs during a weekday afternoon.

3. A. 3. Demand Response

Demand Response programs actively target reductions to peak demand during hours of high expected demand and/or reliability problems. These are in contrast to the more passive, embedded EE savings discussed above that provide savings throughout the year. The DR program in New York has generally been administered by the NYISO in response to system reliability concerns or economic (pricing) signals. During these events customers can actively participate by either cutting their load ("Emergency Demand Response Programs", or "EDRPs") or by turning on a generator (or "Special Case Resources" or "SCRs") to displace load from behind the customer's meter.

A recent decision of the U.S. Court of Appeals for the District of Columbia calls into question whether DR programs will continue to be administered by the NYSIO as they have in the past.[4] If the ruling stands, it has the potential for significantly affecting the operation of DR programs and placing control over such programs primarily with the states. More local oversight of DR also is consistent with the vision set forth in the REV report of a distributed system platform provider ("DSPP") responsible for integrating distributed energy resources – including DR – into distribution system planning.

Regardless of how DR may be implemented or administered in the future, an important issue with respect to existing DR programs in the context of capital planning is the ability to count on the presumed load relief. Although DR programs have the potential to achieve sizeable peak demand reductions, there is no assurance they will be called at peak times, nor is the Company currently in control of these call-out days. Therefore, while the Company recognizes the existence of the DR programs, it must plan in the event that they are not called or that the promised demand reductions are not achieved.

Table 3-3 shows how many MW of SCR demand reductions were enrolled in New York (of which the Company is only a portion) during last summer's peak month.

Table 3-3

SCR Enrollment – July 2013

Special Case Resources

UCAP Available for ICAP Auction

Zone	MWs (UCAP)
A	303.6
B	58.7
C	105.2
D	4.9
E	28.4
F	95.2
G	25.4
H	4.2
I	21.3
J	341.5
K	77.8
Total	1066.2

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The NYISO has called the DR program several times over the last eight years. Table 3-2 shows these call-outs and the estimated reductions for each. These reductions are fully incorporated into the load data used in this report. However, the total DR MW reductions do not always translate into one-to-one reductions to the peak due to the timing of DR call-outs and pre-DR metered loads.

[4] *Electric Power Supply Ass'n v. FERC*, No. 11-1486 (D.C. Cir. 2014).

Table 3-4

SCR/EDRP Events

Year	Date	Zones	Hour **BEG** Start Time	Hour **END** End Time	*ICAP Assigned* TOTAL	A	B	C	D	E	F	*comment*
2013	19-Jul	A-F	13:00	18:00	366.0	202.0	12.0	48.0	1.0	20.0	83.0	*per NYISO*
	18-Jul	A-F	13:00	18:00	311.1	171.7	10.2	40.8	0.9	17.0	70.6	*assume 85% of July 19th, 2013*
2012	17-Jul	B-only	14:00	18:00	2.0	-	2.0	-	-	-	-	*per NYISO*
	21-Jun	A-F	13:00	18:00	183.0	101.0	6.0	24.0	0.5	10.0	41.5	*assume 50% of July 19th, 2013*
	20-Jun	C-only	14:00	18:00	24.0	-	-	24.0	-	-	-	*assume 50% of July 19th, 2013*
	29-May	A-F	13:00	18:00	183.0	101.0	6.0	24.0	0.5	10.0	41.5	*assume 50% of July 19th, 2013*
2011	22-Jul	A-C, E-F	13:00	18:00	485.0	283.8	14.2	39.9	-	28.5	119.6	*per NYISO*
2006	02-Aug	A-C	14:00	19:00	202.0	161.6	10.1	30.3	-	-	-	*total per NYISO; zones inferred*

3. A. 4. Distributed Generation

Distributed Generation (DG) includes non-centralized generation in the region that can inject power into the system and/or lower customer use via “behind the meter” generation. The types of DG that lower customer demand and are contributing to the largest growth in recent years include wind, solar/photovoltaics and combined heat & power (CHP). Of particular interest and impact to the load forecasting process are these “behind the meter” or “net metered” installations because of their direct load lowering impact at the customer level. In New York, distributed generation incentive and support programs are implemented via NYSERDA.

The decision to install and run DG systems is made by customers based on regulatory, economic and operational drivers. These technologies are installed primarily for their energy savings but they also have impacts that reduce the peak loads. The Company has established a DG team in New York to facilitate the interconnection of DG projects on the system. The DG team screens customer DG applications, administers tariff-based DG agreements, educates customers and other stakeholders on processes and policies, and assists with the coordination of complex construction for some DG projects.

Figure 3-4 shows the net-metering on record in 2013. This indicates that there were approximately 14 MW (33 MW nameplate) of DG installations coincident with peak in the Company’s service territory as of 2013.[5]

[5] Because not all nameplate installed MW are coincident with the Company’s summer peaks, a conversion is made to derive estimated coincident values as follows: Wind: 25%; Solar: 40%; CHP: 95%; and Other: 30%.

Figure 3-4

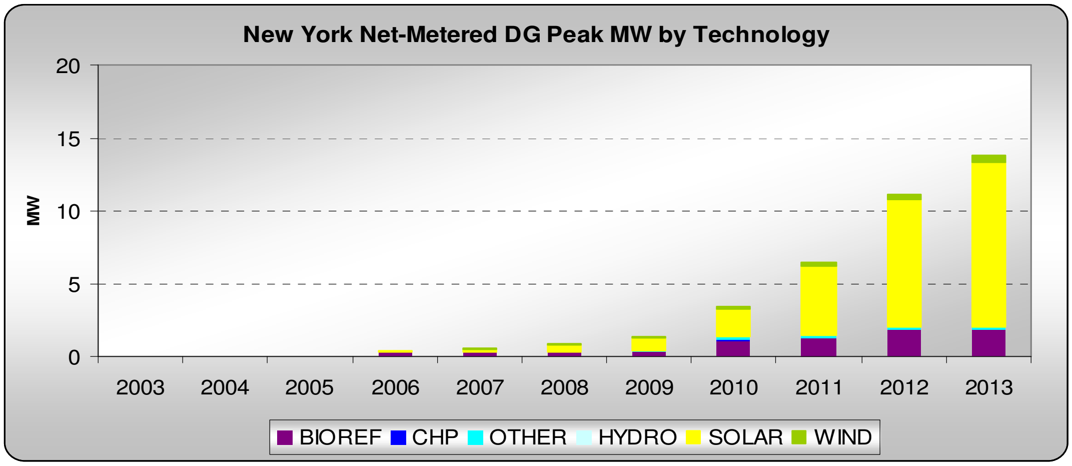
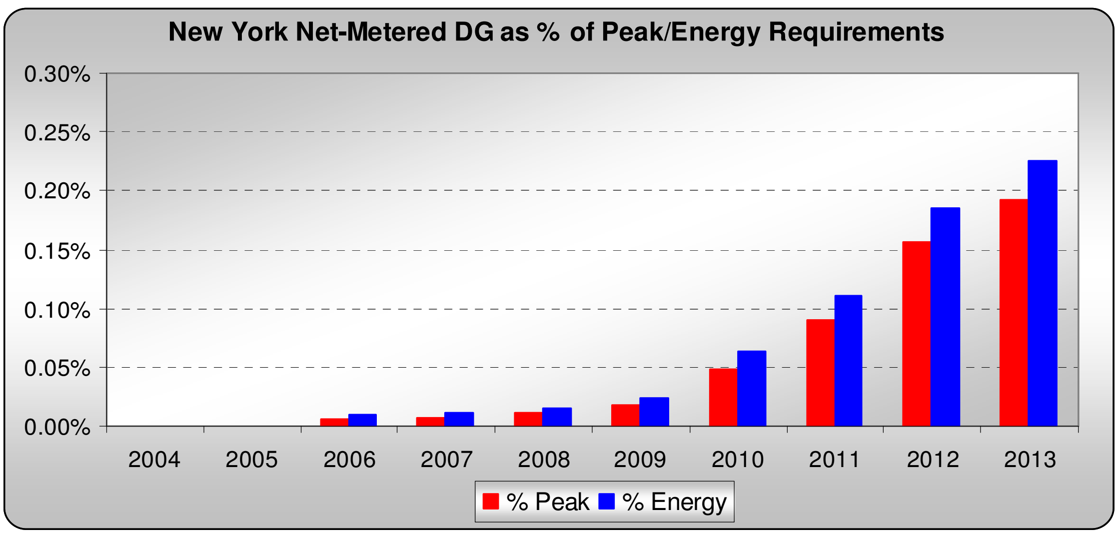


Figure 3-5 shows estimated historical net-metered impacts as a percent of Company load. The current level is about 0.2%.

Figure 3-5



The impact of DG installations on the peak is considered already embedded in the historical values and no additional adjustments were made to the forecast. At this time, the impact on total load is small, and therefore, not significantly impacting the overall load forecast; however, realization of the REV objectives will significantly affect the impact of DG on system loading in the future.

3. A. 5. Regional Economic Drivers

Historical and forecast economic/demographic explanatory variables are obtained under subscription services from Moody's Investor Services. Moody's provides economic / demographic forecasts at the US, state, metro, and county-level area of detail. The Company aligned these sets with its service area to develop load forecasts. Key economic drivers are real personal income, total employment and manufacturing employment.

Figure 3-6 below summarizes Moody's forecast for Real Personal Income. Overall, New York State is expected to generally keep pace with the U.S. projection over the next five years, as is the Western Region (zones A&B). The Eastern Region (zone F) will run a small amount below Zones A&B, while the Central (zone C) and North-Mohawk Valley regions (zones D&E) are expected to lag the others.

Figure 3-6

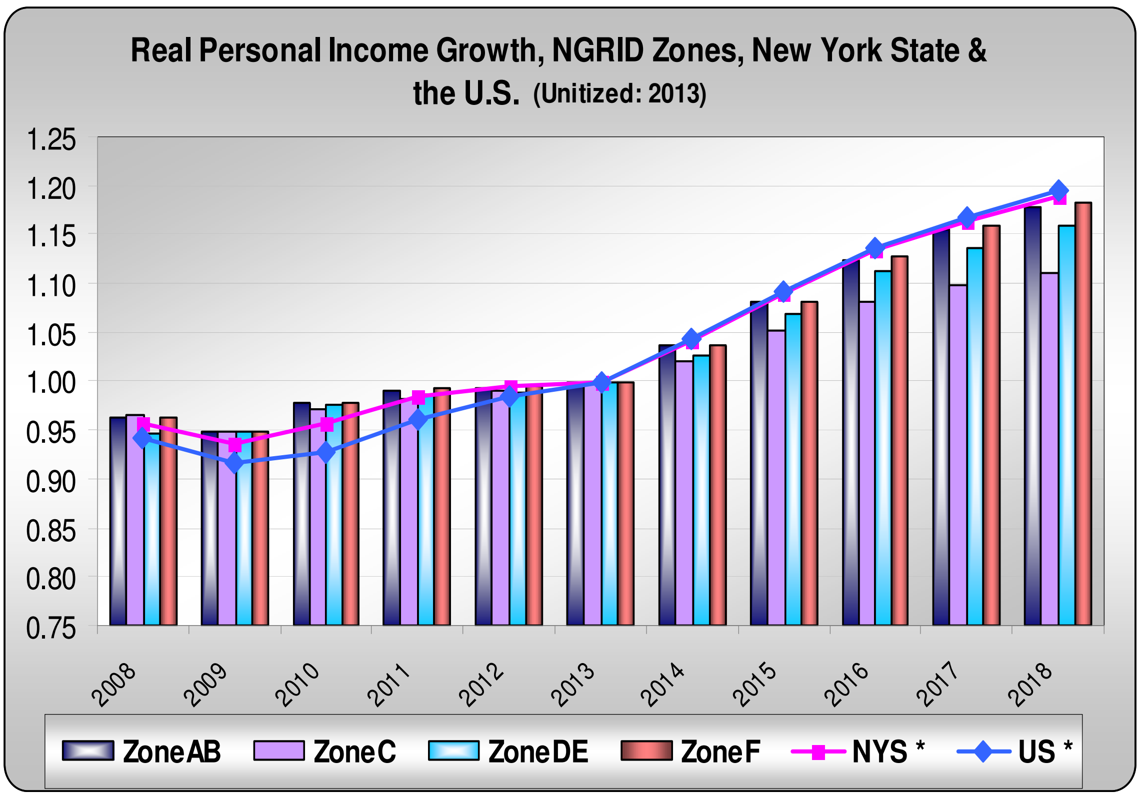


Figure 3-7 shows that the Eastern Region (zone F) is expected to very slightly lead New York State's employment growth rate although both will lag the U.S. Each of the other regions also will lag both NYS and the Eastern Region.

Figure 3-7

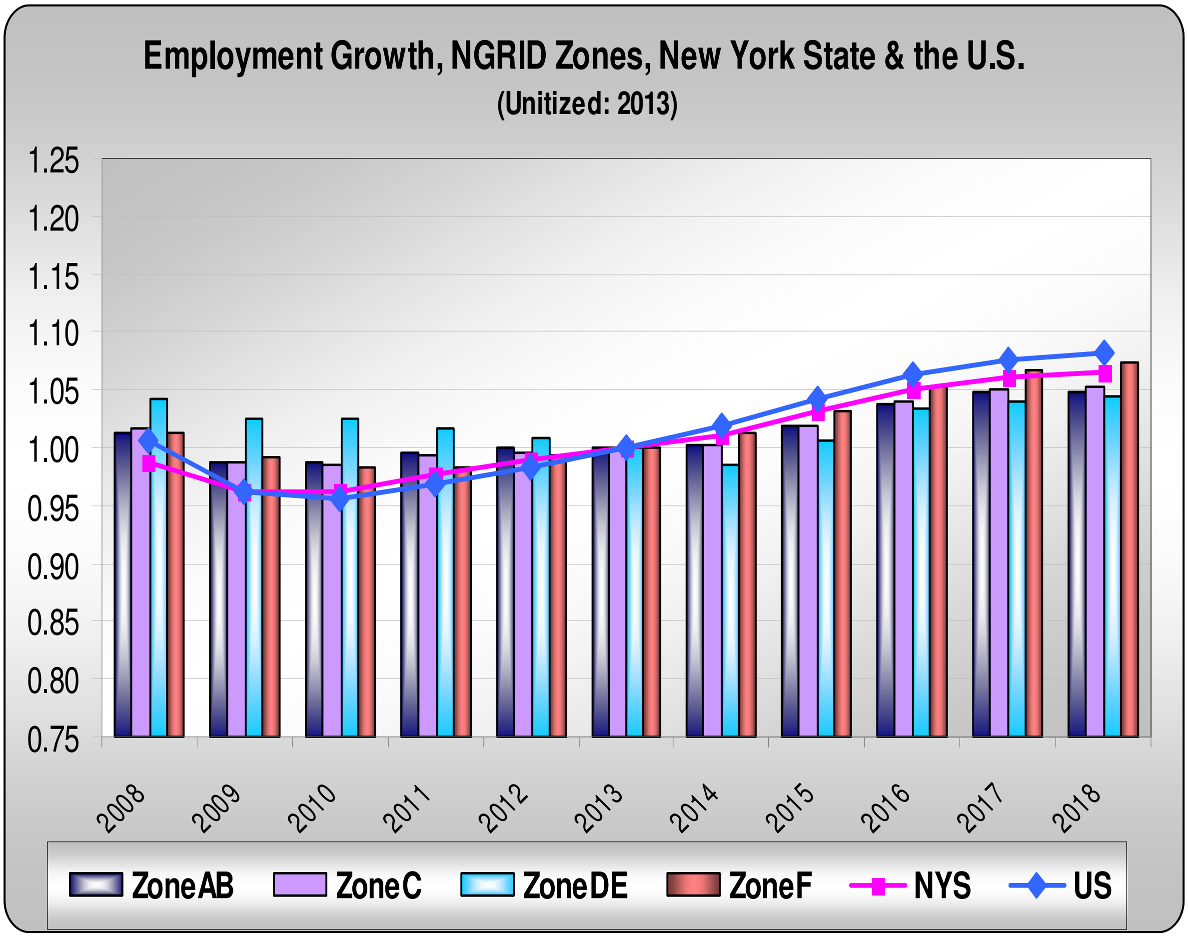
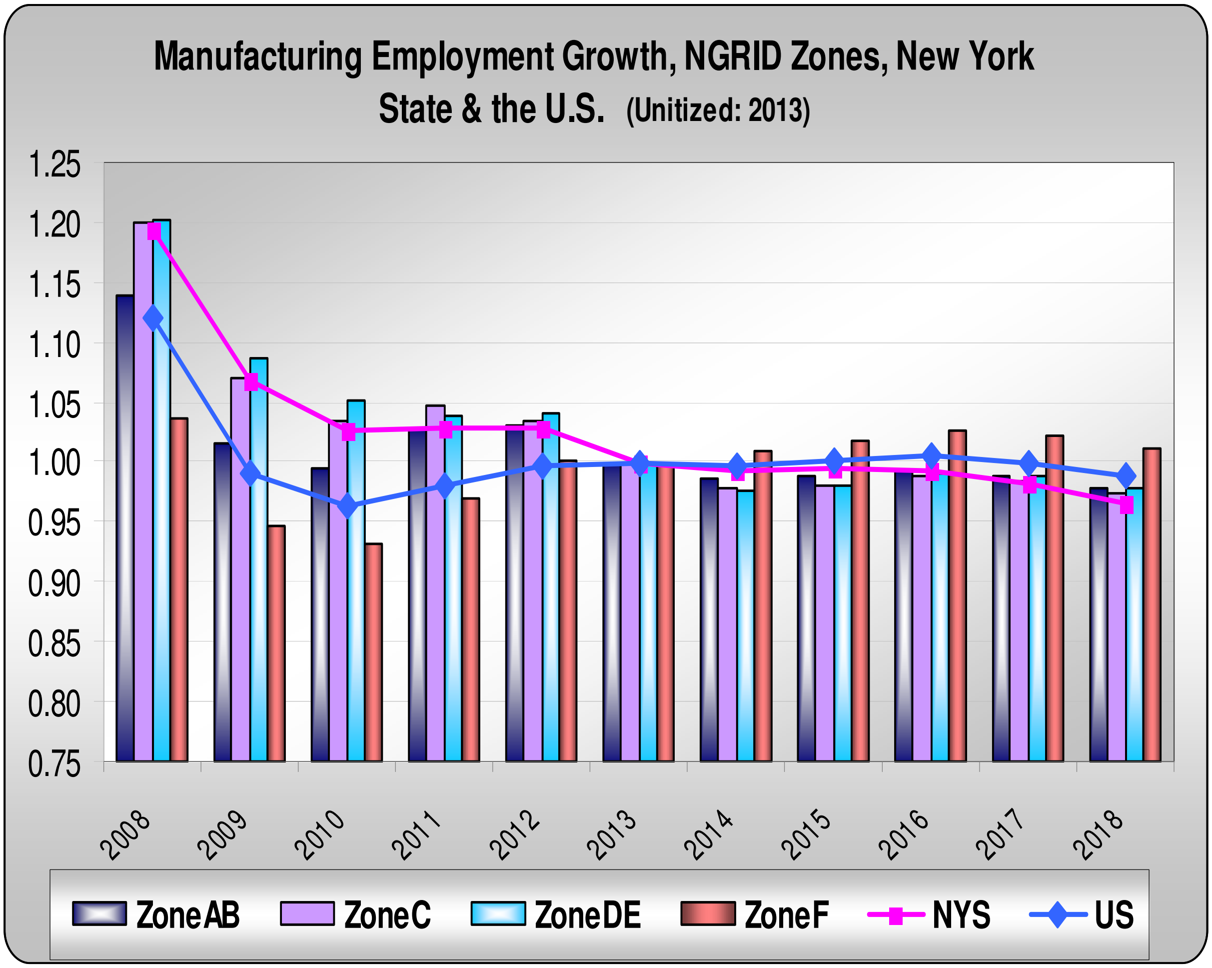


Figure 3-8 shows that New York state, as well as all regions with the exception of the Eastern Region (zone F) are expected to continue their long-term decline in industrial employment. The Eastern Region, in large part due to Global Foundries, will continue its increase in manufacturing jobs over the next three years before leveling off and beginning a decline in 2018.

Figure 3-8



3. A. 6. Forecast Methodology

The Company forecasts peak MW demands for four[7] NYISO zones that make up the Company's service territory in upstate New York for both summer and winter seasonal peaks. Coincident and Non-Coincident peaks are developed. Non-coincident demand is the demand that each zone experiences, regardless of whether that demand is also the same day and time as the Company's peak. Coincident demand is each zone's peak at the same day and time as the Company's peak. The four regions forecast are:

- The Western Region, comprised of the portions of the NYISO Load Zones A and B served by the Company; includes the Buffalo area;

[7] These represent six NYISO zones, however, the forecasting process combines Zones A&B and Zones D&E due to the "smaller" sizes of zones B and D in the Company's service territory.

- The Central Region, comprised of the portion of NYISO Load Zone C served by the Company; includes the Syracuse area;
- The North-Mohawk Valley Region, comprised of the portions of NYISO Load Zones D and E served by the Company; includes the Utica and Watertown areas;
- The Eastern Region, comprised of the portion of the NYISO Load Zone F served by the Company, includes the Albany, Saratoga and Glen Falls areas.

The overall approach to the peak forecast is to use energy growth, which is developed using econometric methods, adjusted by historical trends in load factor. This method allows the peak MW forecasts to grow along with energy growth rates for each zone; however, it also allows the peak to adjust and follow historical trends in the relationship between MW growth and GWh growth (i.e. load factor). Energy growth is tied to the retail sales forecast to ensure consistency between this wholesale forecast and the retail forecast. Differing growth rates among the various zones is developed by determining the mix of residential, commercial and industrial use in each of the zones, and then applying the various growth rates for each customer type. For example, Zones A&B, which have a higher industrial base, may grow slower than the other zones because of the long-term loss of manufacturing jobs in the area creating a related drag on the residential and commercial growth sectors.

County peak growth rates are provided to differentiate the varying economic conditions among the different counties in each zone. The forecast is presented for all three weather scenarios.

The results of this forecast are used as input into various system planning studies. The transmission planning group uses the extreme-90/10 weather scenario for its planning purposes. For distribution planning, the degree of diversity is reduced and the variability of load is greater, so a 95/5 forecast is used.

3. A. 7. Weather Assumptions

Weather data is collected from the relevant weather stations located within the Company's New York service territory and used to weather-adjust peak demands. The relevant weather stations are Buffalo, Rochester, Syracuse, Utica/Rome, Albany, Watertown and Massena. These most closely represent the Company's territory.

The weather variables used in the model include heating degree days for the colder winter months, and temperature – humidity indexes (THIs)[8] for the warmer summer months. These weather variables are correlated to the actual days that each peak occurs in each month over the historical period. Summer THI uses a weighted three day index (WTHI)[9] to capture the effects of prolonged heat waves that drive summer peaks. Weather adjusted peaks are derived for normal (50/50) weather, extreme (90/10)

[8] THI is calculated as (0.55 * dry bulb temperature) + (0.20 dew point) + 17.5. Maximum values for each of the 24 hours in a day are calculated and the maximum value is used in the WTHI formula.

[9] WTHI is weighted 70% day of peak, 20% one day prior and 10% two days prior.

weather and extreme (95/5) weather. Extreme weather scenarios are determined using a "probabilistic" approach that employs "Z-values" and standard deviations (i.e. the more variable the weather has been on peak days over the historical period, the higher the 90/10 and 95/5 levels will be versus the average).

- Normal "50/50" weather is the average weather on the past 20 annual peak days.
- Extreme "90/10" weather is such that it is expected that 90% of the time it should not be exceeded. It is similarly inferred that it should occur no more than one time in a ten year period.
- Extreme "95/5" weather is such that it is expected that 95% of the time it should not be exceeded. It is similarly inferred that it should occur no more than one time in a twenty year period.

These "normals" and "extremes" are used to derive the weather-adjusted historical and forecasted values for each of the normal and extreme cases.

Normal and extreme weather details for each of the zones are provided below.

Table: 3-5

Zones A&B (Western) NON-COINCIDENT Summer Peaks (Actuals and 50/50, 90/10, & 95/5 Weather-Adjusted Cases)

after Energy Efficiency Reductions

YEAR	Actuals (MW)	Actuals (%Grwth)	Normal 50-50 (MW)	Normal 50-50 (%Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (%Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (%Grwth)	WTHI ACTUAL	WTHI NORMAL	WTHI EXT 90/10	WTHI EXT 95/5
2003	2,251		2,307		2,415		2,445		78.0	79.1	81.2	81.8
2004	2,204	-2.1%	2,417	4.8%	2,525	4.6%	2,555	4.5%	74.9	79.1	81.2	81.8
2005	2,436	10.5%	2,430	0.5%	2,538	0.5%	2,568	0.5%	79.2	79.1	81.2	81.8
2006	2,449	0.5%	2,359	-2.9%	2,467	-2.8%	2,497	-2.8%	80.9	79.1	81.2	81.8
2007	2,358	-3.7%	2,285	-3.1%	2,393	-3.0%	2,424	-2.9%	80.5	79.1	81.2	81.8
2008	2,274	-3.6%	2,390	4.6%	2,498	4.4%	2,528	4.3%	76.8	79.1	81.2	81.8
2009	2,268	-0.3%	2,282	-4.5%	2,390	-4.3%	2,420	-4.3%	78.8	79.1	81.2	81.8
2010	2,408	6.2%	2,337	2.4%	2,445	2.3%	2,475	2.3%	80.5	79.1	81.2	81.8
2011	2,544	5.6%	2,440	4.4%	2,548	4.2%	2,579	4.2%	81.1	79.1	81.2	81.8
2012	2,409	-5.3%	2,397	-1.8%	2,505	-1.7%	2,535	-1.7%	79.3	79.1	81.2	81.8
2013	2,453	1.8%	2,375	-0.9%	2,482	-0.9%	2,513	-0.9%	80.6	79.1	81.2	81.8
2014			2,388	0.6%	2,497	0.6%	2,528	0.6%		79.1	81.2	81.8
2015			2,417	1.2%	2,527	1.2%	2,559	1.2%		79.1	81.2	81.8
2016			2,450	1.4%	2,562	1.4%	2,594	1.4%		79.1	81.2	81.8
2017			2,462	0.5%	2,575	0.5%	2,608	0.5%		79.1	81.2	81.8
2018			2,464	0.1%	2,578	0.1%	2,610	0.1%		79.1	81.2	81.8
2019			2,466	0.1%	2,581	0.1%	2,613	0.1%		79.1	81.2	81.8
2020			2,470	0.2%	2,585	0.2%	2,617	0.2%		79.1	81.2	81.8
2021			2,476	0.2%	2,591	0.3%	2,624	0.3%		79.1	81.2	81.8
2022			2,481	0.2%	2,597	0.2%	2,629	0.2%		79.1	81.2	81.8
2023			2,485	0.2%	2,601	0.2%	2,634	0.2%		79.1	81.2	81.8
2024			2,490	0.2%	2,606	0.2%	2,639	0.2%		79.1	81.2	81.8
2025			2,495	0.2%	2,611	0.2%	2,644	0.2%		79.1	81.2	81.8
2026			2,501	0.3%	2,618	0.3%	2,651	0.3%		79.1	81.2	81.8
2027			2,509	0.3%	2,627	0.3%	2,660	0.3%		79.1	81.2	81.8
2028			2,517	0.3%	2,635	0.3%	2,668	0.3%		79.1	81.2	81.8

	Actuals	Normal 50-50	Extreme 90-10	Extreme 95-5		
Compound Avg. 10 yr ('03 to '13)	0.9%	0.3%	0.3%	0.3%	WTHI coeff	50.5
Compound Avg. 5 yr ('08 to '13)	1.5%	-0.1%	-0.1%	-0.1%		
Compound Avg. 5 yr ('13 to '18)		0.7%	0.8%	0.8%		
Compound Avg. 10 yr ('13 to '23)		0.5%	0.5%	0.5%		
Compound Avg. 15 yr ('13 to '28)		0.4%	0.4%	0.4%		

*** There were Demand Response activations in these years on the day of this Zone's peak.*

Table: 3-6

Zone C (Central) NON-COINCIDENT Summer Peaks (Actuals and 50/50, 90/10, & 95/5 Weather-Adjusted Cases)

after Energy Efficiency Reductions

YEAR	Actuals (MW)	(%Grwth)	Normal 50-50 (MW)	(%Grwth)	Extreme 90-10 (MW)	(%Grwth)	Extreme 95-5 (MW)	(%Grwth)	Weighted Temperature-Humidity Index (WTHI) ACTUAL	NORMAL	EXT 90/10	EXT 95/5
2003	1,267		1,321		1,428		1,459		79.5	81.2	84.6	85.6
2004	1,271	0.3%	1,313	-0.6%	1,420	-0.6%	1,451	-0.6%	79.9	81.2	84.6	85.6
2005	1,425	12.1%	1,401	6.7%	1,508	6.2%	1,539	6.1%	82.0	81.2	84.6	85.6
2006	1,483	4.0%	1,431	2.2%	1,539	2.0%	1,569	2.0%	82.8	81.2	84.6	85.6
2007	1,390	-6.3%	1,385	-3.2%	1,492	-3.0%	1,523	-2.9%	81.3	81.2	84.6	85.6
2008	1,358	-2.3%	1,348	-2.7%	1,455	-2.5%	1,486	-2.4%	81.5	81.2	84.6	85.6
2009	1,313	-3.3%	1,341	-0.5%	1,448	-0.5%	1,478	-0.5%	80.3	81.2	84.6	85.6
2010	1,386	5.5%	1,336	-0.3%	1,444	-0.3%	1,474	-0.3%	82.8	81.2	84.6	85.6
2011	1,403	1.3%	1,288	-3.6%	1,395	-3.4%	1,426	-3.3%	84.9	81.2	**84.6**	85.6
2012	1,408	0.3%	1,347	4.6%	1,454	4.2%	1,485	4.1%	83.1	81.2	84.6	85.6
2013	1,428	1.4%	1,361	1.1%	1,469	1.0%	1,499	1.0%	83.3	81.2	84.6	85.6
2014			1,365	0.2%	1,473	0.3%	1,503	0.3%		81.2	84.6	85.6
2015			1,381	1.2%	1,491	1.2%	1,522	1.2%		81.2	84.6	85.6
2016			1,400	1.4%	1,511	1.4%	1,543	1.4%		81.2	84.6	85.6
2017			1,406	0.4%	1,518	0.4%	1,550	0.5%		81.2	84.6	85.6
2018			1,405	0.0%	1,518	0.0%	1,550	0.0%		81.2	84.6	85.6
2019			1,406	0.0%	1,519	0.1%	1,551	0.1%		81.2	84.6	85.6
2020			1,407	0.1%	1,521	0.1%	1,553	0.1%		81.2	84.6	85.6
2021			1,411	0.2%	1,524	0.2%	1,556	0.2%		81.2	84.6	85.6
2022			1,413	0.2%	1,527	0.2%	1,559	0.2%		81.2	84.6	85.6
2023			1,415	0.1%	1,529	0.1%	1,562	0.1%		81.2	84.6	85.6
2024			1,418	0.2%	1,532	0.2%	1,565	0.2%		81.2	84.6	85.6
2025			1,420	0.2%	1,535	0.2%	1,568	0.2%		81.2	84.6	85.6
2026			1,424	0.3%	1,540	0.3%	1,572	0.3%		81.2	84.6	85.6
2027			1,429	0.3%	1,545	0.3%	1,577	0.3%		81.2	84.6	85.6
2028			1,433	0.3%	1,550	0.3%	1,583	0.3%		81.2	84.6	85.6

	Actuals	Normal 50-50	Extreme 90-10	Extreme 95-5		
Compound Avg. 10 yr ('03 to '13)	1.2%	0.3%	0.3%	0.3%	WTHI coeff	31.4
Compound Avg. 5 yr ('08 to '13)	1.0%	0.2%	0.2%	0.2%		
Compound Avg. 5 yr ('13 to '18)		0.6%	0.7%	0.7%		
Compound Avg. 10 yr ('13 to '23)		0.4%	0.4%	0.4%		
Compound Avg. 15 yr ('13 to '28)		0.3%	0.4%	0.4%		

*** There were Demand Response activations in these years on the day of this Zone's peak.*

Table 3-7

Zones D&E (North - Mohawk Valley) NON-COINCIDENT Summer Peaks (Actuals and 50/50, 90/10, & 95/5 Weather-Adjusted Cases)
after Energy Efficiency Reductions

	Actuals		Normal 50-50		Extreme 90-10		Extreme 95-5		Weighted Temperature-Humidity Index (WTHI)			
YEAR	(MW)	(%Grwth)	(MW)	(%Grwth)	(MW)	(%Grwth)	(MW)	(%Grwth)	ACTUAL	NORMAL	EXT 90/10	EXT 95/5
2003	899		922		962		974		79.2	80.3	82.3	82.8
2004	855	-4.9%	904	-2.0%	944	-1.9%	956	-1.9%	77.9	80.3	82.3	82.8
2005	942	10.1%	936	3.5%	976	3.4%	987	3.3%	80.6	80.3	82.3	82.8
2006	947	0.6%	923	-1.4%	963	-1.3%	975	-1.3%	81.5	80.3	82.3	82.8
2007	936	-1.1%	931	0.8%	971	0.8%	983	0.8%	80.6	80.3	82.3	82.8
2008	924	-1.3%	965	3.7%	1,005	3.5%	1,017	3.5%	78.3	80.3	82.3	82.8
2009	897	-2.9%	903	-6.5%	943	-6.2%	954	-6.1%	80.1	80.3	82.3	82.8
2010	965	7.5%	930	3.0%	970	2.9%	982	2.9%	82.0	80.3	82.3	82.8
2011	987	2.4%	934	0.5%	975	0.4%	986	0.4%	82.9	80.3	**82.3**	**82.8**
2012	957	-3.1%	943	0.9%	983	0.9%	995	0.9%	81.0	80.3	82.3	82.8
2013	980	2.4%	943	0.0%	984	0.0%	995	0.0%	82.1	80.3	82.3	82.8
2014			945	0.2%	986	0.2%	997	0.2%		80.3	82.3	82.8
2015			961	1.6%	1,002	1.7%	1,014	1.7%		80.3	82.3	82.8
2016			977	1.7%	1,019	1.7%	1,031	1.8%		80.3	82.3	82.8
2017			984	0.7%	1,027	0.7%	1,039	0.7%		80.3	82.3	82.8
2018			987	0.2%	1,030	0.3%	1,042	0.3%		80.3	82.3	82.8
2019			989	0.3%	1,033	0.3%	1,045	0.3%		80.3	82.3	82.8
2020			993	0.3%	1,036	0.3%	1,048	0.3%		80.3	82.3	82.8
2021			997	0.4%	1,040	0.4%	1,053	0.4%		80.3	82.3	82.8
2022			1,000	0.3%	1,044	0.4%	1,056	0.4%		80.3	82.3	82.8
2023			1,003	0.3%	1,047	0.3%	1,059	0.3%		80.3	82.3	82.8
2024			1,006	0.3%	1,050	0.3%	1,063	0.3%		80.3	82.3	82.8
2025			1,009	0.3%	1,054	0.3%	1,066	0.3%		80.3	82.3	82.8
2026			1,013	0.4%	1,058	0.4%	1,070	0.4%		80.3	82.3	82.8
2027			1,017	0.4%	1,062	0.4%	1,075	0.4%		80.3	82.3	82.8
2028			1,021	0.4%	1,066	0.4%	1,079	0.4%		80.3	82.3	82.8

	Actuals	Normal 50-50	Extreme 90-10	Extreme 95-5		
Compound Avg. 10 yr ('03 to '13)	0.9%	0.2%	0.2%	0.2%	WTHI coeff	20.4
Compound Avg. 5 yr ('08 to '13)	1.2%	-0.5%	-0.4%	-0.4%		
Compound Avg. 5 yr ('13 to '18)		0.9%	0.9%	0.9%		
Compound Avg. 10 yr ('13 to '23)		0.6%	0.6%	0.6%		
Compound Avg. 15 yr ('13 to '28)		0.5%	0.5%	0.5%		

*** There were Demand Response activations in these years on the day of this Zone's peak.*

Table 3-8

Zone F (Eastern) NON-COINCIDENT Summer Peaks (Actuals and 50/50, 90/10, & 95/5 Weather-Adjusted Cases)

after Energy Efficiency Reductions

YEAR	Actuals (MW)	Actuals (%Grwth)	Normal 50-50 (MW)	Normal 50-50 (%Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (%Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (%Grwth)	Weighted Temperature-Humidity Index (WTHI) ACTUAL	WTHI NORMAL	WTHI EXT 90/10	WTHI EXT 95/5
2003	1,954		1,941		2,062		2,096		81.7	81.5	83.8	84.4
2004	1,894	-3.1%	2,027	4.4%	2,147	4.1%	2,181	4.1%	78.9	81.5	83.8	84.4
2005	2,088	10.2%	2,117	4.4%	2,237	4.2%	2,271	4.1%	80.9	81.5	83.8	84.4
2006	2,193	5.0%	2,058	-2.8%	2,179	-2.6%	2,213	-2.6%	84.0	81.5	83.8	84.4
2007	2,090	-4.7%	2,140	4.0%	2,261	3.8%	2,295	3.7%	80.5	81.5	83.8	84.4
2008	2,111	1.0%	2,018	-5.7%	2,138	-5.4%	2,172	-5.3%	83.2	81.5	83.8	84.4
2009	1,984	-6.0%	2,045	1.3%	2,165	1.3%	2,199	1.2%	80.3	81.5	83.8	84.4
2010	2,185	10.1%	2,118	3.6%	2,239	3.4%	2,273	3.3%	82.7	81.5	83.8	84.4
2011	2,235	2.3%	2,094	-1.2%	2,214	-1.1%	2,248	-1.1%	84.2	81.5	83.8	84.4
2012	2,205	-1.3%	2,141	2.3%	2,262	2.2%	2,296	2.1%	82.7	81.5	83.8	84.4
2013	2,270	3.0%	2,160	0.9%	2,281	0.8%	2,315	0.8%	83.6	81.5	83.8	84.4
2014			2,175	0.7%	2,296	0.7%	2,330	0.7%		81.5	83.8	84.4
2015			2,213	1.8%	2,337	1.8%	2,372	1.8%		81.5	83.8	84.4
2016			2,255	1.9%	2,381	1.9%	2,417	1.9%		81.5	83.8	84.4
2017			2,274	0.8%	2,402	0.9%	2,438	0.9%		81.5	83.8	84.4
2018			2,281	0.3%	2,409	0.3%	2,446	0.3%		81.5	83.8	84.4
2019			2,289	0.3%	2,417	0.3%	2,454	0.3%		81.5	83.8	84.4
2020			2,297	0.4%	2,426	0.4%	2,463	0.4%		81.5	83.8	84.4
2021			2,306	0.4%	2,437	0.4%	2,474	0.4%		81.5	83.8	84.4
2022			2,315	0.4%	2,446	0.4%	2,483	0.4%		81.5	83.8	84.4
2023			2,321	0.3%	2,453	0.3%	2,490	0.3%		81.5	83.8	84.4
2024			2,329	0.3%	2,460	0.3%	2,498	0.3%		81.5	83.8	84.4
2025			2,336	0.3%	2,468	0.3%	2,505	0.3%		81.5	83.8	84.4
2026			2,344	0.4%	2,477	0.4%	2,514	0.4%		81.5	83.8	84.4
2027			2,353	0.4%	2,486	0.4%	2,524	0.4%		81.5	83.8	84.4
2028			2,362	0.4%	2,496	0.4%	2,534	0.4%		81.5	83.8	84.4

	Actuals	Normal 50-50	Extreme 90-10	Extreme 95-5		
Compound Avg. 10 yr ('03 to '13)	1.5%	1.1%	1.0%	1.0%	WTHI coeff	52.1
Compound Avg. 5 yr ('08 to '13)	1.5%	1.4%	1.3%	1.3%		
Compound Avg. 5 yr ('13 to '18)		1.1%	1.1%	1.1%		
Compound Avg. 10 yr ('13 to '23)		0.7%	0.7%	0.7%		
Compound Avg. 15 yr ('13 to '28)		0.6%	0.6%	0.6%		

*** There were Demand Response activations in these years on the day of this Zone's peak.*

3. A. 8. Customer needs and Market Information

Transmission and Distribution planners also consider known local information to augment the regional load forecasts as appropriate in developing their plans. The Company is looking at how to better develop and integrate such information into the planning process.

In 2013, the Company commenced a Customer Driven Investment (CDI) pilot project. The CDI pilot team includes representatives from the Company's Economic Development, Engineering, Jurisdiction, Asset Management, and Customer Analytics functions. The team initially is exploring how to integrate robust CDI information at key points of the distribution planning processes, with the goal of expanding the role of CDI within its planning processes. An effort is currently underway to scope out the data and logistical needs that would accompany full implementation of CDI within the Distribution and Transmission processes, including:

- Responsibilities/accountabilities for information gathering
- Frequency and uniformity of customer data
- Governance around how the data will be used, and by whom
- System data requirements, with a focus on I-mapping
- Role of external market participants in the Company's CDI process

The Company also has been developing processes for working with customers to address their needs and implement comprehensive energy solutions. For example, the Company has been working with the Buffalo Niagara Medical Campus ("BNMC") to help the customer plan for and manage growth expected in the Buffalo-Niagara region. Elements of this effort include, a grid modernization study being conducted by EPRI for the BNMC and surrounding neighborhoods. The study is supported by National Grid, which is providing financial as well as in-kind technical support, and is funded in part by a grant from NYSERDA. Companies comprising the BNMC, along with neighborhood groups and key energy partners, will be key participants for the study. The study will assess micro-grid, power conditioning, effective renewable energy connect points, energy storage, demand-side options, among other key components of an optimized, community-oriented distribution system.

The BNMC also received a cleaner greener communities grant from NYSERDA with a significant percentage dedicated to a SmartHome on the campus. The SmartHome, identified in the Five Year Energy Innovation Plan, is a residential home representative of local Buffalo housing stock both in age and environmental challenges. The intent of the SmartHome is to impact the human behavior of energy by creating an educational environment that will address the local history of energy, technology in the home, energy star products, smart metering, renewable energy, EV charging, energy-related jobs, and other educational components. Environmental work is set to begin once a NYSERDA Funding Agreement has been completed. A solicitation for vendor sponsors is currently planned with the intent of demonstrating technology of today, as well as how to integrate technology into regulation/legislation of tomorrow.

In addition to these efforts, the Company has been coordinating with BNMC to implement such projects as installing 21 electric vehicle charging stations, installing 20 Lumi-solar lights (combination wind-solar-led and battery off grid parking lot lighting), and helping to implement bike share and car share programs.

To further the collaborative approach to addressing energy issues, the BNMC has hired a Project Manager and is in the process of establishing a campus energy committee comprised of key energy and facility personnel within the campus members. The energy committee will also involve local college/university professors/students, other utilities and National Grid. The committee will be reviewing a number of energy projects and determining priorities.

3. B. Asset Condition

Investment to address asset condition issues is a significant portion of the Company's system plan over the next fifteen years. In fact, the pace of asset condition program development and execution has increased since the Company's submittal of the previous Fifteen-Year Plan in 2012. National Grid uses asset management techniques to a) reduce the potential for unplanned failures, and b) avoid large populations of assets failing contemporaneously. Such situations are highly undesirable since the lead time for major equipment (e.g., high voltage circuit breakers and power transformers) and work delivery (e.g., transmission line work) can be several years. Asset deterioration is not out of the ordinary; indeed, some deterioration is to be expected with greater service factor and age of an asset. Due to the long service lives of many of its assets, the Company undertakes a systematic and proactive asset management approach.

The term "Asset Management" describes systematic and coordinated activities and practices by which an organization sustainably manages its assets and asset systems, and their associated performance, risks and expenditures over their life cycles. The Company adopted the asset management approach because it is best suited to manage a large number of physical assets and provides the best long-term value for customers. The asset management process targets specific assets for intervention based upon their condition, with assets (or asset families) selected based upon their current performance or condition or forecast performance and condition based on known degradation mechanisms. Although age alone is not a reliable indicator of condition, it is an important factor when considering the volumes of assets that need to be managed to ensure long-term sustainability with acceptable performance.

The Company's Asset Management framework includes developing "strategies." Strategies define the general scope of activities and practices to manage assets and asset systems over their respective life cycles to address either deficiencies in asset condition and performance, or non-compliance with internal and / or external standards. Strategies incorporate information from field inspection data, material samples, maintenance, system studies, industry knowledge, trend analyses and replacement programs to achieve specific operating objectives for the respective assets. Strategies result in implementation plans, in the form of programs or projects. Projects reflecting the cost to deliver these programs are now in the Company's portfolio and contribute to the sustained step increase in capital spend beginning in FY17.

Critical to any systematic and coordinated asset management process is a comprehensive understanding of the condition and performance of the physical assets over their life cycle. In particular, it is important to understand the relationship between short-term asset management activities (maintenance, refurbishment, replacement, etc.) and their actual or potential effect upon long-term costs, risks and performance. Because of observed deteriorating condition and the need to provide customers with sustainable electric service, the Company implemented the proactive asset management approach. The Company has implemented a process of collecting data and evaluating electric system assets through a number of inspection and monitoring programs, including:

- Dissolved Gas Analysis for all substation transformers and load tap changers
- Aerial helicopter surveys of sub-transmission rights-of-way
- Acoustic detection and partial discharge testing of metal-clad installations
- VLF (Very Low Frequency) testing of cables
- Stabilized video/camera surveys, enhanced infra-red surveys and aerial laser surveys of transmission lines
- Substation condition assessments
- Asset health reviews, based primarily on inspection data
- Conductor samples to determine remaining strength

The collection of condition and performance data and the interpretation of that data to guide asset management decisions enable improved risk management. The Company also uses annual asset health reviews for all its transmission and distribution substation and overhead line equipment to improve understanding of system condition and performance. The annual asset health review forms the basis of the annual "Report on the Condition of Physical Elements of Transmission and Distribution Systems,"[10] and provides a methodology for identifying nonconformities with defined strategies and capturing asset-related deterioration, failures or other incidents. The review provides leading indicators to warn of potential non-compliance with performance requirements and lagging indicators to provide data about incidents and failures. The asset health review provides both qualitative and quantitative measures and forms the basis of many of the asset condition driven infrastructure investments.

The deterioration of transmission and distribution assets caused by exposure to the environment and typical usage is managed through routine preventive and corrective maintenance actions. Where deterioration cannot be corrected through maintenance, a partial or full refurbishment, as appropriate, to return an asset to the original manufacturer's design specifications or its intended purpose will be considered where

[10] Case 10-E-0050, Proceeding on Motion of the Commission as to Rates, Charges Rules and Regulations of Niagara Mohawk Power Corporation for Electric Service, *Report on the Condition of Physical Elements of Transmission and Distribution Systems* ("Asset Condition Report") (most recently submitted October 1, 2013).

cost effective. This approach will be continuously evaluated to ensure delivery of safe, economical and adequate service to customers.

For overhead lines, the Company seeks to refurbish overhead transmission line facilities in unacceptably deteriorated condition (i.e., the Company's defined Level 1, Level 2 and Level 3 conditions), as opposed to refurbishing entire lines, unless a compelling justification can be provided for full refurbishment. Any overhead line proposed for refurbishment undergoes a field inspection by qualified transmission line engineers, undergo conductor strength testing and will usually be supported by comprehensive aerial inspection using stabilized video cameras. Although this approach allows for reduced investment amounts in the near term, the Company will evaluate increasing the scope of refurbishment projects where economically or environmentally warranted (e.g., to avoid multiple trips to the same right-of-way, multiple site establishment costs, increased susceptibility to storm damage, additional permitting and licensing costs, greater levels of environmental impact, and more disturbance to property abutters).

Added details on the asset condition programs affecting the Company's system plan are provided described in the annual Asset Condition Report.

3. C. Planning Criteria, Standards and Guides

3. C. 1. Distribution Planning Criteria, Standards and Guides

The distribution system is evaluated to forecast the ability to provide adequate service and reliability to customers while operating the Company's assets within their thermal capabilities. In New York, the criterion for customer service voltage levels is mandated to be within the range of 114V and 123V on a 120V basis. A normal (all lines in) and an emergency rating (N-1) is developed for those elements within a circuit or substation that may limit the load carrying capability of the system and these ratings are utilized as limits for both planning and operating the system. In addition, the system is evaluated in an effort to maintain reliable service within service quality metrics for SAIFI and CAIDI.

The Company optimizes the utilization of existing assets prior to investing in system upgrades. For example, prior to recommending major additions the Company considers measures such as transferring loads between circuits, or installing capacitors to supply local reactive power demands. In general, when planning for capacity issues, system expansion is not recommended until loading is forecasted to exceed 100% of defined ratings. Capacity planning integrates assumptions and criteria that the Company uses to define the: 1) ratings for circuits and equipment, 2) loading threshold accepted before system reinforcements are justified, and 3) manner in which future load levels are forecasted. The uncertainty of assumptions in any of these areas impacts the level of risk associated with the overall planning criteria. In its Distribution Planning Criteria, the Company reflects the region's ambient temperatures and the daily load cycle in developing equipment ratings. In general, distribution planners will attempt to utilize equipment to 100% of rating before recommending major infrastructure enhancements justified for thermal capacity reasons alone. Because the Company takes full advantage of the rating criteria, it must be prepared to support load levels expected under extreme weather scenarios. For this reason, distribution planning is based on the 95/5 extreme weather forecast. Although it is very possible that individual assets may have planned loading to 100% of ratings, system reinforcements to address contingency load at risk may justify system reinforcements in an area in advance of facilities being loaded to 100% of their rating. The capability of a feeder or substation is defined by a combination of circuit and equipment ratings. Ratings are provided for both summer and winter seasons as well as for normal and emergency operating scenarios. The majority of the distribution system in the Company's service territory is summer peaking and summer limited.

The distribution system cannot be economically designed to prevent all customer interruptions. Distribution Planning criteria are also developed to assess the level of risk associated with various contingencies across the power system considering the number of customers that would be impacted by the contingency and the time required for the Company to respond to and enact repairs. As part of its annual capacity assessment, the Company has implemented a practice to evaluate the load at risk of an N-1 contingency utilizing a metric that quantifies the MWh that may be unserved following available switching actions at peak load periods. A threshold of 240MWh for supply and substation contingencies and 16MWh for feeder level contingencies is used to screen the system and prioritize potential system enhancements.

The Company recognizes that outcomes from the REV process likely will affect how it plans the distribution system in the future. At this time the Company is unable to project the nature of changes to the planning process or standards that may result from REV. As the REV process evolves, the Company expects to incorporate changes to its procedures as appropriate.

3.C.2. Transmission Planning Criteria, Standards and Guides

Transmission Planning performs assessments of the transmission system annually for the portions of the system that are considered part of the bulk power system and on a periodic basis, not to exceed three years, for the non-bulk transmission system. These assessments focus on the capacity, reliability, short-circuit and stability needs utilizing NERC, NYISO, NPCC, NYSRC and Company standards. Transmission Planning incorporates the area loads and load forecasts into a NYISO base case system model. Distribution station, customer load and sub-transmission network load that is served in a transmission planning study area is reviewed to determine the most recent peak demand which determines the load distribution across the area. The year-on-year percentage increases in load from the fifteen-year forecast are then applied to the most recently measured peaks to complete the system model for analysis.

Once the starting point has been determined, the modeled load in each study area is compared to the available non-coincident 90/10 fifteen-year forecasts. The conforming loads, or loads that are adjusted based on the fifteen-year forecast within the area, are uniformly scaled such that the total Company load in the study area will be at the forecasted level. The non-conforming loads, specifically the transmission-connected industrial customers, are held at a constant level. It is possible that the staring point loads could be scaled up or down to meet the yearly forecast. This process is repeated to create the one, five, ten and fifteen-year study cases. The fifteen-year forecasts are created by extrapolating the growth rate for year 10 out to years eleven through fifteen.

Assessments of the system performance can then be completed using the system models for the various years. These studies identify any area needs, many of which may be addressed by new capital projects or operational changes. The needs that are determined to be best suited for correction with a capital project are included in the Five-Year Capital Plan.

3. D. Reliability

The Company's ongoing commitment to reliability performance is another driver of investment over the next 15 years. The Company must meet service quality standards for SAIFI and CAIDI and is subject to negative revenue adjustments for failure to achieve service performance. The SAIFI and CAIDI metrics were adjusted to a two-tier system, 1.13/1.19 for SAIFI and 2.05/2.15 for CAIDI, beginning in CY2011 to reflect the impact of utilizing the Interruption Disturbance System, an improved automated data collection system.

Interruptions due to equipment failure and tree contacts (as defined in the PSC's Cause Codes) account for more than half of non-storm incidents, and mitigating customer impacts from these causes has been a primary focus for the Company. During the past several years, the Company has worked with DPS Staff to enhance its vegetation management program with enhancements that continue to minimize the risk of tree related interruptions. The Company's Cycle Pruning Program along with the Enhanced Hazard Tree Mitigation Program, are essential to maintaining reliability and customer satisfaction. Focus on equipment condition has been addressed through the Inspection and Maintenance, Feeder Hardening, and Cutout Replacement Programs and associated work. These programs address deteriorated overhead and underground equipment, which is a major driver of reliability issues on distribution feeders.

Reliability projects and programs are typically evaluated and justified by their expected reductions in customer interruptions or the duration of those interruptions which, in aggregate, will impact the Company's SAIFI and/or CAIDI performance metrics. In addition to stand alone reliability programs (i.e. Vegetation Management, Inspection and Maintenance, and Recloser Installations), electric system planners look to employ these strategies where appropriate when developing specific project scopes addressing various capacity, reliability and asset condition concerns. Historic reliability performance information, specifically interruption cause code analysis, plays a key role in system planning efforts. As part of the electric system planning process, cause code analysis is reviewed annually on select feeders based on their performance. From this review, projects to maintain reliable service performance and projects to maintain the performance of the system via proactive asset replacement are identified.

3. E. External Influences

3. E. 1 Generation Plant Retirements

Aging plants, market rates and environmental regulations could force the retirement of generation plants throughout New York. The EPA's Cross-State Air Pollution Rule (CSAPR), requires 27 states, including New York, to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. Similarly, EPA's Clean Power Plan announced June 2, 2014, proposes to reduce CO2 emissions from fossil-fired power plants by 30% from 2005 levels by 2030. Some generation owners may find it unfeasible or uneconomic to perform the necessary upgrades to come into compliance with the EPA rules, resulting in system performance issues which will need to be addressed through system upgrades. Estimated costs cannot be provided as it is unknown which units will retire due to these rules, however, it can be expected that additional spending in the System Capacity and Performance investment category will be necessary. In situations where this occurs, the Company will engage Staff in discussions on the consideration and evaluation of potential responses.

Generator retirements present a unique challenge to transmission planning—when a plant is retired, other generation must be dispatched to take its place, which can significantly change the pattern of flow within the transmission system. It may add stress to certain network assets and create congestion that did not exist before. Investment in new facilities may be required to address such stress or congestion even absent corresponding load growth or migration. Furthermore, given the limited amount of notice required before a generator could retire (180 days for larger generators), there is little lead time for the Company to plan and implement such investments, and costly contracts may be necessary to keep the generation in service or to repower the generating facility.

Since the 2012 Fifteen-Year Plan, four plants of varying sizes have submitted notices to mothball their facilities. The Company is participating with other New York transmission-owning utilities and the NYISO to evaluate the electric system across the state to proactively identify generation retirements that pose the greatest potential risk to the system operation and reliability, and identify potential solutions to address such impacts.

3. E. 2. External Standards

The Company plans and maintain its system to meet applicable standards promulgated by several different authorities, including the Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Council (NPCC), NYISO, New York State Reliability Council, and the New York Public Service Commission, as well as standards promulgated by the Company itself. The Company is the only transmission-owning utility in New York registered with NERC as a transmission planner, and therefore, is subject to relevant NERC criteria and periodic audits to confirm compliance with those criteria. The Company was audited in 2007 by NPCC, and found to be in conformance with mandatory NERC standards relating to transmission planning. The Company also performs annual planning assessments of the bulk electric system facilities within its service territory, which it shares with its planning coordinator, the NYISO.

The Company must be able to modify its processes accordingly due to changes in required NERC standards.

On March 20, 2014, FERC issued an order approving the proposed definition of Bulk Electric System ("BES") for operating the interconnected transmission network. National Grid Investments in FY15 and beyond will potentially be impacted by the new NERC BES definition change. The new definition will be effective on July 1, 2014, and the compliance obligation will begin on July 2016. The new definition is being used in long term transmission studies that are currently underway. The Company will be entering specific line items in future plans that reflect the full impact of this definition change as planning studies and internal processes required for project approval are completed going forward. .

In addition to the NERC issues surrounding the BES, the implementation of new and modified NERC standards is anticipated to continue at a strong pace over the next few years. NERC has plans to actively progress approximately twelve of those standards at any given time. While not all of the standards under development will impact the Company, it is likely that some may have significant impacts. For example, a re-writing of the existing Transmission Reliability Standard (TPL-001-4) was approved by FERC on October 17, 2013. This rewrite will significant change how planning is conducted. Requirements R1 and R7 of TPL-001-4 will become effective on January 1, 2015; the remaining Requirements will become effective on January 1, 2016.

All these external standards have the potential of impacting the Company's Fifteen-Year Plan. The Company monitors the NERC activities as well as participates in industry forums such as EEI, NPCC and NYSRC to stay current on the latest NERC activities.

3. E. 3. FERC Order 1000 and PSC Proceedings to Improve the Transmission System

FERC issued Order 1000 in 2011, which builds upon previous FERC open access transmission rulemakings (e.g., Order Numbers 888 and 890). The NYISO and the NY Transmission Owners believe New York already largely complies with the Order 1000 mandates. Nonetheless, there is one area the Company has identified thus far which may necessitate changes in the both local and regional planning processes. As a result of Order 1000, these processes will have to consider needs driven by public policy requirements and evaluate potential solutions that meet those needs.

NYISO, on behalf of itself and the NY Transmission Owners, submitted a joint compliance filing in October 2013. Additional rulings on Order 1000 are expected to be issued by FERC in 2014.

In addition to FERC's proceedings under Order 1000, the Commission has initiated several proceedings intended to improve the process for developing transmission projects with the goal of achieving a more efficient and reliable transmission system for the benefit of customers. In November 2012, the Commission initiated a proceeding that solicited proposals for projects that would provide at least 1,000 MW of additional transmission to serve downstate energy needs. Several developers, as well as a consortium of New York utilities, have submitted initial proposals for consideration. Transmission projects developed as a result of solicitations like this one could have significant impact on the system and on how the Company performs system planning going forward.

3. E. 4. Distributed Generation

The addition of Photo-Voltaic (PV) and other Distributed Generation (DG) technologies to the Company's distribution system is increasing and is expected to require changes in the design and operation of the distribution system in the future. The increase in DG is the result of improved technology as well as numerous societal and regulatory incentives, and the Commission's REV proceeding is expected to further accelerate the implementation of DG. The intermittent nature of solar and wind type generation makes capacity planning a challenge. As importantly, as the penetration of distributed generation increases, the manner in which reliability, power quality and operational safety are managed will require redesign. In general, the costs of interconnection of distributed generation is borne by the developer of the generation, however advance investments to modernize the distribution system to facilitate increasing distributed generation may impact distribution System Capacity & Performance spending. Further, to the extent the utility DSPP takes on a greater role as DG integrator, additional system investments to accommodate DG will likely be needed.

3. E. 5. Micro Grids

The Company continues to evaluate the potential integration of micro girds. Near term plans are to review two potential microgrid opportunities, one at the Buffalo Niagara Medical Campus in Buffalo, and another in the Village of Potsdam. These studies will afford the Company an opportunity to explore the integration of distributed energy resources with multiple party owners with critical loads from another set of multiple customers. The goal of the Potsdam review would be to determine if a resiliency-style microgrid could be sustained self-sufficiently for a period of up to two weeks in the advent wide spread area service interruptions due to severe weather.

3. E. 6. Renewable Portfolio Standards

The growth in renewable energy sources, including wind, solar, and biofuels may require additional upgrade and reinforcement of the delivery system to support geographically diverse generation. Among the strategic initiatives of the Cuomo administration are the promotion of on-shore wind projects and an expedited siting process for renewable energy projects. Implementation of such initiatives may provide opportunities to improve overall system performance and risk management; however, new proposals for renewable generation may also change the investment plan moving forward as facilities must be built or upgraded to connect these sources. Implementation of the administration's objective of increasing the penetration of solar technologies and distributed generation also presents potential opportunities, and challenges, in how the Company implements system planning and evaluates infrastructure investment needs.

3. F. Modernizing the Grid

National Grid is making and planning for significant investments to modernize its assets for the benefit of New York customers. These investments are expected to increase even more to achieve the benefits of envisioned in the REV proceeding. The discussion below describes a possible scenario for infrastructure enhancement over the next 15 years. The described investments are not currently reflected in the Company's formal work plan and would be incremental to the plan.

The ambitious objectives of the 2014 NY State Energy Plan and the Staff's Report and Proposal on Reforming the Energy Vision will require upgrades to existing delivery systems, integration of new technologies, along with changes in market rules and customer behavior. It may take many years to transform the grid to deliver fully on the vision of the future: however, recent investments are already paying dividends in improved reliability and resiliency, and the amount of distributed generation in service is rapidly increasing. With a view over the next 15-year horizon, increasing investment levels are necessary to continue to:

- improve reliability
- enhance system resiliency against more frequent severe weather events
- integrate distributed energy resources allowing greater renewable penetration
- improve the overall efficiency of the electric system, from generation through consumption
- provide customers more information, choice and control over how they manage their energy needs

While new technologies and market rules will continue to evolve, progressing towards the utility of the future need not wait. Commercially available technologies exist to improve reliability and efficiency by deploying things such as two-way communications, remote monitoring, advanced automation, and volt-var optimization. Other technologies have also progressed to the point at which grid-scale demonstration projects can be undertaken to test compatibility of a technology for future application. Areas for demonstration could include: advanced inverters, storage, control schemes for integration of distributed energy resources and microgrids. To promote innovation it is important for the Company to continue to advance new products through demonstration, which would require dedicated investment each year.

The integration of high levels of DER will be a significant driver of T&D system investment. The traditional distribution system has been developed to deliver power in one direction. Upgrades to existing facilities are necessary to enable two-way power flow in a safe and reliable fashion. Substation protection schemes will be necessary as will bi-directional voltage control schemes and real-time monitoring, along with control enabled by low latency telecommunications. National Grid looks forward to integrating its share of the 3GW of additional distributed generation envisioned by the NY Sun proposal. To do so, however, investments on the T&D system will be necessary and the cost to upgrade all circuits and substations in advance of interconnection requests is prohibitive.[11] However, targeted DG readiness investments are necessary to realize the goal of significantly increased DER penetration, and the Company believes spending on the order of $750M over the 15 year horizon is within the range of reason.

Continued improvement in reliability and resiliency will be necessary to meet the expectations of customers. National Grid's is developing more resilient construction standards and installing automation schemes on selected sub-transmission and distribution circuits today. In the coming years the Company plans to ramp up these investments to impact a greater percentage of customers. Over the coming 15 years the Company expects that approximately 20% of its radial distribution feeders will have automation schemes that will enhance reliability and resiliency to about 1/3 of its customers at a cost of $170M over the 15 year period.

Improving the end-to-end efficiency is essential to maintain the affordability. On the grid, investments in volt-var optimization and the integration of DER are the means to improving efficiency of delivery. The REV proceeding projects new markets and dynamic pricing structures developing that allow customers greater control over when and how they consume electricity. Telecommunications networks installed on the grid, in combination with new optimization control schemes are expected to improve efficiencies. Enhancements in meter systems will also be required to enable the timely communication of information necessary for real time decisions by customers in the markets that develop. Significant investments – perhaps in the order of $1 billion over 15 years – will be needed to provide the metering, telecommunications, operational and information management systems required to manage this dynamic market.

The $2 billion incremental investment scenario described above would lead to a T&D system with enhanced reliability, improved efficiency, and the capability for customers to better manage their energy and drive the value opportunity.

3. F. 1. Research, Development, and Demonstration

National Grid invests in Research, Development, and Demonstration ("RD&D") initiatives to support strategic needs as identified in the Fifteen-Year Plan. Initiatives are typically funded outside the capital investment plan. National Grid's RD&D program is designed to evaluate emerging and commercially available technologies, to identify those technologies that offer the opportunity to operate the network more efficiently and to better utilize assets by deferring capital expansions and maximizing the value of past investments. Typically, these products, processes, systems, and work methods are new to National Grid and are designed to lower the lifetime operating costs of the T&D system, increase utilization of existing assets, include safety into the design process and reduce the Company's impact on the changing climate. The RD&D program will help bridge identified technology gaps between the current technological capabilities of the system, and those capabilities envisioned to be required in the future, including new information technology development and implementation.

[11] For example, over half of National Grid's distribution system is located in rural areas and operates at the 5kV level. This relatively low distribution voltage has limited capacity for serving load and hosting significant distributed generation.

The RD&D program strives to conduct its projects in collaboration with other parties to leverage resources, minimize risk and incorporate best practices. Collaboration partners typically include the DOE, NYSERDA, as well as the Electric Power Research Institute ("EPRI"), Centre for Energy Advancement through Technological Innovation ("CEATI"), local universities other utility collaborative associations.

Samples of enabling technologies or processes include:

- Phasor Measurement Units – In collaboration with the NYISO, DOE and other NY transmission owners, National Grid deployed sixteen PMUs in upstate New York. The PMUs are measuring the electric system in real time thus providing a new level of visibility of electric system stability.
- Geomagnetic disturbances - This undertaking, in collaboration with NASA, NOAA, EPRI and NERC, seeks to model the relationship between solar flare activity and induced currents on the electric system. These currents can have harmful effects as demonstrated by a blackout on the Hydro-Quebec system in 1989. With recent FERC orders as a backdrop, National Grid has reviewed its Operational procedures to strengthen resiliency against these harmful effects and plans to model the system once there is sufficient data available.
- Arc Flash Detection in network protectors - Prior research showed that arc flash in 480-V spot networks can be hazardous. Several options are available for reducing hazards (arc flash suits, external fuses or disconnects, dead-front protectors, and relaying options), but the industry is still searching for additional alternatives. One alternative is to use fiber optics to detect arcs and subsequently trip network equipment. This could lead to much faster clearing times and lower incident energies.
- Optimized Procedure for Drilled Shaft Embedment in Rock - The objective of this project is to develop a procedure for establishing the interface between soil and various types of resistant rock (sandstone, limestone, granite, etc.) and to establish drilling rates (ft per hour or cubic yards per hour) for these rock types using various drilling rigs, rock augers, core barrels and drilled shaft diameters. The collected data from this research will be used in establishing the procedure of determining the interface between soil and various types of rock and, in the development of specifications and bid documents for the construction of drilled shafts in soil/rock subsurface profiles.

The benefits derived from an RD&D program are demonstrated in many aspects of our system, by increasing the efficiency of the system, increasing asset utilization and making the system safer for employees and customers alike.

3. G. Moreland Report / Storm Hardening Impact

The June 22, 2013 Report of the Moreland Commission on Utility Storm Preparation and Response reviews the responses of the State's utilities to several recent major weather events, including Superstorm Sandy, Tropical Storm Lee and Hurricane Irene. The Moreland Commission report includes several recommendations regarding capital investment and utility operations intended to make utility systems more resilient to future storm events and mitigate the impacts of such events on customers. Recommendations to make the system more resilient include:

- Revised design standards
- Targeted response to flood potential
- Critical equipment location review
- Changes in material types and sizes
- Use of underground cables in specific areas or conditions

The Report recommends developing new standards for future replacement projects and the use of asset health assessments in determining the initial priority of capital investments. National Grid files with the Commission annually an Asset Condition Report and information developed for that report guides the Company's capital investment plan. Increased resilience and infrastructure hardening have been consistent elements of past work plans. Such work includes:

- Additional line fusing
- Small wire replacement
- Tree wire installation
- Select feeder hardening
- Circuit automation
- EMS/communications
- Recloser installations
- Station flood mitigation

As resilience-related investments increase, future capital plans will likely reflect increased spending levels due to greater material and equipment costs. For example the Company may use underground cable in specific locations to avoid overhead damage risk where pole and overhead conductor may have ordinarily been used in the past. Undergrounding such facilities may provide greater storm resilience but also results in greater initial capital investment than an overhead installation.

Similarly, the Company is moving to standardize the use of class 3 poles. Class 3 poles are larger diameter, stronger poles than the class 5 poles previously used by the Company in many standard applications. The Company is also looking at extending the locations that should be hardened by the use of grade B construction. Grade B construction is typically used in situations where a failure could cause significant impact, such as highway or waterway crossings. The Moreland Commission report recommended targeting critical infrastructure in communities and hardening those locations to reduce outage risk. The Company will be revising its standards to provide guidance on the use of grade B construction for different situations such as to reduce risk of service loss to critical community infrastructure.

The Moreland Report also recommends more training and preparation for storm events. Currently employees have primary storm assignments and with increasing importance of storm response performance, the Company will need to provide training and drill experience on multiple assignments based on future storm needs. Although aimed at improving storm response, the additional training will affect labor hours available to complete the capital work.

3. H. Substation Flood Mitigation

Prior to the Moreland Commission Report, the Company in response to an internal storm review commenced a substation flood mitigation study. The study was completed in October of 2013, and yielded the following near term mitigation projects.

- Whitesboro Substation
    - Permanent flood barrier
- Union Falls Substation
    - Distribution transformer to be placed on pole, raise batteries, relocate breakers
- St Johnsville Substation
    - Work with town on pilings and culvert concerns under railroad
    - Develop mobile sub connections in case of flooding
    - Replace breakers with reclosers
- Cambridge Substation
    - Install 34.5kV sectionalizing equipment on a pole and retire sub
- Front Street Substation
    - Build barrier system and look for future relocation

The study also recommended additional distribution planning review for the following locations, and identified the following possible mitigation opportunities.

- Rensselaer Substation
    - Review feeder ties
    - Mobile substation connection toward ROW to support area if needed
- Miller Street Substation
    - Convert feeders from Starr Road Station
    - Develop mobile substation connection in case of flooding
    - Move spare equipment to Cortland crew location
- Homer Substation
    - Develop feeder ties
    - Develop mobile substation connections in case of flooding
- Hammond Substation
    - Develop feeder ties

    - Purchase barriers for use if necessary
- Andover Substation
    - Develop feeder ties
    - Spare relays be kept in stock and local

The study also proposed the following long term replacements.

- Union Falls Substation
    - Rebuild station toward existing ROW
- Andover Substation
    - Develop plan for distribution side of station
    - Raise motor operated cabinet for 115kV circuit switcher
- Inghams Substation relocation

The study also proposed the following retirements if possible.

- Rensselaer Substation
- Whitesboro Substation
- Miller Street Substation
- Homer Substation
- Cambridge Substation

The work identified in the study will be prioritized and reflected in future investment plans as appropriate. Integrating such work into the plan will likely affect the implementation timing of other work in the plan and the overall investment levels.

3. I. Other Drivers That May Affect the Fifteen-Year Plan

3. I. 1. Long-Term Supply Outlook

Over the period addressed in the Fifteen-Year Plan, the composition, availability, and affordability of electric supply may be subject to dramatic change. Based on projections by the U.S. Energy Information Administration (EIA), the Company expects supply costs to rise through the period of the plan, placing upward pressure on customer bills.

The Company procures energy for its full service customers (i.e., those customers that do not procure their energy from electric service companies or other third-party providers), whose consumption in 2013 represented approximately 46% of all of the Company's delivered energy. The Company's procurement strategy follows the Commission's policy on electric commodity portfolios. That policy requires that supply for larger commercial and industrial customers be procured through the NYISO markets without any additional hedges provided on their behalf. The policy also requires that supply for the mass market customers (residential and small non-demand commercial) be procured through a managed program to mitigate supply cost volatility. The mass market procurement plan is a short-term strategy, limited to a three-year view.[12]

[12] The Company has also undertaken a proactive role in energy efficiency and demand response programs to reduce electric demand, as discussed above.

On May 14th 2014, the Company filed revised tariff leaves that, if approved, will allow the Company more flexibility with the timing of the electric supply commodity reconciliations. These proposed changes are in response to the unanticipated extreme cold weather experienced in the Northeast this winter which resulted in significant increases in electric supply costs above the forecast rates. Those higher costs were reconciled for recovery in accordance with the Company's tariff and customers experienced significant volatility in month to month supply costs. The tariff revisions to the Rule 46 commodity rate mechanisms will provide the Company with a measure of flexibility to manage significant volatility resulting from the reconciliation of electric supply costs, like those experienced in January and March this year, for its residential and small commercial customers (mass market customers). The Company continues to explore and discuss with Staff appropriate supply-side opportunities and activities that may benefit customers.

The outcome of the REV process is anticipated to significantly affect the operation of New York's retail and wholesale electric markets, including the Company's role in providing electric supply to customers. Nevertheless, for purposes of the estimates reflected in this Fifteen-Year Plan, the Company used the publicly available electric supply cost estimates.

Projections from the U.S. EIA's Annual Energy Outlook[13] suggest that the cost of supply will grow on a real dollar basis from 6.1 cents per kWh in 2014 to 8.2 cents per kWh by 2029, an increase of 34%. This represents an average annual (compound) growth rate of 2.0%. On a nominal basis, the cost of supply will grow to 10.8 cents per kWh in 2029, an increase of 76%, or an annual growth rate of 3.9%.

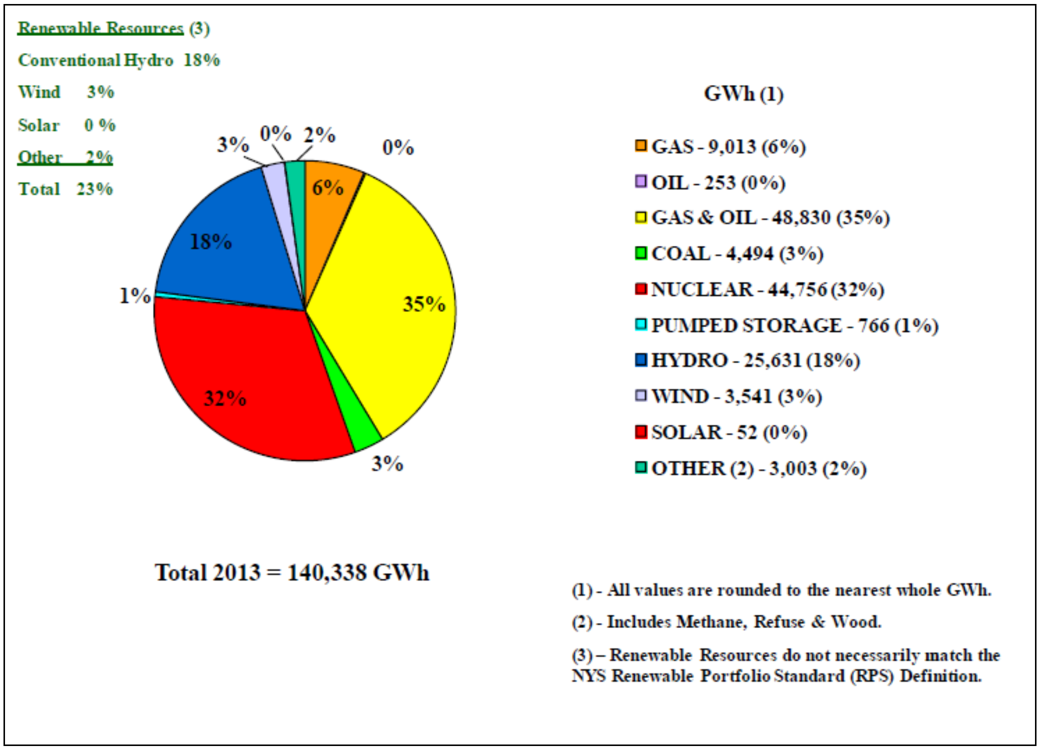
The market price for electricity currently is determined by a market that is administered by the NYISO. The NYISO gathers information from power plants and other resources in the state and the surrounding regions to match customer electricity demand to the lowest cost supply. At any point in time, the market price for energy is set by the highest bid generation unit that needs to be run to meet demand requirements. The Company's customers also pay the cost of maintaining adequate generation supply through the capacity market, also administered by the NYISO. Pricing for capacity is difficult to predict and is a function of the amount of surplus generation available in the market and the assumed cost of new units (cost of new entry). Currently, there is sufficient excess capacity above NYISO reliability minimums, creating a relatively low priced capacity market.[14] Over time, these costs may increase as older generation assets retire, excess capacity in the market is absorbed and the costs of new entry increase with inflation and other factors.

The cost of supply is directly affected by additions or retirements to the generation resource mix supplying customers in the Company's service territory. Figure 3-10 shows the resource mix in New York State as of 2013. The total output from generators that use natural gas as their primary fuel in New York has increased 3% from 2010 levels to become 41% of the total generation production in 2013. This number is only

[13] Based on EIA AEO 2014 report, NPCC Upstate New York EMM region, reference case, vintage Dec. 2013
[14] 'NYCA' market.

expected to rise in the future as natural gas production from the Marcellus shale formation and other shale gas locations expands and older coal-fired and nuclear generators retire and are replaced by gas-fired generators that are cheaper to build. As New York State becomes increasingly more dependent on natural gas for its electric generation, the price of natural gas will have a larger impact on the cost of supply. Natural gas prices rely heavily on the natural gas pipeline infrastructure in place to deliver growing peak demand gas needed for gas-fired electric generators, as well as residential and commercial consumers, especially during periods of cold weather.

Figure 3-9
New York State Fuel Mix
2013 NYCA Generation by Fuel Type[15]



Legislation and regulation are also significant drivers of supply cost increases. Potential legislative changes over the planning period include national Renewable Portfolio Standard and Clean Energy Standard programs, a CO2 cap and trade program. The Regional Greenhouse Gas Initiative is already in place for the Northeast region of the United States. Combined, the Regional Greenhouse Gas Initiative, New York State's major plan to cut New York's energy consumption 15% from levels predicted by 2015, and a Federal CO2 program such as EPA's proposed Clean Power Plan would likely increase the unit cost of centrally-generated electricity for customers by valuing the cost of CO2 emissions.

[15] NYISO "Gold Book," 2014 Load and Capacity Data (April 2014), p. 57.

Also influencing supply cost is the cost of transmission to deliver the generation, including new renewable generation being added to the state's transmission system. However, other than for specific projects identified in Chapters 5 to 7 of the Plan, costs associated with additional infrastructure needed to accommodate new generation sources or better integrate renewable resources into the State's transmission system are not reflected in the Fifteen-Year Plan.

New York currently has several policy goals in place to move the future supply mix toward more renewable generation. There is a "30 by 15" goal to have 30% of the state's generation from renewable sources by 2015. This is being accomplished through a number of New York State initiatives such as the NYSERDA RPS main tier and customer sited tier renewable energy solicitations, the recently announced NY-Sun initiative as well as the implementation and development of other DG programs. In addition, the results of the REV process or other future policies or laws may increase initiatives to lower greenhouse gases, which would further change the future supply landscape.

3. I. 2. Materials/Commodity Price Increases/Inflation

It is difficult to predict the long-term outlook for material and external labor costs in the utility industry. The Company continues to monitor and refine its processes for managing commodity price shifts and the impact to its current and future capital investments. Some of the major commodities such as oil, copper and steel are showing global upward movements as much as thirty percent over the next few years. Knowing how difficult commodities are to predict, the Company works with external experts to monitor trends and highlight major shifts, and is continuing to be proactive in implementing risk mitigation strategies to minimize the financial impact of commodity shifts. The Company manages the capital portfolio to achieve the plan. Cost impacts due to commodity price increases or inflation will be managed accordingly by completing higher priority work within the scope of the plan.

3. I. 3. Availability of Construction Resources

Competition for resources required to construct and deliver transmission and distribution infrastructure projects has increased over the past several years, as utilities across the nation have begun addressing the deteriorating condition of facilities. The Company will supplement its internal workforce with competitively procured contractor resources, and is developing a model to pre-qualify vendors to facilitate future contracting and improve resource certainty. It should be noted that labor costs, even for competitively bid projects, may increase as construction budgets increase across the country and it becomes necessary for utilities to compete against each other for contractor resources. The Company manages the capital portfolio to achieve the plan. Changes due to construction resources will be managed accordingly by completing the highest priority work available within the scope of the plan.

3. I. 4. Engineering Workforce

National Grid recognizes the need to attract, develop and retain a talented engineering workforce to design and implement its system plan. The Company actively engages in workforce planning with the Network Strategy and Operations functions to establish baseline requirements and identify needs. The Company has a Graduate Development Program for targeted hires and a robust Internship Program for Engineers. The Company also is working in collaboration with New York colleges to develop programs and curricula to train the next generation of engineers needed to build and operate advanced grids. National Grid also has developed the Engineering our Future program, which sets a plan for investing in a long term strategy to positively affect attitudes of young people, their parents and teachers toward a career choice of engineering. Through these efforts and others, the Company is doing its part to attract, develop and retain the engineering workforce needed to implement and support the utility of the future.

3. I. 5. Increasing Lead Times

Lead times associated with items such as power transformers, Coupling Capacitor voltage transformers (CCVTs), breakers, switches and other complex larger equipment, are subject to fluctuation within the period of the Plan. Longer lead times present increased challenges in managing project schedules and budgets. Increased lead times are driven by many factors, including: (i) rapid growth and increasing demand for equipment in developing nations, (ii) cost and availability of raw commodity materials, (iii) increased national demand from growth and in response to extreme weather conditions and events, and (iv) increased asset replacement initiatives within the electric utility industry. The Company has established and continuous to establish commercially negotiated agreements with preferred vendors based upon their deliverability, cost, and quality to mitigate the risk of increasing material lead times.

3. I. 6. Changes in Customer Load Patterns

For the past several years, upstate New York has experienced declining industrial load while residential load has been growing. Typically, these patterns have not occurred in the same area. For example, city centers have been losing businesses and residences while suburban areas have grown with new residences and commercial industries. In this situation, the Company may have older equipment in the urban area that is realizing reduced load, while it is simultaneously required to add new facilities to serve new or greater loads in the suburban areas. Nevertheless, because the older equipment is still needed to serve existing customers, there may be condition issues that require repair or replacement for safety, environmental or reliability reasons. Thus, the Company may need to invest in both new facilities and existing ones to provide reliable service to customers even in cases where overall load may not be growing.

In contrast to load migration, some areas (such as in the Northeast Region) have seen significant new load growth. Because of the long lead times associated with much of the Company's infrastructure investments, significant amounts of advanced planning and engineering is needed in such circumstances. Large, new customers may also be expected to bring significant load from ancillary businesses and new residential development as jobs are created. If the anticipated large customer fails to locate in the area, the Company must adjust its investment plans. Similar infrastructure planning issues arise in connection with potential development of new generation. Thus, the

Company may have a forecast for new generator or customer interconnections that may not materialize.

The Company also plays an important role in meeting public requirements work for the State and municipalities. Government agencies request that the Company relocate or re-construct equipment to allow public requirements work to proceed. Such investments may be needed irrespective of electric load projections. The System Plan includes estimates for this type of work based upon historical experience, which may be affected if the agencies substantially reduce or expand their public requirements work from historic levels.

3. I. 7. Governmental and Other Approvals

Article VII Projects involve proposed construction and operation of a major electric transmission facility defined as lines with a design capacity of 100kV or more extending for at least 10 miles, or 125kV and over, extending a distance of one mile or more. (The law excludes underground transmission lines in a city with a population of 125,000.) The Department of Public Service Staff represents the public interest during Article VII proceedings and employs a wide range of experts, including planners, foresters, landscape architects, aquatic and terrestrial ecologists, engineers, and economists who analyze environmental, engineering, and safety issues. An Article VII proceeding also involves other agencies such as the Departments of Environmental Conservation, Agriculture and Markets, and Transportation, and often includes participation by municipalities, environmental, commercial, planning and other groups or interests.

The Article VII process has a major impact on annual and long-term capital plans. The effort, time, and resources utilized on Article VII projects is extensive, including substantial public outreach on the need and scope of the transmission project. The Fifteen-Year Plan includes numerous Article VII projects required due to asset condition, generator retirements, or the state's Energy Highway Initiatives. The Company makes every effort to move these projects forward in a timely manner but schedules and project costs can be affected substantially through the Article VII process.

3. I. 8. Transmission Outage Scheduling

The Company does not have the final authority to approve outages on elements identified as both "controlled" and "secured" by the NYSIO. The Company must coordinate those outages through the NYISO process, which can affect the timing of transmission upgrades that require outages for work to be performed safely. The NYISO may not approve the timing of transmission line outages due to conflicts with work on other transmission facilities, including those of other transmission owners, impacts on generators or impacts on grid congestion. The Company is investigating ways to mitigate the risk of not obtaining outage approval. In addition, as the Company's asset replacement programs increase in number, careful planning is required to ensure that there are not an excessive number of system components simultaneously scheduled for construction work in the same general area to ensure that the system is not limited in its capability to provide service to our customers. Limitations on transmission outage scheduling and coordination can create hurdles to project schedule and cost.

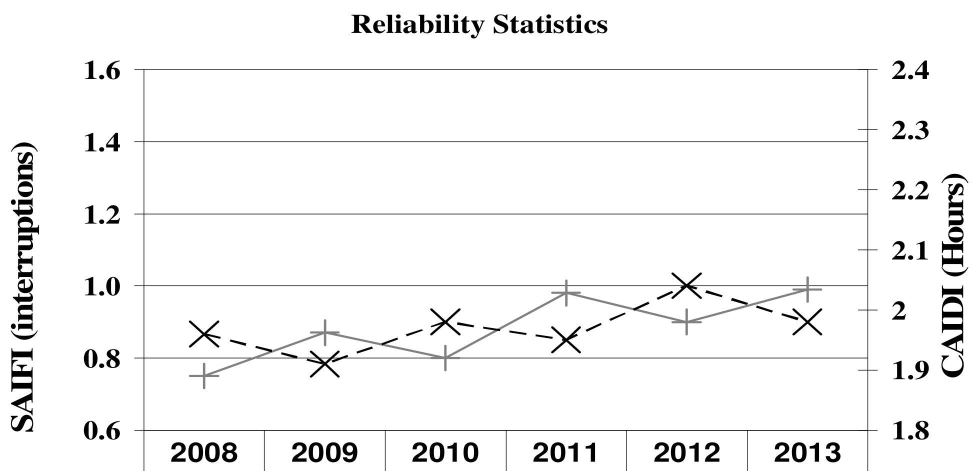
Chapter 4. Assessment of Plan Performance

The Fifteen-Year Plan provides an opportunity to consolidate the results of near and long-term planning processes and activities into one document. It also offers an opportunity to incorporate and coordinate process changes and improvements that affect the Company's integrated transmission and distribution system. The ultimate objective of the Fifteen-Year Plan is to develop new, and strengthen existing, integrated plans to provide customers with safe, reliable and reasonably priced service over the long term. This section presents information regarding the effectiveness of the Fifteen-Year Plan in meeting system planning objectives, including achieving reliability goals and directing capital resources to address specific issue areas and performance trends. In general, the Fifteen-Year Plan has been effective and the Company will apply lessons learned from this assessment in future planning opportunities.

4. A. Reliability

The initial Fifteen-Year Plan was consistent with previous Five-Year Capital Investment Plans in regards to its focus on maintaining system reliability. The Company successfully met the Customer Average Interruption Duration Index (CAIDI) metric for the eighth consecutive year in 2013, and met the System Average Interruption Frequency Index (SAIFI) target for the sixth consecutive year. Actual performance since 2007 of the CAIDI and SAIFI metrics is shown in Figure 4-1, below. During this period the Company increased focus on the existing Inspection and Maintenance Program in the plan years by completing Level 3 inspection items earlier in the three year correction window. The Company believes the increased level of maintenance in both line and stations is a significant factor in maintaining reliability performance. In addition, the feeder hardening, Engineering Reliability Reviews, cutout replacements, recloser installation, and side tap fusing efforts are also believed to have contributed substantially to the Company's ability to achieve reliability targets. All of these efforts were underway within the period of the initial Fifteen-Year Plan.

Figure 4.1 Reliability Performance 2008 – 2013.[1]



	2008	2009	2010	2011	2012	2013
SAIFI	0.75	0.87	0.80	0.98	0.90	0.99
CAIDI	1.96	1.91	1.98	1.95	2.04	1.98

Years

The Company's vegetation management program is divided into two sub-programs, one for the distribution system and another for the transmission system. Both programs include a cycle-based component and a reliability improvement component to minimize tree-related interruptions as well as provide a measure of public and worker safety. For the transmission system, the cycle-based program is an integrated vegetation management (IVM) program used to control vegetation along the floor of the rights-of-way. The details regarding the transmission program performance are reported annually in a separate report to the Commission.

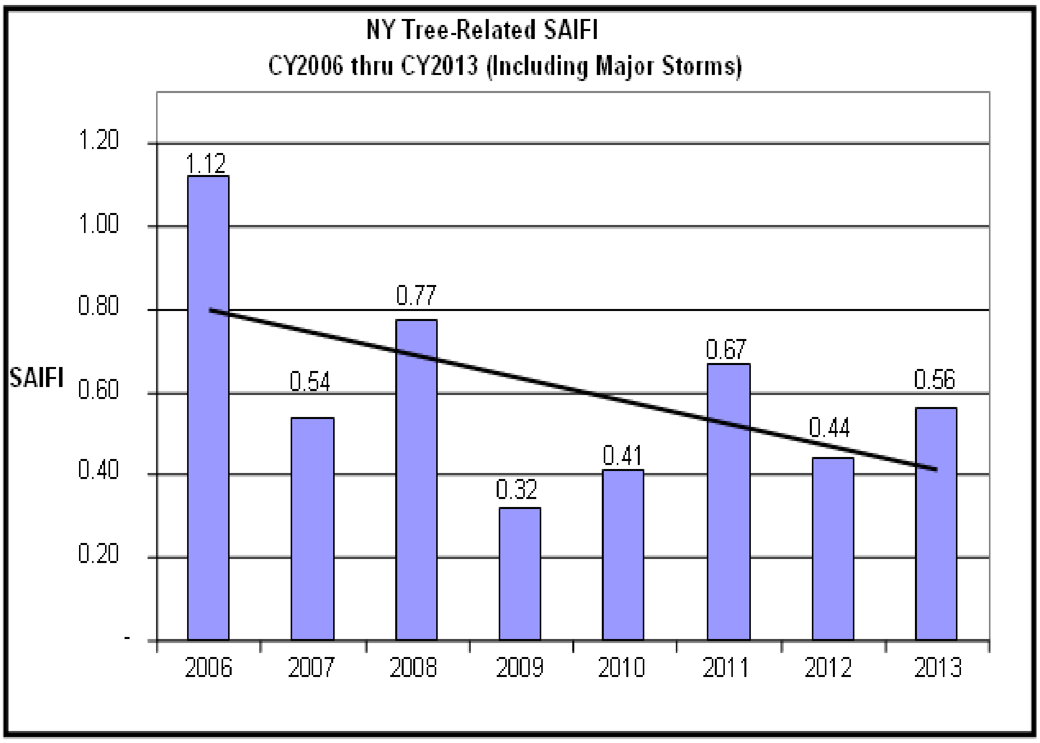
The Company's distribution cycle-based component is circuit pruning, a comprehensive program that provides for the pruning of vegetation along all distribution circuit miles on an average five and one-half year interval or cycle. An optimal cycle length is set for each circuit based on growing season, growth characteristics of predominant tree species in that area, and the appropriate clearance to be created at the time of pruning. The Company has maintained the appropriate level of funding necessary to operate the program for many years allowing the completion of six full cycles of pruning. In addition to the routine pruning, hazard tree removals are performed on prioritized distribution feeders. The Company identifies feeders for the inspection and removal of hazard trees based on field inspections,

[1]Beginning in 2011, the Company implemented the Interruption Disturbance System ("IDS") consistent with the Cap Ex / Op Ex Stipulation in Case 10-E-0050. Because IDS captured more reliability performance information than available under the legacy paper-based system it replaced, corresponding SAIFI and CAIDI standards were increased beginning in 2011 to reflect the greater sensitivity of IDS.

tree exposure, historic interruption data, number of customers served and circuit configuration.

Shown in **Figure 4-2**, below, is the NY system tree-related SAIFI (including major storms) for the past eight years. Although tree-related interruptions are strongly correlated with wind and weather patterns, that variability and its effect on tree interruption data is mitigated when viewed over a longer period of years. In this case, the applied trend line indicates that National Grid's vegetation management program is fulfilling its objective to minimize tree-caused interruptions over the long term.

Figure 4-2 Tree-related SAIFI: CY2006 – CY2013



4. B. Load Forecasting

_Forecasting peak electric load enables the Company to assess the availability of electrical infrastructure, enables timely procurement and installation of necessary infrastructure, and provides system planning with information to prioritize and focus action plans. Table 4-1 below, compares actual peak demands and energy efficiency performance in 2012 and 2013 with forecasts from the 2012 Fifteen-Year Plan. For 2012, the forecast was low by 1.6%, and in 2013 it was low by 0.9%. Considering that energy efficiency targets were not achieved, correcting the model provides that the overall forecast was low by 1.1% in 2012 and on target in 2013.

Table 4.1 – Comparison of 2012-2013 Actual Peaks and Energy Efficiency with Forecasts from the 2012 Fifteen-Year Plan

ITEM	**Units**	**2012**	**2013**
SummerPeak Goal (after EE)	(MW)	6,678	6,728
Actuals (weather adjusted)	(MW)	6,782	6,788
Peak Difference	(MW)	104.0	60.0
Peak Difference	(%)	**1.6%**	**0.9%**
Energy Efficiency Goal	(MW)	(81.0)	(143.0)
Energy Efficiency Actual	(MW)	(47.8)	(83.4)
EE Difference	(MW)	33.2	59.6
Peak Difference (w/adjusted EE)	(MW)	70.8	0.4
Peak Difference (w/adjusted EE)	(%)	**1.1%**	**0.0%**

4. C. Smart Grid Investment Grant Program and Modernizing the Grid

In the 2012 Fifteen-Year Plan, the Company summarized participation in the New York State Capacitor and Phasor Measurement Unit (PMU) Project which originated through a NYISO funding application to the United States Department of Energy's (DOE's) Smart Grid Investment Grant (SGIG) program. National Grid completed installation of 286 MVAR of reactive support in eastern New York and also installed PMUs at twelve key substations.

The Company also discussed grid modernization and evolution of the technology and external standards in the 2012 Fifteen-Year Plan. The plan called for incremental spending for Advanced Grid Applications (AGA) in Year 6 and beyond, with additional ramp up in Years 12 - 15. In 2014, it is apparent the investment profile previously proposed did not reflect the increased call for such investments in the wake of events such as Superstorm Sandy and the recognition of the need for additional electric system hardening and resiliency, or as envisioned by the REV proceeding. The Company is currently working on select micro-grid pilots to develop the knowledge base for creating resilient micro-grids to support community infrastructure and critical loads. The Company recently submitted a request for NYSERDA funding for a micro-grid study and installation in Potsdam, New York with the Town of Potsdam, Clarkson University, and Potsdam State University. The micro-grid will also include select locations for gas, food, banking and medical services in the community. Such initiatives promote the understanding of issues associated with modernizing the electric system.

4. D. External Standards

The Company must plan and maintain its system to meet standards promulgated by several different authorities, including the FERC, NERC, NPCC, NYISO, the New York State Reliability Council, and the Commission. In the initial Fifteen-Year Plan, the Company anticipated the following work due to Bulk Energy System (BES) definition changes by NERC.

- Conductor Clearance requirements not formally included in the A-10 bulk circuit list were included in the plan to be completed over eight years (rather than potentially two to three years if NERC re-issued its NERC Alert).

  The requirements to date are consistent with the Company's plan of completion as presented in the 2012 submittal.
- Application of stricter planning criteria on additional facilities. The Company anticipated expenditures of $50 million over 10 years.

  This estimate has exceeded actuals due to the fact that the anticipated planning criteria are generally consistent with internal standard TGP 28, resulting in little incremental change to the existing requirements.

- Requirements on Disturbance Monitoring due to BES definition change. The plan included $10M over the next 4 years.
  - To date NPCC is working on the standard definition and future requirements are unclear at this time.
- New Cyber Security standards in combination with the new BES definition. The plan included $6 Million over the next 2 years.
  - The plan was consistent with the evolving security requirements. The Company anticipates costs in this area to increase with the need to adapt to future changes.

4. E. Generator Retirements

The Fifteen-Year Plan included discussion of potential generator retirements. Although the Company did not include estimated costs of specific generator retirements, it did note that the greatest likelihood for a retirement existed in western New York. The Company also noted such retirements would likely require additional spending to support the reliability and performance of the electric system. Subsequent to filing the Plan, a number of generators filed retirement notices. Several of the proposed retirements have impacted the Company's system planning and annual work plan, as new projects are needed to support local issues caused by the retirements. To date, projects have been required to respond to Dunkirk, Cayuga, and Syracuse Energy retirements. To accommodate such projects in the Plan, other previously planned work has been deferred. With the support of Staff and in coordination with NYISO, the New York utilities are undertaking a study of generators at risk of retirement to assess the risks and additional work that may be needed to respond to retirements. This study is a positive step to develop an understanding of the impacts of generator retirements on the system and future planning needs.

4. F. Availability of Design and Construction Resources

The Fifteen-Year Plan identifies the need to outsource labor to assist internal staff with design and construction of the work plan. The Company supplements its internal workforce with competitively procured contractor resources. Generally, the Company has managed acquisitions of additional resources and internal staffing to meet the objectives of the Plan. However, the Company has been challenged in acquiring relay and telecommunications staffing to support the Plan. Recent retirements have impacted the Company's internal staffing for relay/communications work. The Company has outsourced some of this work but qualified and knowledgeable workers are limited in this field. The Company has also hired additional full-time employees, thus increasing relay/telecommunications staffing over previous levels.

4. G. Electric Vehicles

The Company described four cases of potential impact on the electric system in the initial Fifteen-Year Plan. Currently, the Company does not collect data on the number of EVs charging on the system; however, from a design and operations perspective, there has been no impact on the system to date. The Company plans to improve data acquisition on EVs by engaging Polk, an auto industry market data firm, which will provide information to aid in understanding the effects on the upstate electric system.

4. H. Capacity and Performance

Many of the projects in the plan are intended to increase capacity and improve performance of the system (*e.g.*, a new station transformer bank, increased transformer size, increased wire size on a line or circuit, etc.). One measure of the effectiveness of the Capacity and Performance work can be seen in a review of recent summer preparedness filings. Table 4-2, below, shows the number of substation transformers, distribution circuits, and sub-transmission circuits identified in the Company's 2012-2014 summer preparedness filings as overloaded. These data show a trend of improvement during the initial years of the Fifteen-Year Plan period relating to system capacity concerns.

Table 4-2 – Overloaded Circuits: 2012 - 2014

	2012	2013	2014	% Change
Substation Transformers	37	36	35	-5.4%
Distribution Circuits	45	45	35	-22.2%
Sub-Transmission Circuits	11	8	5	-54.5%

4. I. Delivering the Plan

The initial Fifteen-Year Plan was filed on February 29, 2012 near the end of Company's Fiscal Year 2012. Table 4-3, below, shows the Company's electric capital plan spending in fiscal years 2012, 2013 and 2014 to budget. Over that period, the Company has delivered the investments developed in the plan.

Table 4-3 - Actual Capital Investment vs. Budget, FY12 – FY14

	2012	2013	2014	Total
Transmission	$129M	$165M	$155M	$449M
Sub-Transmission	$62M	$33M	$37M	$132M
Distribution	$231M	$200M	$300M	$731M
Total - Actual	$422M	$398M	$492M	$1,312M
Investment Plan	$409M	$423M	$426M	$1,258M

4. J. Impact of Hurricane Sandy on Future Plans

Although the Upstate New York electric service territory performed well during Hurricane Sandy based on lessons learned from areas in NY which sustained more damage, the impacts on future planning and design are significant for the upstate electric system. The Company has typically included storm hardening work in its Capital Investment Plans; however, going forward, storm hardening and resiliency related investments will increase in areas such as:

- Circuit automation
- Reconductoring to larger conductor
- Fusing
- Additional sectionalizing / reclosing equipment
- Worst Feeder / Engineering Reliability Reviews
- Wood pole management
- Danger tree clearing
- Enhanced standards (Hendrix Cable, Class III Poles)
- Mobile substation purchases

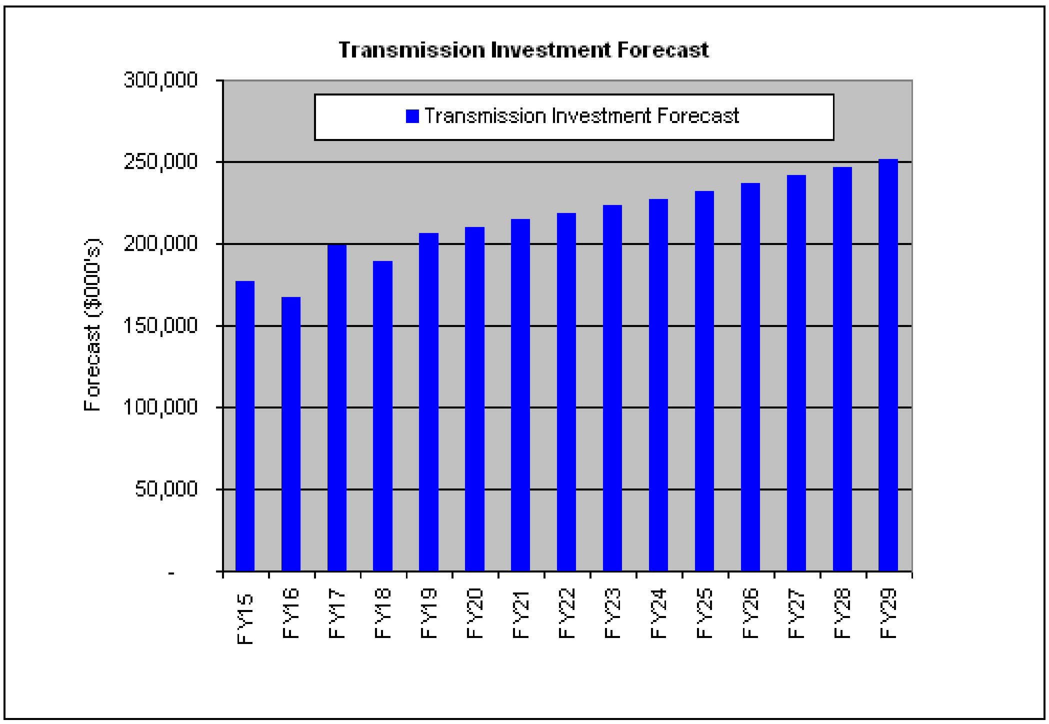
In addition to spending in areas such as those listed above, future plans will also likely reflect investment to address flood prone equipment mitigation/retirement, standards enhancements and materials upgrades, increased automation, and micro-grid trials / implementation. The initial Fifteen-Year Plan does not reflect the level of incremental change on hardening and resiliency that is currently underway.

Chapter 5. Transmission Discussion by Spending Rationale

The discussion below addresses forecast spend for major transmission programs and projects anticipated during the 15-year period of the Plan. More detailed descriptions of the programs and projects forecast for the first five years of the Plan can be found in the Company's most recent Capital Investment Plan filing.[1]

Transmission Investment Forecast for fiscal years FY15 to FY29 is provided in Figure 5-1 below.

Figure 5-1 Transmission Investment Profile



[1] Case 10-E-0050, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service*; Five-Year Transmission and Distribution Capital Investment Plan for FY15-FY19 (filed Jan. 31, 2014).

5. A. Customer Requests/Public Requirements

Transmission investments in this spending rationale can include land rights and public requirements including municipal, customer interconnections and wind farms. Because customer interconnection projects are typically reimbursable (i.e., costs incurred by the Company are paid for by the customer), there is no net effect to the capital plan from such projects. The Company does not anticipate any significant non-reimbursable Customer Requests/Public Requirements transmission system projects in the base plan over the 10-year period of FY20 – FY29 or in the 5-year period of the Capital Investment Plan (FY15 – FY19).

Nevertheless, large commercial/industrial customers (e.g., greater than 5MW) can request service at any location within the Company's service territory. When the proposed location is in area with available capacity, no system upgrade may be needed and the customer can connect under the tariff rules. However, if system upgrades are needed to supply the customer (i.e., upgrades to any facilities that are not considered service laterals), such projects would be included in the capital plan. As an example, there is interest in developing the Griffiss Air Force Base in Rome, NY. One of the potential development options could require an approximately $20 million reconductoring project to serve them.

Range: $0 - $20M annually, assuming one large reconductoring project/year.

5. B. Damage/Failure

Damage/Failure investment levels are primarily based on historical actual costs for such work. The Company views Damage/Failure projects as mandatory work that is non-discretionary in terms of scope and timing. Where condition renders the asset unable to perform its intended electrical or mechanical function on the delivery system, the Company initiates the timely replacement of such assets under the Asset Condition spending rationale.

5. B. 1. Replacement of Priority 4 Transformers (C031656 - $40.2m)

Power transformers and associated components such as tap-changers are managed through routine visual inspection, annual dissolved gas analysis ("DGA") and electrical testing.

Drivers:
Transformers with anomalous DGA results or that have been confirmed in poor condition through electrical testing are targeted for replacement. The five year Capital Investment Plan utilizes a replace on fail approach with failures managed through the use of strategic spares. In this context, failure means either DGA results that suggest an

immediate need for replacement or actual physical/electrical failure. Sufficient strategic spares are available to cover the probability of failure for the majority of the fleet.

For the balance of the Fifteen-Year Plan, the Company anticipates an increase in the number of transformers with anomalous DGA results and budgets for the replacement of more priority transformers starting in FY20.

Customer Benefits:
The failure of an average 20MVA sized transformer could lead to a loss of power for approximately 17,000 residential customers. The prolonged time needed for restoration (either through the installation of a spare or a mobile sub) can translate into millions of customer minutes interrupted.

5. C. System Capacity and Performance

System Capacity and Performance projects are required to ensure that the electric network has sufficient capacity to meet the growing and/or shifting demands of our customers. Projects in this rationale are intended to reduce degradation of equipment from thermal stress, provide system configuration flexibility to limit reliability impacts of large contingencies and changes in bulk power transfers or generator availability, and ensure that system performance adheres to regulatory planning and reliability standards.

As noted in Chapter 3, the impact of energy efficiency and carbon reduction programs, as well as the actual pace of economic recovery, will cause actual load growth to lead or lag forecasted values and accelerate or decelerate the need for capital projects that are driven by load growth. The focus of the REV proceeding on application of new technologies that better utilize existing system capacity also is expected to result in a tradeoff between increased spending on such technology and spending for additional system capacity. Accordingly, there may be a shift away from spending on traditional transmission and subtransmission expansion projects towards distribution projects that involve such advanced technology. However, such shifts may be tempered by shifts in the need for capacity at certain locations within the transmission network or to address performance issues caused by retirement of existing generation, and as the size of renewable energy sources mandates their connection to the transmission system. Such issues introduce uncertainty in the later stages of this Fifteen-Year Plan.

5. C. 1. Northeast Region Reinforcement

This major program consists of reinforcements of the transmission system in the Saratoga and Glens Falls area of the Company's Northeast Region necessitated by thermal and voltage needs as well as area load growth. It is also impacted by expansion at the Luther Forest Technology Campus ("LFTC"). There are a number of major projects under this program being constructed within the FY15 – FY19 period. Only the reconductoring of 22.9 miles of existing 115kV transmission lines in the Northeast Region is expected to continue into FY20 and FY21 (C035771 $3.6m).

The need for future projects within this program is dependent on the actual load growth for the Northeast Region (Saratoga and Global Foundries) during the next ten years. Projects that are needed to address existing performance issues include the new Spier-Rotterdam line, Eastover Road Station, and the rebuilding of the Mohican-Battenkill 115kV lines described in the Company's Capital Investment Plan.

For details of the spending amounts under this program in FY15 – FY19, refer to Table 2-7 in chapter 2.C of the Company's Capital Investment Plan dated January 31, 2014.

5. C. 2. BES 100kV Brightline

Investments in FY20 and beyond will be impacted by NERC's implementation of the Bulk Electric System (BES) criteria. The implementation plan approved by FERC included a two-year period for all NERC registered entities to bring BES elements of the transmission system into compliance with the new standards. Compliance with Phase 1 of the new definition is required by July 1, 2015, while compliance with Phase 2 is required by July 1, 2016.

There are three areas the Company previously identified potentially significant impacts to its investment plans from the bright line rule in the NERC proposal.

- The Company recently completed its conductor clearance program for bulk power circuits. That program was implemented in accordance with a timeframe specified in a NERC alert. For the remainder of its 115 kV system (non-bulk power circuits), the Company is proceeding with an eight-year program to complete conductor clearance projects. The 8-year conductor clearance program is in the capital investment plan at $75 million over the period. If NERC were to apply the NERC Alert timeframe to newly classified BES circuits, it could compress the 8-year program conductor clearance program into 2 years.

- The new NERC BES definition, in combination with the new NERC stricter planning criteria (TPL 001-004), will impose such criteria on a larger set of facilities in the future. Making specific cost estimates of the impact of the new BES definition as finally implemented is difficult at this time. In addition, many of the issues identified under the updated TPL would have been identified based on the Company's internal planning guideline, TGP-28. The Company is factoring the new BES definition and the new TPL standard into its current planning studies, but it has not identified in this plan all specific line items that can be attributed to this definition change.

- New Cyber Security standards version 5 in combination with the BES definition will impact facilities that are expected to be in conformance with the Critical Infrastructure Protection standards. The new Critical Infrastructure Protection standards require facilities that are critical in deriving Interconnection Reliability Operating Limits

(IROLs) that have Special Protection Schemes that could impact an IROL, and that have a high number of lines connected to the substation to be included. These changes in conjunction with the new BES definition are expected to add up to 14 facilities in New York to the list of those that must meet the Critical Infrastructure Protection standards. The impact of this change is estimated at $4-$6 million over the next two years; however, more specific cost estimates are difficult at this point until the impact of version 5 of Critical Infrastructure Protection standards is fully evaluated. The Critical Infrastructure Protection standards are enforceable April 1, 2016 for High and Medium facilities and April 1, 2017 for Low facilities.

To the extent the Company identifies additional investment plan needs specifically related to the BES rules, they will be reflected in future plans.

5. C. 3. FERC Order 1000

FERC Order 1000 builds upon previous FERC open access transmission rulemakings, (e.g., FERC Order Numbers 888 and 890), which New York has previously addressed. New York is already largely compliant with the mandates of Order 1000. However, one feature of Order 1000 has the potential to affect transmission planning and capital investment over the next 15 years. Specifically, Order 1000 requires that transmission planning procedures consider needs driven by Public Policy Requirements and the evaluation of potential solutions to meet those needs in both local and regional planning processes.

National Grid is seeking to work in partnership with our customers, regulators, NYISO, the New York transmission owners and other stakeholders to implement the changes called for by Order 1000. It is likely that FERC Order 1000 will have only a minimal impact on the projects in the Fifteen-Year Plan, as such projects typically address local reliability issues or the replacement of existing assets. However, there may be scenarios where a large public policy project such as the Energy Highway may call for the retirement of or investment in existing 115kV lines. In such cases, the Company anticipates that future investments impacted by Order 1000 projects will be modified in future Plans.

5. C. 4. Generator Retirements

Generator retirement related projects are intended to reinforce the transmission system to avoid or mitigate reliance on market generators to maintain system reliability and performance. In the Capital Investment Plan dated January 31, 2014, the Company included several transmission projects to mitigate the impacts of the closure or potential closure of the Dunkirk, Cayuga and Syracuse Energy Project generating facilities.[2]

The Company does not control, and has limited ability to project, future generator retirements. As a result, investment plans related to unannounced retirements are

[2] *See*, 5-Year CIP, Chapter 2.C (Jan. 31 2014).

difficult to develop and will likely be a major cause of changes in project needs and profiles. The Company participates in NYISO working groups that monitor generator retirements, and is working with the NYISO and other transmission owners in an effort to assess impacts of potential generator retirements across the state. To the extent future generator retirement announcements affect the Company's investment needs, subsequent investment plans will reflect those investment needs. Retirement of units connected to the Company's 115kV system present the most likely need for investment by the Company. Overall, there are more than thirty plants in upstate New York that could potentially impact Company-owned assets and will be reviewed as part of the generator retirement study. The study results are expected to provide more clarity regarding potential scope to mitigate issues. In addition, depending on the unit(s) to be retired, the solution may require a market-based solution to be resolved through the NYISO tariff and not included in the Company's CIP.

5. C. 5. Other System Capacity & Performance

Currently, there are a number of System Capacity & Performance projects with a total forecasted spending level of $2 million or more within this Plan. Projects of this magnitude which are expected to be completed during the first five years of this Plan are described in the Company's Capital Investment Plan in Chapter 2.C and those descriptions are not repeated here. Notable projects in years six through fifteen of this Plan include the following:

5. C. 5. 1. Mortimer Transformer Bank 3 Replacement (C051827 $2.4m)

This project is asset replacement due to poor condition of the transformer.

5. C. 5. 2. Line 853 Rebuild to 115kV (C051828 $66.8m)

Line 853 rebuild includes removal of the last 69kV in the west and extending it for a second 115kV supply to North Lakeville Station and its expansion.

5. C. 5. 3. East Golah 2nd 115kV Tap (C051829 $4.8m), East Golah Substation Rebuild (C051830 $2.5m) and Golah Substation Rebuild (C051831 $2.9m)

This project is needed because the East Golah second 115kV circuit exceeds the applicable outage exposure criteria.

5. C. 5. 4. Huntley Station Grounding Banks (C050918 $1.4m)

The existing grounding sources in the Huntley substation are provided by two transformers associated with generators that are no longer in service. Providing a ground source was not the original purpose of these two transformers; furthermore, they are not owned by the Company. Therefore, their replacement with a proper grounding source is planned.

5. C. 5. 5. Inghams Station Revitalization (C050917- $5.1m)

This project addresses reliability as well as asset condition issues at the Inghams substation. The project will address limitations on phase shifter range of operation, contingency overloads on the #3 line, post contingency low voltage conditions east of the substation, and inadequacy of the SPSS. The original recommended solution called for replacing designated 115kV and 46kV assets, installing new relay and controls to separate the Brookfield powerhouse from the National Grid control house, and installing a new Phase Angle Regulator (PAR) and using the existing PAR as a spare. However, given the recent history of flooding in the Mohawk Valley and the importance of the station to serve local load, the Company anticipates it will relocate the station to an alternate site that is not within the flood plain. This project was submitted to FEMA through the NYS DPS as a candidate for federal funding to assist in this effort.

5. D. Asset Condition

Asset Condition expenditures are those investments required to reduce the likelihood and consequence of the failures of transmission and distribution assets, such as replacing system elements like overhead lines, underground cable or substation equipment. The Company's current approach is to maintain a spares inventory for certain elements of the transmission and distribution system to replace damaged equipment, and to use a more targeted asset replacement approach based on condition rather than wholesale replacement based on "end of useful life" criteria, especially for transmission line refurbishment projects.

5. D. 1. Inspection Programs

The goal of inspection and maintenance programs C026923 ($9.2m) is to replace those damaged or failed components on the transmission overhead line system identified during field inspections (five-year foot patrols). These programs allow both steel tower and wood pole transmission lines to meet governing National Electrical Safety Code ("NESC") standards by replacing hardware, wood poles, and structure components that no longer meet the governing code requirements. This follows standard industry practice and the Commission's 2008 Safety Order in Case 04-M-0159.

Customer Benefits:
This program enhances public and worker safety by assuring that damaged or failed transmission overhead line components are replaced and continue to meet the governing NESC under which they were built. Replacement of damaged and failed components discovered during inspection also promotes reliable service performance.

5. D. 2. Wood Pole Management

This program (C011640 - $12.0m) replaces wood poles and wooden structures that no longer meet the governing NESC code requirements due to damage or failure of the pole or structure. As the modified Overhead Line Refurbishment Program approach shifts from complete replacement of all assets to a targeted approach, the number of reject and priority reject wood poles is expected to increase as the average age of the wood structure population increases. For more details on the drivers of this program refer to Chapter 2.D of the Capital Investment Plan.

Customer Benefits:
Customers will benefit from the maintenance of the appropriate public safety level by assuring that transmission wood structures continue to meet the governing code. In addition to the public safety benefit, unplanned failures of wood poles or structures can reduce service reliability, and may reduce overall system integrity making the transmission system vulnerable to widespread disruption.

5. D. 3. 3A/3B Tower Strategy

The 3A/3B Towers program was established following a 2003 tower failure which resulted from an extreme longitudinal wind load generated by a storm. Phase I of the program (completed in January 2009) was the replacement of 139 transmission towers that were in service at road and other public crossings on the Edic-New Scotland #14 345kV line. The remaining Type 3A and 3B towers on this line have undergone periodic climbing inspections to confirm the integrity of the structures.[3] There are four other 345kV lines that use these same types of towers; the 345kV New Scotland–Leeds #93 and #94 lines, Athens-Pleasant Valley #91 and Leeds–Pleasant Valley #92 lines. As of June 2014, none of these four lines has experienced a tower failure. A similar program addressing public crossings for the remaining four lines is proposed. The project included within this Fifteen-Year Plan is the New Scotland – Leeds #93 and #94 tower reinforcement (C007918 - $16.7m).

Drivers:
This investment is needed because failures of tower types 3A and 3B have already occurred on the Edic-New Scotland #14 line. In June 2013, four structures failed and one was severely damaged during a tornado that passed near the ROW of this line. In

[3] The 3A/3B Tower Strategy (SG 032) was included as Exhibit 21 in Volume 6 of 9 of the September 17, 2007 Transmission Capital Investment Plan, Case 06-M-0878.

October 2003, Structure 347, a type 3A design tower, failed. Two previous failures occurred on type 3B design towers, Structure 3 in 1977 and Structure 66 in 1992 (adjacent towers 63, 64, 65, 67, and 68 were also damaged by the collapsed tower). Phase II will address the four remaining lines noted above after Transmission Planning and the NYISO review the future load needs associated with them. When the study is completed, the likelihood for a system upgrade beyond what is proposed to address the design deficiencies will be better understood.

Customer Benefits:
Public safety is the primary driver of this program. In addition to the safety benefit, the program promotes reliability by reducing the risk of thermal constraints, system instability and widespread cascading failure of the transmission system that could result from the loss of key circuits following a tower failure.

The towers targeted under this program are those 3A/3B towers:

- adjacent to road crossings
- adjacent to railroad crossings
- adjacent to navigable waterways
- towers at transmission line crossings, and
- replaced to reduce excessive cascading potential

5. D. 4. Relay Replacement Strategy

Protective relays are maintained in accordance with Company substation maintenance standards and NERC or NPCC requirements, where applicable. Overall the performance of the relay population remains adequate, but approximately 6% of the population requires investment based on their condition, performance or obsolescence. In addition, the Company is passing the 15-year warranty point for many electronic devices that were previously installed to replace electro-mechanical relays. The program will commence by replacing the worst 6% of the relays over the next eight years. Beyond that, studies and pilot programs will be initiated to explore the most efficient and cost effective approach to addressing the remaining population.

Project C034690 ($72.3m), identifies relay replacement candidates based on historical performance (relay models from the same manufacturer with known performance issues) or obsolescence where parts and technical support are no longer available. The project represents the second phase of the multi-year “NY protection and control replacement” project; the first phase starts in the five-year period of the Capital Investment Plan beginning in FY19. The Company will be reevaluating whether the scope of the relay replacement program should be revised.

Drivers:
This strategy ensures that reliable protective relay systems are in place to preserve the integrity and stability of the transmission system following a fault. This strategy is needed now because properly functioning protective relays are essential for rapid isolation of faults on the system thus protecting customers from potential outages and protecting equipment from damage.

Customer Benefits:
Protective relays limit the extent and duration of interruptions. Further, the protection system is designed to protect high value assets against failure in the event of system anomalies thereby reducing the potential investment needed to recover from an event. The primary benefit of this strategy will be to maintain the reliability performance of the system and customer satisfaction as known poor performing relay families are replaced with modern microprocessor based relays.

5. D. 5. Substation Battery Replacement

Battery and charger systems are needed to ensure substation operational capability during both normal and abnormal system conditions. The intent of the Battery Replacement Strategy (C033847 - $8.2m) is to replace battery and charger systems cost-effectively to maintain reliability. The 20-year replacement cycle used for this strategy is based on industry best practice and experience in managing battery systems. In addition, replacement on a 20-year schedule was a finding from FERC related to a relay mis-operation at New Scotland Substation. This program is discussed in the Company's Capital Investment Plan for FY15-FY19 in Chapter 2.D.

5. D. 6. Substation Rebuilds

The majority of the Company's 313 transmission substations are in satisfactory condition, however, in some limited circumstances, investment is recommended to rebuild substations whose overall condition is deteriorating to the point that wholesale refurbishment is required, the existing arrangement presents potential safety hazards to workers, or their current location leaves them susceptible to flood risk. In these circumstances, a standardized substation design will be utilized to provide greater operational flexibility, increase reliability for customers and determine if the location mitigates flood risk. Where substation rebuilds are proposed, innovative solutions and improvements, such as re-configurations of the layout, will be evaluated. Future design criteria outlines the requirements to avoid locating new substations in flood zones. Relocation of existing substations in the 100-year flood plain with planned major substation rebuild/upgrade projects will be considered as in the case of the Lighthouse Hill Station rebuild described below.

As discussed in greater detail in the Capital Investment Plan in Chapter 2.D and the Asset Condition Report filing (Oct, 1, 2013, p. 67), there are eight stations being studied for either upgrades or rebuilds on the transmission system: Dunkirk, Booneville, Oswego, Rotterdam, Lockport, Lighthouse Hill, Huntley and Oneida. Gardenville and

Rome are expected to be rebuilt within the FY15 – FY19 term of the current Capital Investment Plan and are not discussed here.

5. D. 6. 1. Oneida (C034443 - $42.8m)

Oneida is a 115kV–13.8kV substation located in Verona, NY. The original station was constructed in the 1940s. The substation includes two LTC power transformers, eight 115kV circuit breakers, one 115kV capacitor bank with circuit switcher, and a metal-clad switchgear with seven 13.8kV feeders.

The 115kV bus is fitted with hook switch disconnect switches which are known to be problematic. Outages to maintain the 115kV breakers are difficult since a line outage is required. The two 1959 Federal Pacific Equipment circuit breakers are candidates for replacement due to maintenance issues and a lack of replacement parts. Spare parts also are no longer available for the 13.8kV breakers and the metal-clad switchgear is in poor condition.

The lines to Rome and Yahnundasis are difficult to take out of service due to voltage support issues and taking the R40 line out requires a customer outage. The vertical phase configuration of the East/West 115kV busses is a concern from a maintenance standpoint as the configuration makes tasks such as disconnect repair or replacement difficult due to problems maintaining safe working clearances. Additional switching necessary for safe working clearance for workers weakens the system under certain contingencies. The # 3 and # 4 transformers do not have 115kV “high side” circuit breaking devices resulting in clearing the 115kV bus for operation of the transformer or feeder backup protection.

5. D. 6. 2. Rotterdam (C034850- $67.7m and C034849 - $138.6m)

Given the extent of the asset condition issues and the need for upgrades at the station due to the Northeast Region Reinforcement Project, the Rotterdam 115/230kV Substation is a candidate for replacement. Further study is ongoing at Rotterdam to better identify the actual scope of work and possible options which may include a new 230kV site on level ground, a 230kV GIS substation, or a 345kV option.

5. D. 6. 3. Dunkirk (C005155 - $5.9m)

Dunkirk is a 230-115kV station located south of Buffalo, connected to generation owned by NRG. The Company retains ownership of most of the 230kV and 115kV switch yard; however, the controls are located in the generation control room owned by NRG. The rebuild is expected to begin in FY17 and be completed by FY21.

5. D. 6. 4. Lockport (C035464 - $23.8m)

Lockport is a 115kV transmission station located in western New York. The station has thirteen 115kV transmission lines tying through the East and West bus sections. Given the number of transmission lines at the Lockport Station and the deteriorated conditions of the structures and controls that support them, a station refurbishment with a new control building is proposed to reduce future outages caused by equipment failures. Work is expected to begin in FY17 and be completed by FY22.

5. D. 6. 5. Huntley (C049902 - $18.3m)

Among the Huntley substation asset condition needs are permanent capacitor banks at the 115kV bus to replace the mobile banks currently there, improved grounding in the switchyard, removal of all National Grid controls, batteries and communications equipment from inside the Huntley Generating Station to a control house in the yard (both 115kV & 230kV), adding a second station service supply, refurbishing the existing oil circuit breakers, replacing the potential transformers, installing new CCVTs for 115kV and 230kV relaying, and refurbishing the 230kV cable pumping plant. A station rebuild is expected to begin in FY17 and be completed by FY22.

5. D. 6. 6. Lighthouse Hill (C031662 - $7.1m)

This facility is a significant switching station with two 115kV buses and seven transmission lines connecting to the station, allowing power to flow from the Oswego generating complex to the Watertown area in the north and Clay Station in Syracuse. The disconnect switches are in poor condition, with insulators failing frequently. Seven OCBs are located 200 feet from the Salmon River located about 70 feet below the yard elevation. The station is located approximately one mile up-stream of the New York State Wildlife Fish Hatchery. Although the risk is low, any significant oil spill in the station would have a detrimental environmental impact, and there is also the risk of a flooding event at the station given its proximity to the river.

Based on conceptual engineering, the Company is proposing a new substation located about 1.5 miles west, adjacent to Tar Hill Road on land already owned by the Company. This will all but eliminate the risks of oil contamination to the Salmon River and reduce the likelihood of station flooding.

Work is expected to begin in FY16 and be completed by FY20.

5. D. 6. 7. Boonville (C049903 - $32.7m)

Design and environmental conditions affecting the Boonville substation have resulted in its degradation and need for rebuild. The station was constructed in the 1950s and originally designed as a switching station for several 115kV transmission lines and the single source of the radial 46kv line to Alder Creek, White Lake, Old Forge, Eagle Bay and Raquette Lake. The use has not changed with the exception of the addition of a 23kV terminal for hydro generation.

The station was built alongside highway 12D in a farm field. Over the years it has subsided to an elevation below the highway and farm fields, severely affecting drainage. This drainage issue is also present in the underground manhole and conduit system, and the water table at the station causes the underground control cables to frequently be under water leading to their deterioration. Rebuild with a new location to minimize flood risk is expected to begin in FY17 and be completed by FY22.

5. D. 6. 8. Oswego (SUB0002 - $28.8m)

There are three switchyards located at the Oswego Steam Station: 345kV, 115kV and 34.5kV. These National Grid stations are located on the property of NRG, the owner of the generating station, and were designed and integrated with the generation station when it was under unified ownership.

The 115kV substation is in poor condition with convoluted design changes over the years and out of service equipment that has not been formerly retired. Bus sections have been cut, rerouted, and breakers tagged as out of service. The disconnect switches to the OCBs are original to the station and are the pin and cap design that is subject to an industry recommendation for replacement. The 115kV yard is supplied from the 345kV yard which is in good condition by comparison. Units 3&4 at the generating station, that originally supplied power to the 115kV bus, have since been retired. The electro-mechanical relays and battery for this yard and the 34.5kV yard are still in the NRG owned plant.

The rebuild will be in two phases. The initial phase will occur in the next five years which will include the relocation of relays and controls from the plant to a new control building. In addition, a number of over-dutied breakers will be replaced. The second phase, to address remaining station issues is expected to start in FY21 and be complete by FY22.

Customer Benefits:

The planned replacement of these stations reduces the likelihood of an in-service failure which can lead to long-term interruptions of the transmission system as well as significant customer outages.

5. D. 7. Transmission - Conductor Clearance Strategy

The Conductor Clearance Strategy includes a set of budgeted projects that account for a total of $54.6m during the first five years of the Capital Investment Plan and $30.9m during FY20 and FY21 of this Fifteen-Year Plan.

The Conductor Clearance Strategy will increase the clearance of certain overhead conductors to address locations that may not meet clearance standards prescribed by the NESC in effect at the time of construction under certain loading conditions.[4] The need for greater clearances has been identified as a result of an ongoing Aerial Laser Survey (ALS)[5] being conducted on the transmission system. Clearances are in the process of being measured with aerial surveys providing an accuracy which was previously available by ground inspection only.

[4] The Conductor Clearance Strategy (SG029v3) was approved in April 2009 and discussed on page III-31 of the October 1, 2009 Asset Condition Report Compliance Filing, Case 06-M-0878.

[5] Also known as LiDAR (for Light Detection and Ranging).

Drivers:
The primary driver for this work is safety of the public and Company personnel as they work and travel under the overhead lines. The NESC sets required conductor clearances of overhead lines from the ground and other ground based objects. This program assures that transmission lines meet the governing NESC under which they were constructed by improving ground to conductor clearances in substandard spans. This follows standard industry practice and a Public Service Commission Order (Case 04-M-0159, effective January 5, 2005) that the Company shall adhere to the NESC.

Customer Benefits:
While potential safety issues caused by substandard clearance conductors are rare, their consequences can be very serious and difficult to quantify. Application of the NESC criteria provides a reasonable means to manage the issue and mitigate the risk from such events.

5. D. 8. Overhead Line Refurbishment Strategy ($827.0m)

Over the coming years the Company will refurbish overhead lines based on their condition and work towards developing an overhead line refurbishment approach that to the greatest extent possible addresses only the most deteriorated equipment. This will generally result in refurbishing an entire line only when the conductor tensile strength fails to meet appropriate NESC heavy loading requirements. There is a risk that a number of the lines in the overhead line refurbishment program will fall within this rationale as conductor testing is pursued over the upcoming year.

For overhead lines with acceptable conductor strength, this program will assure that transmission lines meet the minimum governing NESC under which they were built. This will be accomplished through the replacement of deteriorating structures and line components that no longer structurally or electrically adhere to the governing NESC.

To reduce costs during the period of this Plan, the Company has implemented an approach to refurbish only those overhead transmission line facilities that are in unacceptably deteriorated condition (i.e., Niagara Mohawk's defined Level 1, Level 2 and Level 3 condition). Although this approach allows for reduced investment in the five years covered by the Capital Investment Plan, the approach must be evaluated against longer term issues such as a greater number of visits to the same right-of-way, multiple site establishment costs, increased susceptibility to storm damage, additional permitting and licensing costs, greater levels of environmental impact, and more disturbance to abutters, among other things to evaluate the most economical solution for the benefit of customers. Therefore, for certain overhead line condition projects a larger work scope to replace assets that are deteriorated, yet serviceable, may be more appropriate and cost effective. Cost estimates for the Overhead Line Refurbishment Program are based on partial refurbishment of transmission lines. If 25% of the projects fail the conductor strength testing requiring the complete replacement of the line, the cost estimates will be increased significantly, up to $80M more per year.

This Plan is based on the assumption that issues identified during routine foot patrols (Level 1, 2 or 3 issues) will be addressed through the Damage/Failure programs. Where the Company suspects a systemic problem, an engineering inspection and an aerial comprehensive survey will be initiated. Any issues arising from these condition assessments will be addressed through this overhead line refurbishment program.

The Company has begun using a screening tool to help prioritize circuits to consider for future transmission condition-based refurbishments. This tool is solely for the purpose of screening; final priority and project scopes will be determined from engineering field inspections and internal evaluations. In addition, based upon field input by In-House Construction, Transmission Line Engineering, field inspectors, and Asset Management, other circuits may be selected as priority over others.

The screening factors were determined based on the findings of an internal asset criticality review team and assigned weighting percentages: Customer – 20%, Exposure – 20%, Reliability – 20% and Condition – 40%.

For more detailed explanation of this screening methodology approach, please refer to page 14 of the Company's Asset Condition Report filed with the NYPSC on October 1, 2013 (Case 10-E-0050).

Drivers:
The Company has over 6,000 circuit miles of transmission overhead lines and many of these overhead line assets are beyond typical service lives. The program will ensure the Company's transmission lines meet the minimum requirements of the governing code under which they were built as required by the Commission's 2008 Safety Order (Case 04-M-0159).

Customer Benefits:
This program promotes safety and reliability by assuring transmission lines meet the governing NESC under which they were built by replacing deteriorating structures and line components that no longer structurally or electrically conform to the Code.

<u>5. D. 9. Circuit Breaker Replacement Strategy (C037882 - $14.0m)</u>

The circuit breaker population is managed through ongoing inspection and maintenance activity along with routine preventative maintenance activities and electrical testing. In general, the circuit breaker population continues to be adequate; however, there are a number of obsolete circuit breakers that require investment. Obsolete oil circuit breakers will be replaced with modern equivalent circuit breakers; typically breakers employing SF6 gas as an arc interrupting medium. SF6 will be employed until a replacement arc interrupting gas with a lower global warming potential is developed.

Drivers:
There are 742 circuit breakers installed on the transmission system. Of these, 354 are large volume oil-type circuit breakers ("OCBs"). Based on asset condition and

performance, 180 of these large volume OCBs are classified as high replacement priorities. The majority of the circuit breakers addressed in this strategy were installed between 1948 and 1969, are in poor condition or are members of problematic families. The remaining high replacement priority OCBs on the system are either planned for replacement as part of station rebuild requirements or planning needs such as increased short circuit duty or load growth.

There is an increasing trend of problems associated with the large volume OCB population. Common problems include:

- Oil leaks, air leaks, bushing hot spots, high power factors and poor insulation
- Failures of: pressure valves, hoses, gauges, motors, compressors, pulleys, o-rings, control cables, trip coils, close coils, lift rods and contacts

Customer Benefits:
The planned replacement of these circuit breakers reduces the likelihood of an in-service failure which can lead to long-term interruptions of the transmission system as well as significant customer outages. This circuit breaker replacement strategy promotes reliability of the transmission network in terms of CAIDI and SAIFI performance.

5. D. 10. Other Asset Condition

The other asset condition classification includes all of the smaller, typically lower cost, capital investment projects that do not fit within any of the longer-term major programs. There are individual projects within the Other Asset Condition rationale; the largest of these projects are Problem Identification Worksheets.

Customer Benefits:
The planned replacement of these assets reduces the likelihood of an in-service failure which can lead to long-term interruptions of the transmission system as well as significant customer outages.

5. D. 10. 1. Problem Identification Worksheets (PIWs) (C031545 - $10.0m)

The Company employs a process called "Problem Identification Worksheets" to document faults and defects with in-service substation and overhead line equipment that are identified either through normal maintenance activities (often called 'follow-up' work) or through inspection routines (often called 'trouble' work). Typically, the issues identified through the PIW process cannot be corrected immediately and require investigation, engineering analysis and solution design. These activities and the solutions proposed often lead to low cost capital projects to replace or refurbish equipment.

Drivers:
Historically, issues identified during inspection or maintenance were added to the capital plan in outer years to avoid reprioritizing other planned projects. A budgetary line for PIWs recognizes that a number of high priority, low cost, capital projects will inevitably arise during the year and these should be undertaken to address found-on-inspection issues. PIWs typically require some degree of investigation and engineering to identify a solution. PIWs are also used to identify and correct transmission overhead line components that no longer meet minimum NESC requirements. This work is over-and-above that required during normal I&M activities and is likely to increase over the Plan period as a result of overall capital investment reductions.

Customer Benefit:
PIWs identify important issues and work that are high priority, but where the work does not fall into the scope of ongoing strategies and are not yet Damage/Failures. PIWs help identify trends throughout the system and give the Company feedback on how better to manage the system as a whole for the benefit of customers and the overall health of the system.

5. E. Non-Infrastructure

Non-Infrastructure expenditures are those investments necessary to address specific concerns that are not part of the transmission system. Examples include installing new physical security or cyber security systems at substations in response to NERC requirements.

5. E. 1. Substation Security Program (C053136 - $6.0m)

Stations that meet the requirements of NERC CIP-014 will undergo security enhancements. Potential security enhancements may include such as the installation of ballistic walls around equipment, enhanced security fences, crash gates and electronic surveillance. The final number of stations that will meet this requirement and exact scopes are not yet known as the CIP-014 methodology has not been finalized.

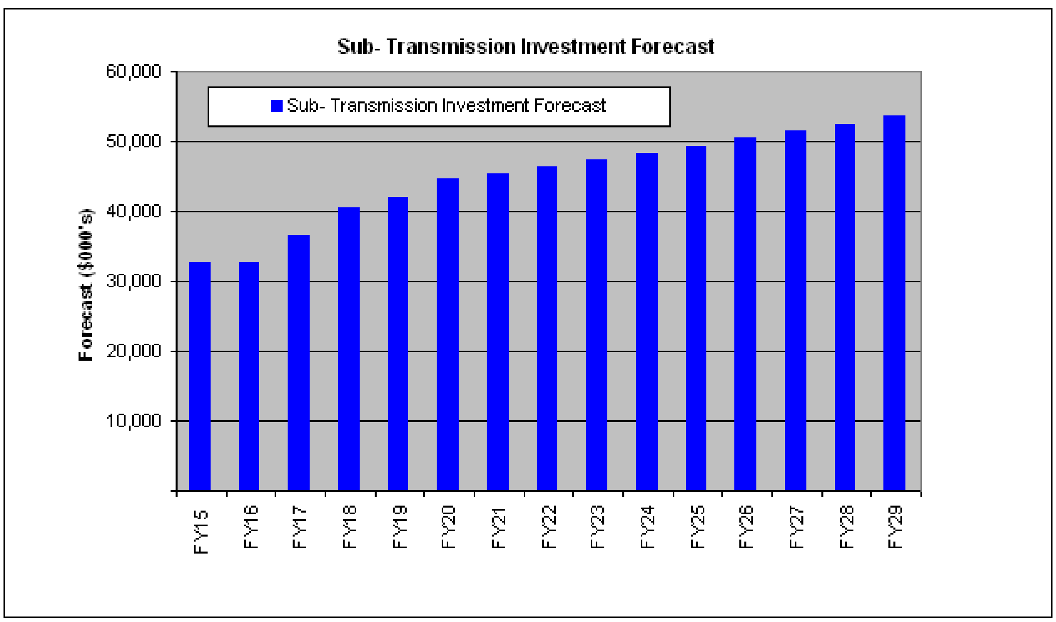
Drivers:
The NERC CIP-014 standard was initiated in response to coordinated physical attacks at other utilities in the United States. The intent of the standard is to improve security at stations that are necessary for the reliable operation of the transmission system.

Chapter 6. Sub-Transmission Discussion by Spending Rationale

The sub-transmission system comprises approximately 4,240 miles of lines including: 290 miles of 69kV, 365 miles of 46kV, 2,330 miles of 34.5kV, 1,050 miles of 23kV and 200 miles of lines below 23kV. The projected investment in the sub-transmission system is shown in Exhibit A. Years one to five (FY15 to FY19) are the same as filed in the 2014 Capital Investment Plan.[1] Years six to fifteen estimates for sub-transmission spending reflect consideration of the factors outlined in Chapter 2 using year five (FY19) of the Capital Investment Plan as the base year. Although spending is categorized by spending rationale, all drivers are considered in determining the optimum project solution.

Sub-Transmission Investment Forecast for fiscal years FY15 to FY29 is provided in Figure 6-1 below.

Figure 6-1 Sub-Transmission Investment Profile



[1] Case 10-E-0050, Transmission and Distribution Capital Investment Plan, January 31, 2014, Exhibit 2.

6. A. Customer Requests/Public Requirements

Customer Requests/Public Requirements work in the sub-transmission system includes work related to new business requests and public requirements such as road widening. The work is reflected in "blankets," programs, or in specific projects where individual jobs are over $100,000. The projected investments in this spending rationale show reduced funding in the first five years, and investments for subsequent years are escalated.

In general, specific projects in response to new business and public requirement requests cannot be itemized in future years; therefore, future spending is forecasted in reserves for these categories of work. Advanced grid applications are not expected to have a significant impact on this spending rationale as costs are generally limited to the interconnection or relocation of facilities to accommodate customer requests at specific locations.

At this time, one project has been identified that is expected to exceed $1 million:

- Project C034722, DOTR NYS Route 28 White Lake - McKeever Substation (Moose River) Transmission Line: This project provides for the mandatory relocation of 6 miles of 46kV overhead sub-transmission facilities along Route 28 in the towns of Forestport and Webb to facilitate a NYSDOT project.

6. B. Damage/Failure

The Damage/Failure spending rationale contains expenditures required to replace failed or damaged equipment, and to restore the electric system to its original configuration and capability, following equipment damage or failure. Damage may be caused by storms, vehicle accidents, vandalism or other deterioration. The Company views this spending as a mandatory spending rationale that is non-discretionary in terms of scope and timing. Damage/Failure budgets are primarily based on recent historical costs.

6. C. System Capacity and Performance

System Capacity and Performance projects are required to ensure the sub-transmission system has sufficient capacity, resiliency, and operability to meet customer demands. Projects in this rationale are intended to maximize equipment service lives by limiting thermal stress, to provide appropriate degrees of system configuration flexibility to limit customer reliability impacts associated with an interruption, and to maintain the requisite power quality. The projected investments in this spending rationale are generally based on specific projects in the near term and forecasted more generally in the longer range as outlined in Chapter 2.

To date, limited distributed generation and renewable energy projects have been connected to the sub-transmission system compared to the distribution system. The intermittent nature of distributed generation prevents it from significantly reducing sub-transmission system peak load. In general, costs associated with the interconnection of generation are borne by the generation developer. As such, these energy alternatives are not expected to significantly impact the Company's sub-transmission system budget within the Fifteen-Year Plan forecast.

As noted in Chapter 3, energy efficiency programs are forecasted to offset the impact of electric vehicles on a system-wide basis. On the sub-transmission system, the mix of residential and non-residential load will result in minimal impact from electric vehicles charged at residential homes. Even assuming a worst charging case (uncontrolled charging), energy efficiency is expected to offset electric vehicles for the 15-year planning period.

Advanced grid applications, as discussed in Chapter 7, may result in reduced future spending in this rationale on the sub-transmission system. For example, advanced distribution automation will foster optimization of sub-transmission circuits, or the distribution circuits supplied from the sub-transmission system, which may defer the need for capacity related projects, such as reconductoring a sub-transmission line. Analysis of Load at Risk following a system contingency considers manual, stepped field switching times. Automated switching to reduce these load transfer times may reduce the number of projects required to address contingency risks while maintaining reliability performance. Advanced capacitor control technology is also expected to reduce losses and allow improved use of existing assets. The Company has recently begun to install automation on several sub-transmission lines and will continue to evaluate the benefits of this technology on a case-by-case basis to best serve our customers.

6. C. 1. Capacity Planning

Drivers:

An annual review of the sub-transmission system, including substation and circuit loading, is performed to review equipment utilization. The review takes into account both normal equipment loading and Load at Risk following an N-1 contingency. Forecasted load additions are applied to historical data and the system is analyzed to determine where and when constraints are expected to develop. Recommendations for area studies are determined for this annual review. System reconfiguration or system infrastructure development may be created as part of this annual review or from area studies to ensure load can be served during peak demand periods.

The normal loading assessment identifies load relief plans for facilities that are projected to exceed 100 percent of normal capability (i.e., maximum peak loading allowed assuming no system contingencies). The projects from these reviews are intended to be in-service during the year the load limit is forecasted to occur. In general, only modest load growth is expected in the service area over the 15-year horizon; however, upgrades will continue to be necessary to address localized growth.

In addition to the normal loading review, the Company has instituted planning criteria for Load at Risk following an N-1 contingency that sets MW and MWh interruption exposure thresholds (“MWh Violations”) for various supply and feeder contingencies for the purpose of setting a standard for minimum electrical system performance. These thresholds are applied in conjunction with other criteria—such as maintaining acceptable delivery voltage and observing equipment capacity ratings—to ensure the system operates in a reliable manner while managing risk of customer interruptions to an acceptable level. MWh thresholds have been identified for three specific contingencies. For loss of a single substation supply line, a maximum interruption load limit of 20MW and/or 240MWh is specified, assuming that the line can be returned to service within 12 hours. For loss of a single substation power transformer, a maximum interruption load limit of 10MW and/or 240MWh is specified, assuming that the transformer can either be replaced or a mobile unit installed within 24 hours. Analysis of the interruptions under this criteria assume that any and all practical means are used to return load to service including use of mobile transformers and field switching via other area supply lines and/or area feeder ties. MWh analysis recognizes the approximate times required to install mobile/back-up equipment as well as stepped field switching, i.e., moving load from the adjoining in-service station with feeder ties, that will be used to pick up customers experiencing an interruption, to a second adjoining station to increase the capability of the feeder ties.

Projects are in the Plan to reinforce the sub-transmission system where required for capacity needs and voltage profile to enhance system resiliency. Projects may include new Transmission Stations, new OH conductor, new UG cables or capacitors. Comprehensive studies/analysis of the supply to several of the urban centers is beginning. The changing needs of these centers will be considered and significant infrastructure development is possible. The next Fifteen Year T&D Plan should have better defined impacts of these efforts. The Livingston Area study is nearing completion. There are several subtransmission system reinforcement projects in common to the various alternatives and are in the existing Capital Investment Plan. Additional analysis is underway and may represent significant spending increases, which would be reflected in the next Fifteen-Year Plan.

Customer Benefits:
The benefit to customers of completing the work identified in capacity planning studies includes less exposure to service interruptions due to overloaded cables and transformers. In addition, the implementation of projects to mitigate MWh Violations will reduce the likelihood that an unacceptable number of customers will be without service for extended periods due to supply, substation equipment or feeder contingencies.

The following specific projects are estimated to have spending in excess of $1 million in any fiscal year:

- Project C028893, Buffalo 23kV Reconductor - Huntley 2. This project will replace cable 11H from Sawyer Station to Buffalo Station 52. This cable has exceeded summer normal ratings in the past and may exceed emergency ratings for the loss of one of the other three supply cables.
- Project C028903, Buffalo 23kV Reconductor - Kensington 2. This project will replace the 10K cable from Kensington Terminal Station to Buffalo Station #28, the 11K and 12K cables from Kensington Terminal Station to Buffalo Station #32 and the 15K cable from Kensington Terminal Station to Buffalo Station #27. These circuits currently exceed emergency ratings for the loss of one cable.
- Project C028894, Buffalo 23kV Reconductor - Kensington. This project will replace the 21K, 22K, 23K and 33K cables from the Kensington Terminal Station to Buffalo Station #53. These circuits currently exceed emergency ratings for the loss of one cable.
- Project C036054, Golah Avon 217 Line Reconductoring. This project will reconductor approximately 5 miles of Line 217 from Golah Substation to Avon Substation.
- Project C046516, Buffalo 23kV Reconductor – Seneca 1S, 2S, 3S, 19S, 31S. This project will replace the 1S, 2S, 3S, 19S and 31S cables from the Seneca Terminal Station to Buffalo Station #44. These circuits currently exceed emergency ratings for the loss of one cable.

6. C. 2. Sub-Transmission Automation

In a continuing effort to modernize the grid the Sub-Transmission Automation Strategy encompasses advanced distribution automation methodologies as well as SCADA for reclosers, fault locators, and switches; and the interface of distribution automation enabled line devices with substation feeder breakers. It also encompasses the communication of these devices with each other and to central operations centers and database warehouses. The Company typically refers to such devices and communications technology as Advanced Grid Applications.

Drivers:
Following the success of pilot automation installations in 2008 and 2009, which verified the capability of advanced distribution automation enabled equipment, the Company recognized the additional benefit of identifying projects where the installation of modernized switching schemes would provide increased reliability to the sub-transmission system.

The number of Advanced Grid Application switches per circuit or installation will vary depending on the number of substations the circuit supplies, the desired segmentation of the line, and the configuration of the supply system. Many of the automation schemes are unique in nature and are developed considering an analysis of expected costs and benefits.

Customer Benefits:
Distribution lines or substations not equipped with automated sectionalizing or throw over schemes may be subject to extended service interruptions as Operations personnel must travel to the field locations to perform switching. This program provides an opportunity to continue to modernize the grid for the benefit of customers by reducing the number of customer interruptions that result from a given contingency and the time required to reconfigure the system to restore service to as many customers as possible while a faulted section of the system is being repaired.

6 D. Asset Condition

Asset Condition expenditures are those investments required to reduce the likelihood and consequences of failures of the sub-transmission system assets by proactively replacing equipment. During the previous ten years, the Company adopted an asset management approach that relied on a holistic, longer-view assessment of assets and asset systems to inform capital-investment decisions. As part of this approach, the Company conducted assessments of major asset classes such as circuit breakers or subsets of asset classes such as a circuit breaker manufactured by a particular vendor. The assessments focused on the identification of specific susceptibilities for assets and asset systems, and the development of potential remedies.

This spending rationale is not expected to be significantly affected by the drivers considered in Chapter 3. The installation of equipment with capabilities to participate in advanced grid applications may moderately increase replacement costs over traditional manual equipment.

The following specific projects have forecasted spending that exceeds $1 million in any fiscal year:

- Project C048968, Randall Road New Substation Install and Remove Sub-transmission Lines. Remove 34.5kV line from Ballston to Randall Road Substation.
- Project C046641, Callanan Tap – Install new Sub-T Line, Install a new sub-transmission line extension from Selkirk to Callanan to allow the removal of the Callanan Tap from Unionville to Callanan.
- Project C046707, Oakfield-Caledonia LN201 Reconductor. Reconductor approximately 11 miles between Churchville and Caledonia including pole replacements.
- Project C046766, N. Lakeville-Ridge LN 218 Refurbishment. Reconductor approximately 6 miles of 34.5kV circuit between Lakeville and Groveland substations including pole replacements.

6. D. 1. Inspection and Maintenance

Under this program, the Company performs visual inspections on all overhead and underground distribution assets once every five years. Each inspection identifies and categorizes all necessary repairs, or asset replacements, against a standard and in terms of criticality to improve customer reliability in compliance with the Commission's Safety Order in Case 04-M-0159.[2]

In addition, the following types of inspections are conducted by the Company:

- Aerial assessments of sub-transmission lines on an annual basis, and
- Infra-red inspection of sub-transmission lines on a three-year schedule.

The Company also performs annual elevated voltage testing per the Commission's Safety Order on all facilities that are capable of conducting electricity and are publicly accessible.

This program has been moved from the Customer Requests/Public Requirements spending rationale to Asset Condition to better reflect its impact on the condition of the Company's electric facilities.

Drivers:
The Company implements the Inspection and Maintenance program in accordance with the Commission's directives in Case 04-M-0159. The Company's annual Asset Condition Report details the application of the Inspection and Maintenance program to sub-transmission assets.[3]

Customer Benefits:
This program is designed to ensure the Company fulfills its obligation to provide safe and adequate service by inspecting it facilities and repairing safety and reliability issues identified in a timely fashion.

[2] Case 04-M-0159, Proceeding on Motion of the Commission to Examine the Safety of Electric Transmission and Distribution Systems, Order Adopting Changes in the Electric Safety Standards (issued and effective Dec. 15, 2008) ("Safety Order").
[3] Report on the Condition of Physical Elements of Transmission and Distribution Systems, Case 10-E-0050, most recently filed on October 1, 2013.

6. D. 2. Overhead Line

Various projects are in place to refurbish or replace sub-transmission overhead assets to ensure the system continues to perform in a safe and reliable manner. This includes pole, tower, overhead groundwire and conductor replacement in addition to the work generated via the Inspection and Maintenance program discussed above.

Drivers:
Although spending is categorized by spending rationale, all drivers are considered in determining the optimum project solution. Reliability and condition are the main drivers for these projects. Historically, the number of reliability events that are initiated on the sub-transmission system is low; however these events can result in a significant number of customers being interrupted where the lines are radial.

Physical condition of the sub-transmission system is being assessed through the Inspection and Maintenance program, helicopter surveys and by local engineering reviews and ‘walk downs’.

Customer Benefits:
Refurbishment and replacement of sub-transmission system components can have a significant impact on regional CAIDI/SAIFI and Customer Minutes Interrupted (CMI) since they typically supply distribution stations.

6. D. 3. Underground Cable

Various projects are completed each year to refurbish or replace sub-transmission underground assets to ensure the system continues to perform in a safe and reliable manner.

Buffalo
A major program has been initiated to replace 23kV cables in the city of Buffalo. The existing distribution system in the City of Buffalo was built starting in 1929 and is supplied by four terminal stations: Sawyer, Seneca, Kensington and Elm Street. The 23kV cable system represents about 433 miles of underground cables and supplies over forty 4.17kV distribution substations. Approximately 385 miles of the original 1-3/C-350kcmil CU PILC (paper in lead covered cable) installed in the late 1930s are still in service. As time progresses, the aging cables experience continued mechanical stress due to annual loading cycles and eventually fail, causing interruptions.

Through analysis of failure records, 83 miles of cables have been identified that are considered high risk. These are cables that have a high rate of failure and have a major impact to distribution substations and customers in an event of cable failure.

Drivers:

Failures of individual sub-transmission cables do not typically impact customer reliability since the portions of the system where they are utilized are generally networked. However, because these systems are located below ground and are out of sight, failures of underground sub-transmission cables can be difficult to locate and time-consuming to repair leaving the system at risk.

There are approximately 1,100 miles of sub-transmission underground cable. Approximately one-half are more than 47 years old and one-third are more than 60 years old. The sub-transmission underground cable asset replacement program replaces cables that are in poor condition, have a history of failure or are of a type known to have performance issues.

Customer Benefits:
Cable replacement projects reduce the likelihood of in-service cable failures, and resulting exposure to the risk of extended outages.

6. E. Non-Infrastructure

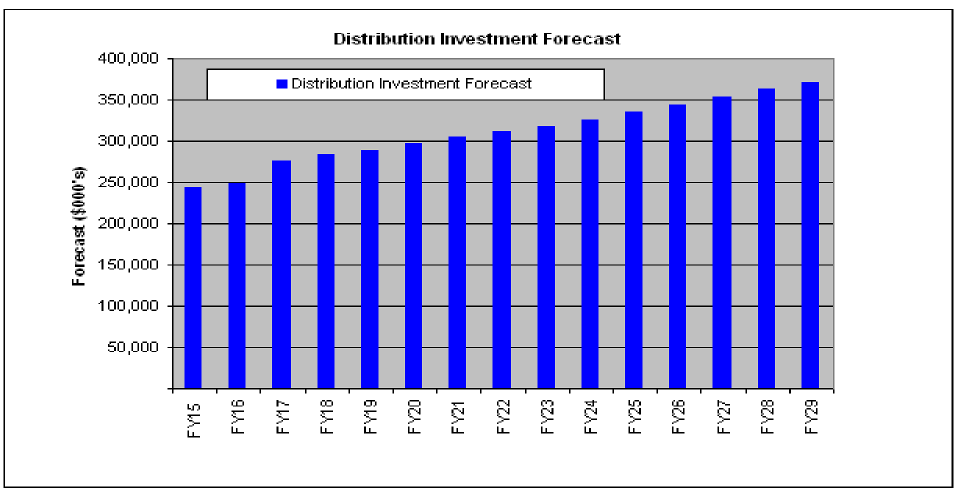
There are no Non-Infrastructure costs currently expected for the sub-transmission system.

Chapter 7. Distribution Discussion by Spending Rationale

The Company's distribution system comprises lines and substations typically operating at 15kV and below. There are nearly 36,000 miles of overhead primary wire and approximately 7,400 miles of underground primary cable on the system supplying approximately 399,450 overhead, padmount and underground transformers. Additionally, there are almost 424 substations providing service to the Company's 1.6 million electric customers.[1] The projected investment in the distribution system is shown in Exhibit A. Years one to five (FY15 to FY19) are the same as filed in the 2014 Capital Investment Plan.[2] The Company's Connect21 initiative is aimed at improving system resiliency and better integrating Distributed Energy Resources ("DER"). The outcome of the REV proceeding underway at the Commission also will significantly influence distribution investment over the time horizon of this plan. Developing all the specific projects that will be implemented on the Distribution system over a fifteen-year horizon is not feasible due to the fact that the majority of the distribution spending needs to be responsive and timely to customer requests and reliability concerns as they arise in specific locations. In general, the longer range forecast reflects distribution system spending increasing at the rate of inflation. For the few areas where this is not the case, the sections that follow will discuss the Company's expectations.

Distribution Investment Forecast for fiscal years FY15 to FY29 is provided in Figure 7-1 below.

Figure 7-1 Distribution Investment Forecast – FY15 to FY29



[1] The distribution system data from National Grid Asset Information Website located at http://infonet2/OurOrganisation/NetworkStrategyUS/AssetManagement/Pages/BlueCard.aspx.

[2] Case 10-E-0050, Transmission and Distribution Capital Investment Plan, Jan. 31, 2014, Exhibit 3.

7. A. Customer Requests/Public Requirements

Customer Requests/Public Requirements work on the distribution system includes work under the following blankets: New Business Residential, New Business Commercial, Outdoor Lighting, Public Requirements, Transformer Purchase and Installation, Meter Purchase and Installation, Third Party Attachments, and Land Rights.

The present forecast for the distribution meter budget is based on an expectation of a modestly increasing volume but does not account for any changes in meter technology. Implementation of an advanced meter program in the future would likely increase investment in this area.

Requests to integrate distributed generation on the distribution system are increasing rapidly as technology advances and incentives continue to be available. Projects to interconnect distributed generation and renewable energy sources may increase spending in this rationale. While distribution system upgrade costs are typically borne by the generator, contributions in aide of construction are limited for certain classes of renewable energy generation. In addition to direct costs to interconnect individual distributed generators, increasing levels of advanced grid applications are likely to be required for the Company to monitor the performance of these generation sources and effectively operate a more networked distribution system. The Company will continue to evaluate how to forecast the impact of generation on system peak loading in light of the increasing penetration of distributed, and often intermittent, energy alternatives.

7. B. Damage/Failure

The Damage/Failure investment level for the distribution system is primarily based on historical actual costs for such work. Where condition renders the asset unable to perform its intended electrical or mechanical function on the delivery system, the Company initiates the timely replacement of such asset under the Damage/Failure spending rationale. The Company forecasts that the rate of damage/failure may decline slightly in the future with continued investment in proactive asset condition replacements. However this decline is expected to be modest and the forecast is actually on a slightly increasing trend due to inflation.

7. C. System Capacity and Performance

System Capacity and Performance projects are required to ensure the distribution system has sufficient capacity, resiliency, or operability to meet the demands of our customers. Projects in this rationale are intended to increase equipment service lives by limiting thermal stress, to provide appropriate degrees of system configuration flexibility to limit the customer reliability impacts associated with an interruption, and to maintain the requisite power quality. We are looking to expand the backbone of the system creating a more resilient system that will more readily integrate DER. In addition, small isolated pockets of 5kV will be eliminated to improve the 13.2kV backbone.

7. C. 1. Capacity Planning

Drivers:

The Company performs an annual review of the distribution system, including substation and feeder loading, to review equipment utilization. The reviews take into account both normal equipment loading and Load at Risk following an N-1 contingency. Forecasted load additions are applied to historical data and the system is analyzed to determine where and when constraints are expected to develop. Recommendations for system reconfiguration or system infrastructure development are created as part of this annual review to ensure load can be served during peak demand periods and is documented in the Annual Capacity Plan.

The normal loading assessment identifies load relief plans for facilities that are projected to exceed 100 percent of normal capability (i.e., maximum peak loading allowed assuming no system contingencies). The projects from these reviews are intended to be in-service during the year the load limit is forecasted to occur. Comprehensive area studies are conducted for a number of planning areas each year to analyze capacity, reliability and asset needs and then to determine the required infrastructure development to address these issues. These projects often have later need dates and may require additional time to engineer, permit and construct. Comprehensive studies/analyses of the supply to several of the urban centers are beginning. The changing needs of these centers will be considered and significant infrastructure development is possible. In general, only modest load growth is expected in the service area over the 15-year horizon; however, upgrades will continue to be necessary to address localized growth.

Customer Benefits:

The benefit to customers of capacity planning driven projects includes less exposure to service interruptions due to overloaded cables and transformers. In addition, the implementation of projects to mitigate MWh violations will reduce the likelihood that an unacceptable number of customers will be without service for extended periods due to supply, substation equipment or feeder contingencies.

Spending forecasts for capacity additions is expected to increase from approximately $43M in FY15 to $56M in FY19 to implement a number of projects as described in the Capital Investment Plan and then the spending is expected to increase at the rate of inflation for the remainder of the fifteen-year horizon.

7. C. 2. Engineering Reliability Review

An Engineering Reliability Review (ERR) can be completed for any feeder experiencing reliability problems or any localized pocket of poor performance. ERRs are often performed on feeders identified as Worst Performing Feeders, as described in the Electric Service Reliability Report filed annually in accordance with Case 90-E-1119. An ERR typically includes:

- Review of one-year and multi-year historical reliability data for current issues and trends.
- Review of recently completed and/or future planned work which is expected to impact reliability.
- Review of the need for the installation of radial and/or loop scheme reclosers.
- Review for additional line fuses to improve the sectionalization of the feeder.
- Comprehensive review of the coordination of protective devices to ensure proper operation.
- Review for equipment in poor condition.
- Review of heavily loaded equipment.
- Review for other feeder improvements such as fault indicators, feeder ties, capacitor banks, load balancing, additional switches and reconductoring (overhead and/or underground).

Projects associated with the ERR program generally are reactive, and are identified as reliability concerns arise. As such, specific projects are only identified in the early years of the plan and budgetary reserves of approximately $3.5M per year are forecasted to fund future projects as they are developed. A total spend of $7M per year is expected over the horizon of the plan resulting from ongoing projects and the $3.5M budgetary reserves.

Drivers:
The ERR recommendations are utilized as a basis to improve reliability on circuits with recent poor reliability performance.

Customer Benefits:
The ERR program will improve customer reliability in areas where performance has been substandard.

7. C. 3. Heavily Loaded Line Transformer

The distribution line transformer strategy endeavors to mitigate outage/failure risks due to overloading of distribution service transformers. Transformer loading is reviewed annually via reports generated from the customer use information within the Geographical Information System. Transformers with calculated demands exceeding load limits specified in the applicable Construction Standard are identified and investigated in the field.

The forecasted spending for this program is estimated to be $3.18M in FY15 and increasing year on year for inflation throughout the plan horizon.

Drivers:
There are approximately 250 transformer failures per year due to overloading, which affect approximately 3,700 customers annually. Proactive management of equipment loading through annual review has prevented overloaded transformers from becoming a significant system performance problem.

Customer Benefits:
The main benefit of this strategy is that asset utilization will be maximized by maintaining units in service until such point that replacement is required as identified through recurring loading reviews or visual and operational inspection, recognizing that transformer life expectancy is predominantly affected by loading and environmental factors rather than age. Implementation of this strategy will ensure the sustainability of this asset class over time and maintain its relatively minor impact on overall system reliability and customer satisfaction.

7. C. 4. Overhead Distribution Fusing

Various projects are in place which will maintain customer reliability through the installation of fuses on overhead distribution lines. Fuses are installed to isolate permanent faults on the distribution system. Ideally, these fuses are installed at locations which limit the interruption to the fewest customers practical. Proper fuse application will limit the duration of the interruption by isolating the fault to a smaller area and reducing the time required to find the fault.

In this program the Company is reviewing the coordination of its overhead distribution system and identifying new locations for sectionalization. The program is expected to conclude at the end of FY17 and is expected to cost an estimated $2.4M per year.

Drivers:
Fuses isolate the faulted area of a feeder and thereby interrupt the smallest practical number of customers. Outage restoration time may also be reduced since fusing will split the overhead circuit into smaller segments of the distribution system that requires patrolling to locate the cause of an unplanned customer interruption.

Customer Benefits:
These projects will result in a reduction in the number of customer interruptions and will help the Company to continue to meet its service quality metrics.

7. C. 5. Remote Terminal Units (RTUs)

This strategy covers the addition of Remote Terminal Units (RTUs) and related infrastructure at substations presently lacking remote monitoring and control capabilities. RTUs in substations communicate with the EMS (Energy Management Systems) and provide the means to leverage substation data that provide operational intelligence and significantly reduce response time to abnormal conditions through real time monitoring and control. There is also a significant investment in replacing outdated RTUs based on their asset condition. That investment is documented in the Asset Condition spending rationale section.

The program for the replacement of outdated RTUs is expected to continue for another ten years with a forecasted expenditure of approximately $550k per year. The installation of new RTUs to expand the Company's remote monitoring and control capabilities is expected to continue for the next ten years at a cost of approximately $2.5M per year.

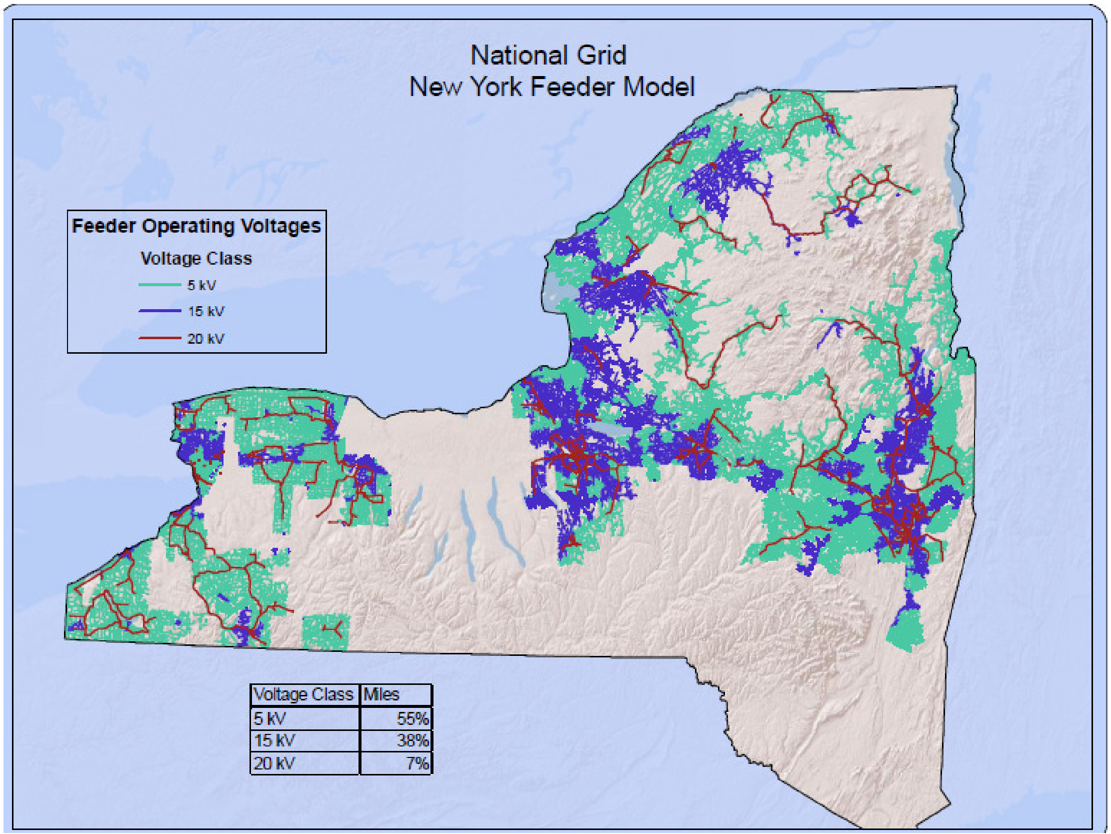
Drivers:
RTUs will allow for remote operation and management of the system at these stations providing benefits in contingency response and recovery and thus improving performance and reliability. In addition, RTUs are key components of automation and modernization of the Company's infrastructure.

Customer Benefits:
This strategy provides the means to leverage operational intelligence and significantly reduce response time to abnormal conditions through real time monitoring and control. The strategy also enables the distribution automation, sub-transmission automation, and future modernization strategies which will improve service to customers consistent with the aims of the REV proceeding and Connect21. When used to monitor and control the distribution feeder breakers and associated feeder equipment, RTUs and EMS facilitate the isolation of faulted equipment and the time required to reconfigure the distribution system to re-energize customers in non-faulted segments of the distribution system. This switching flexibility improves the expected average customer outage duration (CAIDI) when compared with a feeder that is not equipped with these facilities.

7. C. 6. Advanced Grid Applications

The means by which electric power is generated, transported, consumed and paid for will evolve significantly in the years ahead. Although there are many details to work out, there are common themes from which a possible roadmap of near-term and long-term plans can be developed. For example, under a reasonable view of the future, it is possible National Grid will need to increase its forecast capital spending on the distribution system by as much as $2B over the period of this 15-year plan to invest in grid modernization and resiliency. A holistic approach is needed when evaluating grid modernization opportunities to optimize the full portfolio of projects and programs implemented.

National Grid's electric distribution system in upstate NY has its origins in many smaller electric companies and has resulted in a non-contiguous service territory with multiple operating voltages and construction types. The distribution system is predominately of a radial design utilizing overhead construction with limited flexibility for reconfiguration through switching. Although new construction is designed for 15kV operation, the majority of 44,000 distribution line miles within the service territory are designed and operated at the 5kV level. Although an extremely reliable design, the capacity and reach of 5kV systems limits the capabilities for circuit reconfiguration that may increase the system's resiliency following adverse events. The Company's planning criteria are primarily focused on 15kV class, and the Company expects its grid modernization plan will be optimized around this design. The figure below shows the voltage class of distribution assets geographically, with the 15kV class shown in blue. The 5kV areas shown in green are generally areas of lower customer density, with a significant percentage of aged infrastructure, and limited flexibility for circuit reconfiguration. These areas will be evaluated for conversion to higher voltages and the extension of circuits as appropriate to create the necessary feeder ties essential for any kind of distribution automation scheme. The lines operating above 20kV are generally sub-transmission lines supplying small sub-stations and a few larger C&I customers. An automation program has been underway for the last few years targeting these sub-transmission lines.



The National Grid service territory spans the width of NY state from east to west and is comprised of urban, suburban and rural communities. Total load growth has been relatively low such that the need for overall system upgrades has been minimal and has resulted in an aged infrastructure in many regions. Forecasted total load growth is expected to remain low as the result of increasing energy efficiency programs and increased distributed generation behind customer meters (although localized load growth can drive localized investment needs). Without growth, replacement/upgrade of aged infrastructure will be driven by the goals of enhanced system resiliency and increased functionalities of grid modernization.

Advanced Distribution Automation - In recent years reliability has improved as the result of a Reliability Enhancement Program that was completed in 2012. A key element of this program was a $40M program which installed over 1025 electronic line reclosers. These reclosers have microprocessor-based controls that automatically isolate faulted sections of distribution feeders to minimize the impacts of faulted circuits. These devices are also capable of two-way communications with the Operations Control Centers, providing information as to status as well as remote control to facilitate switching operations. Currently, the majority of these devices work independently based on inputs from local sensors; however, they will form the foundation for future distribution automation schemes. The current method of two-way communications to approximately 800 reclosers is via public cell phone infrastructure. It is likely communications systems will need to be upgraded to accommodate more advanced distribution automation. In addition to improving the latency of the telecommunications network, additional sensors and devices will be necessary to implement more advanced automation schemes.

The Company is developing a Feeder Reference Model (FRM) that will form the basis for the design of feeder configuration and operation in the future. The FRM will define the desired switching flexibility for reliability and resiliency. It is likely that new feeder ties will need to be created in areas where a significant number of customers are supplied by a single radial line and large volumes of new automated or remotely controlled switching devices will be installed to optimize reliability performance. Currently, on average, there are 1.2 electronic reclosers installed on a typical 15kV feeder. In the future, four more automated switching devices may be warranted on a typical feeder. Significant analysis remains to be completed before the FRM is implemented. However, initial planning estimates indicate that the FRM may apply to approximately 425 feeders serving 540,000 customers (34% of electric customers) at a cost ranging from $200k (on feeders where existing manual feeder ties would be automated) up to $1.2M per feeder (on feeders where line extensions would be required to create necessary routes for circuit ties). Additional costs on the order of $150k per feeder may be needed to provide two-way communications if they do not already exist. Over the 15-year horizon of the plan, an average cost of $400k/feeder is forecasted, resulting in a capital expenditure of $170M over the period.

Advanced Capacitor Control - Affordability of electric service is a primary criterion for any grid modernization plan, and the investment necessary to enhance the backbone of the electric grid is significant. Therefore, to offset these costs it is imperative that the system be designed and utilized in the most efficient manner possible. End-to-end efficiencies can be gained by reducing losses and by improving system load factor so capacity additions are not required just for limited peak periods. Efficiency can be improved by transporting electricity at higher voltages and consuming it at the lowest accepted utilization voltage level. Losses can also be reduced by improving power factor and minimizing the distance from generation to consumption.

The Company is evaluating Volt-Var Optimization technology that would provide centralized control of capacitors and voltage regulators to flatten feeder voltage profiles and provide customer utilization voltage levels at the low end of the spectrum which may reduce kWh consumption by as much as 3%. Additional voltage sensors and new control schemes enabled by 2-way communications systems are necessary to implement this advanced functionality. Deploying this technology on the same feeders in which Distribution Automation is deployed would foster synergies of communication systems. It is estimated that capital costs of approximately $150M may be expended over the period.

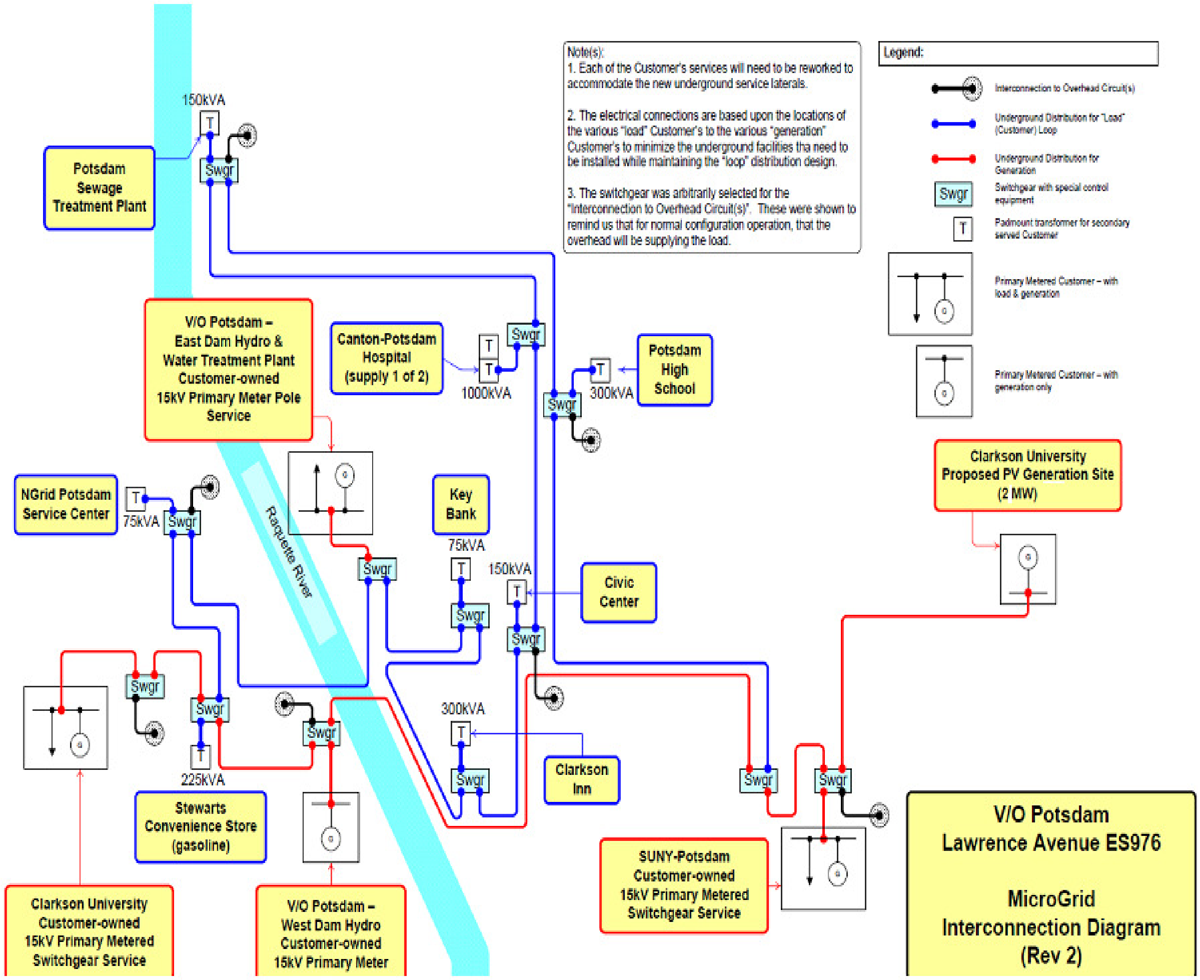
Distributed Generation- In addition to the efficiency of individual generators, there are opportunities to diversify the fuel mix and locate generation sources closer to loads, which may result in a more efficient system. Higher penetrations of DG will require modifications to the distribution grid to safely accommodate two-way power flow and be responsive to voltage fluctuations associated with intermittent generation sources such as solar and wind.

To make the distribution system capable of accommodating the range of potential customer-sited solar generation proposals, changes in system planning will be necessary, as will the need for system upgrades. The State's promotion of increased distributed generation is expected to impact daily and seasonal demand load curves. The intermittency of solar and wind generation brings new challenges to managing the T&D system.

Changes in regulatory policy and pricing tariffs will be key in determining the "DG readiness" of the distribution system. Currently many owners of DG are remunerated for the kWhs generated through net metering and are responsible to pay a Contribution in Aid of Construction (CIAC) for all system upgrade costs associated with their interconnection. At a time of rapid DG growth, determining which specific generator may drive a circuit beyond its allowable DG penetration can be difficult and controversial, particularly if future DG owners can trigger the need for and take advantage of such upgrades without an established mechanism for cost allocation. To facilitate interconnections it may be advantageous to allow utilities to proactively make system improvements which support higher DG penetration levels. Changing design specifications to facilitate two-way power flow include such things as the installation of bi-directional voltage regulator and capacitor controls, direct transfer trip capabilities for high speed protection, high voltage protection schemes on telecommunications, and 3V0 protection schemes for ground fault protection of transmission faults. Including these elements in new substations is estimated to cost approximately $460k per substation. Regulatory consideration is needed to assure the appropriate allocation of costs to benefiting customers.

The value of DG (both to the system and to the DG owner) can be enhanced if it is fully integrated into operation of the distribution system. Combining DG with advanced inverter functionalities, energy storage such as grid scale batteries, and sophisticated control systems, along with a regulatory framework that defines the rules and roles of the market will allow greater penetration levels and enhance the impact of these distributed resources.

Integrating DER into distribution system operations will be a major endeavor. Another option that could be realized with an integrated control of DG and other DER is the microgrid. Microgrids can add value both while interconnected to improve the efficiency of the system as well as when islanded where they provide resiliency benefits for the customers embedded within the microgrid. National Grid is exploring two microgrids projects at this time through studies supported with NYSERDA funding: One in the vicinity of the Buffalo Niagara Medical Campus, and another in the Village of Potsdam. The technologies to create microgrids have been available for many years, and several examples of campus style microgrids already operate on National Grid's system. The efforts presently under exploration are evaluating how DG from multiple owners with various generation types can be integrated with numerous customers' critical loads. The conceptual one-line of the Potsdam microgrid proposal is shown below. If approved, this project will help identify technical requirements for integration as well as identify critical regulatory and business model elements of integrating numerous customers' varied interests.



Integration will require the deployment of numerous field devices as well as a comprehensive low latency telecommunications system to connect these devices to critical control systems.

Drivers:
There are numerous drivers leading to an increasing focus on Advanced Grid Applications:

- Super Storm Sandy illustrated the importance of a resilient T&D system.
- State policy objectives such as NY Sun which is targeting the installation of 3GW of distributed renewable generation will have a significant impact on the T&D system.
- The outcome of the REV proceeding is expected to drive the transformation of distribution operations as well as the market structure at the distribution system level.

Customer Benefits:

Increasing the use of AGA technologies on the T&D system is expected to deliver significant benefits to customers, including:

- Enable more sophisticated control systems
- Improve Reliability and Operational efficiency
- Improve system capacity utilization
- Promote connection of more distributed and renewable resources such as electric vehicles and distributed generation

These AGA technologies may also result in improved service quality.

7. D. Asset Condition

Asset Condition expenditures are those investments required to reduce the likelihood and consequences of failures of distribution system assets by proactively replacing equipment. During the previous ten years, the Company adopted an Asset Management approach that relied on a holistic, longer-view assessment of assets and asset systems to inform capital-investment decisions. As part of this approach, the Company conducted assessments of major asset classes such as circuit breakers or subsets of asset classes such as a circuit breaker manufactured by a particular vendor. The assessments focused on the identification of specific susceptibilities for assets and asset systems, and the development of potential remedies. The installation of equipment with capabilities to participate in advanced grid applications may moderately increase replacement costs over traditional manual equipment.

7. D. 1. Inspection and Maintenance

The Company performs visual inspections on all overhead and underground distribution assets every five years. Each inspection identifies and categorizes necessary repairs or asset replacements, considering criticality to improve customer reliability in accordance with the Commission's Safety Order in Case 04-M-0159.[3]

The Company also performs annual elevated voltage testing per the Commission's Safety Order on all facilities that are capable of conducting electricity and are publicly accessible, such as street lights.

[3] Case 04-M-0159, Proceeding on Motion of the Commission to Examine the Safety of Electric Transmission and Distribution Systems, Order Adopting Changes in the Electric Safety Standards (issued and effective Dec. 15, 2008) ("Safety Order").

Current investment forecasts are based on actual expenditures being incurred with the on-going Inspection and Maintenance program and an expectation that the number of defects found in future year inspections will decrease as the inspection cycle repeats.

7. D. 2. Buffalo Streetlight Cable Replacement

This program maintains underground streetlight service by replacing streetlight cables and conduit, and removing temporary overhead conductors.

The program which has completed two years will continue at a funding level of $2.5M annually to replace approximately 14% of the existing street light cable over the next eight (8) years.

Drivers:
This program was developed to replace deteriorated street light cable in the Buffalo area to address repetitive incidents of elevated voltage as determined through periodic testing. The underground street light cable system in the Buffalo metropolitan area is comprised of a variety of cables and wiring configurations that have been in service for more than 50 years. Recently, Elevated Voltage Testing had identified stray voltage incident rates that are from 2 to 20 times the rates measured in other areas in the Company's service territory.

Customer Benefits:
This work will provide more reliable street light service and reduce the incidence of elevated voltages in the Buffalo area.

7. D. 3. Underground Cable
A strategy proactively replaces underground cable on the Sub-Transmission, Distribution Primary and Distribution Secondary systems in all three divisions of the upstate New York service territory. These replacements will be completed through a series of specific and programmatic projects targeting cables typically found in older urban areas considering their past performance, the history of failures within the manhole and duct system the cable may share with other circuits, the age and type of cable in service and several other factors.

The Company expects to spend $190M during the period FY15 – FY24 on cable replacements due to condition.

Drivers:
Recent manhole events have highlighted the potential public safety risk associated with underground cable and equipment failure. Although the consequence of a manhole event can be severe, the likelihood remains low. This strategy is expected to further reduce the likelihood of manhole events by proactively replacing cable based on condition and past performance.

Customer Benefits:

In addition to safety benefits, there is an environmental benefit to removing paper insulated lead covered (PILC) cable. Much of the cable to be replaced through this strategy will be PILC. Removing this cable will reduce the amount of lead on the system.

Addressing the cable in a prioritized fashion and re-evaluating the criticality model on an annual basis will result in the most cost efficient plan and allow lessons learned from recently completed projects to be applied to subsequent projects. Through a proactive approach, cable replacement projects reduce the likelihood and consequences of a cable failure.

7. D. 4. Conductor Replacement

Various projects are planned which will replace “small” (< #2 AWG) copper, copperweld, amerductor and aluminum conductor.

The Company stopped installing #4 and smaller copper primary wire sometime prior to 1953. This makes the small wire population at least 58 years old (some of the oldest overhead energized equipment in service on the distribution system).

A replacement program of approximately $4.0M per year is expected over the horizon of the plan.

Drivers:
In the course of a 50+ year service life, the average conductor will have lost some of its tensile strength due to loading conditions and elongation during splicing following emergency service restoration. This loss of tensile strength increases the likelihood of conductor breakage during an interruption which involves physical contact with the conductor. Interruptions involving broken conductors typically result in longer service restoration times. With each successive interruption the ability to restore service quickly is deteriorated. This loss of tensile strength is especially significant during a storm situation where the wind and/or ice/snow loading on the conductor will be higher than during clear conditions. These projects will systematically identify and replace the small wire.

Customer Benefits:
Replacing the “small wire” population will improve customer level reliability by reducing the frequency and duration of localized interruptions.

Replacement will also improve voltage performance, especially on those circuits having in excess of two miles of conductor.

7. D. 5. Networks

Underground networks are highly interconnected systems that typically serve city center areas due to their high reliability when they perform as originally designed. However, they also represent an aging infrastructure that requires monitoring, maintenance and replacements to maintain reliability. Individual network studies are completed periodically to identify thermal and voltage concerns. Some smaller networks will be radialized (disassembled) and rebuilt using standard underground commercial development equipment.

Following recent changes to the National Electrical Safety Code, an analysis of the arc flash hazard in the Company's 480V spot networks was concluded. The potential for high arc flash energy exists on these network systems and the Company has developed revised operational procedures to manage this concern in the short term. The Company has also engineered and is installing equipment to enhance the isolation capabilities of elements within the network to mitigate safety risks, accommodate the National Electric Safety Code changes, and retain the reliability benefits of network service.

Drivers:
When major incidents do occur, restoration can be very lengthy and costly.

Customer Benefits:
The approach to managing underground networks is one of prevention and proactive intervention. In general, when network failures occur, they typically require lengthy restoration efforts due to location and feasibility of repairing/replacing equipment, and often require unexpected civil work. Planned replacement of underground assets will reduce the risk of extended interruptions for customers served by underground networks.

7. D. 6. Substation Asset Condition Programs

Substation asset condition issues may require significant projects in terms of cost, complexity and project duration for replacement or refurbishment. Consequently, it is often more efficient and cost effective to review an entire substation. Further, where there are asset issues that indicate replacement as an option, the Company reviews planning and capacity requirements to ensure alternative solutions are evaluated such as system reconfiguration to retire a substation. Thus, asset strategies are coordinated with system planning to develop an integrated system plan.

7. D. 6. 1. Substation Batteries

This program mirrors the Transmission Substation Batteries and Chargers program. Battery and charger systems are needed to ensure substation operational capability during both normal and abnormal system conditions. The intent of this program is to replace battery and charger systems before their condition impacts reliable substation performance. The 20-year target for substation battery replacement is based on industry best practice and experience in managing battery systems. This program work is coordinated with other asset replacement programs where appropriate.

Currently, there are over 300 substation batteries in service. To bring all battery systems to less than twenty years old within fifteen years would require a replacement rate of approximately 13 per year.

Throughout the horizon of this plan, approximately $1M per year is forecasted for battery replacements.

Drivers:
Failure of batteries and charger systems may result in substation protective relays and/or circuit breakers not operating as designed.

Customer Benefits:
The impacts of battery failures can result in additional customers being interrupted as back-up relay schemes at remote substations are needed to isolate a fault. It may also result in equipment damage if a fault is not cleared in a timely fashion. Interruptions related to battery incidents are uncommon at this time as the replacement program is working as desired.

7. D. 6. 2. Substation Circuit Breakers and Reclosers

As noted in the annual asset condition report,[4] certain types, or families, of breakers have been specifically identified for replacement in the next ten years. Breaker families are typically older, obsolete units that are less safe or less reliable. Certain breaker families that are targeted for replacement contain parts that must be custom machined or units that contain asbestos in the interrupting systems and require extra precautions during maintenance, refurbishment and overhaul.

Drivers:
Breaker condition coding is based on engineering assessments and supported by feedback from local Operations personnel. The units are prioritized for replacement based on the condition coding; units in poorer condition are given a higher score. Many of these breakers are obsolete. Obsolete units have been specifically identified for replacement because they are difficult to repair due to the lack of available spare parts. Likewise, unreliable units have been identified for replacement to reduce the number of customer interruptions.

A budget of approximately $2.5M per year is forecasted for the substation breaker replacement program.

Customer Benefits:
In addition to the reliability benefits described above, several of the targeted breaker families also present opportunities to reduce hazards associated with safety and the environment (i.e., oil and asbestos).

7. D. 6. 3. Indoor Substations

[4] Report on the Condition of Physical Elements of Transmission and Distribution Systems, Case 06-M-0878, October 1, 2011, page II-118.

The purpose of this strategy is to replace, retrofit, or retire the twenty-four remaining indoor distribution substations. The indoor substations were built in the 1920s through the 1940s. These substations have inherent safety risks due to design and equipment condition. Sixteen of these indoor substations remain to be rebuilt in the City of Buffalo and five are in Niagara Falls. Details of the asset condition issues and key drivers are outlined in the asset condition report.[5]

It is anticipated that this replacement program will require another 20 years to complete. The costs to address each substation vary considerably, and range from $4 to $8M per location.

Drivers:
These indoor substations are obsolete. Their outmoded design does not meet currently accepted safety practices, equipment and protection schemes are becoming unreliable in interrupting faults, and in general the equipment condition is deteriorating.

Customer Benefits:
Under normal conditions, failure of obsolete indoor substation equipment could result in sustained customer interruptions until some type of replacement is installed. Equipment outages can result in increased operation and loading on parallel equipment. Indoor substations typically supply urban environments, including critical loads such as police, fire and hospitals. This program mitigates the risk for a long-term, sustained, customer interruptions occurring in these urban areas.

7. D. 6. 4. Metal-Clad Switchgear

Deteriorated metal-clad switchgear can be prone to water and animal ingress which leads to failures from moisture, dust or animals. Visual surveys will detect such degradation, but cannot identify surface tracking where hidden behind metal enclosures. Identification of these concerns is more likely with electro-acoustic detection techniques. By using sensors to detect anomalous sound (acoustic) waves or electric signals in the metal-clad switchgear, it is possible to identify equipment condition concerns before failure.

For each substation, an analysis will be conducted to determine if direct replacement is the best course of action or if an alternate means of supplying the load will be constructed.

The capital forecast reflects new condition assessment data and analysis which helped identify and prioritize replacement candidates. Multiple stations are in progress with a program in place to prioritize additional stations. The Company expects to spend approximately $5M per year on these replacements.

Drivers:

[5] Report on the Condition of Physical Elements of Transmission and Distribution Systems, Case 06-M-0878, October 1, 2011, pg. II-109.

Metal-clad switchgear manufactured prior to the 1970s has several factors that can lead to component failure. Electrical insulation voids were more prevalent in earlier vintage switchgear. Higher temperatures due to poor ventilation systems can degrade lubrication in moving parts such as breaker mechanisms; and, gaskets and caulking deteriorate over time leading to ingress of moisture.

Customer Benefits:
The impact of each metal-clad switchgear event on local customers is usually substantial, with nearly 3,000 customers interrupted for over three hours per event. This program would reduce the risk of such events and provide significant benefit to the affected customers.

7. D. 6. 5. Mobile Substation

Mobile substations are key elements for ensuring continued reliability and supporting the system during serious incidents.

Throughout the horizon of this plan the Company expects to spend $1M to $2M per year on this program.

Drivers:
To improve the management of the mobile substation fleet, the Company conducted a review which considered system requirements, the amount of mobile usage, and the uniqueness of the individual unit to better understand the condition of all members of the fleet and their associated risks. Highly utilized units may present a risk if they are not properly maintained or refurbished. Further, uniquely configured units or very highly utilized units in which there is only one available unit on the system, present some risk since they may not be available for an emergency due to utilization elsewhere. Based on the review, mobile substation protection upgrades, rewinds and replacement units were recommended.

Customer Benefits:
A mobile substation or transformer is the quickest method for restoring service to customers when an outage occurs in a substation, typically occurring within sixteen to twenty-four hours. By refurbishing, upgrading, replacing and purchasing new mobile substations, as necessary, via system reviews and condition assessments, the risk of extended customer outages will be significantly reduced. In addition, properly addressing the needs of the mobile fleet will allow us to schedule maintenance for substation transformers in a timely manner since they are one of the most valuable assets on the system. Lastly, having an adequate number of mobile substations on hand will promote the completion of new construction projects on-time and on-budget.

7. D. 6. 6. Substation Power Transformers

Power transformers are large capital items with long lead times. Their performance can have a significant impact on reliability and system capacity. Condition data and condition assessment are the key drivers for identifying replacement candidates. Replacements are prioritized through a risk analysis which includes feedback from operations personnel. The distribution element covers transformers which are identified as replacement candidates through the test and assessment procedure. A 'Watch List' of candidate transformers has been identified and recorded in the Asset Condition Report.[6]

Through on-going review of the distribution substation transformer fleet, new problems are identified. The resulting replacement costs and related annual investment will vary based on the size of the transformer to be replaced with a typical spend of $2M to $3M per year.

Drivers:
As noted in the 2013 Asset Condition Report, there are approximately 765 power transformers plus 24 spares with primary voltages 69kV and below.[7] Each unit is given a condition code based on individual transformer test and assessment data, manufacture/design and available operating history.[8] Higher codes relate to transformers which may have anomalous condition; units with a higher code are subject to more frequent monitoring and assessment, and are candidates for replacement on the Watch List.

Customer Benefits:
The impact of power transformer failure events on customers is historically substantial. By proactively replacing poor condition units there will be direct benefits to customers in reduced impact of power transformers on performance.

7. D. 6. 7. Remote Terminal Unit Replacement

Work in this program relates to distribution assets identified as part of the Transmission - Remote Terminal Unit Replacement strategy in the Customer Requests/Public Requirements section of Chapter 6.

There is also significant investment in installing upgraded distribution Remote Terminal Unit (RTU) equipment as documented in the System Capacity and Performance spending rationale section.

7. E. Non-Infrastructure

In addition to the direct spending on its electric network, the Company also invests a portion of its budget in systems, tools, and general plant. The "non infrastructure" spending rationale is for capital expenditures that do not fit into one of the foregoing categories, but

[6] Report on the Condition of Physical Elements of Transmission and Distribution Systems, Case 06-M-0878, October 1, 2011, pages II-116 to II-117.
[7] Report on the Condition of Physical Elements of Transmission and Distribution Systems, Case 10-E-0050, October 1, 2013, p. 111-12.
[8] Id.

which are necessary to run the electric system. Examples of existing work in this rationale include investments in radio systems, test equipment and physical security work at substations.

Non-Infrastructure investment levels on the distribution system are primarily based on historical actual costs for the first five years of the plan.

Chapter 8. Estimated Rate Impacts

8. A. T&D Delivery Rate Impacts of Fifteen-Year Plan

The Company prepared a simplified analysis to estimate the revenue requirement effects in 2029 associated with the proposed capital investment levels included in the Plan. The analysis looked at the estimated rate impacts assuming two basic investment scenarios: (1) the base level of investment described in the Plan ("Base Case"); and (2) the base level of spending described in the Plan, plus the incremental spending associated with investments designed to modernize the electric system, as described in Chapter 7, Section 7.C.6 ("Advanced Grid Case"). The methodology the Company used for these analyses is described below.

8. A. 1. Base Case

The Base Case estimate was developed using the results of the five-year Transmission and Distribution Capital Investment Plan filed with the Commission January 31, 2014 as a basis for a high-level apportionment to apply to the Fifteen-Year Plan. The Base Case investment levels are those set forth in Exhibit A, Tables 9-1 to 9-3. The rate of return ("ROR") used is consistent with the current ROR authorized in Case 12-E-0201. To estimate 2029 operating costs, the Company applied an inflation factor to the fiscal year 2014 operating costs rate allowance authorized in Case 12-E-0201 and assumed that regulatory deferrals will have been fully amortized by 2029. Below market variable costs will be recovered through the Legacy Transition Charge ("LTC"). Based on the high level revenue requirement assumptions, the Company used the updated 2029 sales forecast described in Chapter 3 to arrive at estimated cumulative distribution delivery rates for typical residential, small commercial and large commercial customers for each applicable voltage delivery level ("VDL").

In 2029, the cumulative distribution delivery rate under the Base Case for a typical residential customer would be estimated at $0.09284 per kWh; for a typical small commercial SC-2D customer, the distribution delivery rate would be estimated at $14.87 per kW; and for a typical large commercial SC3 Secondary, Primary and Sub-transmission/Transmission customer, the distribution delivery rate would be estimated at $13.34, $10.93 and $4.74 per kW, respectively. The below market variable costs would be recovered through the LTC, which is estimated at ($0.00025) per kWh for all service classes in 2029.

Figures 8-1 and 8-2, below, compare estimated 2014 and 2029 bills for a typical residential (SC-1) customer in current ("Nominal") and inflation-adjusted ("Real") dollars, respectively, under the Base Case.[1]

Figure 8-1
Typical Residential Bill – Nominal (Base Case)
(600kWh Monthly Usage)

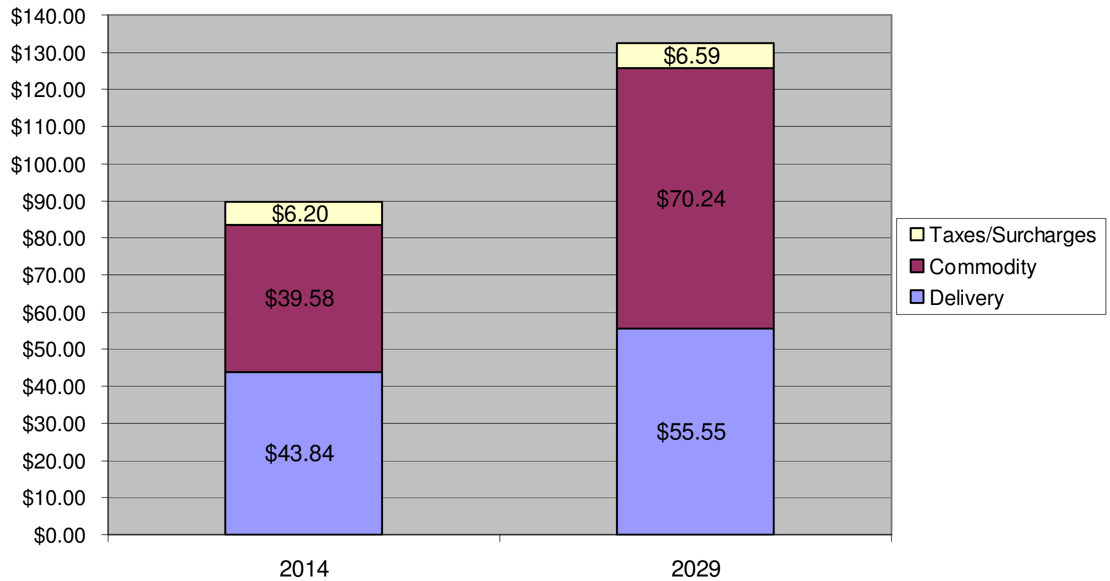
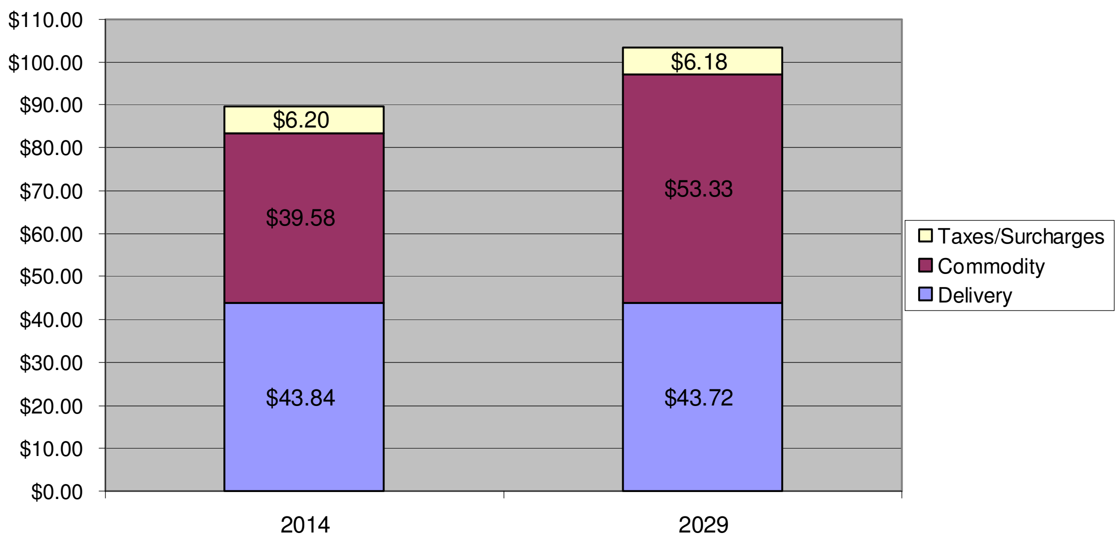


Figure 8-2
Typical Residential Bill – Real (Base Case)
(600kWh Monthly Usage)



[1] Electric supply cost estimates are based on information from the U.S. Energy Information Administration and the Company's Electric Supply group.

Exhibit B, Figures 10-1 to 10-6, includes bill charts comparing 2014 and 2029 for typical residential, small commercial SC-2D, and large commercial SC3 customers for the Base Case assumptions. Exhibit B, Figure 10-19, provides details of the simplified analysis, including assumptions, used to estimate the Base Case rates and bill impacts.

8. A. 2. Advanced Grid Case

The Advanced Grid Case estimates were developed using the base Fifteen-Year Plan estimates, then adding incremental capital associated with the Advanced Grid Applications investments described in Chapter 7, Section 7.C.6, as well as associated increases in operating expenses and property taxes related to the incremental capital. The amounts of and schedule for the incremental investments used to develop the Advanced Grid Case are shown in Exhibit A, Table 9-4. These investments represent a high case scenario and will be modified as implementation plans are developed in response to the REV objectives. Apart from the incremental capital investments, operating expenses and property taxes, all other assumptions used to determine the Advanced Grid Case estimated rates and bill impacts are the same as used for the Base Case.

Based on these assumptions, the cumulative distribution delivery rate in 2029 under the Advanced Grid Case for a typical residential customer would be estimated at $0.10107 per kWh; for a typical small commercial SC-2D customer, the distribution delivery rate would be estimated at $16.19 per kW; and for a typical large commercial SC3 Secondary, Primary and Sub-transmission/Transmission customer, the distribution delivery rate would be estimated at $14.53, $11.91 and $5.17 per kW, respectively.

Figures 8-3 and 8-4, below, compare estimated 2014 and 2029 bills for a typical residential (SC-1) customer in current (“Nominal”) and inflation-adjusted (“Real”) dollars, respectively, under the Advanced Grid Case.

Figure 8-3
Typical Residential Bill – Nominal (Advanced Grid Case)
(600kWh Monthly Usage)

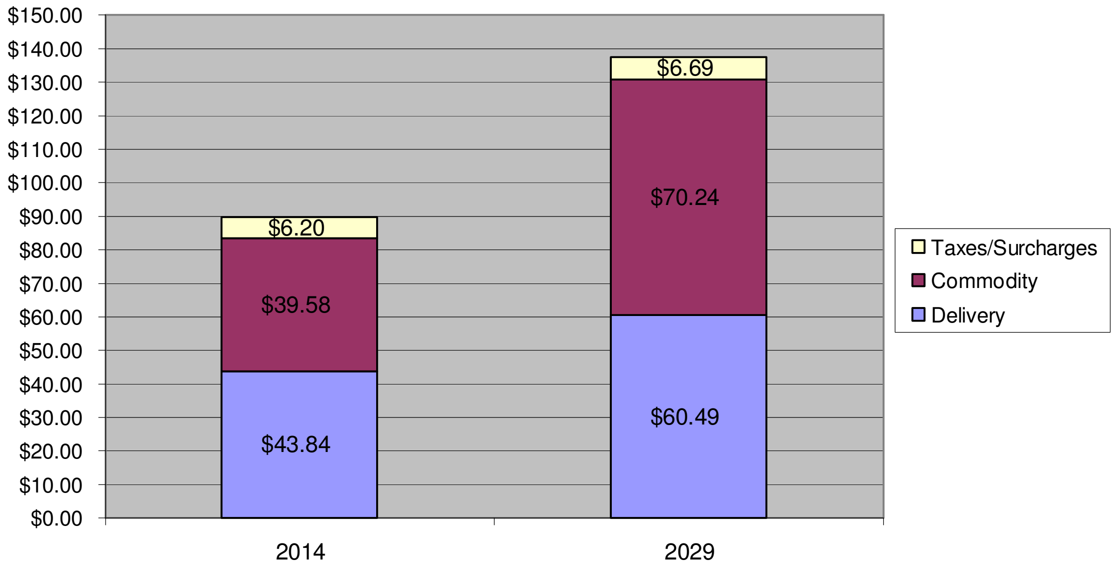


Figure 8-4
Typical Residential Bill – Real (Advanced Grid Case)
(600kWh Monthly Usage)

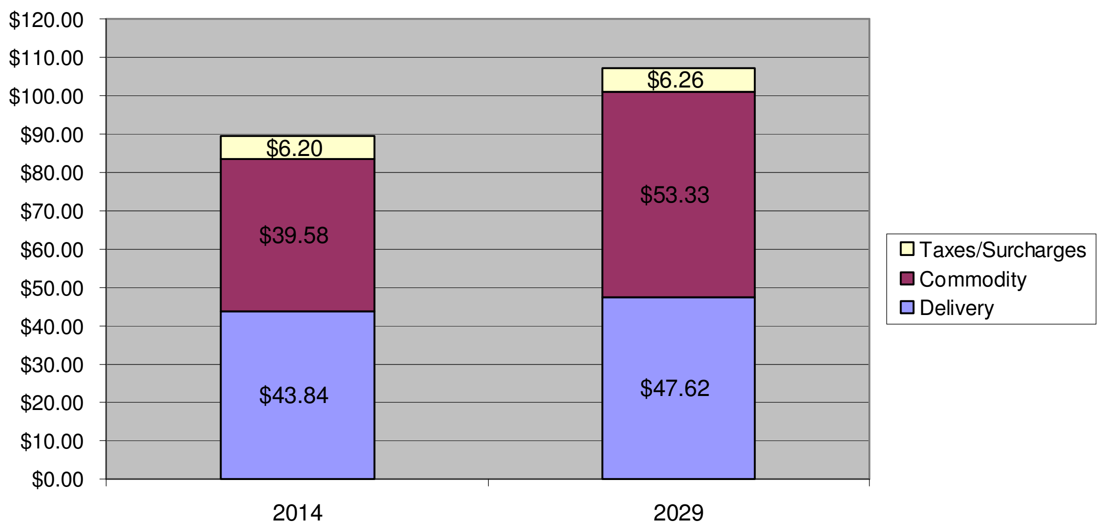


Exhibit B, Figures 10-7 to 10-12, includes bill charts comparing 2014 and 2029 for typical residential, small commercial SC-2D, and large commercial SC3 customers for the Advanced Grid Case assumptions. Exhibit B, Figure 10-20, provides details of the simplified analysis, including assumptions, used to estimate the Advanced Grid Case rates and bill impacts.

Comparison of Base and Advanced Grid Cases

Figures 8-5 and 8-6, below, compare estimated 2029 bills under the Base and Advanced Grid cases for a typical residential (SC-1) customer in current ("Nominal") and inflation-adjusted ("Real") dollars, respectively.

Figure 8-5
Typical Residential Bill – 2029 Nominal
Base Case vs. Advanced Grid Case
(600kWh Monthly Usage)

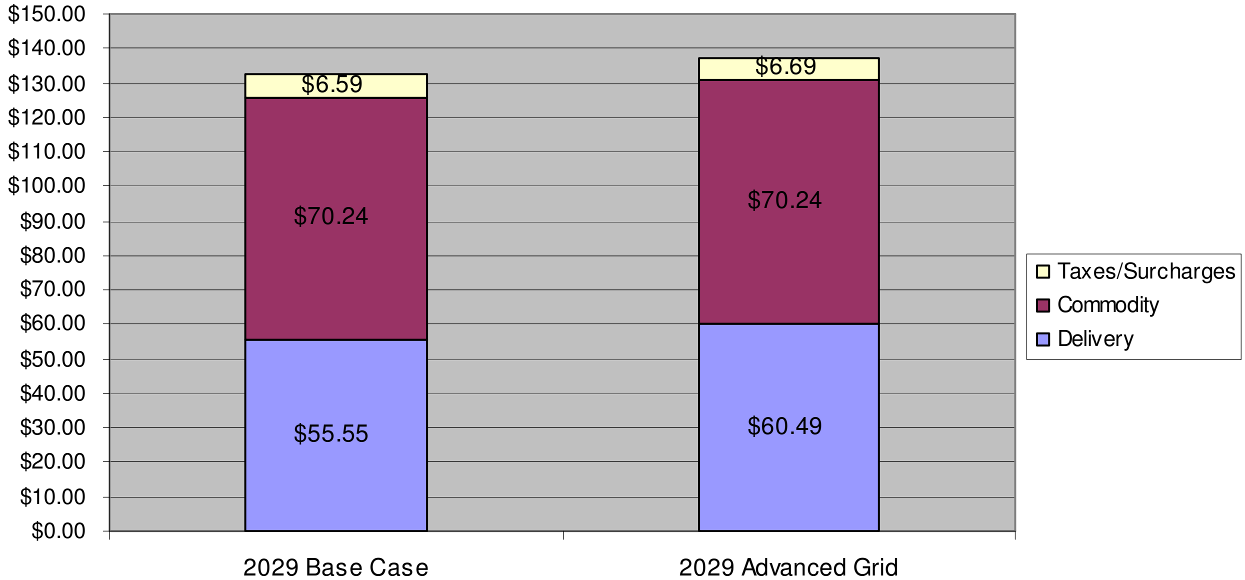


Figure 8-6
Typical Residential Bill – 2029 Real
Base Case vs. Advanced Grid Case
(600kWh Monthly Usage)

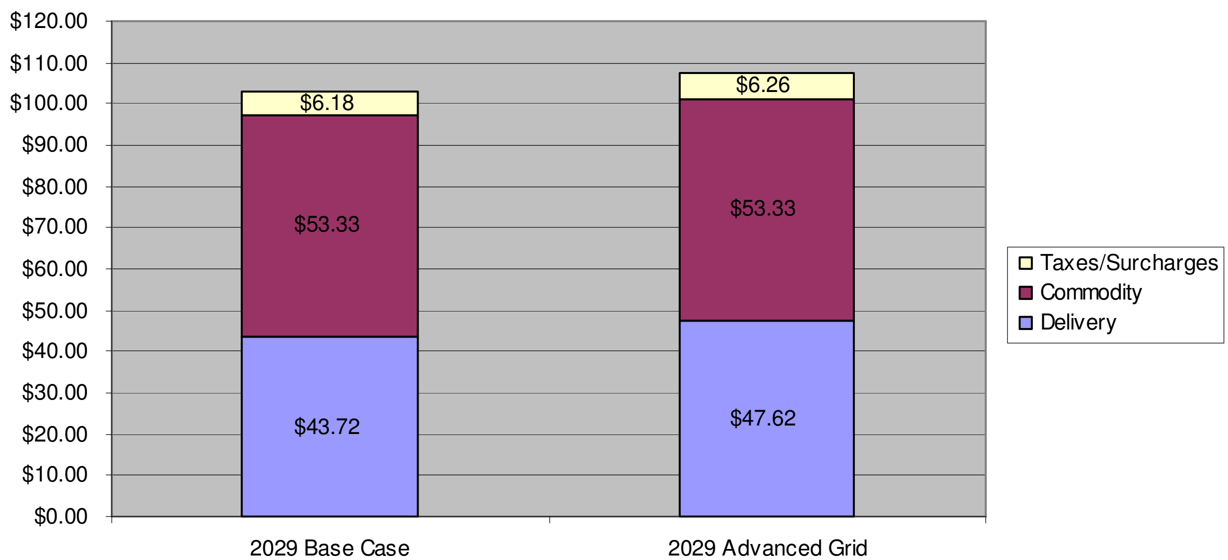


Exhibit B, Figures 10-13 to 10-18, includes bill charts comparing 2029 bills under the Base and Advanced Grid cases for typical residential, small commercial SC-2D, and large commercial SC3 customers. Exhibit B, Figure 10-21, provides details of the simplified analysis, including assumptions, used to develop the comparison.

Chapter 9. Exhibit A - CAPEX Plan

Exhibit A - Table 9-1
A. Transmission Forecast Investment Level by Spending Rationale for the period FY2015 – FY2029 ($000's)

Spending Rationale	Program	FY15 Budget	FY16 Budget	FY17 Budget	FY18 Budget	FY19 Budget	FY20 Budget	FY21 Budget	FY22 Budget	FY23 Budget	FY24 Budget	FY25 Budget	FY26 Budget	FY27 Budget	FY28 Budget	FY29 Budget	Total
Customer Requests/Public Requirements	Customer Interconnection/ Public Requirement	56	10	0	0	0	0	0	0	0	0	0	0	0	0	0	66
Customer Requests/Public Requirements Total		**56**	**10**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**66**
Damage Failure	Damage/Failure	12,008	7,200	7,200	6,450	6,450	11,679	11,913	12,151	12,394	12,642	12,895	13,152	13,415	13,684	13,957	167,190
Damage Failure Total		**12,008**	**7,200**	**7,200**	**6,450**	**6,450**	**11,679**	**11,913**	**12,151**	**12,394**	**12,642**	**12,895**	**13,152**	**13,415**	**13,684**	**13,957**	**167,190**
System Capacity & Performance	Generator Retirements	21,248	9,629	0	0	0	0	0	0	0	0	0	0	0	0	0	30,877
	NERC/NPCC Standards	3,382	125	250	1,000	15,000	0	0	0	0	0	0	0	0	0	0	19,757
	TO Led System Studies	78,316	59,706	69,392	33,361	23,744	27,836	34,851	32,870	35,253	30,448	37,009	42,678	33,876	25,037	26,072	590,451
System Capacity & Performance Total		**102,946**	**69,460**	**69,642**	**34,361**	**38,744**	**27,836**	**34,851**	**32,870**	**35,253**	**30,448**	**37,009**	**42,678**	**33,876**	**25,037**	**26,072**	**641,084**
Asset Condition	Asset Condition I&M	6,200	12,300	4,300	3,000	3,000	1,173	1,196	1,220	1,245	1,270	1,295	1,321	1,347	1,374	1,402	41,644
	Component Fatigue/Deterioration/ Failure Trend	43,831	64,968	105,158	132,989	141,106	153,912	150,534	172,059	173,809	182,840	180,601	179,248	192,461	205,905	209,469	2,288,889
	NERC/NPCC Standards	7,467	10,700	10,700	10,700	15,000	15,300	15,606	0	0	0	0	0	0	0	0	85,473
Asset Condition Total		**57,499**	**87,968**	**120,158**	**146,689**	**159,106**	**170,385**	**167,337**	**173,279**	**175,054**	**184,110**	**181,896**	**180,569**	**193,808**	**207,279**	**210,870**	**2,416,006**
Non-Infrastructure	Station Control and Monitoring System	3,792	2,197	1,500	1,500	1,500	0	0	0	0	0	0	0	0	0	0	10,489
Non-Infrastructure Total		**3,792**	**2,197**	**1,500**	**1,500**	**1,500**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**10,489**
Grand Total		**176,300**	**166,835**	**198,500**	**189,000**	**205,800**	**209,900**	**214,100**	**218,300**	**222,700**	**227,200**	**231,800**	**236,400**	**241,100**	**246,000**	**250,900**	**3,234,835**

Exhibit A - Table 9-2
B. Sub-Transmission Forecast Investment Level by Spending Rationale for the period FY2015 – FY2029 ($000’s)

Spending Rationale	Budget Class	FY15 Budget	FY16 Budget	FY17 Budget	FY18 Budget	FY19 Budget	FY20 Budget	FY21 Budget	FY22 Budget	FY23 Budget	FY24 Budget	FY25 Budget	FY26 Budget	FY27 Budget	FY28 Budget	FY29 Budget	Total
Customer Requests/Public Requirements	3rd Party Attachments	35	35	35	35	35	40	40	40	40	40	40	40	40	40	40	575
	Asset Replacement - I&M (NY)	12,127	11,942	11,357	11,107	11,107	8,000	8,160	8,320	8,490	8,660	8,830	9,010	9,190	9,370	9,560	145,231
	New Business - Commercial	1,330	1,352	1,313	1,375	1,437	1,490	1,550	1,610	1,670	1,740	1,810	1,880	1,960	2,040	2,120	24,677
	Public Requirements	146	238	209	1,717	125	130	140	150	160	170	180	190	200	210	220	4,185
Customer Requests/Public Requirements Total		**13,637**	**13,566**	**12,915**	**14,235**	**12,704**	**9,660**	**9,890**	**10,120**	**10,360**	**10,610**	**10,860**	**11,120**	**11,390**	**11,660**	**11,940**	**174,668**
Damage/Failure	Damage/Failure	2,419	2,148	2,188	2,228	2,268	2,290	2,310	2,330	2,350	2,370	2,390	2,410	2,430	2,450	2,470	35,051
	Major Storms	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	3,000
Damage/Failure Total		**2,619**	**2,348**	**2,388**	**2,428**	**2,468**	**2,490**	**2,510**	**2,530**	**2,550**	**2,570**	**2,590**	**2,610**	**2,630**	**2,650**	**2,670**	**38,051**
System Capacity & Performance	Load Relief	1,151	2,052	1,534	2,098	2,020	3,070	3,150	3,230	3,310	3,390	3,470	3,560	3,650	3,740	3,830	43,255
	Reliability	1,291	1,626	3,865	3,957	3,193	3,280	3,360	3,420	3,490	3,580	3,660	3,750	3,860	3,930	4,030	50,291
System Capacity & Performance Total		**2,441**	**3,677**	**5,399**	**6,055**	**5,214**	**6,350**	**6,510**	**6,650**	**6,800**	**6,970**	**7,130**	**7,310**	**7,510**	**7,670**	**7,860**	**93,546**
Asset Condition	Asset Replacement	14,077	13,158	15,873	17,683	21,614	26,050	26,570	27,100	27,640	28,190	28,750	29,330	29,920	30,520	31,130	367,605
Asset Condition Total		**14,077**	**13,158**	**15,873**	**17,683**	**21,614**	**26,050**	**26,570**	**27,100**	**27,640**	**28,190**	**28,750**	**29,330**	**29,920**	**30,520**	**31,130**	**367,605**
Grand Total		**32,775**	**32,750**	**36,575**	**40,400**	**42,000**	**44,550**	**45,480**	**46,400**	**47,350**	**48,340**	**49,330**	**50,370**	**51,450**	**52,500**	**53,600**	**673,870**

Exhibit A - Table 9-3
C. Distribution Forecast Investment Level by Spending Rationale for the period FY2015 – FY2029 ($000's)

Spending Rationale	Budget Class	FY15 Budget	FY16 Budget	FY17 Budget	FY18 Budget	FY19 Budget	FY20 Budget	FY21 Budget	FY22 Budget	FY23 Budget	FY24 Budget	FY25 Budget	FY26 Budget	FY27 Budget	FY28 Budget	FY29 Budget	Total
Customer Requests/Public Requirements	3rd Party Attachments	404	409	414	420	426	430	440	450	460	470	480	490	500	510	520	6,823
	Asset Replacement - I&M (NY)	25,501	21,844	21,844	21,844	21,844	22,280	22,730	23,180	23,640	24,110	24,590	25,080	25,580	26,090	26,610	356,766
	Distributed Generation	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100	1,200
	Land and Land Rights	2,061	2,092	2,124	2,156	2,188	2,230	2,270	2,320	2,370	2,420	2,470	2,520	2,570	2,620	2,670	35,081
	Meters	4,516	4,700	4,697	4,862	5,035	5,240	5,450	5,670	5,900	6,140	6,390	6,650	6,920	7,200	7,490	86,860
	New Business - Commercial	12,533	12,734	12,982	13,235	13,491	14,030	14,590	15,170	15,780	16,410	17,070	17,750	18,460	19,200	19,970	233,405
	New Business - Residential	23,357	23,162	23,554	23,952	24,359	25,330	26,340	27,390	28,490	29,630	30,820	32,050	33,330	34,660	36,050	422,474
	Outdoor Lighting - Capital	7,327	7,316	7,426	7,537	7,650	7,800	7,960	8,120	8,280	8,450	8,620	8,790	8,970	9,150	9,330	122,726
	Public Requirements	9,010	9,380	9,322	9,444	9,567	9,950	10,350	10,760	11,190	11,640	12,110	12,590	13,090	13,610	14,150	166,163
	Transformers & Related Equipment	25,287	26,046	26,827	27,632	28,461	29,600	30,780	32,010	33,290	34,620	36,000	37,440	38,940	40,500	42,120	489,553
Customer Requests/Public Requirements Total		**109,996**	**107,683**	**109,190**	**111,182**	**113,120**	**116,990**	**121,010**	**125,170**	**129,500**	**133,990**	**138,650**	**143,460**	**148,460**	**153,640**	**159,010**	**1,921,050**
Damage/Failure	Damage/Failure	22,393	22,423	22,833	23,253	23,676	23,910	24,150	24,390	24,630	24,880	25,130	25,380	25,630	25,890	26,150	364,718
	Major Storms*	718	718	629	629	0	0	0	0	0	0	0	0	0	0	0	2693556
Damage/Failure Total		**23,111**	**23,141**	**23,462**	**23,882**	**23,676**	**23,910**	**24,150**	**24,390**	**24,630**	**24,880**	**25,130**	**25,380**	**25,630**	**25,890**	**26,150**	**367,412**
System Capacity & Performance	Load Relief	42,833	45,296	54,869	55,974	56,152	57,560	59,000	60,480	61,990	63,540	65,130	66,760	68,430	70,140	71,890	900,045
	Reliability	25,964	28,369	37,476	40,040	41,658	42,490	43,340	44,190	45,060	45,970	46,890	47,840	48,820	49,780	50,790	638,676
System Capacity & Performance Total		**68,796**	**73,665**	**92,346**	**96,014**	**97,810**	**100,050**	**102,340**	**104,670**	**107,050**	**109,510**	**112,020**	**114,600**	**117,250**	**119,920**	**122,680**	**1,538,721**
Asset Condition	Asset Replacement	31,244	33,330	41,303	44,885	48,625	49,600	50,590	51,600	52,630	53,680	54,750	55,850	56,970	58,110	59,270	742,436
	Outdoor Lighting - Discretionary	2,500	2,500	2,500	2,500	2,500	2,550	2,600	2,650	500	510	520	530	540	550	560	24,010
	Safety*	4,000	4,111	4,000	2,104	0	0	0	0	0	0	0	0	0	0	0	14214996
Asset Condition Total		**37,744**	**39,941**	**47,803**	**49,489**	**51,125**	**52,150**	**53,190**	**54,250**	**53,130**	**54,190**	**55,270**	**56,380**	**57,510**	**58,660**	**59,830**	**780,661**
Non-Infrastructure	General Equipment - Dist	2,234	2,268	2,302	2,336	2,371	2,420	2,470	2,520	2,570	2,620	2,670	2,720	2,770	2,830	2,890	37,991
	Telecommunications Capital	1,398	1,398	998	998	998	1,020	1,040	1,060	1,080	1,100	1,120	1,140	1,160	1,180	1,200	16,890
Non-Infrastructure Total		**3,632**	**3,666**	**3,300**	**3,334**	**3,369**	**3,440**	**3,510**	**3,580**	**3,650**	**3,720**	**3,790**	**3,860**	**3,930**	**4,010**	**4,090**	**54,881**
Grand Total		**243,279**	**248,096**	**276,100**	**283,900**	**289,100**	**296,540**	**304,200**	**312,060**	**317,960**	**326,290**	**334,860**	**343,680**	**352,780**	**362,120**	**371,760**	**4,662,725**

* **Budget Class is evaluated on yearly bases to determine the 5-yr budget.**

Exhibit A - Table 9-4
D. Advanced Grid Case Incremental Investment Levels for the period FY2016 – FY2030 ($M)

	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	Total
Advanced Distribution Automation (No Communications)	7	11	15	15	15	15	15	15	15	15	15	15	15	16	16	215
CVR / VVO (No Communications, no 4KV)	3	6	9	9	9	9	9	9	9	9	9	9	9	9	9	126
Tier 2 Telecoms	3	5	8	8	8	8	8	8	8	6	6	6	6	6	6	100
DG Readiness	10	20	30	50	50	50	60	60	60	60	60	60	60	60	60	750
Advanced Metering Infrastructure					30	100	150	150	70							500
Misc Demonstration Projects	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	30
IT/OT Data Management Systems (NY)					9	28	43	43	20							142
Total	25	44	64	84	123	212	287	287	184	92	92	92	92	93	93	1,863

Chapter 10. Exhibit B - Bill Comparisons

10. A. Base Case

Figures 10-1 – 10-6
Bill Comparisons 2014 to 2029 (Nominal and Real)
Typical Customers by Service Class and Voltage

Figure 10-1
Typical Residential Bill – Nominal (Base Case)
(600kWh Monthly Usage)

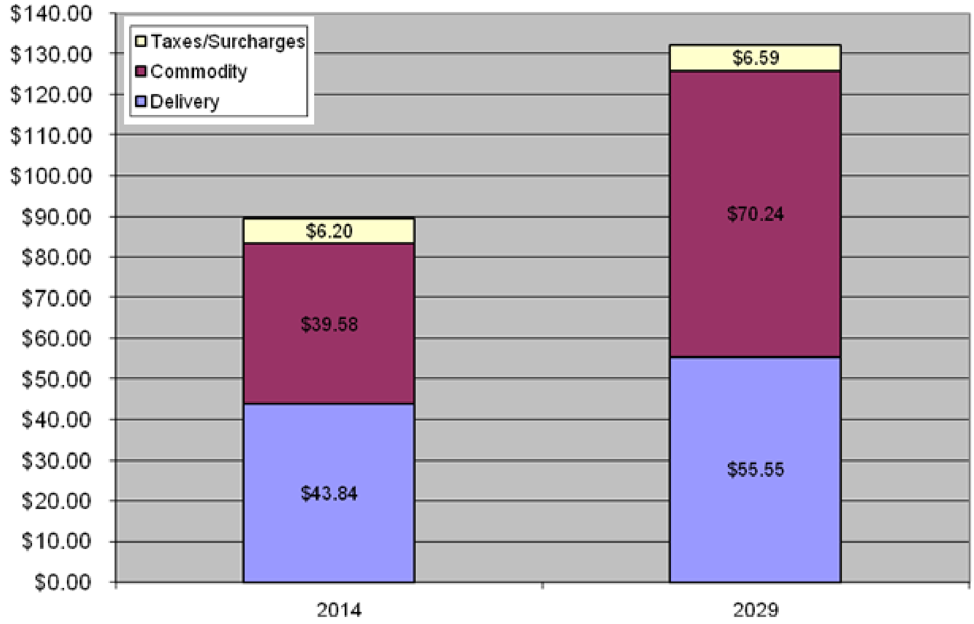


Figure10-2
Typical Residential Bill – Real (Base Case)
(600kWh Monthly
Usage)

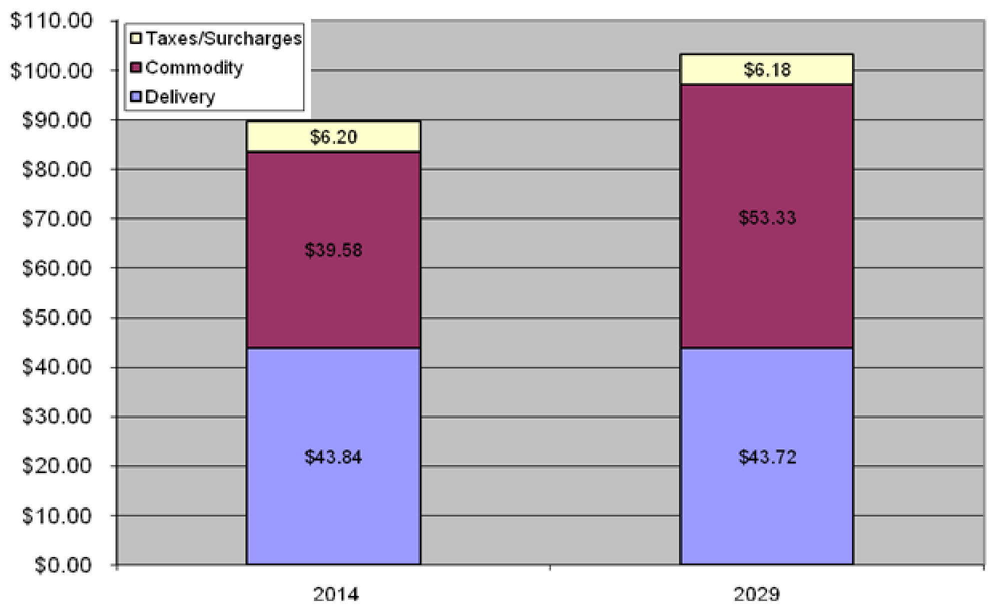


Figure 10-3
Average Small Commercial Bill - SC2D-Nominal (Base Case)
(50kW; 14,200kWh)

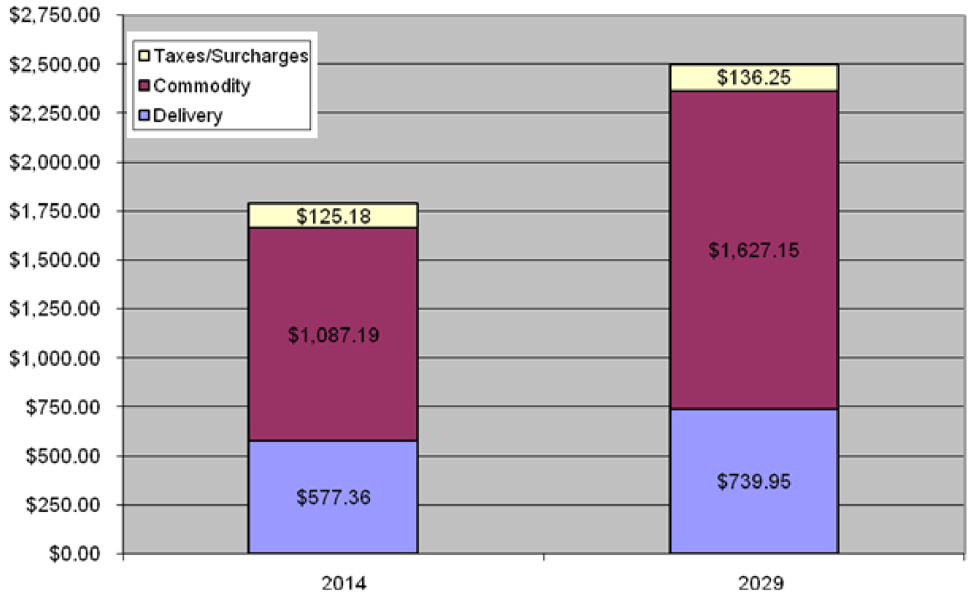


Figure 10-4
Average Small Commercial Bill - SC2D-Real (Base Case)
(50kW; 14,200kWh)

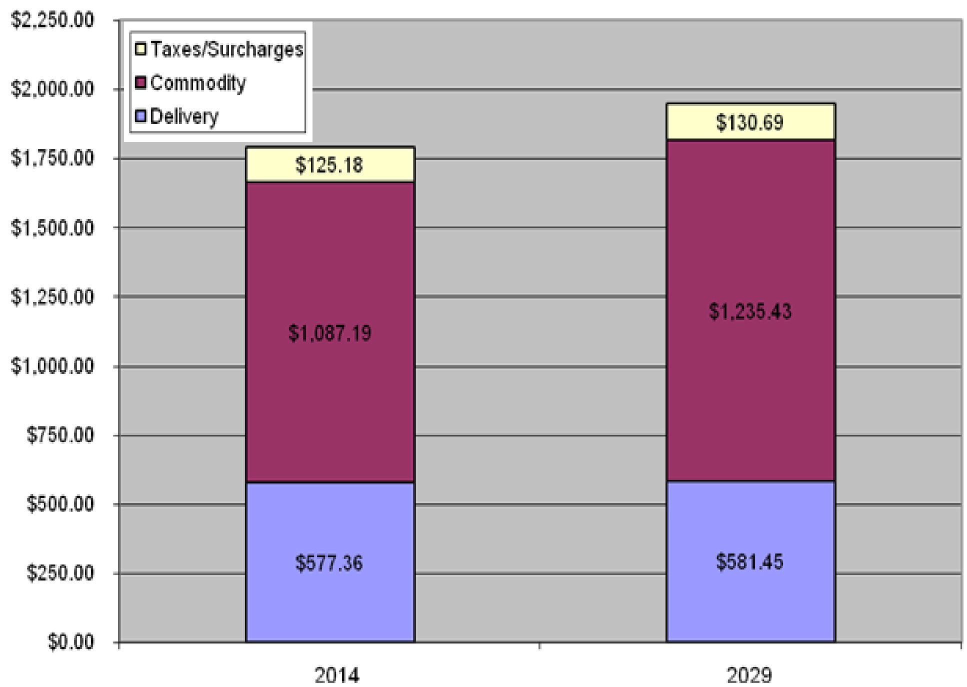


Figure 10-5
Average Large Commercial Bill – SC3 Sec-Nominal (Base Case)
(250kW; 90,000kWh)

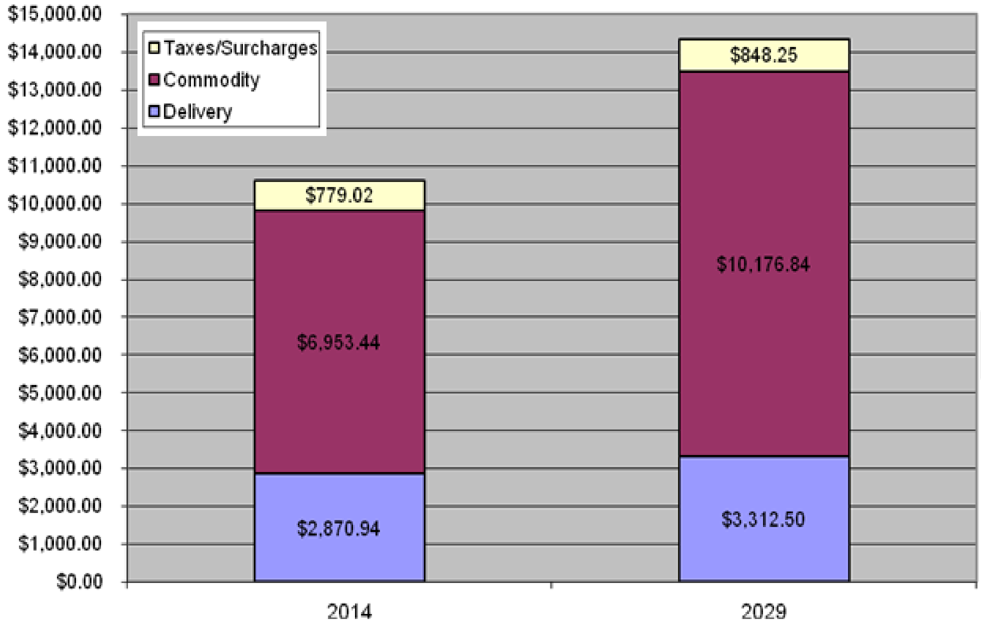
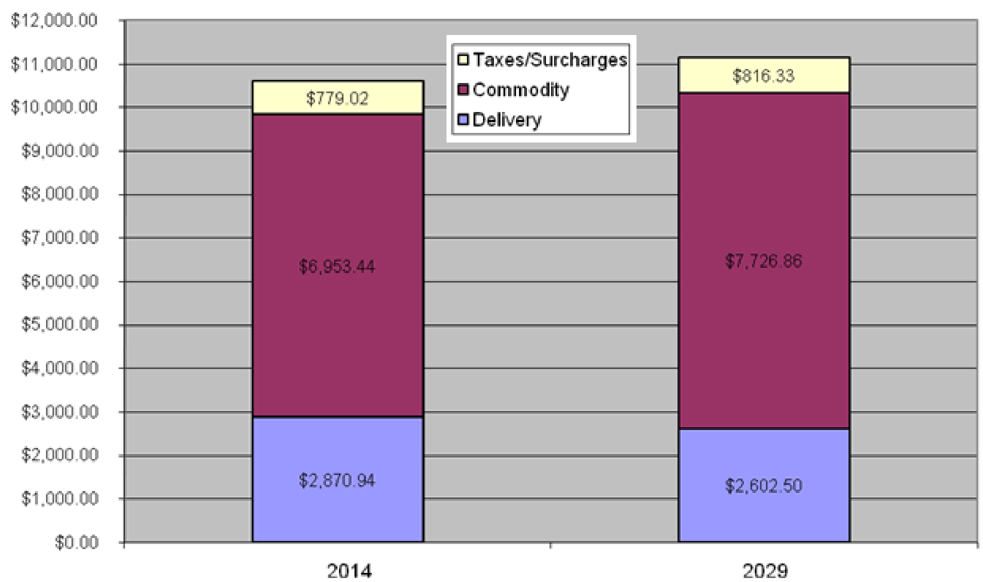


Figure 10-6
Average Large Commercial Bill – SC3 Sec-Real (Base Case)
(250kW; 90,000kWh)



Figures 10-7 – 10-12
Bill Comparisons 2014 to 2029 (Nominal and Real)
Typical Customers by Service Class and Voltage

Figure 10-7
Typical Residential Bill – Nominal (Advanced Grid Case)
(600kWh Monthly Usage)

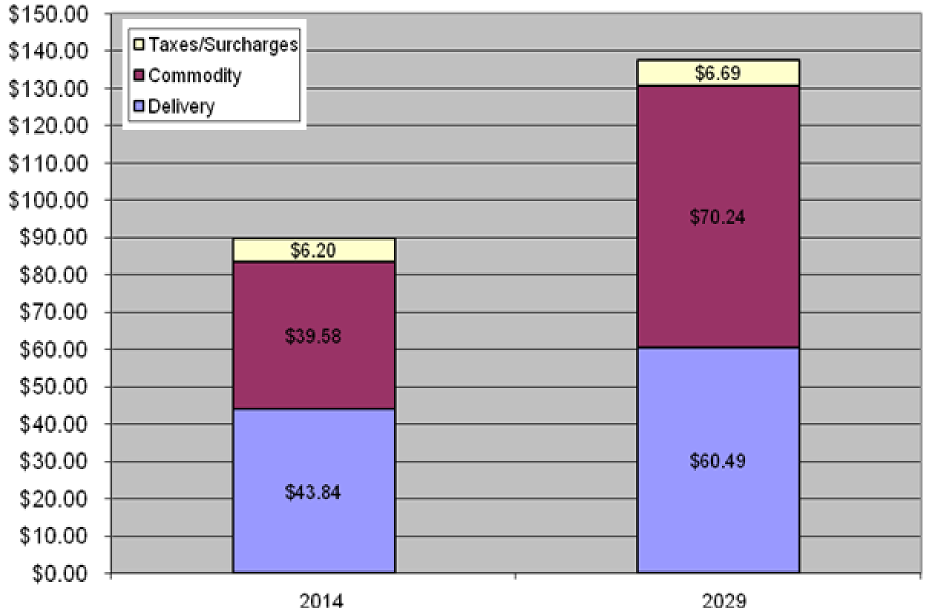


Figure 10-8
Typical Residential Bill – Real (Advanced Grid Case)
(600kWh Monthly Usage)

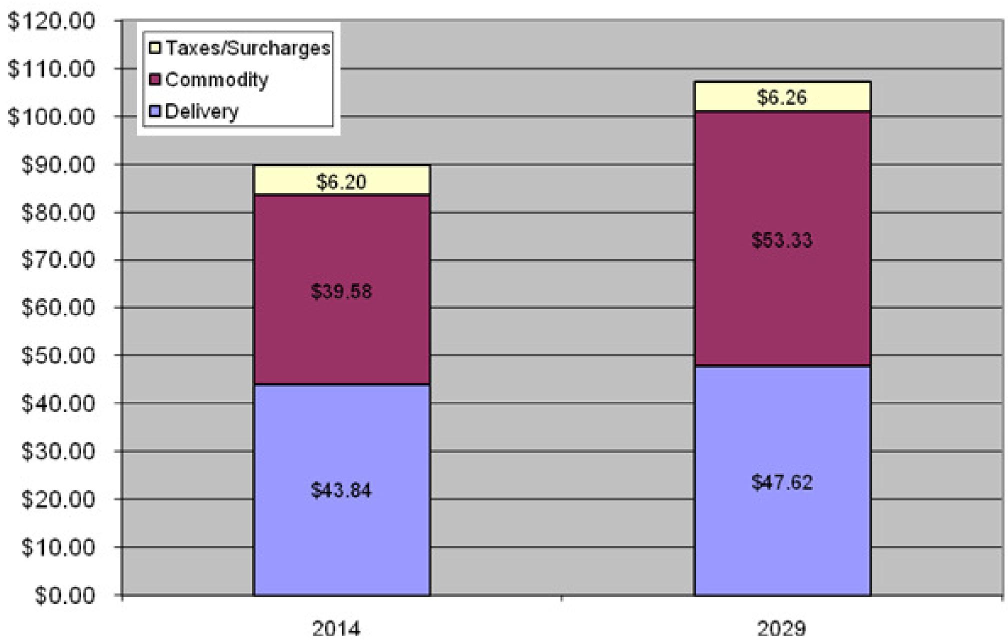


Figure 10-9
Average Small Commercial Bill - SC2D-Nominal (Advanced Grid Case)
(50kW; 14,200kWh)

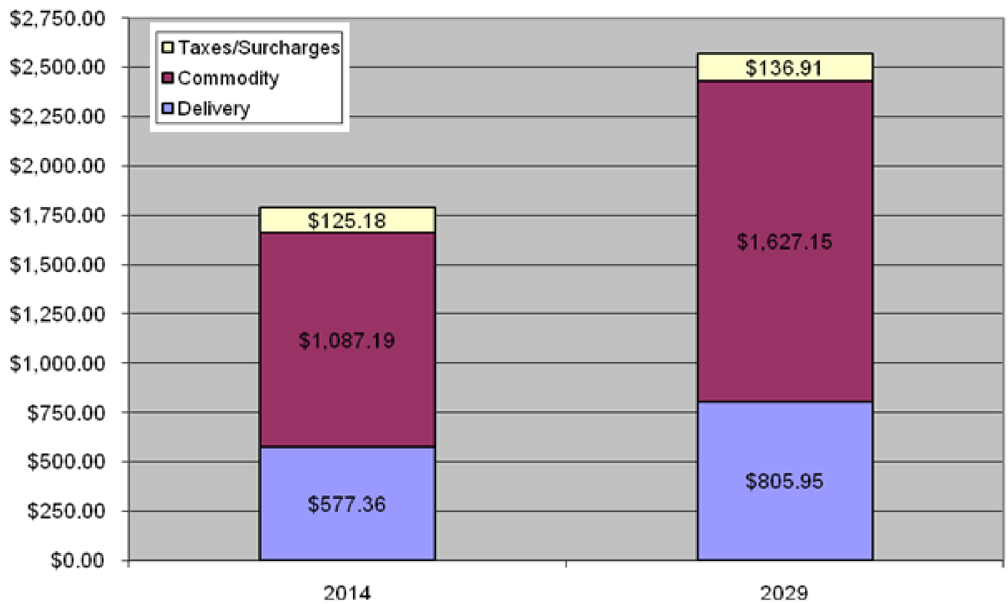


Figure 10-10
Average Small Commercial Bill - SC2D-Real (Advanced Grid Case)
(50kW; 14,200kWh)

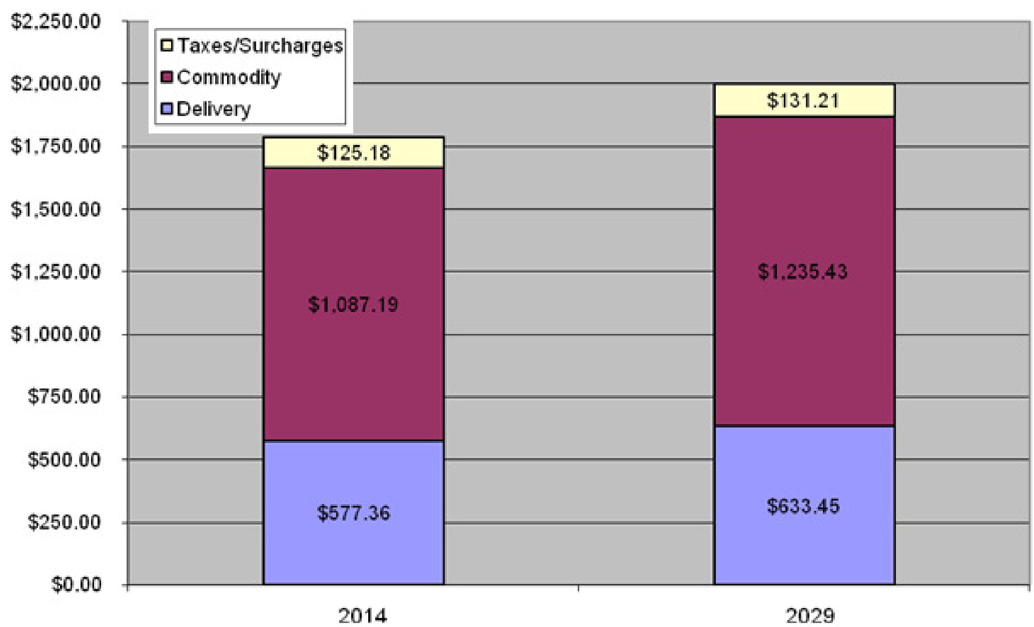


Figure 10-11
Average Large Commercial Bill – SC3 Sec-Nominal (Advanced Grid Case)
(250kW; 90,000kWh)

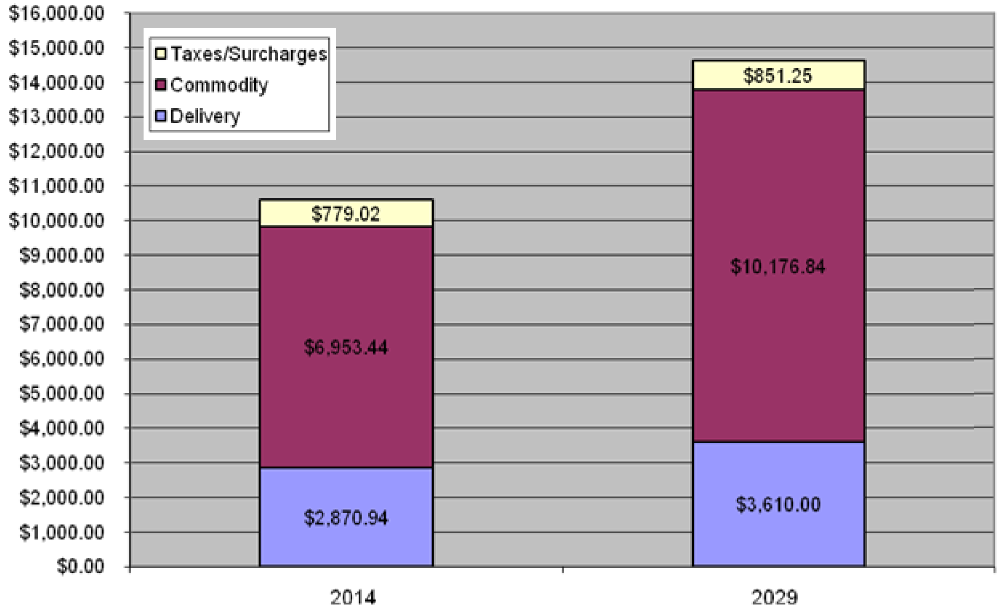
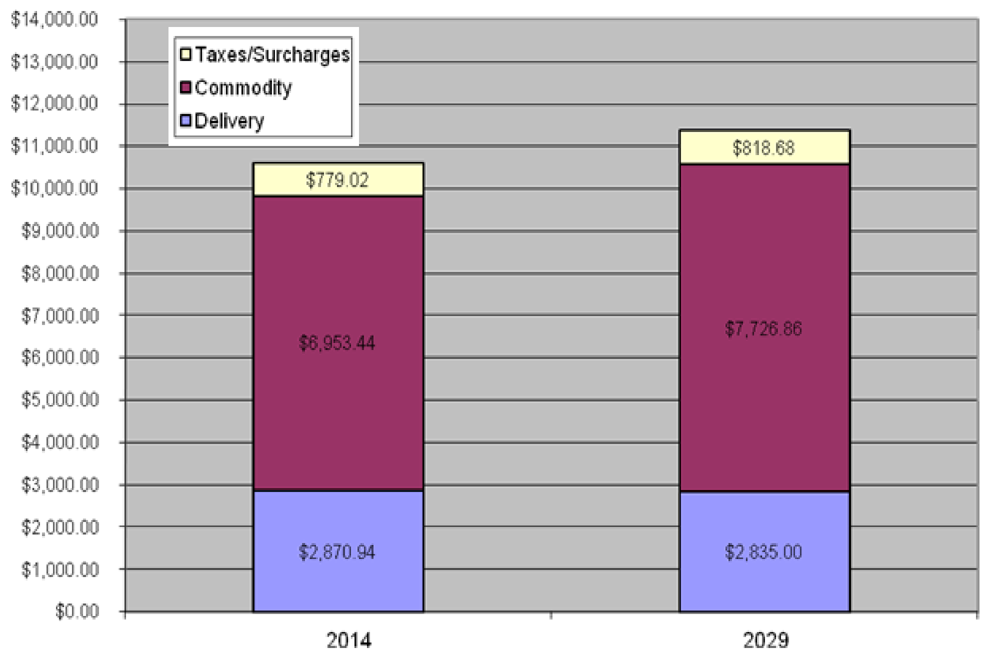


Figure 10-12
Average Large Commercial Bill – SC3 Sec-Real (Advanced Grid Case)
(250kW; 90,000kWh)



Figures 10-13 – 10-18
2029 Bill Comparisons (Nominal and Real)
Typical Customers by Service Class and Voltage

Figure 10-13
2029 Bill Comparison—Base Case vs. Advanced Grid Case
Typical Residential Bill – Nominal
(600kWh Monthly Usage)

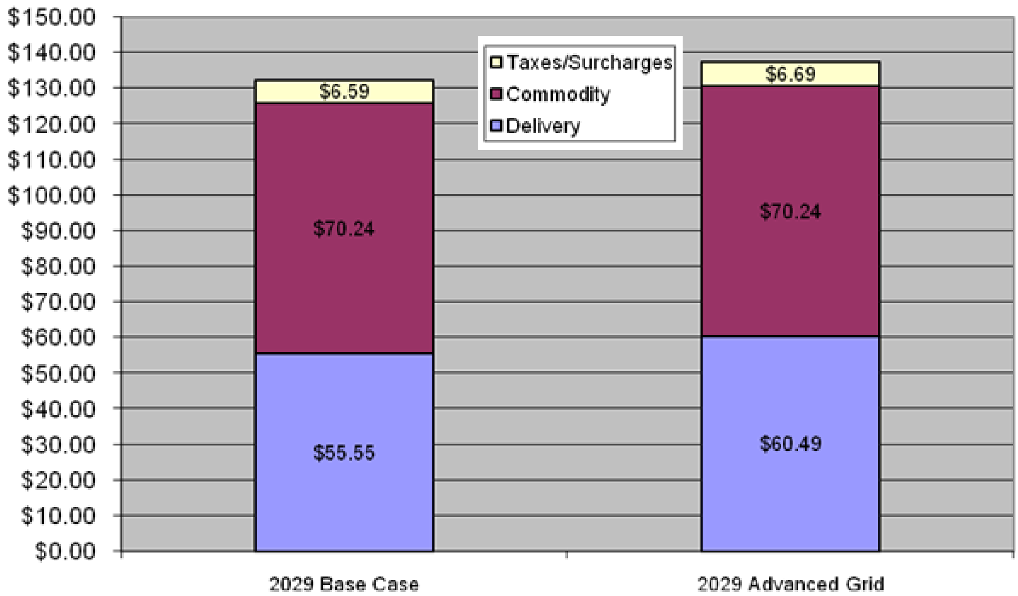


Figure 10-14
2029 Bill Comparison—Base Case vs. Advanced Grid Case
Typical Residential Bill – Real
(600kWh Monthly Usage)

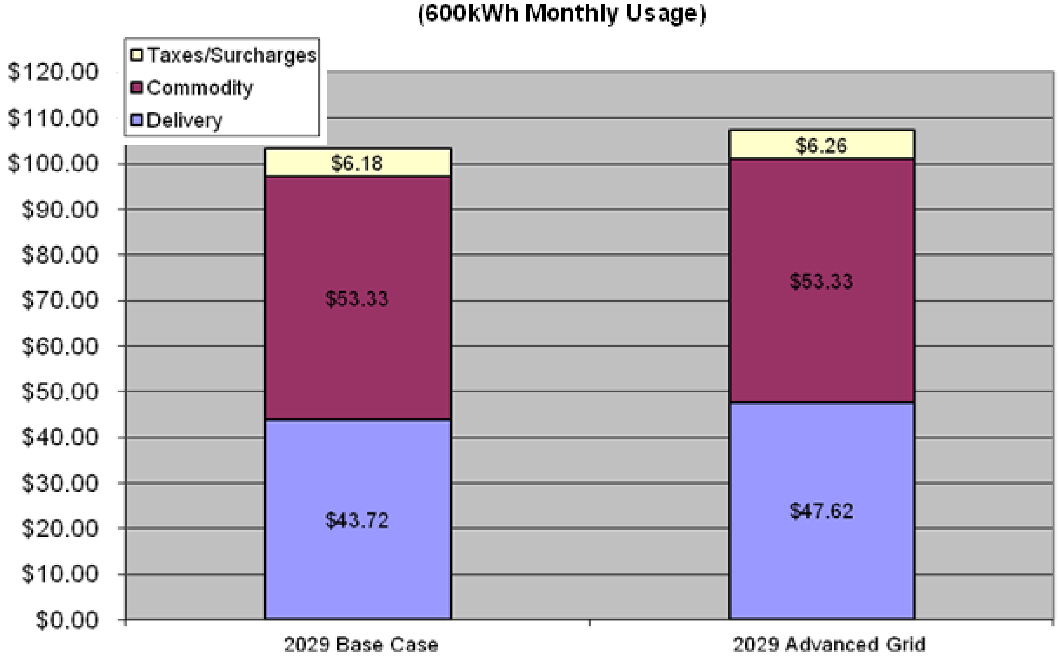


Figure 10-15
2029 Bill Comparison—Base Case vs. Advanced Grid Case
Average Small Commercial Bill - SC2D – Nominal
(50kW; 14,200kWh)

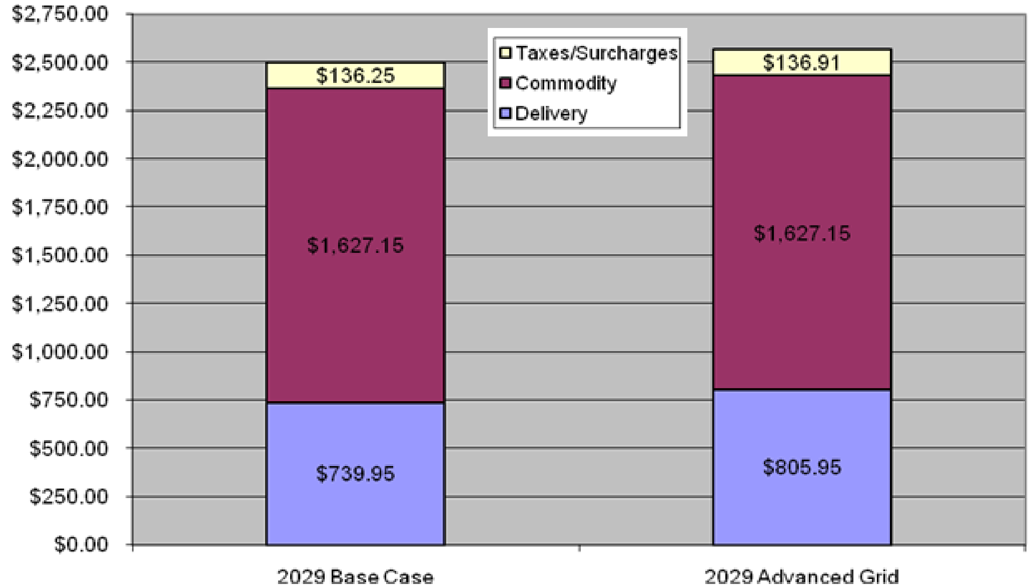


Figure 10-16
2029 Bill Comparison—Base Case vs. Advanced Grid Case
Average Small Commercial Bill - SC2D-Real
(50kW; 14,200kWh)

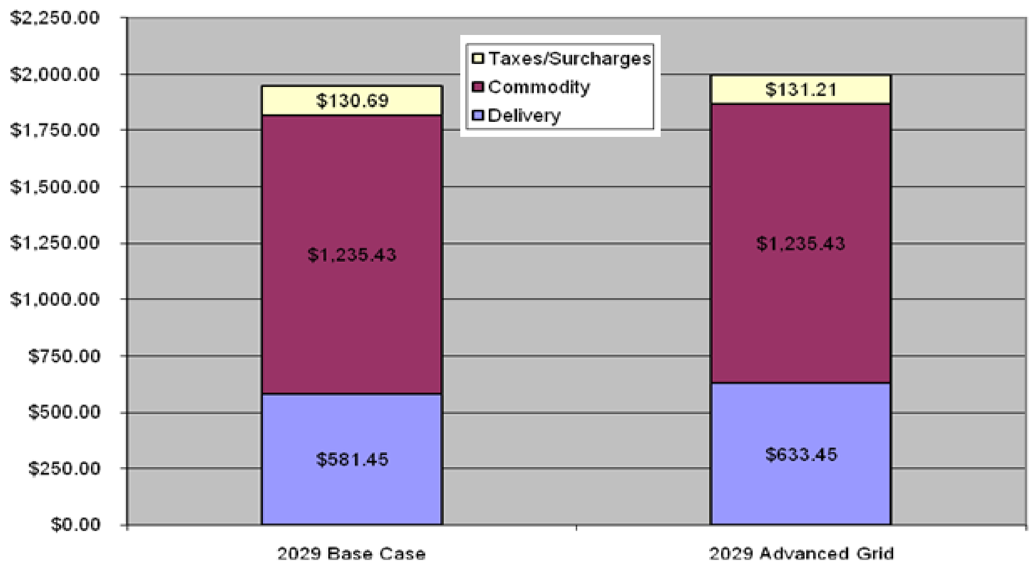


Figure 10-17
2029 Bill Comparison—Base Case vs. Advanced Grid Case
Average Large Commercial Bill – SC3 Sec - Nominal
(250kW; 90,000kWh)

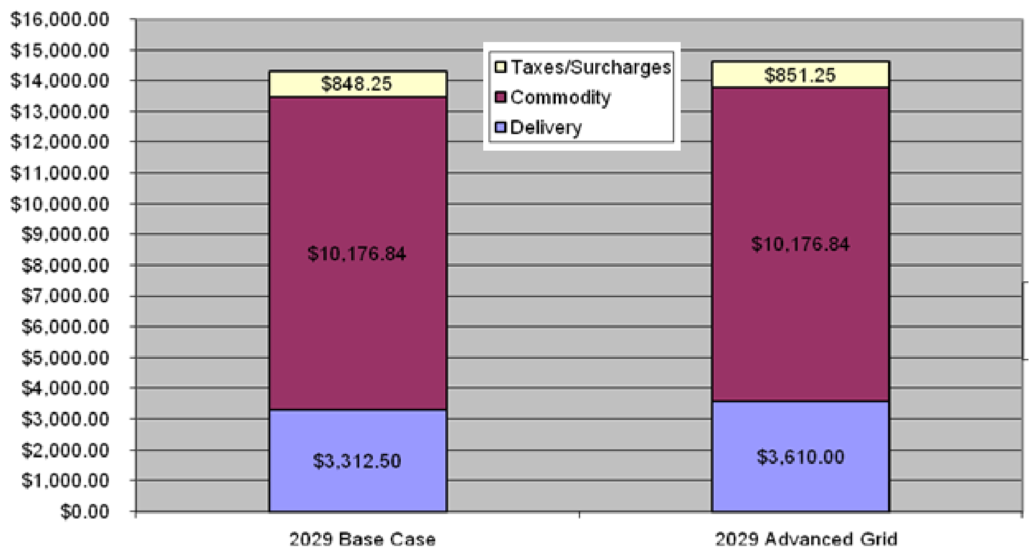
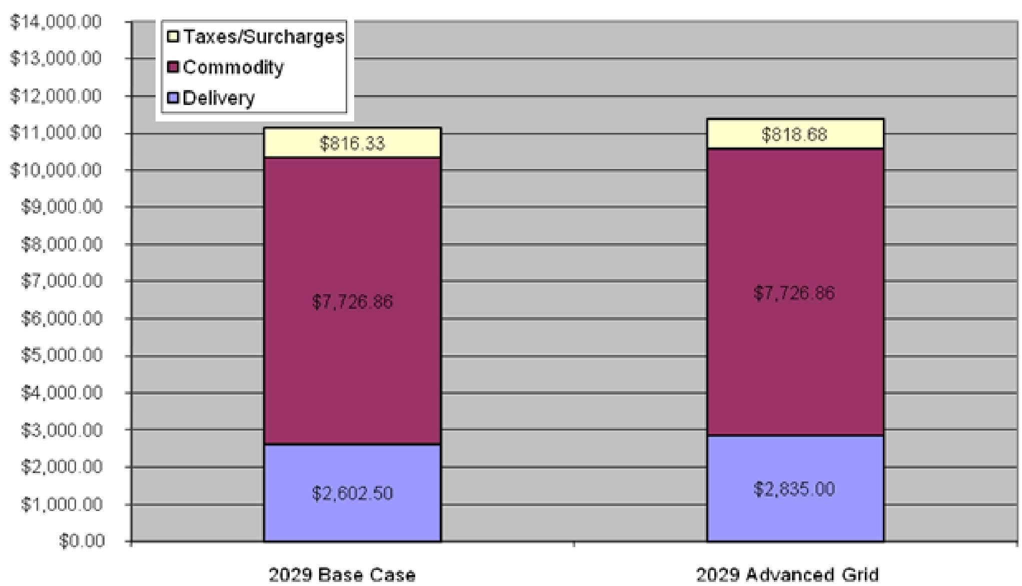


Figure 10-18
2029 Bill Comparison—Base Case vs. Advanced Grid Case
Average Large Commercial Bill – SC3 Sec - Real
(250kW; 90,000kWh)



10. D. Revenue Requirement and Bill Impact Analysis and Comparison Details and Assumptions

Figures 19 - 21

Exhibit B
Figure 19

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Revenue Requirement and Bill Impacts - Base Case
Estimated For the Fiscal Year Ended March 31, 2029

Based on the 15 Year Electric Transmission & Distribution System Plan

($000's)

	Fiscal Year Ending March 31, 2029 Revenue Requirement
Operating Revenues	$4,331,403
Deductions	
Purchased Power Costs	1,790,273
Revenue Taxes	52,402
Total Deductions	1,842,675
Gross Margin	2,488,728
Total Operation & Maintenance Expenses	1,122,039
Amortization of Regulatory Deferrals	0
Depreciation, Amort. & Loss on Disposition	313,286
Taxes Other Than Revenue & Income Taxes	212,042
Total Operating Revenue Deductions	1,647,366
Operating Income Before Income Taxes	841,362
Income Taxes	
Federal Income Taxes	216,827
State Income Taxes	47,010
Total Income Taxes	263,838
Operating Income After Income Taxes	$577,524
Rate Base	$8,884,985
Rate of Return	6.50%
Return On Equity	9.30%

	SC1 Residential (kWh)	SC2D - Small Commercial (kW)	SC3 Secondary (kW)	SC3 Primary (kW)	SC3 Sub/Tran (kW)
Allocation of T&D Delivery Revenue Requirement to Service Class (000)	$1,176,878	$207,356	$155,568	$50,863	$7,095
FY 2029 Delivery Sales Forecast - kWh (000)	12,676,982	4,160,489	4,462,168	2,018,394	582,331
FY 2029 Delivery Sales Forecast - kW (000)		13,948.2	11,659.7	4,651.6	1,496.0
T&D Delivery Rate per kWh/kW	**$0.09284**	**$14.87**	**$13.34**	**$10.93**	**$4.74**
Legacy Transition Charge Rate per kWh	**($0.00025)**	**($0.00025)**	**($0.00025)**	**($0.00025)**	**($0.00025)**

Major Assumptions:
Estimated Net Utility Plant based on high level analysis of 5 year capex included in 1/31/14 CIP filing
Estimated Accumulated Deferred Taxes based on high level analysis of 5 year capex
Depreciation expense estimated based on high level Net Utility Plant analysis
Inflated Operations & Maintenance Expense and Taxes Other than Revenue & Income Taxes by 1.6% per year
Excluded 18A Regulatory Assessment from 2029 Operations & Maintenance expense, due to its discontinuance
Assumed no Regulatory Assets/Liabilities along with no associated amortization expense
Assumed Rate of Return and Return on Equity consistent with FY2014 Rate Year per Commission Order Case 12-E-0201
Allocation of Revenue Requirement to customer classes based on FY2014 Case 12-E-0201 T&D revenue allocation
Purchase power retail rates based on a $.082 per kWh wholesale rate provided by Electric Supply
Legacy Transition Charge rates based on a ($8.2) million below market variable cost forecast provided by Electric Supply
Sales based on sales forecast as described in Chapter 3

Exhibit B
Figure 20

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Revenue Requirement and Bill Impacts - Advanced Grid Case
Estimated For the Fiscal Year Ended March 31, 2029
Based on the 15 Year Electric Transmission & Distribution System Plan and Advanced Grid Capex
($000's)

	Fiscal Year Ending March 31, 2029 Revenue Requirement
Operating Revenues	$ 4,517,552
Deductions	
Purchased Power Costs	1,790,273
Revenue Taxes	54,654
Total Deductions	1,844,927
Gross Margin	2,672,625
Total Operation & Maintenance Expenses	1,128,781
Amortization of Regulatory Deferrals	0
Depreciation, Amort. & Loss on Disposition	339,305
Taxes Other Than Revenue & Income Taxes	234,202
Total Operating Revenue Deductions	1,702,288
Operating Income Before Income Taxes	970,337
Income Taxes	
Federal Income Taxes	249,789
State Income Taxes	54,208
Total Income Taxes	303,997
Operating Income After Income Taxes	$ 666,339
Rate Base	$ 10,251,375
Rate of Return	6.50%
Return On Equity	9.30%
Rate Impacts:	
Total T&D Delivery Revenue	2,672,625
Less Revenues from 18A and SBC	(222,356)
Less Miscellaneous Revenue	(180,105)
T&D Delivery Revenue Subject to Rate Design	2,270,164

	SC1 Residential (kWh)	SC2D - Small Commercial (kW)	SC3 Secondary (kW)	SC3 Primary (kW)	SC3 Sub/Tran (kW)
Allocation of T&D Delivery Revenue Requirement to Service Class (000)	$1,281,302	$225,797	$169,433	$55,407	$7,734
FY 2029 Delivery Sales Forecast - kWh (000)	12,676,982	4,160,489	4,462,168	2,018,394	582,331
FY 2029 Delivery Sales Forecast - kW (000)		13,948.2	11,659.7	4,651.6	1,496.0
T&D Delivery Rate per kWh/kW	**$0.10107**	**$16.19**	**$14.53**	**$11.91**	**$5.17**
Legacy Transition Charge Rate per kWh	**($0.00025)**	**($0.00025)**	**($0.00025)**	**($0.00025)**	**($0.00025)**

Major Assumptions:
Included additional $1.77 billion distribution capex for Advanced Grid Case
Included incremental opex of 7.25% of $1.77 billion distribution capex per three year historic percentage for Advanced Grid Case
Included incremental property taxes of 3% of taxable distribution capex for Advanced Grid Case's capex
Estimated Net Utility Plant based on high level analysis of 5 year capex included in 1/31/14 CIP filing.
Estimated Accumulated Deferred Taxes based on high level analysis of 5 year capex
Depreciation expense estimated based on high level Net Utility Plant analysis
Inflated Operations & Maintenance Expense and Taxes Other than Revenue & Income Taxes by 1.6% per year
Excluded 18A Regulatory Assessment Fees from 2029 Operations & Maintenance expense, due to its discontinuance
Assumed no Regulatory Assets/Liabilities along with no associated amortization expense
Assumed Rate of Return and Return on Equity consistent with FY2014 Rate Year per Commission Order Case 12-E-0201
Sales based on sales forecast as described in Chapter 3
Allocation of Revenue Requirement to customer classes based on FY2014 Case 12-E-0201 T&D revenue allocation
Purchase power retail rates based on a $.082 per kWh wholesale rate provided by Electric Supply
Legacy Transition Charge rates based on a ($8.2) million below market variable cost forecast provided by Electric Supply
Sales based on sales forecast as described in Chapter 3

Figure 21

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Comparison of Base Case and Advanced Grid Case
Estimated For the Fiscal Year Ended March 31, 2029
($000's)

	BASE CASE Fiscal Year Ending March 31, 2029 with Base Revenue Requirement	ADVANCED GRID CASE Fiscal Year Ending March 31, 2029 with Base Revenue Requirement	Difference
Operating Revenues	$ 4,331,403	$ 4,517,552	$ 186,149
Deductions			
Purchased Power Costs	1,790,273	1,790,273	0
Revenue Taxes	$ 52,402	$ 54,654	$ 2,252
Total Deductions	1,842,675	1,844,927	2,252
Gross Margin	2,488,728	2,672,625	183,897
Total Operation & Maintenance Expenses	1,122,039	1,128,781	6,743
Amortization of Regulatory Deferrals (assume fully amortized)	0	0	0
Depreciation, Amort. & Loss on Disposition (per Plant detail)	313,286	339,305	26,019
Taxes Other Than Revenue & Income Taxes	212,042	234,202	22,160
Total Operating Revenue Deductions	1,647,366	1,702,288	54,922
Operating Income Before Income Taxes	841,362	970,337	128,975
Income Taxes			
Federal Income Taxes	$ 216,827	$ 249,789	$ 32,962
State Income Taxes	$ 47,010	$ 54,208	$ 7,198
Total Income Taxes	263,838	303,997	40,160
Operating Income After Income Taxes	$ 577,524	$ 666,339	$ 88,815
Rate Base (per Plant & other Ratebase detail)	$ 8,884,985	$ 10,251,375	$ 1,366,390
Rate of Return (consistent with FY 2014 RY)	6.50%	6.50%	0.00%
Return On Equity (assumed consistent with Case 12-E-0201)	9.30%	9.30%	0.00%

Major Difference in Assumptions:
Advanced Grid Case includes additional $1.77 billion distribution capex
Advanced Grid Case includes incremental opex of 7.25% of $1.77 billion distribution capex, per three year historic opex percentage
Advanced Grid Case includes incremental property taxes of 3% of taxable distribution capex

Total Bill Impacts by Service Classification

	2014	Base Case	Advanced Grid Case	Advanced Grid Case vs. Base Case	
SC1					
Nominal	$89.62	$132.38	$137.42	$5.04	Increase in Total Monthly Bill
Real	$89.62	$103.23	$107.21	$3.98	Increase in Total Monthly Bill
SC2D					
Nominal	$1,789.73	$2,503.35	$2,570.01	$66.66	Increase in Total Monthly Bill
Real	$1,789.73	$1,947.57	$2,000.09	$52.52	Increase in Total Monthly Bill
SC3 Sec					
Nominal	$10,603.40	$14,337.59	$14,638.09	$300.50	Increase in Total Monthly Bill
Real	$10,603.40	$11,145.69	$11,380.54	$234.85	Increase in Total Monthly Bill