AMPARO NIETO
VICE PRESIDENT

Amparo Nieto is an economist based in NERA's Los Angeles office, where she specializes in the regulation of the energy industry. Since 1995, Ms. Nieto has assisted a large number of utilities and regulatory commissions in the US and around the world on electricity regulatory policy analysis; improvement of electricity rates; marginal cost studies; evaluation of net metering and distributed generation rates; development of demand response programs for energy conservation; feed-in tariffs to support investment in renewable resources; auctions for electricity standard offer service; generation capacity markets; and transmission cost allocation policies.

In addition to her many clients in the US, she has assisted utilities and energy regulatory commissions in Canada, Spain, Ireland, Italy, Australia, New Zealand, Argentina, Mexico, Brazil, Barbados, and Kenya. Ms. Nieto is currently the Director of the Marginal Cost Working Group (MCWG), a forum for electric utilities from in the US and Canada that focuses on addressing new challenges from ongoing regulatory reforms and environmental policies, including impact of distributed generation solar on retail pricing, renewables procurement decisions and cost of service studies. She annually conducts workshops on electricity marginal cost estimation methods and optimal tariff design. She has been published in *The Electricity Journal* and the Centre for the Study of Regulated Industries (CRI).

Education

Fiscal Studies Institute, Madrid, Spain
M.A. on Public Finance and Economics (Honors), 1996

Carlos III University, Madrid, Spain
B.A., Economics, 1994

Professional Experience

2000 – present	**NERA Economic Consulting**, Los Angeles, USA
	Vice President (current title)
1995 – 1999:	**NERA Economic Consulting,** Madrid, Spain
	Consultant/ Senior Analyst

Project Experience

Tariff Design and Cost of Service Advisory Service

Rochester Gas & Electric Corp. and New York Gas & Electric Corp. (NYSEG), USA. (subsidiaries of Iberdrola USA). Updated the Companies' electricity and natural gas marginal cost studies and advice on the design of rates for electric vehicles and distributed generation rates; expert testimony for their rate case filings.

Newfoundland Labrador and Hydro, Canada. Advice on the methodology to assess marginal cost of electricity generation and transmission given the recent generation expansion, changes in contractual arrangements and transmission interconnections to other regions.

Sunrun, Inc. CA, USA. Evaluate the trend of residential electricity volumetric rates across a number of regions in the US, based on on-going regulatory initiatives, including net metering proceedings. Evaluate expected procurement costs, investment plans, and distributed generation potential in each case.

Salt River Project, Arizona. USA. Review and assessment of SRP's proposed residential rate design for new customers under net metering. Discuss whether the new rate would appropriately recover SRP's fixed costs from customers who choose to generate their own electricity with solar rooftop panels, and provide support as needed throughout the price process. In an earlier assignment, reviewed the utility's marginal cost of service study and recommended revisions to standard distributed generation rates.

Otter Tail Power (OTP), MN, ND, SD. Directed an analysis of OTP's interruptible rate portfolio and avoided costs associated with its residential and commercial direct load control programs, for water heating, space heating and air conditioning, and industrial interruptible rates, based on expected demand and energy impacts. Analyzed expected generation, transmission and distribution avoided costs for the utility for each type of rate under different weather and control scenarios over a 15 year timeframe and compared with expected program implementation costs. Recommended improvements, based on the results of the analysis, to the existing interruptible rate structures and programs with a view to maximize the value of OTP's demand response resources going forward. The report included guidance on setting dynamic rates, such as critical peak pricing and real time pricing for large commercial customers.

Manitoba Hydro, Manitoba, Canada. Provided training to the utility staff on methods to estimate marginal costs in the context of rate design. In an earlier assignment, advised Manitoba Hydro on electricity tariff reform to introduce Time-Of-Use rates and inverted- block rates in Manitoba. Analyzed marginal energy costs by time-of-day periods; developed the welfare and cost-benefit models that took into account a range of price elasticity by class and the potential load shifting due to new TOU rate structures and the impact on net welfare. Co-authored the study report for submission to the Manitoba Public Utility Board.

Con Edison, New York. Developed ten-year projections of avoided cost estimates of electricity transmission and distribution for use in the context of the Company's demand-side management and energy efficiency programs. Authored a report with findings and summarized by sub-region.

Otter Tail Power Company, Fergus Falls, MN, US. Provided support to the utility in the development of more efficient class revenue requirements for their electricity rates in Minnesota, taking marginal costs into account.

New Brunswick Power, New Brunswick, Canada. Recommended and developed a mechanism to charge customers who choose to opt-out of smart metering based on the incremental costs to the utility.

NV Energy, Nevada. Supported NV Energy in the review of their marginal cost methods and recommended improvements in the context of the merging of Sierra Pacific and Nevada Power's transmission systems; provided support during implementation phase.

For the Abu Dhabi Regulation and Supervision Bureau, Abu Dhabi, advised on the proper method to allocate costs of generation, transmission and distribution efficiently and equitably to electricity customer classes, and recommended an efficient structure for distribution use of system charges and connection policy.

Barbados Federal Trade Commission. Advised the Barbados energy regulatory commission during their audit of Barbados Power and Light's rate application. Wrote a report with assessment of the key aspects of the determination of utility revenue requirement, computation of embedded and marginal electricity cost studies, class cross-subsidy policy and optional time-of-use rates, and restructuring of the Barbados Light & Power Company rates.

BC Hydro, British Columbia, Canada. Directed the review of the methodology for setting BC Hydro Reactive Power Service and Voltage Control Rates.

BC Hydro, Canada. Developed marginal cost estimates of generation, transmission and distribution to support BC Hydro's upcoming rate case.

CPI USA North Carolina LLC, North Carolina, US. Ms Nieto filed an Affidavit with the North Carolina Utilities Commission in the context of establishing the pricing terms of a long-term power purchase agreement between two CPI USA's qualifying facilities and Progress Energy Carolinas, Inc. Her testimony included an assessment of CPI USA's methodology to estimate the avoided energy and capacity costs associated with the dispatch of the qualifying facilities.

Otter Tail Power Company, Fergus Falls, MN. Prepared a report on the appropriateness of phasing out declining block rates; updated the marginal cost study for generation, transmission and distribution service; and recommended marginal cost-based TOU tariffs for major customer classes based on the results of the cost study. Supported rate design and testimony.

Newfoundland Power, Newfoundland, Canada. Managed the team developing a generation and transmission marginal cost of service study, which included projections for 2007-2025 for use in Demand-Side-Management efforts.

Tennessee Valley Authority (TVA), TN, US. Conducted a generation and transmission marginal cost of service study for TVA to be used for rates and to evaluate demand response programs.

Newfoundland Labrador & Hydro, Newfoundland, Canada. Participated in a study of the marginal cost of generation and transmission for the vertically-integrated utility in Newfoundland, for use in development of Time-of-Use rates.

Fair Trading Commission (FTC), Barbados. Reviewed Barbados Light & Power Company's embedded cost of service study and conducted a marginal electricity cost study.

Saudi Electricity Company, Saudi Arabia. Assisted Saudi utility on a reasonable approach to develop standby and buyback rates for cogeneration facilities.

Hawaiian Electric Company, Hawaii. US. Advised the utility on improvements to their Power Cost Adjustment, options to hedge fuel price risks and electricity rate smoothing mechanisms to moderate the impact of sudden fuel price changes.

Midwestern Utility. Advised on the design of wholesale rates for back-up and supplemental energy service provided by the utility to generators connected to its network, such as wind farms and co-generators.

New Brunswick Public Intervenor, New Brunswick, Canada. Provided joint testimony before the New Brunswick Board of Commissioners of Public Utilities, on the role of DSM and demand response mechanisms in the resource planning process and load forecasts. The testimony assessed whether NB Power sufficiently integrates DSM and DR into its long-term load forecast.

Xcel Energy, Minnesota, US. Headed the marginal costing work involving development of generation, transmission, distribution, and retailing cost estimates for Northern States Power Company (a subsidiary of Xcel Energy) in Minnesota.

Commission for Energy Regulation, Ireland. Advised the regulatory commission in Ireland on the review of their electricity tariff structures. Evaluated the existing locational tariffs for generators and transmission access tariffs for distributors, including charges for connection to the system. Developed marginal cost estimates for transmission, provided recommendations on efficient tariff structures and connection policy. Trained the Commission staff on tariff screening models.

Nicor Gas, Naperville, IL. Modeled the marginal costs of natural gas transmission and distribution service for Nicor Gas, and advised the utility on methods for setting efficient gas delivery rates and class-revenue requirements.

Manitoba Hydro, Winnipeg, Manitoba. Advised Manitoba Hydro on embedded-cost methods for classification and allocation of generation and transmission costs that take into account the utility's opportunity costs. Recommendations were based on the particular physical and operational characteristics of the Manitoba Hydro system and its significant export trading activity.

Electricity Regulatory Board (ERB), Kenya, Africa. Co-authored an Electricity Tariff Policy for ERB, aimed to ensure the financial health of the sector and promote the efficient provision and expansion of electricity service; developed financial models for use in calculation of utility revenue requirement; provided on-site training to the ERB staff on regulatory analysis.

Kenya Electricity Generating Company (KenGen), Kenya, Africa. Responsible for designing a new sample Power Purchase Agreement between the incumbent generator (KenGen) and the distribution utility (KPLC).

Elektro, Brazil. Provided on-site training on computation of revenue requirement for an electricity distribution company in Brazil. PArticipated in setting up revenue requirement and financial models, identifying the data necessary for the simulation, and training the company's staff on the suitable method to estimate the different components of the revenue requirement.

Transmission Pricing

Australian Energy Market Commission (AEMC), Sydney, Australia. Directed the review of AEMC's firm transmission access policy proposal; reviewed the US experience with Financial Transmission Rights (FTRs) and recommended changes to AEMC's proposed approach.

Grid Australia, Sidney: Authored a report for Grid Australia (the body representing the electricity transmission network owners in Australia) analyzing procurement methods for transmission investment, and use of a competitive solicitation process by Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) in the US, as a result of FERC's Order 1000.

Alberta Electric System Operator (AESO), Calgary, Alberta. Analyzed AESO's cost study and transmission cost recovery methods. Delivered presentation with findings and discussed methods to improve cost allocation.

Mighty River Power Ltd., New Zealand. Assisted Mighty River Power Ltd. in preparing comments to the New Zealand Electricity Regulatory Commission's 2005 Consultation Report on Transmission Alternatives. Contributor to a report discussing mechanisms to provide transmission investment incentives and the potential negative efficiency implications of adopting the procurement options suggested by the Commission.

Australian Energy Market Commission (AEMC), Sydney, Australia. Report advising the regulatory commission on transmission pricing and revenue requirement provisions under the Australian national electricity rules.

Commission for Energy Regulation, Ireland. Advised the regulatory commission in Ireland on the review of their existing transmission cost allocation policy between generators and load, incentives for generators through locational tariffs and efficient connection policies.

Renewable Resources

Illinois Power Agency (IPA), US. Conducted a benchmarking analysis of Solar Renewable Energy Credits (SRECs) and prepared a five-year forecast of SREC values given expected energy and capacity revenues and the economics of a new solar photovoltaic ("PV") generating facility. The solar benchmark would be applied to qualified solar PV bids received for the procurement of SREC by Ameren Illinois Company and Commonwealth Edison Company via a competitive auction.

Iberdrola US, California. Reviewed forecasts of fuel costs, energy market conditions, and regulatory policy to assess the outlook of growth of wind and solar resources in California over a 20 year horizon.

Southern California Edison, Los Angeles, California. Provided support to SCE's Supply Group regarding improvements in the procurement mechanism for new renewable generation resources.

Grid Australia. Contributed to a report for Grid Australia with recommendations on the design of a regulatory process for coordinating transmission network expansion to accommodate renewable generation.

Hawaiian Electric Company, USA: Provided advice on technical, transmission and distribution tariff design, and regulatory issues related to wheeling of renewable power generated by governmental agencies.

Regulatory Office for Network Industries (RONI), Slovakia. Directed the NERA team that assisted the Slovakian regulatory commission on the design of efficient support mechanisms for renewable energy sources (RES) and a reliable system of issuing guarantees of origin for RES. Trained the commission staff on best practice RES regulation.

Wholesale Market Design and Energy Contract Advisory Service

Secretary of Energy, Mexico. Currently providing advice to develop rules for wholesale energy, and ancillary services market, as well as the design of a generation capacity market in Mexico upon restructuring of the system. Additionally, providing advice on market power mitigation rules. Participating in working groups to develop manuals and procedures.

American Electric Power (AEP), Ohio, US. Design of competitive auction rules to procure default service supply for residential and commercial customers that do not switch to a competitive supplier. Design of parameters to determine that the auction is conducted in a way that is fair and competitive.

NYISO, New York, US. Provided recommendations to the New York Independent System Operator for a reform of their Black Start service compensation mechanism.

PECO Energy Company, Pennsylvania. Coordinated the Independent Evaluator team that administers the Default Service Supply solicitations on behalf of PECO Energy Company. The auctions procure standard offer full-requirements power for Default Service residential, commercial and industrial customers.

First Energy. Philadelphia, US. Manager of the NERA team in charge of administering the Default Service Supply solicitations via a descending-clock auction on behalf of Met-Ed and Penelec utilities in Pennsylvania. The auctions procure standard offer full-requirements power for Default Service residential, commercial and industrial customers.

MidAmerican Energy Company, Iowa. Directed a comprehensive audit of MidAmerican Energy Unregulated Retail Group regarding its compliance as a competitive electricity retailer with the regional wholesale market rules in ERCOT, MISO and PJM. The team conducted on-site interviews with regulatory and operations department personnel, and reviewed billing information, energy and capacity transactions in MISO, PJM and ERCOT, load and network resource forecasts, regulatory filings and operational records and procedures corresponding to the audit period. NERA reviewed and evaluated the company's load forecasting and bidding procedures, and provided recommendations to improve their effectiveness, minimize load forecast errors and their exposure to real time market prices. We also discussed the expected market developments in the various RTOs that could affect MidAmerican's compliance and strategies going forward.

Independent System Operator (ISO) of New England, US. Assisted the ISO in making revisions to its Forward Capacity Market (FCM) and in particular, the *Alternative Capacity Price Rule*, and analyzed the potential impact of the revisions on generators' bidding strategies.

PPL Electric Utilities Corporation, Pennsylvania, US. Advised PPL on and evaluated bids for the procurement of Demand Response and Energy Efficiency products.

Spanish National Energy Commission (CNE), Madrid, Spain. Administered the default service electricity supply ("CESUR") auctions on behalf of the large distribution companies in Spain and Portugal. Assessed the bidders' competitive behavior during the auctions and prepared an assessment report for the Commission.

California Electricity Market Review. Analysis of the California wholesale energy market for a private equity firm.

Southern Minnesota Municipal Power Agency. Wrote a report on the factors affecting the decisions of building new capacity versus long-term contracting as part of a utility's Integrated Resource Planning.

Commission for Energy Regulation (CER), Ireland. Advised the CER on the design of a generation capacity payment mechanism for the new Irish Single Electricity Market (SEM), and the development of a regulatory mechanism to address market power mitigation.

Dresdner Kleinwort Wasserstein, London, UK. Analyzed the California electricity wholesale market, including an analysis of the existing CAISO-operated energy and ancillary service markets, the CAISO congestion management process, reliability problems of the transmission system and transmission access pricing, and the expected market policy and regulatory changes.

Endesa, Rome, Italy. Assisted Endesa-Italia to develop several potential capacity payment schemes for Italy. Wrote a report on the remuneration method for electricity generators in Chile, including a description on how capacity payments are calculated for pumping and hydro plants, and a discussion of the problems and criticism of the mechanism to date.

Iberdrola, Spain. Advice on the restructuring of the Spanish electricity sector and the design of an electricity wholesale spot market. Adviced on the drafting of Royal Decrees and regulations following the 1997 restructuring Electricity Law; provided seminars on wholesale energy trading and adviced on commercial strategy and contract design; recommended marginal cost-based electricity tariffs and trained utility staff on marginal costing and tariff design.

Ministry of Economy, Works and Public Services in Argentina, Argentina. Analysis of the wholesale market rules in Argentina, with the aim of identifying the key reforms required for efficiency of the market. Suggested changes to the rules governing the electricity contract market between generators, distributors, and large users in order to encourage competition in the retail market; and analyzed pass-through mechanisms of generation costs to the retail tariffs.

Comisión Del Sistema Eléctrico Nacional, Spain. Advised the Spanish electricity regulatory commission on the development of regulations in the light of the new Spanish electricity sector Law (LOSEN), aimed to improve efficiency in the sector through the introduction of competition.

Expert Testimony

Before the New York State Public Service Commission, Testimony on the electricity and natural gas marginal cost of service studies conducted for Rochester Gas & Electric Corporation (RG&E) (*Forthcoming*).

Before the New York State Public Service Commission, Testimony on the electricity and natural gas marginal cost of service studies conducted for New York State Electric and Gas (NYSEG) (*Forthcoming*).

Before The State Of North Carolina Utilities Commission, Testimony: "*Review of Alternative Application of the Peaker Method Proposed by EPCOR USA North Carolina LLC with respect to Computation of Avoided Energy and Capacity Costs*". July 23, 2010.

Before the New Brunswick Board of Commissioners of Public Utilities, Joint Rebuttal Testimony on behalf of New Brunswick Public Intervenor. On the role of DSM and demand response programs in load forecasting and integrated resource planning. (with Wayne P. Olson). November 9, 2006.

Speeches

"Solar Distributed Generation and Residential Rate Restructuring". Presented at the California Municipal Rates Group (CMRG) meeting in Sacramento, California, May 18, 2015.

"Integrating Renewable Resources through Capacity Markets: The Case of California". Presented at *Law Seminars International*, *Energy in California Conference*, San Francisco, California. September 16, 2014.

"Capacity Markets Put to the Test: New Approaches to Meet Evolving Reliability Needs". Presented at the 27th Annual Western Conference of CRRI at Rutgers University. June 26, 2014.

"Rate Design Options to Deal with Solar Net Metering Concerns". Presented at the California Municipal Rates Group (CMRG) meeting in Sacramento, California, April 25, 2014.

"Connecting Wholesale and Retail Pricing: A Look at Required Policy and Market Design Decisions". Presented at the *Harvard Electricity Policy Group (HEPG)* in Dana Point, California, March 7, 2013.

"Making Sense of Demand Response and its Role within Wholesale Energy and Capacity Markets." Presented at the 25th Annual Western Conference organized by the Center for Research in Regulated Industries (CRRI) at Rutgers University. Monterrey, California, June 2012.

"Achieving Efficient Demand Response through Dynamic Rates", Law Seminars International Conference. Las Vegas, Nevada, Feb 9, 2009.

"Probability of Peak Analysis for TOU Rate Design", presented at the Marginal Cost Working Group in Boston, MA, Oct 8, 2008.

"Critical Peak Pricing: A Marginal Cost Approach", presented at the Marginal Cost Working Group in Phoenix, Arizona, April 2008.

"Electricity Rate Structure Design: Sector Issues in Rate Design, Marginal and Embedded Cost Studies"; a lecture delivered at the University of PURC as part of the World Bank International Training Program on Utility Regulation and Strategy, Florida, January 16, 2007.

"Demand Bidding Programs in ISO/RTO Environments", presented at the Marginal Cost Working Group (MCWG), Austin, Texas. October 12, 2006

"Locational Generation Capacity Payments in New England," paper presented to the Marginal Cost Working Group (MCWG). Albuquerque, New Mexico, April 27, 2005.

Publications

"Wholesale Energy Markets: Setting the Right Framework for Price Responsive Demand". *The Electricity Journal*, December 2012.

"The Role of Demand Response in the Efficiency of Electricity Wholesale Markets". *Papeles de Economía Española*, Madrid. Issue 134, December 2012.

"Locational Electricity Capacity Markets: Alternatives to Restore the Missing Signals". *The Electricity Journal*. Volume 20, March 2007.

Co-author of NERA Energy monograph "The Line in the Sand: The Shifting Boundary between Markets and Regulation in Network Industries." September 2007.

"Responding to EPAct 2005: Looking at Smart Meters for Electricity, Time-Based Rate Structures, and Net Metering". (With Kenneth Gordon and Wayne Olson). Edison Electric Institute, May 2006.

"Performance-Based Regulation of Electricity Transmission in the US: Goals and Necessary Reforms". *Energy Regulation Insights* (NERA newsletter publication), Issue 28, March 2006.

"The Electricity Sector in Spain." Utility Regulation in the EU. Privatisation International and Centre for the Study of Regulated Industries (CRI). *Utility Regulation 2000 series*, Volume 1. June 2000.

“Effects of the Removal of the Subsidies to the National Coal Industry on Electricity Tariffs, Sector Income and Social Welfare in Spain.” Masters Thesis. Institute of Fiscal Studies of Madrid, Spain, Dec. 1995.

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NYSEG
Marginal Cost of Electric Delivery Service

Prepared for Iberdrola USA

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I. INTRODUCTION

Iberdrola USA retained NERA Economic Consulting (NERA) to update the Marginal Cost of Electric Delivery Service Study (MCOSS), previously developed by NERA on behalf of New York State Electric & Gas Corporation (NYSEG) in February 2010. The key underlying assumptions of the former study (the "2010 Report") are still applicable. This report summarizes the approach followed to estimate the marginal cost for each element of service, including marginal transmission, distribution and customer-related costs, and presents a summary of the results. To conduct the MCOSS update, NERA relied on the most up to date investment plans, the most recent Operation and Maintenance expenses, expected incremental capital structure and updates to other relevant input data. NERA applied updated escalation factors[1] to some of the elements of the 2010 Report. We reassessed the allocation of customer accounts and expenses to each customer class by relying on the Company's 2013 embedded cost study. All costs are expressed in 2016 dollars.

What are marginal costs? Marginal cost is defined as the change in total cost with respect to a small change in output. To quantify the marginal costs of electricity service one must answer the question: What are the additional costs that would be incurred with changes in kilowatt-hours of energy, kilowatts of demand and number of customers?

Our method for estimating marginal costs is based on the system planning process, and takes into account the wholesale market and transmission access arrangements specific to the environment where the utility operates. We determine the marginal cost of electricity by examining the utility's planning processes to determine what drives new investment and operating decisions and how changes in consumption affect utility system operations. The method is not a formula, but a series of guidelines outlining what should be measured and how the measurements can be made. Because some of the cost of additional consumption differs depending upon the time of the change in output, it is important to estimate time-differentiated marginal costs of electricity delivery. In this study we developed time-differentiated marginal cost estimates for loss-adjusted NYISO transmission charges as applicable to NYSEG, upstream distribution equipment and distribution substations and trunkline feeders.

[1] We applied the average forecasted growth in GDP Chained Price Index through 2016 as reported by Blue Chip Economic Indicators in June 2016, or in some cases, a weighted labor & cost index.

II. COSTING/PRICING PERIODS

The summary tables in Section VIII show time-differentiated cost components aggregated by NYSEG's current time-of-day pricing periods and seasonal periods in SC12, shown in Table 1.

Table 1. Costing/Pricing Periods

Residential TOU (SC 12)		
Winter (Dec-Feb)	On-Peak:	7 – 10 am; 5-10 pm, Mon. – Fri., EST
	Mid-Peak:	10 am – 5 pm and 10 pm to 11:30 pm, Mon. – Fri.; and 7 am – 11:30 pm Sat., Sun. and Holidays,[2] EST
	Off-Peak:	11:30 pm – 7 am, EST
Summer (Jun-Aug)	On-Peak:	10 am – 6 pm, Mon. – Fri., EST
	Mid-Peak:	7 – 10 am and 6 – 11:30 pm, Mon. – Fri.; 7 am – 11:30 pm, Sat., Sun., and Holidays[3,] EST
	Off-Peak:	11:30 pm – 7 am, EST
Off-Season: (Mar – May and Sep – Nov)	Peak:	NA
	Mid-Peak:	7 am – 11:30 pm, EST
	Off-Peak:	11:30 pm – 7 am, EST
Large General Service TOU (SC 7)		
	On-Peak:	Mon. – Fri., 7 am to 10 pm, local time, except Holidays[3]
	Off-Peak:	All remaining hours
General Service and Residential Day-Night (SC 8,9)		
	Day:	7 am – 11:30 pm EST
	Night:	All remaining hours

[2] Holidays are New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas.

III. MARGINAL TRANSMISSION COST

As a Transmission Owner subject to the rules of the New York Independent System Operator (NYISO), NYSEG's transmission revenue requirement is the basis for the Company's Transmission Service Charge (TSC). NYSEG's transmission facilities consist of transmission lines of various voltage levels, and transmission substations. Lines of a particular voltage level can function either as transmission or distribution. The determination of what is considered a transmission facility is governed by FERC rules. Certain facilities upstream of distribution substations, not meeting the FERC definition as transmission facilities, are referred to as "upstream distribution facilities" in this study.

Users of NYSEG's transmission system are required to pay the TSC, which are flat values per MWh sold or transported. If NYSEG's delivery service customers use more electricity, NYSEG is responsible for additional TSC-related bill, which constitute NYSEG's marginal transmission cost.[3] Other NYISO charges applicable to NYSEG are considered commodity-related and are not included in this study.

A forecast of TSC charges was not available. We used the average of recent historical TSC charges from January 2013 through October 2014 (all stated in year 2016 dollars), which equals $4.18 per MWh, as the basis for NYSEG's marginal transmission costs. We applied factors that account for losses from the transmission tie point to customer meters, using estimates of average marginal energy losses by period.[4]

Table 2 shows the results, all stated in 2016 dollars by period and voltage level of service.

[3] NYSEG does not explicit pay it to itself, but it is a cost to NYSEG as an Electric Distribution Company.

[4] Section V.E discusses the development of the marginal energy loss factors.

Table 2. Summary of 2016 Marginal Transmission Costs

		Summer Season			Winter Season			Off Season		
		On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid-Peak	Off-Peak
		---------- (2016 Dollars per kWh) ----------								
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Marginal Transmission Cost		$0.00400	$0.00400	$0.00400	$0.00400	$0.00400	$0.00400	$0.00400	$0.00400	$0.00400
LOSS ADJUSTED MARGINAL TRANSMISSION COSTS										
Residential TOU (SC 12) Periods										
Secondary Service										
(1)	**TOD**	$0.00434	$0.00430	$0.00423	$0.00434	$0.00431	$0.00426		$0.00428	$0.00422
(2)	**Seasonal**	$0.00429			$0.00430			$0.00426		
(3)	**Annual**	$0.00428								
LGS TOU (SC 7) Periods										
Transmission Service										
(4)	**TOD**	$0.00400		$0.00400	$0.00400		$0.00400	$0.00400		$0.00400
(5)	**Seasonal**	$0.00400			$0.00400			$0.00400		
(6)	**Annual**	$0.00400								
Primary Service										
(7)	**TOD**	$0.00427		$0.00421	$0.00427		$0.00423	$0.00424		$0.00420
(8)	**Seasonal**	$0.00424			$0.00426			$0.00422		
(9)	**Annual**	$0.00423								
Secondary Service										
(10)	**TOD**	$0.00433		$0.00425	$0.00433		$0.00427	$0.00429		$0.00424
(11)	**Seasonal**	$0.00429			$0.00431			$0.00426		
(12)	**Annual**	$0.00428								
Day-Night (SC 8 & 9) Periods										
Secondary Service										
(13)	**TOD**	$0.00431		$0.00423	$0.00432		$0.00426	$0.00428		$0.00422
(14)	**Seasonal**	$0.00429			$0.00430			$0.00426		
(15)	**Annual**	$0.00428								

IV. MARGINAL DISTRIBUTION COSTS

Conceptually, most costing practitioners agree that the design of the distribution system is determined by two major factors: (1) the number and location of customers and (2) their demands. Marginal cost studies have traditionally attempted to identify a portion of distribution costs as customer-related and the remaining portion as demand-related. In fact, for most distribution systems, this two-part segmentation of distribution equipment is not consistent with the cost drivers. There are two types of demand that determine distribution capacity requirements for a particular customer, one is the customer's design (or contract) demand and the other is the customer's expected demand at the time of likely neighborhood peaks in the near-term. Our study identifies which category of demand triggers investment in each component of the distribution infrastructure.

Figure 1 below includes a simplified illustration of NYSEG's distribution system. The various distribution components are categorized as:

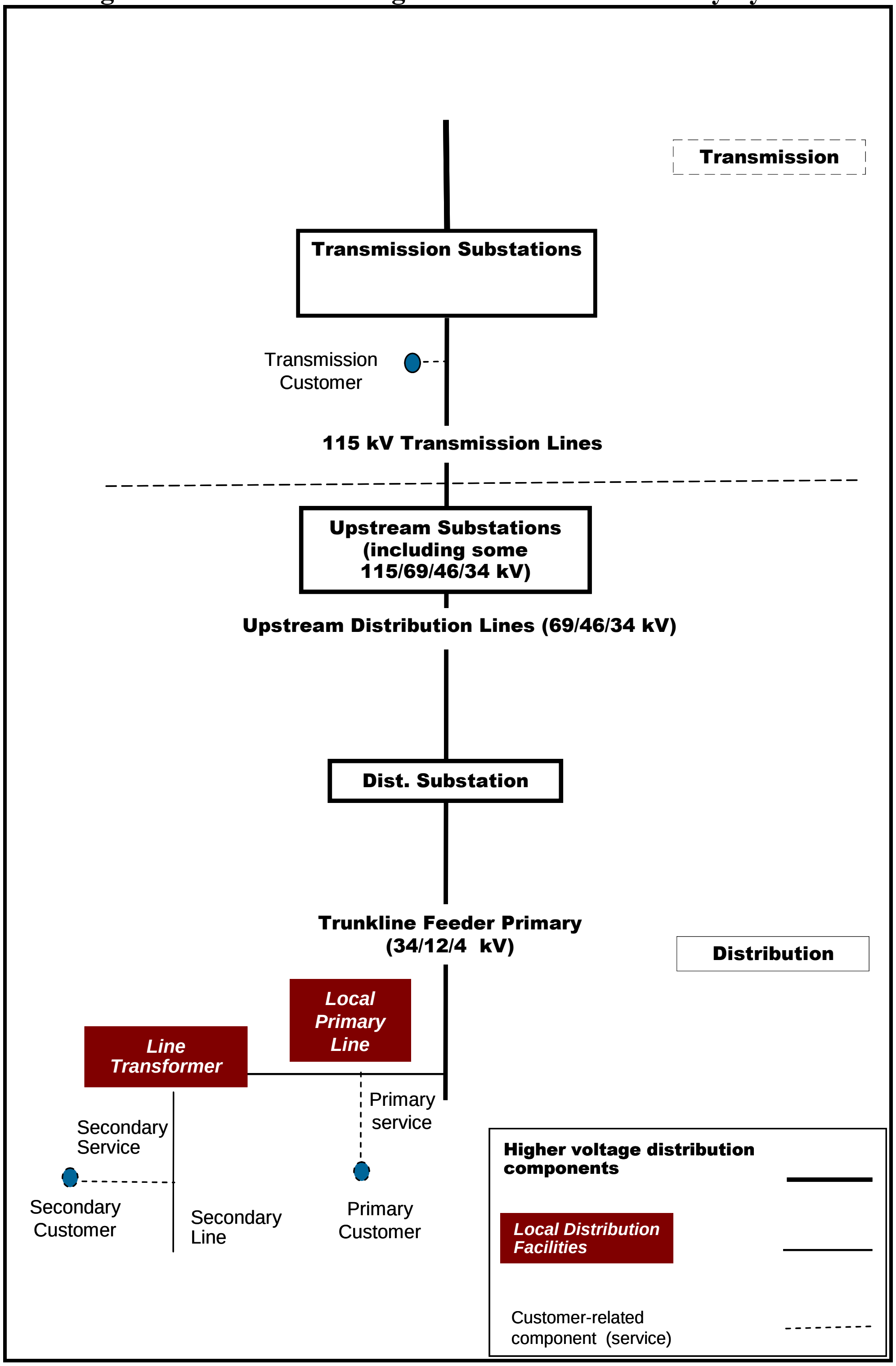
- stations and lines upstream from distribution substations, but defined as distribution;
- distribution substations and primary trunkline feeders;
- local distribution facilities: consisting of secondary lines, primary-to-secondary transformers and local primary lines;
- customer-related service drops.[5]

NYSEG adds distribution substation capacity and distribution equipment upstream of these substations as peak load grows, either from connection of new customers or growth by existing customers. The trunkline feeders that start at the substation and end at the point where the line branches to create a local primary line are also upgraded or rerouted as load grows. These more extensively shared, higher voltage distribution components are expanded as customer loads grow in critical hours, and so marginal costs are different by time of day and season.

Local distribution facilities are designed using engineering design standards that take into consideration the number of customers and the *maximum expected* loads (or "design demands") of the customers who will eventually use those facilities, over the life of the facilities. For example, residential customers with electric space heat typically have design demands higher than those without, and single family homes typically have higher design demands than apartments or condos. Local distribution facilities for commercial and industrial customers are generally designed on a case-by-case basis, again taking into consideration the expected long-term peak demand by the customer.

[5] The service drop in most cases serves a single customer. The service, along with the meter and associated equipment such as current transformer, are part of the marginal customer cost, and is discussed in Section IV.D.

Figure 1. Generalized Diagram of NYSEG's Delivery System



A. Upstream Distribution and Distribution Substation and Trunkline Feeder Costs

To estimate the marginal cost of upstream distribution station and lines and the marginal distribution substation and trunkline feeder cost per kW of demand, we typically identify the cost of system-wide budgeted load growth-related projects of this type (excluding any replacement projects that do not add capacity) and divide that investment by the expected sum of load growth across the substations in the system. In the case of NYSEG, only some parts of the service territory are experiencing growth that will trigger investment while others are not growing or are expected to continue to have sufficient capacity to accommodate load growth in the coming years. To account for this specific situation to NYSEG, we used an adjustment factor to recognize the share of stations with limited growth and excess capacity, both in the 2010 Report and in this update. In particular, our approach followed a three-step process:

1. We looked at NYSEG's most recent five-year (2015-2019) investment budget on growth-related upstream station and lines, as well as growth-related distribution substation and trunkline feeder.[6] To the extent that any of these projects started in earlier years, we included the earlier year's dollars (2010-2013) to obtain a representative investment per kVA of capacity added. We divided the sum of these investments, all stated in 2016 dollars, by the additions to nameplate capacity corresponding to those projects, to obtain a typical investment per kVA of capacity.

2. To convert this figure to a cost per kW of peak load, we multiplied the cost per kVA of capacity by one plus an estimate of the typical planning reserve margin in NYSEG's substations[7] . To do that, we first identified substations that have experienced load growth since 2008 and that are scheduled for a capacity expansion sometime within the next five years. Our goal was to identify the range of reserve margins that will typically trigger investment as load grows in the near term. The median of those stations' reserve margins was used as a proxy for a distribution substation planning reserve margin (29.56 percent).[8]

3. To convert the result from Step 2 to a system-wide marginal investment, we multiplied it by a factor that represents the share (43.72 percent) of total substation peak loads

[6] This budget was filed by NYSEG with the New York Public Service Commission (NYPSC) in April 2014.

[7] Reserve margin is the ratio of nameplate capacity to existing substation peak load, minus 1.

[8] Even though capacity additions are lumpy, stations with reserve margins greater than 200% were not included in the calculation of the median reserve margin as they are unlikely to require new investment to meet local load growth in the area in the next five years.

corresponding to stations that had a reserve margin equal or below the typical reserve margin as of year 2011.[9]

The computations for each of the two components are shown on Table 3 and Table 4.

Table 3. Upstream Substations Investment

(1)	Upstream Distribution Station and Line Investment per kW of Nameplate Capacity Added, 2015 -2019 (2016 Dollars/kW)	$150.67
(2)	Typical Planning Reserve Margin	29.56%
(3)	Investment per kW of Load Growth (2016 Dollars/kW) [(1) x (1+(2))]	$195.21
(4)	Peak Load Share of Stations in Growing Areas with Lower than Average Planning Reserve Margin	43.72%
(5)	System-wide Marginal Investment in Upstream Distribution Stations (2016 Dollars per kW) (7) x (4)	**$85.35**

Table 4. Distribution Substations and Trunkline Feeder Investment

(1)	Distribution Substation and Trunkline Feeder Investment per kW of Nameplate Capacity Added, 2015-2019 (2016 Dollars/kW)	$228.24
(2)	Typical Planning Reserve Margin	29.56%
(3)	Investment per kW of Load Growth (2016 Dollars/kW) [(1) x (1+(2))]	$295.71
(4)	Peak Load Share of Stations in Growing Areas with Lower than Average Planning Reserve Margin	43.72%
(5)	System-wide Marginal Investment in Distribution Substations and Trunkline Feeders (2016 Dollars per kW) (3) x (4)	**$129.28**

[9] Year 2011 was the most recent year for which complete substation peak load data for the entire NYSEG service territory was available.

B. Upstream Substation and Distribution Substation Marginal O&M Expenses

The addition of related distribution plant gives rise to increased operation and maintenance expenses. O&M expenses are, therefore, marginal with regard to peak load growth. NYSEG's station expenses reflect the aggregate annual expenses for both distribution stations and upstream stations. To allocate the expenses, along with associated overheads[10], to each category, we used the total non-coincident peak loads at each level. We reviewed distribution substation and line O&M expenses from the period 2009-2013, and divided these values by an estimate of the sum of non-coincident peak demands at the upstream substations for each year of the period.[11]

After reviewing the trend in annual expense per kW, we used the average of the 2009-2013 expenses (all estimates stated in 2016) as the basis for the marginal substation O&M expenses per kW of load. However, as explained above, some areas of NYSEG's service territory are not likely to require additions to either upstream or distribution substation capacity in the coming years to meet load growth. To account for this, we multiplied the initial expense per kW estimate by the share (43.72 percent) of substation peak loads corresponding to stations with lower than typical reserve margin. To estimate the expense per kW at the upstream station level we divided the distribution substation marginal expense estimate by the appropriate loss factor. These calculations are shown in Table 5.

[10] These general accounts consist of Operation Supervision and Engineering, Miscellaneous Operations, Maintenance Supervision and Engineering, and Miscellaneous Maintenance Expense.

[11] This estimate was developed by taking the sum of the non-coincident peak demands on distribution substations and the annual peak demands of customers served at subtransmission voltage, all measured at the substation level.

Table 5. Upstream Station and Distribution Substation O&M Expense per kW

	Year	Total Distribution Station O&M Expenses	Upstream Station Non-coincident Peak Loads	Distribution Substation Non-coincident Peak Loads	O&M expense per kW of Station Peak Load	Weighted Labor and Materials Cost Index	Distribution O&M expense per kW of Station Peak Load
		(000 Dollars)	(MW)	(MW)	(Dollars) (1)/[(2)+(3)]	(2016=1.00)	(2016 Dollars) (4) / (5)
		(1)	(2)	(3)	(4)	(5)	(6)
(1)	2009	$11,691	3,723	3,423	1.64	0.81	$2.03
(2)	2010	11,164	3,518	3,253	1.65	0.83	1.98
(3)	2011	10,430	3,589	3,324	1.51	0.87	1.74
(4)	2012	8,766	2,839	2,566	1.62	0.90	1.80
(5)	2013	11,300	2,554	2,282	2.34	0.93	2.50
(6)	Marginal Distribution Substation O&M Expense per kW of Peak Load Average of 2009-2013, $/kW						$2.01
(7)	Adjustment for share of station load in areas that do not require investment to meet grov						43.72%
(8)	Marginal Distribution Substation Expense adjusted to recognize surplus capacity ($/kW) Line (6) x Line (7)						$0.878
(7)	Marginal Upstream Station O&M Expense per kW of Peak Load ($/kW)						$0.851

1. Time-differentiation of Marginal Upstream Distribution, Distribution Substation & Trunkline Feeder Costs

Only load growth when capacity is strained triggers additions to the higher voltage distribution system. For the 2010 Report, we analyzed three-years of hourly loads on a sample of representative rural and suburban NYSEG distribution substations for the years 2006-2008 to identify patterns of loads. We estimated the relative probability of peak for months, day-types (e.g., weekdays, weekends) and hours for each substation, taking into account the higher carrying capability of this equipment in cold temperatures. We then calculated weighted averages of these individual substation relative probabilities of peak for each set of pricing periods, using as weights the nameplate capacity of all urban/suburban and rural substations in the NYSEG system. For purposes of the 2014 study update we confirmed that no significant change has taken place in the patterns of substation loads upon review of the most recent years of hourly loads (2011-2013) for the same substations. Therefore the earlier probabilities of peak remain valid. The period assignment factors are shown on Table 6.

Table 6. Probability of Peak for Upstream Substations and Lines, Distribution Substations & Trunkline Feeders

		Relative Probability of Substation Peak		
		Residential Periods (SC 12)	LGS TOU Periods (SC 7)	Day-Night Periods (SC 8 & 9)
		(1)	(2)	(3)
	Summer Season			
(1)	On-Peak	90.0%	99.1%	100.0%
(2)	Mid-Peak	10.0%		
(3)	Off-Peak	0.0%	0.9%	0.0%
(4)	Subtotal	100.0%	100.0%	100.0%
	Winter Season			
(5)	On-Peak	0.0%	0.0%	0.0%
(6)	Mid-Peak	0.0%		
(7)	Off-Peak	0.0%	0.0%	0.0%
(8)	Subtotal	0.0%	0.0%	0.0%
	Off Season			
	On-Peak		0.0%	0.0%
(9)	Mid-Peak	0.0%		
(10)	Off-Peak	0.0%	0.0%	0.0%
(11)	Subtotal	0%		
(12)	**Total**	**100%**	**100%**	**100%**

C. Local Distribution Facility Costs

1. Local Distribution Facility Investment

The marginal cost of local distribution facilities is incurred based on design (or contract) demand, and does not vary with a customer's actual peak load from hour to hour or month to month. Therefore we computed these costs as a monthly cost per kW of design demand. These costs are marginal when the customer is initially connected to the grid, and again whenever the facilities have to be replaced because of age. At that point some costs could be avoided if one or more service connections were eliminated or the design demands of customers using those facilities were reduced.[12] These facilities are also marginal when there is a major increase in the design demand of the customers using them and larger capacity is required.

The calculation of local facilities costs rely on estimates provided by NYSEG of the typical replacement cost per kW of design demand in services,[13] secondary lines, transformers, and local primary lines for various types and sizes of customers on a sample of three circuits – one urban-rural and two village-rural as of year 2010. NYSEG estimated the design demand for each customer in the sample by using customer bills to determine if the circuit was summer or winter peaking, and then using the customer's billing demand (or a conversion factor applied to kWh) of the customer's peak season bill. We computed weighted averages of facilities investment per kW for each customer group within a circuit using the number of sample customers of each type on that circuit as weights. To combine the results from the three circuits, we weighted by the number of customers by class on rural and urban/suburban circuits over the entire NYSEG system. In consultation with NYSEG, the sample of circuits and design demands used in the 2010 Report plus an expanded sample for SC2, SC 7-1 and SC 7-2 large customer connections as of 2012, capture a sufficient range of possible configurations and therefore they continue to be representative for purposes of this study update. We applied the corresponding GDP-based inflation factor forecast[14] of 11.54% to put these estimates in 2016 dollars.

The distribution facilities investments for residential and non-residential customer categories are shown on Table 7. No local facilities costs were identified for lighting customers because their usage does not affect the sizing of distribution facilities. Transmission-level customers provide their own local facilities, so no facilities cost was estimated. No secondary line costs are assigned to SC 7-1 rate class since NYSEG indicated that few customers would use secondary lines. A portion of local facilities costs is sometimes recovered upfront in contributions in aid of construction (CIAC) charges. The marginal local facilities cost estimates are shown two ways—

[12] This might occur, for example, if the customers using the specific local facilities decided to go off-grid, or the homes or businesses were demolished.

[13] Service drop costs are discussed in Section IV D below.

[14] As of June 2013.

excluding the portion of local facilities costs paid up front, to avoid double-counting when the estimates are used to inform rate design, and including the full cost of the equipment.

Table 7. Marginal Distribution Facilities Investment per kW of Design Demand

		Customer Class	Average Investment (after CIAC) per kW of Design Demand (2016 Dollars)	Average Investment (before CIAC) per kW of Design Demand (2016 Dollars)
(1)	SC 1	Residential Service	$671.73	$904.41
(2)	SC 8	Residential Service Day Night Service	$671.73	$904.41
(3)	SC 12	Residential Service with Time-of-Use Metering	$671.73	$904.41
(4)	SC 2	General Service with Demand Metering	$367.50	$569.76
(5)	SC 3	Primary Service - 25 kW or more - Primary	$306.79	$409.51
(6)	SC5	Outdoor Lighting Service	n/a	n/a
(7)	SC 6	General Service	$639.45	$841.96
(8)	SC 7-1	LGS with TOU Metering - Secondary	$143.46	$177.70
(9)	SC 7-2	LGS with TOU - Primary	$306.79	$409.51
(10)	SC 7-4	LGS with TOU Metering - Transmission	n/a	n/a
(11)	SC 9	General Service - Day Night Service	$639.45	$841.96
(12)	SL 1	Street Lighting - Contributory Provisions	n/a	n/a
(13)	SL 2	Street Lighting - Energy and Limited Maintenance	n/a	n/a
(14)	SL 3	Standard Street Lighting Service	n/a	n/a

2. Local Distribution Facility Operation and Maintenance Expenses

During the 2014 study update we reviewed the 2009-2013 local distribution facilities portion of distribution line O&M expenses,[15] plus maintenance of line transformers[16] and separated line-related expenses into primary and secondary categories on the basis of circuit miles of conductor.[17] We divided the expenses for each voltage level by estimates of total design demand of customers using those facilities. Total design demand is the product of customer counts and

[15] FERC accounts 583, 584, 593, 594, plus an allocation of accounts 580, 588, 590 and 598. The portion of these accounts attributable to upstream lines was excluded, based on circuit miles of conductor.

[16] FERC account 595, plus an allocation of accounts 580, 588, 590 and 598.

[17] We treated all primary lines O&M as local facilities cost, rather than trying to identify the portion of primary line miles that is trunkline feeders.

per-customer design demand estimates based on a variety of data sources.[18] There were large maintenance expenses mainly related to storm damage in 2011 and 2012. We concluded that the average of five years of expense (2009-2013) would be representative of typical marginal levels of these costs. As shown on Table 8, all annual O&M values were converted in 2016 dollars using updated (as of June 2014) weighted labor and material cost indexes.

Table 8. Distribution Facilities O&M Expense per kW of Design Demand

	Year	Secondary Portion of Distribution Facilities O&M Expenses (000's Dollars)	Primary Portion of Distribution Facilities O&M Expenses (000's Dollars)	Load on Secondary (MW)	Load on Primary (MW)	Weighted Labor and Materials Cost Index (2016 = 1.00)	Secondary Distribution Facilities Expense Per kW of Load (2016 Dollars/kW) [(1)/(3)]/(5)	Primary Distribution Facilities Expense Per kW of Load (2016 Dollars/kW) [(2)/(4)]/(5)
		(1)	(2)	(3)	(4)	(5)	(6)	
(1)	2009	5,746	68,124	4,637	4,963	0.81	$1.54	$17.02
(2)	2010	11,042	125,231	4,662	4,986	0.83	$2.84	$30.10
(3)	2011	9,391	103,831	4,662	4,988	0.87	$2.32	$23.94
(4)	2012	8,555	94,041	4,669	4,989	0.90	$2.03	$20.87
(5)	2013	6,821	82,444	4,683	5,004	0.93	$1.56	$17.64
(6)	Estimated Annual Weighted Primary Distribution Facilities O&M Expense (Average 2009 - 2013)							**$21.92**
(7)	Estimated Annual Weighted Secondary Distribution Facilities O&M Expense (Average 2009- 2013 plus primary O&M unit cost)						**$23.97**	

D. Lighting Costs

1. Lighting Investment

The amount of investment NYSEG makes to provide lighting service depends upon the type of service offered and the specific equipment required for each installation. Lighting service equipment is categorized in three components:

- Circuit equipment – This is dedicated equipment comparable to a service drop for a non-lighting customer and may include overhead wire, wood poles, underground conductor and conduit, and buried cable.

[18] These include the design demands of customer on the sample circuits, load data used to develop allocators for the embedded cost-of-service study, actual individual customer actual peak demands, and maximum demands permitted by a tariff.

- Fixtures – This equipment includes various types of poles (other than circuit poles), bases, brackets and luminaires.

- Lamps – This category consists of the lamps and photo eyes.

NYSEG offers two lighting services in which the company provides and maintains the lighting equipment: SC 5 - Outdoor Lighting Service and SC 3 - Standard Street Lighting Service. For two other lighting services, SC1 and SC2, NYSEG provides only lamp and photo control replacement.

For the 2010 Report, NYSEG provided estimates of the installed cost of marginal outdoor light and standard street light equipment (fixtures, poles, lines and associated facilities) and associated annual O&M expense, per foot. After consulting with the Company, these numbers are still representative in 2014. We applied the most up-to-date GDP-based inflation forecast of 11.54% to put these estimates into 2016 dollars, as shown on Table 9 and Table 10.

Table 9. Outdoor Lighting Investment and O&M

SC 5 Outdoor Lighting Equipment	Total Installed Cost Excluding Lamp and Photo Eye	Annual O&M (Excl. Relamping)
	--------- (2016 $ per Unit)	----------
	(1)	(2)
Safeguard Luminaires		
14,500 Nominal Lumen 150 Watt H.P.S. (replacing 7,000 L. 175 Watt M.V.)	$583.85	
43,000 Nominal Lumen 400 Watt H.P.S. (replacing 17,200 L. 400 Watt M.V.)	650.38	
123,000 Nominal Lumen 940 Watt H.P.S. (replacing 48,000 L. 1,000 Watt M.V.)	918.36	
Area Lights		
8,500 Nominal Lumen (100 Watt) H.P.S.*	33.61	
8,500 Nominal Lumen (100 Watt) H.P.S. Power Bracket	634.04	
14,400 Nominal Lumen (150 Watt) H.P.S.	583.85	
24,700 Nominal Lumen (250 Watt) H.P.S.	614.99	
45,000 Nominal Lumen (400 Watt) H.P.S.	650.38	
126,000 Nominal Lumen (1,000 Watt) H.P.S.	918.36	
10,500 Nominal Lumen (175 Watt) Metal Halide Power Bracket	728.95	
16,000 Nominal Lumen (250 Watt) Metal Halide	622.46	
28,000 Nominal Lumen (400 Watt) Metal Halide	650.27	
Flood Lights		
14,400 Nominal Lumen (150 Watt) H.P.S.	674.50	
24,700 Nominal Lumen (250 Watt) H.P.S	687.80	
45,000 Nominal Lumen (400 Watt) H.P.S.	688.21	
126,000 Nominal Lumen (1,000 Watt) H.P.S.	799.27	
16,000 Nominal Lumen (250 Watt) Metal Halide	685.04	
28,000 Nominal Lumen (400 Watt) Metal Halide	685.05	
88,000 Nominal Lumen (1,000 Watt) Metal Halide	783.17	
"Shoebox" Luminaire		
14,400 Nominal Lumen (150 Watt) H.P.S.	784.55	
24,700 Nominal Lumen (250 Watt) H.P.S.	787.51	
45,000 Nominal Lumen (400 Watt) H.P.S.	847.96	
16,000 Nominal Lumen (250 Watt) Metal Halide	834.33	
28,000 Nominal Lumen (400 Watt) Metal Halide	821.84	
88,000 Nominal Lumen (1,000 Watt) Metal Halide	940.58	
Post Tops		
5,200 Nominal Lumen (70 Watt) H.P.S.	643.93	
8,500 Nominal Lumen (100 Watt) H.P.S.	650.96	
Brackets 16' and over	253.24	$0.00
Additional Wood Pole Installed for Lamp	655.47	57.62
Wire Service (Overhead) (Per circuit foot of extension)	1.49	0.00
18' Fiberglass Pole - Direct Embedded	617.48	5.14
20' Fiberglass Pole - Pedestal Mount	617.48	5.14
20' Metal Pole - Pedestal Mount	926.71	29.70
30' Metal Pole - Pedestal Mount	1,079.30	29.70
30' Fiberglass Pole - Pedestal Mount	1,594.31	5.14
30' Fiberglass Pole - Direct Embedded	1,594.31	5.14
Screw Base for Pedestal Mounted Pole - Light Duty	767.57	0.00
Screw Base for Pedestal Mounted Pole - Heavy Duty	776.96	0.00

Table 10. Standard Street Lighting Service Investment and O&M

	SC3 Streetlighting Equipment	Luminaire & Mast Arm Total Installed Cost Excluding Lamp and Photo Eye	Facilities Installed Cost	Facilities Annual O&M
			(2016 $ per Unit)	
		(1)	(2)	(3)
	High Pressure Sodium Cobra			
(1)	70 Watts - 5,200 Lumen	$591.19		
(2)	150 Watts - 14,400 Lumen	600.44		
(3)	250 Watts - 24,700 Lumen	631.22		
(4)	400 Watts - 45,000 Lumen	667.71		
(5)	1000 Watts - 126,000 Lumen	962.71		
	High Pressure Sodium Post Top			
(6)	50 Watts - 3,300 Lumen	668.07		
(7)	70 Watts - 5,200 Lumen	659.14		
(8)	150 Watts - 14,400 Lumen	673.81		
	High Pressure Sodium Cut Off ("Shoebox")			
(9)	250 Watts - 24,700 Lumen	803.73		
(10)	400 Watts - 45,000 Lumen	897.96		
	Metal Halide Cobra			
(11)	100 Watts – 5,800 Lumen	660.08		
(12)	175 Watts – 12,000 Lumen	634.42		
(13)	250 Watts - 16,000 Lumen	631.72		
(14)	400 Watts - 28,000 Lumen	716.22		
	Metal Halide Cut Off (“Shoebox”)			
(15)	175 Watts – 12,000 Lumen	731.21		
(16)	250 Watts - 16,000 Lumen	776.20		
(17)	400 Watts - 28, 000 Lumen	839.02		
	Metal Halide Post Top			
(18)	70 Watts – 4,000 Lumen	703.63		
(19)	100 Watts- 5,800 Lumen	724.86		
(20)	175 Watts - 12,000 Lumen	695.61		
	High Pressure Sodium Special Luminaires			
(21)	250 Watts - 24,700 - Hiway Liter	1,733.98		
(22)	400 Watts - 45,000 - Hiway Liter	1,485.65		
(23)	150 Watts - 14,400 - Turnpike	1,027.44		
(24)	250 Watts - 24,700 - Turnpike	1,041.31		
(25)	400 Watts - 45,000 - Turnpike	1,109.27		
(26)	150 Watts - 14,400 - Floodlight	690.36		
(27)	250 Watts - 24,700 - Floodlight	704.03		
(28)	400 Watts - 45,000 - Floodlight	704.86		
	Metal Halide - Floodlights			
(29)	250 Watts - 16,000 Lumen	729.67		
(30)	400 Watts - 28,000 Lumen	702.15		
	Pole Installed by the Corporation			
(31)	Standard Wood Pole		$422.56	$57.62
(32)	Wood Pole - high mount use (45' or greater)		603.37	57.62
(33)	Aluminum Pole 16' and under		407.31	0.00
(34)	Alum. Pole over 16' installed prior to August 1, 1987		648.84	0.00
(35)	Alum. Pole over 16' direct embedded installed after July 31, 1987		648.84	0.00
(36)	Alum. Pole over 16' pedestal mounted		771.67	0.00
(37)	Fiberglass Pole 18' and under		390.87	5.14
(38)	Fiberglass Pole 18' to 22'		390.87	5.14
	Screw-in steel base for pedestal mounted poles:			
(39)	Light Duty		270.74	0.00
(40)	Heavy Duty		278.57	0.00
	Special Brackets			
(41)	Standard Bracket - 16' and over		388.17	0.00
	Circuit Control			
(42)	Group Controllers		654.76	0.00
	Circuits (Per Trench Foot)**			
(43)	Cable and Conduit		2.58	0.00
(44)	Direct Burial Cable		1.93	0.00
(45)	Cable Only (Conduit Supplied by Customer)		1.47	0.00
(46)	Underground Circuits		2.58	0.00

2. Lamp Replacement Expense

For the 2010 Report, NYSEG provided estimates of annual expense for relamping (including replacement of lamps and photo cells) applicable to all of the lighting services. These estimates were adjusted by adding loaders for A&G expense and cash working capital. After consulting with the Company, we agreed these numbers were still representative and we applied the GDP inflation factor of 11.54% to put these estimates into 2016 dollars, as shown on Table 11.

Table 11. Relamping Expense per Unit

Lamp Type	Relamping Expense per Unit per Year (2016 Dollars)
High Pressure Sodium	
50 Watts - 3,300 Lumen	$19.33
70 Watts - 5,200 Lumen	19.33
100 Watts - 8,500 Lumen	19.84
150 Watts - 14,400 Lumen	19.91
250 Watts - 24,700 Lumen	19.99
400 Watts - 45,000 Lumen	20.21
940 Watts - 123,000 Lumen	25.70
1000 Watts - 126,000 Lumen	25.70
Metal Halide	
70 Watts – 4,000 Lumen	22.58
100 Watts - 5,800 Lumen	26.90
175 Watts - 10,500 or 12,000 Lumen	20.10
250 Watts - 16,000 Lumen	20.10
400 Watts - 28,000 Lumen	20.18
1000 Watts - 88,000 Lumen	22.49
Mercury Vapor	
100 Watts - 3,200 Lumen	20.66
175 Watt - 7,000 Lumen	20.66
250 Watts - 9,400 Lumen	20.66
400 Watts - 17,200 Lumen	20.66
1000 Watts - 48,000 Lumen	20.66

E. Meter and Service Costs

NYSEG provided year 2014 installed cost of a typical meter (including current and transformer, if applicable) for each service classification. We applied the GDP-based factor of 3.95% to convert these estimates into 2016 dollars, as shown on the next two For the 2010 Report NERA developed estimates of the installed cost of services for each customer classification by analyzing cost of services corresponding to a sample of circuits supplemental large customer sample that had been provided by NYSEG. After consulting

the Company, we agreed that these cost estimates are still representative and we applied the GDP inflation factor of 11.54% to restate the 2010 service cost estimates in 2016 dollars. A portion of service costs is sometimes recovered upfront in contributions in aid of construction (CIAC) charges. The marginal service cost estimates are shown two ways—Table 12 provides the costs excluding the portion of service costs paid up front, to avoid double-counting when the estimates are used to inform rate design, and

Table 13 provides the costs including the full cost of the equipment.

Table 12. Investment per Customer in Meters and Services (before CIAC)

	Rate	Description	Meter Investment	Service Investment (before CIAC)	Total Meter & Service Investment (before CIAC)
			------------- (2016 $ per Customer)		--------------
					(1) + (2)
			(1)	(2)	(3)
(1)	SC 1	Residential Service	$125.43	$817.60	$943.03
(2)	SC 8	Residential Service Day Night Service	202.46	817.60	1,020.06
(3)	SC 12	Residential Service with Time-of-Use Metering	202.46	817.60	1,020.06
(4)	SC 2	General Service with Demand Metering	426.72	9,328.48	9,755.20
(5)	SC 3	Primary Service - 25 kW or more - Primary	7,865.73	7,507.62	15,373.35
(6)	SC5	Outdoor Lighting Service	na	na	na
(7)	SC 6	General Service	172.99	456.04	629.03
(8)	SC 7-1	LGS with TOU Metering - Secondary	944.39	14,648.00	15,592.39
(9)	SC 7-2	LGS with TOU - Primary	7,138.51	7,507.62	14,646.13
(10)	SC 7-4	LGS with TOU Metering - Transmission	57,648.91	0.00	57,648.91
(11)	SC 9	General Service - Day Night Service	196.90	456.04	652.94

Table 13. Investment per Customer in Meters and Services (after CIAC)

	Rate	Description	Meter Investment	Service Investment (after CIAC)	Total Meter & Service Investment (after CIAC)
			(2016 $ per Customer)		
					(1) + (2)
			(1)	(2)	(3)
(1)	SC 1	Residential Service	$125.43	$458.80	$584.23
(2)	SC 8	Residential Service Day Night Service	202.46	458.80	661.26
(3)	SC 12	Residential Service with Time-of-Use Metering	202.46	458.80	661.26
(4)	SC 2	General Service with Demand Metering	426.72	6,060.88	6,487.60
(5)	SC 3	Primary Service - 25 kW or more - Primary	7,865.73	2,515.13	10,380.86
(6)	SC5	Outdoor Lighting Service	na	na	na
(7)	SC 6	General Service	172.99	22.37	195.36
(8)	SC 7-1	LGS with TOU Metering - Secondary	944.39	6,737.40	7,681.79
(9)	SC 7-2	LGS with TOU - Primary	7,138.51	2,515.13	9,653.64
(10)	SC 7-4	LGS with TOU Metering - Transmission	57,648.91	0.00	57,648.91
(11)	SC 9	General Service - Day Night Service	196.90	22.37	219.27

1. Meter and Service Operation and Maintenance Expenses

We analyzed meter O&M expenses[19] per average customer over the past five years. We decided to use the average of years 2009 through 2013 as the estimate of the marginal level of these expenses, as shown on Table 14. Table 15 multiplies the result by the class weights to yield annual meter O&M by service classification.

[19] FERC accounts 586 and 597, plus associated overheads.

Table 14. Meter O&M Expense per Weighted Customer

	Year	Total Meter Operation & Maintenance Expenses	Average Number of Metered Customers	Weighted Average Number of Customers	Meter Expense Per Weighted Customer	Weighted Labor and Materials Cost Index	Meter Expense Per Weighted Customer
		(000's Dollars)			(Dollars)	(2015 = 1.00)	(2015 Dollars)
				(2) x 1.34	[(1) x 1000]/(3)		(4)/(5)
		(1)	(2)	(3)	(4)	(5)	(6)
(1)	2009	$12,894	866,805	1,164,675	$11.07	0.81	$13.73
(2)	2010	15,157.06	869,144	1,167,818	12.98	0.83	15.55
(3)	2011	12,202.51	869,411	1,168,176	10.45	0.87	12.01
(4)	2012	14,366.11	870,870	1,170,137	12.28	0.90	13.59
(5)	2013	15,983.57	872,790	1,172,716	13.63	0.93	14.59
(6)	Estimated Annual Weighted Meter O&M Expense (average 2009- 2013)						**$13.90**

Table 15. Meter O&M Expense by Service Classification

	Rate	Class	Weighting Factor	Annual Meter Expense Per Customer
				(2016 Dollars)
				(1) x $13.90
			(1)	(2)
(1)	SC 1	Residential Service	1.00	$13.90
(2)	SC 8	Residential Service Day Night Service	1.61	22.43
(3)	SC 12	Residential Service with Time-of-Use Metering	1.61	22.43
(4)	SC 2	General Service with Demand Metering	3.40	47.28
(5)	SC 3	Primary Service - 25 kW or more - Primary	62.71	871.51
(6)	SC5	Outdoor Lighting Service	na	na
(7)	SC 6	General Service	1.38	19.17
(8)	SC 7-1	LGS with TOU Metering - Secondary	7.53	104.64
(9)	SC 7-2	LGS with TOU - Primary	56.91	790.94
(10)	SC 7-4	LGS with TOU Metering - Transmission	459.62	6,387.43
(11)	SC 9	General Service - Day Night Service	1.57	21.82

V. OTHER MARGINAL COSTS

A. Customer Accounts Expenses

Customer accounts expenses,[20] composed mainly of meter-reading and billing expenses and uncollectibles, are a function of the number of customers on the system. We used the latest available data from the results of the NYSEG's 2013 embedded cost of service study.[21] Table 16 shows the estimated marginal costs by service classification.[22]

Table 16. Customer Accounts and Uncollectibles Expense by Service Classification

	Rate	Class	Customer Accounts Expense (excl. uncollectibles) (2016 $/cust)	Estimated Marginal Uncollectibles (2016 $/cust)
			(1)	(2)
(1)	SC 1	Residential Service	$50.02	$9.84
(2)	SC 8	Residential Service Day Night Service	53.06	13.08
(3)	SC 12	Residential Service with Time-of-Use Metering	65.48	41.09
(4)	SC 2	General Service with Demand Metering	65.55	7.62
(5)	SC 3	Primary Service - 25 kW or more - Primary	154.95	33.88
(6)	SC5	Outdoor Lighting Service	28.07	0.90
(7)	SC 6	General Service	45.54	1.18
(8)	SC 7-1	LGS with TOU Metering - Secondary	159.92	36.64
(9)	SC 7-2	LGS with TOU - Primary	666.51	209.64
(10)	SC 7-4	LGS with TOU Metering - Transmission	1,312.22	433.18
(11)	SC 9	General Service - Day Night Service	47.71	1.83
(12)	SL 1	Street Lighting - Contributory Provisions	101.25	26.03
(13)	SL 2	Street Lighting - Energy and Lim. Maintenance	101.25	26.03
(14)	SL 3	Standard Street Lighting Service	101.25	26.03

[20] FERC accounts 901-906.

[21] We excluded from the analysis the share of uncollectibles, credit and collection and call center expenses that are associated with the Merchant Function since these are commodity-related and are recovered in a separate Merchant Function Charge.

[22] Uncollectibles per customer are shown separately because this component of customer accounts expense is not subject to the cash working capital adjustment factor or the A&G loader that apply to the rest of accounts.

B. Customer Service and Informational Expenses

Customer service and informational expenses[23] include the costs of disseminating information to consumers. These costs typically vary with the number of customers on the system and are, therefore, marginal. In consultation with the Company we allocated the per-customer expense by class based on NYSEG's 2013 embedded cost of service study. We divided the total allocated expenses[24] by the total number of customers in the class as our estimate of marginal customer service and informational expenses. Table 17 shows the customer service and informational expenses per customer by service classification.

Table 17. Customer Services and Informational Expenses by Service Classification

	Rate	Class	Annual Customer Service and Informational Expense Per Customer (2016 $)
			(1)
(1)	SC 1	Residential Service	$1.01
(2)	SC 8	Residential Service Day Night Service	1.34
(3)	SC 12	Residential Service with Time-of-Use Metering	4.23
(4)	SC 2	General Service with Demand Metering	8.64
(5)	SC 3	Primary Service - 25 kW or more - Primary	39.97
(6)	SC5	Outdoor Lighting Service	1.10
(7)	SC 6	General Service	1.24
(8)	SC 7-1	LGS with TOU Metering - Secondary	42.91
(9)	SC 7-2	LGS with TOU - Primary	258.26
(10)	SC 7-4	LGS with TOU Metering - Transmission	699.77
(11)	SC 9	General Service - Day Night Service	1.91
(12)	SL 1	Street Lighting - Contributory Provisions	32.23
(13)	SL 2	Street Lighting - Energy & Limited Maintenance	32.23
(14)	SL 3	Standard Street Lighting Service	32.23

[23] FERC Accounts 908, 909 and 910.

[24] We excluded expenses associated with Energy Efficiency and Renewable Portfolio Standards since these are recovered in separate charges.

C. Administrative and General Expenses and General Plant

When a utility adds transmission or distribution infrastructure and incurs additional O&M expenses, it typically incurs additional corporate overhead costs as well. Certain administrative and general (A&G) expenses can grow either with plant or with O&M expenses. General plant consists of items such as office buildings, warehouses, cars, trucks and other equipment, and the need for general plant typically increases with marginal increases in other types of plant. The approach used to determine plant-related A&G, non-plant-related A&G and General Plant loaders in our marginal cost study is summarized below.

For the non-plant-related A&G loader, we used the year 2013 ratio of social security and unemployment benefits to total O&M (less fuel, purchased power and transmission by others) because these benefits clearly grow with O&M. This is the same approach used in the 2010 Report. Regarding plant-related A&G, we also relied on the methodology from the 2010 Report. NYSEG provided the expected 2014-15 insurance premium per dollar of investment and we applied an annual escalation factor of 10%, as agreed with NYSEG, to convert this rate into a year 2016 rate.[25]

To estimate General Plant loaders, we updated the regression analysis that we had undertaken for the 2010 Report. The analysis includes a regression of cumulative additions to general plant net of retirements and the electric share of common plant, during the period 1992 -2011, on cumulative additions to plant net of retirements less general and common plant, all stated in constant dollars. Dummy shift variables for post 1999 and post 2006 were used to account for large increases in general plant. The coefficient of the explanatory variable is the loader used in this study. The resulting A&G and General plant loaders are shown on Table 18 below.

Table 18. Administrative & General and General Plant Loaders

		Estimate of Loading Factor
(1)	Non-Plant Related A&G Loader	1.52%
(2)	Plant-Related A&G Loader	0.04%
(3)	General Plant & the Electric Share of Common Plant Loader	21.09%

[25] NYSEG's property insurance covers distribution substations, but not lines or other distribution facilities. Thus the plant-related A&G loader is used only in the calculation of substation marginal costs.

D. Marginal Losses

The marginal cost study develops transmission, upstream distribution, and distribution substation and trunkline feeder costs stated on a per-kW or per-kWh basis, stated at each particular component of the system. For use in ratemaking, these costs must be adjusted to costs at the meter of customers served at the various voltage levels of service.

The marginal loss calculations in this study are based on estimates of variable and total losses at time of system peak at each voltage level for which costs are calculated. Marginal capacity losses, applied to upstream substations and to distribution substation and trunkline feeder costs, reflect the fact that to accommodate a kW of additional peak load at the customer's meter, facilities must be expanded by successively more than a kW as you move up the distribution system to accommodate the fixed and variable losses on the system in the peak hour. Peak capacity loss factors were developed from NYSEG's most recent detailed loss study and the Company considered these loss factors to be still applicable for purposes of marginal cost estimates.

Marginal energy losses reflect the additional losses incurred to move an added kWh through the system at a particular level of system load. Fixed losses are, by definition, not affected by the increments of load to a fixed system. Only variable losses come into these calculations. Marginal energy losses increase in proportion to the square of the load. We calculated average hourly losses in each pricing period by means of an approximation of quadratic losses based on variable losses at system peak load (from NYSEG's most recent detailed loss study) and system hourly system loads. These marginal energy losses are applicable to the marginal transmission costs, which are incurred on a per-kWh basis.

VI. COMPUTATION OF ECONOMIC CARRYING CHARGES

To be useful in ratemaking and other marginal cost applications, the marginal investment in several categories of distribution plant must be converted into annual costs using an economic carrying charge (ECC). The annual charge reflects the elements of NYSEG's revenue requirement associated with incremental plant: return to stockholders and bondholders, depreciation, and income and property taxes. For use in a marginal cost study, the appropriate stream of annual charges is a stream that rises at the rate of inflation net of technical progress and yields the total present value of all costs over the life of the investment. In such a stream, the first year's charge represents the cost in today's dollars of owning the plant or equipment for a year. It also represents the rental rate for such an investment in a competitive market.

Key inputs for the ECC calculation include: (1) the utility's incremental cost of capital (mix of debt and equity), (2) the long-term return on equity and cost of debt, (3) the expected inflation rate for that type of plant, net of technical progress, and (4) the average service life and patterns of failure ("Iowa curve") for that type of plant. NYSEG foresees financing of near-term incremental investment through additional equity (retained earnings and/or infusion of equity capital from the parent company) and long-term debt. The capital structure and costs for these components are shown in Table 19.

Table 19. Incremental Capital Structure and Cost

	Share (%)	Cost (%)
Debt	50.00	6.00
Common Stock	50.00	10.06

Another integral part of the economic carrying charge calculation is the estimation of the rate of inflation applicable over the life of the investment. We used 2.07 percent as an estimate of the future inflation rate net of technical progress, based on the average of the updated GDP inflation forecast (as of June 2014) for the ten-year period 2014-2023.

Finally, an adjustment is required to account for the fact that not all plant and equipment will last its estimated service life. Some components will require early replacement, causing added costs, while some will last longer than expected and produce savings. The pattern of expected required replacement for each type of plant is defined by an Iowa Curve.[26] An adjustment for this dispersed pattern of replacements using Iowa Curves was included in the derivation of the

[26] Iowa curves provided for the 2010 Report were still applicable for this study.

economic carrying charges. The aggregated[27] results of these economic carrying charge calculations are presented below. The adjustments for dispersed retirements are shown on line (2) of this table.

Table 20. Economic Carrying Charges

		Distribution Substations	Distribution Facilities	Meters & Services	Street Lights
		(1)	(2)	(3)	(4)
(1)	Present Value of Revenue Requirements Related to Incremental $1,000 Investment	$1,783.19	$1,819.96	$1,758.08	$1,686.27
(2)	Present Value Cost of Replacing Dispersed Retirements Related to Incremental $1,000 Investment	$94.21	$112.44	$111.05	$142.19
(3)	Total Present Value Cost Related to Incremental $1,000 Investment (1)+(2)	$1,877.40	$1,932.40	$1,869.13	$1,828.46
(4)	First-Year Annual Economic Charge Related to Incremental $1,000 Investment	$109.79	$106.76	$112.50	$121.06
(5)	First-Year Annual Economic Charge Related to Incremental Investment (4)/$1,000	10.98%	10.68%	11.25%	12.11%

[27] The economic carrying charge calculations were performed separately for each of these accounts and aggregated to the five categories reported by weighting according to dollars of gross plant.

VII. ANNUAL MARGINAL COSTS

To compute marginal investment for each distribution component of service to annual marginal costs, we adjusted upwards the investment per unit by the general plant loading factor. We multiplied the resulting figures by the annual economic carrying charge percentage (plus the plant-related A&G loading factor for substations) to yield the annualized plant costs. To these costs we added the associated O&M and A&G expenses and the revenue requirements for working capital.

The computation of working capital includes components for cash, materials, supplies and prepayments. The materials, supplies and prepayments needs were estimated based on recent historical amounts. The cash working capital factor is the FERC approach (1/8 of O&M). The revenue requirement for working capital is computed as NYSEG’s weighted average incremental cost of capital plus an income tax component that recognizes that the equity portion of return on capital is taxable.

Table 21 shows the derivation of the annual distribution substation and trunkline feeder costs and upstream station costs.

Table 21. Derivation of Annual Distribution Substation and Trunkline Feeder and Upstream Substation Costs

		Distribution Substations and Trunkline Feeders	Upstream Distribution Stations
		--------- (2016 Dollars/kW) ---------	
		(1)	(2)
(1)	Marginal Investment per kW	$129.28	$85.35
(2)	With General Plant Loading (1) x 1.2109	156.55	103.35
(3)	Annual Economic Carrying Charge Related to Capital Investment	10.98%	10.98%
(4)	A&G Loading (plant related)	0.04%	0.04%
(5)	Total Annual Carrying Charge (3) + (4)	11.01%	11.01%
(6)	Annualized Costs (2) x (5)	$17.24	$11.38
(7)	O&M Expenses	0.88	0.85
(8)	With A&G Loading (7) x 1.0152 (Non-plant Related)	0.89	0.86
(9)	Subtotal (6) + (8)	$18.13	$12.25
	Working Capital		
(10)	Material and Supplies (2) x 0.22%	$0.34	$0.23
(11)	Prepayments (2) x 1.25%	1.96	1.29
(12)	Cash Working Capital Allowance (8) x 12.50%	0.11	0.11
(13)	Total Working Capital (10) + (11) + (12)	$2.41	$1.63
(14)	Revenue Requirement for Working Capital (13) x 11.28%	0.27	0.18
(15)	Total Annual Cost (9) + (14)	$18.41	$12.43

Table 22 A-D below show the development of the annual marginal cost for local distribution facilities.

Table 22. A. Derivation of Annual Distribution Facilities Costs – After CIAC

		SC 1 Residential	SC 8 Residential Day Night	SC 12 Residential TOU	SC 2 General Service with Demand	SC 3P Primary Service (Primary)
		(2016 Dollars per kW of Design Demand)				
		(1)	(2)	(3)	(4)	(5)
(1)	Marginal Investment per kW of Design Demand	$671.73	$671.73	$671.73	$367.50	$306.79
(2)	With General Plant Loading (1) x 1.2109	862.47	862.47	862.47	487.66	393.15
(3)	Annual Economic Carrying Charge Related to Capital Investment	10.68%	10.68%	10.68%	10.68%	10.68%
(4)	A&G Loading (plant-related)	0.00%	0.00%	0.00%	0.00%	0.00%
(5)	Total Annual Carrying Charge (3) + (4)	10.68%	10.68%	10.68%	10.68%	10.68%
(6)	Annualized Costs (2) x (5)	$92.08	$92.08	$92.08	$52.06	$41.97
(7)	Annual Expense per kW of Design Demand	23.97	23.97	23.97	23.97	21.92
(8)	With A&G Loading (7) x 1.0152 (non-plant related)	24.34	24.34	24.34	24.34	22.25
(9)	Distribution Facilities Related Costs (6) + (8)	$116.41	$116.41	$116.41	$76.40	$64.22
	Working Capital					
(10)	Material and Supplies (2) x 0.22%	$2.41	$2.41	$2.41	$1.52	$1.09
(11)	Prepayments (2) x 1.25%	13.69	13.69	13.69	8.62	6.20
(12)	Cash Working Capital Allowance (8) x 12.50%	3.04	3.04	3.04	3.04	2.78
(13)	Total Working Capital (10) + (11) + (12)	$19.14	$19.14	$19.14	$13.18	$10.07
(14)	Revenue Requirement for Working Capital (13) x 11.28%	2.16	2.16	2.16	1.49	1.14
(15)	Total Annual Marginal Distribution Facilities Related Costs (9) + (14)	**$118.57**	**$118.57**	**$118.57**	**$77.89**	**$65.36**

Table 22. B. Derivation of Total Annual Distribution Facilities Costs - After CIAC

		SC 6 General Service	SC 7-1 LGS TOU Secondary	SC 7-2 LGS TOU Primary	SC 7-4 LGS TOU Transmission	SC 9 General Service Day Night
		(2016 Dollars per kW of Design Demand)				
		(6)	(7)	(8)	(9)	(10)
(1)	Marginal Investment per kW of Design Demand	$639.45	$143.46	$306.79	n/a	$639.45
(2)	With General Plant Loading (1) x 1.2109	817.02	180.93	393.15	0.00	817.02
(3)	Annual Economic Carrying Charge Related to Capital Investment	10.68%	10.68%	10.68%	10.68%	10.68%
(4)	A&G Loading (plant-related)	0.00%	0.00%	0.00%	0.00%	0.00%
(5)	Total Annual Carrying Charge (3) + (4)	10.68%	10.68%	10.68%	10.68%	10.68%
(6)	Annualized Costs (2) x (5)	$87.22	$19.32	$41.97	$0.00	$87.22
(7)	Annual Expense per kW of Design Demand	23.97	23.97	21.92	0.00	23.97
(8)	With A&G Loading (7) x 1.0152 (non-plant related)	24.34	24.34	22.25	0.00	24.34
(9)	Distribution Facilities Related Costs (6) + (8)	$111.56	$43.65	$64.22	$0.00	$111.56
	Working Capital					
(10)	Material and Supplies (2) x 0.22%	$2.24	0.47	1.09	0.00	2.24
(11)	Prepayments (2) x 1.25%	12.74	2.69	6.20	0.00	12.74
(12)	Cash Working Capital Allowance (8) x 12.50%	3.04	3.04	2.78	0.00	3.04
(13)	Total Working Capital (10) + (11) + (12)	$18.03	$6.20	$10.07	$0.00	$18.03
(14)	Revenue Requirement for Working Capital (13) x 11.28%	2.03	0.70	1.14	0.00	2.03
(15)	Total Annual Marginal Distribution Facilities Related Costs (9) + (14)	**$113.59**	**$44.35**	**$65.36**	**$0.00**	**$113.59**

Table 22. C. Derivation of Annual Distribution Facilities Costs – Before CIAC

		SC 1 Residential	SC 8 Residential Day Night	SC 12 Residential TOU	SC 2 General Service with Demand	SC 3P Primary Service (Primary)
		---------- (2016 Dollars per kW of Design Demand) ----------				
		(1)	(2)	(3)	(4)	(5)
(1)	Marginal Investment per kW of Design Demand	$904.41	$904.41	$904.41	$569.76	$409.51
(2)	With General Plant Loading (1) x 1.2109	1,095.15	1,095.15	1,095.15	689.93	495.87
(3)	Annual Economic Carrying Charge Related to Capital Investment	10.68%	10.68%	10.68%	10.68%	10.68%
(4)	A&G Loading (plant-related)	0.00%	0.00%	0.00%	0.00%	0.00%
(5)	Total Annual Carrying Charge (3) + (4)	10.68%	10.68%	10.68%	10.68%	10.68%
(6)	Annualized Costs (2) x (5)	$116.92	$116.92	$116.92	$73.66	$52.94
(7)	Annual Expense per kW of Design Demand	23.97	23.97	23.97	23.97	21.92
(8)	With A&G Loading (7) x 1.0152 (non-plant related)	24.34	24.34	24.34	24.34	22.25
(9)	Distribution Facilities Related Costs (6) + (8)	$141.25	$141.25	$141.25	$97.99	$75.19
	Working Capital					
(10)	Material and Supplies (2) x 0.22%	2.41	2.41	2.41	1.52	1.09
(11)	Prepayments (2) x 1.25%	13.69	13.69	13.69	8.62	6.20
(12)	Cash Working Capital Allowance (8) x 12.50%	3.04	3.04	3.04	3.04	2.78
(13)	Total Working Capital (10) + (11) + (12)	$19.14	$19.14	$19.14	$13.18	$10.07
(14)	Revenue Requirement for Working Capital (13) x 11.28%	2.16	2.16	2.16	1.49	1.14
(15)	Total Annual Marginal Distribution Facilities Related Costs (9) + (14)	**$143.41**	**$143.41**	**$143.41**	**$99.48**	**$76.32**

Table 22. D. Derivation of Total Annual Distribution Facilities Costs - Before CIAC

		SC 6	SC 7-1	SC 7-2	SC 7-4	SC 9
		General Service	LGS TOU Secondary	LGS TOU Primary	LGS TOU Transmission	General Service Day Night
		(2016 Dollars per kW of Design Demand)				
		(6)	(7)	(8)	(9)	(10)
(1)	Marginal Investment per kW of Design Demand	$841.96	$177.70	$409.51	n/a	$841.96
(2)	With General Plant Loading (1) x 1.2109	1,019.53	215.17	495.87	0.00	1,019.53
(3)	Annual Economic Carrying Charge Related to Capital Investment	10.68%	10.68%	10.68%	10.68%	10.68%
(4)	A&G Loading (plant-related)	0.00%	0.00%	0.00%	0.00%	0.00%
(5)	Total Annual Carrying Charge (3) + (4)	10.68%	10.68%	10.68%	10.68%	10.68%
(6)	Annualized Costs (2) x (5)	$108.84	$22.97	$52.94	$0.00	$108.84
(7)	Annual Expense per kW of Design Demand	23.97	23.97	21.92	0.00	23.97
(8)	With A&G Loading (7) x 1.0152 (non-plant related)	24.34	24.34	22.25	0.00	24.34
(9)	Distribution Facilities Related Costs (6) + (8)	$133.18	$47.31	$75.19	$0.00	$133.18
	Working Capital					
(10)	Material and Supplies (2) x 0.22%	2.24	0.47	1.09	0.00	2.24
(11)	Prepayments (2) x 1.25%	12.74	2.69	6.20	0.00	12.74
(12)	Cash Working Capital Allowance (8) x 12.50%	3.04	3.04	2.78	0.00	3.04
(13)	Total Working Capital (10) + (11) + (12)	$18.03	$6.20	$10.07	$0.00	$18.03
(14)	Revenue Requirement for Working Capital (13) x 11.28%	2.03	0.70	1.14	0.00	2.03
(15)	Total Annual Marginal Distribution Facilities Related Costs (9) + (14)	**$135.21**	**$48.01**	**$76.32**	**$0.00**	**$135.21**

Table 23 shows the annualization of meters and service drops and also include customer-related expenses.

Table 23. A. Derivation of Annual Meter, Service and Customer-Related Costs – After CIAC

		SC 1 Residential	SC 8 Residential Day Night	SC 12 Residential TOU	SC 2 General Service with Demand	SC 3 Primary Service (Primary)
		----------	(2016 Dollars per Customer)	----------		
		(1)	(2)	(3)	(4)	(5)
(1)	Meter and Service Investment	$584.23	$661.26	$661.26	$6,487.60	$10,380.86
(2)	With General Plant Loading (1) x 1.2109	783.11	876.39	876.39	8,544.97	13,623.09
(3)	Annual Economic Charge Related to Capital Investment	11.25%	11.25%	11.25%	11.25%	11.25%
(4)	A&G Loading (Plant Related)	0.00%	0.00%	0.00%	0.00%	0.00%
(5)	Total (3) + (4)	11.25%	11.25%	11.25%	11.25%	11.25%
(6)	Annualized Costs (2) x (5)	$88.10	$98.60	$98.60	$961.34	$1,532.65
(7)	Meter O&M Expenses	13.90	22.43	22.43	47.28	871.51
(8)	Customer Accounts Expenses excl. Uncoll.	50.02	53.06	65.48	65.55	154.95
(9)	Uncollectibles	9.84	13.08	41.09	7.62	33.88
(10)	Customer Service & Informational Expenses	1.01	1.34	4.23	8.64	39.97
(11)	A&G Loading [(7)+(8)+(10)] x 0.0152 (Non-plant Related)	0.98	1.16	1.40	1.84	16.17
(12)	Customer-Related Costs (6)+(7)+(8)+(9)+(10)+(11)	$163.85	$189.67	$233.22	$1,092.28	$2,649.13
	Working Capital					
(13)	Materials and Supplies (2) x 0.22%	2.51	2.72	2.72	25.99	40.95
(14)	Prepayments (2) x 1.250%	14.27	15.44	15.44	147.66	232.69
(15)	Cash Working Capital [(7)+(8)+(10)+(11)] x 12.50%	8.24	9.75	11.69	15.41	135.32
(16)	Revenue Requirement for Working Capital [(13)+(14)+(15)] x 11.28%	$2.82	$3.15	$3.37	$21.33	$46.13
(17)	Total Annual Marginal Customer-Related Costs (12) + (16)	**$166.67**	**$192.82**	**$236.59**	**$1,113.61**	**$2,695.26**

Table 23. B. Derivation of Total Annual Meter, Service and Customer-Related Costs – After CIAC

		SC 6 General Service	SC 7-1 LGS TOU Secondary	SC 7-2 LGS TOU Primary	SC 7-4 LGS TOU Trans-mission	SC 9 General Service Day Night
		------------------------ (2016 Dollars per Customer)				-----------------------
		(6)	(7)	(8)	(9)	(10)
(1)	Meter & Service Investment	$195.36	$7,681.79	$9,653.64	$57,648.91	$219.27
(2)	With General Plant Loading (1) x 1.2109	328.03	10,970.23	12,742.51	69,807.07	356.97
(3)	Annual Economic Charge Related to Capital Investment	11.25%	11.25%	11.25%	11.25%	11.25%
(4)	A&G Loading (Plant Related)	0.00%	0.00%	0.00%	0.00%	0.00%
(5)	Total (3) + (4)	11.25%	11.25%	11.25%	11.25%	11.25%
(6)	Annualized Costs (2) x (5)	$36.90	$1,234.19	$1,433.58	$7,853.56	$40.16
(7)	Meter O&M Expenses	19.17	104.64	790.94	6,387.43	21.82
(8)	Customer Accounts Expenses excl. Uncoll.	45.54	159.92	666.51	1,312.22	47.71
(9)	Uncollectibles	1.18	36.64	209.64	433.18	1.83
(10)	Customer Service & Informational Expenses	1.24	42.91	258.26	699.77	1.91
(11)	A&G Loading [(7)+(8)+(10)] x 0.0152 (Non-plant Related)	1.00	4.66	26.01	127.32	1.08
(12)	Customer-Related Costs (6)+(7)+(8)+(9)+(10)+(11)	$105.03	$1,582.96	$3,384.94	$16,813.50	$114.52
	Working Capital					
(13)	Materials and Supplies (2) x 0.22%	1.68	41.54	39.02	153.58	1.74
(14)	Prepayments (2) x 1.250%	9.52	236.01	221.69	872.59	9.88
(15)	Cash Working Capital [(7)+(8)+(10)+(11)] x 12.50%	8.37	39.02	217.71	1,065.84	9.07
(16)	Revenue Requirement for Working Capital [(13)+(14)+(15)] x 11.28%	$2.21	35.71	53.97	235.98	2.33
(17)	Total Annual Marginal Customer-Related Costs (12) + (16)	**$107.23**	**$1,618.67**	**$3,438.90**	**$17,049.47**	**$116.85**

Table 23. C. Derivation of Annual Meter, Service and Customer-Related Costs (Lighting)

		SC 5	SL 1	SL 2	SL 3
			St. Light with Contrib	St. Light Energy & Limited	Standard Street Light
		Outdoor Lighting	Provisions	Maint.	Service
		(2016 Dollars per Customer)			
		(11)	(12)	(13)	(14)
(1)	Meter & Service Investment	na	$0.00	$0.00	$0.00
(2)	With General Plant Loading (1) x 1.2109	0.00	0.00	0.00	0.00
(3)	Annual Economic Charge Related to Capital Investment	11.25%	11.25%	11.25%	11.25%
(4)	A&G Loading (Plant Related)	0.00%	0.00%	0.00%	0.00%
(5)	Total (3) + (4)	11.25%	11.25%	11.25%	11.25%
(6)	Annualized Costs (2) x (5)	$0.00	$0.00	$0.00	$0.00
(7)	Meter O&M Expenses	na	0.00	0.00	0.00
(8)	Customer Accounts Expenses excl. Uncoll.	28.07	101.25	101.25	101.25
(9)	Uncollectibles	0.90	26.03	26.03	26.03
(10)	Customer Service & Informational Expenses	1.10	32.23	32.23	32.23
(11)	A&G Loading [(7)+(8)+(10)] x 0.0152 (Non-plant Related)	0.44	2.02	2.02	2.02
(12)	Customer-Related Costs (6)+(7)+(8)+(9)+(10)+(11)	$30.50	$161.53	$161.53	$161.53
	Working Capital				
(13)	Materials and Supplies (2) x 0.22%	0.00	0.00	0.00	0.00
(14)	Prepayments (2) x 1.250%	0.00	0.00	0.00	0.00
(15)	Cash Working Capital [(7)+(8)+(10)+(11)] x 12.50%	3.70	16.94	16.94	16.94
(16)	Revenue Requirement for Working Capital [(13)+(14)+(15)] x 11.28%	$0.42	1.91	1.91	1.91
(17)	Total Annual Marginal Customer-Related Costs (12) + (16)	**$30.92**	**$163.44**	**$163.44**	**$163.44**

Table 23. D. Derivation of Total Annual Meter, Service and Customer-Related Costs – Before CIAC

		SC 1	SC 8	SC 12	SC 2	SC 3
		Residential	Residential Day Night	Residential TOU	General Service with Demand	Primary Service (Primary)
		(2016 Dollars per Customer)				
		(1)	(2)	(3)	(4)	(5)
(1)	Meter and Service Investment	$943.03	$1,020.06	$1,020.06	$9,755.20	$15,373.35
(2)	With General Plant Loading (1) x 1.2109	1,141.91	1,235.19	1,235.19	11,812.57	18,615.59
(3)	Annual Economic Charge Related to Capital Investment	11.25%	11.25%	11.25%	11.25%	11.25%
(4)	A&G Loading (Plant Related)	0.00%	0.00%	0.00%	0.00%	0.00%
(5)	Total (3) + (4)	11.25%	11.25%	11.25%	11.25%	11.25%
(6)	Annualized Costs (2) x (5)	$128.47	$138.96	$138.96	$1,328.96	$2,094.33
(7)	Meter O&M Expenses	13.90	22.43	22.43	47.28	871.51
(8)	Customer Accounts Expenses excl. Uncoll.	50.02	53.06	65.48	65.55	154.95
(9)	Uncollectibles	9.84	13.08	41.09	7.62	33.88
(10)	Customer Service & Informational Expenses	1.01	1.34	4.23	8.64	39.97
(11)	A&G Loading [(7)+(8)+(10)] x 0.0152 (Non-plant Related)	0.98	1.16	1.40	1.84	16.17
(12)	Customer-Related Costs (6)+(7)+(8)+(9)+(10)+(11)	$204.22	$230.04	$273.59	$1,459.90	$3,210.80
	Working Capital					
(13)	Materials and Supplies (2) x 0.22%	2.51	2.72	2.72	25.99	40.95
(14)	Prepayments (2) x 1.250%	14.27	15.44	15.44	147.66	232.69
(15)	Cash Working Capital [(7)+(8)+(10)+(11)] x 12.50%	8.24	9.75	11.69	15.41	135.32
(16)	Revenue Requirement for Working Capital [(13)+(14)+(15)] x 11.28%	2.82	3.15	3.37	21.33	46.13
(17)	Total Annual Marginal Customer-Related Costs (12) + (16)	**$207.04**	**$233.19**	**$276.95**	**$1,481.22**	**$3,256.93**

Table 23. E. Derivation of Total Annual Meter, Service and Customer-Related Costs – Before CIAC

		SC 6 General Service	SC 7-1 LGS TOU Secondary	SC 7-2 LGS TOU Primary	SC 7-4 LGS TOU Trans-mission	SC 9 General Service Day Night
		(2016 Dollars per Customer)				
		(6)	(7)	(8)	(9)	(10)
(1)	Meter & Service Investment	$629.03	$15,592.39	$14,646.13	$57,648.91	$652.94
(2)	With General Plant Loading (1) x 1.2109	761.70	18,880.83	17,735.00	69,807.07	790.64
(3)	Annual Economic Charge Related to Capital Investment	11.25%	11.25%	11.25%	11.25%	11.25%
(4)	A&G Loading (Plant Related)	0.00%	0.00%	0.00%	0.00%	0.00%
(5)	Total (3) + (4)	11.25%	11.25%	11.25%	11.25%	11.25%
(6)	Annualized Costs (2) x (5)	$85.69	$2,124.17	$1,995.26	$7,853.56	$88.95
(7)	Meter O&M Expenses	19.17	104.64	790.94	6,387.43	21.82
(8)	Customer Accounts Expenses excl. Uncoll.	45.54	159.92	666.51	1,312.22	47.71
(9)	Uncollectibles	1.18	36.64	209.64	433.18	1.83
(10)	Customer Service & Informational Expenses	1.24	42.91	258.26	699.77	1.91
(11)	A&G Loading [(7)+(8)+(10)] x 0.0152 (Non-plant Related)	1.00	4.66	26.01	127.32	1.08
(12)	Customer-Related Costs (6)+(7)+(8)+(9)+(10)+(11)	$153.82	$2,472.93	$3,946.61	$16,813.50	$163.31
	Working Capital					
(13)	Materials and Supplies (2) x 0.22%	1.68	41.54	39.02	153.58	1.74
(14)	Prepayments (2) x 1.250%	9.52	236.01	221.69	872.59	9.88
(15)	Cash Working Capital [(7)+(8)+(10)+(11)] x 12.50%	8.37	39.02	217.71	1,065.84	9.07
(16)	Revenue Requirement for Working Capital [(13)+(14)+(15)] x 11.28%	2.21	35.71	53.97	235.98	2.33
(17)	Total Annual Marginal Customer-Related Costs (12) + (16)	**$156.02**	**$2,508.64**	**$4,000.58**	**$17,049.47**	**$165.64**

Table 23. F. Derivation of Total Annual Meter, Service and Customer-Related Costs – Before CIAC

		SC 5	SL 1	SL 2	SL 3
		Outdoor Lighting	St. Light with Contrib Provisions	St. Light Energy & Limited Maint.	Standard Street Light Service
		------------------------- (2016 Dollars per Customer) --------			
		(11)	(12)	(13)	(14)
(1)	Meter & Service Investment	na	$0.00	$0.00	$0.00
(2)	With General Plant Loading (1) x 1.2109	0.00	0.00	0.00	0.00
(3)	Annual Economic Charge Related to Capital Investment	11.25%	11.25%	11.25%	11.25%
(4)	A&G Loading (Plant Related)	0.00%	0.00%	0.00%	0.00%
(5)	Total (3) + (4)	11.25%	11.25%	11.25%	11.25%
(6)	Annualized Costs (2) x (5)	$0.00	$0.00	$0.00	$0.00
(7)	Meter O&M Expenses	na	0.00	0.00	0.00
(8)	Customer Accounts Expenses excl. Uncoll.	28.07	101.25	101.25	101.25
(9)	Uncollectibles	0.90	26.03	26.03	26.03
(10)	Customer Service & Informational Expenses	1.10	32.23	32.23	32.23
(11)	A&G Loading [(7)+(8)+(10)] x 0.0152 (Non-plant Related)	0.44	2.02	2.02	2.02
(12)	Customer-Related Costs (6)+(7)+(8)+(9)+(10)+(11)	$30.50	$161.53	$161.53	$161.53
	Working Capital				
(13)	Materials and Supplies (2) x 0.22%	0.00	0.00	0.00	0.00
(14)	Prepayments (2) x 1.250%	0.00	0.00	0.00	0.00
(15)	Cash Working Capital [(7)+(8)+(10)+(11)] x 12.50%	3.70	16.94	16.94	16.94
(16)	Revenue Requirement for Working Capital [(13)+(14)+(15)] x 11.28%	0.42	1.91	1.91	1.91
(17)	Total Annual Marginal Customer-Related Costs (12) + (16)	**$30.92**	**$163.44**	**$163.44**	**$163.44**

Table 24 and Table 25 show the annualization of lighting costs for Outdoor Lighting Service and Standard Lighting Service components.

Table 24. Derivation of Annual Outdoor Lighting Costs

		Investment per Unit	With General Plant Loading	Annual Economic Carrying Charge	Annualized Cost	O&M With A&G Loading (Non-plant)	Materials & Supplies & Prepayments	Revenue Requirement for Working Capital	Total Annual Cost per Unit
			(1) x 1.2109	12.11%	(2) x (3)		(2) x 0.0147	[(8)+(9)] x 0.1128	(4) + (5)+(7)
		(2016 Dollars per Unit)							
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Safeguard Luminaires								
(1)	14,500 Nominal Lumen 150 Watt H.P.S. (replacing 7,000 L. 175 Watt M.V.)	$583.85	$706.98	12.11%	$85.58	$0.00	$10.39	$1.17	**$86.76**
(2)	43,000 Nominal Lumen 400 Watt H.P.S. (replacing 17,200 L. 400 Watt M.V.)	$650.38	$787.54	12.11%	$95.34	$0.00	$11.58	$1.31	**$96.64**
(3)	123,000 Nominal Lumen 940 Watt H.P.S. (replacing 48,000 L. 1,000 Watt M.V.)	$918.36	$1,112.04	12.11%	$134.62	$0.00	$16.35	$1.84	**$136.46**
	Area Lights								
(4)	8,500 Nominal Lumen (100 Watt) H.P.S.*	$33.61	$40.70	12.11%	$4.93	$0.00	$0.60	$0.07	**$4.99**
(5)	8,500 Nominal Lumen (100 Watt) H.P.S. Power Bracket	$634.04	$767.76	12.11%	$92.94	$0.00	$11.29	$1.27	**$94.22**
(6)	14,400 Nominal Lumen (150 Watt) H.P.S.	$583.85	$706.98	12.11%	$85.58	$0.00	$10.39	$1.17	**$86.76**
(7)	24,700 Nominal Lumen (250 Watt) H.P.S.	$614.99	$744.69	12.11%	$90.15	$0.00	$10.95	$1.23	**$91.38**
(8)	45,000 Nominal Lumen (400 Watt) H.P.S.	$650.38	$787.54	12.11%	$95.34	$0.00	$11.58	$1.31	**$96.64**
(9)	126,000 Nominal Lumen (1,000 Watt) H.P.S.	$918.36	$1,112.04	12.11%	$134.62	$0.00	$16.35	$1.84	**$136.46**
(10)	10,500 Nominal Lumen (175 Watt) Metal Halide Power Bracket	$728.95	$882.68	12.11%	$106.85	$0.00	$12.98	$1.46	**$108.32**
(11)	16,000 Nominal Lumen (250 Watt) Metal Halide	$622.46	$753.73	12.11%	$91.24	$0.00	$11.08	$1.25	**$92.49**
(12)	28,000 Nominal Lumen (400 Watt) Metal Halide	$650.27	$787.41	12.11%	$95.32	$0.00	$11.57	$1.31	**$96.63**
	Flood Lights								
(13)	14,400 Nominal Lumen (150 Watt) H.P.S.	$674.50	$816.76	12.11%	$98.87	$0.00	$12.01	$1.35	**$100.23**
(14)	24,700 Nominal Lumen (250 Watt) H.P.S	$687.80	$832.86	12.11%	$100.82	$0.00	$12.24	$1.38	**$102.20**
(15)	45,000 Nominal Lumen (400 Watt) H.P.S.	$688.21	$833.35	12.11%	$100.88	$0.00	$12.25	$1.38	**$102.26**
(16)	126,000 Nominal Lumen (1,000 Watt) H.P.S.	$799.27	$967.83	12.11%	$117.16	$0.00	$14.23	$1.60	**$118.77**
(17)	16,000 Nominal Lumen (250 Watt) Metal Halide	$685.04	$829.51	12.11%	$100.42	$0.00	$12.19	$1.38	**$101.79**
(18)	28,000 Nominal Lumen (400 Watt) Metal Halide	$685.05	$829.53	12.11%	$100.42	$0.00	$12.19	$1.38	**$101.80**
(19)	88,000 Nominal Lumen (1,000 Watt) Metal Halide	$783.17	$948.35	12.11%	$114.80	$0.00	$13.94	$1.57	**$116.38**
	"Shoebox" Luminaire								
(20)	14,400 Nominal Lumen (150 Watt) H.P.S.	$784.55	$950.01	12.11%	$115.01	$0.00	$13.97	$1.58	**$116.58**
(21)	24,700 Nominal Lumen (250 Watt) H.P.S.	$787.51	$953.59	12.11%	$115.44	$0.00	$14.02	$1.58	**$117.02**
(22)	45,000 Nominal Lumen (400 Watt) H.P.S.	$847.96	$1,026.79	12.11%	$124.30	$0.00	$15.09	$1.70	**$126.00**
(23)	16,000 Nominal Lumen (250 Watt) Metal Halide	$834.33	$1,010.30	12.11%	$122.30	$0.00	$14.85	$1.68	**$123.98**
(24)	28,000 Nominal Lumen (400 Watt) Metal Halide	$821.84	$995.17	12.11%	$120.47	$0.00	$14.63	$1.65	**$122.12**
(25)	88,000 Nominal Lumen (1,000 Watt) Metal Halide	$940.58	$1,138.95	12.11%	$137.88	$0.00	$16.74	$1.89	**$139.77**
	Post Tops								
(26)	5,200 Nominal Lumen (70 Watt) H.P.S.	$643.93	$779.74	10.68%	$83.24	$0.00	$11.46	$1.29	**$84.54**
(27)	8,500 Nominal Lumen (100 Watt) H.P.S.	$650.96	$788.25	10.68%	$84.15	$0.00	$11.59	$1.31	**$85.46**
(28)	Brackets 16' and over	$253.24	$306.65	10.68%	$32.74	$0.00	$4.51	$0.51	**$33.25**
(29)	Additional Wood Pole Installed for Lamp	$655.47	$793.71	10.68%	$84.74	$58.50	$11.67	$2.14	**$145.37**
(30)	Wire Service (Overhead) (Per circuit foot of extension)	$1.49	$1.81	10.68%	$0.19	$0.00	$0.03	$0.00	**$0.20**
(31)	18' Fiberglass Pole - Direct Embedded	$617.48	$747.71	10.68%	$79.83	$5.22	$10.99	$1.31	**$86.36**
(32)	20' Fiberglass Pole - Pedestal Mount	$617.48	$747.71	10.68%	$79.83	$5.22	$10.99	$1.31	**$86.36**
(33)	20' Metal Pole - Pedestal Mount	$926.71	$1,122.15	10.68%	$119.80	$30.15	$16.50	$2.29	**$152.23**
(34)	30' Metal Pole - Pedestal Mount	$1,079.30	$1,306.93	10.68%	$139.53	$30.15	$19.21	$2.59	**$172.27**
(35)	30' Fiberglass Pole - Pedestal Mount	$1,594.31	$1,930.55	10.68%	$206.11	$5.22	$28.38	$3.27	**$214.60**
(36)	30' Fiberglass Pole - Direct Embedded	$1,594.31	$1,930.55	10.68%	$206.11	$5.22	$28.38	$3.27	**$214.60**
(37)	Screw Base for Pedestal Mounted Pole - Light Duty	$767.57	$929.45	10.68%	$99.23	$0.00	$13.66	$1.54	**$100.77**
(38)	Screw Base for Pedestal Mounted Pole - Heavy Duty	$776.96	$940.82	10.68%	$100.44	$0.00	$13.83	$1.56	**$102.00**

Table 25. Derivation of Annual Standard Lighting Service Costs

		Investment per Unit	With General Plant Loading	Annual Economic Carrying Charge	Annualized Cost	O&M With A&G Loading (Non-plant)	Materials & Supplies & Prepayments	Revenue Requirement for Working Capital	Total Annual Cost per Unit
			(1) x 1.2109	12.11%	(2) x (3)		(2) x 0.0147	[(8)+(9)] x 0.1128	(4)+(5)+(7)
		----------	----------	----------	----------	(2016 Dollars per Unit)	----------	----------	----------
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	High Pressure Sodium Cobra								
(1)	70 Watts - 5,200 Lumen	$591.19	$715.87	12.11%	$86.66	$0.00	$10.52	$1.19	**$87.85**
(2)	150 Watts - 14,400 Lumen	$600.44	$727.07	12.11%	$88.02	$0.00	$10.69	$1.21	**$89.22**
(3)	250 Watts - 24,700 Lumen	$631.22	$764.34	12.11%	$92.53	$0.00	$11.24	$1.27	**$93.80**
(4)	400 Watts - 45,000 Lumen	$667.71	$808.52	12.11%	$97.88	$0.00	$11.89	$1.34	**$99.22**
(5)	1000 Watts - 126,000 Lumen	$962.71	$1,165.74	12.11%	$141.12	$0.00	$17.14	$1.93	**$143.05**
	High Pressure Sodium Post Top								
(6)	50 Watts - 3,300 Lumen	$668.07	$808.97	12.11%	$97.93	$0.00	$11.89	$1.34	**$99.27**
(7)	70 Watts - 5,200 Lumen	$659.14	$798.15	12.11%	$96.62	$0.00	$11.73	$1.32	**$97.94**
(8)	150 Watts - 14,400 Lumen	$673.81	$815.92	12.11%	$98.77	$0.00	$11.99	$1.35	**$100.12**
	High Pressure Sodium Cut Off ("Shoebox")								
(9)	250 Watts - 24,700 Lumen	$803.73	$973.24	12.11%	$117.82	$0.00	$14.31	$1.61	**$119.43**
(10)	400 Watts - 45,000 Lumen	$897.96	$1,087.34	12.11%	$131.63	$0.00	$15.98	$1.80	**$133.43**
	Metal Halide Cobra								
(11)	100 Watts – 5,800 Lumen	$660.08	$799.29	12.11%	$96.76	$0.00	$11.75	$1.33	**$98.08**
(12)	175 Watts – 12,000 Lumen	$634.42	$768.22	12.11%	$93.00	$0.00	$11.29	$1.27	**$94.27**
(13)	250 Watts - 16,000 Lumen	$631.72	$764.95	12.11%	$92.60	$0.00	$11.24	$1.27	**$93.87**
(14)	400 Watts - 28,000 Lumen	$716.22	$867.27	12.11%	$104.99	$0.00	$12.75	$1.44	**$106.43**
	Metal Halide Cut Off ("Shoebox")								
(15)	175 Watts – 12,000 Lumen	$731.21	$885.42	12.11%	$107.19	$0.00	$13.02	$1.47	**$108.65**
(16)	250 Watts - 16,000 Lumen	$776.20	$939.90	12.11%	$113.78	$0.00	$13.82	$1.56	**$115.34**
(17)	400 Watts - 28, 000 Lumen	$839.02	$1,015.97	12.11%	$122.99	$0.00	$14.93	$1.68	**$124.67**
	Metal Halide Post Top								
(18)	70 Watts – 4,000 Lumen	$703.63	$852.03	12.11%	$103.14	$0.00	$12.52	$1.41	**$104.56**
(19)	100 Watts- 5,800 Lumen	$724.86	$877.73	12.11%	$106.26	$0.00	$12.90	$1.46	**$107.71**
(20)	175 Watts - 12,000 Lumen	$695.61	$842.31	12.11%	$101.97	$0.00	$12.38	$1.40	**$103.36**
	High Pressure Sodium Special Luminaires								
(21)	250 Watts - 24,700 - Hiway Liter	$1,733.98	$2,099.68	12.11%	$254.18	$0.00	$30.87	$3.48	**$257.66**
(22)	400 Watts - 45,000 - Hiway Liter	$1,485.65	$1,798.97	12.11%	$217.78	$0.00	$26.44	$2.98	**$220.76**
(23)	150 Watts - 14,400 - Turnpike	$1,027.44	$1,244.12	12.11%	$150.61	$0.00	$18.29	$2.06	**$152.67**
(24)	250 Watts - 24,700 - Turnpike	$1,041.31	$1,260.92	12.11%	$152.64	$0.00	$18.54	$2.09	**$154.73**
(25)	400 Watts - 45,000 - Turnpike	$1,109.27	$1,343.21	12.11%	$162.60	$0.00	$19.75	$2.23	**$164.83**
(26)	150 Watts - 14,400 - Floodlight	$690.36	$835.96	12.11%	$101.20	$0.00	$12.29	$1.39	**$102.58**
(27)	250 Watts - 24,700 - Floodlight	$704.03	$852.51	12.11%	$103.20	$0.00	$12.53	$1.41	**$104.62**
(28)	400 Watts - 45,000 - Floodlight	$704.86	$853.52	12.11%	$103.32	$0.00	$12.55	$1.42	**$104.74**
	Metal Halide - Floodlights								
(29)	250 Watts - 16,000 Lumen	$729.67	$883.56	12.11%	$106.96	$0.00	$12.99	$1.47	**$108.43**
(30)	400 Watts - 28,000 Lumen	$702.15	$850.23	12.11%	$102.93	$0.00	$12.50	$1.41	**$104.34**
	Pole Installed by the Corporation								
(31)	Standard Wood Pole	$422.56	$511.68	10.68%	$54.63	$58.50	$7.52	$1.67	**$114.80**
(32)	Wood Pole - high mount use (45' or greater)	$603.37	$730.62	10.68%	$78.00	$58.50	$10.74	$2.04	**$138.53**
(33)	Aluminum Pole 16' and under	$407.31	$493.21	10.68%	$52.65	$0.00	$7.25	$0.82	**$53.47**
(34)	Alum. Pole over 16' installed prior to August 1, 1987	$648.84	$785.68	10.68%	$83.88	$0.00	$11.55	$1.30	**$85.18**
(35)	Alum. Pole over 16' direct embedded installed after July 31, 1987	$648.84	$785.68	10.68%	$83.88	$0.00	$11.55	$1.30	**$85.18**
(36)	Alum. Pole over 16' pedestal mounted	$771.67	$934.42	10.68%	$99.76	$0.00	$13.74	$1.55	**$101.31**
(37)	Fiberglass Pole 18' and under	$390.87	$473.31	10.68%	$50.53	$5.22	$6.96	$0.86	**$56.60**
(38)	Fiberglass Pole 18' to 22'	$390.87	$473.31	10.68%	$50.53	$5.22	$6.96	$0.86	**$56.60**
	Screw-in steel base for pedestal mounted poles:								
(39)	Light Duty	$270.74	$327.84	10.68%	$35.00	$0.00	$4.82	$0.54	**$35.54**
(40)	Heavy Duty	$278.57	$337.32	10.68%	$36.01	$0.00	$4.96	$0.56	**$36.57**
	Special Brackets								
(41)	Standard Bracket - 16' and over	$388.17	$470.03	10.68%	$50.18	$0.00	$6.91	$0.78	**$50.96**
	Circuit Control								
(42)	Group Controllers	$654.76	$792.85	10.68%	$84.64	$0.00	$11.65	$1.31	**$85.96**
	Circuits (Per Trench Foot)**								
(43)	Cable and Conduit	$2.58	$3.12	10.68%	$0.33	$0.00	$0.05	$0.01	**$0.34**
(44)	Direct Burial Cable	$1.93	$2.34	10.68%	$0.25	$0.00	$0.03	$0.00	**$0.25**
(45)	Cable Only (Conduit Supplied by Customer)	$1.47	$1.78	10.68%	$0.19	$0.00	$0.03	$0.00	**$0.19**
(46)	Underground Circuits	$2.58	$3.12	10.68%	$0.33	$0.00	$0.05	$0.01	**$0.34**

VIII. SUMMARY TABLES

Annual marginal upstream substation and distribution substation and trunkline feeder costs were time-differentiated using the probability of peak analysis described in Section IV.A.2 above. In Table 26 we show these monthly costs, adjusted by losses, for each TOD period, season, and averaged over the entire year. These costs can also be expressed on a per-kWh basis by dividing by the number of hours in the period, as shown on Table 26. Table 26 also includes the per-kWh marginal transmission costs.

Table 26. A. Summary of Monthly Marginal Upstream Substation, Distribution Substation and Trunkline Feeder Costs per kW by Season and Time of Day

			Summer Season			Winter Season			Off Season		
			On-Peak	Shoulder	Off-Peak	On-Peak	Shoulder	Off-Peak	On-Peak	Shoulder	Off-Peak
			(2016 Dollars per kW per month)								
			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Residential TOU Periods										
	Secondary Service										
(1)	**TOD**	Upstream Dist.	$4.120	$0.459	$0.000	$0.000	$0.000	$0.000		$0.000	$0.000
(2)		Dist. Substation	$5.972	$0.665	$0.000	$0.000	$0.000	$0.000		$0.000	$0.000
			$10.092	$1.125	$0.000	$0.000	$0.000	$0.000		$0.000	$0.000
(3)	**Seasonal**	Upstream Dist.	$4.579			$0.000			$0.000		
(4)		Dist. Substation	$6.637			$0.000			$0.000		
			$11.217			$0.000			$0.000		
(5)	**Annual**	Upstream Dist.	$1.145								
(6)		Dist. Substation	$1.659								
			$2.804								
	LGS TOU Periods										
	Transmission Service										
(7)	**TOD**		$0.000		$0.000	$0.000		$0.000	$0.000		$0.000
(8)	**Seasonal**		$0.000			$0.000			$0.000		
(9)	**Annual**		$0.000								
	Primary Service										
(10)	**TOD**	Upstream Distribution	$4.231		$0.040	$0.000		$0.000	$0.000		$0.000
(11)	**Seasonal**	Upstream Distribution	$4.271			$0.000			$0.000		
(12)	**Annual**	Upstream Distribution	$1.068								
(10)	**TOD**	Upstream Dist.	$4.327		$0.041	$0.000		$0.000	$0.000		$0.000
(11)		Dist. Substation	$6.272		$0.059	$0.000		$0.000	$0.000		$0.000
			$10.599		$0.101	$0.000		$0.000	$0.000		$0.000
(12)	**Seasonal**	Upstream Dist.	$4.368			$0.000			$0.000		
(13)		Dist. Substation	$6.331			$0.000			$0.000		
			$10.700			$0.000			$0.000		
(14)	**Annual**	Upstream Dist.	$1.092								
(15)		Dist. Substation	$1.583								
			$2.675								
	Secondary Service										
(16)	**TOD**	Upstream Dist.	$4.536		$0.043	$0.000		$0.000	$0.000		$0.000
(17)		Dist. Substation	$6.575		$0.062	$0.000		$0.000	$0.000		$0.000
			$11.111		$0.105	$0.000		$0.000	$0.000		$0.000
(18)	**Seasonal**	Upstream Dist.	$4.579			$0.000			$0.000		
(19)		Dist. Substation	$6.637			$0.000			$0.000		
			$11.216			$0.000			$0.000		
(20)	**Annual**	Upstream Dist.	$1.145								
(21)		Dist. Substation	$1.659								
			$2.804								

Table 26. B. Summary of Monthly Marginal Upstream Substation, Distribution Substation and Trunkline Feeder Costs per kW by Time of Day, No seasonal differentiation

		Annual Cost		
		On-Peak	Mid-Peak	Off-Peak
		($/kW-month)		
		(1)	(2)	(3)
Residential TOU Periods				
Secondary Service				
TOD	Upstream Dist.	$2.095	$0.092	$0.000
	Dist. Substation	$3.036	$0.133	$0.000
		$5.131	$0.225	$0.000
LGS TOU Periods				
Primary Service				
TOD	Upstream Dist.	$0.956		$0.012
	Dist. Substation	$1.386		$0.017
		$2.342		$0.029
Secondary Service				
TOD	Upstream Dist.	$1.002		$0.012
	Dist. Substation	$1.453		$0.018
		$2.455		$0.030
Day Night Periods				
Secondary Service				
TOD	Upstream Dist.	$1.154		$0.000
	Dist. Substation	$1.673		$0.000
		$2.827		$0.000

Table 27. Summary of Marginal Transmission and Distribution Costs on a per-kWh basis

			Summer Season			Winter Season			Off Season		
			On-Peak	Shoulder	Off-Peak	On-Peak	Shoulder	Off-Peak	On-Peak	Mid-Peak	Off-Peak
			(2016 Dollars per kWh)								
			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Residential TOU Periods										
	Secondary Service										
(1)	**TOD**	Transmission	$0.0043	$0.0043	$0.0042	$0.0043	$0.0043	$0.0043		$0.0043	$0.0042
(2)		Upstream Dist.	$0.0238	$0.0014	$0.0000	$0.0000	$0.0000	$0.0000		$0.0000	$0.0000
(3)		Dist. Substation	$0.0345	$0.0020	$0.0000	$0.0000	$0.0000	$0.0000		$0.0000	$0.0000
			$0.0626	$0.0077	$0.0042	$0.0043	$0.0043	$0.0043		$0.0043	$0.0042
(4)	**Seasonal**	Transmission	$0.0043			$0.0043			$0.0043		
(5)		Upstream Dist.	$0.0062			$0.0000			$0.0000		
(6)		Dist. Substation	$0.0090			$0.0000			$0.0000		
			$0.0195			$0.0043			$0.0043		
(7)	**Annual**	Transmission	$0.0043								
(8)		Upstream Dist.	$0.0016								
(9)		Dist. Substation	$0.0023								
			$0.0081								
	LGS TOU Periods										
	Transmission Service										
(10)	**TOD**	Transmission	$0.0040		$0.0040	$0.0040		$0.0040	$0.0040		$0.0040
(11)	**Seasonal**	Transmission	$0.0040			$0.0040			$0.0040		
(12)	**Annual**	Transmission	$0.0040								
(13)	De **TOD**	Transmission	$0.0041		$0.0041	$0.0041		$0.0041	$0.0041		$0.0041
(14)		Upstream Distribution	$0.0130		$0.0001	$0.0000		$0.0000	$0.0000		$0.0000
			$0.0172		$0.0042	$0.0041		$0.0041	$0.0041		$0.0041
(15)	**Seasonal**	Transmission	$0.0041			$0.0041			$0.0041		
(16)		Upstream Dist.	$0.0058			$0.0000			$0.0000		
			$0.0099			$0.0041			$0.0041		
(17)	**Annual**	Transmission	$0.0041								
(18)		Upstream Dist.	$0.0015								
			$0.0056								
	Primary Service										
(13)	**TOD**	Transmission	$0.0043		$0.0042	$0.0043		$0.0042	$0.0042		$0.0042
(14)		Upstream Dist.	$0.0133		$0.0001	$0.0000		$0.0000	$0.0000		$0.0000
(15)		Dist. Substation	$0.0193		$0.0001	$0.0000		$0.0000	$0.0000		$0.0000
			$0.0369		$0.0045	$0.0043		$0.0042	$0.0042		$0.0042
(16)	**Seasonal**	Transmission	$0.0042			$0.0043			$0.0042		
(17)		Upstream Dist.	$0.0059			$0.0000			$0.0000		
(18)		Dist. Substation	$0.0086			$0.0000			$0.0000		
			$0.0188			$0.0043			$0.0042		
(19)	**Annual**	Transmission	$0.0042								
(20)		Upstream Dist.	$0.0015								
(21)		Dist. Substation	$0.0022								
			$0.0079								
	Secondary Service										
(22)	**TOD**	Transmission	$0.0043		$0.0043	$0.0043		$0.0043	$0.0043		$0.0042
(23)		Upstream Dist.	$0.0140		$0.0001	$0.0000		$0.0000	$0.0000		$0.0000
(24)		Dist. Substation	$0.0202		$0.0002	$0.0000		$0.0000	$0.0000		$0.0000
			$0.0385		$0.0045	$0.0043		$0.0043	$0.0043		$0.0042
(25)	**Seasonal**	Transmission	$0.0043			$0.0043			$0.0043		
(26)		Upstream Dist.	$0.0062			$0.0000			$0.0000		
(27)		Dist. Substation	$0.0090			$0.0000			$0.0000		
			$0.0195			$0.0043			$0.0043		
(28)	**Annual**	Transmission	$0.0043								
(29)		Upstream Dist.	$0.0016								
(30)		Dist. Substation	$0.0023								
			$0.0081								
	Day Night Periods (SC8)										
	Secondary Service										
(31)	**TOD**	Transmission	$0.0043		$0.0042	$0.0043		$0.0043	$0.0043		$0.0042
(32)		Upstream Dist.	$0.0091		$0.0000	$0.0000		$0.0000	$0.0000		$0.0000
(33)		Dist. Substation	$0.0131		$0.0000	$0.0000		$0.0000	$0.0000		$0.0000
			$0.0265		$0.0042	$0.0043		$0.0043	$0.0043		$0.0042
(34)	**Seasonal**	Transmission	$0.0043			$0.0043			$0.0043		
(35)		Upstream Dist.	$0.0062			$0.0000			$0.0000		
(36)		Dist. Substation	$0.0090			$0.0000			$0.0000		
			$0.0195			$0.0043			$0.0043		
(37)	**Annual**	Transmission	$0.0043								
		Upstream Dist.	$0.0016								
		Dist. Substation	$0.0023								
			$0.0081								

Table 28 A summarizes monthly marginal customer-related and local distribution facilities costs per kW of design demand and on a per customer basis, by service classification. The monthly costs on this table exclude the portion of paid for upfront in customer contributions. Table 28 B shows the same marginal cost components, but includes all costs.

Table 28. A. Summary of Monthly Marginal Customer and Local Distribution Facilities Costs (after CIAC payments)

	Customer Class		Monthly Distribution Facilities Marginal Unit Costs	Typical Design Demand	Monthly Distribution Facilities Cost per Customer	Monthly Marginal Customer Unit Costs	Total Monthly Costs
			(2016 $/kW/Month)	(kW)	--------------(2016 $/Customer/Month)--------------		
					(1) x (2)		(3) + (4)
			(1)	(2)	(3)	(4)	(5)
(1)	SC 1	Residential Service	$9.88	4.00	39.52	$13.89	$53.41
(2)	SC 8	Residential Service Day Night Service	$9.88	4.00	39.52	$16.07	$55.59
(3)	SC 12	Residential Service with Time-of-Use Metering	$9.88	10.00	98.80	$19.72	$118.52
(4)	SC 2	General Service with Demand Metering	$6.49	24.00	155.76	$92.80	$248.56
(5)	SC 3	Primary Service - 25 kW or more - Primary	$5.45	102.00	555.90	$224.60	$780.50
(6)	SC5	Outdoor Lighting Service	NA	NA	NA	$2.58	$2.58
(7)	SC 6	General Service	$9.47	5.00	47.35	$8.94	$56.29
(8)	SC 7-1	LGS with TOU Metering - Secondary	$3.70	83.00	307.10	$134.89	$441.99
(9)	SC 7-2	LGS with TOU - Primary	$5.45	733.00	3,994.85	$286.58	$4,281.43
(10)	SC 7-4	LGS with TOU Metering - Transmission	NA	NA	NA	$1,420.79	$1,420.79
(11)	SC 9	General Service - Day Night Service	$9.47	5.00	47.35	$9.74	$57.09
(12)	SL 1	Street Lighting - Contributory Provisions	NA	NA	NA	$13.62	$13.62
(13)	SL 2	Street Lighting - Energy and Limited Maintenance	NA	NA	NA	$13.62	$13.62
(14)	SL 3	Standard Street Lighting Service	NA	NA	NA	$13.62	$13.62

Table 28. B. Summary of Total Monthly Marginal Customer and Local Distribution Facilities Costs (total before CIAC payments)

	Customer Class		Monthly Distribution Facilities Marginal Unit Costs	Typical Design Demand	Monthly Distribution Facilities Cost per Customer	Monthly Marginal Customer Unit Costs	Total Monthly Costs
			(2016 $/kW/Month)	(kW)	--------------(2016 $/Customer/Month)--------------		
					(1) x (2)		(3) + (4)
			(1)	(2)	(3)	(4)	(5)
(1)	SC 1	Residential Service	$11.95	4.00	47.80	$17.25	$65.05
(2)	SC 8	Residential Service Day Night Service	$11.95	4.00	47.80	$19.43	$67.23
(3)	SC 12	Residential Service with Time-of-Use Metering	$11.95	10.00	119.50	$23.08	$142.58
(4)	SC 2	General Service with Demand Metering	$8.29	24.00	198.96	$123.44	$322.40
(5)	SC 3	Primary Service - 25 kW or more - Primary	$6.36	102.00	648.72	$271.41	$920.13
(6)	SC5	Outdoor Lighting Service	na	na	na	$2.58	$2.58
(7)	SC 6	General Service	$11.27	5.00	56.35	$13.00	$69.35
(8)	SC 7-1	LGS with TOU Metering - Secondary	$4.00	83.00	332.00	$209.05	$541.05
(9)	SC 7-2	LGS with TOU - Primary	$6.36	733.00	4,661.88	$333.38	$4,995.26
(10)	SC 7-4	LGS with TOU Metering - Transmission	na	na	na	$1,420.79	$1,420.79
(11)	SC 9	General Service - Day Night Service	$11.27	5.00	56.35	$13.80	$70.15
(12)	SL 1	Street Lighting - Contributory Provisions	na	na	na	$13.62	$13.62
(13)	SL 2	Street Lighting - Energy and Limited Maintenance	na	na	na	$13.62	$13.62
(14)	SL 3	Standard Street Lighting Service	na	na	na	$13.62	$13.62

Table 29 - Table 31 summarize monthly lighting costs per unit.

Table 29. Summary of Monthly Marginal Outdoor Lighting Cost per Component

	Component	Monthly Marginal Cost Per Unit (2016 Dollars per Unit)
	Safeguard Luminaires	
(1)	14,500 Nominal Lumen 150 Watt H.P.S. (replacing 7,000 L. 175 Watt M.V.)	$7.23
(2)	43,000 Nominal Lumen 400 Watt H.P.S. (replacing 17,200 L. 400 Watt M.V.)	$8.05
(3)	123,000 Nominal Lumen 940 Watt H.P.S. (replacing 48,000 L. 1,000 Watt M.V.)	$11.37
	Area Lights	
(4)	8,500 Nominal Lumen (100 Watt) H.P.S.*	$0.42
(5)	8,500 Nominal Lumen (100 Watt) H.P.S. Power Bracket	$7.85
(6)	14,400 Nominal Lumen (150 Watt) H.P.S.	$7.23
(7)	24,700 Nominal Lumen (250 Watt) H.P.S.	$7.62
(8)	45,000 Nominal Lumen (400 Watt) H.P.S.	$8.05
(9)	126,000 Nominal Lumen (1,000 Watt) H.P.S.	$11.37
(10)	10,500 Nominal Lumen (175 Watt) Metal Halide Power Bracket	$9.03
(11)	16,000 Nominal Lumen (250 Watt) Metal Halide	$7.71
(12)	28,000 Nominal Lumen (400 Watt) Metal Halide	$8.05
	Flood Lights	
(13)	14,400 Nominal Lumen (150 Watt) H.P.S.	$8.35
(14)	24,700 Nominal Lumen (250 Watt) H.P.S	$8.52
(15)	45,000 Nominal Lumen (400 Watt) H.P.S.	$8.52
(16)	126,000 Nominal Lumen (1,000 Watt) H.P.S.	$9.90
(17)	16,000 Nominal Lumen (250 Watt) Metal Halide	$8.48
(18)	28,000 Nominal Lumen (400 Watt) Metal Halide	$8.48
(19)	88,000 Nominal Lumen (1,000 Watt) Metal Halide	$9.70
	"Shoebox" Luminaire	
(20)	14,400 Nominal Lumen (150 Watt) H.P.S.	$9.72
(21)	24,700 Nominal Lumen (250 Watt) H.P.S.	$9.75
(22)	45,000 Nominal Lumen (400 Watt) H.P.S.	$10.50
(23)	16,000 Nominal Lumen (250 Watt) Metal Halide	$10.33
(24)	28,000 Nominal Lumen (400 Watt) Metal Halide	$10.18
(25)	88,000 Nominal Lumen (1,000 Watt) Metal Halide	$11.65
	Post Tops	
(26)	5,200 Nominal Lumen (70 Watt) H.P.S.	$7.04
(27)	8,500 Nominal Lumen (100 Watt) H.P.S.	$7.12
(28)	Brackets 16' and over	$2.77
(29)	Additional Wood Pole Installed for Lamp	$12.11
(30)	Wire Service (Overhead) (Per circuit foot of extension)	$0.02
(31)	18' Fiberglass Pole - Direct Embedded	$7.20
(32)	20' Fiberglass Pole - Pedestal Mount	$7.20
(33)	20' Metal Pole - Pedestal Mount	$12.69
(34)	30' Metal Pole - Pedestal Mount	$14.36
(35)	30' Fiberglass Pole - Pedestal Mount	$17.88
(36)	30' Fiberglass Pole - Direct Embedded	$17.88
(37)	Screw Base for Pedestal Mounted Pole - Light Duty	$8.40
(38)	Screw Base for Pedestal Mounted Pole - Heavy Duty	$8.50

Table 30. Summary of Monthly Marginal Standard Lighting Service Cost per Component

	Component	Monthly Marginal Cost Per Unit
		(2016 Dollars per
	High Pressure Sodium Cobra	
(1)	70 Watts - 5,200 Lumen	$7.32
(2)	150 Watts - 14,400 Lumen	$7.44
(3)	250 Watts - 24,700 Lumen	$7.82
(4)	400 Watts - 45,000 Lumen	$8.27
(5)	1000 Watts - 126,000 Lumen	$11.92
	High Pressure Sodium Post Top	
(6)	50 Watts - 3,300 Lumen	$8.27
(7)	70 Watts - 5,200 Lumen	$8.16
(8)	150 Watts - 14,400 Lumen	$8.34
	High Pressure Sodium Cut Off ("Shoebox")	
(9)	250 Watts - 24,700 Lumen	$9.95
(10)	400 Watts - 45,000 Lumen	$11.12
	Metal Halide Cobra	
(11)	100 Watts – 5,800 Lumen	$8.17
(12)	175 Watts – 12,000 Lumen	$7.86
(13)	250 Watts - 16,000 Lumen	$7.82
(14)	400 Watts - 28,000 Lumen	$8.87
	Metal Halide Cut Off (“Shoebox”)	
(15)	175 Watts – 12,000 Lumen	$9.05
(16)	250 Watts - 16,000 Lumen	$9.61
(17)	400 Watts - 28, 000 Lumen	$10.39
	Metal Halide Post Top	
(18)	70 Watts – 4,000 Lumen	$8.71
(19)	100 Watts- 5,800 Lumen	$8.98
(20)	175 Watts - 12,000 Lumen	$8.61
	High Pressure Sodium Special Luminaires	
(21)	250 Watts - 24,700 - Hiway Liter	$21.47
(22)	400 Watts - 45,000 - Hiway Liter	$18.40
(23)	150 Watts - 14,400 - Turnpike	$12.72
(24)	250 Watts - 24,700 - Turnpike	$12.89
(25)	400 Watts - 45,000 - Turnpike	$13.74
(26)	150 Watts - 14,400 - Floodlight	$8.55
(27)	250 Watts - 24,700 - Floodlight	$8.72
(28)	400 Watts - 45,000 - Floodlight	$8.73
	Metal Halide - Floodlights	
(29)	250 Watts - 16,000 Lumen	$9.04
(30)	400 Watts - 28,000 Lumen	$8.69
	Pole Installed by the Corporation	
(31)	Standard Wood Pole	$9.57
(32)	Wood Pole - high mount use (45' or greater)	$11.54
(33)	Aluminum Pole 16' and under	$4.46
(34)	Alum. Pole over 16' installed prior to August 1, 1987	$7.10
(35)	Alum. Pole over 16' direct embedded installed after July 31, 1987	$7.10
(36)	Alum. Pole over 16' pedestal mounted	$8.44
(37)	Fiberglass Pole 18' and under	$4.72
(38)	Fiberglass Pole 18' to 22'	$4.72
	Screw-in steel base for pedestal mounted poles:	
(39)	Light Duty	$2.96
(40)	Heavy Duty	$3.05
	Special Brackets	
(41)	Standard Bracket - 16' and over	$4.25
	Circuit Control	
(42)	Group Controllers	$7.16
	Circuits (Per Trench Foot)**	
(43)	Cable and Conduit	$0.03
(44)	Direct Burial Cable	$0.02
(45)	Cable Only (Conduit Supplied by Customer)	$0.02
(46)	Underground Circuits	$0.03

Table 31. Summary of Monthly Relamping Expense per Component

Lamp Type	Monthly Cost per Unit (2016$/ Unit)
High Pressure Sodium	
50 Watts - 3,300 Lumen	$1.61
70 Watts - 5,200 Lumen	$1.61
100 Watts - 8,500 Lumen	$1.65
150 Watts - 14,400 Lumen	$1.66
250 Watts - 24,700 Lumen	$1.67
400 Watts - 45,000 Lumen	$1.68
940 Watts - 123,000 Lumen	$2.14
1000 Watts - 126,000 Lumen	$2.14
Metal Halide	
70 Watts – 4,000 Lumen	$1.88
100 Watts - 5,800 Lumen	$2.24
175 Watts - 10,500 or 12,000 Lumen	$1.68
250 Watts - 16,000 Lumen	$1.68
400 Watts - 28,000 Lumen	$1.68
1000 Watts - 88,000 Lumen	$1.87
Mercury Vapor	
100 Watts - 3,200 Lumen	$1.72
175 Watt - 7,000 Lumen	$1.72
250 Watts - 9,400 Lumen	$1.72
400 Watts - 17,200 Lumen	$1.72
1000 Watts - 48,000 Lumen	$1.72

IX. COMPARISON TO CURRENT RATES

The next set of tables compares current charges effective August 2013 to charges that equal marginal cost for each service classification using current rate designs. An adjustment to marginal costs would be necessary to produce the target revenue requirement in 2016, but the comparisons in Table 32 A –F are still useful to assess the overall efficiency of current prices.

Efficient rate designs for NYSEG's electric delivery service customers would mirror the structure of NYSEG's marginal costs. This structure would consist of a fixed monthly customer charge, a monthly facilities charge based on kW of design demand (perhaps based on annual peak demand), and time-differentiated charges. The upstream substation and distribution substation and trunkline feeder costs would be recovered either in a demand charge (using the per kW costs in Table 26) or combined with marginal transmission costs in time-differentiated energy charges (using the per kWh costs in Table 27).

Table 32. A. Marginal Costs Compared to Year 2013 Electric Rates (Non-Lighting)

Service Classification		Current Rates (as of year 2013)				Marginal Costs (in 2016$)			
		"Total" Customer Charge	Demand	Delivery	RKVAH	Customer and Facilities Cost after CIAC	Demand	Delivery	Delivery Costs by TOD
		($/month)	($/kw-mo)	($/kwh)	($/rkvah)	($/cust/mo)	($/cust/mo)	($/kWh)	($/kWh)
SC 1	All	$15.11		$0.0333		$53.41		$0.00812	
SC 8	Day	$17.40		$0.0298		$55.59			$0.00989
	Night			$0.0298					$0.00423
SC 12	On	$24.11		$0.0336		$118.52			$0.03394
	Mid			$0.0336					$0.00497
	Off			$0.0336					$0.00423
SC 6	All	$17.60		$0.0325		$56.29		$0.00812	
SC 9	Day	$20.41		$0.0314		$57.09			$0.00989
	Night			$0.0314					$0.00423
SC 2	All Blocks	$17.61	$8.32	$0.00339	$0.00078	$248.56	$2.80	$0.00428	
SC 2 I/HLF	All Blocks	$17.61	$4.88	$0.00224	$0.00078	$248.56	$2.80	$0.00428	
SC 7-1	On	$117.11	$8.17	$0.00000	$0.00078	$441.99	$2.80		$0.00431
	Off			$0.00000					$0.00425
SC 7-1 I/HLF	On	$117.11	$6.52	$0.00000	$0.00078	$441.99	$2.80		$0.00431
	Off			$0.00000					$0.00425
SC 3P	All Blocks	$72.81	$4.86	$0.00355	$0.00078	$780.50	$2.68	$0.00423	
SC 3P I/HLF	All Blocks	$72.81	$3.66	$0.00272	$0.00078	$780.50	$2.68	$0.00423	
SC 7-2	On	$409.11	$7.18	$0.00000	$0.00078	$4,281.43	$2.68		$0.00426
	Off			$0.00000					$0.00420
SC 7-2 I/HLF	On	$409.11	$5.35	$0.00000	$0.00078	$4,281.43	$2.68		$0.00426
	Off			$0.00000					$0.00420
SC 3S	All Blocks	$242.51	$4.14	$0.00039	$0.00078				
SC 3S I/HLF	All Blocks								
SC 7-3	On	$849.11			$0.00078				
	Off		$3.03						
SC 7-3 I/HLF	On	$849.11		$0.00000	$0.00078				
	Off		$1.55	$0.00000					
SC 7-4	On	$1,914.01	$1.28	$0.00000	$0.00078	$1,420.79	$0.00		$0.00400
	Off			$0.00000					$0.00400
SC 7-4 I/HLF	On	$1,914.11	$0.62	$0.00000	$0.00078	$1,420.79	$0.00		$0.00400
	Off			$0.00000					$0.00400

Table 32. B. Marginal Costs Compared to Year 2013 Electric Rates
(Lighting Delivery and Fixed Charges)

	Current Rates (2013)		Marginal Costs (2016$)	
Service Classification	Delivery without SBC ($ per kWh)	Bill Isuance Charge	Delivery ($ per kWh)	Customer Charge ($ per month)
SC 5 (Outdoor)	$0.02500	$0.73	$0.0081	$2.58
SC 1 (Street Lighting)	0.02500	0.73	$0.0081	$13.62
SC 2 (Street Lighting)	0.02500	0.73	$0.0081	$13.62
SC 3 (Street Lighting)	0.02500	0.73	$0.0081	$13.62

Table 32. C. Marginal Costs Compared to Year 2013 Electric Rates (SC1 and SC2 Charges)

	Current Rates (year 2013)			Marginal Costs (2016$)
	Lumen	Watts	Monthly O&M Charge	Monthly Relamping
			($ per light)	($ per light)
Street Lighting SC-1				
High Pressure Sodium	3,300	50	$2.66	$1.61
High Pressure Sodium	5,200	70	$2.70	$1.61
High Pressure Sodium	8,500	100	$2.70	$1.65
High Pressure Sodium	14,400	150	$2.70	$1.66
High Pressure Sodium	24,700	250	$2.70	$1.67
High Pressure Sodium	45,000	400	$2.70	$1.68
High Pressure Sodium	126,000	1,000	$3.85	$2.14
Metal Halide	16,000	250	$2.95	$1.68
Metal Halide	28,000	400	$2.95	$1.68
Mercury Vapor	3,200	100	$2.34	$1.72
Mercury Vapor	7,000	175	$2.34	$1.72
Mercury Vapor	9,400	250	$2.34	$1.72
Mercury Vapor	17,200	400	$2.34	$1.72
Mercury Vapor	48,000	1,000	$3.63	$1.72
Street Lighting SC-2 (customer-owned equipment)				
High Pressure Sodium	3,300	50	$1.20	$1.61
High Pressure Sodium	5,200	70	$1.20	$1.61
High Pressure Sodium	8,500	100	$1.21	$1.66
High Pressure Sodium	14,400	150	$1.21	$1.67
High Pressure Sodium	19,800	200	$1.22	$1.66
High Pressure Sodium	24,700	250	$1.23	$1.67
High Pressure Sodium	45,000	400	$1.26	$1.68
High Pressure Sodium	126,000	1,000	$2.80	$2.14
Mercury Vapor	3,200	100	$0.83	$1.72
Mercury Vapor	7,000	175	$0.85	$1.72
Mercury Vapor	9,400	250	$0.87	$1.72
Mercury Vapor	17,200	400	$0.91	$1.72
Mercury Vapor	48,000	1,000	$1.16	$1.72
Incandescent	4,000	327	$2.87	$1.61
Flourescent	5,000	95	$1.51	$1.61
Flourescent	10,000	235	$1.64	$1.65
Flourescent	20,000	380	$1.90	$1.66
Metal Hallide	4,000	70	$2.45	$8.71
Metal Hallide	5,800	100	$2.45	$8.17
Metal Hallide	12,000	175	$2.45	$7.86
Metal Hallide	16,000	250	$2.47	$7.82
Metal Hallide	28,000	400	$2.52	$8.87
Metal Hallide	88,000	1000	$4.09	na

Table 32. D. Marginal Costs Compared to Current Rates (SC 3 Fixture Charges)

Street Lighting SC-3			Current Luminaire Charge (year 2013)			Monthly Marginal Costs			
	Lumen	Watts	Cobra	Post Top	Cut Off / Shoebox	Cobra	Post Top	Cut Off / Shoebox	Monthly Relamping
			------------ ($ per light/month) -----------			---------------- (2016 $ per light/month) ----------------			
High Pressure Sodium	3,300	50	$6.82	$7.88		n.a.	$8.27		$1.61
High Pressure Sodium	5,200	70	$6.82	$7.88	$13.83	$7.32	$8.16	na	$1.61
High Pressure Sodium	8,500	100	$6.82	$8.95	$13.83	$6.60	$7.40	na	$1.66
High Pressure Sodium	14,400	150	$6.82	$10.00	$13.83	$7.44	$8.34	na	$1.67
High Pressure Sodium	24,700	250	$6.82	$10.00	$12.20	$7.82	na	$9.95	$1.68
High Pressure Sodium	45,000	400	$7.21	$10.39	$14.75	$8.27	na	$11.12	$2.14
High Pressure Sodium	126,000	1,000	$10.69	$13.88		$11.92	na		$2.14
Metal Halide	4,000	70	$4.17	$4.71			$8.71		$1.88
Metal Halide	5,800	100	$4.17	$4.79		$8.17	$8.98		$2.24
Metal Halide	12,000	175	$4.11	$4.86	$5.66	$7.86	$8.61	$9.05	$1.68
Metal Halide	16,000	250	$13.28		$16.29	$7.82		$9.61	$1.68
Metal Halide	28,000	400	$13.28		$17.11	$8.87		$10.39	$1.68
Mercury Vapor	3,200	100	$3.72	$4.82		$7.32	$8.16		$1.72
Mercury Vapor	7,000	175	$3.72	$4.86		$8.17	$8.98		$1.72
Mercury Vapor	9,400	250	$3.89	$4.91		$6.60	$7.40		$1.72
Mercury Vapor	17,200	400	$3.95	$4.99		$7.82	$8.34		$1.72
Mercury Vapor	48,000	1,000	$5.80	$6.81		$11.92	$8.34		$1.72
Incandescent	1,000	103	$5.26	$5.94		na	$8.27		$1.61
Fluorescent	5,000	95	$6.92			$7.32			$1.61
Fluorescent	10,000	235	$7.06			$6.60			$1.66
Fluorescent	20,000	380	$7.84			$7.44			$1.67

Table 32. E. Marginal Costs Compared to Current Rates (SC 3 Circuit Charges)

Street Lighting SC-3	Current Rates Facility Charge (Year 2013) ($ per unit)	Marginal Cost Monthly Facilities Cost (2016 $ per unit)
Pole Installed by the Corporation		
Standard Wood Pole	$10.26	$9.57
Wood Pole - high mount use (45' or greater)	28.07	11.54
Steel Pole	4.53	8.44
Square Steel Pole 30'	16.49	8.44
Aluminum Pole 16' and under	6.18	4.46
Alum. Pole over 16' installed prior to August 1, 1987	16.41	7.10
Alum. Pole over 16' direct embedded installed after July 31, 1	16.41	7.10
Alum. Pole over 16' pedestal mounted	24.5	8.44
Concrete Pole	5.16	4.72
Laminated Wood Pole	4.12	4.72
Fiberglass Pole 18' and under	5.77	4.72
Fiberglass Pole 18' to 22'	7.84	4.72
Concrete Base for pedestal mounted poles	21.77	3.05
Screw-in steel base for pedestal mounted poles:		
Light Duty	13.49	2.96
Heavy Duty	17.16	3.05
Special Brackets		
Standard Bracket - 16' and over	$2.42	4.25
Bracket allowance	(0.64)	na
Bracket for post-top use on wood poles	0.41	4.25
Circuit Control		
Group Controllers	$3.09	7.16
3000 Watt Photo Cell	2.05	7.16
Circuits (Per Trench Foot)**		
Cable and Conduit	$0.08	0.03
Direct Burial Cable	0.0688	0.02
Cable Only (Conduit Supplied by Customer)	0.0366	0.02
Underground Circuits	0.0489	0.03

Table 32. F. Marginal Costs Compared to Year 2013 Rates (SC 5 Charges)

NYSEG Street Lighting SC-5	Current Rates (year 2013) ($/unit/month)	Marginal Monthly Cost (excluding Lamp and Photo Eye) (2016$ per unit)
Safeguard Luminaires		
14,500 Nominal Lumen 150 Watt H.P.S. (replacing 7,000 L. 175 Watt M.V.)	$6.09	$7.23
43,000 Nominal Lumen 400 Watt H.P.S. (replacing 17,200 L. 400 Watt M.V.)	8.94	8.05
123,000 Nominal Lumen 940 Watt H.P.S. (replacing 48,000 L. 1,000 Watt M.V.)	7.41	11.37
Area Lights		
3,300 Nominal Lumen (50 Watt) H.P.S.* (PACKLITE)	3.31	7.85
5,200 Nominal Lumen (70 Watt) H.P.S.* (PACKLITE)	3.26	7.85
8,500 Nominal Lumen (100 Watt) H.P.S.*	3.23	4.99
3,200 Nominal Lumen (100 Watt) Mercury (PACKLITE)*	3.13	9.03
5,200 Nominal Lumen (70 Watt) H.P.S. Power Bracket	6.24	
8,500 Nominal Lumen (100 Watt) H.P.S. Power Bracket	6.79	7.85
14,400 Nominal Lumen (150 Watt) H.P.S.	11.2	7.23
24,700 Nominal Lumen (250 Watt) H.P.S.	10.98	7.62
45,000 Nominal Lumen (400 Watt) H.P.S.	10.73	8.05
126,000 Nominal Lumen (1,000 Watt) H.P.S.	10.01	11.37
10,500 Nominal Lumen (175 Watt) Metal Halide Power Bracket	4.62	9.03
16,000 Nominal Lumen (250 Watt) Metal Halide	11.9	7.71
28,000 Nominal Lumen (400 Watt) Metal Halide	11.75	8.05
Flood Lights		
14,400 Nominal Lumen (150 Watt) H.P.S.	11.94	8.35
24,700 Nominal Lumen (250 Watt) H.P.S	11.74	8.52
45,000 Nominal Lumen (400 Watt) H.P.S.	11.53	8.52
126,000 Nominal Lumen (1,000 Watt) H.P.S.	12.84	9.90
16,000 Nominal Lumen (250 Watt) Metal Halide	11.13	8.48
28,000 Nominal Lumen (400 Watt) Metal Halide	12.26	8.48
88,000 Nominal Lumen (1,000 Watt) Metal Halide	12.7	9.70
"Shoebox" Luminaire		
14,400 Nominal Lumen (150 Watt) H.P.S.	12.61	9.72
24,700 Nominal Lumen (250 Watt) H.P.S.	14.88	9.75
45,000 Nominal Lumen (400 Watt) H.P.S.	15.78	10.50
16,000 Nominal Lumen (250 Watt) Metal Halide	11.92	10.33
28,000 Nominal Lumen (400 Watt) Metal Halide	11.76	10.18
88,000 Nominal Lumen (1,000 Watt) Metal Halide	16.93	11.65
Post Tops		
3,300 Nominal Lumen (50 Watt) H.P.S.	9.17	7.04
5,200 Nominal Lumen (70 Watt) H.P.S.	9.17	7.04
8,500 Nominal Lumen (100 Watt) H.P.S.	9.15	7.12
Brackets 16' and over	2.24	2.77
Additional Wood Pole Installed for Lamp	11.48	12.11
Wire Service (Overhead) (Per circuit foot of extension)	0.032	0.02
18' Fiberglass Pole - Direct Embedded	11.83	7.20
20' Fiberglass Pole - Pedestal Mount	41.08	7.20
20' Metal Pole - Pedestal Mount	41.08	12.69
30' Metal Pole - Pedestal Mount	41.08	14.36
30' Fiberglass Pole - Pedestal Mount	41.08	17.88
30' Fiberglass Pole - Direct Embedded	17.99	17.88
Screw Base for Pedestal Mounted Pole - Light Duty	12.51	8.40
Screw Base for Pedestal Mounted Pole - Heavy Duty	15.96	8.50

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NYSEG
Marginal Cost of Gas Delivery Service Study

Prepared for Iberdrola USA

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Contents

List of Tables and Figures

I. INTRODUCTION

Iberdrola USA retained NERA Economic Consulting (NERA) to update the New York State Electric & Gas Corporation (NYSEG)'s Marginal Cost of Gas Delivery Service Study (MCOSS), previously developed by NERA in February 2010 (the "2010 Report"). The key underlying assumptions of the former study are still applicable. This report summarizes the approach followed to estimate the marginal cost for each element of service, including marginal transmission, distribution and customer-related costs, and presents a summary of the results.

To conduct the 2014 MCOSS update, NERA relied on the most up to date investment plans, additional recent years of Operation and Maintenance expenses, current incremental capital structure and other updates to relevant input data. NERA applied updated escalation factors[1] to some of the elements of the 2010 Report. We reassessed the allocation of customer accounts and expenses to each customer class by relying on the Company's 2013 embedded cost study. All costs are expressed in 2016 dollars.

What are marginal costs? Marginal cost is defined as the change in total cost with respect to a small change in output. To quantify the marginal costs of gas service one must ask and answer the question: What are the additional costs that would be incurred with changes in gas delivered and consumed at different times of the year? How does the cost changes with additional number of customers served? Our method for estimating marginal costs is based on the system planning process. We determine the marginal cost of gas delivery service by examining the utility's planning processes to determine what drives new investment and purchase decisions and how changes in consumption affect system operations. The method is not a formula, but a series of guidelines outlining what should be measured and how the measurements can be made.

[1] We applied the average forecasted growth in GDP Chained Price Index through 2016 as reported by Blue Chip Economic Indicators in June 2014, or in some cases, a weighted labor & cost index.

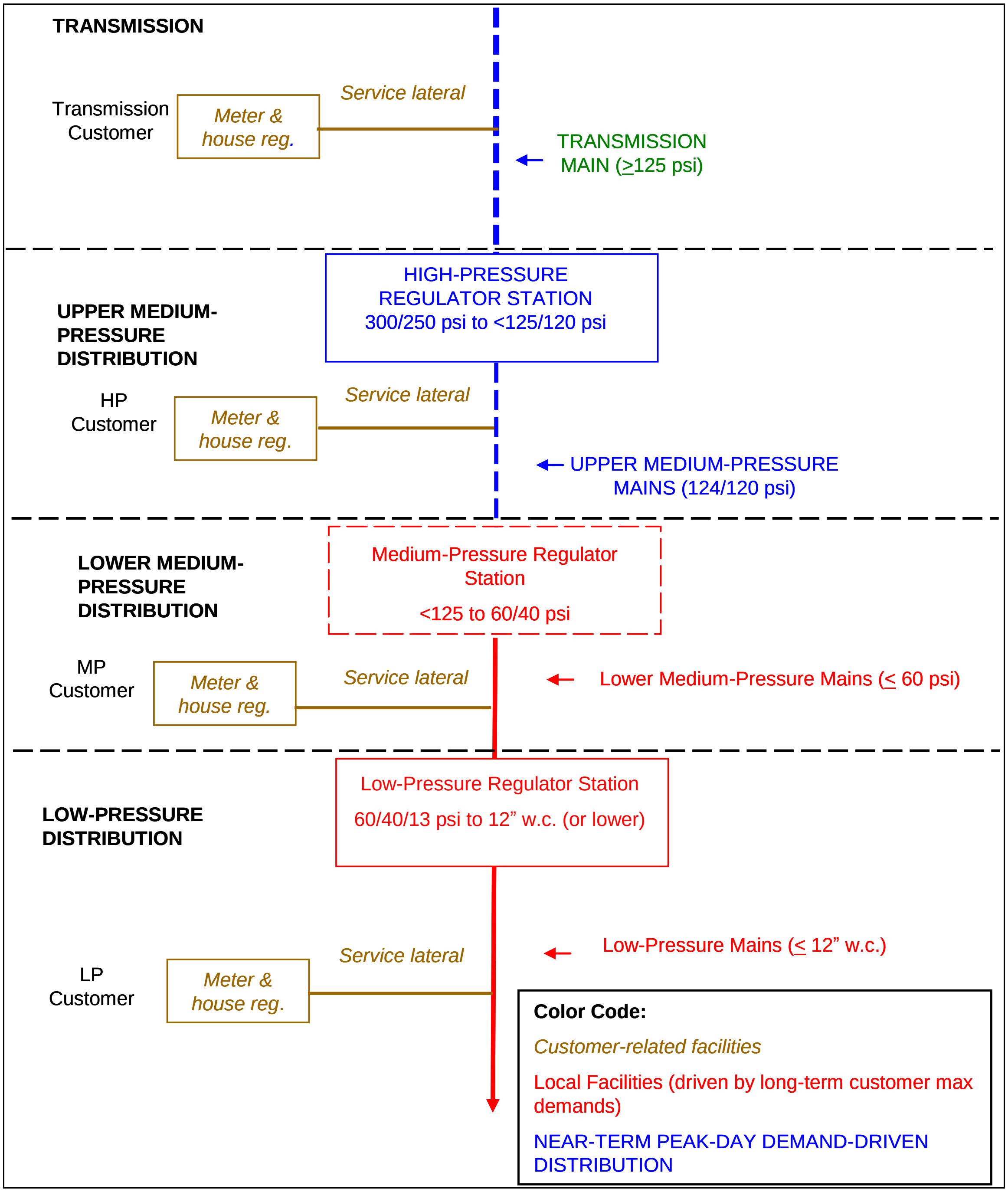
II. DESCRIPTION OF NYSEG GAS DELIVERY SYSTEM

For purposes of estimating marginal costs of delivery, it is important to distinguish the different components of delivery service, which can be grouped in four main categories:

1. Transmission system: high-pressure mains that move the gas to high-pressure regulator stations;
2. Upper-medium system, which includes the high-pressure regulator stations, upper medium-pressure mains, and reliability storage;
3. Local distribution facilities consisting of medium-pressure regulator stations that feed lower medium-pressure mains, and low-pressure regulator stations that feed low-pressure mains;
4. Customer-related facilities and functions, including:
    a. Meters, house regulators, relief valves and service laterals;
    b. Customer-related services (meter-reading, billing, accounting, customer information and customer service).

Figure 1 is a simplified diagram of these components.

Figure 1. Simplified NYSEG's Gas Delivery System



III. MARGINAL TRANSMISSION COSTS

NYSEG's investments in transmission mains are typically planned to meet expected growth in system design-day requirements over the next three to five years, taking into consideration the peak day demands under severe weather conditions. Transmission costs can therefore be estimated by dividing the cost of growth-related transmission investment by the demand growth triggering that investment. The annualized investment per MCF of Design Day demand is assigned to periods of the year based on the relative likelihood that demand growth in each period will require additional investment.

We confirmed that NYSEG has not undertaken a transmission project in the past five years and it is not planning any transmission investment in the following five years since demand growth in the near term can be accommodated with no need for additional transmission mains capacity. This means that NYSEG's near-term marginal cost of transmission is zero.

IV. MARGINAL HIGH-PRESSURE DISTRIBUTION COSTS

A. High-Pressure Regulator Stations and Upper Medium-Pressure Distribution Mains

High-pressure regulator stations connect the high-pressure system to the upper medium-pressure system, as illustrated in Figure 1.

Regulator stations are sized based on expected downstream design-day demand in the near-term, including an allowance for additional potential future load growth in the area to maintain system reliability. NYSEG expects to add one high-pressure regulator station over the period 2015 - 2018. To estimate the Company's marginal investment in high-pressure regulator stations, we computed the cost of this station per MCF/day of capacity. Because capacity in excess of expected load must be installed to provide reliable service, we adjusted upwards the cost per MCF/day of capacity by an estimated reserve margin of 14% to convert the investment per unit of capacity to an investment per unit of load.

Investment in upper-medium pressure mains is also driven by increases in the near-term peak day demand. Following the same procedure described for high-pressure regulator stations, we divided NYSEG's planned five-year investment in upper medium-pressure mains by their estimated capacity.

NYSEG's high-pressure regulator station and upper-medium pressure mains capacity in the overall service area is currently larger than the minimum required to handle expected load growth in the near term. Since we intend to estimate a region-wide marginal cost, the estimated marginal investment needs to be adjusted to reflect the excess capacity situation. This factor was estimated as 0.18%, representing the share of the system in which demand growth will likely trigger investment. These calculations are shown on Table 1.

Table 1. Marginal Investment in Upper Medium-Pressure Mains and High-Pressure Regulator Stations

		High-Pressure Regulator Stations	Upper-Medium Pressure Main
		(2)	(1)
(1)	Growth-related investment 2014-2016 (Thousands of 2016 Dollars)	$4,000.00	$6,765.14
(2)	Capacity Added (MCF/Day)	10,300.00	10,300.00
(3)	Marginal Investment per MCF/Day (2016 Dollars/MCF/Day) [(1) x 1000 / (2)]	$388.35	$656.81
(4)	Adjustment for Typical Reserve Margin [(3) x 1.14] (2016$/MCF/Day)	$442.72	$748.76
(5)	Adjustment for Share of Upper-Medium system requiring load-related investment (4) x 0.18% (2016$/MCF/Day)	$0.80	$1.35

The annualized investment in high-pressure regulator stations and upper medium-pressure mains per MCF/day can be assigned to periods of the year based on the relative likelihood that demand growth in each period will require additional investment (typically the measure used is probability of peak).

Table 2. Relative Probability of Peak Day

Month	Relative Probability of Peak	Seasonal Probabilities: Winter (Dec. - Mar.)	Seasonal Probabilities: Summer (April - Nov.)
	(1)	(2)	(3)
Jan	85.02%	100.00%	0.00%
Feb	12.16%		
Mar	2.34%		
Apr - Nov	0.00%		
Dec	0.48%		

B. Underground Reliability Storage

NYSEG contracts with underground storage that provides reliability benefits to the distribution system. For each additional unit of gas delivered, NYSEG plans for an incremental change in reliability needs. Thus there is a marginal reliability storage cost. NYSEG has developed an estimate of the embedded cost per therm of these resources, including capacity costs and carrying charges on the stored gas, which is used as the basis for a reliability surcharge.

We used the year 2013 reliability storage surcharge provided by NYSEG, escalated to 2016 dollars. This element of marginal cost is applicable to all NYSEG firm gas customers except SC 1T and SC 5T. This component has increased since the 2010 Report due to the sale of the Seneca storage facility. Table 3 below shows the estimated cost.

Table 3. Marginal Reliability Storage Cost per Therm

(1)	Reliability Surcharge per Therm (2016 Dollars per Therm)	$0.0131
(2)	Storage Marginal Cost per Therm Including Losses (1) x 1.00181	$0.01

V. MARGINAL LOCAL DISTRIBUTION FACILITIES

Local distribution facilities include: medium and low-pressure regulator stations; lower medium-pressure mains; and low-pressure mains. These facilities are typically designed using engineering standards that take into consideration the expected maximum demands of customers that will use them over the long term or the useful life of these facilities, i.e., not the near-term design-day demands. This means that the costs of this portion of the system are marginal when the mains and regulator stations are installed and when they are replaced because of age, but typically do not vary with customers' actual gas usage from month to month or year to year.

The capacity of these facilities would be expanded only if there were a major increase in the design demands of the customers using them. Therefore, these costs should ideally be recovered in a fixed component of the rate design, rather than in charges based on gas consumption. In this update of the study, we used the same basic approach that was used in the 2010 Report to estimate marginal investment for each element of local distribution facilities, which rely on the following three assumptions:

- The characteristics of local facilities installed for customers of various design demands are relatively constant over time.
- The average replacement cost of such facilities on the entire NYSEG system is typical of the marginal cost of these facilities going forward.
- Meter capacity is a reasonable basis for estimating long-term design-day demand, provided that residential meter capacity is adjusted to reflect the fact that meter capacity for these customers is about 1.66 times their connected load.

For each component of local distribution facilities, we computed the current replacement cost (in 2016 dollars) of all such facilities on NYSEG's system. Some local distribution facilities costs are recovered up front through a customer contribution in aid of construction (CIAC); the remaining costs are recovered over time through rates. At the Company's request, we developed estimates of local distribution facilities before and after these customer contributions. In the version that recognizes CIAC, we subtracted the share of investment typically paid for up front by customers.

A. Medium- and Low-Pressure Regulator Stations

NYSEG provided the replacement cost of typical medium- and low-pressure regulator stations (including farm tap regulators) as of year 2014, as well as the current number of regulator stations and farm taps. NERA computed the weighted average of the replacement cost of medium and low-pressure stations and farm tap regulators, and multiplied them by the number of these regulators on the system. Typically customers do not pay upfront for any portion of these stations, so no adjustment for CIAC was required. We then divided the total weighted replacement cost, stated in 2016 dollars, by the year 2013 aggregate medium and low-pressure design-day demand at the customer premises, using meter capacity (with adjustment for residential meters) as a proxy.

Table 4. Marginal Investment in Medium- and Low-Pressure Regulator Stations

(1)	Weighted Average Replacement Cost of Medium and Low-pressure Regulator Station (incl. Farm Taps) (Thousands of 2016 Dollars)	$163.91
(2)	Total Number of Medium- and Low-pressure Regulator Stations and Farm Taps in the System	518
(3)	Total Replacement Cost of Medium- and Low-pressure Regulator Stations [(1) * (2)] (Thousands of 2016 Dollars)	$84,906.81
(4)	Year 2013 Aggregate Medium and Low-Pressure Design Demand at Customer Premises (MMCF/Day)	1,252
(5)	Marginal Investment in Medium- and Low-pressure Regulator Station [(3) / (4)] (2016 Dollars/MCF/day)	$67.80

B. Lower Medium and Low-Pressure Mains Investment

Table 5 shows the derivation of marginal investment in lower medium-pressure and low-pressure distribution mains. We divided the current cost (stated in 2016 dollars) of all existing low and lower medium-pressure mains by the year 2013 aggregate medium and low-pressure design demand at the customer premises (discussed above).

The investment is shown before and after adjusting for CIAC. In consultation with the Company, we concluded that it was appropriate to use the same CIAC percentage (11%) of investment estimated for the 2010 Report. This percentage represents the share of annual customer contributions as a percent of lower medium-pressure mains investment in the same year.[2]

Table 5. Marginal Investment in Lower Medium- and Low-Pressure Mains

	Replacement Cost of Lower Medium and Low-Pressure Distribution Mains (Thousands of 2016 Dollars)	
(1)	After CIAC	$1,672,675
(2)	Before CIAC	$1,879,410
(3)	Year 2013 Total Medium and Low-Pressure Design Demand at Customer Premises (MMCF/Day)	1,252
	Marginal Investment in Lower Medium and Low-Pressure Distribution Mains (2016 Dollars/MCF/Day)	
(4)	After CIAC (1) / (3)	$1,335.73
(5)	Before CIAC (2) / (3)	$1,500.82

[2] The ratio was estimated in 2008 but the connection policy has not changed since then. NYSEG indicated that all of the year 2008 customer contributions were for lower medium-pressure mains, and 98% of mains investment was lower medium-pressure. We assumed that the same percentage would apply to low-pressure mains.

VI. DISTRIBUTION OPERATION AND MAINTENANCE EXPENSES

The amount of O&M expenses depend on the amount of plant in service. The addition of distribution facilities to meet increments in near-term or long-term design-day demand gives rise to increased O&M expenses as well. Distribution O&M expenses on marginal investment are, therefore, marginal costs. We used NYSEG's average level of distribution O&M expenses in the past five years as a guide for estimating marginal O&M costs.[3]

NYSEG's accounting system does not show separate O&M expenses for equipment of various pressure levels. We allocated Distribution Main and Service operation expenses (Account #874) to the various distribution pressure mains and to service laterals in proportion to mileage. Distribution overheads[4] were allocated to each type of main, as well as to services and meter and house regulators in proportion to their shares of total distribution O&M less these overhead accounts. We allocated O&M expenses related to regulator stations to pressure categories in proportion to the number of regulator stations at each level and the typical O&M per regulator station (categorized by their outlet pressure). Since NYSEG's marginal transmission main investments are zero, there is no marginal O&M cost associated with this system element in the near term.[5]

NYSEG provided typical O&M expenses for each pressure level station, which we used to apportion the marginal regulator station expenses to low/medium- and high-pressure stations. On Table 6, for each year of the period 2009-2013 we divided the assigned medium and low-pressure regulator station O&M (which corresponds to 94.0% of total regulator station O&M expenses) by total medium and low-pressure aggregate design demand, which we approximated from the sum of total meter capacity. We then converted these historical costs to 2016 dollars. After examining the trend in unit costs over the five-year period and consulting with NYSEG, we selected the average of the 2009 through 2013 values as likely to be representative of future marginal levels of these costs.

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[3] We excluded Account 871 (load dispatching) as non-marginal and Account 881 (rents) because rents are substitutes for past investment and are not marginal expenses.

[4] Distribution overheads include: Operation Supervision and Engineering (870), Other Expenses (880), Maintenance Supervision and Engineering (885), Maintenance of Other Equipment (894) and Maintenance of Structures and Improvements (886).

[5] In addition, marginal demand reductions would not reduce the expenses associated with operating and maintaining the existing transmission mains.

Table 6. Regulator Station O&M Expense per MCF/Day

	Year	Medium and Low-Pressure Reg. Station O&M Expenses	Aggregate Medium and Low-Pressure Design Demand At Customer Premises	O&M Expense Per MCF of Design Demand	Weighted Labor and Materials Cost Index	Medium and Low-Pressure Reg. Station O&M per MCF of Design Demand
		(000 Dollars)	(MMCF/day)	($/MCF/day)	(2016=1.00)	(2016$/MCF/day)
				(1) / (2)		(3) / (4)
		(1)	(2)	(3)	(4)	(5)
(1)	2009	$2,434.53	1,223	$1.99	0.8171	$2.44
(2)	2010	$2,567.80	1,235	2.08	0.8371	$2.48
(3)	2011	$2,859.67	1,242	2.30	0.8775	$2.62
(4)	2012	$2,708.38	1,244	2.18	0.9254	$2.35
(5)	2013	$2,832.42	1,252	2.26	0.9322	$2.43
(6)	Estimated Marginal Medium and Low-Pressure Reg. Station O&M per MCF/day [Average 2009 - 2013]					$2.46

Error! Reference source not found. and Table 8 show a corresponding calculation for upper medium-pressure mains and low- and lower medium-pressure mains. There was an atypically large cost for maintenance of distribution mains in 2011 due to storm-related damage. After consulting with NYSEG, we selected the average of the 2009 through 2013 values (excluding 2011) as likely to be representative of future marginal levels of these costs.

Table 7. Marginal Upper Medium- Pressure Mains O&M Expense per MCF/Day

	Year	Upper Medium-Pressure Mains O&M Expense	Total System Design Demand Incl. Losses	O&M Expense Per MCF of Design Demand	Weighted Labor and Materials Cost Index	Upper Medium Pressure Mains O&M per MCF of Design Demand
		(000 Dollars)	(MMCF/day)	($/MCF/day)	(2016=1.00)	(2016$/MCF/day)
				(1) / (2)		(3) / (4)
		(1)	(2)	(3)	(4)	(5)
(1)	2009	$858.68	1,223	$0.70	0.8171	$0.86
(2)	2010	984.00	1,235	0.80	0.8371	0.95
(3)	2011	2,140.57	1,242	1.72	0.8775	1.96
(4)	2012	1,219.23	1,244	0.98	0.9254	1.06
(5)	2013	945.36	1,252	0.75	0.9322	0.81
(6)	Estimated Annual Upper Medium Pressure Mains O&M per MCF/day [average of 2009, 2010, 2012, 2013]					$0.92
(7)	Adjustment for percent of upper medium-pressure system requiring investment in response to load growth (6) x 0.18%					$0.00

Table 8. Marginal Lower Medium- and Low-Pressure Mains O&M Expense

	Year	Lower Medium & Low-pressure Mains O&M Expense	Distribution System Design Demand	O&M Expense Per MCF of Design Demand	Weighted Labor and Materials Cost Index	Lower Medium & Low-pressure Mains O&M per MCF of Design Demand
		(000 Dollars)	(MMCF/day)	($/MCF/day)	(2016=1.00)	(2016$/MCF/day)
				(1) / (2)		(3) / (4)
		(1)	(2)	(3)	(4)	(5)
(1)	2009	$8,472.39	1,223	$6.93	0.8171	$8.48
(2)	2010	9,708.85	1,235	7.86	0.8371	9.39
(3)	2011	21,120.39	1,242	17.00	0.8775	19.37
(4)	2012	12,029.82	1,244	9.67	0.9254	10.45
(5)	2013	9,327.61	1,252	7.45	0.9322	7.99
(6)	Estimated Annual Lower Medium and Low-pressure Mains O&M per MCF/day [average of 2009, 2010, 2012, 2013]					$9.08

VII. OTHER MARGINAL COSTS

A. Meter, House Regulator and Service Lateral

NYSEG supplied the current weighted-average installed costs of meters, including house regulators and relief valves, for each customer category. NYSEG also supplied the typical cost of service lateral by class. We applied a ratio to the residential service per-customer cost to reflect that there are about 0.89 services per residential customer. These customer-related marginal investments, converted to 2016 dollars, are shown on Table 9 and Table 10.

Table 9. Installed Cost of Meter & House Regulator by Service Classification

	Customer Class	Description	Average Cost Per Customer (2016$)
(1)	SC1S	SC 1 Residential Heat	$ 341.89
(2)	SC1S	SC 1 Residential Non Heat	341.89
(3)	SC2S	SC 2 General Service	836.31
(4)	SC3S	SC 3 Interruptible Sales	8,276.78
(5)	SC5S	SC 5 Gas Cooling	n/a
(6)	SC9S	SC 9 Industrial Manufacturing	4,507.09
(7)	SC13T	SC 13T Residential Heat Aggregation Service	341.89
(8)	SC13T	SC 13T Residential Non-Heat Aggregation Service	341.89
(9)	SC14T	SC 14T Non-Residential Aggregation Service	1,247.41
(10)	SC1T	SC 1T Large Firm Transportation	8,208.08
(11)	SC2T	SC 2T Interruptible Transportation	8,518.93
(12)	SC5T	SC 5T Small Firm Transportation	6,179.67
(13)	SC7T	SC 7T Firm or Limited Firm Negotiated Transportation	8,986.70
(14)	SC16T	SC16T Non-Residential Distributed Generation Firm Transportation Service	5,200.21

Table 10. Installed Cost of Service Lateral by Service Classification

	Customer Class	Description	Average Cost Per Customer (2016$)
(1)	SC1S	SC 1 Residential Heat	$ 1,680.25
(2)	SC1S	SC 1 Residential Non Heat	1,680.25
(3)	SC2S	SC 2 General Service	3,650.20
(4)	SC3S	SC 3 Interruptible Sales	8,334.96
(5)	SC5S	SC 5 Gas Cooling	n/a
(6)	SC9S	SC 9 Industrial Manufacturing	6,464.97
(7)	SC13T	SC 13T Residential Heat Aggregation Service	1,680.25
(8)	SC13T	SC 13T Residential Non-Heat Aggregation Service	1,680.25
(9)	SC14T	SC 14T Non-Residential Aggregation Service	3,650.20
(10)	SC1T	SC 1T Large Firm Transportation	8,334.96
(11)	SC2T	SC 2T Interruptible Transportation	8,334.96
(12)	SC5T	SC 5T Small Firm Transportation	6,464.97
(13)	SC7T	SC 7T Firm Or Limited Firm Negotiated Transportation	10,013.00
(14)	SC16T	SC16T Non-Residential Distributed Generation Firm Transportation Service	n/a

Meter and House Regulator O&M expenses vary by service classification. We divided these expenses, along with their associated overheads (as explained in Section IV), by weighted number of customers, where the weights reflect an allocation of 10% of the expenses to residential customers and 90% to non-residential customers, with the non-residential component further segmented based on meter cost (see Table 8.) After converting the historical costs per weighted customer to 2016 dollars, we reviewed the trend and, in consultation with NYSEG, chose the average of 2009 through 2013 values (excluding 2011) as best representing the future levels of these expenses.

Table 11 shows the Meter and House Regulator O&M for each service classification. These values are the cost per weighted customer multiplied by each service classification's meter O&M weight.

Table 11. Meter and House Regulator O&M Expense per Weighted Meter

		2009	2010	2011	2012	2013
		(1)	(2)	(3)	(4)	(5)
(1)	Meter Operation and Maintenance Expenses (Thousand Dollars)	$8,888	$8,532	$3,898	$8,098	$10,186
(2)	Number of Customers	257,915	259,131	259,916	260,216	261,628
(3)	Weighted Customers (2) x 8.85	2,282,921	2,293,681	2,300,633	2,303,289	2,315,784
(4)	Expense Per Weighted Customer (Dollars) [(1) / (3)] x 1000	$3.89	$3.72	$1.69	$3.52	$4.40
(5)	Labor Cost Index (2016 = 1.00)	0.8123	0.8367	0.8619	0.8880	0.9148
(6)	Expense Per Weighted Customer in 2016 Dollars (4) / (5)	$4.79	$4.45	$1.97	$3.96	$4.81
(7)	Annual Marginal Meter and House Regulator O&M Expense per Weighted Customer (average of 2009, 2010, 2012, 2013) (2016 Dollars)					**$4.50**

Table 12. Meter and House Regulator O&M Expense by Service Classification

	Rate	Class	Meter O&M Weighting Factor	Annual Meter O&M Expense per Customer
				(2016 Dollars)
				(1) x $4.50
			(1)	(2)
(1)	SC1S	SC 1 Residential Heat	1.00	$4.50
(2)	SC1S	SC 1 Residential Non Heat	1.00	4.50
(3)	SC2S	SC 2 General Service	52.89	238.10
(4)	SC3S	SC 3 Interruptible Sales	523.46	2,356.39
(5)	SC5S	SC 5 Gas Cooling	0.00	0.00
(6)	SC9S	SC 9 Industrial Manufacturing	285.05	1,283.16
(7)	SC13T	SC 13T Residential Heat Aggregation Service	1.00	4.50
(8)	SC13T	SC 13T Residential Non-Heat Aggregation Service	1.00	4.50
(9)	SC14T	SC 14T Non-Residential Aggregation Service	78.89	355.14
(10)	SC1T	SC 1T Large Firm Transportation	519.12	2,336.83
(11)	SC2T	SC 2T Interruptible Transportation	538.78	2,425.33
(12)	SC5T	SC 5T Small Firm Transportation	390.83	1,759.34
(13)	SC7T	SC 7T Firm Or Limited Firm Negotiated Trans.	568.36	2,558.50
(14)	SC16T	SC16T Non-Residential Distributed Generation Firm Transportation Service	328.89	1,480.49

Service O&M expenses do not vary with the size of service laterals. However, on average, residential customers have less than one service line per customer. We divided the service O&M expenses, along with an assigned share of overhead expenses, by the average number of services to compute marginal service-related O&M costs per service (see Table 13). After converting the resulting costs to 2016 dollars, we reviewed the trend and in consultation NYSEG, we chose the average of the values in years 2012 through 2013 as best representing the future levels of these expenses. Table 14 shows the service O&M for each service classification. These values are the cost per service multiplied by services per customer.

Table 13. Service Lateral O&M Expense per Service

	Year	Service Lateral Operation & Maintenance Expenses	Average Number of Services	Expense Per Service	Weighted Labor and Materials Cost Index	Annual Expense Per Service
		(000 Dollars)		(Dollars) [(1) x 1000]/(2)	(2016=1.00)	(2016 Dollars) (3)/(4)
		(1)	(2)	(3)	(4)	(5)
(1)	2009	$6,382	223,460	$28.56	0.82	34.95
(2)	2010	$6,539	224,547	29.12	0.84	34.79
(3)	2011	$7,123	225,224	31.63	0.88	36.04
(4)	2012	$8,995	225,450	39.90	0.93	43.12
(5)	2013	$8,846	226,675	39.03	0.93	41.86
(6)	Estimated Annual Marginal Service Lateral O&M Expense [Average of 2012-2013]					$42.49

Table 14. Service Lateral O&M Expense by Service Classification

	Customer Class	Description	Services per Customer	Annual Service Lateral O&M Expense Per Customer
				(2016 Dollars)
				(1) * 42.49
			(1)	(2)
(1)	SC1S	SC 1 Residential Heat	0.89	37.84
(2)	SC1S	SC 1 Residential Non Heat	0.89	37.84
(4)	SC2S	SC 2 General Service	1.00	42.49
(5)	SC3S	SC 3 Interruptible Sales	1.00	42.49
(6)	SC5S	SC 5 Gas Cooling	0.00	0.00
(7)	SC9S	SC 9 Industrial Manufacturing	1.00	42.49
(8)	SC13T	SC 13T Residential Heat Aggregation Service	0.89	37.84
(9)	SC13T	SC 13T Residential Non-Heat Aggregation Service	0.89	37.84
(10)	SC14T	SC 14T Non-Residential Aggregation Service	1.00	42.49
(11)	SC1T	SC 1T Large Firm Transportation	1.00	42.49
(12)	SC2T	SC 2T Interruptible Transportation	1.00	42.49
(13)	SC5T	SC 5T Small Firm Transportation	1.00	42.49
(14)	SC7T	SC 7T Firm Or Limited Firm Negotiated Transportation	1.00	42.49
(15)	SC16T	SC16T Non-Residential DG Firm Transportation	n/a	0.00

B. Customer Accounts Expenses

Customer accounts expenses, composed mainly of meter-reading and billing expenses and uncollectibles,[6] are costs directly attributable to the existence of customers on the system. We excluded expenses associated with the merchant function from the marginal delivery cost estimates. For customer accounts expenses, other than uncollectibles we determined, in consultation with NYSEG, that the 2013 expenses are a reasonable proxy for the marginal cost in future years. We used the results from the NYSEG's 2013 embedded cost of service study to identify the cost per customer for each class. Table 15 shows the estimated marginal costs by service classification.

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[6] We dealt with uncollectibles separately because this component of customer accounts expense is not subject to the cash working capital adjustment or the A&G non-plant loading factor, discussed later.

Table 15. Customer Accounts and Uncollectibles Expense by Service Classification

	Rate	Class	Customer Accounts Expense (excl. uncollectibles) per Customer (2016 Dollars)	Estimated Marginal Uncollectibles per Customer (2016 Dollars)
			(1)	(2)
(1)	SC1S	SC 1 Residential Heat	$60.49	$13.56
(2)	SC1S	SC 1 Residential Non Heat	$59.26	$7.24
(3)	SC2S	SC 2 General Service	$67.27	$4.65
(4)	SC3S	SC 3 Interruptible Sales	$661.92	$281.47
(5)	SC5S	SC 5 Gas Cooling	$67.27	$4.65
(6)	SC9S	SC 9 Industrial Manufacturing	$152.50	$35.05
(7)	SC13T	SC 13T Residential Heat Aggregation Service	$60.11	$14.02
(8)	SC13T	SC 13T Residential Non-Heat Aggregation Service	$57.47	$7.80
(9)	SC14T	SC 14T Non-Residential Aggregation Service	$72.78	$7.57
(10)	SC1T	SC 1T Large Firm Transportation	$661.92	$281.47
(11)	SC2T	SC 2T Interruptible Transportation	$661.92	$281.47
(12)	SC5T	SC 5T Small Firm Transportation	$174.45	$61.14
(13)	SC7T	SC 7T Firm Or Limited Firm Negotiated Transportation	$661.92	$281.47
(14)	SC16T	SC16T Non-Residential Distributed Generation Firm Transportation Service	$264.74	$102.29

C. Customer Service and Informational Expenses

Customer service and informational expenses also vary with the number of customers on the system and are, therefore, marginal.[7] In consultation with NYSEG we used the 2013 embedded cost values per customer for each classification as our estimate of marginal customer service and informational expenses. Table 16 shows the expense by service classification.

[7] Customer service expenses related to energy efficiency are excluded from the costs in these calculations since they are recovered in a system benefit charge.

Table 16. Customer Services and Informational Expenses by Service Classification

	Rate	Class	Customer Service Expense
			(2016 Dollars)
			(1)
(1)	SC1S	SC 1 Residential Heat	$1.77
(2)	SC1S	SC 1 Residential Non Heat	$0.95
(3)	SC2S	SC 2 General Service	$1.93
(4)	SC3S	SC 3 Interruptible Sales	$119.56
(5)	SC5S	SC 5 Gas Cooling	$1.93
(6)	SC9S	SC 9 Industrial Manufacturing	$14.45
(7)	SC13T	SC 13T Residential Heat Aggregation Service	$1.83
(8)	SC13T	SC 13T Residential Non-Heat Aggregation Service	$1.02
(9)	SC14T	SC 14T Non-Residential Aggregation Service	$3.15
(10)	SC1T	SC 1T Large Firm Transportation	$119.56
(11)	SC2T	SC 2T Interruptible Transportation	$119.56
(12)	SC5T	SC 5T Small Firm Transportation	$25.56
(13)	SC7T	SC 7T Firm Or Limited Firm Negotiated Transportation	$119.56
(14)	SC16T	SC16T Non-Residential Distributed Generation Firm Transportation Service	$42.12

D. Administrative and General Expenses

Certain general corporate administrative and general (A&G) expenses tend to vary with operating and maintenance expenses. Based on our understanding of NYSEG's FERC accounts for A&G expenses (including social security and unemployment taxes), we divided these expenses into two categories: (1) those associated with other types of expenses and (2) those associated with plant. We normally use regression analysis on about 20 years of historical data to identify marginal A&G expenses and general plant. However, changes at NYSEG over this period make this approach inappropriate for A&G loaders, thus we will use the same methodology that was used for the 2010 Report. We reviewed recent levels of potentially marginal non-plant related A&G expenses and again we found that only social security and unemployment taxes are strongly linked to O&M. We developed the non-plant related A&G loader by computing year 2013 social security and unemployment taxes as a percent of non-fuel O&M. The loader is shown in Table 17 below.

For plant-related A&G expenses, we determined that the only A&G account directly related to the amount of plant on the system is property insurance, following the same approach as for the 2010 Report. Therefore, for this update, NYSEG provided an estimate of the year 2014-15 property insurance rate per $100 of replacement cost of affected plant and we applied an annual escalation factor of 10% to convert this rate to a year 2016 rate. Property insurance only applies to stock/inventory items, buildings and equipment and metering and regulator stations valued over $100,000. We applied this loader only to regulator stations. The plant-related A&G loader is shown on Table 17 below.

E. General Plant Loader

General plant consists of items such as office buildings, warehouses, cars, trucks and other equipment. When a utility adds transmission and distribution plant, the need for general plant increases as well. Our estimate of NYSEG's general plant loader is based on a regression of cumulative additions general plant net of retirements plus the gas portion of common plant on cumulative additions to total gas plant new of retirements (less general and common plant), all stated in constant dollars, using data from 1992 – 2011. The coefficient of the explanatory variable is the loader.

Table 17. Loading Factors for A&G Expenses and General Plant

		Estimate of Loading Factor
(1)	Non-Plant Related A&G Loader	1.96%
(2)	Plant Related A&G Loader	0.04%
(3)	General Plant Loader	7.39%

VIII. COMPUTATION OF CARRYING CHARGES

The sections above describe the development of estimates of marginal investment in several categories of plant. To be useful in ratemaking and other marginal cost applications, the investment must be converted into annual costs using an economic carrying charge. The annual charge reflects the elements of NYSEG's revenue requirement associated with incremental plant: return to stockholders and bondholders, depreciation, and taxes. For use in a marginal cost study, the appropriate stream of annual charges is a stream that rises at the rate of inflation net of technical progress and yields the total present value of all costs over the life of the investment. In such a stream, the first year's charge represents the cost in today's dollars of owning the plant or equipment for a year. It also represents the rental rate for such an investment in a competitive market.

Key inputs for the economic carrying charge calculation include the utility's incremental cost of capital (mix of debt and equity) and their respective long-term market costs. NYSEG foresees financing of near-term incremental investment through additional equity (retained earnings and/or infusion of equity capital from the parent company) and long-term debt with the capital structure and costs shown in Table 18.

Table 18. Incremental Capital Structure and Cost

	Share (%)	Cost (%)
Debt	50.00	6.00
Common Stock	50.00	10.06

Another integral part of the economic carrying charge calculation is the estimation of the rate of inflation net of technical progress applicable over the life of the investment. We used 2.07 percent as an estimate of the future inflation rate net of technical progress, based on the average of the GDP inflation forecast for the ten-year period 2014-2023.

Finally, an adjustment is required for the fact that not all plant and equipment will last its estimated service life. Some components will require early replacement, causing added costs, while some will last longer than expected and produce savings. The pattern of expected required replacement for each type of plant is defined by an Iowa Curve. An adjustment for this dispersed pattern of replacements using Iowa Curves was included in the derivation of the economic carrying charges. The results of these economic carrying charge calculations are presented below. The adjustments for dispersed retirements are shown on line (2) of this table.

Table 19. Economic Carrying Charges

		Mains	Regulator Stations	Services	House Meters, Regulators and Install.
		(1)	(2)	(3)	(4)
(1)	Present Value of Revenue Requirements Related to Incremental $1,000 Investment	$1,928.95	$1,880.61	$1,839.50	$1,752.49
(2)	Present Value Cost of Replacing Dispersed Retirements Related to Incremental $1,000 Investment	$62.71	$48.39	$100.20	$96.57
(3)	Total Present Value Cost Related to Incremental $1,000 Investment (1)+(2)	$1,991.66	$1,929.00	$1,939.70	$1,849.06
(4)	First-Year Annual Economic Charge Related to Incremental $1,000 Investment	$100.36	$102.70	$105.34	$112.27
(5)	First-Year Annual Economic Charge Related to Incremental Investment [(4)/$1,000]	10.04%	10.27%	10.53%	11.23%

IX. ANNUAL MARGINAL COSTS

The next step of the study was to apply the economic carrying charges to the marginal investment and add the associated expenses.

A. Annual Local Facilities Marginal Costs

The marginal investments per MCF-day in upper medium- pressure mains and high-pressure regulator stations and medium- and low-pressure regulator stations and lower medium- and low-pressure mains were adjusted upwards by the general-plant loading factor. We multiplied the resulting figures by the annual economic carrying charge percentage plus the plant-related A&G loading factor, where appropriate, to yield the annualized plant costs. The plant-related A&G loading factor (based on property insurance costs) does not apply to the mains. To these costs we added the associated O&M and non-plant related A&G expenses and the revenue requirements for working capital.

The computation of working capital includes cash working capital, materials, supplies and prepayments. Table 20 shows the total annual unit marginal cost calculations for upper medium-pressure mains and high-pressure regulator stations and Table 21 shows the annual unit marginal cost calculations for medium- and low-pressure regulator stations and lower medium- and low-pressure mains. The annualized costs are expressed in $/MCF of long-term design-day demand. The upper medium-pressure mains costs are shown after customer contributions and lower medium-pressure and low-pressure mains costs are shown before and after customer contributions.

Table 20. Annual Upper Medium-Pressure Mains and High-Pressure Regulator Stations

		High-Pressure Regulator Station	Upper Medium-Pressure Mains
		(2016 $ per MCF of Design Day Demand)	
		(1)	(2)
(1)	Marginal Investment	$0.797	$1.348
(2)	With General Plant Loading (1) x 1.0739	$0.856	$1.422
(3)	Annual Economic Carrying Charge Related to Capital Investment	10.27%	10.04%
(4)	A&G Loading (plant related)	0.04%	0.00%
(5)	Total Annual Carrying Charge (3) + (4)	10.30%	10.04%
(6)	Annualized Costs (2) x (5)	$0.088	$0.143
(7)	O&M Expenses	$2.465	$0.002
(8)	O&M exp. with A&G Loading (Non-plant Related) (7) x 1.0196	$2.513	$0.002
(9)	Annual Cost (6) + (8)	$2.601	$0.144
	Working Capital		
(10)	Material and Supplies (2) x 0.73%	$0.006	$0.010
(11)	Prepayments (2) x 1.21%	$0.010	$0.017
(12)	Cash Working Capital Allowance (8) x 12.50%	$0.314	$0.000
(13)	Total Working Capital (10) + (11) + (12)	$0.331	$0.028
(14)	Revenue Requirement for Working Capital (13) x 11.28%	$0.037	$0.003
(15)	Annual Marginal Unit Costs (9) + (14)	$2.638	$0.147
(16)	Annual Marginal Unit Costs (with losses) (15) * 1.00181	**$2.643**	**$0.148**
(17)	Winter Season (Dec. - Mar.) Marginal Unit Costs (with losses) - (16) x Winter Probability of Peak (100%)	$2.643	$0.148
(18)	Summer Season (Apr. - Nov.) Marginal Unit Costs (with losses) - (16) x Summer Probability of Peak (0%)	$0.000	$0.000
		------- (2016 cents/therm) --------	
(19)	Annual Unit Costs 100 x (16) / [(Days in Year * Annual LF) * (1.00 * 10)]	$0.194	$0.011
(20)	Winter Season Unit Costs 100 x (17) / [(Days in Winter * Winter LF) * (1.00 * 10)]	$0.343	$0.019
(21)	Summer Season Unit Costs 100 x (18) / [Days in Summer * Summer LF) * (1.00 * 10)]	$0.000	$0.000

Table 21. Annual Lower Medium and Low Pressure Mains and Regulator Stations

		Medium and Low-pressure Reg. Stations	Total Lower Medium and Low-Pressure Mains (after CIAC)	Total Lower Medium and Low-Pressure Mains (before CIAC)
		-- (2016 $ per MCF of Long-Term Design Day Demand)---		
		(1)	(2)	(3)
(1)	Marginal Investment	$67.80	$1,335.73	$1,500.82
(2)	With General Plant Loading (1) x 1.0739	72.81	1434.44	1611.73
(3)	Annual Economic Carrying Charge Related to Capital Investment	10.27%	10.04%	10.04%
(4)	A&G Loading (plant related)	0.04%	0.00%	0.00%
(5)	Total Annual Carrying Charge (3) + (4)	10.30%	10.04%	10.04%
(6)	Annualized Costs (2) x (5)	$7.50	$143.96	$161.75
(7)	O&M Expenses	2.46	9.08	9.08
(8)	O&M exp. with A&G Loading (Non-plant Related) (7) x 1.0196	2.51	9.26	9.26
(9)	Annual Cost (6) + (8)	$10.02	$153.21	$171.00
	Working Capital			
(10)	Material and Supplies (2) x 0.73%	$0.53	$10.47	$11.77
(11)	Prepayments (2) x 1.21%	0.88	17.36	19.50
(12)	Cash Working Capital Allowance (8) x 12.50%	0.31	1.16	1.16
(13)	Total Working Capital (10) + (11) + (12)	1.73	28.99	32.42
(14)	Revenue Requirement for Working Capital (13) x 11.28%	$0.19	$3.27	$3.66
(15)	Annual Marginal Unit Costs (9) + (14)	**$10.21**	**$156.48**	**$174.66**

B. Annual Customer-Related Costs

The annual customer-related marginal costs were developed using a procedure similar to that for the other types of plant. This component includes the cost of the meter and house regulator, service lateral, and customer-related expenses. The resulting costs (in $ per customer) are shown by customer category in Table 22. The cash working capital component does not apply to uncollectibles.

Table 22. A. Computation of Annual Customer-Related Marginal Costs

		SC1S Residential Heat	SC1S Residential Non Heat	SC2S General Service	SC3S Interruptible Sales
		(2016 Dollars per Customer)			
		(1)	(2)	(3)	(4)
	<u>Investment - Meter, House Regulators & Services</u>				
(1)	Meter & H. Regulator Investment (cost per unit)	$341.89	341.89	836.31	8,276.78
(2)	With General Plant Loading (1) x 1.074	$367.15	$367.15	$898.11	$8,888.44
(3)	Annual Economic Charge Related to Capital Investment	11.23%	11.23%	11.23%	11.23%
(4)	Service Investment (cost per service)	$1,680.25	1,680.25	3,650.20	8,334.96
(5)	With General Plant Loading (4) x 1.074	$1,804.42	$1,804.42	$3,919.95	$8,950.92
(6)	Annual Economic Charge Related to Capital Investment	10.53%	10.53%	10.53%	10.53%
(7)	A&G Loading (Plant Related)	0.00%	0.00%	0.00%	0.00%
(8)	Total Carrying Charge Meters & H. Reg. (3) + (7)	11.23%	11.23%	11.23%	11.23%
(9)	Total Carrying Charge Services (6)+(7)	10.53%	10.53%	10.53%	10.53%
(10)	Annualized Meter & H. Regulator Costs (2) x (8)	$41.22	$41.22	$100.83	$997.92
(11)	Annualized Service Costs (5) x (9)	$190.08	$190.08	$412.94	$942.92
(12)	Total Annualized Meter, H. Reg. & Service Costs (10)+(11)	$231.30	$231.30	$513.77	$1,940.84
	<u>O&M - Meter, House Regulators & Services</u>				
(13)	Meter & H. Reg. O&M Expense	$4.50	$4.50	$238.10	$2,356.39
(14)	Service Lateral O&M Expense	$37.84	$37.84	$42.49	$42.49
(15)	Customer Accounts Expense (excluding uncollectables)	$60.49	$59.26	$67.27	$661.92
(16)	Uncollectibles Customer Accounts Expense	$13.56	$7.24	$4.65	$281.47
(17)	Customer Service and Informational Expense	$1.77	$0.95	$1.93	$119.56
(18)	A&G Loading [(13)+(14)+(15)+(17)] x 0.0196 (Non-plant Related)	$2.05	$2.01	$6.85	$62.25
	Working Capital				
(19)	Materials and Supplies [(2)+(5)] x 0.73%	$15.85	$15.85	$35.17	$130.23
(20)	Prepayments [(2)+(5)] x 1.210%	$26.28	$26.28	$58.30	$215.86
(21)	Cash Working Capital Allowance [(13)+(14)+(15)+(17)+(18)] x 12.50%	$13.33	$13.07	$44.58	$405.33
(22)	Revenue Requirement for Working Capital [(19)+(20)+(21)] x 11.28%	$6.26	$6.23	$15.57	$84.76
(23)	Total Customer-Related Costs [(12)+(13)+(14)+(15)+(16)+(17)+(18)+(22)]	**$357.78**	**$349.33**	**$890.63**	**$5,549.68**

Table 22. B. Computation of Annual Customer-Related Marginal Costs

		SC5S	SC9S	SC13T	SC13T	SC14T
				Res. Heat	Res. Non-Heat	Non-Res.
			Industrial	Aggregation	Aggregation	Aggregation
		Gas Cooling	Manufacturing	Service	Service	Service
		(2016 Dollars per Customer)				
		(1)	(2)	(3)	(4)	(5)
	Investment - Meter, House Regulators & Services					
(1)	Meter & H. Regulator Investment (cost per unit)	n/a	4,507.09	341.89	341.89	1,247.41
(2)	With General Plant Loading (1) x 1.074	$0.00	$4,840.16	$367.15	$367.15	$1,339.60
(3)	Annual Economic Charge Related to Capital Investment	11.23%	11.23%	11.23%	11.23%	11.23%
(4)	Service Investment (cost per service)	n/a	6,464.97	1,680.25	1,680.25	3,650.20
(5)	With General Plant Loading (4) x 1.074	$0.00	$6,942.73	$1,804.42	$1,804.42	$3,919.95
(6)	Annual Economic Charge Related to Capital Investment	10.53%	10.53%	10.53%	10.53%	10.53%
(7)	A&G Loading (Plant Related)	-	0.00%	0.00%	0.00%	0.00%
(8)	Total Carrying Charge Meters & H. Reg. (3) + (7)	11.23%	11.23%	11.23%	11.23%	11.23%
(9)	Total Carrying Charge Services (6)+(7)	10.53%	10.53%	10.53%	10.53%	10.53%
(10)	Annualized Meter & H. Regulator Costs (2) x (8)	$0.00	$543.41	$41.22	$41.22	$150.40
(11)	Annualized Service Costs (5) x (9)	$0.00	$731.37	$190.08	$190.08	$412.94
(12)	Total Annualized Meter, H. Reg. & Service Costs (10)+(11)	$0.00	$1,274.78	$231.30	$231.30	$563.34
	O&M - Meter, House Regulators & Services					
(13)	Meter & H. Reg. O&M Expense	-	$1,283.16	$4.50	$4.50	$355.14
(14)	Service Lateral O&M Expense	-	$42.49	$37.84	$37.84	$42.49
(15)	Customer Accounts Expense (excluding uncollectables)	$67.27	$152.50	$60.11	$57.47	$72.78
(16)	Uncollectibles Customer Accounts Expense	$4.65	$35.05	$14.02	$7.80	$7.57
(17)	Customer Service and Informational Expense	$1.93	$14.45	$1.83	$1.02	$3.15
(18)	A&G Loading [(13)+(14)+(15)+(17)] x 0.0196 (Non-plant Related)	$1.35	$29.22	$2.04	$1.97	$9.27
	Working Capital					
(19)	Materials and Supplies [(2)+(5)] x 0.73%	$0.00	$86.02	$15.85	$15.85	$38.39
(20)	Prepayments [(2)+(5)] x 1.210%	$0.00	$142.57	$26.28	$26.28	$63.64
(21)	Cash Working Capital Allowance [(13)+(14)+(15)+(17)+(18)] x 12.50%	$8.82	$190.23	$13.29	$12.85	$60.35
(22)	Revenue Requirement for Working Capital [(19)+(20)+(21)] x 11.28%	$0.99	$47.24	$6.25	$6.20	$18.32
(23)	Total Customer-Related Costs [(12)+(13)+(14)+(15)+(16)+(17)+(18)+(22)]	**$76.20**	**$2,878.89**	**$357.91**	**$348.12**	**$1,072.06**

Table 22. C. Computation of Annual Customer-Related Marginal Costs

		SC1T Large Firm Transportation	SC2T Interruptible Transportation	SC5T Small Firm Transportation	SC7T Firm or Limited Firm Negotiated Transportation	SC16T Non-Residential DG Firm Transportation
		(2016 Dollars per Customer)				
		(1)	(2)	(3)	(4)	(5)
	Investment - Meter, House Regulators & Services					
(1)	Meter & H. Regulator Investment (cost per unit)	$8,208.08	8,518.93	6,179.67	8,986.70	5,200.21
(2)	With General Plant Loading (1) x 1.074	$8,814.66	$9,148.47	$6,636.35	$9,650.81	$5,584.50
(3)	Annual Economic Charge Related to Capital Investment	11.23%	11.23%	11.23%	11.23%	11.23%
(4)	Service Investment (cost per service)	8,334.96	8,334.96	6,464.97	10,013.00	n/a
(5)	With General Plant Loading (4) x 1.074	$8,950.92	$8,950.92	$6,942.73	$10,752.96	$0.00
(6)	Annual Economic Charge Related to Capital Investment	10.53%	10.53%	10.53%	10.53%	10.53%
(7)	A&G Loading (Plant Related)	0.00%	0.00%	0.00%	0.00%	0.00%
(8)	Total Carrying Charge Meters & H. Reg. (3) + (7)	11.23%	11.23%	11.23%	11.23%	11.23%
(9)	Total Carrying Charge Services (6)+(7)	10.53%	10.53%	10.53%	10.53%	10.53%
(10)	Annualized Meter & H. Regulator Costs (2) x (8)	$989.64	$1,027.11	$745.07	$1,083.51	$626.98
(11)	Annualized Service Costs (5) x (9)	$942.92	$942.92	$731.37	$1,132.75	$0.00
(12)	Total Annualized Meter, H. Reg. & Service Costs (10)+(11)	$1,932.56	$1,970.03	$1,476.44	$2,216.27	$626.98
	O&M - Meter, House Regulators & Services					
(13)	Meter & H. Reg. O&M Expense	$2,336.83	$2,425.33	$1,759.34	$2,558.50	$1,480.49
(14)	Service Lateral O&M Expense	$42.49	$42.49	$42.49	$42.49	n/a
(15)	Customer Accounts Expense (excluding uncollectables)	$661.92	$661.92	$174.45	$661.92	$264.74
(16)	Uncollectibles Customer Accounts Expense	$281.47	$281.47	$61.14	$281.47	$102.29
(17)	Customer Service and Informational Expense	$119.56	$119.56	$25.56	$119.56	$42.12
(18)	A&G Loading [(13)+(14)+(15)+(17)] x 0.0196 (Non-plant Related)	$61.87	$63.60	$39.19	$66.21	$34.99
	Working Capital					
(19)	Materials and Supplies [(2)+(5)] x 0.73%	$129.69	$132.13	$99.13	$148.95	$40.77
(20)	Prepayments [(2)+(5)] x 1.210%	$214.96	$219.00	$164.31	$246.89	$67.57
(21)	Cash Working Capital Allowance [(13)+(14)+(15)+(17)+(18)] x 12.50%	$402.83	$414.11	$255.13	$431.09	$227.79
(22)	Revenue Requirement for Working Capital [(19)+(20)+(21)] x 11.28%	$84.32	$86.32	$58.49	$93.28	$37.92
(23)	Total Customer-Related Costs [(12)+(13)+(14)+(15)+(16)+(17)+(18)+(22)]	**$5,521.01**	**$5,650.72**	**$3,637.11**	**$6,039.69**	**$2,589.53**

X. SUMMARY TABLES

Table 23 summarizes the seasonal and annual per-therm costs of high-pressure regulator stations and upper medium-pressure mains developed in Table 20 above, as well as the marginal reliability storage cost from Table 3.

Table 23. Summary of Marginal High-Pressure Regulator Stations and Upper Medium-Pressure Mains and Reliability Storage Marginal Costs

	Seasonal Costs		
	Winter (Dec. - Mar.)	Summer (April - Nov.)	Annual Cost
	(2016 cents/therm)		(2016 cents/therm)
	(1)	(2)	(3)
High-Pressure Regulator Stations	0.3432	0.0000	0.1943
Upper Medium-Pressure Mains	0.0192	0.0000	0.0109
Reliability Storage	0.0131	0.0131	0.0131
Total	0.3756	0.0131	0.2183
Total without Reliability Storage	0.3624	0.0000	0.2052

Table 24 summarizes the monthly local facilities marginal costs that vary with design demand (lower medium- and low-pressure distribution mains and medium and low-pressure regulator stations) by service classification, before and after CIAC. Columns (1) and (2) show these costs per-MCF of design-day demand. Table 24 also shows, in columns (4) and (5), these monthly marginal costs on a per-customer basis, derived by multiplying the unit cost by the typical customer's design demand in each service classification.

Table 24. Summary of Monthly Local Facilities Marginal Costs by Service Classification

Rate	Classification	Facilities Costs (after CIAC)	Total Facilities Costs (before CIAC)	Average Design Day Demand	Per Customer Facilities Costs (after CIAC)	Per Customer Total Facilities Costs (before CIAC)
		2016 $ / MCF of design day demand /mo.		(MCF)	---- 2016 $ per cust/mo.-----	
					(1)*(3)	(2)*(3)
		(1)	(2)	(3)	(4)	(5)
SC1S	SC 1 Residential Heat	$13.89	$15.41	3.01	$41.81	$46.38
SC1S	SC 1 Residential Non Heat	13.89	15.41	3.01	41.81	46.37
SC2S	SC 2 General Service	13.89	15.41	12.80	177.80	197.20
SC3S	SC 3 Interruptible Sales	13.89	15.41	260.00	3,611.66	4,005.57
SC5S	SC 5 Gas Cooling	n/a	n/a	n/a	n/a	n/a
SC9S	SC 9 Industrial Manufacturing	13.89	15.41	73.33	1,018.63	1,129.72
SC13T	SC 13T Residential Heat Aggregation Service	13.89	15.41	3.01	41.81	46.37
SC13T	SC 13T Residential Non-Heat Aggreg. Service	13.89	15.41	3.01	41.81	46.37
SC14T	SC 14T Non-Residential Aggregation Service	13.89	15.41	20.03	278.24	308.58
SC1T	SC 1T Large Firm Transportation	13.89	15.41	247.00	3,431.08	3,805.29
SC2T	SC 2T Interruptible Transportation	13.89	15.41	275.00	3,820.03	4,236.66
SC5T	SC 5T Small Firm Transportation	13.89	15.41	150.80	2,094.76	2,323.23
SC7T	SC 7T Firm Or Limited Firm Negotiated Trans.	13.89	15.41	301.43	4,187.17	4,643.84
SC16T	SC16T Non-Residential Distributed Generation Firm Transportation Service	13.89	15.41	100.00	1,389.10	1,540.60

Table 25 summarizes the monthly marginal customer-related cost (in dollars per customer per month), by service classification.

Table 25. Summary of Monthly Marginal Customer-Related Cost by Service Classification

	Customer Classification	Description	Monthly Customer-related Cost per Customer
			(2016 Dollars)
(1)	SC1S	SC 1 Residential Heat	$29.81
(2)	SC1S	SC 1 Residential Non Heat	29.11
(3)	SC2S	SC 2 General Service	74.22
(4)	SC3S	SC 3 Interruptible Sales	462.47
(5)	SC5S	SC 5 Gas Cooling	6.35
(6)	SC9S	SC 9 Industrial Manufacturing	239.91
(7)	SC13T	SC 13T Residential Heat Aggregation Service	29.83
(8)	SC13T	SC 13T Residential Non-Heat Aggreg. Service	29.01
(9)	SC14T	SC 14T Non-Residential Aggregation Service	89.34
(10)	SC1T	SC 1T Large Firm Transportation	460.08
(11)	SC2T	SC 2T Interruptible Transportation	470.89
(12)	SC5T	SC 5T Small Firm Transportation	303.09
(13)	SC7T	SC 7T Firm Or Limited Firm Negotiated Trans.	503.31
(14)	SC16T	SC16T Non-Residential DG Firm	215.79

This study found that NYSEG's marginal gas delivery costs in the foreseeable future consist of the costs of reliability storage, local distribution facilities costs (regulator stations and lower medium- and low-pressure mains) and the customer-related costs of meters, house regulators, service laterals, and customer-related expenses. Only the first component is a function of gas consumption. NYSEG's other marginal gas delivery costs are a function of a customer's presence on the system (customer-related costs) and the customer's expected long-term design-day demand (local facilities costs), which can be approximated by meter capacity (with the appropriate adjustment for residential customers).[8]

[8] See the discussion in Section III.

XI. COMPARISON TO CURRENT RATES

Table 26 A, B and C compare current charges to efficient prices equal to marginal cost for each service classification, using current rate designs. An adjustment would be necessary to produce the target revenue requirement.

We note that efficient rates would mirror the structure of NYSEG's gas service marginal cost and would consist of winter volumetric charges to recover upper medium-pressure mains costs, a year-round volumetric charge to recover reliability storage costs,[9] and two fixed monthly charges – one a customer charge that varies by class to cover monthly marginal customer costs, and a second local facilities charge based on meter capacity. For classes in which all customers have similar meter capacities, the customer and local facilities charges could be combined in a single per-customer charge. All volumetric efficient charges have been averaged and are shown as a flat year-round dollar per-therm charge as opposed to a seasonally differentiated charge, for easier comparison with existing rates.

[9] This reliability charge could be combined with the other volumetric charge in winter months.

Table 26. A. Marginal Costs Compared to Current Rates

	Current Rates	Marginal Costs ($2016)		Current Rates	Marginal Costs ($2016)
	Customer charge	Monthly Fixed Cost ($2016)		Per Therm	All Therms
SC1S					
Basic Service Charge	$16.30	Customer Cost	$29.81		
Bill Issuance Charge	$0.73	Facilities Cost	$41.81		
0 -3	$17.03		$71.62	$0.0000	$0.0022
4 -50				$0.5193	
Over 50				$0.1220	
SC1S NON-HEAT					
Basic Service Charge	$12.30	Customer Cost	$29.11		
Bill Issuance Charge	$0.73	Facilities Cost	$41.81		
0 3	$13.03		$70.92	$0.0000	$0.0022
4 50				$0.5193	
Over 50				$0.1220	
SC2S					
Basic Service Charge	$23.60	Customer Cost	$74.22		
Bill Issuance Charge	$0.73	Facilities Cost	$177.80		
0 3	$24.33		$252.02	$0.0000	$0.0022
4 500				$0.3378	
501 15,000				$0.1946	
Over 15,000				$0.1197	
SC3S Interruptible Sales					
		Customer Cost	$462.47		$0.0022
		Facilities Cost	$3,611.66		
			$4,074.14		
SC5S Seasonal Gas Cooling					
Basic Service Charge	$16.86	Customer Cost	$6.35		
Bill Issuance Charge	$0.73	Facilities Cost	n/a		
0 3	$17.59		$6.35	$0.0000	$0.0022
Over 3				$0.0314	
SC9S Industrial (Binghamton Only)					
Basic Service Charge	$243.87	Customer Cost	$239.91		
Bill Issuance Charge	$0.73	Facilities Cost	$1,018.63		
0 500	$244.60		$1,258.54	$0.0000	$0.0022
501 15,000				$0.1655	
Over 15,000				$0.1200	
SC13T (Res Agg-Heat)					
Basic Service Charge	$16.30	Customer Cost	$29.83		
Bill Issuance Charge	$0.73	Facilities Cost	$41.81		
0 3	$17.03		$71.64	$0.0000	$0.0022
4 50				$0.5193	
Over 50				$0.1220	
SC13T (Res Agg Non-Heat)					
Basic Service Charge	$12.30	Customer Cost	$29.01		
Bill Issuance Charge	$0.73	Facilities Cost	$41.81		
0 3	$13.03		$70.82	$0.0000	$0.0022
4 50				$0.5193	
Over 50				$0.1220	
SC14T (Non-Res Agg)					
Basic Service Charge	$23.60	Customer Cost	$89.34		
Bill Issuance Charge	$0.73	Facilities Cost	$278.24		
0 - 3	$24.33		$367.58	$0.0000	$0.0022
4- 500				$0.3378	
501 15,000				$0.1946	
Over 15,000				$0.1197	

Table 26. B. Marginal Costs Compared to Current Rates

		Current Rates		**Marginal Costs**		**Current Rates**		**Marginal Costs**
		Customer Charge per Month				Charge per Therm		
		Without Sales Status Reserved	With Sales Status Reserved	Monthly Fixed Costs (2016 $)		Without Sales Status Reserved	With Sales Status Reserved	All Therms (2016 $)
SC1T (Owego, Goshen, Lockport, Combined, Champlain)								
Basic Service Charge		$1,124.19	$1,179.74	Customer Cost	460.08			
Bill Issuance Charge		$0.73	$0.73	Facilities Cost	3,431.08			
0	500	$1,124.92	$1,180.47		$3,891.16	$0.0000	$0.0000	$0.0021
501	15,000					$0.1186	$0.2297	
15,001	50,000					$0.0639	$0.1750	
Over	50,000					$0.0605	$0.1716	
SC1T (Elmira)								
Basic Service Charge		$1,124.19	$1,179.74	Customer Cost	460.08			
Bill Issuance Charge		$0.73	$0.73	Facilities Cost	3,431.08			
0	500	$1,124.92	$1,180.47		$3,891.16	$0.0000	$0.0000	$0.0021
501	15,000					$0.1186	$0.2297	
15,001	50,000					$0.0639	$0.1750	
Over	50,000					$0.0605	$0.1716	
SC1T (Binghamton)								
Basic Service Charge		$1,124.19	$1,179.74	Customer Cost	460.08			
Bill Issuance Charge		$0.73	$0.73	Facilities Cost	3,431.08			
0	500	$1,124.92	$1,180.47		$3,891.16	$0.0000	$0.0000	$0.0021
501	15,000					$0.1186	$0.2297	
15,001	50,000					$0.0639	$0.1750	
Over	50,000					$0.0605	$0.1716	
SC 2T Interruptible Transportation				Customer Cost	470.89			$0.0022
				Facilities Cost	3,820.03			
					$4,290.92			
SC5T								
Basic Service Charge		$243.87	$299.42	Customer Cost	303.09			
Bill Issuance Charge		$0.73	$0.73	Facilities Cost	2,094.76			
0	500	$244.60	$300.15		$2,397.86	$0.0000	$0.0000	$0.0021
501	15,000					$0.1687	$0.2798	
Over	15,000					$0.1200	$0.2311	
SC 7T Firm Or Limited Firm Negotiated Transportation				Customer Cost	503.31			$0.0022
				Facilities Cost	4,187.17			
					$4,690.48			

Table 26. C. Marginal Costs Compared to Current Rates

		Current Rates		Marginal Costs		Current Rates		Marginal Costs
		Customer Charge per Month		Monthly Fixed Costs (2016 $)		Charge per Therm		All Therms (2016 $)
		Summer	Winter			Summer	Winter	
SC 16T Non-Residential DG Firm Transportation								
Small DG < 5 MW								
Using 0 to 40,000 Therms/year								
Basic Service Charge		$23.60	$23.60	Customer Cost	$215.79			$0.0022
Bill Issuance Charge		$0.73	$0.73	Facilities Cost	$1,389.10			
0	497					$0.1341	$0.1792	
498	14,998					$0.0772	$0.1010	
14,999	49,999					$0.0475	$0.0620	
Over	50,000					$0.0475	$0.0620	
Using 40,001 to 250,000								
Basic Service Charge		$243.87	$243.8700	Customer Cost	$215.79			$0.0022
Bill Issuance Charge		$0.73	$0.7300	Facilities Cost	$1,389.10			
0	14,997					$0.0724	$0.0874	
Over	15,000					$0.0515	$0.0601	
Using > 250,000 Therms/year								
Basic Service Charge		$1,124.19	$1,124.1900	Customer Cost	$215.79			$0.0022
Bill Issuance Charge		$0.73	$0.7300	Facilities Cost	$1,389.10			
0	14,500					$0.0872	$0.1114	
14,501	35,000					$0.0470	$0.0579	
Over	50,000					$0.0445	$0.0550	
Large DG – 5 > MW <50								
Basic Service Charge		$1,124.19	$1,124.19	Customer Cost	$215.79			$0.0022
Bill Issuance Charge		$0.73	$0.73	Facilities Cost	$1,389.10			
Demand Charge (per Therm of demand)		$1.06	$1.06					
0	500					$0.0000	$0.0000	
Over	500					$0.0135	$0.0166	

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INDEX OF WORKPAPERS SUPPORTING
DIRECT TESTIMONY OF AMPARO NIETO (NYSEG)

Exhibit Reference	Description of Exhibit	No. WP	Title of Workpaper (or WP) File	Content of Workpaper	WP Format	Trade Secret
NYSEGAN-2	Electric marginal cost of delivery service reports and supporting papers	5	• NYSEG Marginal Cost of Electric Delivery Service. • NYSEG Electric ECC Dist Fac • NYSEG Electric ECC Dist Sub • NYSEG Electric ECC Meters and Services • NYSEG Electric ECC Street Lights	• Detailed description of the marginal cost of service study for NYSEG Electric • Calculation of first year carrying charge for local distribution facilities • Calculation of first year carrying charge for distribution substations and primary lines • Calculation of first year carrying charge for meters and services • Calculation of first year carrying charge for street light	Pdf .xls .xls .xls .xls	No No No No No
NYSEGAN-3	Gas marginal cost of delivery service reports and supporting papers	5	• NYSEG Marginal Cost of Gas Delivery Service. • NYSEG Gas ECC House Meters, Reg, and Install • NYSEG Gas ECC Mains • NYSEG Gas ECC Regulator Stations • NYSEG Gas ECC Services	• Detailed description of the marginal cost of service study for NYSEG Gas • Calculation of first year carrying charge for house meters and regulators • Calculation of first year carrying charge for gas mains • Calculation of first year carrying charge for regulator stations equipment • Calculation of first year carrying charge for gas services	Pdf .xls .xls .xls .xls	No No No No No