BEFORE THE
NEW YORK STATE
PUBLIC SERVICE COMMISSION

---x

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service	Case 17-E-___

---x

---x

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service	Case 17-G-___

---x

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

July 28, 2017

TABLE OF CONTENTS

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

I. INTRODUCTION

Q. Please state the names of the members of the Forecasting and Rates ("Panel").

A. Our names are Glynis Bunt, Darlene Clay, Amy Dittmar and Jennifer Lorenzini.

Q. Ms. Bunt, please state your current employer and business address.

A. I am employed by Central Hudson Gas & Electric Corporation ("Central Hudson" or the "Company") and my business address is 284 South Avenue, Poughkeepsie, New York 12601.

Q. Ms. Bunt, in what capacity are you employed by Central Hudson and what is your scope of responsibilities?

A. I am employed by Central Hudson as Senior Director of Cost, Rates, and Forecasts. In that capacity, I am responsible for the day to day oversight of the Cost, Rates and Forecasting groups responsibilities including but not limited to: maintaining the Company's gas and electric tariffs; developing monthly commodity and commodity related prices; analyzing and designing electric and gas delivery and surcharge rates; preparing annual sales, peak demand and revenue forecasts; cost of service studies; maintaining the load research program for load forecasting purposes; and preparing/presenting testimony in regulatory proceedings related to customers, sales and revenue forecasts, rates and cost of service.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. Ms. Bunt, what is your educational background and professional experience?

A. I hold an Associate in Science Degree in Business Administration from Dutchess County Community College, a Bachelor of Science Degree in Business Administration from the State University of New York at New Paltz, and a Master of Business Administration Degree with a concentration in Finance from Marist College. I have been continuously employed by Central Hudson since June 1987 in positions of increasing responsibility in the Internal Auditing, Financial Planning, and Cost and Rate Divisions. I was promoted to Director of Cost, Rates and Forecasts in September 2002 and to my current position in March 2011.

Q. Ms. Bunt, have you previously testified before the New York State Public Service Commission ("PSC" or the "Commission")?

A. Yes. I have testified before this Commission in Cases 95-G-1034, 05-E-0934, 05-G-0935, 08-E-0887, 08-G-0888, 09-E-0588, 09-G-0589, 12-M-0192, 14-E-0318, 14-G-0319 and have submitted an affidavit in 07-M-1139.

Q. Ms. Clay, please state your current employer and business address.

A. I am employed by Central Hudson and my business address is 284 South Avenue, Poughkeepsie, New York 12601.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. Ms. Clay, in what capacity are you employed by Central Hudson and what is your scope of responsibilities?

A. I am employed by Central Hudson as an Associate Cost and Rate Analyst. In that capacity, my responsibilities include: developing electric customer, sales and revenue forecasts for yearly business plans and regulatory proceedings; analyzing monthly electric budget variations; completion of monthly electric and gas cost responsibilities to develop commodity and commodity-related prices; assisting with and supporting implementation of outcomes in rate proceedings; and tariff and regulatory filings.

Q. Ms. Clay, what is your educational background and professional business experience?

A. I hold an Associate in Science Degree in Liberal Arts from Dutchess County Community College and a Bachelor of Science Degree in Business Administration with a concentration in Finance from Marist College. I have been employed by Central Hudson since 2006 in various positions within the Customer Accounting and Treasury divisions. I was promoted to the position of Customer Choice Coordinator in October 2011 and was subsequently transferred to my current position of Associate Cost and Rate Analyst in August 2013. Prior to my employment with Central Hudson, I was a Branch Manager for M&T Bank Corporation for 10 years.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. Ms. Clay, have you previously testified before the Commission?

A. Yes. I have testified before the Commission in Cases 12-M-0192, 14-E-0318 and 14-G-0319.

Q. Ms. Dittmar, please state your current employer and business address.

A. I am employed by Central Hudson and my business address is 284 South Avenue, Poughkeepsie, New York 12601.

Q. Ms. Dittmar, in what capacity are you employed by Central Hudson and what is your scope of responsibilities?

A. I am employed by Central Hudson as a Cost and Rate Analyst. In that capacity, my responsibilities include: compiling and analyzing financial and sales data in the preparation of reports and filings with regulatory agencies; developing monthly commodity and commodity-related prices; analyzing and designing delivery and surcharge rates; preparing customer, sales and revenue forecasts using econometric models; preparing and presenting testimony in regulatory proceedings; filing tariff and regulatory updates; and, performing economic and financial analyses of various electric and gas business initiatives.

Q. Ms. Dittmar, what is your educational background and professional business experience?

A. I received a Bachelor of Science Degree in Financial Economics with a Business Management adjunct from Binghamton University in 2004 and a Master's in Business Administration from Marist College in 2013. I was employed by Central Hudson in February 2006 as an Accounting Clerk in the Plant Accounting Division. I was then promoted to the position of Assistant Financial Analyst in May 2006 and was subsequently transferred to the position of Assistant Cost and Rate Analyst in January 2008. I was promoted to Associate Cost and Rate Analyst in January 2009 and was promoted to my current position of Cost and Rate Analyst in March 2014.

Q. Ms. Dittmar, have you previously testified before this Commission?

A. Yes. I have testified before the Commission in Cases 08-E-0887, 08-G-0888, 09-E-0589, 09-G-0589, 14-E-0318, and 14-G-0319.

Q. Ms. Lorenzini, please state your current employer and business address.

A. I am employed by Central Hudson and my business address is 284 South Avenue, Poughkeepsie, New York 12601.

Q. Ms. Lorenzini, in what capacity are you employed by Central Hudson and what is your scope of responsibilities?

A. I am employed by Central Hudson as a Cost and Rate Analyst. In that capacity, my responsibilities include administering the Retail Choice program and providing support to the Cost & Rate department including regulatory filings, analysis of data and preparation of various reports.

Q. Ms. Lorenzini, what is your educational background and professional business experience?

A. I received a Bachelor of Science in Business Administration with a concentration in Management Science and Information Systems from the

University of Rhode Island. I was hired at Central Hudson in August of 2013 as the Customer Choice Coordinator. In August 2016, I was promoted to Cost and Rate Analyst. Prior to my employment at Central Hudson I was employed by IBM for 10 years.

Q. Ms. Lorenzini, have you previously testified before this Commission?

A. No.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of the Panel's testimony in this proceeding?

A. The Panel presents projected inflation rates as well as the following with respect to electric and gas service: 1) historical sales and revenues; 2) the development of the forecast of electric and gas customers, and sales and base delivery revenues for all service classes for the period April 1, 2017 through June 30, 2019; 3) the development of the projection of interruptible gas sales and revenues, and an overview of the current mechanism for interruptible profit calculation; 4) other operating revenues; 5) the interclass revenue allocation of the Company's proposed electric and gas delivery rate changes; 6) the proposed changes in the Company's electric and gas delivery rates and the revenue effect of those changes; 7) the Company's method for collecting purchased power costs from customers; 8) the Company's method for collecting natural gas supply costs from customers; and 9) other cost recovery mechanisms.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. Is the Panel sponsoring any exhibits in support of its testimony?

A. Yes, we are sponsoring the following Exhibits:

Exhibit __ (FRP-1) contains a Statement of Electric and Gas Operating Revenues;

Exhibits __ (FRP-2) and __ (FRP-3) contain a summary of electric and gas sales, base delivery revenues and customers;

Exhibits __ (FRP-4) and __ (FRP-5) contain a summary of electric and gas model specifications and statistics;

Exhibits __ (FRP-6) and __ (FRP-7) contain a summary of the electric and gas forecast results by forecasting group;

Exhibit __ (FRP-8) summarizes historic heating and cooling degree days;

Exhibit __ (FRP-9) contains design day and winter season demand requirements;

Exhibit __ (FRP-10) summarizes cumulative photovoltaic (“PV”) net metered kilowatt (“kW”) installed;

Exhibits __ (FRP-11) and __ (FRP-12) summarize the estimated effect of proposed electric and gas revenue increases;

Exhibit __ (FRP-13) reflects a comparison of gas bills under declining block rates and flat rates based on currently effective rates;

Exhibits __ (FRP-14) and __ (FRP-15) reflect a summary of present and proposed electric and gas rates; and

Exhibits __ (FRP-16) and __ (FRP-17) reflect a comparison of present and proposed electric and gas rates.

Q. With respect to the subject of inflation, what are the projections of the inflation rate and how were they developed?

A. A Gross Domestic Product ("GDP") implicit price deflator was developed using the consensus forecast of Blue Chip Economic Indicators included in the March 10, 2017 publication. An extrapolation from this forecast was used to develop the forecast for the Rate Year ending June 30, 2019 ("Rate Year") shown below. The Panel proposes that the GDP implicit price deflator be updated for latest known levels at the time the Company files its Brief on Exceptions, which is consistent with prior litigated cases.

GDP Implicit Price Deflator		
Year	Index 2009=100	Annual Percent Change
2016	111.4	1.3 over 2015
12 Months Ended March 2017	111.9	0.5 over 2016
2017	113.7	1.5 over 12 ME March 2017
2018	116.2	3.8 over 12 ME March 2017
Rate Year	117.6	1.2 over 2018

Q. Turning to the subject of electric and gas service, please begin by describing the Panel's exhibits which summarize sales, revenue and customer data for recent historical periods and for the forecast period.

A. Exhibit __ (FRP-1) consists of Schedules A and B for electric and gas, respectively. These schedules present, for the calendar years 2014, 2015 and 2016, and the twelve months ended March 31, 2017 (the historic year), the operating revenues of the Company by prime revenue account, as required by the Commission's policy statements and rules. These exhibits also show, for each revenue account, the kilowatt hour ("kWh") or thousand cubic feet ("Mcf") of electricity or gas delivered (designated as sales), base delivery revenue and the average base delivery revenue per kWh or Mcf sold. Exhibit __ (FRP-2) consists of six schedules. Schedule A presents a summary by customer class of electric sales, base delivery revenues and customers for the twelve-month periods ended March 31, 2017, December 31, 2017, December 31, 2018, and the Rate Year. Schedule B sets forth monthly electric sales, base delivery revenue and customer data by revenue account for the twelve months ended March 31, 2017. Schedules C through F contain similar monthly information by service classification ("S.C.") for the twelve-month periods ended March 31, 2017, December 31, 2017, December 31, 2018, and the Rate Year, respectively.

Exhibit __ (FRP-3) sets forth six schedules similar to Exhibit __ (FRP-2), summarizing gas sales, base delivery revenues and customers for the same time periods.

Q. Were sales to full service customers (i.e., those customers continuing to purchase their energy and/or natural gas requirements from Central Hudson) addressed differently in the forecast than sales to retail access and/or transport customers?

A. No. In prior Central Hudson general rate proceedings (Cases 00-E-1273 and 00-G-1274), the Commission approved the unbundling of commodity supply from delivery, resulting in the same base delivery rates for both full service sales and retail access/transportation customers. Therefore, the sales forecasts we present reflect total full service and retail access deliveries.

III. ELECTRIC AND GAS SALES FORECASTS

Q. Were the electric and gas forecasts for firm sales both developed in a similar fashion?

A. Yes, they were.

Q. Would the Panel please provide an overview of the process by which the forecast of electric own territory and firm gas sales were developed?

A. Customer forecasts were developed for each electric and gas customer class. For a number of these classes, sales volume forecasts were developed on a sales per customer basis, with total sales specified as a function of sales per customer and customer count. Sales forecasts for the remaining classes were developed on a total class basis.

Q. Why were forecasted sales volumes for certain classes developed on a sales per customer basis?

A. Generally, this approach was applied to the classes with relatively large numbers of customers. Separating total consumption into customer and sales per customer components recognizes that each component is influenced by different factors and provides the opportunity to incorporate more structure into the analysis of total consumption. For instance, total residential consumption can be influenced by such factors as customer count (e.g., total number of residential customers), weather, and the economy. In this example, weather will most likely not influence the number of customers, but could greatly influence use per customer. As a result, separating total consumption into components provides the opportunity to incorporate more structure into the forecast of each component.

Q. What forecasting methodologies were used to forecast or project customer and sales levels?

A. Forecasts of customers and sales were developed utilizing various econometric or time series models, or trend projections, as summarized in the table below. The models developed to produce the forecasts were estimated using actual monthly billed customer and sales data covering the period January 1999 to December 2016. Estimation periods vary somewhat for the different classes in order to recognize structural changes, including changes to the billing process and data quality issues that can sometimes limit data availability. For example, revisions to billing cycles, in terms of customer composition, and recording of customers' end-use category (residential, commercial, industrial, etc.) can cause shifts in data requiring different estimation periods.

A summary of the methods utilized to develop each forecast is provided below, with detail regarding model specifications and statistics presented on Exhibit __ (FRP-4) for electric forecasts and Exhibit __ (FRP-5) for gas forecasts. Electric forecast results for each class, and in total, are shown on Exhibit __ (FRP-6). Similarly, gas forecast results for each class, and in total, are shown on Exhibit __ (FRP-7).

REMAINDER OF PAGE INTENTIONALLY LEFT BLANK

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

List of Electric Customer and Sales Forecast Methods		
Class	Customers	Sales
Res. Heat	econometric	econometric (per customer)
Res. Non-Heat	econometric	econometric (per customer)
Com. Demand	econometric	econometric (per customer)
Com. Non-Dmd.	econometric	econometric (per customer)
OPA Demand	time series	econometric (per customer)
OPA Non-Dmd.	time series	econometric (per customer)
Ind. Demand	historic constant	econometric (per customer)
Ind. Non-Dmd.	historic constant	econometric (per customer)
SC 13	individual	individual
Area Light	historic trend	fixture specific growth
Street Light	historic constant	fixture specific growth
Traffic Signal	historic trend	historic trend
Interdepartmental	historic constant	historic constant

List of Gas Customer and Sales Forecast Methods		
Class	Customers	Sales
Res. Heat	econometric	econometric (per customer)
Res. Non-Heat	econometric	econometric (per customer)
Com. Heat	econometric	econometric (per customer)
Com. Non-Heat	econometric	econometric (per customer)
OPA	historic constant	econometric (per customer)
Industrial	historic constant	econometric (per customer)
Interdepartmental	historic constant	historic constant

Q. Please describe the types of variables utilized in the econometric models.

A. The econometric models make use of two types of variables: economic and binary (or dummy).

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. Would the Panel please explain what economic and binary variables are?

A. For the purposes of the forecast presented here, economic variables represent measurements of demographic or economic activity including, but not limited to, such items as population, GDP and household income. Utilization of binary or “dummy” variables is reflected in many of the customer and sales models presented here, consistent with standard modeling practices. In many instances, this type of variable was added as a switch to turn various parameters on and off, such as differences in odd/even month billing to reflect bimonthly billing for certain accounts versus monthly billing, or to accommodate a specific data point to reduce model error, while maintaining a longer estimation period.

Q. What is the source for the economic data utilized in the Company’s forecast models?

A. Economic projections for the region served by the Company were based on the January 2017 forecast provided by Moody’s Analytics. Composite forecast drivers for the Central Hudson region were constructed from the four data regions included in the forecast that contain the Company’s service territory: Albany, Catskills, Dutchess County and Orange County. The composite economic forecast drivers were calculated as a weighted sum of the regional forecasts, where the weights reflect actual average residential and non-residential sales in the region for calendar years 2014 through 2016. These data were the latest available to the Panel at the time of the preparation of our analyses. We recommend, later at an appropriate time, that the data employed by the Company and any party be fully updated, and models re-specified as appropriate to reflect changes to methodology, variables, and/or estimation period resulting from this updated data.

Q. Are there any other items to note regarding the actual monthly billed customer and sales data?

A. Yes. Prior to July 1, 2016, historic billed data reflected bimonthly billing, for non-demand metered customers, where each month a subset of customers were billed for two months, with the remaining subset billed in the subsequent month. Effective July 1, 2016, historic billed data reflects monthly billing, with the majority of customers billed each month. Billed customer counts can vary from actual number of customers connected to the system as a result of a variety of things such as billing cycles, customers being billed for fractional months, cancels and rebills, and vacant accounts.

Q. Were any adjustments made related to the transition to monthly billing?

A. Yes. The July 2016 historic billed customers and sales utilized to develop the customer and sales per customer models were adjusted to normalize out the increased billed customers and sales resulting from the transition to monthly billing. The historic exhibits on the other hand reflect actual billed customers and sales.

Q. Please describe the structures of the models used to develop the electric customer forecasts.

A. Econometric models were constructed to forecast customer levels for the residential classes, commercial demand, and Other Public Authority ("OPA") non-demand classes. The customer levels for the commercial non-demand and OPA demand classes were developed utilizing exponential smoothing models. The exponential smoothing technique was applied to the time series of monthly billed customers in each of the respective classes. This technique replicates the underlying trends, placing more emphasis on the most recent data. The small industrial demand and non-demand customer forecasts were developed by maintaining the historic year levels. As of March 31, 2017, Central Hudson provided transmission or substation service to thirteen customers under the provisions of S.C. No. 13. These customers include customers who require service at transmission voltage or who have provided all the necessary equipment to take service directly from a substation. The Company expects to continue providing service to these thirteen customers. The Company has experienced diminishing customer growth in S.C. No. 5 (Area Lighting) and little to no customer growth in S.C. No. 8 (Street Lighting) in recent years which is discussed later in this testimony. As a result, overall contraction in area lighting customers is anticipated for the forecast period, while the street lighting customer level as of March 31, 2017 was maintained throughout the forecast period. As approved by the Commission in its Order issued October 25, 2001 in Case 00-E-1273, S.C. No. 9, which provides unmetered service, was closed to new customers effective November 1, 2001. Customers requiring service for new traffic signals are now required to take service under S.C. No. 2. Since the closing of this service class, the Company has experienced a minor contraction in the customer level for S.C. No. 9. As a result, continued contraction in customers is anticipated for the forecast period.

Q. Please describe the structures of the models utilized to develop the gas customer forecasts.

A. Econometric models were constructed to forecast customer levels for the residential and commercial heating and non-heating classes. Two types of variables were employed in the specification of these models: economic and binary (or dummy). The model specification for the residential heating class utilizes population whereas residential non-heat utilizes households. The commercial heating and non-heating class customer forecasts reflect utilization of non-manufacturing employment. Many schools, hospitals and government offices, which could be included in the OPA classification, are coded as commercial heating. As a result, the customer forecast for OPA assumes no growth in the forecast period, reflecting the most recent trend in historic data.

Q. Please explain how the gas industrial customer forecast was developed.

A. As industrial customer counts have both contracted and expanded in recent years, but to a minimal degree, the forecast assumes no growth in the forecast period, holding customer counts at the most recent calendar year levels.

Q. Are there any other items the Panel would like to note regarding gas customer forecasts?

A. As was reflected in the final customer forecasts adopted in the Orders in Case 09-G-0589 (issued on June 18, 2010) and Case 14-G-0319 (issued on June 17, 2015), the Company has continued to include a post-forecast adjustment to account for the difference between the historic aggregate customer counts as reported by the billing system and the historic customer counts reflected in the forecasting models.

Q. What forecasting methods were used to project sales volumes?

A. As discussed later in our testimony, post-forecast adjustments are made to reflect the Energy Efficiency Portfolio Standard (“EEPS”). As a result, modifications were first made to adjust historic data to reflect the EEPS savings estimated to actually have been acquired in the historic period. Estimated actual savings reflect information filed on Company and the New York State Energy Research and Development Authority (“NYSERDA”) scorecards through December 31, 2016, as this was the most up to date information available at the time of preparation.

Econometric models were then constructed to forecast all electric classes, excluding: 1) S.C. No. 13; 2) the three lighting classes; and 3) interdepartmental. Econometric models were also constructed for all firm gas classes, excluding interdepartmental and S.C. No. 11. Further, the forecasts developed for the electric residential and commercial classes and all firm gas classes utilize Statistically Adjusted End-Use ("SAE") models.

Q. What is the SAE model approach?

A. The SAE approach integrates structural changes in end-use saturation and efficiency trends, as well as addresses the interaction of economic variables through the construction of end-use variables: heating, cooling and other (base use). These end-use variables include weather, price, economic drivers and end-use saturation and efficiency trends. Additionally, the electric end-use variables constructed for the residential classes reflect changes in housing square footage and thermal shell integrity.

Q. What is the goal of this approach?

A. The goal of the SAE model approach is the construction of sound theoretical forecast models through the identification and utilization of variables that impact energy consumption, including incorporation of estimated long-term impacts in end-use saturation and appliance efficiency trends.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. What is the source for end-use saturation and efficiency data?

A. Residential appliance and commercial end-use saturation and efficiency trends are based on Energy Information Administration estimates for the Middle Atlantic Census Region as compiled by Itron, Inc. Where possible, electric estimates are calibrated to Central Hudson's service territory based on results from the Company's Residential Appliance Saturation and/or Energy Management surveys.

Q. Would the Panel please describe these surveys?

A. For the period 1977 through 2006, the Company surveyed its residential customers eleven times to obtain information about housing stock, appliance saturation, usage patterns, preferences, and household characteristics in order to assist in the determination of growth in energy demand. In 2013, the Company commissioned an energy management survey of its residential customers to assist in efforts to develop and promote effective energy efficiency programs.

Q. What is the basis for the electric price variable?

A. We used the latest information available to us at the time of the preparation of our analyses. The historic price series for each class was determined as a function of the total bundled revenue (including delivery and supply) billed to full service customers divided by sales to full service customers in each class. Monthly forecast prices for each class include applicable base delivery charges, a projected delivery rate increase of approximately 16 percent effective July 1, 2018, as well as Merchant Function Charges ("MFC"), the New York State Assessment ("NYSA"), System Benefits Charges ("SBC"), inclusive of Clean Energy Fund and Energy Efficiency Tracker components, the Purchased Power Adjustment ("PPA"), Miscellaneous Charges and the Market Price Charge ("MPC"). The MPC, or supply price, was forecasted using monthly regression equations to estimate MPC prices as a function of the on-peak price forecast for NYISO Zone G as of March 3, 2017 as obtained from SNL.com. The price variable is expressed as the Consumer Price Index ("CPI")-indexed twelve-month moving average on a one-month lag.

Q. What is the basis for the gas price variable?

A. We used the latest information available to us at the time of the preparation of our analyses. The historic price series for each class was determined as a function of the total bundled revenue (including delivery and supply) billed to full service customers divided by sales to full service customers in each class. Monthly forecast prices for each class include applicable base delivery charges, and a projected delivery rate increase of approximately 21 percent effective July 1, 2018, as well as the MFC, the NYSA, the SBC (inclusive of Clean Energy Fund and Energy Efficiency Tracker components), the Gas Bill Credit ("GBC"), and the Gas Supply Charge ("GSC"). The forecast of the GSC, or supply price, reflects utilization of assets currently under contract to Central Hudson, including pipeline transport, storage and commodity supplies, with commodity supply based on New York Mercantile Exchange ("NYMEX") natural gas futures prices as of March 3, 2017. The price variable is expressed as the CPI-indexed twelve-month moving average on a one-month lag.

Q. What economic variables are utilized in the electric sales models?

A. The residential and OPA models utilize household income and household size, while the commercial models utilize GDP and manufacturing employment, and the industrial models utilize GDP. As previously noted, these data are part of the forecast supplied by Moody's Analytics and subsequently compiled by Central Hudson to correspond more precisely to the Company's service territory.

Q. What economic variables are utilized in the gas sales models?

A. The residential models utilize household income and household size, while the commercial, industrial and OPA models utilize GDP.

Q. How is weather incorporated into the sales models?

A. Monthly actual heating degree days ("HDD") and cooling degree days ("CDD") are transformed into billed HDDs to more closely correspond to the sales billing periods. The sales forecasts are based on normal weather conditions, where the normal weather is determined by a ten-year average of monthly HDD or CDD, as applicable and pursuant to the Commission's Order issued on June 22, 2009 in Cases 08-E-0887 and 08-G-0888, based on hourly temperature readings obtained from the

Dutchess County Airport for the calendar year ending 2016, which is the latest calendar year for which this information was available at the time the Company prepared its sales forecast. We recommend that the latest ten-year average ending December be reflected in the final Rate Year forecasts utilized to determine the revenue requirement and rate design.

Q. Please define a HDD.

A. Weather is expressed in terms of degree days measured over an electric day and a gas day consistent with industry standard definitions of these days. Electric HDDs are defined as the amount by which 65 degrees Fahrenheit exceeds the average of the high and low temperatures for a given day as measured midnight to midnight. Gas HDDs are defined as the amount by which 65 degrees Fahrenheit exceeds the twenty-four hour average of temperatures for a given gas day as measured 10 AM to 10 AM.

Q. Please define a CDD.

A. CDDs are measured for electric only and are defined as the amount by which the average of the high and low temperatures for a given day, as measured midnight to midnight, exceeds 65 degrees Fahrenheit.

Q. Does the Panel still believe that a 10-year weather variable provides a reasonable basis for sales forecasting purposes?

A. Yes. Traditionally, and specifically for the Company prior to Cases 08-E-0887 and 08-G-0888, a 30-year average of surface temperatures observed at a designated weather station was utilized to define normal weather. Based on the continuing warming trend that has been prevalent over the past several decades, as shown on Exhibit __ (FRP-8), utilization of a 30-year weather variable would be cold-biased, would not be representative of expected weather, and would have significant implications on revenue recovery as a result of higher sales forecasts, and resulting lower volumetric rates. These revenue recovery implications would result in lower revenue collections, either in total or on a current basis (with the existence of a Revenue Decoupling Mechanism ("RDM")). Even with the presence of an RDM, the implications of utilizing a cold-biased weather variable impacts the development of relevant, temporal price signals by delaying revenue recovery. In fact, an article in the August/September 2016 issue of American Gas ("Eye on the Sky: Changing weather patterns affect rate case forecasting", p. 7) cites this emerging trend of warmer weather and indicates that a growing number of state utility regulatory commissions have approved the use of a shorter time period, as short as ten years, to define normal weather resulting in "more stability in sales revenues and gas bills."

Q. Has the Panel defined the weather variable differently for any other purpose?

A. Yes. The Panel has continued to define the normal weather variable utilized for the development of the annual gas capability forecast included in the annual winter preparedness review as the 30-year average of HDD. The utilization of two differing definitions of normal weather is supported by the fact that each forecast serves a different purpose. The sales forecast utilized for rate design purposes relies on an accurate estimate of billed sales in order to optimize rate design and, ultimately, current revenue collection. As indicated previously, a longer definition of normal weather would introduce an automatic revenue shortfall through sub-optimal rate design or rely on the RDM for delayed collection. The capability forecast, however, seeks to determine the Company's ability to serve customers under extreme weather conditions in which case a cold-biased weather variable is appropriate. Due to the distinct intent of each forecast, the definition and utilization of two separate weather variables is appropriate and necessary.

As required by Order issued on June 17, 2015 in Case 14-G-0319, Exhibit __ (FRP-9) provides the design day and winter season demand requirement tables as filed in conjunction with the most recent winter preparedness review in Case 17-M-0280, which reflect the utilization of 30 year normal weather.

Q. Do the sales models contain any other assumptions or variables?

A. Yes. The electric residential, electric OPA, and gas residential sales models include price, income and household size elasticity estimates. The electric industrial and gas commercial and gas OPA and industrial models include price and GDP elasticity estimates. The electric commercial sales models include price, GDP, and manufacturing employment elasticity estimates.

Q. Please describe the remaining customer classes for which the previously described econometric models were not utilized.

A. These classes include S.C. No. 13, the lighting classes and interdepartmental for electric. For gas these classes include S.C. No. 11 and interdepartmental.

Q. Please discuss the sales forecast development for electric S.C. No. 13.

A. The sales forecast for this class has been developed based on discussions with these customers over the period January – February 2017. These customers provided the Company with either written or verbal general forecasts/indications of future electric consumption. The customers were asked to comment on potential changes in usage, demand, or operations affecting electric consumption for a period of several years, including the Rate Year.

In the absence of customer provided forecasts/indications, the Company considered historical customer-specific information including, but not limited to, usage, demand and load factor data in order to develop customer-specific forecasts.

Q. Please describe how the forecast of sales for the street and area lighting classes were developed.

A. Street and area lighting sales were projected by extrapolating inventory trends for existing fixtures. Sales per existing fixture continue to decrease as more efficient LED lamps are installed as replacements. As a result of the switch to more efficient lighting and no growth in customer level, overall contraction in sales is anticipated for the forecast period.

Q. How were sales under S.C. No. 9 (Traffic Signals) forecast?

A. As previously indicated, S.C. No. 9 was closed to new customers effective November 1, 2001. As required by Order issued on January 26, 2017 in Case 16-E-0617, adjustments to the forecast were made to reflect the reduction of sales based on the conversion of non-metered traffic signals to LED technology. The Company anticipates that all traffic signals will be converted to LED.

Q. How many S.C. No. 9 customers have been converted to LED?

A. As of the end of June 2017, 92% of S.C. No. 9 customers have been converted to LED, with anticipation that 100% conversion occurs in the Rate Year.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. How were sales under gas S.C. No. 11 forecast?

A. Sales forecasts for S.C. No. 11 Transmission and Distribution customers were developed using the most recent three-year average of historic data. A regression model utilizing historic usage and degree days was constructed to develop the sales forecast for the Company's one S.C. No. 11 Distribution Large Mains customer.

Q. Does the Company have interdepartmental sales and how were those sales forecasts developed?

A. Yes, the Company has such sales. Based on the extremely small volume of such sales, they were projected by analyzing several years of actual sales data. The electric forecast is based on the most recent three years of historic data, while the gas sales forecast was developed using the most recent two-year average of historic data. Both electric and gas interdepartmental sales were held constant throughout the forecast period.

Q. Are the forecasting methodologies utilized by the Company in the preparation of the sales forecasts generally consistent with those presented by the Company in its last major rate filings?

A. The forecasting methodologies are generally consistent with those presented by the Company in Cases 09-E-0588, 09-G-0589, 14-E-0318 and 14-G-0319, although different methodologies have been applied to different customer classes.

Q. Were sales forecasts developed for gas S.C. No.14 or Sales for Resale?

A. No. Historic sales to S.C. No. 14 have been fairly erratic and since this service class is included in the interruptible profit mechanism we discuss later, a forecast has not been developed for this class. The Company also did not prepare a forecast of Sales for Resale, which are commodity sales, since the Company's filing in this proceeding pertains to delivery service. Historic sales for resale are reflected, but associated historic revenues are not, as those revenues are addressed within the Gas Cost Adjustment.

Q. Previously the Panel mentioned post-forecast adjustments were made to the electric and gas sales forecasts. For what purposes were these adjustments made?

A. These adjustments were made to reflect the projected sales reductions associated with EEPS and PV net metering.

Q. Please describe any changes made to the sales forecasts to incorporate sales reductions related to ongoing Energy Efficiency efforts.

A. The electric sales reductions attributable to the EEPS were developed by allocating certain annual reductions identified in various Orders issued by the Commission in Cases 07-M-0548, 14-M-0094 and 15-M-0252 across applicable customer classes and months based on the pre-adjustment forecast of sales.

The gas sales reductions attributable to the EEPS were developed by allocating the annual reductions itemized in various Orders issued by the Commission in Cases 07-M-0548, 14-M-0094, and 15-M-0252 across months based on historic actual acquired savings.

In contrast to the EEPS Phase II detailed reductions provided in Case 07-M-0548, detailed targeted reduction values have not been identified by the Commission beyond 2015. As a result, for the forecast period, annual electric and gas reductions for EEPS programs reflect the Case 14-M-0094 Clean Energy Fund minimum energy efficiency goal, as measured in cumulative first year savings of approximately 10.6 million MWh and 13.4 million MMBtu. The MWh and MMBtu minimum goals equate to ten times NYSERDA's 2015 EEPS Phase II MWh and MMBtu targets. Savings targets were adjusted to reflect a reasonable assumption of savings that would actually be achieved based on an analysis of actual historic achieved results.

Q. Please describe any changes made to the sales forecasts to incorporate sales reductions related to net-metered PV systems.

A. Consistent with the approved forecasts in prior rate proceedings, most recently in Case 14-E-0318, adjustments were made to the electric sales forecast to reflect forecasted sales reductions resulting from penetration of residential and non-residential net-metered PV systems.

Q. Why does the forecast reflect sales reductions from penetration of net-metered PV systems?

A. In 1997, legislation was enacted to add §66-j to the Public Service Law ("PSL") providing for the net energy metering ("NEM") of residential solar electric generation sized at no more than 10 kW. Over the subsequent two decades, further amendments were made to the PSL to expand net metering in terms of application of additional technologies, increase in generator size and accommodation of non-residential customers. More recently, further legislative and regulatory action have further expanded NEM through the introduction of remote net metering ("RNM") and community distributed generation ("CDG") in 2012 via legislative amendment to §66-j and in 2015 via Commission Order issued on July 17, 2015 in Case 15-E-0082, respectively. These actions, together with Central Hudson's continued active support of solar resources, continue to produce further sales reductions as new solar installations are made. As a result, it is necessary to build into the sales forecast, and ultimately into base rate design, a forecast of sales reductions resulting from PV penetration to ensure reasonable opportunity for recovery of the Commission approved revenue requirement.

Q. Does the Company routinely address other NEM eligible technologies in addition to PV?

A. Yes, but to date, the overwhelming majority of interconnections have been solar and, as such, the Company has continued to use the prior nomenclature.

Q. Please explain how these sales reduction adjustments for PV penetration were developed.

A. In developing sales reductions attributable to increased penetration of net-metered PV systems, the Company employed the same methodology utilized in prior rate proceedings, most recently Case 14-E-0318, also recognizing the current status in Case 15-E-0751 – In the Matter of the Value of Distributed Energy Resources. The sales reductions attributable to NEM PV penetration are based on a forecast of installations developed by applying a polynomial regression to the monthly cumulative kW installed for the period August 2014 through November 2016. This reflects the most recent response to legislative, regulatory and Company initiatives at the time of forecast, with NEM eligibility continued past the January 1, 2020 eligibility date directed in the Commission's March 9, 2017 Order in Case 15-E-0751 based on the continued uncertainty surrounding the transition to a new compensation methodology, which will be addressed in Phase Two of Case 15-E-0751. This NEM model is presented on Exhibit __ (FRP-8). In addition, 39 MW of CDG currently in the Company's interconnection queue were included based on the eligibility and capacity threshold requirements contained in the aforementioned March 9, 2017 Order.

Q. Has the Panel made a post-forecast adjustment for gas customers and sales to reflect the Company's gas expansion efforts, similar to the adjustments made in Case 14-G-0319?

A. No. Unlike in prior forecasts, where a post forecast adjustment was made to the gas customer forecast to reflect the Company's gas customer expansion efforts, the forecasts included herein reflect embedded customer growth which is consistent with the targeted customer addition efforts noted by the Business Development Panel.

Q. Please explain how the Panel selected the estimation period for each model or individual forecast.

A. Generally, the Panel started with a prior version of each model. After updating the model to bring in actual data through December 2016, each model was re-specified, often in many iterations, until a model was produced that the Panel considered to provide the most reasonable results in terms of both statistical validation and production of a realistic forecast. This repeated re-specification of the model can include different variables as well as changes to the estimation period.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. Is the utilization of different estimation periods between models or forecasts a reasonable practice?

A. Yes. Just as different models may utilize differing variables to explain growth, different models may utilize differing estimation periods to address structural changes resulting from economic, industry or business process changes.

Q. Should the length of an estimation period correspond to the length of the forecast period?

A. No. The length of the estimation period should be sufficient to yield a reasonable depiction of the identified future period, regardless of forecast length, in order to inform decisions. Utilization of a short estimation period introduces the risk that the period of time selected does not sufficiently embody activity for the item being forecast.

Q. How did the Panel validate the models used to develop the forecasts of customers and sales?

A. The Panel utilized several statistical measures to validate model performance including Adjusted R-squared, mean absolute percentage error, Durbin-Watson, t-value and coefficient sign. A summary of these statistics for specific models is provided on Exhibits __ (FRP-4) and (FRP-5). Additionally, the Panel relied on judgment as applicable in determining whether each model, despite strong statistical measures, produced a reasonable forecast.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. What do the Company's final electric and gas sales forecasts show?

A. While the Company continues to experience growth in the number of electric and gas customers, overall use per customer has decreased significantly since 2005. Use per customer is forecast to continue to decline, with usage reductions due to the EEPS and lost electric sales due to PV net-metering contributing to this decline. As a result, electric sales are forecast to decrease during the Rate Year. Electric own territory sales (excluding unbilled) as shown on Schedule A of Exhibit __ (FRP-2) are forecast to decrease by 160,219 MWh, or 3.4 percent, based on the Rate Year estimate of 4,578,738 MWh as compared to the calendar year 2017 estimate of 4,738,957 MWh.

Gas own territory sales (excluding unbilled, Sales for Resale and S.C. No. 14) as shown on Schedule A of Exhibit __ (FRP-3) are forecast to increase by 285 MMcf, or 1.9 percent, based on the Rate Year estimate of 15,543 MMcf as compared to the calendar year 2017 estimate of 15,258 MMcf.

Q. Does the Panel have any additional comments to make regarding the topic of sales forecasts?

A. Yes. The models and methods that we have described incorporate a number of assumptions regarding economic activity, prices and consumption patterns, including load factor, and legislative and regulatory initiatives. To the extent that activity in our service territory, in terms of the level of customers, changes dramatically or customers change their consumption habits in response to changes in economic, price or regulatory conditions, these changes should be reflected in the final Rate Year forecasts utilized to determine the revenue requirement and rate design.

IV. REVENUES

Q. How were the revenues associated with the sales forecast for 2017, 2018 and the Rate Year developed?

A. Monthly electric sales were based on an annual historical distribution to allocate revenue account sales to a service class or sub-class basis. Billing demands were projected based on historical load factor trends. The forecasted billing parameters derived were priced at present rates as filed by the Company in compliance with Cases 14-E-0318 and 14-G-0319.

Monthly gas sales, by forecasting group, were allocated between heating and non-heating sub-classes, for the purposes of billing block distribution. The resulting gas sales were spread between blocks based on an O-Give analysis of the actual bill distribution for calendar years 2015 and 2016. An O-Give analysis reflects a curve fitting process, which proportions actual billing blocks and billing block volumes to the forecast use per customer pursuant to the methodology proposed by New York State Department of Public Service Staff ("Staff") in its testimony in Case

08-G-0888 and subsequently utilized in the forecasts approved in Case 09-G-0589 and Case 14-G-0319. The monthly distributions were priced at present rates, effective July 1, 2017 as described above.

Electric and gas other operating revenues were estimated by extrapolating recent experience and adjusting for known changes as more fully discussed below.

The Panel proposes that along with sales, both base revenue and other operating revenue be updated at the time the Company files its Brief on Exceptions, which is consistent with prior litigated cases.

Q. Were electric S.C. No. 14 revenues excluded from the forecast?

A. No. Historical customers and sales for this service classification were included in the appropriate revenue group forecasts as previously detailed. Due to minimal activity under this service classification, forecasted customers and sales were allocated to the respective parent service classifications as previously detailed.

Q. What assumptions were made with respect to interruptible gas sales and transport service (S.C. Nos. 8 and 9)?

A. Forecasts of sales/deliveries to these customers have been estimated based on historic usage patterns over the 36 months ended December 31, 2016. The forecasts were included on the assumption that these customers will continue to take service under the service classification for which they were billed as of February 2017 through the forecast period.

Currently, both the Company's base delivery rates and Gas Cost Adjustment factor include credits derived from the net of fuel revenues received from interruptible sales (S.C. Nos. 8 and 9) and sales to generating facilities (S.C. No. 14). Pursuant to the Order in Case 14-G-0319 issued June 17, 2015, current base delivery rates include a profit imputation of $3.0 million estimated to be received from such sales. As a result, the Company is permitted to retain the first $3.0 million in net of fuel revenue in each Rate Year that it may receive from interruptible service and service to generating facilities. If the net of fuel revenue, or profit, is less than $3.0 million in any Rate Year, the Company is authorized to surcharge firm customers for 90% of the shortfall. If the profit exceeds $3.0 million in any Rate Year, the Company credits ratepayers 90% of the excess. Any such surcharges or credits are applied through the Gas Cost Adjustment factor as detailed below.

Q. Please elaborate on the process used to determine interruptible profit and apply the interruptible ratemaking mechanism.

A. This is a two-step process. Step one involves determining the profit (or net of fuel revenue, excluding all penalties) derived from interruptible service and service to electric generators. The profit is calculated as revenue less revenue tax and fuel cost.

In step two, the imputation is applied by subtracting $3.0 million from the profit as determined in step one. Ninety percent of the resulting shortfall or excess is collected from or returned to customers.

Q. Is the Company proposing any changes to this interruptible profit mechanism?

A. Yes. With fewer customers taking interruptible service due to continued migration to firm service, the Company is less likely to be able to meet the existing imputation of $3 million. The Company proposes to reset the imputation to $2.6 million based on the most recent two year average ending April 2017 historic profit levels.

Q. Did the Panel include a forecast of unbilled sales and revenue?

A. No. The historic billed sales that the Panel relies on for forecasting and the resulting annual forecasts of billed sales and revenue developed by the Panel comprise twelve months of billed sales and revenue on a cash, not an accrual, basis. Including an estimate of unbilled sales and revenue would produce a forecast containing more than twelve months of sales and revenue, incorrectly comingling cash and accrual accounting methods, and would result in the incorrect match of twelve months of expense against an excess of twelve months of revenue.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. Did the Panel produce forecasts for any other revenue items?

A. Yes. The Panel produced a forecast of Other Operating revenues including a variety of sub accounts related to such items as finance charges, purchase of receivables discount, rents, etc.

Q. Were these items included in the development of Other Operating Revenue in the Company's last major rate filings?

A. Yes.

Q. What are the primary items included in Other Operating Revenue and how were these estimated for the Rate Year?

A. In its development of finance, or late payment, charges included in the forecast of Other Operating Revenue, the Company developed a separate factor, to be applied to base revenue, for each of the three finance charge categories – residential, commercial and industrial. The factors were estimated by dividing a historic three year average of finance charges for each category by the respective average base revenue for each category and then extrapolating recent experience and adjusting for known changes.

Q. Are the forecasting methodologies utilized by the Company in the preparation of the estimates of these items generally consistent with those presented by the Company in its last major rate filings?

A. Yes.

V. REVENUE ALLOCATION

Q. With respect to the subject of revenue allocation, please describe the criteria Central Hudson applied in allocating revenues and designing rates.

A. For both electric and gas, the Company has historically sought to bring the rates of return of the various service classifications to within 15 percent of the system average rate of return. In this filing, in order to mitigate impacts on those customer classes earning less than 85% of the system average rate of return, the maximum increase allocated to all electric and gas service classifications is 1.25 times the overall applicable system increase. The minimum increase allocated to customer classes earning more than 115% of the system average rate of return is 0.75 times the overall applicable system increase.

Q. What was the source of the constraints utilized for allocating the electric and gas revenue increases?

A. The constraints utilized for allocating the electric and gas revenue increases were based on the constraints most recently utilized and approved in Cases 14-E-0318 and 14-G-0319. The Company is proposing to maintain these constraints for all electric and gas service classifications.

Q. Were any changes made to forecasted revenues for purposes of revenue allocation and rate design?

A. No, the Company did not make any normalizing adjustment or exclusions.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. Please explain Exhibits __ (FRP-11) and __ (FRP-12), relating to the estimated effect of the proposed revenue increases.

A. Exhibit __ (FRP-11) for electric and Exhibit __ (FRP-12) for gas each consist of two schedules that present the details of the proposed interclass revenue allocation. Schedule A details the methodology used to allocate the revenue increases among the various service classifications. Schedule B combines the allocated revenue increases from Schedule A with revenues at present rates to determine total filed base rate revenue by service classification for the Rate Year.

Q. What revenue requirement was used in developing the proposed rate revisions?

A. Electric own territory operating revenue must be increased by $63,407,000 in the Rate Year in order to meet the Company's costs of providing service. The rate increase is to be obtained from S.C. Nos. 1, 2, 3, 5, 6, 8, 9 and 13 rates as explained below.

Gas own territory operating revenue must be increased by $22,220,000 in the Rate Year in order to meet the Company's costs of providing service. The increase of $22,220,000, plus $2,600,000 that is offset through imputation to S.C. Nos. 1, 2, 6, 12 and 13 in the rate design process, or a total of $24,820,000, is to be obtained from S.C. Nos. 1, 2, 6, 12 and 13 rates as explained below.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. Please describe your procedure for allocating the Company's proposed revenue increase among the various service classifications.

A. The Company has allocated both the electric and gas proposed increases with reference to the results of the Historic 2015 and Pro-Forma Rate Year Embedded Cost of Service Studies (“ECOSS”), which are contained in Exhibits __ (COSP-1) and __ (COSP-2), Schedules A and B and supported by the testimony of the Cost of Service Panel (“COSP”). Pursuant to the methodology utilized in the Joint Proposal adopted in Cases 14-E-0318 and 14-G-0319, if the results of the ECOSS indicated varying results in the unitized rate of return for a service class, that class received an allocation of the incremental revenue requirement using the overall system average. If the results of the ECOSS did not indicate varying results in the unitized rate of return for a service class, those classes with a unitized rate of return less than 85 percent of the system average received 1.25 times the overall system average and those classes with a unitized rate of return more than 115 percent of the system average received 0.75 times the over system average. The revenue allocation methodology is a three-step process.

Q. Please elaborate on the three step process.

A. The first step is to use results from the ECOSS for the historic period and the Rate Year to determine what revenue adjustment is necessary for each class utilizing its unitized rate of return as shown in columns 1-6 of Exhibits __ (FRP-11), Schedule A and __ (FRP-12), Schedule A. The second step is to allocate the proposed revenue increase based on total delivery service revenue, under the constraints as previously described. The results of step two are shown in columns 7 and 8 of Exhibits __ (FRP-11), Schedule A and __ (FRP-12), Schedule A. The third step then determines the resulting adjustment that must be allocated to each as a result of the previously described constraints, as shown in column 9 of these two exhibits.

Q. What were the results the Panel obtained by applying the revenue allocation methodology to the proposed electric revenue increase?

A. For S.C. Nos. 1, 2 (Non-Demand, Secondary, and Primary), 3, 5, 6, 9 and 13 (Substation and Transmission), the unitized rate of return varied among the Historic and Pro Forma Rate Year ECOSS. As a result, these classes received an allocation of the incremental revenue requirement using the overall system average.

For S.C. No. 8, the rate of return varied but was consistently positive and exceeded the upper tolerance level for the Pro Forma ECOSS. As a result the minimum increase of 0.75 times the average overall increase was utilized.

Application of these increases produced a revenue shortfall as compared to the rate increase revenue. This revenue shortfall was then allocated pro-rata among the service classes. The resulting increases are shown in columns 9 and 10 of Exhibit __ (FRP-11), Schedule A.

Q. What were the results the Panel obtained by applying the revenue allocation methodology to the proposed gas revenue increase?

A. For S.C. Nos. 1 and 12, S.C. Nos. 2, 6 and 13 as well as all three S.C. No. 11 subclasses, the rates of return in the ECOSS produced differing results. As such, the average overall system increase was utilized pursuant to the methodology described above.

Application of the system average increase to all classes therefore did not produced a revenue shortfall as compared to the rate increase revenue. The resulting increases are shown in column 10 of Exhibit __ (FRP-12), Schedule A.

Q. Were any adjustments made to the final electric and gas base revenue increases?

A. Yes. For each class, the base revenue increase was adjusted by the estimated difference in revenue to be collected through the redesigned MFCs for that class calculated as: 1) redesigned base MFC rates developed in the Pro Forma Rate Year ECOSS, multiplied by 2) class total deliveries. These adjustments are presented on Schedule A of Exhibits __ (FRP-11) and __ (FRP-12).

VI. RATE DESIGN

Q. Please explain Schedule B of Exhibits __ (FRP-11) and __ (FRP-12), regarding the effects of the proposed electric and gas rates.

A. Schedule B of both exhibits sets forth, by service classification, present base rate delivery revenues, the proposed revenue increase, total proposed delivery revenue and the net effect of the proposed revenue increase.

Q. Is the Company proposing any structural changes to gas rate design?

A. Yes. The Company is proposing to eliminate the gas S.C. Nos. 1, 2, 6, 12 and 13 block rate differentials.

Q. Please explain the current and proposed rate structures for S.C. Nos. 1, 2, 6, 12 and 13.

A. Pursuant to the current rate structure provided in PSC No. 12 (Gas), customers served under gas S.C. Nos. 1, 2, 6, 12 and 13 are subject to declining block gas base delivery rates. Under S.C. Nos. 1 and 12, separate declining rates are applied to monthly Ccf usage based on three usage blocks: 1) the first 2 Ccf; 2) the next 48 Ccf; and 3) any additional Ccf. Under S.C. Nos. 6, 12 and 13, separate declining rates are applied to monthly Ccf usage based on four usage blocks: 1) the first 2 Ccf; 2) the next 98 Ccf; 3) the next 4900 Ccf; and 4) any additional Ccf. The Company proposes to eliminate the declining block rate structure in favor of flat rates. The rate structure for S.C. Nos. 1, 2, 6, 12 and 13 would continue to include the first 2 Ccf in the customer charge, however all remaining Ccf billed would be at the same class-specific rates.

Q. Why has the Company proposed to eliminate this rate differential?

A. The proposal to eliminate declining block rates is consistent with the Commission's goal to promote energy efficiency. Declining block rates send the wrong price signal since prices decrease when consumption increases.

Q. Aside from energy efficiency goals, were other considerations evaluated by the Company?

A. Yes. Considerations such as bill simplicity were evaluated. Under flat rate design, customers will more easily be able to ascertain how each incremental unit of gas impacts their total bill.

Q. How will this change affect customers?

A. The Company understands that the elimination of declining block rates will result in some customers experiencing decreases while others experience increases in typical bills. To understand bill impacts, the Company redesigned Case 14-G-0319 Rate Year 3 rates to reflect a flat rate design. To achieve revenue neutrality, customer charges were kept at the levels agreed upon in Case 14-G-0319. The currently effective block rates and the re-designed flat rates were then used to analyze typical bill impacts. Exhibit __ (FRP-13) provides comparisons of charges for typical usages under S.C. Nos. 1/12 and 2/6/13 at Case 14-G-0319 Rate Year 3 declining block rates and at re-designed flat rates to demonstrate the impacts on bills to customers at various levels of consumption.

Q. Please describe some of the more important findings of the bill impact calculations.

A. As can be seen in Exhibit __ (FRP-13), Schedules A and B at the actual sales per customer levels for the twelve months ending March 31, 2017, an average residential and commercial heat customer would have experienced favorable bill impacts at flat rates. In general customers with higher than average use would see bill increases, where customers with lower than average use would see bill decreases. Although the majority of the Company's customers are served under S.C. 1, the largest use per customer is attributed to S.C. 6 customers. Average annual use per customer for the S.C. 6 customer class as a whole for the twelve months ended March 31, 2017 was 9,945 Mcf. As shown on Exhibit __ (FRP-13), Schedule B the resulting bill impact would be an increase of approximately 3.71%. Customers taking service under S.C. 6 who have an annual consumption of 50,000 Ccf or greater are subject to pricing only at the tail block rate. For the twelve months ended March 31, 2017, there were 103 high volume S.C. 6 customers with average use per customer of 14,591 Mcf. The resulting bill impact on these customers would be an increase of approximately 8.47%, as shown on Exhibit __ (FRP-13), Schedule B. However, in order to retain these customers on firm service, the Company

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

is proposing that a discount rate be continued for high volume S.C. 6 customers consistent with the magnitude of the current tail block discount.

Q. Is the Panel proposing any other structural changes to gas rate design?

A. Yes. The Panel is proposing to transition the current volumetric S.C. 11 rate design back to a Maximum Daily Quantity ("MDQ") based pricing structure. The MDQ is the maximum volume of gas the Company is obligated to accept on behalf of a transportation customer during a 24 hour period beginning at 10 AM Eastern Standard Time each day.

Q. Please explain the current and proposed rate structures for S.C. No. 11.

A. For S.C. 11 transmission, distribution and distribution large mains customers, the Transportation Rate component of the Monthly Rate reflects a monthly customer charge and a volumetric charge per Mcf. For the S.C. 11 subclass, Electric Generation ("S.C. 11 EG"), the rate design is based on an MDQ structure with the Transportation Rate component of the Monthly Rate reflecting a monthly customer charge and a demand charge per Mcf of MDQ. The Panel is proposing that similar to the existing S.C. 11 EG rates, the rates for the transmission, distribution and distribution large mains customers be based on an MDQ structure. As the two existing S.C. 11 EG customers are served at the transmission level, the Company proposes that S.C. 11 EG customers be billed under transmission subclass rates.

Q. Why has the Company proposed to revise this rate structure at this time?

A. Since the gas system is built to meet peak period demand, the Company's costs to serve these customers are essentially fixed. As a result, an MDQ-based rate better matches revenue recovery with cost causation. Additionally, in Case 14-G-0319 when MDQ based rates were transitioned to volumetric rates, volumetric rates were designed for each existing customer, with no provisions in place to address movement between rates in the event of changes to a customer's operations. MDQ based rates by subclass allow for more flexibility in rate design, categorizing and designing rates for a subclass of customers rather than individually.

Q. Is there any Commission precedent or support for this proposed change?

A. MDQ-based rates were proposed in Case 92-G-1056 by Alan Rosenberg on behalf of Multiple Intervenors. MDQ-based rates remained in effect for all of the Company's S.C. 11 customers for more than 20 years, until the Order issued on June 17, 2015 in Case 14-G-0319.

Q. How will this change affect customers?

A. With MDQ-based rates, bill volatility is minimized and customers have stable predictable prices. Customers maintain an ability to control bills as the Company's tariff includes provisions to raise and lower the MDQ, and benefits from employed energy efficiency measures are immediately realized by customers through lower total commodity costs resulting from reduced volumes.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. Is the Company proposing any changes to electric rate design?

A. Yes. The Company's is proposing to implement a monthly Service Size Charge for residential customers taking service under S.C. 1 that would be designed to collect a portion of the costs allocated to this class that are designated as demand-related within the Rate Year Pro Forma embedded cost of service study sponsored by the Cost of Service Panel.

Q. How would the Service Size Charge be integrated into the current S.C. rate structure?

A. Currently, the S.C. 1 rate structure consists of a monthly customer charge and a volumetric delivery charge. The Company is proposing that the Service Size Charge would be an additional monthly charge that would be applicable based on a customer's annual usage level. On an annual basis, a customer's usage over the most recent twelve months would be compared to the Service Size threshold levels, with the customer assigned to a specific Service Size level and the concomitant Service Size Charge applied to the customer's bill for the succeeding twelve months.

Q. Would the Service Size Charge be applicable to all S.C. 1 customers?

A. Yes. The Company intends to apply the Service Size Charge across the population of S.C. 1 customers through a phase in that would initially set the upper limit of the first threshold level slightly above the annual class average usage. Threshold limits would decrease with succeeding rate changes resulting in the Service Size Charge being applied to consistently more bills.

Q. Why is the Company making this proposal?

A. The Company believes that the implementation of this rate structure element will help to balance the interests between the short-term nature of the cost structure, which is predominantly fixed, and the impacts associated with continuing to rely on recovery through a fixed customer charge and volumetric delivery charge. For example, based on the proforma embedded cost of service study filed by the Company in Case 14-E-0318, approximately 94% of the S.C. 1 revenue requirement was identified as demand-related and customer-related. However, the rate design approved by the Commission resulted in 34% of revenue being collected through the customer charge with the remaining 66% being collected through volumetric charges. In contrast to a static fixed charge, the annual variability of the Service Size Charge will not discourage energy efficiency or installation of distributed energy resources, reduce customer control over energy costs, or negatively impact low-usage customers.

Q. Please summarize how this rate element was designed.

A. The Company analyzed the twelve month equivalent usage for 255,350 accounts billed under S.C. 1 for the twelve months ended June 2016 yielding a twelve month average usage of approximately 8,000 kWh. The following table presents both the resulting frequency distribution and the proposed monthly Service Size Charge.

Annual kWh (Upper Limit of Threshold)	*Percent of Customers*	*Cumulative Percent*	*Proposed Monthly Service Size Charge*
1,000	3.6%	3.6%	$ -
2,000	5.5%	9.1%	$ -
3,000	7.8%	16.9%	$ -
4,000	8.6%	25.5%	$ -
5,000	8.9%	34.4%	$ -
6,000	8.9%	43.3%	$ -
7,000	8.4%	51.7%	$ -
8,000	7.8%	59.5%	$ -
9,000	6.9%	66.4%	$ 1.00
10,000	6.0%	72.5%	$ 2.00
11,000	5.1%	77.6%	$ 2.00
12,000	4.2%	81.8%	$ 2.00
13,000	3.4%	85.2%	$ 3.00
14,000	2.7%	87.9%	$ 3.00
15,000	2.2%	90.1%	$ 3.00
20,000	6.0%	96.1%	$ 4.00
Over 20,000	3.9%	100.0%	$ 4.00

Q. Is the Company proposing any changes to its unbundled rate structure?

A. No. The Company is proposing to continue to maintain the unbundled rate structure approved by the Commission in the Company's most recent general rate proceeding, Cases 14-E-0318 and 14-G-0319, including recovery of net lost revenues related to MFCs. However, the Company proposes to update certain rate elements to reflect the results of the ECOSS. The update to base rates (excluding lost revenue) for the MFC Administration Charge and the MFC Supply Charge as reflected on Schedule A of Exhibits __ (FRP-14) and __ (FRP-15) as well as the update to the billing services credit are based on the results of the ECOSS, as contained in Exhibits __ (COSP-1) and __ (COSP-2), Schedule C.

Q. After allocating the proposed electric revenue increase between various service classifications, how did the Panel proceed to design the proposed charges for S.C. Nos. 1 (Residential) and 6 (Residential TOU)?

A. For S.C. No. 1, the monthly customer charge was increased from $24.00 to $25.00. The monthly customer charge for S.C. No. 6 was increased by approximately the same percentage, from $27.00 to $28.00. These changes are intended to bring the customer charge closer to the embedded costs shown on Schedule C of Exhibit __ (COSP-1), and supported by the testimony of the COSP. A flat delivery rate of $0.08495 per kWh was developed to produce the remainder of the S.C. No. 1 revenue requirement.

The on-peak and off-peak delivery rate differential ratio used for S.C. No. 6 was 3:1. This resulted in on-peak and off-peak delivery rates of $0.12022 and $0.04007 per kWh, respectively, to produce the remainder of the S.C. No. 6 revenue requirement.

Q. Please describe how the charges to S.C. No. 2 (General Service) were developed.

A. The monthly customer charge for non-demand and secondary service was increased from $35.00 and $84.00 to $39.00 and $128.00 respectively.

The monthly customer charge for primary service was decreased from $310.00 to $290.00, to bring the customer charge closer to the embedded cost of service. For the Non-Demand class, a flat delivery rate of $0.04050 per kWh was developed to produce the remainder of the requirement.

Base delivery revenue from the secondary class is primarily driven by demand revenue, which currently represents approximately 65% of secondary revenue while the volumetric rate contributes only 14% of the revenue. A flat demand charge of $10.22 per kW and a flat delivery rate of $0.00662 per kWh were developed for the secondary class by increasing each by approximately 12% to produce the remainder of the revenue requirement.

Similarly, demand revenue for the primary class currently represents approximately 81% of base revenue while the volumetric rate contributes only about 7% of the revenue. Therefore, the energy delivery charge and the demand charge for the primary class were each increased by approximately 25% to produce the remainder of the revenue requirement. This resulted in a flat delivery rate of $0.00210 per kWh and a flat demand charge of $9.62 per kW/per month.

Q. Please describe how the charges to S.C. Nos. 3 and 13 were developed.

A. The monthly customer charge for S.C. No. 3 and S.C. No. 13 (Substation), were decreased from $1,500.00 and $3,800.00 to $935.00 and $1,970.00, respectively. The monthly customer charge for S.C. No. 13 (Transmission) was increased from $5,020.00 to $5,725.00. These changes are intended to bring the customer charge closer to the embedded costs shown on Schedule C of Exhibit __ (COSP-1), supported by the testimony of the COSP.

The overall increase in the customer charge does not produce a significant customer bill impact for either S.C. No. 3, because of the 500 kW minimum bill provision in this service classification, or S.C. No. 13, due to the size of these customers.

A flat demand rate of $12.56 per kW was developed to produce the remainder of the S.C. No. 3 revenue requirement while maintaining the reactive demand charge continued by the Commission most recently in Case 14-E-0318. S.C. No. 13 (Substation and Transmission) flat demand rates of $10.14 per kW and $5.28 per kW, respectively, were developed to produce the remainder of the revenue requirement for this class while also maintaining the reactive demand charge continued by the Commission in Case 14-E-0318.

Q. How were proposed charges to S.C. Nos. 5 (Area Lighting) and 8 (Street Lighting) developed?

A. These charges were developed by applying the class increase to each offering across the classes.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. Are there any electric service classifications for which the Company is proposing no change at this time?

A. Yes. The Company currently offers standby service under S.C. No. 14. As there is minimal activity under this service classification with respect to the tariff rates, and these rates follow the parent service classification rates/cost of service, the Company believes that any rate design changes required to this service classification should be made at a later stage in this proceeding consistent with the determination of the final revenue requirement and consistent with any determination in the on-going review of standby rates directed by the Commission's Order Adopting a Ratemaking and Utility Revenue Model Policy Framework issued May 19, 2016 in Case 14-M-0101.

Q. To what extent do the proposed changes to customer charges move the Company closer to costs reflected in the ECOSS?

A. Since the Company fully supports movement toward the costs reflected in ECOSS, the Company is proposing increases to those customer classes with the greatest number of customers. The table below shows, for customer classes with the greatest number of customers, the extent to which the current customer charges fall below the indicated costs of service and the movements towards costs proposed by the Company:

Electric Customer Charges					
S.C. No.	Current	Proposed	ECOSS	Current vs ECOSS	Proposed vs ECOSS
1 – Nht	$24.00	$25.00	$48.36	-50%	-48%
2 – ND	$35.00	$39.00	$52.55	-33%	-26%

Gas Customer Charges					
S.C. No.	Current	Proposed	ECOSS	Current vs ECOSS	Proposed vs ECOSS
1 & 12 Ht	$26.00	$30.00	$54.58	-52%	-45%
2, 6 & 13 Ht	$39.00	$45.00	$84.70	-54%	-47%

Q. Are there any other electric and gas rates for which the Company is proposing a change at this time?

A. Yes. Pursuant to Case 11-M-0542, the Company currently offers specific delivery rates for electric and gas Excelsior Jobs Program ("EJP") participants. The rates for these provisions are required to reflect the marginal cost of providing service. As a result, the Company proposes that the results of the marginal cost study be utilized to develop the EJP rates.

We are also proposing to update the current level of the electric contract demand charges for S.C. No. 10 consistent with the marginal cost of service study. The underlying customer charges for this service classification have also been updated consistent with the updated customer charges proposed for electric S.C. Nos. 2 (Primary), 3 and 13.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. After allocating the proposed gas revenue increase between various service classifications, how did the Panel proceed to design the proposed residential rates (S.C. Nos. 1 and 12)?

A. In designing rates for residential customers, the initial goal was to increase the customer charge to be more in line with the customer charge indicated by the ECOSS. To accomplish this, the minimum charge for the first 200 cubic feet or less was increased from $26.00 to $30.00 per month. The remaining increase was then allocated to the volumetric delivery charge.

Q. Please describe how the charges to S.C. Nos. 2, 6 and 13 were developed.

A. The primary goals in designing the rates for these classes were to increase the customer charge to be more in line with the customer charge indicated by the ECOSS and to maintain a similar increase in the customer charge in comparison to the residential customer classes. The first step in the rate design was to increase the minimum charge from $39.00 to $45.00, moving this charge closer to the percentage increase allocated to S.C. Nos. 1 and 12. The next step was to allocate the remaining increase to the volumetric delivery charge.

Q. Please describe how the discount applicable to High Volume S.C. No. 6 customers was developed.

A. First, a composite rate was calculated to reflect high volume usage priced out at currently effective block rates. The usage was calculated as 20% of the S.C. Nos. 2, 6 and 13 sales forecasted for the Rate Year as the average 2012 to 2016 high volume sales accounted for approximately 20% of actual total S.C. Nos. 2, 6 and 13 sales. The composite rate was then compared to the current tail block rate to determine the current percentage discount. This percentage discount, which is approximately 9.44%, was then applied to proposed rates. While high volume tail block customers will experience larger rate increases than non-high volume customers as a result of the approved rate design in Case 14-G-0319 where minimal rate increases were allocated to the tail block, the aforementioned method continues to maintain a 9.44 percent discount from standard rates for these customers.

Q. Should this discount also be utilized for S.C. Nos. 2 and 13 gas air conditioning customers?

A. As of June 30, 2017, the Company did not serve any customers under this S.C. No. 2 or S.C. No. 13 Special Provision. However, as current tariff provisions provide the same tail block discount for gas air conditioning customers as is reflected for high volume S.C. No. 6 customers, the Company is proposing to maintain the same discounted rate for both.

Q. Please describe how the charges for S.C. No. 11 (Transmission, Distribution and DLM) were developed.

A. To accommodate the move back to MDQ based rate design, the monthly customer charge for each subclass was set to $1,500, a modest increase from the current SC 11 EG monthly customer charge rate of $1,200. Due to the limited number of customers taking service under S.C. No. 11, this proposed increase does not generate a significant amount of revenue. The remaining increases were allocated by subclass (Transmission, Distribution, DLM) to the Maximum Daily Quantity ("MDQ") charge.

Q. Are there any other gas service classifications for which the Company is proposing revised rates?

A. No. The Company does not currently serve any customers under S.C. Nos. 15 and 16 (Distributed Generation ("DG") – Commercial and Industrial and DG – Residential), respectively. Therefore the Company recommends that any rate design changes required to this service classification be made at a later stage in this proceeding consistent with the determination of the final revenue requirement.

Q. Is the Company proposing any additional delivery rates?

A. Yes. The Company is proposing an Electric Bill Credit and a Gas Bill Credit. These bill credits would serve as rate moderators; the level of moderation is further discussed in the testimony of Company Witness Campagiorni. Bill credits have been designed to reflect total amounts available for moderation of approximately $22.0 and $10.1 million to electric and gas customers, respectively, over the Rate Year. The credits were allocated based on the adjusted base rate increase as a percentage of system, which is the same methodology utilized for the Electric and Gas

Bill Credits approved in Cases 14-E-0318 and 14-G-0319. The Electric Bill Credit is reflected on Schedule B of Exhibit __ (FRP-14). The Gas Bill Credit is reflected on Schedule C of Exhibit __ (FRP-15).

Q. Does the Company's proposed Gas Bill Credit reflect any additional items?

A. Yes. The Company is proposing to continue the Danskammer Generating Station ("Danskammer") delivery revenue deferral and bill credit mechanisms established in Case 14-G-0319. Accordingly, Danskammer revenue has not been included in the delivery revenues and revenue requirements. To the extent that the Company receives gas delivery revenue from Danskammer in any Rate Year, 50% of those revenues will be refunded via a bill credit to the Company's gas customers in the subsequent Rate Year and 50% deferred for the future benefit of the Company's gas customers. All Danskammer gas delivery revenue related bill credits will be allocated to each service class in proportion to its contribution to overall gas delivery revenue. The Danskammer portion of the Gas Bill Credit is reflected on Schedule C of Exhibit __ (FRP-15).

Q. Are there any other rate items for which the Company is proposing a change?

A. Yes. The Company is proposing to update the electric and gas reconnection charges. The Company last updated the re-connection charges in November 2001 in compliance with the Order Establishing

Rates issued October 25, 2001 in Cases 00-E-1273 and 00-G-1274. As the re-connection charge reflects the labor, vehicle and materials costs related to performing the re-connections, the Company believes it is reasonable to update these rates to reflect more recent information in order to more accurately allocate costs to those customers for whom those costs are incurred.

Q. Please describe how the re-connection charge rates were developed.

A. The re-connection charge was designed to reflect hours of work required for re-connection at appropriate labor costs for collectors, commercial representatives, line crews and gas crews. The Company also included call center and dispatch labor costs. Finally, the re-connection charge rates reflect vehicle expense related to travel and material costs related to performing the re-connection.

Exhibits

Q. Please explain Exhibits __ (FRP-14) and __ (FRP-15), which set forth a summary of present and proposed rates.

A. Exhibit __ (FRP-14) consists of ten schedules. Schedule A and Schedule B set forth the present and proposed MFC Charges, and the proposed Electric Bill Credit, respectively, as previously discussed. Each of the remaining schedules sets forth a comparison of the provisions of a present service classification and the proposed superseding service classification.

Exhibit __ (FRP-15) consists of three schedules. As previously noted, Schedule A sets forth present and proposed base MFC charges. Schedule B sets forth a comparison of the provisions of present S.C. Nos. 1, 2, 6, 11, 12 and 13 and the proposed superseding service classifications. Schedule C sets forth proposed Gas Bill Credit rates.

Q. Please explain Exhibits __ (FRP-16) and __ (FRP-17) regarding comparative bills.

A. Exhibit __ (FRP-16) provides comparisons of charges for typical usages under S.C. Nos. 1 and 2 at present and proposed rates, including and excluding rate moderation as further discussed above and in the testimony of Company Witness Campagiorni.

Exhibit __ (FRP-17) provides comparisons of charges for typical usages under S.C. Nos. 1 and 12 and 2, 6, and 13 at present and proposed rates, including and excluding rate moderation as further discussed above and in the testimony of Company Witness Campagiorni. These comparisons were prepared using the monthly Energy Cost Adjustment Mechanism ("ECAM") factors effective July 12, 2017 and the monthly GSC factors effective June 30, 2017, respectively, in order to develop estimates of full service bills to allow for a more accurate estimate of the utility bill impacts of the proposed rate changes.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. Has the Panel provided additional information for annual periods beyond the Rate Year?

A. Yes, the Panel has included additional schedules similar to Schedule F of Exhibits __ (FRP-2) and __ (FRP-3) for the twelve month periods ending June 30, 2020 and 2021. These schedules have been provided as additional information to the letter transmitting the Company's filing.

VII. <u>OTHER RATE PROVISIONS</u>

Q. How are the Company's energy supply costs recovered from full service customers?

A. From November 2001 to May 1, 2005, all energy costs incurred on behalf of full service customers were fully recovered through the MPC and MPA components of the Company's ECAM or through the Hourly Pricing Provision ("HPP") for S.C. Nos. 2, 3 and 13 customers electing to take service under the terms of the HPP. Effective May 1, 2005, S.C. Nos. 3 and 13 customers continuing to purchase their energy supply requirements from Central Hudson were required to do so under the HPP. Effective October 1, 2011, S.C. No. 2 customers with demand exceeding 500 kW in any two of the previous twelve months continuing to purchase their energy supply requirements from Central Hudson were also required to do so under the HPP. Effective October 1, 2012, HPP was further required for all full service S.C. No. 2 customers with demand exceeding 300 kW in any two of the previous twelve months.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. Please describe the ECAM.

A. The ECAM consists of four components: the MPC, MPA, the Miscellaneous Charges ("MISC") and PPA.

Q. Please describe the MPC and MPA components of ECAM.

A. The MPC and MPA factors are applicable to all service classifications excluding S.C. Nos. 2, 3 and 13 HPP as previously noted. The MPC charge recovers the Company's cost of electricity supply related purchases, including firm energy, capacity, ancillary charges, risk management fees, and other charges imposed by the NYISO. The MPC also includes working capital carrying charges and an uncollectible allowance. Energy and capacity purchased under mandatory Independent Power Producer ("IPP") contracts and the Company's retained generation is priced at the monthly average of NYISO day-ahead market prices. The MPC charge is calculated on a monthly basis for each MPC group based on actual costs incurred during the previous month allocated over projected deliveries for the collection period. The MPA is the reconciliation mechanism for the MPC. It is also calculated on a monthly basis by MPC group and reconciles actual MPC recoveries with MPC costs.

Q. Please describe any recent changes to the MPC billed to customers.

A. Effective April 1, 2017, the MPC is increased by a component designed to recover from full service delivery customers the costs of Renewable

Energy Credits ("REC"), Zero Emissions Credits ("ZEC") and Alternative Compliance Payments ("ACP") purchased pursuant to Case 15-E-0302.

Q. Please describe the MISC component of the ECAM.

A. The MISC factor recovers the cost or benefit of non-avoidable, variable energy-related revenues or costs associated with the Company's retained generating facilities and from mandatory IPP purchases. The MISC also includes working capital carrying charges and an uncollectible allowance. The MISC charge or credit is calculated on a monthly basis by dividing the previous month's benefit or cost by estimated deliveries and is applicable to all energy deliveries as a uniform factor. The Company reconciles MISC recoveries with actual costs or benefits on a three-month lag.

Q. Is there anything else to note regarding MISC?

A. Yes. Effective February 2, 2017, the MISC II factor was implemented. The MISC II factor was designed to recover the costs of the Company's alternative infrastructure project approved for recovery pursuant to the July 15, 2016 Order in Case 14-E-0318. In addition, pursuant to the Commission's July 13, 2017 Order Approving Deferral Accounting and Recovery of Distributed System Platform ("DSP") Related Costs in Case 17-E-0113, the Commission authorized similar recovery treatment through the MISC for DSP-related costs. For billing purposes, cost recovery for non-demand customers will be included in the Miscellaneous Charges, with the combined amount shown as one line item on customer bills. Cost recovery for demand customers will be through the Miscellaneous Charges II, a separate line item on customer bills.

Q. Please describe the PPA component of ECAM.

A. The PPA factor is also applicable to all energy deliveries as service class and sub-class specific PPA factors. Prior to December 1, 2011, these factors recovered the cost or benefit of the Company's PPA with Constellation Energy for energy and capacity from Nine Mile Point 2 ("NMP2"). Effective December 1, 2011, the PPA reflects the Revenue Sharing Agreement ("RSA") with Constellation. Under the RSA, Constellation is required to pay 80% of the net cumulative positive spread, if any, between the actual revenues per MWh earned by NMP2 and the floor price per MWh for the period as set forth in the RSA. The PPA factors also include an allowance for uncollectibles and are subject to reconciliation similar to the MISC.

Q. Please provide a brief explanation of the Company's other supply recovery mechanism, the HPP.

A. Since May 1, 2005, the HPP has been the only commodity pricing option available to S.C. Nos. 3 and 13 customers that continue to elect to purchase their energy supply requirements from Central Hudson. In Case 08-E-0887, the Company was required to expand HPP to all S.C. No. 2 customers exceeding 500 kW in any two months in a twelve month period. In Case 09-E-0588, the Company was further required to expand HPP to all S.C. No. 2 customers exceeding 300 kW in any two months in a twelve month period. Under the HPP, the Company recovers its costs by charging customers for their hourly supply requirements at the NYISO Zone G day-ahead market price, increased to reflect the applicable factor of adjustment. Customers under the HPP plan are also subject to the HPP charge which recovers costs for energy balancing ancillary services, allowances for working capital and uncollectibles, as well as the HPP unforced capacity ("UCAP") charge which recovers capacity charges, as well as REC/ZEC/ACP costs as described previously.

Q. Is the Company proposing any structural changes to the way it recovers purchased electricity costs?

A. No, the Company seeks to continue to fully recover the costs of electricity purchased for full service customers through the continued application of the provisions of the ECAM and HPP. Continued application of these mechanisms entails the continued use of deferral accounting, as necessary, to recognize the timing differences that occur between the actual purchases of energy requirements and the collection of costs from customers.

Despite the sale of the Company's fossil and nuclear generating facilities, the unbundling of the supply and delivery function, the implementation of MFCs and the establishment of a mature wholesale electricity market, the Company continues to bear the obligation to forecast, procure, and manage the electricity supply obligation for the great majority of its customers. The Company continues to source and contract for cost effective supply on behalf of those customers that choose to purchase their supply from the Company. Full recovery of these purchase costs is essential to the financial health and stability of the Company, given the absence of the ability to control generation and wholesale market costs.

Q. How are the Company's natural gas supply costs recovered from full service customers?

A. Gas supply expense (demand and commodity) incurred by the Company to serve full service customers taking service under S.C. Nos. 1 and 2 is recovered through the GSC. The GSC is determined monthly and reconciled annually, for the twelve-month period ending August 31, in accordance with 16 NYCRR §720-6. The GSC is equal to the sum of the average demand cost of gas and the average commodity cost of gas, multiplied by the factor of adjustment and adjusted for the annual reconciliation of gas expense, gas supplier refunds, interruptible sales credits, capacity release credits, and all other adjustments as approved by the Commission.

Q. Does the Panel have any other rate design proposals?

A. Yes. The Accounting and Tax Panel has proposed the institution of a Rate Adjustment Mechanism ("RAM") to allow for the timely recovery from customers of certain deferred balances and carrying charges identified at the conclusion of the Rate Year. The Forecasting and Rates Panel proposes that the under-collected balances so identified be submitted in a RAM filing with the Secretary by August 1, with rate recovery implemented on September 1 for collection over the twelve months from September 1 through August 31. Any over- or under-recovery of balances would be included in a succeeding recovery period.

Q. How would the RAM recovery amounts be allocated to service classes?

A. The Panel proposes that the annual electric RAM recovery amount be allocated to service class/sub-class on the basis of delivery service revenues and recovered on a per kWh basis for non-demand billed customers, on a per kW basis for demand billed customers, and on an as-used demand basis for standby customers. The annual gas RAM recovery amounts would also be allocated to service classes, excluding interruptible, on the basis of delivery service revenues and recovered on a per Ccf basis. Recovery would be implemented when the annual under-collected balances meet or exceed the thresholds of $350,000 and $40,000, for electric and gas respectively, such that recovery factors can be developed for each service class/sub-class. Any RAM balances not meeting these thresholds would be carried forward for collection in a subsequent recovery period.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. Would the RAM recovery be accomplished through an existing rate mechanism currently included on customer's bills?

A. The Panel proposes to include the electric RAM recovery in the existing MISC similar to the MISC II treatment afforded the alternative infrastructure project approved for recovery pursuant to the July 15, 2016 Order in Case 14-E-0318 as previously noted. Currently there is no contemporaneous mechanism for gas recovery which would require the development of a separate mechanism and line item on customer's gas bills.

Q. Is the Panel proposing any other changes to the MISC?

A. Yes. The Panel proposes to include recovery of the incremental funding requirement and the incentives associated with the Earnings Adjustment Mechanisms addressed by the EAM Panel in the MISC. Recovery would be accomplished in a manner similar to the aforementioned MISC II, with recovery amounts allocated to service class/sub-class on the basis of delivery service revenues.

Q. Have RDMs been implemented for the Company's electric and gas operations?

A. Yes. In its Order Adopting Recommended Decision with Modifications issued and effective June 22, 2009 in Case 08-E-0887 and Case 08-G-0888, the Commission adopted RDMs for both the electric and gas operations of the Company. The RDMs were subsequently continued, with revisions, in accordance with the Commission's Order Establishing Rate Plan issued and effective June 18, 2010 in Case 09-E-0588 and Case 09-G-0589 and again in accordance with the Commission's Order issues and effective June 17, 2015 in Case 14-E-0318 and Case 14-G-0319.

Q. Please describe the electric RDM currently in place.

A. The electric RDM is a revenue per class model applicable to S.C. Nos. 1, 2ND, 2PD, 2SD, 6, and 14. Pursuant to the RDM, actual delivery revenue by service class or sub-class for RDM eligible classes is compared, on a monthly basis, to a delivery revenue target. If the monthly actual delivery revenue exceeds the delivery revenue target, the delivery revenue excess is accrued for refund to customers at the end of the semi-annual RDM period (six months ending December or six months ending June). Likewise, if the monthly actual delivery revenue is less than the delivery revenue target, the delivery revenue shortfall is accrued for recovery from customers at the end of the semi-annual RDM period.

At the end of a semi-annual RDM period, total delivery revenue excess/shortfalls are refunded/surcharged to customers through service class or sub-class specific RDM adjustments applicable during a corresponding semi-RDM adjustment period (six months beginning February 1 or six months beginning August 1 immediately following the semi-annual RDM period).

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. Please describe the gas RDM currently in place.

A. The gas RDM is a revenue per customer (“RPC”) model and is applicable to S.C. Nos. 1 and 12 combined and S.C. Nos. 2, 6 and 13 combined. The RDM provides for a monthly comparison of actual RPC as adjusted by the Weather Normalization Adjustment (“WNA”) and billed customer months, to RPC targets, with any revenue excess/shortfall refunded to/recovered from customers over a semi-annual RDM adjustment period (six months beginning February 1 or the six months beginning August 1).

Q. Is the Company proposing any changes to the electric and gas RDMs currently in place?

A. Yes. The Company is proposing that the electric RDM be applicable to S.C. Nos. 3 and 13 and that gas RDM be applicable to S.C. No. 11 (Transmission), S.C. No. 11 (Distribution) and S.C. No. 11 (DLM). These customers are currently excluded from the RDM due to their prior lack of access to formally administered energy efficiency programs. However, recent changes have provided access to energy efficiency funding for these customers. Accordingly, they should now be included in the RDM. The Company is also proposing that the electric RDM be applicable to lighting customers served under S.C. Nos. 5, 8 & 9. The Company is proposing to include lighting classes in conjunction with the introduction of LED street and highway lighting in 2015 in Case 15-E-0126 as well as the recent sales of systems to municipalities. Therefore, the Company believes it is appropriate to reflect these classes of customers in the RDM, which is designed to offset conservation-related revenue losses.

Q. Is the Company's gas business subject to a WNA?

A. Yes. Pursuant to the Commission's Order in Case 08-G-0888, a WNA was implemented for all heating customers taking service under S.C. Nos. 1, 2, 6, 12 and 13.

Q. Is the Company proposing any changes to the WNA currently in place?

A. No. However, if the Company's proposal to eliminate the gas block rate structure is approved, a conforming change to the WNA will be required to revise the definition of "pure base rate" from the tail block delivery charge to the volumetric delivery charge.

Q. Does this conclude the Panel's direct testimony at this time?

A. Yes, it does.