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Q. Please state your name and business address.

A. My name is Peter T. Carnavos and my business address is 111 Broadway, Suite 1601, New York, New York 10006.

Q. By whom are you employed and in what capacity?

A. I am a Director, Energy Management Gas Supply of Consolidated Edison Company of New York, Inc. (“Con Edison” or “Company”).

Q. Please state your educational background.

A. I graduated from Saint John’s University with a Bachelor of Arts degree in Secondary Education and I hold a Graduate Business Certificate from Long Island University. I have also attended the Duke University Fuqua School of Business Program for Management Development. I am a member of the Northeast Gas Association’s New York State Gas Utility Planning Committee (“NYPLAN”) and Supply Task Force.

Q. Please describe your work experience.

A. I joined Con Edison in 1980 and have over 30 years of both regulated utility and competitive energy service company experience. In my career I have been responsible for various planning, forecasting, business development, regulatory strategy and operational areas related to contracting, purchasing,
infrastructure, retail services and the delivery of natural gas and fuel oil for both gas customers, power generators and Con Edison electric and steam generation.

Q. Please generally describe your current responsibilities.

A. I am responsible for the following areas in the Gas Supply Department: (i) gas purchasing and scheduling; (ii) gas billing and analysis and contract administration and (iii) gas transportation services and planning. As Director of Gas Supply, I oversee these areas for both Con Edison and Orange and Rockland Utilities, Inc. ("O&R" or "Orange and Rockland") (jointly referred to as "the Companies") including gas for company owned generation with gas expenditures of over $700 million dollars per year. In addition, I contributed to the development of the Gas Hedging Program which is executed by Electric Supply.

Q. Have you previously testified before the New York State Public Service Commission ("Commission")?

A. I submitted testimony in Case 00-M-0504. I also submitted testimony to the New York State Board on
Electric Generation Siting and the Environment in Case 99-F-1314.

Q. Please summarize the areas covered in your testimony.

A. I will discuss the changing nature of the gas supply and transportation industry and how these market forces are affecting the Companies’ gas purchasing, hedging programs and capacity plans. I will address: (i) Market Conditions Affecting Supply; (ii) Gas Supply Program; (iii) Gas Volatility Reduction; (iv) Capacity and Supply Portfolio Changes; (v) Marginal Cost Study; (vi) Regulatory Activities; and (vii) Lost and Unaccounted for Gas (“LAUF”). I will also explain how the Companies strive to provide a reasonably-priced gas supply for their customers and act as system operator providing balancing services to all customers in our service territory. The capacity and supply portfolio maintained reflects the Companies’ efforts to (i) maintain a reliable gas supply, (ii) minimize gas costs to their firm customers, and (iii) reduce gas price volatility, consistent with Commission policy for gas utilities.

Q. I show you Exhibit__(PTC-1), Schedules 1 through 13 and Exhibit__(PTC-2), and ask if these were prepared
under your direction and supervision?

A. Yes, they were.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (PTC-1) AND Exhibit___ (PTC-2)

MARKET CONDITIONS AFFECTING SUPPLY

Q. What are the recent changes in market conditions that affect how the Companies’ execute the gas supply program?

A. The rate of annual natural gas discoveries has tripled over the last decade with 66 percent of the increase in discoveries from 2002 to 2008 coming from unconventional (including tight sands and shale) gas discoveries. Shale gas is the most significant of the recent gas discoveries and is forecasted by the Energy Information Administration ("EIA") to compose 49 percent of total US natural gas production by 2035. It will likely play a major role in foreseeable additions to proven reserves. The location of the new discoveries is placing structural constraints on the existing interstate pipeline system. This is leading to new infrastructure build outs and changes in interstate pipeline operations. In addition, customer conversions from oil to natural gas are increasing the
demand for firm natural gas service through the phase out of permits to utilize No. 6 and No. 4 fuel oil in NYC.

Q. How do these changes affect your operation?

A. The Companies strive to maintain a portfolio that provides the flexibility to obtain the lowest cost gas to our firm customers consistent with maintaining reliable gas service. In addition, the Companies act as a system operator providing balancing services for all firm and interruptible delivery customers. This gas supply is provided through multiple points of delivery from the interstate pipeline systems into the Companies' service areas. The addition of new interstate pipeline capacity to our gas system, as well as the Company's gas transmission and distribution system enhancements (discussed by the Gas Infrastructure and Operations Panel), will enable the Company to serve the increasing service requirements of gas customers and generators in a safe and reliable manner. Con Edison currently has five large electric power generation ("Power Gen") customers active on its system. Those customers are the New York Power Authority ("NYPAs"), TransCanada-Ravenswood
PETER T. CARNAVOS - GAS SUPPLY

("Ravenswood"), Astoria Generating Company ("US Power Generation" or "USPG"), NRG Power Marketing ("NRG") and Astoria Energy LLC ("SCS"). In addition, the Company’s Steam Operations Department ("Steam") operates several facilities on the system that produce steam and electricity. Collectively, they will be referred to as "Generators".

GAS SUPPLY PROGRAM

Q. Please describe the nature of the Companies’ gas portfolio.

A. The Companies have implemented a joint gas supply and capacity portfolio (joint portfolio) that allows for the joint utilization of their gas supply and interstate pipeline capacity contracts including storage. The joint portfolio is operated for the benefit of the firm gas customers of both Con Edison and O&R. The structure of the Companies’ joint portfolio is illustrated on Schedules 1, 2, 3, and 4 of Exhibit __ (PTC-1).

Q. Please describe the objective of the Companies’ gas purchasing and hedging programs.

A. The Companies’ objective is to obtain a reasonably-priced gas supply that reflects their efforts to (i)
maintain a reliable gas supply, (ii) minimize gas costs to their firm customers, and (iii) reduce gas price volatility. The objective also includes maintaining a diverse gas supply and capacity portfolio, thus giving the Companies the ability to meet design winter requirements of firm gas customers, the flexibility to react to changing weather conditions, and the ability to maximize the means to maintain service during a contingency event affecting a major pipeline or supply basin.

Q. How do the Companies seek to maintain reliability of supply?

A. One of the cornerstones of a reliable gas portfolio is its diversity. The Companies’ joint gas supply and capacity portfolio includes supplies of both domestic and Canadian gas production, as set forth on Exhibit __ (PTC-1), Schedule 1, Gas Supply Contracts. The Companies also have firm pipeline capacity contracts with ten different interstate pipeline transportation companies, as set forth on Exhibit __ (PTC-1), Schedule 2, Pipeline Transportation Contracts, that provide access to diverse sources of supply. In addition, the Companies have a number of contracts for
underground storage. These storage contracts are listed on Exhibit ___ (PTC-1), Schedule 3, Storage Contracts. The deliverability of the LNG peaking facility is set forth on Exhibit ___ (PTC-1), Schedule 4.

Q. What are design weather conditions?

A. The peak day represents the quantity of gas that firm customers would require in a twenty-four hour period of a gas day, which starts at 10 am, at a Temperature variable of zero degrees Fahrenheit. The Temperature Variable is defined as the sum of 70 percent of the projected gas day average temperature plus 30 percent of the prior gas day average temperature, which provides the best correlation with firm customer demand. Exhibit ___ (PTC-1), Schedule 5, Consolidated Edison/O&R Peak Day Forecasted Requirements, shows the forecast of each Company’s firm customers’ peak day demand for each winter period (i.e., November through March) beginning with the winter of 2013/2014 through winter 2015/2016. Gas Supply also calculates the gas requirements for meeting demand over the course of a winter under severe weather conditions (a “design winter”) in order to establish storage and peaking
supplies that are adequate.

Q. Please explain how the Companies’ contracts enable them to meet these design weather conditions.

A. Peak day demand is met through the delivery of firm supply via the Companies’ firm interstate pipeline transportation capacity, withdrawals from firm market area storage capacity, delivery of firm peaking supplies to the Companies’ city gates, and gas vaporized at the LNG plant. Exhibit ___ (PTC-1), Schedules 2, 3, and 4, demonstrate how the Companies plan to meet design winter conditions.

Q. Why is underground market area storage an important component of the Companies’ gas supply portfolio?

A. Underground market area storage serves three purposes for local distribution companies. First, the proximity of market area storage to the service territory avoids the higher costs of contracting for long-haul interstate pipeline transportation capacity to meet load on only the coldest days and increases utilization of existing long-haul interstate pipeline transportation capacity during the summer storage injection season to fill market area storage fields.
Second, market area storage provides flexibility for gas deliveries that helps keep the Companies’ system supply in balance with both full service and retail choice customer demand. That is, market area storage is an integral part of the Companies’ ability to provide essential load-following services, which in turn provides the Companies with flexibility to react to lower customer demand during warmer-than-normal periods and higher demand during colder-than-normal periods. In addition, the ability to divert city gate deliveries into storage or to move gas out of storage to the city gate within a gas day enables the Companies to balance their system deliveries with customer usage and gas marketers’ deliveries.

Third, market area storage allows the Companies to take advantage of seasonal price opportunities. Gas prices in the summer have been lower on average than during winter months. The process of filling storage to the Companies’ targeted levels during the summer and withdrawing this gas during the winter assists in reducing price volatility to firm gas customers.

Q. Why is production area storage an important component of the Companies’ portfolio?
A. The current major role of production area storage is to provide flexibility to balance the intra-day changes in system loads by allowing deliveries in and out of the fields as required. These Production Area Storages are utilized in conjunction with the Companies' no-notice transportation services on Transcontinental Gas Pipe Line Corporation. Production area storage also serves as an additional source of supply.

Q. Has the role of production area storage changed?

A. Yes. As the Companies' retail choice programs have grown, this flexibility to balance intra-day changes in system loads has increased in importance. Since the recent development of shale gas located in the Northeast (Marcellus), Gulf Coast (Haynesville) and the Southwest (Barnett) regions and the decline of off-shore Gulf of Mexico production, the Companies rely less on production area storage for protection against wellhead freeze-offs and delivery disruptions during hurricane-related events.

Q. Please describe the initiatives the Companies have taken in the wholesale market to minimize gas costs.

A. The Companies strive to minimize gas costs by using a
competitive bidding process through Requests for
Proposals ("RFPs") to the marketplace, participating
in on-line reverse auctions, and by taking advantage
of opportunities that arise through the Companies’
participation in the Northeast Gas Markets group.
With the recent development of the Marcellus Shale
region in Pennsylvania, the Companies have also had
the opportunity to purchase more economic natural gas
at alternate delivery locations along the path of its
interstate pipeline capacity. The Companies also seek
to optimize their joint portfolio primarily through
capacity releases, asset management arrangements and
off-system bundled sales.
Q. Please provide an illustration of the historical and
projected benefits from the Companies’ portfolio
optimization efforts.
A. Exhibit __ (PTC-1), Schedule 6, Non-Traditional
Revenues, illustrates annual benefits received, or
projected to be received from the Companies’ portfolio
optimization efforts to minimize overall costs to
their firm gas customers.
Q. How are portfolio optimization benefits derived?
A. The expected benefits are derived when available
capacity, not used to serve the Companies’ customer requirements or balancing needs, is offered to the market through capacity releases, off-system sales, or Asset Management Arrangements ("AMA"s) that together are referred to as "discretionary capacity releases."

Q. Do you project the market value of discretionary capacity releases to decrease?

A. Yes, we expect the market value of capacity will decrease, resulting in lower future benefits. The available capacity is expected to decrease for the following three reasons. First, with the projected load growth, more of the existing capacity will be used to serve the new load. Secondly, with the increased participation in the retail choice program, more of the Companies’ capacity will be assigned to the marketers serving retail choice customers through mandatory capacity assignment. Third, Orange and Rockland marketers will be assigned more firm transportation capacity during the summer months, which reduces the amount of capacity available to release into the gas market.

The market value is expected to decrease for two reasons. First, the increase in gas supply production
in the northeast, and second, the projected increase in pipeline capacity in the region and to New York City starting in November 2013.

Q. Does Con Edison subscribe to Platts index publications?

A. Yes. Pursuant to the Commission’s Order, issued September 27, 2004 in Case 03-G-1671, Platts index publications (Platt’s Gas Daily and Platt’s Inside FERC First of the Month Price Report), referred to as Platts, are utilized to establish market prices in setting balancing and cash-out costs. In addition, Platt’s Petroleum NY Harbor spot prices are currently used to price and verify oil purchases for the Company’s steam electric operations.

Q. How are these indices used?

A. Con Edison uses the First-of-Month Transco Zone 6 Citygate index and the average of the Transco Zone 6 City Gate index midpoint prices as reported in Platt’s Gas Daily for calculating cashout prices for marketers serving firm gas customers, as set forth in the Gas Tariff and Gas Transportation Operating Procedure (“GTOP”). Con Edison uses Platt’s Gas Daily to record the average of the Transco Zone 6 City Gate index
midpoint prices and the average of the Transco Station
65 Production Area midpoint prices for calculating
Cashout prices for marketers serving interruptible gas
customers. Additionally, the Company utilizes Platt’s
Gas Daily to record the Transco Zone 3 and Transco
Zone 6 NY Weekly Weighted Average Price for the
calculation of the SC9 interruptible gas and Power
Generation Transportation Customer’s monthly Cashout
credits and charges. Platt’s NY Harbor Spot prices
are used to verify fuel oil purchased on behalf of the
Company’s generation.

Q. Are there any other reasons why the Company subscribes
to Platts index publications?
A. Yes. The Federal Energy Regulatory Commission
(“FERC”) has established Platts as the fixed price
reporting clearinghouse, developer and reporter of
monthly and daily indices for the natural gas
industry. FERC has reported that the gas industry has
relied upon Platts pricing indices for over 80 percent
of the volume of gas that is sold and purchased.

Q. Are you proposing a program change related to Platts?
A. Yes. Platts costs are projected to increase from
$101,000 in the test year to $424,000 in the Rate
Year, of which $322,000 or 76 percent would be allocated to Gas and $102,000 or 24 percent to Steam/Electric Operations. For future years, Platts costs are projected to increase at 4 percent per year and rise to $459,000 during 2016 based on discussions with Platts.

Q. What is the reason for the projected increase in costs?

A. Platts has reviewed their pricing structure based on how their services are being used in the industry. They are encouraging site licenses as a cost effective method of using their products over individual user subscriptions. The Company has reviewed its business requirements as it relates to the utilization of Platts and has determined that a site license is the most cost effective solution. For example, provisions of the Dodd-Frank Act require more disclosure and transparency in our interactions with the markets. This leads to increased reporting by the Company. A site license from the vendor is the preferred means to meet these increased reporting requirements.

Q. How are Platts costs currently recovered?
A. Platts costs are currently included in base rates.

Q. How do you propose to recover these costs?

A. We propose to recover Gas’ share of Platts costs (or the costs of any clearinghouse publication that may substitute for Platts in the future) through the Monthly Rate Adjustment (“MRA”), which is applicable to all firm customers.

Q. Why are you proposing to recover these costs through the MRA instead of through base rates?

A. As discussed above, the use of Platts is integral to the Company’s provision of gas service and embedded in the Company’s gas tariff and GTOP. Moving the recovery of these costs to the MRA better reflects the relationship between these publications and the balancing services to which they are integral. And, as evident from the recent developments regarding site licenses and Platts’ essentially monopoly position in this area, these costs are not subject to reasonable estimation. Using the MRA would properly facilitate customers bearing any variations between projected costs and actual costs for Platts services, including enjoying any cost savings that may result from negotiations with Platts for the required services.
In addition, the MRA provides an appropriate cost recovery vehicle should new circumstances result in the Company substituting a new index publication for Platts, where the fees charged by the new service provider may be higher or lower than Platts’ fees.

Q. How would the Commission’s adoption of the proposed recovery of these costs through the MRA affect the proposed revenue requirement?

A. If the Company’s proposal is adopted, the Company would lower the Gas revenue requirement by Gas’ share of the amount of the proposed program change ($322,000 for Gas). The Company would then implement a tariff change to address recovery of the Platts index publication service costs (or the costs of any replacement index provider) through the MRA.

Q. Does Con Edison utilize any transaction management systems?

A. Con Edison uses Integrated Gas System ("IGS") and related systems, the official system of record for recording gas purchases, transportation and balancing transactions.

Q. What changes are required for IGS?
A. IGS is being updated for changes in the market place and for compliance with Sarbanes-Oxley. Exhibit (PTC-2) contains White Papers that describe the capital program changes expected to be implemented during 2013 and 2014. These projects are budgeted for $900,000.

Q. What are the benefits of these changes?

A. IGS is our system of record. The primary benefit is compliance with Sarbanes-Oxley requirements of accountability, transparency, and conformity with the Company’s accounting systems. In addition, system upgrades enable internal company software communication that streamlines data flow and avoids increased labor costs. The Energy Management – Gas Supply Department is responsible for executing the Company’s gas commodity transactions which requires strict compliance with Sarbanes-Oxley controls. The upgraded system will adapt to standard industry practice from an auditing perspective and will provide a clear audit trail of transaction activity. Furthermore, the recently enacted Dodd-Frank Wall Street Reform and Consumer Protection Act significantly increases the amount of energy transaction data to be collected and saved in a
database for recordkeeping and reporting purposes. The upgrade will facilitate and help assure compliance with the new law. Additional changes are required to upgrade underlying development tools to stay current with the product version upgrades. This upgrade is necessary as the older versions are no longer supported by Microsoft.

Q. Are there any other ongoing costs for IGS?
A. Yes, there are. IGS is an in-house developed application. After the implementation of the capital project, the system must be maintained. The projected annual O&M expenditures beginning in the Rate Year is approximately $330,000 per year. These expenses reflect the annual labor costs for persons included as part of the capital expense for their services in installing and testing the new system, as explained in the white paper, who will thereafter provide the maintenance services. Since it is anticipated that the capital portion of the project will be completed during the first quarter of the Rate Year, the maintenance expense reflected in the Rate Year is approximately $250,000.

PRICE VOLATILITY REDUCTION
Q. What efforts have the Companies undertaken to reduce the volatility of gas prices to their firm gas customers?

A. Through active management of the joint gas supply and transportation portfolio, the Companies seek to reduce the volatility of gas prices delivered to their firm gas customers. Specifically, the Companies take advantage of: (i) pricing mechanisms in their gas supply contracts, (ii) storage utilization, (iii) firm transportation agreements on numerous interstate pipelines, and (iv) a gas hedging program.

Q. Please explain.

A. The Companies’ gas supply contracts generally provide the option to trigger a NYMEX price, use first-of-the-month index prices and daily index prices, or negotiate a monthly commodity price months before commencement of the delivery period. If the future commodity price is agreed upon in advance, the cost of gas for these quantities is no longer subject to market volatility. As I previously described, storage also plays a significant role in reducing the volatility of total gas costs. Gas is purchased and injected into storage during the summer months, when
the price of gas has traditionally been lower than in the winter months, and stored for use by firm customers during colder winter days.

Long-haul firm transportation agreements, in addition to satisfying the need for reliability of gas deliveries, enable the Companies to avoid the volatility of basis (i.e., the value of transporting gas from a supply point to a delivery point), which would be the case if the Companies were to buy transportation capacity to the market area on an as-needed basis.

Q. Please describe the Companies’ gas hedging program.

A. The Companies’ hedging program is designed to reduce gas price volatility. One of the hedging program’s components is the Monthly Plan, which dictates the use of physical price locks and/or various financial instruments to hedge natural gas prices for part of the gas supply necessary to meet the monthly requirements of firm sales customers. The program provides for the Companies to hedge a minimum quantity of its forecasted sales using physical and/or financial price hedges for the winter period.

Q. How have the Companies managed credit issues?
A. Credit risk is managed by the oversight of two risk committees. One is the Risk Oversight Committee ("ROC"), comprised of senior officers of the Companies, and the other is the Regulated Risk Management Committee ("RRMC"), comprised of other officers of the Companies. The ROC oversees corporate risk strategy and establishes risk policies from an enterprise-wide perspective, including credit risk. The ROC also establishes credit risk tolerances, including the amount of credit the Companies will extend to a counterparty. The RRMC approves credit risk policies and procedures and assures compliance with the policies and procedures governing the wholesale energy activities of the Companies. The RRMC approves the appropriate risk measurement methodologies so that exposures are consistent with the Companies’ risk policies and credit limits.

Furthermore, the Companies have a separate department, Energy Risk Management Utilities ("ERM"), to oversee and manage credit risks associated with gas and electric purchases. ERM establishes a credit limit for each counterparty with whom the Companies have physical or financial exposure. ERM monitors and
reports to the RRMC and ROC on the counterparties’
credit limits and ratings and the Companies’ exposure
to these counterparties.

CAPACITY AND SUPPLY PORTFOLIO CHANGES

Q. Have there been recent changes to the capacity
   portfolio?

A. Yes. In 2008, the Companies did not extend firm
   transportation contracts with TransCanada from Alberta
to the United States border at two locations of
Niagara and Waddington, which were in place for nearly
two decades. The contracts were replaced with lower-
cost, shorter-distance contracts with Union Gas and
TransCanada with receipt point at Ontario. The
contract restructuring reduced pipeline demand
charges, and provided supply options at the Dawn Hub,
which is a liquid point. This has resulted in an
estimated net annual gas supply cost savings of about
$9 million.

Q. Do you anticipate any additional changes to the
capacity portfolio?

A. As transportation and storage contracts near the end
   of their existing terms, Gas Supply evaluates and
determines the need for each contract. Assuming the
contract is required to meet firm gas customer load
and/or manage gas system operations, Gas Supply
cconducts an assessment of the marketplace to determine
if alternative transportation and/or storage contracts
of at least equal reliability and flexibility can be
acquired more economically. If more desirable
replacement contracts cannot be supplied by the
marketplace, these contracts will be renewed,
consistent with existing interstate pipeline tariff
Right of First Refusal ("ROFR") provisions or other
applicable contract provisions.

This past year, the Companies have entered into two
and three year citygate delivered services contracts
to meet firm gas customers' current and future peak
day requirements. These multi-year contracts provide
needed supply to our gas system prior to the in-
service date of new interstate pipeline capacity.
The Companies contracted for additional interstate
pipeline capacity on Texas Eastern Pipeline to a new
point of delivery on the Con Edison System in lower
Manhattan that is anticipated to be in-service on
November 1, 2013. This additional interstate pipeline
capacity benefits customers by enhancing reliability
through the creation of a new delivery point to the
Con Edison system and additional supply diversity by
providing access to multiple sources of supply. It
also benefits customers by increasing the available
delivered services to New York City and the Companies’
ability to meet future growth.
The Companies are expected to rely more on delivered
services expected to be offered by producers,
marketers, and other market participants that have
contracted for interstate pipeline capacity to New
York City (“NYC”). Con Edison has been successful in
encouraging additional interstate pipeline capacity to
NYC, so that delivered services are available in the
future as gas demand grows.

Q. What changes to the Companies’ supply portfolio have
taken place?

A. As illustrated in Exhibit __ (PTC-1), Schedule 1,
certain of the Companies’ gas supply contracts expire
each year. Existing domestic contracts may be
renegotiated or replaced through competitive bidding
or RFPs; and Canadian supplies may be added/replaced
through NorthEast Gas Markets, which (as discussed
above) acts as the agent for a group of utilities,
including the Companies.

In the past, the gas supply contracts required to fill open firm transportation capacity typically had one, three, or five-year terms. Over the past three years, the Companies have altered their purchasing strategy to limit supply purchases to one year or less. As a result of all the shale production coming on-line, the new pipeline projects that will move the shale gas to market and the increased pipeline capacity to NYC, the Companies are monitoring the natural gas markets in order to better evaluate the impact these events will have on supply availability and pricing. The Companies will re-evaluate their purchasing strategy and make changes as circumstances dictate.

Prior to contract expiration, Gas Supply evaluates whether the supply is required, which depends on, among other things, the status of retail access in the Companies’ service territories. Over the past few winter seasons, the Companies have released three new interstate pipeline capacity paths at Waddington and Niagara, NY, to the marketers serving our transportation customers. As a result, the Companies Canadian natural gas purchases have been reduced.
Exhibit ___ (PTC-1), Schedule 1, lists all gas supply contracts effective winter 2012/2013.

REGULATORY ACTIVITIES

Q. Have the Companies undertaken any regulatory efforts to maintain the reasonableness of their gas costs and the reliability of their supply?

A. The Companies participate in a myriad of FERC proceedings involving (i) their interstate pipeline and storage providers (“service providers”) and (ii) generic issues that impact the cost and quality of the gas service received by the Companies from FERC-regulated entities. The Companies review all significant FERC filings made by the interstate pipelines and storage companies from which it receives service. Since November 6, 2009, the Companies have intervened in over 800 FERC proceedings and have filed 51 sets of detailed comments or objections. Exhibit ___ (PTC-1), Schedule 7, lists the FERC dockets in which Con Edison has filed detailed comments since November 6, 2009. The Companies are also active participants in the American Gas Association (“AGA”) FERC Regulatory Committee, which takes an active role in a range of federal regulatory issues relating to
gas supply (Scott Butler of Con Edison’s Energy Policy and Regulatory Affairs Department was the Chairman of the Committee in calendar year 2010). The Companies closely follow FERC proceedings that impact rates and terms of service of their interstate pipeline service providers and actively participate in litigation as well as settlement negotiations. The Companies have also actively participated in the FERC’s inquiries into gas-electric coordination and the discussions at the NYISO’s Electric-Gas Coordination Working Group. The Companies have sought to incorporate an evaluation of potential fuel availability issues into the NYISO’s planning processes and make enhancements to gas and electric industry communications. When appropriate, the Companies also participate in other forums such as collaborative discussions among pipelines and their customers, the North American Energy Standards Board ("NAESB") and the Natural Gas Council ("NGC"), either directly or through their membership in the AGA.

Q. Please provide examples of the Companies’ active participation in the rate proceedings of their interstate pipeline suppliers.

A. Specific examples of the Companies’ activities include
In the Tennessee Gas Pipeline rate case, Con Edison participated in a customer group comprised of Tennessee’s major Northeastern customers, which successfully worked to secure a series of favorable cost allocation and cost of service changes. The Tennessee Rate Case Settlement reduced the impact on the Companies of Tennessee’s filed rate increase request from $12.3 million per year to approximately $3.7 million per year. As part of the settlement, Con Edison was able to secure favorable rates on an expansion project to access the Stagecoach Storage Field.

In the Columbia Gulf rate case, the Companies participated in a customer group formed to seek more favorable rates than those filed by the pipeline. The Settlement in this case reduced the impact of the filed rates from an annual increase of approximately $521,000 (61 percent) to approximately $208,000 (24...
percent).

In the National Fuel Gas Supply rate case, Con Edison also achieved favorable results. Prior to National Fuel’s rate request, the Companies’ annual costs for service were approximately $6.5 million. Under the initially filed rate case, the Companies’ costs would have risen by between $800,000 (12 percent) and $2.7 million (29 percent) per year. The settlement reduces the Companies’ costs by approximately $700,000 (11 percent) annually. The rate reduction is the result of rolling Niagara expansion project costs into system rates and replacing National Fuel’s fixed fuel retention rate with a tracker.

The Companies also participated actively in Columbia Gas’s recent efforts to develop an additional charge to recover the costs of planned capital projects to replace aging facilities and meet pipeline integrity requirements. The settlement, recently filed by Columbia Gas, which the Companies support, includes a number of measures advocated by the Companies to protect customers against misuse of the modernization rate mechanism.

Other FERC proceedings the Companies are following
relate to interstate pipeline cost allocation issues involving, for example, fuel retention and electric power compression charges. The Companies closely monitor proposed tariff changes by service providers that modify their terms of service, including matters related to rights of first refusal, bidding rules, shipping priority, service provider credit policies and tariff and negotiated agreement filings that could affect the quality of pipeline service to the Companies. The Companies also closely monitor new incremental services being offered by the Companies’ current service providers so that the rates of those new incremental services are not subsidized by existing customers, such as the Companies.

Q. What other steps have the Companies taken to maintain the reliability of their supply?

A. The Companies have actively supported the adoption by the natural gas industry of gas quality specifications that will allow for the safe integration of increased supplies, particularly from shale gas. The Companies have also been active in negotiating gas quality tariff changes with their supplier pipelines, which balance the needs of end users and Con Edison’s LNG
liquefaction plant and other system equipment with the
beneficial effect of additional supplies. For
Algonquin Gas Transmission, Iroquois Gas Transmission,
Texas Eastern Transmission, and Tennessee Gas
Pipeline, these gas quality tariff changes have been
approved by FERC and implemented by the pipelines, and
have served to set precedent for other pipelines in
the process of changing their own gas quality tariffs.

Q. Are the Companies a member of any groups addressing
gas reliability issues in New York State?
A. Yes. The Companies have been an active participant in
the Natural Gas Reliability Advisory Group ("NGRAG")
from its initiation. The NGRAG was formed to consider
the evolving capacity markets and how they affect
reliability, and to inform the Commission about issues
that need to be addressed to protect reliability.
During the past year, the NGRAG focused discussion on
the NYISO gas/electric workgroup to address gas supply
and transportation issues, updates of an ongoing LDC
collaborative addressing Gas Marketer Transportation
and Balancing Programs, and operational updates
provided by gas industry LDCs, Pipelines, Marketers,
Customer Groups, NYSERDA and NYMEX representatives.
Q. Please describe the Companies' efforts in connection with NAESB.

A. We have been a member of NAESB and its predecessor organization, the Gas Industry Standards Board ("GISB"), since the latter's inception in 1994. The transformation of GISB to NAESB in 2001 was designed to address changes in the energy industry. The Companies continue to monitor the development of new business standards and, as appropriate, participate in periodic revisions to the NAESB Base Contract, a form agreement frequently used in the industry for purchase and sale of natural gas.

Q. Please describe the Companies' efforts in connection with the Northeast Gas Association ("NGA").

A. The Companies' participation in the NGA is through their New York State Gas Utility Planning Committee ("NYPLAN"). NYPLAN is comprised of planning, supply and regulatory personnel from New York's investor-owned natural gas utilities. Its mission is to provide a forum for New York State gas companies to address the broad spectrum of issues relating to the natural gas supply, transportation, storage, peak shaving and demand planning process. This includes,
but is not limited to, such responsibilities as responding to regulatory mandates, discussion/follow-up on key regulatory/legislative issues, and working in collaboration with NYSEARCH on R&D projects. NYPLAN has worked with NGA in 2009 to provide comments on the developing "New York State Energy Plan" among other activities. The Companies are members of the NGA Gas Supply Task Force ("Task Force"). The Task Force includes representation from all the interstate transmission companies serving the region, liquefied natural gas ("LNG") importers and trucking companies, and the largest of the northeast region's local distribution companies. Recent members include several of the larger power generation owners who utilize natural gas as a major part of their fuel supply. The Task Force meets prior to the winter heating season, to confirm communication protocols and to provide updates on the status of company transmission and storage systems. The Task Force is convened during the winter to monitor supply and deliverability issues. The region’s state regulators and the electric grid
operators are notified of Task Force meetings and are provided meeting summaries.

MARGINAL COST STUDY

Q. Please address Con Edison’s marginal cost study with respect to gas supply costs.

A. Supply-side marginal costs are the costs of procuring and transporting an additional unit of gas to the Companies’ distribution systems. Fixed costs that are associated with existing resources are not considered because they do not vary with additional usage and because Con Edison cannot avoid paying them.

Q. Did you consider individual marginal cost components?

A. Yes, I considered marginal capacity costs and commodity costs.

Q. Please define marginal capacity cost.

A. Marginal capacity cost is the cost of adding reliable gas deliverability, which may include pipeline capacity, storage capacity, and/or firm gas supply at the city gate, to satisfy additional firm customer demand at design conditions.

Q. Please define marginal commodity cost.

A. Marginal commodity cost is the cost of an incremental purchase of gas required to meet system demand that
exceeds committed supply sources and planned supply additions.

Q. What is the forecast period used in your marginal cost study?
A. The forecast period for the marginal cost study is the three-year period from November 2013 through October 2016.

Q. Please explain the development of the marginal cost.
A. Exhibit __ (PTC-1), Schedule 8, Consolidated Edison Company of New York, Inc./Orange & Rockland, Inc. Summer Season Supply/Demand Balance, Schedule 9, Consolidated Edison Company of New York, Inc./Orange & Rockland, Inc. Winter Season Supply/Demand Balance, and Schedule 10, Consolidated Edison Company of New York, Inc./Orange & Rockland, Inc. Peak Day Supply/Demand Balance compare the Companies’ firm transportation and supply capability to gas demand on a summer season, normal winter season, and peak-day basis. The Companies’ firm transportation and supply capability includes all firm transportation deliverability and currently flowing firm supplies. These Schedules demonstrate that the need to add capacity to serve firm customer requirements is driven
by the Companies’ requirement to provide for firm
customer needs on a design-day basis.

Q. Please explain the calculation of the marginal
commodity cost.

A. The marginal commodity cost is measured by using an
optimization model that compares the difference in
system utilization costs between two scenarios, the
second, featuring a small increase in incremental
load. The unitized costs are calculated by dividing
the incremental costs by incremental loads. Exhibit
__ (PTC-1), Schedule 11, Consolidated Edison Company
of New York, Inc. /Orange & Rockland, Inc. Natural Gas
Marginal Monthly Commodity Costs, displays the monthly
marginal commodity costs for the three years of the
study. Exhibit __ (PTC-1), Schedule 12, Combined
Consolidated Edison Company of New York, Inc./Orange &
Rockland, Inc. Marginal Commodity Costs, summarizes
these costs to show the impact of the incremental
increase on an average annual, summer season, winter
season and design day basis.

LOST AND UNACCOUNTED FOR GAS (LAUF)

Q. Please explain the current methodology for calculating
lost and unaccounted for gas.

A. The current methodology compares the total
distribution sendout (which includes firm sales and
transportation and interruptible off-peak firm sales
and transportation while netting out gas for
Generators, LNG injections and heater/compressor fuels
from the total citygate receipts) to the total
customer metered volumes (firm sales and
transportation, interruptible off-peak firm sales and
transportation, Company use, theft of service and
CNG).

Q. Are you proposing changes to Con Edison’s LAUF
calculations for the period commencing October 1,
2013?

A. Yes, the Company proposes a LAUF calculation based on
throughput as opposed to distribution sendout to
establish a line loss factor (“LLF”). The new
methodology would take into account metered supplies
into the system divided by metered deliveries to
customers. The throughput calculation would include
LNG injections, heater/compressor fuel, and deliveries
associated with Generators who are served by the
Company’s high pressure transmission mains. The
calculation would exclude net deliveries to Keyspan Gas East Corporation ("KEDLI") and the Brooklyn Union Gas Corporation dba Keyspan Gas Corporation of NY ("KEDNY"), who, with Con Edison, are member companies of the "New York Facilities" operating arrangement.

Q. Why are you proposing a change in methodology?
A. The current sendout methodology includes accounting adjustments, such as theft of service, which may include deliveries that are out of the period being measured. In addition, although generation customers account for a significant portion of the total throughput, their usage is excluded from the current LAUF calculation. Use of a throughput methodology is a better measure of the losses across the system. However, as discussed below, I propose a further adjustment in order to establish a reasonable LLF for generation customers.

Q. Why are you excluding net deliveries to the New York Facilities members?
A. The New York Facilities operating arrangement allows for the receipt and deliveries of gas across member companies’ transmission mains from various pipelines. Currently the member companies do not charge each
other a line loss for these receipts and deliveries.
We are proposing that a line loss adjustment attributable to these receipts and deliveries among New York Facilities members not be considered in this case but instead be considered in a forum in which an appropriate adjustment, if any, can be considered for all three member companies.

Q. Are you proposing to change the contribution made by Generators to system losses?

A. Yes. We are proposing that the Generators increase their current contribution to the system line loss but at a rate lower than the total system line loss.

Q. Why should Generators be subject to a different line loss rate?

A. Losses from leaks on the transmission mains system are negligible. Due to the high operating pressure of the system, any leaks present are discovered quickly and repaired expeditiously by the Company. In addition, the Generators are large volume customers using highly accurate meters to measure their usage. Line losses due to Generators meter inaccuracies are estimated to be 0.1 percent.

Q. What is your proposed line loss charge to Generators?
We propose to charge Generators a line loss contribution of 0.5 percent, superseding the current 0.1 percent contribution, effective October 1, 2013.

What is the basis for the 0.5 percent contribution?

As noted above, it is reasonable to attribute 0.1 percent to meter calibration for Generators. It is also reasonable to attribute 0.1 percent for heater/compressor fuels. An additional 0.3 percent was added as a reasonable contribution to the total system line loss. This contribution recognizes the fact that there is no segregation of the high pressure transmission facilities from the lower pressure distribution system. Customers of the high pressure transmission system therefore benefit from the whole system and should make a reasonable contribution to the system line loss.

How does this affect the system LLF?

The volumes associated with generation customers and their contribution to the line loss at 0.5 percent will be subtracted from metered throughput and system line loss respectively to arrive at a LLF.

Are you also proposing to change the target for the incentive mechanism?
A. Yes. We propose the use of a five-year rolling average LLF to establish the target.

Q. Why are you proposing a five-year rolling average?

A. A five-year rolling average LLF helps to mitigate the volatility caused by weather and economic conditions. In addition, we are recommending the use of a deadband equal to two standard deviations around the average LLF. The deadband establishes a zone where no incentives or penalties will be assessed and is intended to recognize the natural volatility of line losses from accounting conventions and timing of measuring delivered volumes. The actual LLF would be reconciled to the target annually in August. A penalty would be assessed to the Company if the actual line loss is between two and four standard deviations above the target. An incentive would be earned for line losses between two and four standard deviations below the target subject to a cap equal to the greater of the calculated incentive cap and zero. A LLF outside of the four standard deviation limit would be credited to or absorbed by the gas customers.

Q. What prior periods will comprise the five-year average for the initial LAUF calculations under the proposed
throughput methodology?

A. The target will be the rolling five-year average of the immediate five annual periods ending August 31 before the rate year. For illustrative purposes as shown on Exhibit __ (PTC-1), Schedule 13, the LLF has been calculated annually for five twelve-month periods ended August 31, 2008, 2009, 2010, 2011 and 2012 using the methodology proposed above. Subtracting a 0.5 percent contribution to line losses from the generators, the five-year average LLF target is calculated to be 2.629 percent, with a standard deviation of 0.329 percent. Based on this calculation, the deadband limits around the LLF target where no penalty or incentive would be assessed is between 1.970 percent and 3.288 percent. A penalty would be assessed if the LLF is between 3.288 percent and 3.947 percent. An incentive would be earned if the LLF is between 1.970 percent and 1.312 percent.

Q. If the Company were to continue the current LLF approach and calculate the LLF effective October 1, 2013 making the adjustments contemplated by the Commission’s orders in Case 10-G-0643, what would be the new LLF?
A. The LLF would be 3.0 percent, as compared to 2.629 percent under the proposed approach.

Q. Are you proposing to update the calculation of the 2.629 percent at the end of this proceeding?

A. Yes. The Company will restate the target and upper and lower bands in October 2013 when the August 2013 LLF percentage becomes available. The new period will be for five twelve month periods ended August 2009, 2010, 2011, 2012, and 2013 using the methodology described above. Each year thereafter we would update the calculation by adding the most recent 12-month period and dropping the oldest 12-month period, and recalculating the applicable values and bands.

Q. Does this conclude your testimony?

A. Yes.