BEFORE THE
NEW YORK STATE
PUBLIC SERVICE COMMISSION

---x

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Electric Service	Case 15-E- ____
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Gas Service	Case 15-G- ____

---x

DIRECT TESTIMONY OF
AMPARO NIETO

May 20, 2015

DIRECT TESTIMONY OF AMPARO NIETO

TABLE OF CONTENTS

DIRECT TESTIMONY OF AMPARO NIETO

I. INTRODUCTION

Q. Please state your name.

A. My name is Amparo Nieto.

Q. Ms. Nieto, please state your current position and business address.

A. I am a Vice President at NERA Economic Consulting ("NERA"). My business address is 777 South Figueroa Street, Suite 1950, Los Angeles, California 90017.

Q. Please summarize your educational background and work experience.

A. I have an M.A. degree in Public Finance and Economics from the Madrid Institute for Fiscal Studies in Spain, and a B.A. in Economics from the University of Carlos III of Madrid, Spain. I joined NERA as part of the Energy practice in the Madrid office in 1996 and I transferred to Los Angeles, California in 2000. At NERA, I have specialized in regulatory energy pricing policy, including electric and gas rate design, transmission pricing and cost allocation and capacity payment mechanisms. I have extensively advised utilities and regulatory commissions in the U.S. and overseas on the use of marginal cost techniques for use in designing innovative rates, evaluating demand response programs and interruptible rates, reforming distributed generation rates, revising pricing terms in energy contracts, procurement aspects of renewable resources, and many other pricing-related issues. I have also advised independent system operators and energy regulatory commissions in the U.S. and Australia on transmission planning, financial transmission rights, and wholesale capacity market design.

For more than a decade, I have taught seminars on electricity marginal costing and rate design for rate managers and regulatory commission staff. Since

2009, I have directed NERA's Marginal Cost Working Group, a utility group dedicated to improving methods for estimating and using marginal cost information in a variety of utility applications. I have presented numerous papers on industry and academic forums in the U.S. On several occasions, I have participated as an instructor in the University of Florida Public Utility Research Center/World Bank International Training Program on Utility Regulation and Strategy, intended to enhance regulatory capabilities to new regulatory entities in developing countries. My Curriculum Vitae is set forth in Exhibit __ (NYSEGAN-1).

Q. Have you previously testified in other proceedings before the New York State Public Service Commission ("PSC" or the "Commission") or any other state or federal regulatory agency or court?

A. Yes, I have testified before the North Carolina Utilities Commission in the context of establishing the pricing terms of a long-term power purchase agreement between the incumbent utility, Progress Energy Carolinas, Inc., and two qualifying facilities. In particular, my testimony included an assessment of both parties' methodologies to estimate the avoided energy and capacity costs associated with the dispatch of the qualifying facilities. I also provided expert opinion before the Board of Directors of Salt River Project ("SRP") regarding the cost basis and rationale for a new rate proposed for distributed generation customers under net metering in SRP's service territory.

DIRECT TESTIMONY OF AMPARO NIETO

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to: 1) define marginal cost principles and explain why they are an appropriate basis for utility rate design; 2) describe the history of marginal cost-based rates in New York State; and 3) describe the development of the gas and electric marginal costs and the resulting efficient prices developed for use by New York State Electric & Gas Corporation ("NYSEG" or the "Company") in this case.

Q. Please summarize your testimony.

A. As the Commission has long recognized, electric and gas rates that are based on marginal costs provide price signals that: 1) encourage efficient energy consumption decisions by consumers; 2) lead to an efficient use and expansion of the available infrastructure that are consistent with how consumers value reliability; and 3) promote efficient competition in the energy sector. Working closely with Company staff, my team (working under my supervision) and I developed estimates of NYSEG's marginal costs of providing electric and gas delivery service. The marginal cost studies use methods tailored to current market arrangements and NYSEG's situation, and make use of the best available information. The marginal costs of each element of delivery service provide the starting point for efficient class revenue allocation and rate design.

Q. Are there differences in the marginal costing approaches you used for this case as compared to those used in the Company's last-filed marginal cost studies?

A. No, the approaches used for the Company's last-filed marginal cost studies continue to be appropriate for this case. I was the lead consultant in the development of the marginal cost of service studies ("MCOSS") on behalf of NYSEG in 2010 and the accompanying report (the "2010 Report").

Q. Are you sponsoring any exhibits?

A. As I mentioned, Exhibit __ (NYSEGAN-1) contains additional details on my credentials. Exhibit __ (NYSEGAN-2) and Exhibit __ (NYSEGAN-3) are the electric and gas marginal cost of delivery service reports, respectively, that my staff and I prepared for this case. Exhibit __ (NYSEGAN-4) provides an index of my workpapers. A copy of the workpapers will be provided to New York State Department of Public Service Staff ("Staff").

II. THE ROLE OF MARGINAL COST PRICING AND ITS HISTORY IN NEW YORK

A. Marginal Cost Definition

Q. What are marginal costs?

A. Marginal costs in the context of electricity or natural gas are the additional costs that the utility incurs to provide a hypothetical small increment of electric or natural gas usage or the cost savings from a hypothetical small decrement in load. It is a forward-looking concept that requires examining the utility's planning processes and operating decisions to determine what drives new investment and how a small change in consumption affects utility system costs. While marginal costs do not include sunk costs, the utility's existing resources with regard to expected levels of demand affect the answer to these questions.

Q. What are the elements of the marginal costs of electric delivery service?

A. There are three major components of electric delivery service. First, there are customer-related costs that vary with the number of customers on the system.

These costs include the meter and service drop and their associated operation and maintenance expenses ("O&M"), as well as customer-related expenses, such as meter-reading, billing, customer accounts, uncollectibles, and customer information services.

Second, there are design demand-related costs associated with local distribution facilities, which include line transformers, local primary lines and secondary lines. These facilities are sized based on the expected maximum loads of the customers using them over the life of the equipment. The planners' expectation is that local distribution facilities will not be expanded in response to month-to-month or year-to-year variations in actual usage, so long as there is no change in the customer's design demand. These costs are marginal when customers are initially connected to the distribution network, when there are major changes in design demand that require local distribution facility capacity to be expanded, and when the local facilities are replaced at the end of their lives. As a result, the optimal way to recover the marginal costs of local distribution facilities is in a fixed charge applied to a measure of design demand, not in charges based on energy use or actual peak demand in the billing period.

The third major component of marginal electric delivery costs consists of marginal distribution substation and trunkline feeder costs, upstream line and substation costs (along with their associated O&M), and marginal transmission costs. These elements of the system must be expanded as the system peak load grows, i.e., they do depend on customers' ongoing changes in electricity use and the timing of that use within the day. These costs vary by season and time of day, depending on the likelihood that a particular period will include the relevant peak.

Q. What are the elements of the marginal costs of gas delivery service?

A. The elements of gas delivery service marginal costs parallel those of electric delivery service. First, there are customer-related costs—meter, regulator, relief valve and service lateral and their associated O&M, and customer-related expenses.

Second, there are local facilities' costs that vary with long-term expected peak-day demands (design demand). For NYSEG, these local facilities costs consist of medium- and low-pressure regulator stations and lower medium- and low-pressure mains and their associated O&M.

Third, there are marginal costs of transmission, high-pressure regulator stations, and upper medium-pressure mains. These plant components are sized based on near-term design-day demands and are expanded as load grows. Furthermore, the costs of these components are seasonally differentiated because there is a high probability that load growth in winter months will trigger the need for capacity expansion.

Finally, there is the cost associated with storage (capacity and carrying charges on the gas stored) required to provide reliability for the distribution system.

B. Role of Marginal Cost Pricing

Q. Why should rate designs be based on marginal costs?

A. There are three main reasons, based on economic theory. The primary argument for using marginal costs in setting electric and gas rates is that consumers will make efficient energy consumption and investment decisions when the prices they face for electricity and gas reflect the underlying opportunity costs of using a little more or a little less at any given time. In New York, the commodity portion of gas and electric bills generally reflects market prices. Therefore, that component of the rate approximately equals marginal costs.

Q. How does a marginal cost-based delivery price contribute to efficient consumption and investment decisions by consumers?

A. Although electric and gas delivery prices are only a portion of the total electric or gas bill, the delivery charges contribute to the total price signal to which consumers respond. A consumer deciding what type of appliance to buy will compare the cost of electricity with other alternatives. If electricity and gas prices (including delivery charges) reflect the economic costs of service, those comparisons can be made on an apples-to-apples basis. In this situation, consumers deciding which alternative is most advantageous from a personal point of view are also picking the option which is best (i.e., most economically efficient) from society's point of view.

DIRECT TESTIMONY OF AMPARO NIETO

Q. What is the second economic reason for basing electric and gas delivery rates on marginal costs?

A. The second argument is that marginal cost pricing will lead to consumption patterns and levels that make an efficient use of the capacity that is available. Efficient consumption is a prerequisite for efficient system expansion. Because system expansion is influenced by energy use levels and patterns, pricing below marginal costs may lead to unnecessary investment in delivery facilities as well as procurement costs. Pricing above marginal cost may lead to inefficiently low consumption, poor utilization of existing facilities, and net social loss.

Q. Please provide an example of this effect.

A. A good illustration of this effect is when delivery rates fail to reflect the underlying structure of marginal transmission and distribution costs. Any costs that do not vary with changes in usage by time of day are appropriately recovered in a fixed customer charge. Local distribution systems include distribution transformers, secondary lines, and local primary lines and are driven by changes in design demand, i.e., the local demands that are expected over the service life of the facility. When a rate is designed so that the local facilities costs are recovered in volumetric charges (per-kWh), there is an efficiency loss because the customer, as a result, may face overall per-kWh price signals that are above the actual marginal costs across all hours of the day. As mentioned above, this effect will normally result in consumption that is inefficiently low because the marginal cost of procuring electricity and delivering it to the customer is lower than both the per-kWh charge and the value of electricity to the consumer. More importantly, when rates do not properly reflect marginal costs, there is an overstated incentive for customers to shift to another choice of fuel or to self-generate, e.g., by installing solar panels on their premises. This is not only an inefficient result but also inequitable because, if the consumer's bill decreases by more than the costs avoided by the utility, other customers' bills are ultimately affected.

Q. What is the third economic argument for marginal cost-based electric and gas delivery rates?

A. Marginal cost-based rates promote effective competition in the industry, both in terms of suppliers' competition for customers and in terms of competition among alternative types of energy. Business customers tend to migrate to, or expand production in, the area where their energy demands can be served at least cost, all else equal. Delivery rates that are based on marginal costs will influence efficient decisions since they will provide cost-reflective price signals. Similarly, in choosing among various energy sources, consumers of all types tend to pick the energy source that can most efficiently power the end-use services they need.

Q. You have explained how marginal cost pricing is economically efficient. Are marginal cost-based rates also equitable?

A. Yes. Marginal cost-based pricing is equitable because every consumer pays the cost of supplying his/her electricity or natural gas usage at the margin. If the customer consumes more, his/her bill goes up by an amount consistent with the incremental costs incurred by the utility, thus no one else needs to bear the additional cost. If the consumer cuts back on energy use, his or her bill goes down by the amount of the costs avoided. Again, no other customer's bill is affected.

Q. You referred to marginal cost-*based* rates. Are such rates different from pricing *at* marginal cost?

A. Yes. For most utilities, the total revenue requirement for delivery service is set equal to an allowed rate of return on rate base, plus depreciation, operating expenses and taxes. These costs are accounting costs and have little in common with forward-looking marginal costs. Therefore, charging marginal costs as prices would only generate the approved level of revenue by coincidence. The difference is called the "marginal cost revenue gap." Some charges must be set above or below marginal cost to produce the correct amount of revenue, and this should be done in a way that minimizes the distortion in the most price-elastic components of the rate.

Q. Are there reasons, other than closing the marginal cost revenue gap, to deviate from rate designs based on marginal cost?

A. Yes. There may be metering and billing constraints that affect the price signal level and bill impact considerations from moving towards marginal cost-based rates that are often taken into account.

C. Use of Marginal Cost Pricing in New York

Q. Has the philosophy of marginal cost rate design been used in New York State in the past?

A. Yes. In fact, New York was one of the first states to endorse marginal cost principles for utility rates. Beginning with its August 10, 1976, Opinion and

Order Determining Relevance of Marginal Costs to Electric Rate Structures in the "Generic Electric Rate Design" case,[1] the Commission has continued to move forward with marginal cost pricing for electric service. In addition, the Commission, in its September 17, 1979 Opinion and Order Determining the Relevance of Marginal Costs to the Regulation of Gas Distribution Companies in the "Long-Range Gas Planning" case,[2] determined that marginal cost concepts are properly applicable to gas service. In subsequent decisions and pronouncements, the Commission has continued to move electric and gas pricing toward more complete implementation of marginal cost principles. The use of marginal costs in the rate setting process is also discussed in the testimony of the Revenue Allocation, Rate Design, Tariff, and Economic Development Panel.

Q. What indication is there that the Commission continues to support implementation of these principles?

A. With regard to electric cost allocation and rate design, as New York moved toward retail competition, the Commission stated that "as the company moves to a more competitive environment, the cornerstone of electric rate designs will be to approximate marginal cost in pricing."[3] The Commission went on to say: "Marginal cost-based pricing rests on the sound economic principle that efficient

---

[1] Case 26806 – Proceeding on Motion of the Commission as to the Rate Design for Electric Corporations, Opinion and Order Determining Relevance of Marginal Costs to Electric Rate Structures (Aug. 10, 1976).

[2] Case 26835 – Proceeding on Motion of the Commission as to the Long-Range Plans of New York State's Gas Distribution Companies, Opinion and Order Determining the Relevance of Marginal Costs to the Regulation of Gas Distribution Companies (Sept. 17, 1979).

[3] Cases 95-E-0673 et al. – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Electric Service, Opinion and Order Concerning Revenue Requirement and Rate Design at 23 (Sept. 26, 1996).

resource allocation is enhanced by pricing goods and services as closely as reasonably achievable to marginal costs. It has been our long-standing policy to price electricity such that consumers pay for the cost their consumption imposes on the utility so that scarce resources are efficiently allocated."[4]

III. NYSEG's MARGINAL COSTS OF ELECTRIC DELIVERY SERVICE

A. Methods Used

Q. What basic approach did you use to estimate NYSEG's marginal costs of electric delivery service?

A. My basic approach was to determine the response of NYSEG's planners and system operators to changes in the number and size of electricity customers taking service and their expected electricity consumption in various seasons and times of day. As I mentioned above, I analyzed marginal costs for the following components of electric delivery service:

1) Customer-related costs
   – Meter and service
   – Customer accounts expenses
   – Customer service and information expenses

2) Local distribution facilities
   – Secondary lines
   – Line transformers
   – Local primary lines

3) Time-differentiated delivery costs
   – Distribution substations and trunkline feeders
   – Upstream substations
   – Transmission

[4] Id. at 23-24.

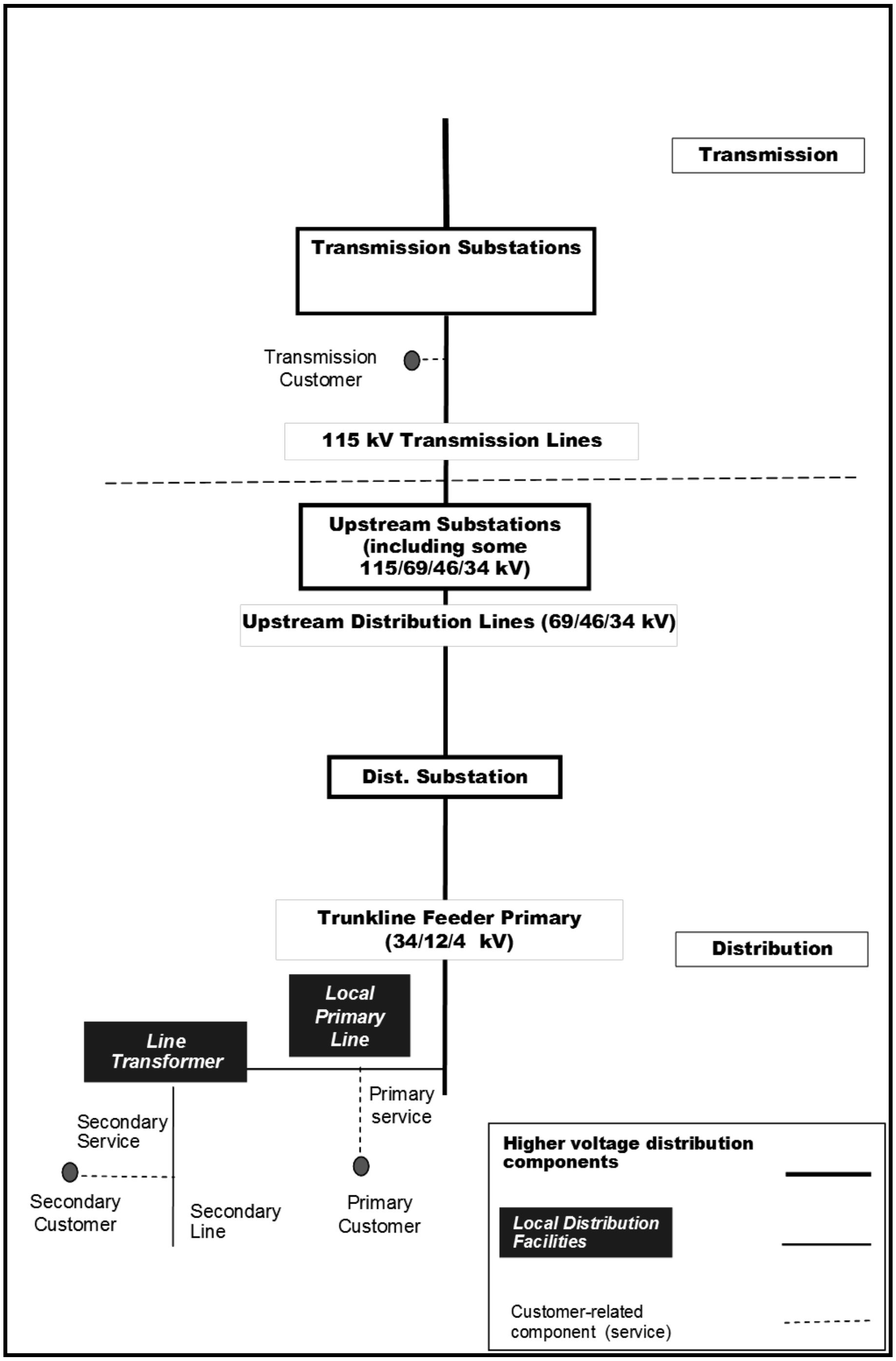
4) Lighting costs

– Lighting equipment costs and related O&M
– Relamping expenses

The diagram below illustrates the components of NYSEG's electric delivery system. A full description of my approach is contained in Exhibit __ (NYSEGAN-2).

[THE REMAINDER OF THIS PAGE INTENTIONALLY LEFT BLANK]

DIRECT TESTIMONY OF AMPARO NIETO



Q. Please describe your method for estimating marginal customer costs.

A. Using information supplied by NYSEG, I computed the average investment in meters and services, before and after Contributions In Aid of Construction ("CIAC"), per customer for each class. I annualized these investments using an economic carrying charge and added estimates of meter O&M, customer accounts expenses (excluding those related to the commodity function), and customer service and information expenses. These marginal expense estimates were based on recent historical levels of expense and class weighting factors based on meter cost, in the case of meter O&M, and results from NYSEG's 2013 embedded cost of service study.

Q. How did you estimate the marginal cost of local electric distribution facilities?

A. For the 2010 Report, NYSEG provided estimates of typical replacement cost per kW of design demand for secondary lines, transformers and local primary lines associated with various types and sizes of customers. Estimates of replacement costs were provided for all customer classes, except for lighting and transmission customers. Street lighting usage does not affect the sizing of distribution facilities and transmission customers either provide their own local facilities or pay up front. NYSEG calculated the replacement cost of the equipment on a sample of three types of circuits – one urban-rural and two village-rural. NYSEG estimated the design demand for each customer in each sample using customer bills to determine whether the circuit was summer- or winter-peaking and then using the customer's billing demand (or a conversion factor applied to kWh) from the customer's peak season bill. I computed estimates of local facilities investment for each service classification by first calculating a weighted average of the facilities per-kW cost for each customer group within a circuit, using the number of sample customers of each type on that circuit as weights. Next, I combined the results from the three circuits, using as weights the number of customers on rural and urban/suburban circuits over the entire NYSEG system. I then annualized the local facilities investment using an economic carrying charge and added estimates of O&M based on recent levels of distribution O&M, with distribution line expenses apportioned to secondary and primary lines on the basis of circuit miles. For most of the service classifications, the 2014 update of distribution facilities costs simply involved applying a forecast of the Gross Domestic Product ("GDP") inflation factor of 11.54% to the 2010 local facility per-kVA cost estimates to put them in 2016 dollars, after the Company confirmed that the typical replacement costs used for the 2010 Report were still representative for those classes. The exceptions were service classifications SC 2, SC 7-1, and SC 7-2. In these cases, I expanded the sample from the 2010 Report in order to include more examples of connection jobs that had taken place from 2010 through 2012 for customers within those classes. This was done to make sure that our sample for the SC 2, SC 7-1, and SC 7-2 classifications captured a sufficient range of possible configurations.

Q. What approach did you use for estimating marginal distribution costs other than local facilities?

A. Local distribution facilities are connected to trunkline feeders, which are in turn connected to distribution substations. Beyond these substations are lines and substations that I refer to as "upstream distribution equipment." In the case of NYSEG, only some parts of the service territory are experiencing load growth while others are not growing or are expected to continue to have sufficient distribution capacity to accommodate load growth in the coming years. NYSEG provided estimates of the planned (2015-2019) growth-related upstream substation and line investment budget, as well as growth-related distribution substation and trunkline feeders. I divided the cost (stated in 2016 dollars) of these typical upstream substation projects by the additions to nameplate capacity corresponding to those projects to obtain a typical investment per kVA of capacity. To convert these costs per kW of capacity to a cost per kW of load, I multiplied the cost per kVA of capacity by a typical planned reserve margin in NYSEG's distribution substation equipment. To identify the average planning reserve margin threshold that will typically trigger load-related investment, I identified substations that have experienced load growth since 2008 and that are scheduled for a capacity expansion sometime within the next five years. The median of those stations' reserve margins (29.56%) in 2011 was used as a proxy for a distribution substation planning reserve margin. Year 2011 was the most recent year for which complete substation peak load data for the entire NYSEG service territory was available at the time of my analysis. By looking only at substations experiencing growth, I avoided distorting the average planning reserve margin by including substations with higher-than-typical reserve margins because they have lost load.

I applied a final adjustment to take into the account the fact that NYSEG is not experiencing load growth in all portions of its service territory and increments in load in substations with substantial excess capacity will not require a capacity expansion. To determine system-wide marginal substation investment, I multiplied the per kW of load cost by the share (43.72%) of 2011 substation peak loads corresponding to stations located in parts of the service territory where load growth is expected (with lower than typical reserve margins).

The marginal investment in these components of the distribution system was annualized using an economic carrying charge and adjusted by estimates of O&M on marginal plant investment. These O&M estimates use recent average historical levels of O&M as a starting point and take into account the fact that not all regions would require new investment and its corresponding O&M in the event of load growth.

I time-differentiated these components of marginal distribution costs using the statistical probability of peak analysis that I completed for the 2010 Report, which used hourly loads on a sample of distribution substations for the years 2004-2008. At that time, I estimated the relative probability of any given hour being the peak hour on the substation, taking into account the effects of ambient temperatures on the carrying capability of the equipment, for a sample of substations and summarized the results by the three sets of pricing periods in NYSEG's current time-of-use rates. For the 2014 update, I reviewed three more recent years of hourly loads (2011-2013) for the same substations and confirmed that there has been no material change to the load patterns. Thus, the earlier probability of peak analysis remains valid. Finally, I applied loss factors to convert the upstream and distribution substation cost per kW at the equipment to a cost measured at the meters of secondary and primary customers.

Q. How did you estimate marginal transmission costs?

A. As a transmission owner subject to the rules of the New York Independent System Operator ("NYISO"), NYSEG's transmission revenue requirement is recovered in a Transmission Service Charge ("TSC"), a monthly price per MWh transported or sold. Users of NYSEG's transmission system (implicitly including NYSEG) are required to pay this charge. If NYSEG's delivery service customers use more electricity, NYSEG is responsible for additional TSC charges, which constitute NYSEG's marginal transmission cost. Other NYISO charges are not marginal delivery costs and therefore are not included in this study. I used as a starting point, the average of the TSC monthly charges for the most recent two years. I adjusted these estimates of near-term TSC charges for average marginal energy losses by pricing period between the transmission tie point and customers' meters.

Q. How did you estimate marginal lighting costs?

A. For the 2010 Report, NYSEG had provided costs for circuit equipment (dedicated equipment comparable to a service drop for a non-lighting customer) that may include overhead wire, wood poles, underground conductor and conduit and buried cable, and various lighting fixtures (bases, brackets, and housings) and that are maintained for two lighting service classifications: SC 5 (Outdoor Lighting Service) and SC 3 (Standard Street Lighting Service). The Company provided the current material and installation costs of circuit and fixture equipment and estimates of maintenance costs for each type of equipment. Separate estimates of the material and labor costs of relamping were made for the various types of lamps used by NYSEG's lighting customers. After consulting with the Company, these numbers were still representative in 2014. We applied the most up-to-date GDP-based inflation factor to put these estimates into 2016 dollars.

B. <u>Efficient Prices</u>

Q. What would be the efficient design and levels of charges for NYSEG's electric delivery service customers if there were no marginal cost revenue gap?

A. Efficient rate designs would mirror the structure of NYSEG's marginal costs and charges for each rate component would be equal to marginal costs. Efficient rate designs for NYSEG's electric delivery service customers would consist of:

1) A fixed monthly per-customer charge that would recover monthly marginal customer-related expenses and, assuming relatively homogeneous customers within the class, could also recover the monthly marginal distribution facilities cost, calculated on the basis of typical kW of design demand by class, and stated on a per-customer basis (see Table 1 below);
2) A monthly per-kW facilities charge (if local facilities costs are not included in the fixed charge) which could be set based on the ratcheted annual peak demand or contract demand as a proxy for design demand (see also Table 1 below); and
3) Time-differentiated per-kWh charges or metered per-kW (demand) charges, which might need to vary by season and time of day if deemed necessary to reflect any significant upstream distribution and distribution substation differentials by period. Table 2 below shows these components of the costs on a per-kW basis, in three ways: first, as time-of-day and seasonally-

differentiated charges; then seasonally differentiated only; and finally, as a flat charge across all months of the year. Table 3 shows loss-adjusted marginal cost-based transmission charges, which remain relatively constant across time-of-day periods and seasons, even in the time-of-day option. Table 4 shows transmission per-kWh charges.

Lighting customers would pay monthly fixed charges for the equipment NYSEG provides and maintains for them (see Tables 5 and 6 below) and for relamping (see Table 7 below).

Table 1: Monthly Efficient Customer and Distribution Facilities Charges (After CIAC)

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

DIRECT TESTIMONY OF AMPARO NIETO

Table 2: Monthly Efficient Distribution Demand Charges

			Summer Season		Winter Season		Off Season		Annual	
			On-Peak	Shoulder	On-Peak	Shoulder	On-Peak	Mid-Peak	On-Peak	Mid-Peak
			(2016 Dollars per kW per month)							
			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Residential TOU Periods									
	Secondary Service									
(1)	**TOD**	Upstream Dist.	$4.12	$0.46	$0.00	$0.00	$0.00	$0.00	$2.09	$0.09
(2)		Dist. Substation	$5.97	$0.67	$0.00	$0.00	$0.00	$0.00	$3.04	$0.13
			$10.09	$1.12	$0.00	$0.00	$0.00	$0.00	$5.13	$0.22
(3)	**Seasonal**	Upstream Dist.	$4.58		$0.00		$0.00			
(4)		Dist. Substation	$6.64		$0.00		$0.00			
			$11.22		$0.00		$0.00			
(5)	**Annual**	Upstream Dist.	$1.14							
(6)		Dist. Substation	$1.66							
			$2.80							
	LGS TOU Periods		On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
	Transmission Service									
(7)	**TOD**		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
(8)	**Seasonal**		$0.00		$0.00		$0.00			
(9)	**Annual**		$0.00							
	Primary Service									
(10)	**TOD**	Upstream Dist.	$4.33	$0.04	$0.00	$0.00	$0.00	$0.00	$0.96	$0.01
(11)		Dist. Substation	$6.27	$0.06	$0.00	$0.00	$0.00	$0.00	$1.39	$0.02
			$10.60	$0.10	$0.00	$0.00	$0.00	$0.00	$2.34	$0.03
(12)	**Seasonal**	Upstream Dist.	$4.37		$0.00		$0.00			
(13)		Dist. Substation	$6.33		$0.00		$0.00			
			$10.70		$0.00		$0.00			
(14)	**Annual**	Upstream Dist.	$1.09							
(15)		Dist. Substation	$1.58							
			$2.68							
	Secondary Service									
(16)	**TOD**	Upstream Dist.	$4.54	$0.04	$0.00	$0.00	$0.00	$0.00	$1.00	$0.01
(17)		Dist. Substation	$6.57	$0.06	$0.00	$0.00	$0.00	$0.00	$1.45	$0.02
			$11.11	$0.11	$0.00	$0.00	$0.00	$0.00	$2.46	$0.03
(18)	**Seasonal**	Upstream Dist.	$4.58		$0.00		$0.00			
(19)		Dist. Substation	$6.64		$0.00		$0.00			
			$11.22		$0.00		$0.00			
(20)	**Annual**	Upstream Dist.	$1.14							
(21)		Dist. Substation	$1.66							
			$2.80							
	Day Night Periods									
	Secondary Service									
(22)	**TOD**	Upstream Dist.	$4.58	$0.00	$0.00	$0.00	$0.00	$0.00	$1.15	$0.00
(23)		Dist. Substation	$6.64	$0.00	$0.00	$0.00	$0.00	$0.00	$1.67	$0.00
			$11.22	$0.00	$0.00	$0.00	$0.00	$0.00	$2.83	$0.00
(24)	**Seasonal**	Upstream Dist.	$4.58		$0.00		$0.00			
(25)		Dist. Substation	$6.64		$0.00		$0.00			
			$11.22		$0.00		$0.00			
(26)	**Annual**	Upstream Dist.	$1.14							
(27)		Dist. Substation	$1.66							
			$2.80							

DIRECT TESTIMONY OF AMPARO NIETO

Table 3: Monthly Efficient Transmission Charges per kWh

		Summer Season			Winter Season			Off Season			Annual		
		On-Peak	Mid-Peak	Off-Peak	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)	(10)	(11)	(12)
	LOSS ADJUSTED MARGINAL TRANSMISSION COSTS												
	Residential TOU (SC 12) Periods												
	Secondary Service												
(1)	**TOD**	$0.0043	$0.0043	$0.0042	$0.0043	$0.0043	$0.0043		$0.0043	$0.0042	$0.00	$0.00429	$0.00423
(2)	**Seasonal**	$0.0043			$0.0043			$0.0043					
(3)	**Annual**	$0.0043											
	LGS TOU (SC 7) Periods												
	Transmission Service												
(4)	**TOD**	$0.0040		$0.0040	$0.0040		$0.0040	$0.0040		$0.0040	$0.00400		$0.00400
(5)	**Seasonal**	$0.0040			$0.0040			$0.0040					
(6)	**Annual**	$0.0040											
	Primary Service												
(7)	**TOD**	$0.0043		$0.0042	$0.0043		$0.0042	$0.0042		$0.0042	$0.00426		$0.00420
(8)	**Seasonal**	$0.0042			$0.0043			$0.0042					
(9)	**Annual**	$0.0042											
	Secondary Service												
(10)	**TOD**	$0.0043		$0.0043	$0.0043		$0.0043	$0.0043		$0.0042	$0.00		$0.00425
(11)	**Seasonal**	$0.0043			$0.0043			$0.0043					
(12)	**Annual**	$0.0043											
	Day-Night (SC 8 & 9) Periods												
	Secondary Service												
(13)	**TOD**	$0.0043		$0.0042	$0.0043		$0.0043	$0.0043		$0.0042	$0.00		$0.00423
(14)	**Seasonal**	$0.0043			$0.0043			$0.0043					
(15)	**Annual**	$0.0043											

[THE REMAINDER OF THIS PAGE LEFT INTENTIONALLY BLANK.]

DIRECT TESTIMONY OF AMPARO NIETO

Table 4: Monthly Efficient Transmission and Distribution Charges per kWh

			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.	$0.0214	$0.0012	$0.0000	$0.0000	$0.0000	$0.0000		$0.0000	$0.0000
(3)		Dist. Substation	$0.0331	$0.0019	$0.0000	$0.0000	$0.0000	$0.0000		$0.0000	$0.0000
			$0.0589	$0.0075	$0.0042	$0.0043	$0.0043	$0.0043		$0.0043	$0.0042
(4)	**Seasonal**	Transmission	$0.0043			$0.0043			$0.0043		
(5)		Upstream Dist.	$0.0056			$0.0000			$0.0000		
(6)		Dist. Substation	$0.0087			$0.0000			$0.0000		
			$0.0186			$0.0043			$0.0043		
(7)	**Annual**	Transmission	$0.0043								
(8)		Upstream Dist.	$0.0014								
(9)		Dist. Substation	$0.0022								
			$0.0079								
	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)	Dc **TOD**	Transmission	$0.0041		$0.0041	$0.0041		$0.0041	$0.0041		$0.0041
(14)		Upstream Distribution	$0.0117		$0.0001	$0.0000		$0.0000	$0.0000		$0.0000
			$0.0159		$0.0042	$0.0041		$0.0041	$0.0041		$0.0041
(15)	**Seasonal**	Transmission	$0.0041			$0.0041			$0.0041		
(16)		Upstream Dist.	$0.0052			$0.0000			$0.0000		
			$0.0094			$0.0041			$0.0041		
(17)	**Annual**	Transmission	$0.0041								
(18)		Upstream Dist.	$0.0013								
			$0.0054								
	Primary Service										
(13)	**TOD**	Transmission	$0.0043		$0.0042	$0.0043		$0.0042	$0.0042		$0.0042
(14)		Upstream Dist.	$0.0120		$0.0001	$0.0000		$0.0000	$0.0000		$0.0000
(15)		Dist. Substation	$0.0186		$0.0001	$0.0000		$0.0000	$0.0000		$0.0000
			$0.0348		$0.0044	$0.0043		$0.0042	$0.0042		$0.0042
(16)	**Seasonal**	Transmission	$0.0042			$0.0043			$0.0042		
(17)		Upstream Dist.	$0.0054			$0.0000			$0.0000		
(18)		Dist. Substation	$0.0083			$0.0000			$0.0000		
			$0.0179			$0.0043			$0.0042		
(19)	**Annual**	Transmission	$0.0042								
(20)		Upstream Dist.	$0.0013								
(21)		Dist. Substation	$0.0021								
			$0.0077								
	Secondary Service										
(22)	**TOD**	Transmission	$0.0043		$0.0043	$0.0043		$0.0043	$0.0043		$0.0042
(23)		Upstream Dist.	$0.0126		$0.0001	$0.0000		$0.0000	$0.0000		$0.0000
(24)		Dist. Substation	$0.0195		$0.0001	$0.0000		$0.0000	$0.0000		$0.0000
			$0.0364		$0.0045	$0.0043		$0.0043	$0.0043		$0.0042
(25)	**Seasonal**	Transmission	$0.0043			$0.0043			$0.0043		
(26)		Upstream Dist.	$0.0056			$0.0000			$0.0000		
(27)		Dist. Substation	$0.0087			$0.0000			$0.0000		
			$0.0186			$0.0043			$0.0043		
(28)	**Annual**	Transmission	$0.0043								
(29)		Upstream Dist.	$0.0014								
(30)		Dist. Substation	$0.0022								
			$0.0079								
	Day Night Periods (SC8)										
	Secondary Service										
(31)	**TOD**	Transmission	$0.0043		$0.0042	$0.0043		$0.0043	$0.0043		$0.0042
(32)		Upstream Dist.	$0.0082		$0.0000	$0.0000		$0.0000	$0.0000		$0.0000
(33)		Dist. Substation	$0.0126		$0.0000	$0.0000		$0.0000	$0.0000		$0.0000
			$0.0251		$0.0042	$0.0043		$0.0043	$0.0043		$0.0042
(34)	**Seasonal**	Transmission	$0.0043			$0.0043			$0.0043		
(35)		Upstream Dist.	$0.0056			$0.0000			$0.0000		
(36)		Dist. Substation	$0.0087			$0.0000			$0.0000		
			$0.0186			$0.0043			$0.0043		
(37)	**Annual**	Transmission	$0.0043								
		Upstream Dist.	$0.0014								
		Dist. Substation	$0.0022								
			$0.0079								

DIRECT TESTIMONY OF AMPARO NIETO

Table 5: Monthly Efficient Outdoor Lighting Charges (Excluding Relamping)

	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.)	$6.91
(2)	43,000 Nominal Lumen 400 Watt H.P.S. (replacing 17,200 L. 400 Watt M.V.)	$7.69
(3)	123,000 Nominal Lumen 940 Watt H.P.S. (replacing 48,000 L. 1,000 Watt M.V.)	$10.86
	Area Lights	
(4)	8,500 Nominal Lumen (100 Watt) H.P.S.*	$0.40
(5)	8,500 Nominal Lumen (100 Watt) H.P.S. Power Bracket	$7.50
(6)	14,400 Nominal Lumen (150 Watt) H.P.S.	$6.91
(7)	24,700 Nominal Lumen (250 Watt) H.P.S.	$7.27
(8)	45,000 Nominal Lumen (400 Watt) H.P.S.	$7.69
(9)	126,000 Nominal Lumen (1,000 Watt) H.P.S.	$10.86
(10)	10,500 Nominal Lumen (175 Watt) Metal Halide Power Bracket	$8.62
(11)	16,000 Nominal Lumen (250 Watt) Metal Halide	$7.36
(12)	28,000 Nominal Lumen (400 Watt) Metal Halide	$7.69
	Flood Lights	
(13)	14,400 Nominal Lumen (150 Watt) H.P.S.	$7.98
(14)	24,700 Nominal Lumen (250 Watt) H.P.S	$8.14
(15)	45,000 Nominal Lumen (400 Watt) H.P.S.	$8.14
(16)	126,000 Nominal Lumen (1,000 Watt) H.P.S.	$9.45
(17)	16,000 Nominal Lumen (250 Watt) Metal Halide	$8.10
(18)	28,000 Nominal Lumen (400 Watt) Metal Halide	$8.10
(19)	88,000 Nominal Lumen (1,000 Watt) Metal Halide	$9.26
	"Shoebox" Luminaire	
(20)	14,400 Nominal Lumen (150 Watt) H.P.S.	$9.28
(21)	24,700 Nominal Lumen (250 Watt) H.P.S.	$9.32
(22)	45,000 Nominal Lumen (400 Watt) H.P.S.	$10.03
(23)	16,000 Nominal Lumen (250 Watt) Metal Halide	$9.87
(24)	28,000 Nominal Lumen (400 Watt) Metal Halide	$9.72
(25)	88,000 Nominal Lumen (1,000 Watt) Metal Halide	$11.13
	Post Tops	
(26)	5,200 Nominal Lumen (70 Watt) H.P.S.	$6.70
(27)	8,500 Nominal Lumen (100 Watt) H.P.S.	$6.78
(28)	Brackets 16' and over	$2.64
(29)	Additional Wood Pole Installed for Lamp	$11.76
(30)	Wire Service (Overhead) (Per circuit foot of extension)	$0.02
(31)	18' Fiberglass Pole - Direct Embedded	$6.87
(32)	20' Fiberglass Pole - Pedestal Mount	$6.87
(33)	20' Metal Pole - Pedestal Mount	$12.19
(34)	30' Metal Pole - Pedestal Mount	$13.78
(35)	30' Fiberglass Pole - Pedestal Mount	$17.04
(36)	30' Fiberglass Pole - Direct Embedded	$17.04
(37)	Screw Base for Pedestal Mounted Pole - Light Duty	$7.99
(38)	Screw Base for Pedestal Mounted Pole - Heavy Duty	$8.09

DIRECT TESTIMONY OF AMPARO NIETO

Table 6: Monthly Efficient Street Lighting Charges (Excluding Relamping)

	Component	Monthly Marginal Cost Per Unit (2016 Dollars per
	High Pressure Sodium Cobra	
(1)	70 Watts - 5,200 Lumen	$6.99
(2)	150 Watts - 14,400 Lumen	$7.10
(3)	250 Watts - 24,700 Lumen	$7.47
(4)	400 Watts - 45,000 Lumen	$7.90
(5)	1000 Watts - 126,000 Lumen	$11.39
	High Pressure Sodium Post Top	
(6)	50 Watts - 3,300 Lumen	$7.90
(7)	70 Watts - 5,200 Lumen	$7.80
(8)	150 Watts - 14,400 Lumen	$7.97
	High Pressure Sodium Cut Off ("Shoebox")	
(9)	250 Watts - 24,700 Lumen	$9.51
(10)	400 Watts - 45,000 Lumen	$10.62
	Metal Halide Cobra	
(11)	100 Watts – 5,800 Lumen	$7.81
(12)	175 Watts – 12,000 Lumen	$7.50
(13)	250 Watts - 16,000 Lumen	$7.47
(14)	400 Watts - 28,000 Lumen	$8.47
	Metal Halide Cut Off (“Shoebox”)	
(15)	175 Watts – 12,000 Lumen	$8.65
(16)	250 Watts - 16,000 Lumen	$9.18
(17)	400 Watts - 28, 000 Lumen	$9.92
	Metal Halide Post Top	
(18)	70 Watts – 4,000 Lumen	$8.32
(19)	100 Watts- 5,800 Lumen	$8.57
(20)	175 Watts - 12,000 Lumen	$8.23
	High Pressure Sodium Special Luminaires	
(21)	250 Watts - 24,700 - Hiway Liter	$20.51
(22)	400 Watts - 45,000 - Hiway Liter	$17.57
(23)	150 Watts - 14,400 - Turnpike	$12.15
(24)	250 Watts - 24,700 - Turnpike	$12.32
(25)	400 Watts - 45,000 - Turnpike	$13.12
(26)	150 Watts - 14,400 - Floodlight	$8.17
(27)	250 Watts - 24,700 - Floodlight	$8.33
(28)	400 Watts - 45,000 - Floodlight	$8.34
	Metal Halide - Floodlights	
(29)	250 Watts - 16,000 Lumen	$8.63
(30)	400 Watts - 28,000 Lumen	$8.31
	Pole Installed by the Corporation	
(31)	Standard Wood Pole	$9.34
(32)	Wood Pole - high mount use (45' or greater)	$11.22
(33)	Aluminum Pole 16' and under	$4.24
(34)	Alum. Pole over 16' installed prior to August 1, 1987	$6.76
(35)	Alum. Pole over 16' direct embedded installed after July 31, 1987	$6.76
(36)	Alum. Pole over 16' pedestal mounted	$8.03
(37)	Fiberglass Pole 18' and under	$4.51
(38)	Fiberglass Pole 18' to 22'	$4.51
	Screw-in steel base for pedestal mounted poles:	
(39)	Light Duty	$2.82
(40)	Heavy Duty	$2.90
	Special Brackets	
(41)	Standard Bracket - 16' and over	$4.04
	Circuit Control	
(42)	Group Controllers	$6.82
	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 7: Monthly Efficient Relamping Charges

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

Q. If NYSEG were to set efficient (marginal cost) electric delivery rates using current rate designs, but without adjusting to a particular class or total revenue requirement, how would these rates compare to current rates?

A. These comparisons are shown in Tables 8 through 13 below show for all classes except SC 3S and SC 7-3 rate classes, which have been grandfathered and therefore, no marginal costs were developed for them.

DIRECT TESTIMONY OF AMPARO NIETO

Table 8: Current Rates and Efficient Charges (Non-Lighting Classes)

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		$51.52		$0.00788	
SC 8	Day	$17.40		$0.0298		$53.65			$0.00954
	Night			$0.0298					$0.00423
SC 12	On	$24.11		$0.0336		$114.21			$0.03209
	Mid			$0.0336					$0.00492
	Off			$0.0336					$0.00423
SC 6	All	$17.60		$0.0325		$54.33		$0.00788	
SC 9	Day	$20.41		$0.0314		$55.11			$0.00954
	Night			$0.0314					$0.00423
SC 2	All Blocks	$17.61	$8.32	$0.00339	$0.00078	$239.51	$2.63	$0.00428	
SC 2 I/HLF	All Blocks	$17.61	$4.88	$0.00224	$0.00078	$239.51	$2.63	$0.00428	
SC 7-1	On	$117.11	$8.17	$0.00000	$0.00078	$429.48	$2.63		$0.00431
	Off			$0.00000					$0.00425
SC 7-1 I/HLF	On	$117.11	$6.52	$0.00000	$0.00078	$429.48	$2.63		$0.00431
	Off			$0.00000					$0.00425
SC 3P	All Blocks	$72.81	$4.86	$0.00355	$0.00078	$755.94	$2.51	$0.00423	
SC 3P I/HLF	All Blocks	$72.81	$3.66	$0.00272	$0.00078	$755.94	$2.51	$0.00423	
SC 7-2	On	$409.11	$7.18	$0.00000	$0.00078	$4,142.61	$2.51		$0.00426
	Off			$0.00000					$0.00420
SC 7-2 I/HLF	On	$409.11	$5.35	$0.00000	$0.00078	$4,142.61	$2.51		$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 Off	$849.11	$3.03		$0.00078				
SC 7-3 I/HLF	On	$849.11	$1.55	$0.00000	$0.00078				
	Off			$0.00000					
SC 7-4	On	$1,914.01	$1.28	$0.00000	$0.00078	$1,387.64	$0.00		$0.00400
	Off			$0.00000					$0.00400
SC 7-4 I/HLF	On	$1,914.11	$0.62	$0.00000	$0.00078	$1,387.64	$0.00		$0.00400
	Off			$0.00000					$0.00400

Table 9: Comparison of Current Rates and Efficient Charges (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	$0.0079	$2.57
SC 1 (Street Lighting)	0.02500	0.73	$0.0079	$13.45
SC 2 (Street Lighting)	0.02500	0.73	$0.0079	$13.45
SC 3 (Street Lighting)	0.02500	0.73	$0.0079	$13.45

[THE REMAINDER OF THIS PAGE LEFT INTENTIONALLY BLANK.]

Table 10: Comparison of Current Rates and Efficient Charges (Lighting SC1 and SC2 O&M 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	$8.32
Metal Hallide	5,800	100	$2.45	$7.81
Metal Hallide	12,000	175	$2.45	$7.50
Metal Hallide	16,000	250	$2.47	$7.47
Metal Hallide	28,000	400	$2.52	$8.47
Metal Hallide	88,000	1000	$4.09	na

DIRECT TESTIMONY OF AMPARO NIETO

Table 11: Comparison of Current Rates and Efficient Charges (Lighting SC3 Luminaire 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.	$7.90		$1.61
High Pressure Sodium	5,200	70	$6.82	$7.88	$13.83	$6.99	$7.80	na	$1.61
High Pressure Sodium	8,500	100	$6.82	$8.95	$13.83	$6.30	$7.07	na	$1.66
High Pressure Sodium	14,400	150	$6.82	$10.00	$13.83	$7.10	$7.97	na	$1.67
High Pressure Sodium	24,700	250	$6.82	$10.00	$12.20	$7.47	na	$9.51	$1.68
High Pressure Sodium	45,000	400	$7.21	$10.39	$14.75	$7.90	na	$10.62	$2.14
High Pressure Sodium	126,000	1,000	$10.69	$13.88		$11.39	na		$2.14
Metal Halide	4,000	70	$4.17	$4.71			$8.32		$1.88
Metal Halide	5,800	100	$4.17	$4.79		$7.81	$8.57		$2.24
Metal Halide	12,000	175	$4.11	$4.86	$5.66	$7.50	$8.23	$8.65	$1.68
Metal Halide	16,000	250	$13.28		$16.29	$7.47		$9.18	$1.68
Metal Halide	28,000	400	$13.28		$17.11	$8.47		$9.92	$1.68
Mercury Vapor	3,200	100	$3.72	$4.82		$6.99	$7.80		$1.72
Mercury Vapor	7,000	175	$3.72	$4.86		$7.81	$8.57		$1.72
Mercury Vapor	9,400	250	$3.89	$4.91		$6.30	$7.07		$1.72
Mercury Vapor	17,200	400	$3.95	$4.99		$7.47	$7.97		$1.72
Mercury Vapor	48,000	1,000	$5.80	$6.81		$11.39	$7.97		$1.72
Incandescent	1,000	103	$5.26	$5.94		na	$7.90		$1.61
Fluorescent	5,000	95	$6.92			$6.99			$1.61
Fluorescent	10,000	235	$7.06			$6.30			$1.66
Fluorescent	20,000	380	$7.84			$7.10			$1.67

[THE REMAINDER OF THIS PAGE LEFT INTENTIONALLY BLANK.]

DIRECT TESTIMONY OF AMPARO NIETO

Table 12: Comparison of Current Rates and Efficient Charges (Lighting SC3 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	$9.34
Wood Pole - high mount use (45' or greater)	28.07	11.22
Steel Pole	4.53	8.03
Square Steel Pole 30'	16.49	8.03
Aluminum Pole 16' and under	6.18	4.24
Alum. Pole over 16' installed prior to August 1, 1987	16.41	6.76
Alum. Pole over 16' direct embedded installed after July 31, 1	16.41	6.76
Alum. Pole over 16' pedestal mounted	24.5	8.03
Concrete Pole	5.16	4.51
Laminated Wood Pole	4.12	4.51
Fiberglass Pole 18' and under	5.77	4.51
Fiberglass Pole 18' to 22'	7.84	4.51
Concrete Base for pedestal mounted poles	21.77	2.90
Screw-in steel base for pedestal mounted poles:		
Light Duty	13.49	2.82
Heavy Duty	17.16	2.90
Special Brackets		
Standard Bracket - 16' and over	$2.42	4.04
Bracket allowance	(0.64)	na
Bracket for post-top use on wood poles	0.41	4.04
Circuit Control		
Group Controllers	$3.09	6.82
3000 Watt Photo Cell	2.05	6.82
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

DIRECT TESTIMONY OF AMPARO NIETO

Table 13: Comparison of Current Rates and Efficient Charges
(Lighting SC5 Luminaire 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

DIRECT TESTIMONY OF AMPARO NIETO

IV. NYSEG's MARGINAL COSTS OF GAS DELIVERY SERVICE

A. Methods Used

Q. What basic approach did you use to estimate NYSEG's marginal costs of gas delivery service?

A. As was the case for the electric study, my basic approach for the gas study was to determine the response of NYSEG's planners and system operators to changes in the number and size of customers taking service and their gas consumption by season. I analyzed marginal costs for the following components of gas delivery service:

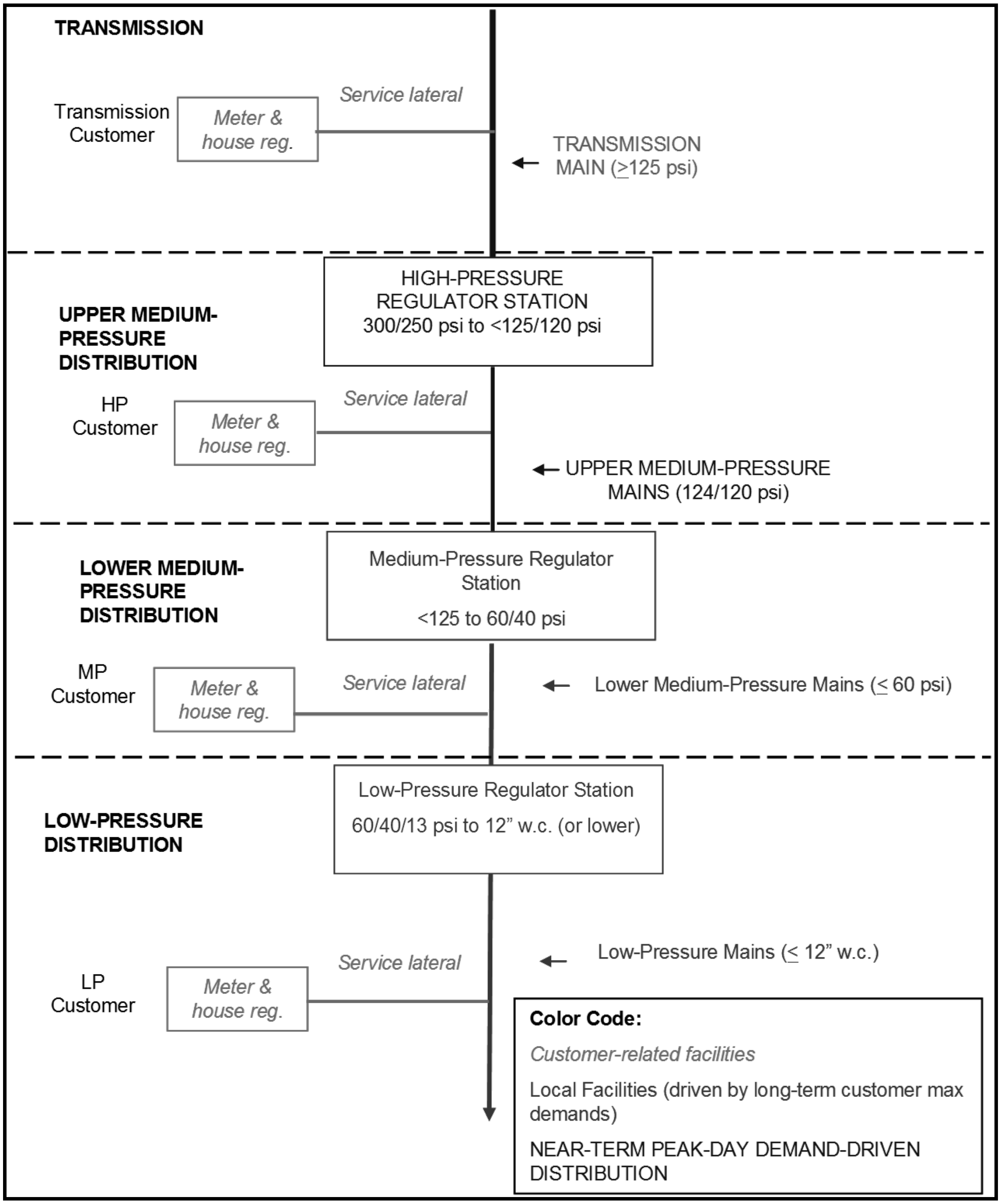
1) Customer-related costs
   - Meter, house regulator, relief valves, and service lateral
   - Customer accounts expenses
   - Customer service and information expenses

2) Local distribution facilities
   - Low-pressure lines
   - Low-pressure regulator stations
   - Lower medium-pressure mains
   - Medium-pressure regulator stations

3) Seasonally-differentiated delivery costs
   - Reliability storage
   - Upper medium-pressure mains
   - High-pressure regulator stations
   - Transmission mains

The components of NYSEG's gas delivery system are illustrated on the diagram below. A full description of the approach is contained in Exhibit __ (NYSEGAN-3).

DIRECT TESTIMONY OF AMPARO NIETO



Q. Please describe your method for estimating marginal gas customer costs.

A. NYSEG provided the most up to date average investment in meters and service laterals per customer for each class. I annualized these investments using an economic carrying charge and added estimates of meter and service lateral O&M,

customer accounts expenses (excluding the portion associated with the merchant function), and customer service and informational expenses. These marginal expense estimates were based on recent historical levels of expense and weighting factors based on meter cost and a 10% / 90% split for residential/non-residential, in the case of meter O&M, and results from NYSEG's 2013 embedded cost of service study for customer accounts and service expenses.

Q. How did you estimate the marginal cost of local distribution facilities?

A. For each component of local facilities, including medium- and low-pressure mains and medium- and low-pressure regulator stations, I used the updated replacement costs (in 2016 dollars) of all such facilities on NYSEG's system (before and after CIAC). I divided the totals by estimates of design demand at customer's meters as of year 2013. I used meter capacity as the design demand estimate for all classes, with an adjustment for the residential class to reflect that meter capacity for these customers is about 1.66 times their connected load.

Q. What approach did you use for estimating marginal transmission mains?

A. NYSEG has not undertaken a gas transmission project in the past five years and has no such projects in its near-term plans because demand growth in any area of its service territory can be accommodated with the existing transmission mains capacity. Consequently, I treated the marginal cost of this component as zero in the near term.

Q. What approach did you use for estimating marginal high-pressure regulator stations and upper-medium pressure mains?

A. High-pressure regulator stations connect the high-pressure transmission system to the upper medium-pressure system, as illustrated above. NYSEG expects to add one high-pressure regulator station in the next few years. Regulator stations are 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. I computed the cost of this station per MCF/day of capacity and adjusted it upwards by an estimated reserve margin of 14% to obtain an investment per unit of load. To estimate growth-related investment in upper-medium pressure mains, I divided NYSEG's planned five-year investment in upper medium-pressure mains by their estimated capacity and applied the same adjustment for reserve margin as described for regulator station. Finally, since I intended to estimate a region-wide marginal cost, the estimated marginal investment needed to be adjusted to reflect the current reserve margin. NYSEG's high-pressure regulator station and upper-medium pressure mains capacity in the overall service area is larger than the minimum required to handle expected load growth in the near term. I estimated that demand growth will trigger investment only in 0.18% of the system and applied this factor to the initial estimates of marginal costs for these components.

Q. What approach did you use for local storage?

A. NYSEG maintains some local storage to provide reliability to the distribution system. Sale of additional distribution service requires providing additional reliability storage. I used the reliability surcharge developed by NYSEG, adjusted to 2016 dollars, as the estimate of marginal reliability storage cost. A final adjustment to these components of marginal cost uses an estimate of losses to convert the cost per near-term design-day MCF at the equipment to a cost at customers' meters.

B. <u>Efficient Prices</u>

Q. What would be the efficient design and levels of charges for NYSEG's gas delivery service customers if there were no marginal cost revenue gap?

A. Efficient pricing would use a rate design that mirrors the structure of NYSEG's marginal cost and charges for each rate component set equal to marginal cost. Efficient gas delivery rate designs would consist of:

1) Winter per-therm charges to recover any marginal costs of transmission mains, high-pressure regulator station and upper medium-pressure mains costs;
2) A year-round per-therm charge for reliability storage for classes other than SC 1T and SC 5T (in the winter, this storage charge could be combined with other per-therm charges, see Table 14 below);
3) A monthly local facilities charge per MCF of design demand (which could be approximated by typical meter capacity, with an appropriate adjustment for the extra capacity in residential meters). For service classifications with customers of similar design demands, the local facilities charge could instead be stated as a per-customer cost and be combined with the customer charge (see Table 15 below); and

4) A fixed monthly customer charge (see Table 16).

Table 14: Efficient Seasonal or Annual Gas Delivery per-Therm Charges

	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

[THE REMAINDER OF THIS PAGE LEFT INTENTIONALLY BLANK.]

DIRECT TESTIMONY OF AMPARO NIETO

Table 15: Efficient Monthly Gas Local Facilities Charges per MCF of Design Demand (or Per Customer)

	Rate	Classification	Per MCF of long-term design day demand per month — Facilities Charges 2016 $ (1)	or	Per customer per month — Facilities Charges 2016 $ (2)
(1)	SC1S	SC 1 Residential Heat	$13.89		$41.81
(2)	SC1S	SC 1 Residential Non Heat	$13.89		$41.81
(3)	SC2S	SC 2 General Service	$13.89		$177.80
(4)	SC3S	SC 3 Interruptible Sales	$13.89		$3,611.66
(5)	SC5S	SC 5 Gas Cooling	n/a		n/a
(6)	SC9S	SC 9 Industrial Manufacturing	$13.89		$1,018.63
(7)	SC13T	SC 13T Residential Heat Aggregation Service	$13.89		$41.81
(8)	SC13T	SC 13T Residential Non-Heat Aggreg. Service	$13.89		$41.81
(9)	SC14T	SC 14T Non-Residential Aggregation Service	$13.89		$278.24
(10)	SC1T	SC 1T Large Firm Transportation	$13.89		$3,431.08
(11)	SC2T	SC 2T Interruptible Transportation	$13.89		$3,820.03
(12)	SC5T	SC 5T Small Firm Transportation	$13.89		$2,094.76
(13)	SC7T	SC 7T Firm Or Limited Firm Negotiated Trans.	$13.89		$4,187.17

DIRECT TESTIMONY OF AMPARO NIETO

Table 16: Efficient Gas Customer Charges

	Customer Classification	Description	Monthly Customer Charge (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

Q. If NYSEG were to set efficient (marginal cost) gas delivery rates using current rate designs, but without adjusting to a particular class or total revenue requirement, how would these rates compare to current rates?

A. Tables 17A through 17C below compare efficient marginal-cost based prices to current charges. All volumetric efficient charges have been averaged and are shown as a flat year-round dollar per-therm charge as opposed to seasonally-differentiated, for easier comparison with existing rates.

DIRECT TESTIMONY OF AMPARO NIETO

Table 17A: Comparison of Current Rates and Efficient Charges

	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		
	$17.03		$71.62		
0- 3				$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		
	$13.03		$70.92		
0- 3				$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		
	$24.33		$252.02		
0- 3				$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		
	$17.59		$6.35		
0- 3				$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		
	$244.60		$1,258.54		
0- 500				$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		
	$17.03		$71.64		
0- 3				$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		
	$13.03		$70.82		
0- 3				$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		
	$24.33		$367.58		
0 - 3				$0.0000	$0.0022
4- 500				$0.3378	
501- 15,000				$0.1946	
Over 15,000				$0.1197	

Table 17B: Comparison of Current Rates and Efficient Charges (Continued)

	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	$0.00000	$0.00205
501- 15,000					$0.1186	$0.22970	
15001- 50,000					$0.0639	$0.17500	
Over 50,000					$0.0605	$0.17160	
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	$0.00000	$0.00205
501- 15,000					$0.1186	$0.22970	
15001- 50,000					$0.0639	$0.17500	
Over 50,000					$0.0605	$0.17160	
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	$0.00000	$0.00205
501- 15,000					$0.1186	$0.22970	
15001- 50,000					$0.0639	$0.17500	
Over 50,000					$0.0605	$0.17160	
SC 2T Interruptible Transportation			Customer Cost	470.89			$0.00218
			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	$0.00000	$0.00205
501- 15,000					$0.1687	$0.27980	
Over 15,000					$0.1200	$0.23110	
SC 7T Firm Or Limited Firm Negotiated Transportation			Customer Cost	503.31			$0.00218
			Facilities Cost	4,187.17			
				$4,690.48			

DIRECT TESTIMONY OF AMPARO NIETO

Table 17C: Comparison of Current Rates and Efficient Charges (Continued)

	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	
14999 - 49,999					$0.0475	$0.0620	
Over 50,000					$0.0475	$0.0620	
Using 40,001 to 250,000							
Basic Service Charge	$243.87	$243.87	Customer Cost	$215.79			$0.0022
Bill Issuance Charge	$0.73	$0.73	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	$1,124.19	Customer Cost	$215.79			$0.0022
Bill Issuance Charge	$0.73	$0.73	Facilities Cost	$1,389.10			
0 - 14,500					$0.0872	$0.1114	
14501- 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)	$1.06	$1.06					
0 - 500					$0.0000	$0.0000	
Over 500					$0.0135	$0.0166	

Q. Does this conclude your direct testimony at this time?

A. Yes.