Before the Public Service Commission

THE BROOKLYN UNION GAS COMPANY D/B/A NATIONAL GRID NY

And

KEYSPAN GAS EAST CORPORATION D/B/A NATIONAL GRID

Direct Testimony

of

Elizabeth D. Arangio

Dated: April 2019

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Testimony of Elizabeth D. Arangio

I. Introduction and Qualifications

Q. Please state your name and business address.

A. My name is Elizabeth D. Arangio. My business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. Please describe your business position and responsibilities.

A. I am the Director of Gas Supply Planning with responsibility for the gas supply resource portfolios of National Grid USA's ("National Grid") local gas distribution companies in New York, including The Brooklyn Union Gas Company d/b/a National Grid NY ("KEDNY") and KeySpan Gas East Corporation d/b/a National Grid ("KEDLI") (collectively the "Companies"). In addition to the New York portfolios, I am responsible for planning the gas resource portfolios of National Grid's New England subsidiaries. I also manage National Grid's gas Customer Choice programs.

Q. Please summarize your educational background and your professional experience.

A. I graduated from the University of Massachusetts in 1991 with a Bachelor of Business Administration. In 1995, I graduated from Bentley College with a Master of Business Administration. From 1991 to 1994, I worked as a Gas Accounting Analyst in the Marketing Operations Department at Algonquin Gas Transmission Company. In 1994, I joined Boston Gas Company as a Gas Supply Analyst. In 1997, I was promoted to Group Leader Transportation Services, with responsibility for managing all activities associated with the customer choice program. In 1998, I was promoted to Director of Gas Acquisition and Transportation Services and assumed responsibility for the administration of Boston Gas's gas resource portfolio and customer choice program in Massachusetts and, in 2000, the resource portfolio of EnergyNorth Natural Gas, Inc. in New Hampshire. In February 2004, I assumed the additional responsibility for gas supply planning for the Companies' resource portfolios. Following the acquisition of KeySpan Corporation by National Grid, I was named to my current position and assumed added responsibility for National Grid's gas resource portfolios in Upstate New York and Rhode Island. In August 2018, I assumed the added responsibility of managing National Grid's gas Customer Choice programs.

II. <u>Purpose of Testimony</u>

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to:

(i) describe the Companies' efforts to purchase gas supply, pipeline transportation, and storage services on a reliable, least-cost basis in the twelve months ended December 31, 2018 ("Historic Test Year"), the twelve months ending March 31, 2021 ("Rate Year"), the twelve months ending March 31, 2022 ("Data Year 1"), the twelve months ending March 31, 2023 ("Data Year 2") and the twelve months ending March 31, 2024 ("Data Year 3," and together with Data Years 1 and 2, "Data Years");

(ii) discuss the Companies' efforts to supplant pipeline capacity with additional indigenous and renewable gas supplies;

(iii) discuss the existing gas supply constraints in the downstate New York area and the potential impact on the Companies' ability to meet forecast demand, the Companies' efforts to alleviate the supply shortage by supporting additional pipeline capacity to the region, and the potential need to impose a moratorium on new or additional gas service if constraints are not resolved;

(iv) present the Companies' forecast of gas costs for the Rate Year;

(v) describe the results of the marginal cost gas supply studies for the Rate Year;

(vi) discuss the Companies' Gas Cost Volatility Program; and

(vii) discuss the Companies' Customer Choice Program.

Pursuant to the New York State Public Service Commission's ("Commission") "Order Authorizing Combined Gas Portfolios" issued October 28, 2005 in Case 05-G-0903, as of November 2005, the Companies have combined the planning and dispatching of their gas supply portfolios to provide the Companies' customers enhanced reliability of supply and lower costs. Therefore, my testimony addresses the combined portfolios of the Companies and the material I present is applicable to both KEDNY and KEDLI.

Q. Does your testimony include any exhibits?

A. Yes. My testimony includes the following exhibits that were prepared under my supervision and direction:

Exhibit __ (EDA-1)	KEDNY & KEDLI Portfolio Schematics;
Exhibit __ (EDA-2)	KEDNY & KEDLI Pipeline Transportation Contracts;
Exhibit __ (EDA-3)	KEDNY & KEDLI Storage Contracts;
Exhibit __ (EDA-4)	KEDNY/KEDLI Projected Monthly Gas Stored Volumes and Dollars for the Rate Year and Data Years Summarized by Market Area, Gulf Coast and LNG storage;
Exhibit __ (EDA-5)	KEDNY/KEDLI Purchased Gas Expense for the Twelve Months Ending ("TME") December 31, 2018;
Exhibit __ (EDA-6)	KEDNY/KEDLI Forecast of Variable Gas Expense for the TME March 31, 2021, 2022, 2023 and 2024;
Exhibit __ (EDA-7)	KEDNY/KEDLI Forecast of Purchased Gas Expense for the TME March 31, 2021, 2022, 2023 and 2024;
Exhibit __ (EDA-8)	KEDNY & KEDLI Estimated Marginal Commodity Cost of Gas;
Exhibit __ (EDA-9)	KEDNY & KEDLI Estimated Annualized Marginal Capacity Cost of Gas;
Exhibit __ (EDA-10)	KEDNY & KEDLI Non-Migration Capacity Release Revenues; and
Exhibit __ (EDA-11)	KEDNY & KEDLI OSS Transaction Revenues.

III. Gas Supply Portfolio

Q. Please describe the Companies' gas distribution systems.

A. KEDNY's gas distribution system serves Brooklyn, Staten Island, and portions of Queens, all located within New York City. KEDLI's gas distribution system serves a portion of Queens not served by KEDNY, as well as Nassau and Suffolk counties on Long Island. KEDNY and KEDLI are parties to an agreement with Consolidated Edison Company of New York, Inc. ("Con Edison") concerning the ownership and operation of the New York Facilities System ("NYFS"), the high-pressure gas transmission system serving the three downstate New York distribution companies. This agreement permits the parties to contract for the transportation and receipt of gas from various interstate pipelines that interconnect with the NYFS, including Transcontinental Gas Pipeline Company LLC ("Transco"), Texas Eastern Transmission LP ("Texas Eastern"), Iroquois Gas Transmission System LP ("Iroquois"), and Tennessee Gas Pipeline Company, LLC ("Tennessee"). KEDNY and KEDLI contract for service from each of these pipelines as well as various other upstream pipelines and storage service providers.

Q. Please describe the Companies' gas supply planning process.

A. Typically, in the spring of each year, the Gas Supply Department develops plans to meet the Companies' gas supply obligation for the annual period from November 1 of that year through October 31 of the following year. This planning process begins with an updated ten-year demand forecast that provides the foundation for customer requirements that ultimately determine incremental pipeline, storage, or peaking needs.

Q. What are the Companies' combined forecast design day requirements for the Rate Year and Data Years?

A. The Companies' design day requirements are as follows:

- Rate Year = 2,894 MDth (thousand dekatherms)/day
- Data Year 1 = 2,912 MDth/day
- Data Year 2 = 2,954 MDth/day
- Data Year 3 = 2,987 MDth/day

Q. What is the basis for the Companies' city gate requirements?

A. The primary firm demand (*i.e.*, core customer load forecast) forms the basis for the Companies' gas supply portfolio. The primary firm demand is the demand imposed on the Companies by their firm customers, regardless of whether they purchase gas commodity from the Companies or energy service companies ("ESCOs"). Pipeline and storage capacity, along with peaking assets, are used to satisfy the primary firm demand. An annual load duration curve or similar approach is utilized to structure capacity contracts to best meet the shape and frequency of the anticipated loads and to assure the Companies' ability to meet those loads. The Companies do not incorporate any reserve margin assumptions when developing their design weather forecasts and capacity requirement determinations.

Q. What contracts or assets are included in the Companies' existing portfolio?

A. Exhibit __ (EDA-1) sets forth schematics of the Companies' gas portfolios and provides their maximum delivery entitlements from various sources of supply, including underground storage contracts.

Q. Please describe Exhibit __ (EDA-2) – Pipeline Transportation Contracts.

A. Exhibit __ (EDA-2) summarizes the firm pipeline transportation capacity and bundled peaking assets in the Companies' gas supply portfolio for the 2018-2019 winter season (November 1, 2018 to March 31, 2019). Listed for each contract is information concerning the service provider (pipeline or supplier), tariff rate schedule, contract volume, and contract expiration date.

Q. Please describe Exhibit __ (EDA-3) – Storage Contracts.

A. Exhibit __ (EDA-3) summarizes the Companies' firm storage contracts and the transportation contracts used to deliver storage withdrawal volumes to the city gate for the 2018-2019 winter season. Listed for each contract is information concerning the storage service provider, tariff rate schedule, contract volume, and contract expiration date.

The Companies source gas supply at the following liquid points:

- Dawn, Ontario
- Transco, zone 4
- Dominion, South Point
- Tx. Eastern, M-3
- Transco, zone 6 N.Y.

- Transco, zone 6 non-N.Y.
- Transco, zone 6 non-N.Y. North
- Transco, zone 3
- Iroquois, receipts (Waddington)
- Texas Eastern, M-2 receipts
- Tennessee, zone 4-300 Leg (Marcellus)
- Iroquois, zone 2
- Transco, zone 1
- Millennium, East receipts
- Dominion, North Point
- Leidy Hub
- Transco, zone 2
- Transco, Leidy Line receipts
- Tennessee, zone 5 White Plains (no index)

Q. What is the role of underground storage in satisfying customer requirements?

A. Approximately 31 percent of the Companies' normal winter supply obligation and 28 percent of their design day demand requirement are met by deliveries of gas withdrawn from storage. Under the Companies' storage contracts, storage deliverability typically declines as inventory decreases (known as "withdrawal ratchets"). Once reached, these ratchets cannot be reversed until the following year. Therefore, the Companies establish a storage withdrawal plan prior to the winter season to maintain inventories at levels that allow sufficient storage deliverability to meet forecast winter peak conditions (storage rule curve).

Market area storage provides the Companies with services that cannot be easily duplicated with other assets. The most important attribute of storage assets is flexibility, which is vital in serving changing customer requirements. The Companies' Transco storage service contracts provide end-of-day balancing that minimize the risk of over/under run penalties. Whereas typical supply purchases must be dispatched at the same volume for each day of a weekend or holiday, storage allows enhanced flexibility by allowing intraday adjustments to meet changing conditions. In addition, storage improves the load factor of flowing pipeline assets and is critical in meeting design weather conditions. This value cannot be duplicated by replacing storage with Marcellus production. The Companies utilize a least-cost dispatch to fill storage. Where Marcellus shale supplies present an opportunity to displace long haul supplies for storage refill, the Companies take advantage of the economically priced supply.

The Companies also have approximately 20 billion cubic feet ("Bcf") of Gulf Coast storage capacity. These storage fields are made available to ESCOs as part of the optional Gulf Coast storage release that occurs every April. Assuming no ESCOs opt-in for the Gulf Coast storage release, approximately 4.5 Bcf of the total capacity is reserved for *force majeure* purposes. The remaining 15 Bcf of capacity, usually the entire KEDNY Washington Storage Service ("WSS") field, is utilized for off-system sales ("OSS"). If all ESCOs opt-in, the capacity utilized for OSS would be reduced accordingly.

Q. What is the role of liquefied natural gas ("LNG") in the Companies' portfolio?

A. The Companies maintain two on-system LNG facilities in Greenpoint, Brooklyn and Holtsville, Long Island. The Greenpoint LNG facility allows KEDNY to store approximately 1.6 Bcf of gas and has peak day vaporization capability of approximately 291,000 dekatherms (Dth) per day. The Holtsville LNG facility allows KEDLI to store approximately 0.6 Bcf of gas and has vaporization capability of 103,000 Dth/day. Collectively, the Greenpoint and Holtsville LNG facilities provide the Companies with approximately 10 percent of their peak day gas supplies.

LNG provides the Companies with on-system services that cannot be easily duplicated with other assets. Because these resources can be brought on line quickly, the LNG plants can be used to meet hourly fluctuations in demand, maintain deliveries to customers, and balance pressures across portions of the distribution system during periods of high demand. Most importantly, these resources are vital in preserving delivery pressures in the event that an off-system resource becomes unavailable.

Q. What changes are planned related to swing services, peak shaving or winter peaking assets, facilities, or operations for the Rate Year through a five-year planning horizon?

A. As further discussed in the direct testimony of the Gas Infrastructure and Operations Panel ("GIOP"), the Companies plan to take the Holtsville LNG facility out of service for critical maintenance repairs in April 2022. This planned capital work, however, is contingent on the availability of additional supply expected to be provided by the Northeast Supply Enhancement ("NESE") project by December 2020. There are no other planned changes related to swing services, peak shaving or winter peaking assets, facilities or operations through a five-year planning horizon.

Q. What are the projected monthly beginning and ending volumes and dollar balances for gas stored through the end of the Rate Year and Data Years?

A. Exhibit __ (EDA-4) provides the projected monthly volume and cost of injections and withdrawals for the Companies' underground and LNG storage facilities for the Rate Year and Data Years, summarized by market area, Gulf Coast, and LNG storage.

A. Indigenous and Renewable Natural Gas

Q. Do the Companies purchase supply from any local natural gas production?

A. Currently, the Fresh Kills Landfill ("Landfill"), located in Staten Island, is the Companies' only source of local production and accounts for less than one percent of the total system throughput. The Landfill is owned by the City of New York. KEDNY has a supply agreement with the Landfill for up to 6,500 Dth/day, but there is no contractual minimum daily quantity. Landfill supply is directly fed into the distribution system.

The Companies' use of local production has not changed over the past several years; the Companies continue to purchase any supply the Landfill can provide. There is no forecast of Landfill production, but the Gas Control department communicates with the Landfill regularly and is notified of maintenance work and outages. When the Landfill is unable to sell supply, the Companies replace planned volumes with other resources in the portfolio.

The table below shows the Landfill's production for the last three years:

Year	Total (Dth)
2016	510,838
2017	406,245
2018	448,990

Additionally, as discussed in the direct testimony of the Future of Heat Panel, the Companies expect a new bio-gas facility at Newtown Creek to be placed into service by November 2019. The new facility is expected to produce approximately 275,000 Dth/year (750 Dth/day) of renewable natural gas ("RNG").

Q. What steps are the Companies taking to capture the benefits of connecting additional indigenous and RNG gas supplies directly to their distribution systems?

A. KEDNY and KEDLI recently updated their Gas Transportation Operating Procedures ("GTOP") manual to include a "Renewable Natural Gas Engineering Services Agreement" template and "Gas Sales (Interconnect) Agreement" template. These documents define the respective responsibilities of the developer and the Companies in connecting new RNG projects. The agreements also list the billing and payment terms and conditions, gas quality specifications, and other relevant provisions for interconnecting to the Companies' distribution systems. The "Gas Sales (Interconnect) Agreement" template is modeled after the existing agreement with the Landfill.

Further, the Companies recently collaborated in the development of the "NYS Interconnect Guide for RNG" document along with the Gas Technology Institute ("GTI"), Northeast Gas Association ("NGA"), and other gas distribution companies in New York State. The document establishes a clear process for both project developers and utilities to successfully connect RNG projects. Please refer to the testimonies of GIOP and Future of Heat Panel for further discussion.

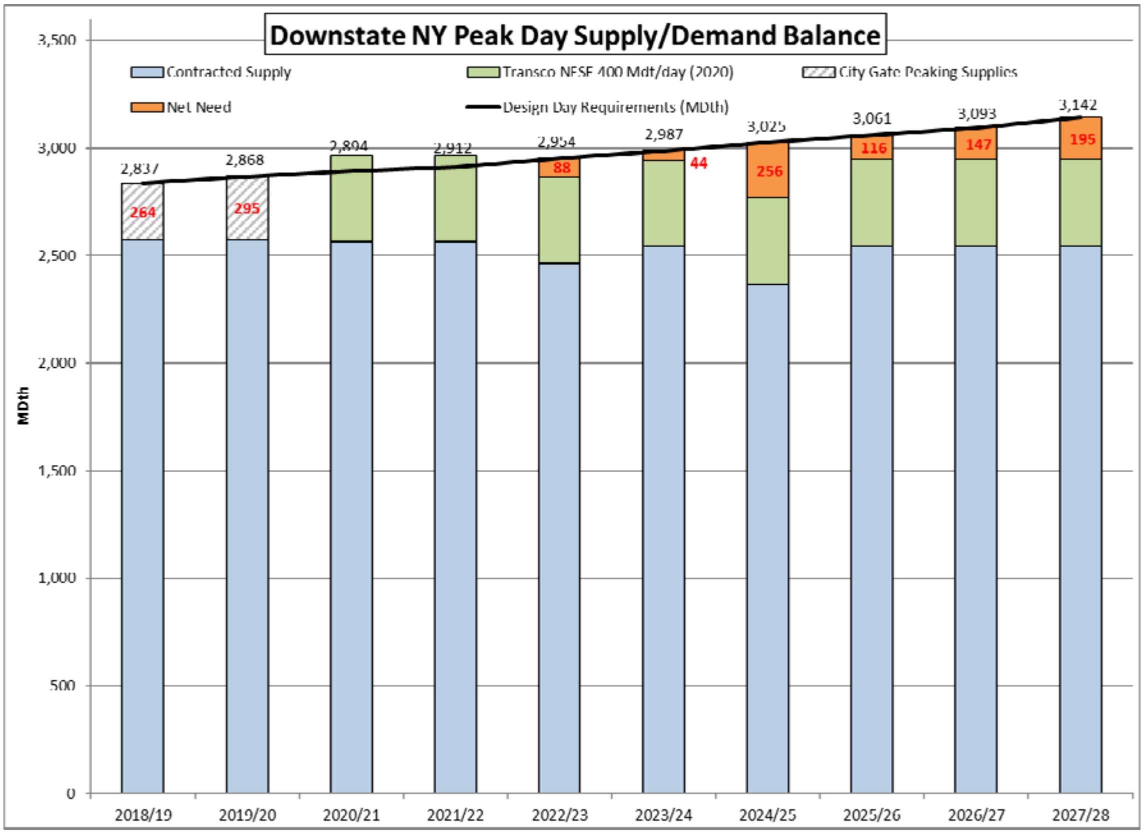
Q. What efforts are the Companies making to reduce their pipeline capacity?

A. Pipeline capacity is an integral component of the Companies' gas supply portfolio to deliver sufficient natural gas to serve our customers. While pipeline capacity cannot be entirely displaced, the Companies continue to explore ways to reduce reliance on pipeline capacity. As discussed in the Future of Heat Panel's testimony, the Companies are pursuing various decarbonization initiatives including renewable gas projects to reduce their carbon footprint while meeting customer needs.

B. Northeast Supply Enhancement Project

Q. Do the Companies plan to add any incremental pipeline capacity in the next five years to meet forecast design day load requirements?

A. Yes. Due to continued customer interest in conversions from oil to natural gas for space and water heating, as well as increased demand from existing customers and new construction in their service territories, the Companies have continued to experience growth in the demand for natural gas. The Companies' ten-year load forecasts show that demand for gas will continue to grow. KEDNY and KEDLI expect the demand for gas to grow at an annual rate of more than 1.3 percent and 1.0 percent for the next ten years, respectively. The graph below shows the balance between the forecast demand and the Companies' supply portfolio for the ten-year period ending 2027/28. The graph shows that without significant additional pipeline capacity, as further described below, supply falls short of the demand.



In response to the forecast growth, KEDNY and KEDLI signed precedent agreements with Transco to deliver an additional 400,000 Dth of natural gas per day to the downstate New York area. To provide the additional supply, Transco will expand its existing pipeline system along Pennsylvania, New Jersey, and New York to connect to the Companies' system in the Rockaway Peninsula. The NESE project will provide access to abundant and economical gas supplies, thereby relieving supply constraints in the Companies' service territories. Furthermore, NESE will include a fully looped pipeline segment to interconnect with the existing delivery lateral in New York Bay, further enhancing reliability of the system. The Companies have contracted for 100 percent of the incremental pipeline capacity that will become available via NESE.

Q. What will be the impact to the Companies' ability to meet forecast demand if the NESE project is not completed in time?

A. In the absence of additional pipeline capacity, the Companies cannot continue to add new gas load without creating an unacceptable risk of significant supply shortfalls and corresponding drops in system pressure to below minimum thresholds. Such conditions will jeopardize the reliability of service and public safety for the Companies' existing firm customers.

As can be seen in the graph above, the Companies' current supply planning assumes that the NESE project will be completed in time to meet the forecast growth in demand for natural gas. Currently, NESE is awaiting permit approval from New York Department of Environmental Conservation. If the project does not become available by the 2020/21 winter season, the Companies will not be able to prudently satisfy new or additional service requests without jeopardizing the Companies' ability to provide safe, reliable service to its existing firm customers. In that case, National Grid will have no choice but to impose a moratorium on new and additional gas service in affected areas to maintain system reliability.

The GIOP direct testimony addresses NESE's impact to the Companies' capital projects. Notably, as mentioned above, the Companies will not be able to take their LNG facilities out of service to complete necessary maintenance repairs if NESE is not completed in time.

IV. Portfolio Management

Q. Please describe the Companies' gas supply planning goals.

A. The Companies' primary gas supply planning goals are to:

(i) Dispatch the gas supply portfolio assets under a least-cost strategy to reliably meet projected primary firm demand;

(ii) Maintain a diverse portfolio of gas supply, storage, and transportation capacity contracts with varying terms and pricing provisions; and

(iii) Implement a formal hedging program to mitigate price volatility.

These goals are consistent with the Commission's "Statement of Policy Regarding Gas Purchasing Practices" issued in Case 97-G-0600 and updated by letter issued March 31, 2011. The Companies maintain a portfolio that meets requirements under design conditions while maintaining sufficient flexibility for mild winters.

The Companies monitor these goals with regular meetings (monthly supply plan, quarterly review, and annual RFP review). Pursuant to Recommendation IX-4 from the final audit report in the Commission's previous gas management audit (Case 13-G-0009), the Companies established a process for the quarterly review of gas supply procurement plans compared to actual purchases for a sample of days during the quarter. The review identifies variances in volumes and the use of storage and delivery pipelines caused by weather, market conditions, operational constraints, or other factors. Variances are reviewed for patterns and opportunities to improve the procurement process. The Companies' Energy

Procurement group has been conducting quarterly reviews since 2015. Reviews are attended by representatives from Gas Supply Planning, Gas Trading, and Origination and Price Volatility Management.

Q. Please describe the Companies' gas purchasing process.

A. The Companies contract for quantities of gas to ensure sufficient supply to reliably meet design conditions, as well as to account for daily and seasonal load variations. A combination of term and spot contracts provides necessary flexibility with respect to volume, which allows the Companies to respond to fluctuations in demand. Both term and spot contracts are firm to ensure reliability. The varying provisions in these contracts allow for pricing diversity as well.

<u>Term Contracts</u>

Term contracts have durations of longer than one month and less than one year. These contracts generally have a specified fixed daily base load quantity necessary to satisfy requirements under a "warm winter" scenario and may include some summer storage refill quantities. Other term contracts provide call options to buy bundled gas supplies delivered either to the Companies' city gates or other upstream supply points. KEDNY and KEDLI also utilize no-notice storage to manage variations in load that allow the Companies to automatically withdraw or inject gas at the end of the day to balance system load.

Term contracts are generally priced monthly. In addition to first-of-the-month (FOM) published indices, monthly prices for some term domestic supply contracts also use the New York Mercantile Exchange ("NYMEX") last day settle price plus a competitively bid location basis differential. Monthly pricing ensures the effectiveness of the NYMEX futures contracts entered as part of the Companies' hedging strategy.

<u>Spot Contracts</u>

Spot contracts are firm contracts with a term of one month or less. There are no specific contractual triggers that require the purchase of spot gas. These contracts are made throughout the year to supplement term contract supplies, manage demand variations due to weather, and maintain storage inventory targets. Spot contracts also provide pricing diversity (*i.e.*, daily index vs. monthly index).

The Companies purchase spot gas from a number of qualified and reliable suppliers who have North American Energy Standards Board ("NAESB") contracts to minimize risk and obtain competitive pricing. The amount of capacity available depends on the time of year and storage availability.

Daily spot purchases are priced either at reliable, daily published index prices or at a negotiated short-term (daily) fixed price.

Q. What is the current level of natural gas supply used by the Companies to meet normal customer requirements, and how will that amount change in the Rate Year?

A. Of the 230 Bcf of forecast normal customer requirements for November 2018 to October 2019, the Companies are required to purchase approximately 201 Bcf. The remainder will be procured by ESCOs. For the Rate Year, forecast normal customer requirements are approximately 221 Bcf, with 208 Bcf served by the Companies and the remainder by ESCOs.

Q. How do the Companies evaluate expiring contracts for gas supply?

A. As decision dates for contract extension/termination approach, the Companies determine the need to maintain and or modify (to the extent possible) each contract as part of the resource portfolio. The Companies use several criteria to assess the need for transportation and storage contracts including but not limited to: receipt point liquidity, reliability, complement to the existing portfolio, and economics.

Also, the Companies consider options to replace long-haul capacity with shorter-haul capacities. For example, as supplies from the Marcellus shale region became abundant and readily accessible, the Companies did not renew expiring long-haul contracts with Union, TransCanada, and Empire pipelines that delivered more expensive supplies from Dawn, Canada.

While the current level of Transco long haul capacity is required to serve the Companies' peak day and peak season needs, it is not always the least cost option for supply. Recently, the Companies were able to reduce the path on Transco long-haul contracts to reduce fixed costs. Effective March 1, 2019, the Companies have agreed to turnback 40 percent (27,473 Dth/day) of their combined entitlements from Zone 1 (Sta 30). Transco will allow the remaining portion (41,210 Dth/day) to be turned back as early as October 2020. After the turnbacks, the Companies will still be able to reliably fill 100 percent of the original contract volumes at downstream points. The option to reduce capacity paths is not one typically offered by the pipelines, so, when the opportunities occur, the Companies will seek to take full advantage of such de-contracting providing such options do not have an adverse effect on the reliability and economics of the portfolio.

Q. Does the Companies' supply purchasing strategy enable them to benefit from the increased production from the Marcellus and Utica shale regions?

A. Yes. KEDNY and KEDLI purchased approximately 75.6 Bcf from the Northeast producing region during the 2017/18 winter. In addition, KEDNY and KEDLI purchased approximately 17.0 Bcf from the Gulf Coast and 3.7 Bcf from Canadian transportation paths.

The table below shows the Companies' actual purchases from November 2017 through March 2018. Over the last several years, the Companies have decreased reliance on Gulf Coast and Canadian resources, while increasing reliance on points associated with Marcellus shale.

Firm Transportation	
Gulf Coast	11.0%
Canadian	2.0%
Marcellus Shale	50.0%
Total Firm Transportation	**64.0%**
Storage Withdrawals	34.0%
Peaking Supplies	1.6%
Local LNG Vapor	0.4%
Total	**100.0%**

For the Historic Test Year, the Companies met their city gate requirements as follows:

96.4%	Domestic purchases and underground storage
3.4%	Canadian purchases at Dawn and Waddington
<1%	LNG and Landfill

Based on current and forecast prices, the Companies expect continued reliance on domestic supply purchases and underground storage going forward.

Q. Do the Companies engage in off-system sales, capacity release and other arrangements to reduce their total gas costs?

A. Yes. The Companies constantly monitor their gas resource portfolio to ensure that the appropriate mix of pipeline transportation capacity, market area storage, bundled city gate supply, and peaking resources are available to serve projected firm design requirements. To further minimize costs, the Companies seek to optimize portfolio assets when they are not being utilized for the benefit of firm customers. Except for Gulf Coast storage, for the Rate Year and beyond, the Companies have no plans to enter any pre-arranged off-system sales, capacity release, or streaming arrangements that would encumber upstream assets. As in years past, once the winter heating season begins, the Companies will actively pursue opportunities to sell available supply and/or capacity in a manner that does not diminish overall supply adequacy, reliability or operational flexibility to firm customers. For example, on warm days in shoulder months when pipeline capacity is not fully utilized, the Companies will seek to sell excess capacity to off-system customers. Under this type of transaction, the Companies will purchase supply and transport gas on available pipeline capacity and then assess the associated variable costs plus a negotiated margin to the off-system customers. The Companies will also look for opportunities to execute physical pipeline trades where available. Under such trades, the Companies would purchase firm supply delivered to the city gate on one interstate pipeline and sell a like amount of supply to another third party at a higher price on a different interstate pipeline.

The Companies hold approximately 20 Bcf of production area storage that is used to:

1. maintain supply reliability during force majeure supply outages in the Gulf coast;
2. balance on-system loads;
3. support the Companies' Price Volatility Management Program; and
4. make off-system production area sales.

KEDNY and KEDLI used approximately 15.4 Bcf of that capacity for production area off-system sales for the 2018/19 winter. The amount of Gulf Coast storage capacity released to marketers under the retail access program for 2018/19 was 12,920 Dth. At this time, the Companies do not propose to modify their OSS practices.

Q. Do the Companies enter into asset management agreements ("AMAs") to maximize the value of their supply portfolio and reduce their overall supply costs?

A. Yes. The Companies currently have eight AMAs in place for the 2018/19 period. These arrangements permit the Companies to benefit from the expertise of third-parties who are more familiar with market conditions and opportunities in particular regions or on particular pipeline systems while still maintaining access to essential firm supply sources. The terms of these arrangements do not exceed one year. The Companies will explore beneficial opportunities to enter asset optimization agreements in the future as current agreements expire.

Below are the list of current AMAs and a summary of the terms:

KEDNY:

- Counterparty: Nextera Energy Marketing, LLC
  - Key terms: Baseload or Daily Call (April 2019-October 2019); Transco Contract 1006500; Transco Z2/Z3 Gulf to Transco Z6 Leidy NNY; November 2018-October 2019; 10,688 Dth/day;
- Counterparty: J. Aron & Company LLC
  - Key terms: Daily Call (November 2018-March 2019); Transco Long-Haul Station 65 to Transco Z6 Narrows NY; November 2018-October 2019; 25,000 Dth/day;
- Counterparty: EQT Energy, LLC ("EQT")
  - Key terms: Daily Call (November 2018-March 2019); Transco Long-Haul Station 65 to Transco Z6 Narrows NY; November 2018-October 2019; 25,000 Dth/day; and
- Counterparty: Emera Energy Services, Inc. ("Emera")
  - Key terms: Daily Call (December 2018- April 2019); Union Dawn to Iroquois S. Commack; December 2018-October 2019; 57,498 Dth/day.

KEDLI:

- Counterparty: EQT
  - Key terms: Daily Call (November 2018-March 2019); Transco Long-Haul Station 65 to Transco Z6 Long Beach NY; November 2018-October 2019; 25,000 Dth/day;

- Counterparty: Emera
    - Key terms: Daily Call (December 2018- April 2019); Union Dawn to TransCanada Waddington; December 2017-October 2018; 25,357 Dth/day;
- Counterparty: Emera
    - Key terms: November Daily Call; Base-Load Winter Supplies (December 2018-March 2019); Off-Peak Season Daily Call on any 60 days during April 2019-October 2019; Additional Call on any Day during the Term; NE07 capacity; Millennium Corning to Iroquois S. Commack; November 2018-October 2019; 25,000 Dth/day; and
- Counterparty: Consolidated Edison Energy, Inc.
    - Key terms: November Daily Call; Base-Load Winter Supplies December 2018-March 2019; Off-Peak Season Daily Call on any 60 days during the period April 2019-October 2019; Additional Call on any Day during the Term; NE07 capacity; Millennium Corning to Iroquois S. Commack; November 2018-October 2019; 50,000 Dth/day.

The Companies regularly evaluate the contracts in their supply portfolio, taking into account market interest in the asset, whether the resource is utilized by the Companies to meet baseload or swing requirements on a seasonal or year-round basis, intraday flexibility of the asset, and whether the Companies believe the resource may be better managed by a third party. At this time, the Companies determined that the existing AMAs are in the best interest of the firm gas customer but will consider additional opportunities in future years based on market conditions.

Q. Do the Companies have existing or previous gas supply arrangements with any affiliated marketing/trading organizations?

A. No.

Q. What are the revenues received over the last five fiscal years (April 2014 – January 2019) from releases to shippers other than on-system customers that have migrated from bundled sales to transportation service?

A. Exhibit __ (EDA-10) summarizes the revenues received from non-migration capacity releases. Over the five-year period (April 2014 – January 2019), the revenues received from such capacity releases totaled $37.5 million, of which $31.9 million (85 percent) was credited to customers and the remaining $5.6 (15 percent) was retained by the Companies.

Q. What are the revenues received over the last five fiscal years (April 2014 – January 2019) from OSS transactions, WSS transactions, and AMAs?

A. Exhibit __ (EDA-11) summarizes the revenues received from revenues received from off-system sales transactions. Over the five-year period (April 2014 – January 2019), the revenues received from off-system sales transactions, WSS transactions and AMAs totaled $284.2 million, of which $241.7 million (85 percent) was credited to customers and the remaining $42.5 million (15 percent) was retained by the Companies.

Q. Please describe Exhibit __ (EDA-5) – Purchased Gas Expense.

A. Exhibit __ (EDA-5) shows the Companies' purchased gas expense for the Historic Test Year. This expense includes the purchased cost of gas minus the cost of storage injections plus the cost of storage withdrawals, and all pipeline fixed and variable charges.

Q. Please describe Exhibit __ (EDA-6) – Forecast of Variable Gas Expense TME March 31, 2021, 2022, 2023 and 2024.

A. Exhibit __ (EDA-6) shows the projected commodity prices of the various natural gas supplies that are forecast to be purchased and delivered to the Companies for the Rate Year and the Data Years to serve the estimated requirements of the Companies' firm customers under the assumption of normal weather. This commodity price projection serves as the basis for the forecast of purchased gas expense developed for these periods. A least cost dispatch analysis was performed to determine the mix of flowing supplies and storage withdrawals that would be dispatched to the city gate each month to serve estimated normal firm customer demand.

Q. Please describe Exhibit __ (EDA-7) – Forecast of Purchased Gas Expense TME March 31, 2021, 2022, 2023 and 2024.

A. Exhibit __ (EDA-7) shows a forecast of purchased gas expense for the Rate Year and Data Years. This expense includes the purchased cost of gas minus the cost of storage injections plus the cost of storage withdrawals, and all pipeline fixed and variable charges. The forecast assumes the NESE project is available by the 2020/21 winter season. If it is not, the Companies will update the forecast in corrections and updates.

Q. How do the Companies review and monitor the costs associated with their pipeline capacity?

A. The Companies closely monitors and reviews all rate and tariff filings submitted to the Federal Energy Regulatory Commission ("FERC") by the interstate natural gas pipelines with whom the Companies contract for service. The Companies will intervene, and when necessary, actively participate in such proceedings to ensure the Companies continue to pay fair rates and receive just and reasonable service. In interstate pipeline base rate proceedings, the Companies often participate with other local distribution company customers in a shipper group, which will retain an expert witness to advance commonly-held positions and enhance the Companies' influence. The Companies also regularly engage in settlement discussions with gas pipelines and FERC Staff to settle tariff-related matters without the need for a formal and costly hearing process. More broadly, the Companies monitor all natural gas related activity at FERC to stay abreast of and influence policy developments that could impact the Companies and their customers. The Companies track FERC orders, attend technical conferences convened by FERC to address major policy issues, and submit comments in response to notices of proposed rulemaking and notices of inquiry issued by FERC on policy matters impacting wholesale gas markets.

V. Marginal Cost Studies

Q. Please describe Exhibit __ (EDA-8) – Estimated Marginal Commodity Cost of Gas For Period: November 1, 2020 through March 31, 2021.

A. Exhibit __ (EDA-8) shows the projected marginal gas commodity costs for the period November 1, 2020 to March 31, 2021. By running two dispatch simulations, the marginal gas supply sources that would be dispatched to serve an incremental increase in customer demand were identified. First, a baseline dispatch on the simulation model was prepared to establish the least-cost mix of gas supplies that would be dispatched to serve firm sales customer demand under normal weather. Then, the simulation model was rerun with an increased customer demand of 1,000 Dth per day over the winter months (November through March) to identify those marginal supplies that would be dispatched to serve the increased demand. The exhibit reflects the average monthly commodity cost of the marginal supplies that were dispatched.

Q. Please describe Exhibit __ (EDA-9) – Estimated Annualized Marginal Capacity Cost of Gas for Period November 1, 2020 through March 31, 2021.

A. Exhibit __ (EDA-9) shows the projected annualized marginal gas capacity cost for the period November 1, 2020 to March 31, 2021. This study incorporates the fixed costs of new capacity that the Companies would acquire for the Rate Year to reliably meet projected design demand growth. Based on this calculation, the annualized marginal capacity cost was determined to be $1.12 per dekatherm, as set forth on Exhibit __ (EDA-9).

VI. Customer Choice Program

Q. Describe the Companies' Customer Choice Program.

A. The Companies' Customer Choice Program provides customers the option to purchase their supplies from Marketers. There are two service options, Daily and Monthly Balancing. The Companies currently assign to Marketers at maximum rates such interstate pipeline transportation and storage capacity as is necessary to meet migrating firm customers' load. This practice is consistent with the Commission's August 30, 2007 Order in Case 07-G-0299. City gate pipeline and storage capacity contracted for core customers is assigned to Retail Marketers for migrating customers in proportion to the anticipated design day load of the customers. All migrating firm customers are required to participate in the Companies' mandatory assignment program.

Q. What service classes are available to transportation customers?

A. For KEDNY, transportation customers can receive service under Service Classification (“SC”) 17 Firm and SC-18 Non-firm. For KEDLI, transportation service is available under SC-5 Firm, SC-7 Non-Firm, and SC-13 Non-Firm.

Q. How are transportation customer imbalances tracked and reconciled?

A. When an ESCO customer’s meter is read, the customer’s account transaction is sent from the customer system to the Companies’ Gas Transportation Information System (“GTIS”). GTIS then compares the ESCO’s expected deliveries, adjusted for actual weather for the billing period, to the customer’s actual usage for that same period. The usage is prorated into the applicable calendar month based on actual degree days. Thereafter, a cash-out index price is applied to the difference between the ESCO’s deliveries and customer usage. Cancel and rebill activity will be captured in the month in which the cancel or the rebill occurred as far back as three years. There have been no imbalance penalties assessed to a customer in the last three years.

Q. Were there any problems or issues arising from implementation of the Commission's August 30, 2007 and March 28, 2008 Mandatory Capacity Release Orders (in Case 07-G-0299) and FERC Order 712?

A. The Companies have not experienced any issues from implementation of the Commission’s Mandatory Release orders. The Companies no longer have any ESCO capacity that is grandfathered to the city gate.

Q. What are the pipelines and allocation percentages being utilized for the mandatory assignment of capacity?

A. The table below provides a list of the pipelines being utilized for mandatory assignment of capacity, and the allocated percentage of each, for Winter 2018-2019.

Transco Long Haul	29.7%
Transco Leidy	4.4%
Transco Leidy Seasonal	2.5%
Transco Rockaway	17%
Tetco Long Haul	7.1%
Tetco Leidy Short Haul	5.6%
Dominion Leidy	7.0%
Tennessee	2.6%
Northeast 07	15.1%
Dawn to Iroquois	9.0%

Q. What process, if any, is utilized to true-up any differences between the Companies' weighted average cost of capacity ("WACOC") and the charges paid by marketers and direct customers for released capacity?

A. For the 2017/2018 winter season (November 2017 through October 2018), the Companies' WACOC was between $0.8872 and $0.9006 per Dth. There is no true-up and/or reconciliation process in place to account for any differences in cost.

Q. Did the Companies implement any changes to their Customer Choice Programs as a result of the non-firm service collaborative in the 2016 KEDNY Rate Case?

A. Yes. In accordance with the "Order Approving Tariff Provisions and Directing Further Tariff Filings" issued February 7, 2019 following the non-firm service collaborative in the 2016 KEDNY Rate Case, the Companies modified their Customer Choice Programs to address concerns raised by ESCOs that participated in the collaborative.

First, the Companies modified their procedures for accepting month-ahead and day-ahead nominations to allow ESCOs more flexibility with the delivery points. Whereas ESCOs were previously required to deliver 100 percent of their supplies on Transco, they are now permitted to deliver gas supply on behalf of their temperature controlled ("TC") and interruptible ("IT") customers up to the following percentage of their TC and IT customers' total requirements:

- Transco – up to 100 percent
- Texas Eastern – up to 50 percent
- Iroquois – up to 50 percent
- Tennessee – up to 6 percent

These modifications do not apply to power generation customers who have negotiated points of receipt in their gas transportation agreements.

Second, the Companies modified their operating procedures to allow ESCOs serving non-firm loads and power generation customers to request access to any available city gate capacity on an intra-day basis. To request access to such capacity, ESCOs must notify the Companies by phone or email between 8:30 A.M. and 10:00 A.M. prior to the start of the effective Gas Day. Between 10:00 A.M. and 11:00 A.M., the Companies will allocate available capacity on a pro rata basis to each requesting ESCO and notify the ESCOs of the capacity they have received. If there is any remaining capacity after allocation, it will be made available on a first-come, first-served basis after 11:00 A.M.

Both changes to the Companies' Customer Choice Programs have been reflected in the latest version of the GTOPs.

Q. Did the Companies modify the TC/IT penalties as suggested in the non-firm service collaborative in Cases 16-G-0058 and 16-G-0059?

A. Yes. The Companies submitted revised tariff leaves for changing the current penalties from:

- the *higher* of (i) two times the sum of the market gas price plus the applicable IT or TC transportation rate; or (ii) nine times the applicable IT or TC sales rate, to
- the *lower* of (i) two times the sum of the market gas rate plus the applicable or IT or TC transportation rate; or (ii) nine times the applicable IT or TC sales rate

This modified TC/IT penalty language provides a strong incentive for customers to switch to their alternate fuel at the designated temperature thresholds.

Q. Are the Companies proposing to make any further changes to their Customer Choice Programs?

A. No.

VII. <u>Gas Cost Volatility Management</u>

Q. What steps do the Companies take to mitigate the impact of gas cost volatility on their customers?

A. The Companies mitigate volatility in the gas commodity markets in several ways. First, they maintain a balanced portfolio that includes contract storage. This allows the Companies to inject gas during the summer for withdrawal during the winter, which enables the Companies to mitigate price volatility during the winter when demand is greatest. Second, the Companies maintain a geographically diverse gas supply portfolio that helps to reduce exposure to volatility in any single supply region. Third, the portfolio incorporates pricing diversity that minimizes exposure to volatility at a single pricing point or market index. Finally, the Companies mitigate price volatility with a formal hedging program.

Q. Please describe the Companies' hedging program.

A. The Companies' overall pricing diversity and volatility mitigation plan is to protect prices for approximately 50 percent, but no more than 60 percent, of forecast winter firm sales and to allow prices to float with the market for the remaining forecast winter sales. For this purpose, the "winter period" is defined as November through March. Prices are fixed through a combination of planned storage withdrawals, which provide a natural hedge at the average price of summer period injections, and financial hedging using NYMEX gas futures contracts or NYMEX Over the Counter ("OTC") financial settled swaps and options using bilateral master agreements. Beginning in the 2015-2016 winter, the Companies are also using basis hedges for forecast purchases in the Northeast producing region. Locational basis swaps in conjunction with NYMEX hedges are being used because of an observed disconnect between prices in the Marcellus and Utica supply basins and NYMEX prices. The use of these locational basis swaps ensures that the Companies are mitigating volatility in the markets where they purchase supplies.

To determine the quantity to be hedged, the Companies forecast firm sales for each month November through March, assuming normal winter weather conditions, and multiply the results by 50 percent (Step 1). Next, monthly storage withdrawals to meet system operational needs are forecast and subtracted from the result obtained in Step 1 (Step 2). The results from Step 2 equal the quantity of gas to be financially hedged to achieve the 50 percent target in each month.

Once the volume of gas to be financially hedged each month is known, a monthly hedging plan is created. The purchases are spread evenly over 16 months starting

18 months prior to the start of each November. Each financial transaction is settled against the expiring month's last day settlement price and the applicable Inside FERC "First of the Month" index price. The gross settlement payout or gain is included in the gas cost for that month.

The table below summarizes the percentage of forecasted gas supply hedged physically and financially for November 2017-March 2018:

Pricing Mechanism	Downstate NY
Physical (storage)	30%
Financial (swaps and options)	19%
Index	51%

The table below itemizes the number of financial swap (futures) and option contracts hedged for the November 2017 through March 2018 winter season. The units for the data below are in contracts; one contract equals 10,000 Dth.

Pricing Mechanism	Quantity
Swaps	1,815
Options	750

Q. Have the Companies' hedging practices changed in the past year?

A. Yes. The derivatives market at Dominion South Point has developed with enough liquidity so that the Companies can adequately acquire financially settled Dominion South Point options. The Companies have incorporated these options in the winter 2018-19 hedge portfolio. The Companies continue to monitor the effectiveness of NYMEX and South Point for all receipt points in the forecast to determine the most appropriate hedging location.

Lower market volatility and market prices have translated to lower option premiums. Options provide superior downside protection versus swaps. As a result, "lessons learned" include favoring up to 100 percent of options for the financial hedge component of the portfolios for the next winter

Q. **Please explain how the Companies calculate gas price volatility**.

A. Gas price volatility is measured as the standard deviation of the lognormal of the ratio of the monthly hedged price change through the winter, November through March. This standard deviation is compared against a similar calculation for the NYMEX and South Point Natural Gas monthly settlement prices for the same November through March period.

Q. **Discuss how the Companies determine the success or failure of their gas price mitigation program**.

A. The success or failure of the gas price mitigation program is determined by comparing the physical and financial hedged prices with natural gas market price indices over the same period. The hedge program is expected to show lower month-to-month price volatility than that of the market index.

Q. Please discuss internal reporting, oversight, and the audit structure of the Companies' gas price mitigation program.

A. The Companies' hedging program reporting and oversight is documented in the US Energy Commodity Risk Management Policy. National Grid's US based energy procurement activities are managed under the direction of National Grid plc's Finance Committee. The Finance Committee authorized the Energy Procurement Risk Management Committee ("EPRMC") and delegated authority to focus on energy risk, metrics, energy strategies, financial impacts and other opportunities to the EPRMC. The EPRMC provides Vice President level review of strategies, with a focus on market risks, inclusive of price, credit, operational, liquidity and reputational risks and Policy compliance. The EPRMC serves to administer a consistent and comprehensive sanctioning process for such strategies and commitments across the organization. The EPRMC has delegated some of its authority to the Commodity Management Committee ("CMC"). The EPRMC appoints the CMC members and chairperson. The CMC provides detailed review of strategies, products and new opportunities with a focus on energy risk, metrics, financial impacts and opportunities. The CMC conducts research to understand market rules, regulatory requirements, customer needs, risks, barriers to entry, logistical requirements, competition, deal economics, risk measurement and valuation requirements, all related requirements and exposures (including credit, liquidity, tax and legal), and the impact of current and proposed strategies on existing controls and limits, while administering a consistent and comprehensive sanctioning process for such strategies and commitments across the organization.

The Companies review the hedging program and highlights any changes with the Commission on an annual basis. The Companies have a comprehensive internal approval process to authorize a hedge strategy and maintain oversight requirements. Prior to execution, a hedging strategy is documented with details that may include: risks to be hedged, volumetric targets, duration and cadence of hedge plan transactions, and types of instruments to be used. This documentation is then reviewed and approved by the CMC prior to going to the EPRMC for approval and authorization.

The Companies employs the industry standard best practice of an independent three-office model:

- The Front Office develops and executes the hedge strategies hedges in accordance with the prevailing policies and strategies by entering into transactions with counterparties to mitigate natural gas price volatility.
- Risk Management is part of the Middle Office and maintains the overall control environment and assesses compliance with the Companies' risk policy. The Middle Office reports through the Treasury organization and provides a significant level of control and independent policing of the Front Office's activities. The Middle Office confirms all trades with counterparties and monitors the risk exposures of the deals, as well as verifying approved strategies are executed in accordance with the plan.
- The Accounting Department is part of the Back Office whose functions include processes in support of the Front Office, such as accounting,

invoicing, check-outs, actualization, accounts receivable and payable, and financial reporting. The Back Office is also independent of both the Front and Middle Offices and reports up through the Finance organization.

Additionally, the Companies' internal auditing department has performed audits to ensure compliance, for example, with Sarbanes-Oxley.

Q. Please provide the actual price hedging performance versus planned price hedging performance for the last winter season.

A. A comparison of actual price hedging performance versus planned price hedging performance for winter 2017/2018, which includes separate quantities for each hedging instrument, is shown in the tables below:

Winter 2017-18 Purchasing Plan & Projected Prices

notes	Percent Hedged	Portfolio	Amount	Price
		Physical Hedges		
1	32%	Market Area Storage	38,619,000	$ 2.14
1	1%	Gulf Coast Storage	1,500,000	$ 2.14
		Fixed Price Contracts		
		Financial Hedges *		
	6%	NYMEX Correlated Futures or Swaps	7,860,000	$ 3.26
2	8%	Dom. SP Correlated Futures or Swaps	10,290,000	$ 2.80
2	0%	Collars		
2	6%	Calls	7,500,000	$ 2.73
		Puts		
		Flowing or Floating Price Gas		
	46%	NYMEX/Dom SP (18%/82%)	55,707,000	$ 2.52
		Spot/Daily Price		
	100%	**TOTAL**	121,476,000	

Winter 2017-18 Actual Purchases & Prices

notes	Percent Hedged	Portfolio	Amount	Price
		Physical Hedges		
	32%	Market Area Storage	41,587,000	$ 2.02
	1%	Gulf Coast Storage	1,500,000	$ 2.02
		Fixed Price Contracts		
		Financial Hedges *		
3	5%	NYMEX Futures or Swaps	6,700,000	$ 3.25
2,3	9%	Dom. SP Correlated Futures or Swaps	11,450,000	$ 2.81
2,3	0%	Collars	0	$ -
2,3	6%	Calls	7,500,000	$ 2.64
		Puts		
		Flowing or Floating Price Gas		
3	1%	Monthly Index	746,000	$ 2.46
3	**20%**	**Subtotal Monthly/Baseload**	**26,396,000**	**$ 2.86**
	44.0%	Spot (non-peaking)	57,855,000	**$ 4.10**
	2%	Peaking	2,500,000	**$ 22.40**
	46%	**Subtotal Spot/Daily Price**	60,355,000	$ 4.86
	100%	**TOTAL**	129,838,000	$ 3.51

note 1 In the ground volumes and WACOG
note 2 Financial hedges settled against Domionion SP index.
note 3 Represents total Baseload, financial and physical

Q. What percentage of the Companies' gas supply is physically hedged?

A. As a result of planned storage withdrawals, which are based on normal weather, approximately 30 percent of the forecasted November through March firm sales demand is physically hedged. The Companies do not hedge storage injections. The Companies do not have any physical supply contracts with fixed price terms.

Q. How do the Companies use swaps/futures?

A. The Companies use OTC swaps to execute fixed price hedged transactions. OTC swaps do not have any execution, transaction or commission fees. The Companies rely on credit thresholds in their bilateral master agreements to limit the amount and frequency of margin calls associated with the daily mark-to-market valuation of each hedge transaction. When the mark-to-market with each OTC counterparty exceeds the credit threshold, the Companies use their various credit facilities to meet the cash collateral margin calls.

Q. What types of options do the Companies use?

A. The Companies use calls, puts, and collars.

Q. Describe how the Companies decide which types of options to use.

A. When the underlying futures price is expected to fall, then call options are preferred over swaps. Collars may be purchased instead to reduce the premiums paid or when the underlying futures prices are expected to be stable.

Q. Do the Companies place a limit on what they spend on options in any year?

A. The Companies cap their option premiums at $13 million per year.

VIII. <u>Conclusion</u>

Q. Does this conclude your testimony?

A. Yes, it does.

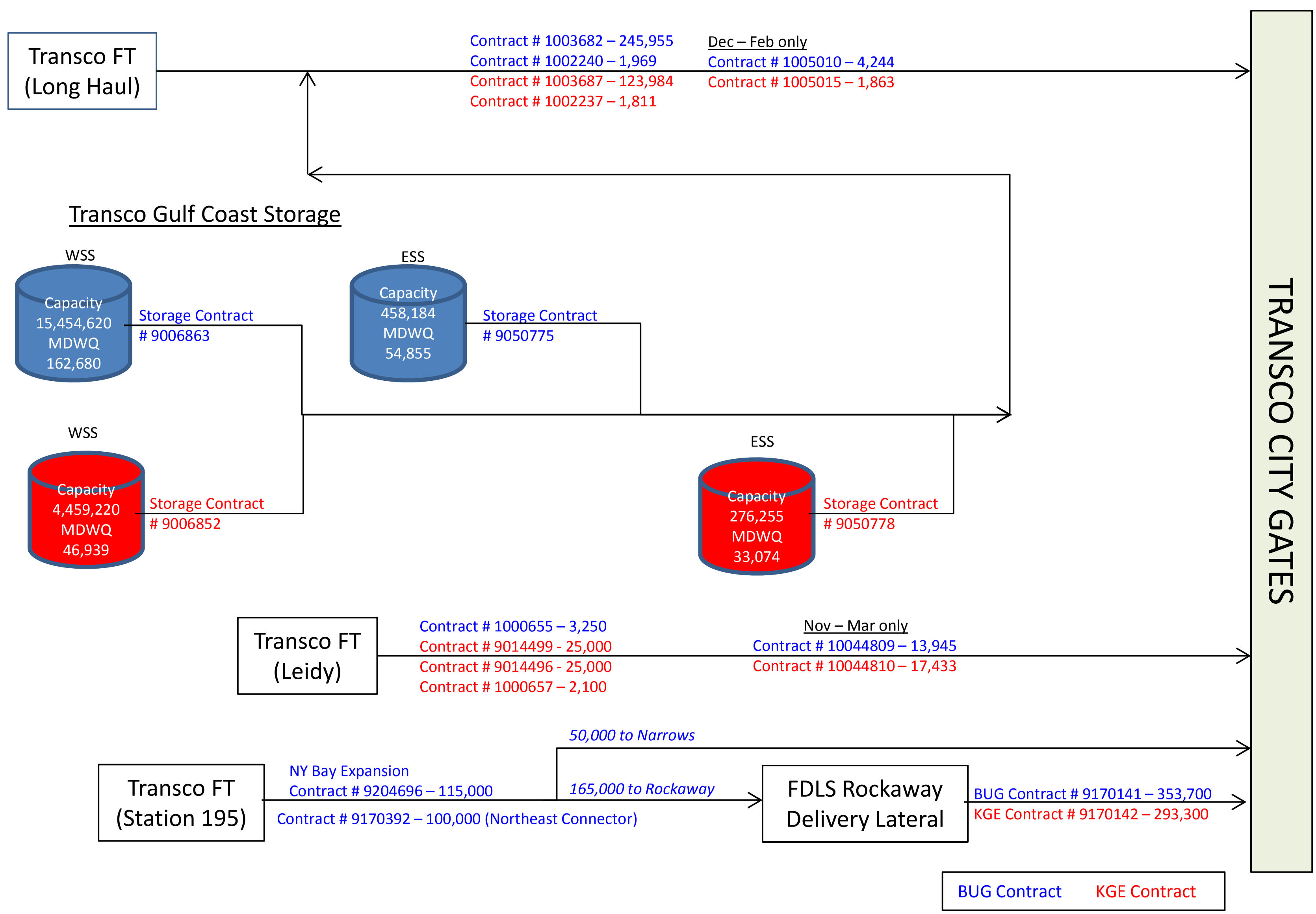
Testimony of Elizabeth D. Arangio

Index of Exhibits

Exhibit __ (EDA-1)

KEDNY & KEDLI Portfolio Schematics

Brooklyn Union Gas & KeySpan Gas East
Combined Flow Diagram



Exhibit_(EDA-1)
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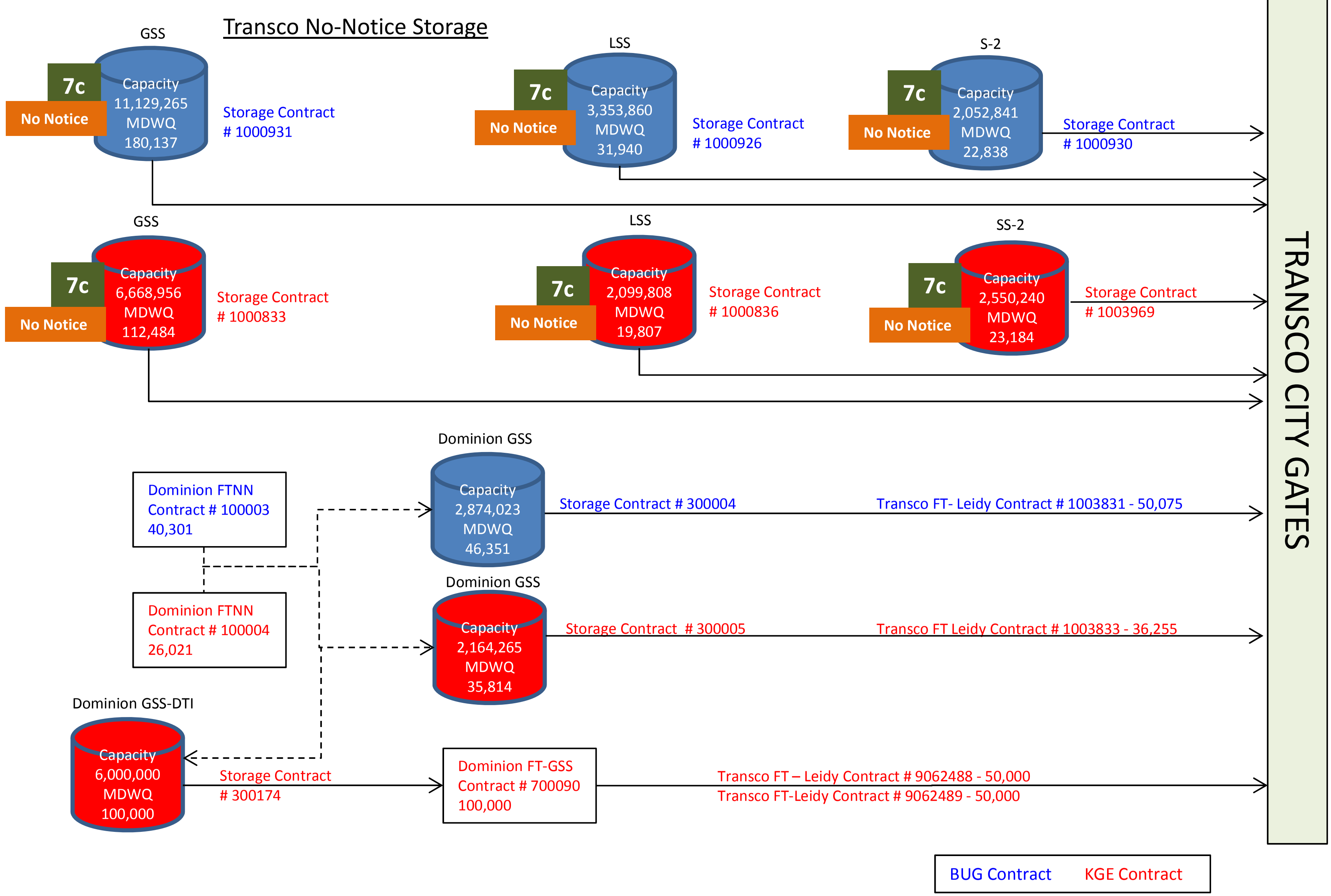
Brooklyn Union Gas & KeySpan Gas East
Combined Flow Diagram



Exhibit_(EDA-1)
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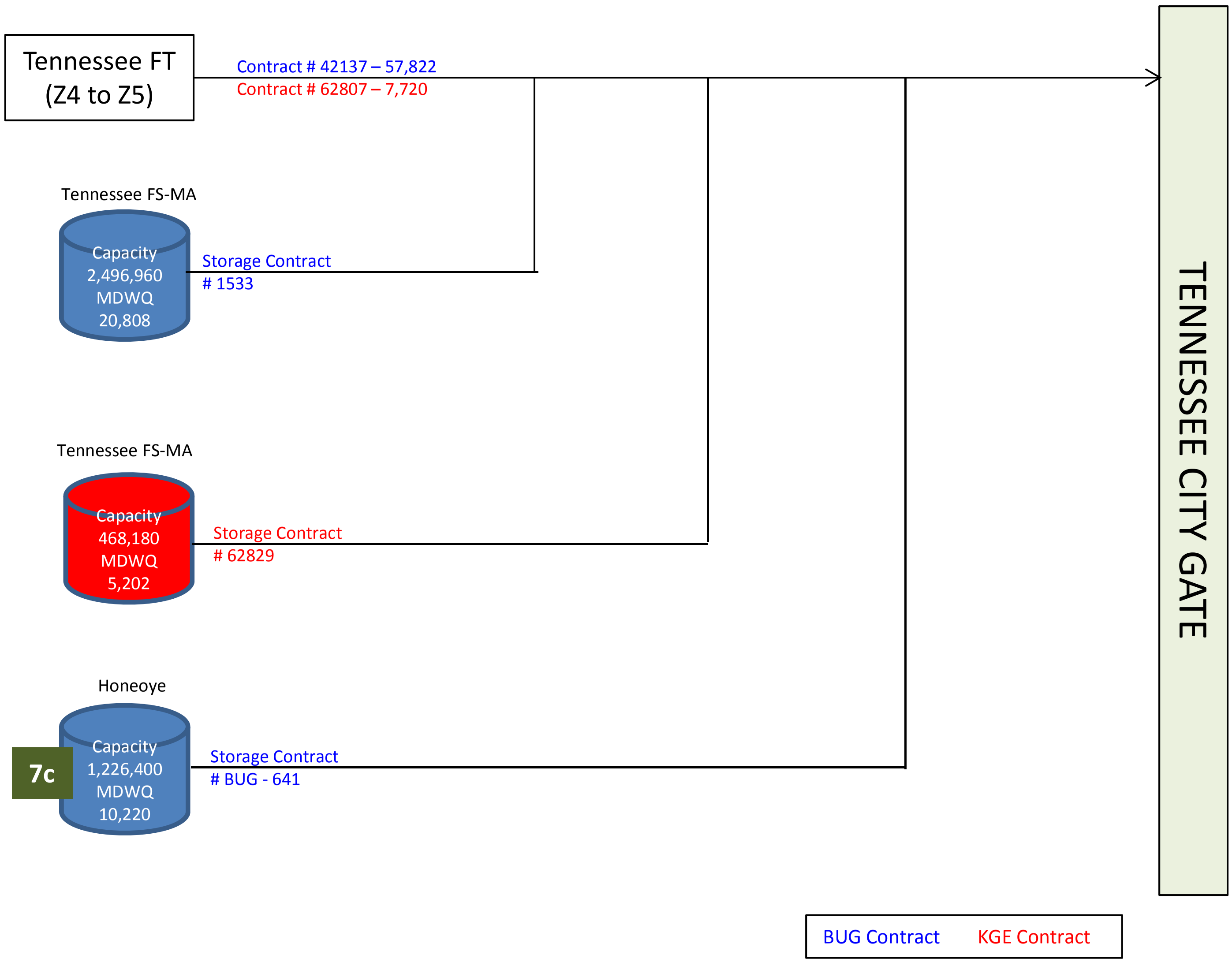
Brooklyn Union Gas & KeySpan Gas East Combined Flow Diagram



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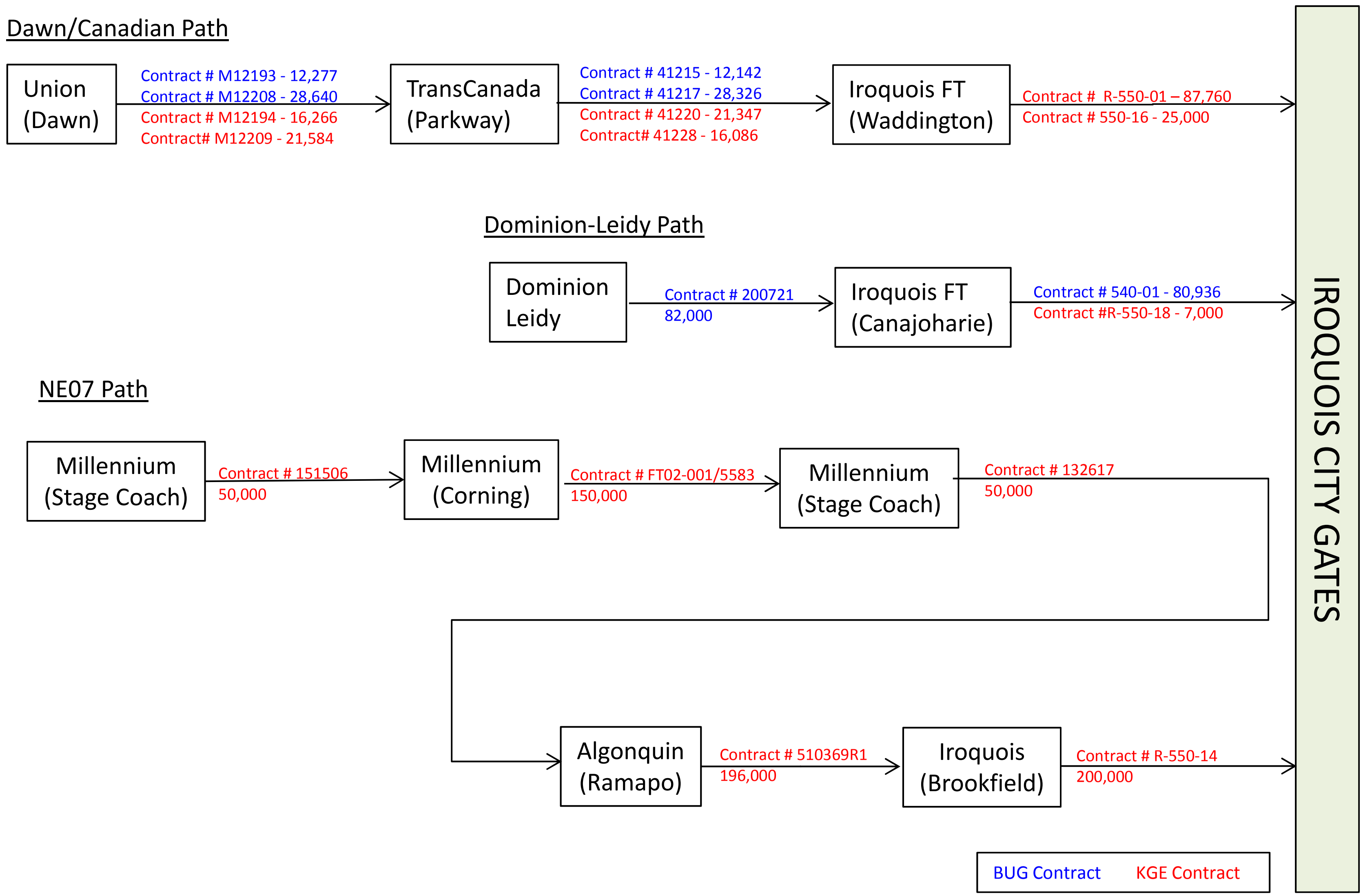
Brooklyn Union Gas & KeySpan Gas East
Combined Flow Diagram



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Brooklyn Union Gas & KeySpan Gas East
Combined Flow Diagram

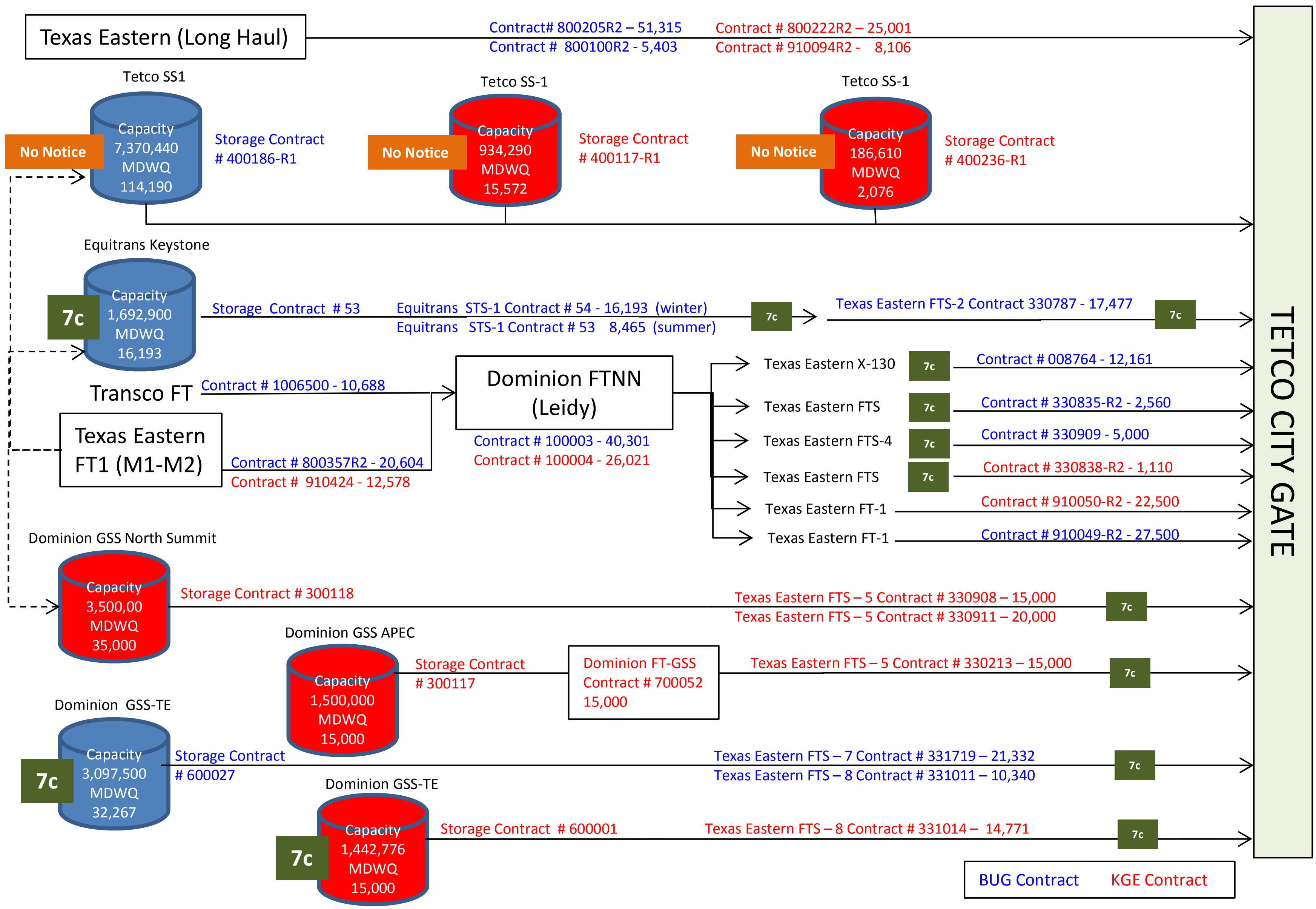

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Exhibit __ (EDA-2)

KEDNY & KEDLI Pipeline Transportation Contracts

KEDNY Pipeline Transportation Contracts

Pipeline Company Name	Rate Schedule	Daily Quanity (DT)	Expiration Date
Flowing Gas To Citygate			
Transco Year-Round	FT	245,955	5/31/2020
Transco Year-Round	FT	1,969	3/19/2020
Transco Seasonal - 90 Day	FT	4,244	7/31/2020
Texas Eastern	CDS	51,315	10/31/2020
Texas Eastern	CDS	5,403	10/31/2020
Tennessee	FT-A	57,822	5/31/2022
Iroquois	RTS	80,936	11/1/2022
~~Transco* 1/~~	~~FT (X-265)~~	~~3,500~~	~~1/1/2014~~
Transco	FT (X-266)	3,250	12/31/2020
Texas Eastern	FTS	2,560	10/31/2020
Texas Eastern *	FT-1	27,500	3/31/2023
Texas Eastern	FTS-4-2	5,000	12/1/2019
Texas Eastern	X-130	12,161	10/31/2019
Transco (avail Nov - Mar)	FT	13,945	3/31/2013
Transco	FDLS	353,700	5/14/2030
Upstream Pipeline Support [1]			
First Leg			
Transco	FT	10,688	10/31/2019
Texas Eastern	FT-1	20,604	10/31/2024
Dominion	FTNN	40,301	3/31/2023
Dominion - New Market Project 5/	FT	82,000	10/31/2031
TransCanada (Dawn to Wad)	FT	12,142	10/31/2022
TransCanada (Dawn to Wad)	FT	28,326	10/31/2022
Union (Dawn to Parkway)	M12	28,640	10/31/2020
Union (Dawn to Parkway)	M12	12,277	10/31/2020
Equitrans Keystone SS-3 Storage, Winter 2/	STS-1	16,193	4/1/2020
Equitrans Keystone SS-3 Storage, Summer 2/	STS-1	8,465	4/1/2020
Transco	FT	100,000	5/14/2030
Transco	FT	115,000	11/1/2032
Deliveries from Storage			
Dominion GSS Storage 1/	FT (X-285)	50,075	12/13/2019
Transco GSS Market Area Storage 3/	GSS	180,137	3/31/2023
Transco LSS Market Area Storage 3/	LSS	31,940	3/31/2023
Transco S-2 Market Area Storage 3/	S-2	22,838	4/15/2020
Equitrans Keystone SS-3 Storage	FTS-2	17,477	3/31/2020
Texas Eastern SS-1 Market Area Storage 3/	SS-1	114,190	4/30/2024
Dominion GSS-TE Storage	FTS-7	21,332	4/15/2020
Dominion GSS-TE Storage	FTS-8	10,340	3/31/2020
Winter Peaking Service			
Total (Flowing Gas to City Gate, Deliveries from Storage, and Winter Peaking Service)			
		1,178,889	

[1] Capacity used to deliver gas to pipelines that deliver to the citygate.

* Contract does NOT have renewal rights.

1/ Effective 10/1/2016, contract consolidation
2/ Transportation associated with Keystone Storage.
3/ Bundled Transportation and Storage contracts.

KEDLI Pipeline Transportation Contracts

Pipeline Company Name	Rate Schedule	Daily Quanity (DT)	Expiration Date
Flowing Gas To Citygate			
Transco Year-Round 2/	FT	154,287	5/31/2020
Transco Year-Round	FT	1,811	2/24/2020
Transco Seasonal - 90 Day	FT	1,863	7/31/2020
Texas Eastern	CDS	8,106	10/31/2019
Texas Eastern	CDS	25,001	10/31/2019
Tennessee	FT-A	7,720	5/31/2022
Iroquois	RTS	87,760	11/1/2021
Iroquois	RTS	25,000	11/1/2021
Iroquois NE07	RTS	200,000	11/1/2023
Transco	FT (X-271)	2,100	1/31/2019
Transco 3/	FT (X-287)	536	10/31/2019
Texas Eastern	FTS	1,110	10/31/2019
Texas Eastern *	FT-1	22,500	3/31/2023
Transco (avail Nov - Mar)	FT	17,433	3/31/2020
Transco Leidy East	FT	25,000	3/31/2020
Transco Market Link	FT	25,000	11/30/2019
Transco	FDLS	293,300	5/14/2030
Iroquois	RTS	7,000	11/1/2021
Upstream Pipeline Support [1]			
Texas Eastern	FT-1	12,578	10/31/2019
Dominion	FTNN	26,021	3/31/2023
TransCanada (Dawn to Wad)	FT	16,086	10/31/2024
TransCanada (Dawn to Wad)	FT	21,347	10/31/2024
Union (Dawn to Parkway)	M12	21,584	10/31/2020
Union (Dawn to Parkway)	M12	16,266	10/31/2020
Millennium	FT-1	150,000	12/31/2023
Millennium	FT-1	50,000	12/31/2023
Millennium	FT-1	50,000	12/31/2023
Algonquin	AFT-1	196,000	10/31/2023
Deliveries from Storage			
Dominion GSS Storage 3/	FT (X-287)	35,689	10/31/2007
Leidy to Long Island for Dominion DTI GSS	FT	50,000	12/12/2027
Leidy to Long Island for Dominion DTI GSS	FT	50,000	12/12/2027
Transco GSS Market Area Storage 4/	GSS	112,484	3/31/2023
Transco LSS Market Area Storage 4/	LSS	19,807	3/31/2023
Transco SS-2 Market Area Storage 4/	SS-2	23,184	3/31/2020
Texas Eastern SS-1 Market Area Storage 4/	SS-1	2,076	4/30/2020
Texas Eastern SS-1 Market Area Storage 4/	SS-1	15,572	4/30/2020
Dominion GSS N. Summit	FTS-5	20,000	3/31/2020
Dominion GSS N. Summit	FTS-5	15,000	3/31/2020
Dominion GSS Apec	FTS-5	15,000	3/31/2020
Dominion GSS-TE Storage	FTS-8	14,771	3/31/2020
GSS "Apec"	FT-GSS	15,000	3/31/2022
DTI GSS	FT-GSS	100,000	3/31/2022
Winter Peaking Service			
Total (Flowing Gas to City Gate, Deliveries from Storage, and Winter Peaking Service)			
		985,810	

[1] Capacity used to deliver gas to pipelines that deliver to the citygate.

* Contract does NOT have renewal rights.

1/ Capacity used to deliver gas to pipelines that deliver to the citygate.
2/ The actual max daily contract volume is 154,287 dt/day, 30,303 dt/day is released to the Brooklyn Navy Yard.
3/ MDQ is 36,225 dth/day
4/ Bundled Transportation and Storage contracts.

Exhibit __ (EDA-3)

KEDNY & KEDLI Storage Contracts

KEDNY Storage Contracts

Storage Company Name	Rate Schedule	MDWQ Dth/Day	Expiration Date
Market Area Storage			
Transco	GSS	180,137	3/31/2023
Transco	LSS (1)	31,940	3/31/2023
Transco	S-2	22,838	4/16/2020
Texas Eastern	SS-1	114,190	4/30/2024
Equitrans-Keystone	SS-3/STS-1	16,193	4/1/2020
Tennessee	FS-MA (5)	20,808	10/31/2019
Honeoye	SS-NY (7)	10,220	4/1/2020
Dominion	GSS (3)	46,351	3/31/2023
Dominion	GSS-TE (4)	32,267	3/31/2021
Total		**474,944**	
Gulf Coast Storage			
Transco	WSS (2)	162,680	8/31/2019
Transco	ESS (6)	54,855	4/11/2019
Total		**217,535**	

** Deliveries do not reflect fuel losses at the Citygate

(1) Extended term of LSS from March 31, 1994 to March 31, 2013 by amendment dated March 31, 2008.
(2) Quantity reduced to 162,680 from 181,819 by amendment dated 5/1/2011.
(3) Extended term of GSS to March 31, 2013 by amendment dated July 20, 2006.
(4) Extended term of GSS-TE from March 31, 2006 to March 31, 2013 by amendment dated July 20, 2006.
(5) Extended term of FS-MA to October 31, 2014 by amendment dated August 1, 2008.
(6) Contract volumes reduced to reflect the abandonment of ESS caverns 1-4
(7) The Company cannot withdraw maximum amount from Honeoye Storage due to transportation MDQ

KEDLI Storage Contracts

Storage Company Name	Rate Schedule	MDWQ Dth/Day	Expiration Date
Market Area Storage			
Transco	GSS	112,484	3/31/2023
Transco	LSS (1)	19,807	3/31/2023
Transco	SS-2	23,184	3/31/2028
Texas Eastern	SS-1	15,572	4/30/2024
Texas Eastern	SS-1	2,076	4/30/2020
Tennessee	FS-MA	5,202	10/31/2020
Dominion	GSS	35,814	3/31/2023
Dominion	GSS-TE (3)	15,000	3/31/2021
Dominion	GSS-N Summit	35,000	3/31/2022
Dominion	GSS-APEC	15,000	3/31/2022
Dominion	GSS	100,000	3/31/2022
Total		**379,139**	
Gulf Coast Storage			
Transco	WSS (2)	46,939	8/31/2020
Transco	ESS (4)	33,074	3/4/2019
Total		**80,013**	

** Deliveries do not reflect fuel losses at the Citygate

(1) Extended term of LSS from March 31, 1994 to March 31, 2013 by amendment dated March 31, 2008.
(2) Quantity reduced to 46,939 from 52,461 by amendment dated 5/1/2011.
(3) Extended term of GSS-TE from March 31, 2006 to March 31, 2011 by amendment dated August 20, 2004.
(4) Contract volumes reduced to reflect the abandonment of ESS caverns 1-4

Exhibit __ (EDA-4)

KEDNY/KEDLI Projected Monthly Gas Stored Volumes and Dollars for the Rate Year and Data Years Summarized by Market Area, Gulf Coast and LNG storage

KEDNY / KEDLI

Projected Gas Storage Inventory

Twelve Months Ended March 2021

Market Area	Forecast Apr-2020	Forecast May-2020	Forecast Jun-2020	Forecast Jul-2020	Forecast Aug-2020	Forecast Sep-2020	Forecast Oct-2020	Forecast Nov-2020	Forecast Dec-2020	Forecast Jan-2021	Forecast Feb-2021	Forecast Mar-2021
Dth												
Beginning Inventory	686,000	3,864,000	13,632,000	23,109,000	32,356,000	41,675,000	50,763,000	59,072,000	57,950,000	44,896,000	24,834,000	8,730,000
Injections	3,613,000	9,768,000	9,477,000	9,247,000	9,319,000	9,088,000	8,308,000	1,484,000	5,000	-	-	5,000
Withdrawals	435,000	-	-	-	-	-	-	2,605,000	13,059,000	20,062,000	16,104,000	7,963,000
EndingBalance	3,864,000	13,632,000	23,109,000	32,356,000	41,675,000	50,763,000	59,072,000	57,950,000	44,896,000	24,834,000	8,730,000	773,000
$												
Beginning Inventory	$ 1,691,000	$ 8,892,000	$ 29,119,000	$ 48,739,000	$ 67,490,000	$ 86,405,000	$ 103,414,000	$ 118,808,000	$ 116,746,000	$ 90,485,000	$ 49,992,000	$ 17,642,000
Injections	$ 8,172,000	$ 20,227,000	$ 19,620,000	$ 18,751,000	$ 18,915,000	$ 17,008,000	$ 15,395,000	$ 3,212,000	$ 12,000	$ -	$ -	$ 13,000
Withdrawals	$ 971,000	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,275,000	$ 26,273,000	$ 40,493,000	$ 32,350,000	$ 15,967,000
EndingBalance	$ 8,892,000	$ 29,119,000	$ 48,739,000	$ 67,490,000	$ 86,405,000	$ 103,414,000	$ 118,808,000	$ 116,746,000	$ 90,485,000	$ 49,992,000	$ 17,642,000	$ 1,688,000
Average Rate	$ 2.3012	$ 2.1361	$ 2.1091	$ 2.0859	$ 2.0733	$ 2.0372	$ 2.0112	$ 2.0146	$ 2.0154	$ 2.0130	$ 2.0208	$ 2.1837

Gulf Coast	Forecast Apr-2020	Forecast May-2020	Forecast Jun-2020	Forecast Jul-2020	Forecast Aug-2020	Forecast Sep-2020	Forecast Oct-2020	Forecast Nov-2020	Forecast Dec-2020	Forecast Jan-2021	Forecast Feb-2021	Forecast Mar-2021
Dth												
Beginning Inventory	2,553,000	2,767,000	3,397,000	3,611,000	3,616,000	3,616,000	3,831,000	4,053,000	4,053,000	4,053,000	4,053,000	4,053,000
Injections	214,000	629,000	214,000	5,000	-	214,000	222,000	-	-	-	-	-
Withdrawals	-	-	-	-	-	-	-	-	-	-	-	1,500,000
EndingBalance	2,767,000	3,397,000	3,611,000	3,616,000	3,616,000	3,831,000	4,053,000	4,053,000	4,053,000	4,053,000	4,053,000	2,553,000
$												
Beginning Inventory	$ 6,696,000	$ 7,239,000	$ 8,814,000	$ 9,353,000	$ 9,366,000	$ 9,366,000	$ 9,902,000	$ 10,457,000	$ 10,457,000	$ 10,457,000	$ 10,457,000	$ 10,457,000
Injections	$ 543,000	$ 1,576,000	$ 538,000	$ 13,000	$ -	$ 536,000	$ 555,000	$ -	$ -	$ -	$ -	$ -
Withdrawals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,870,000
EndingBalance	$ 7,239,000	$ 8,814,000	$ 9,353,000	$ 9,366,000	$ 9,366,000	$ 9,902,000	$ 10,457,000	$ 10,457,000	$ 10,457,000	$ 10,457,000	$ 10,457,000	$ 6,587,000
Average Rate	$ 2.6162	$ 2.5946	$ 2.5901	$ 2.5902	$ 2.5902	$ 2.5847	$ 2.5801	$ 2.5801	$ 2.5801	$ 2.5801	$ 2.5801	$ 2.5801

LNG	Forecast Apr-2020	Forecast May-2020	Forecast Jun-2020	Forecast Jul-2020	Forecast Aug-2020	Forecast Sep-2020	Forecast Oct-2020	Forecast Nov-2020	Forecast Dec-2020	Forecast Jan-2021	Forecast Feb-2021	Forecast Mar-2021
Dth												
Beginning Inventory	2,191,000	2,113,000	2,077,000	1,999,000	1,918,000	2,040,000	2,207,000	2,295,000	2,298,000	2,268,000	2,236,000	2,207,000
Injections	-	44,000	-	-	202,000	245,000	169,000	29,000	-	-	-	12,000
Withdrawals	78,000	80,000	78,000	80,000	80,000	78,000	80,000	26,000	30,000	32,000	29,000	27,000
EndingBalance	2,113,000	2,077,000	1,999,000	1,918,000	2,040,000	2,207,000	2,295,000	2,298,000	2,268,000	2,236,000	2,207,000	2,192,000
$												
Beginning Inventory	$ 4,671,000	$ 4,504,000	$ 4,418,000	$ 4,252,000	$ 4,081,000	$ 4,293,000	$ 4,555,000	$ 4,681,000	$ 4,686,000	$ 4,624,000	$ 4,559,000	$ 4,501,000
Injections	$ -	$ 85,000	$ -	$ -	$ 382,000	$ 424,000	$ 291,000	$ 59,000	$ -	$ -	$ -	$ 27,000
Withdrawals	$ 166,000	$ 172,000	$ 166,000	$ 171,000	$ 170,000	$ 162,000	$ 165,000	$ 53,000	$ 62,000	$ 65,000	$ 58,000	$ 55,000
EndingBalance	$ 4,504,000	$ 4,418,000	$ 4,252,000	$ 4,081,000	$ 4,293,000	$ 4,555,000	$ 4,681,000	$ 4,686,000	$ 4,624,000	$ 4,559,000	$ 4,501,000	$ 4,472,000
Average Rate	$ 2.1316	$ 2.1271	$ 2.1271	$ 2.1277	$ 2.1044	$ 2.0639	$ 2.0397	$ 2.0392	$ 2.0388	$ 2.0389	$ 2.0394	$ 2.0401

Exhibit_(EDA-4)
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KEDNY / KEDLI

Projected Gas Storage Inventory

Twelve Months Ended March 2022

Market Area	Forecast Apr-2021	Forecast May-2021	Forecast Jun-2021	Forecast Jul-2021	Forecast Aug-2021	Forecast Sep-2021	Forecast Oct-2021	Forecast Nov-2021	Forecast Dec-2021	Forecast Jan-2022	Forecast Feb-2022	Forecast Mar-2022
Dth												
Beginning Inventory	773,000	4,569,000	14,907,000	24,434,000	33,735,000	42,825,000	51,664,000	59,865,000	58,152,000	46,059,000	25,612,000	10,526,000
Injections	3,806,000	10,338,000	9,527,000	9,301,000	9,090,000	8,840,000	8,201,000	1,087,000	5,000	-	-	4,000
Withdrawals	10,000	-	-	-	-	-	-	2,800,000	12,098,000	20,447,000	15,086,000	9,533,000
EndingBalance	4,569,000	14,907,000	24,434,000	33,735,000	42,825,000	51,664,000	59,865,000	58,152,000	46,059,000	25,612,000	10,526,000	996,000
$												
Beginning Inventory	$ 1,688,000	$ 9,737,000	$ 29,920,000	$ 48,529,000	$ 66,074,000	$ 83,229,000	$ 98,406,000	$ 113,167,000	$ 110,059,000	$ 87,307,000	$ 48,556,000	$ 20,122,000
Injections	$ 8,069,000	$ 20,183,000	$ 18,609,000	$ 17,545,000	$ 17,155,000	$ 15,177,000	$ 14,761,000	$ 2,177,000	$ 11,000	$ -	$ -	$ 9,000
Withdrawals	$ 20,000	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,286,000	$ 22,763,000	$ 38,751,000	$ 28,433,000	$ 18,041,000
EndingBalance	$ 9,737,000	$ 29,920,000	$ 48,529,000	$ 66,074,000	$ 83,229,000	$ 98,406,000	$ 113,167,000	$ 110,059,000	$ 87,307,000	$ 48,556,000	$ 20,122,000	$ 2,090,000
Average Rate	$ 2.1311	$ 2.0071	$ 1.9861	$ 1.9586	$ 1.9435	$ 1.9047	$ 1.8904	$ 1.8926	$ 1.8955	$ 1.8958	$ 1.9116	$ 2.0984

Gulf Coast	Forecast Apr-2021	Forecast May-2021	Forecast Jun-2021	Forecast Jul-2021	Forecast Aug-2021	Forecast Sep-2021	Forecast Oct-2021	Forecast Nov-2021	Forecast Dec-2021	Forecast Jan-2022	Forecast Feb-2022	Forecast Mar-2022
Dth												
Beginning Inventory	2,553,000	2,767,000	3,397,000	3,616,000	3,838,000	3,838,000	4,053,000	4,053,000	4,053,000	4,053,000	4,053,000	4,053,000
Injections	214,000	629	220	222	-	214	-	-	-	-	-	-
Withdrawals	-	-	-	-	-	-	-	-	-	-	-	1,500
EndingBalance	2,767,000	3,397,000	3,616,000	3,838,000	3,838,000	4,053,000	4,053,000	4,053,000	4,053,000	4,053,000	4,053,000	2,553,000
$												
Beginning Inventory	$ 6,587,000	$ 7,113,000	$ 8,650,000	$ 9,192,000	$ 9,742,000	$ 9,742,000	$ 10,274,000	$ 10,274,000	$ 10,274,000	$ 10,274,000	$ 10,274,000	$ 10,274,000
Injections	$ 526,000	$ 1,537,000	$ 542,000	$ 550,000	$ -	$ 532,000	$ -	$ -	$ -	$ -	$ -	$ -
Withdrawals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,802,000
EndingBalance	$ 7,113,000	$ 8,650,000	$ 9,192,000	$ 9,742,000	$ 9,742,000	$ 10,274,000	$ 10,274,000	$ 10,274,000	$ 10,274,000	$ 10,274,000	$ 10,274,000	$ 6,472,000
Average Rate	$ 2.5707	$ 2.5464	$ 2.5420	$ 2.5383	$ 2.5383	$ 2.5349	$ 2.5349	$ 2.5349	$ 2.5349	$ 2.5349	$ 2.5349	$ 2.5351

LNG	Forecast Apr-2021	Forecast May-2021	Forecast Jun-2021	Forecast Jul-2021	Forecast Aug-2021	Forecast Sep-2021	Forecast Oct-2021	Forecast Nov-2021	Forecast Dec-2021	Forecast Jan-2022	Forecast Feb-2022	Forecast Mar-2022
Dth												
Beginning Inventory	2,192,000	2,114,000	2,257,000	2,245,000	2,165,000	2,084,000	2,298,000	2,292,000	2,298,000	2,261,000	1,735,000	1,603,000
Injections	-	223,000	66,000	-	-	291,000	74,000	33,000	-	-	-	9,000
Withdrawals	78,000	80,000	78,000	80,000	80,000	78,000	80,000	26,000	37,000	526,000	132,000	38,000
EndingBalance	2,114,000	2,257,000	2,245,000	2,165,000	2,084,000	2,298,000	2,292,000	2,298,000	2,261,000	1,735,000	1,603,000	1,574,000
$												
Beginning Inventory	$ 4,472,000	$ 4,314,000	$ 4,554,000	$ 4,517,000	$ 4,356,000	$ 4,195,000	$ 4,502,000	$ 4,468,000	$ 4,477,000	$ 4,406,000	$ 3,356,000	$ 3,093,000
Injections	$ -	$ 403,000	$ 120,000	$ -	$ -	$ 461,000	$ 123,000	$ 60,000	$ -	$ -	$ -	$ 18,000
Withdrawals	$ 159,000	$ 163,000	$ 156,000	$ 161,000	$ 161,000	$ 154,000	$ 157,000	$ 51,000	$ 71,000	$ 1,050,000	$ 263,000	$ 74,000
EndingBalance	$ 4,314,000	$ 4,554,000	$ 4,517,000	$ 4,356,000	$ 4,195,000	$ 4,502,000	$ 4,468,000	$ 4,477,000	$ 4,406,000	$ 3,356,000	$ 3,093,000	$ 3,038,000
Average Rate	$ 2.0407	$ 2.0177	$ 2.0120	$ 2.0120	$ 2.0130	$ 1.9591	$ 1.9494	$ 1.9482	$ 1.9487	$ 1.9343	$ 1.9295	$ 1.9301

Exhibit_(EDA-4)
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KEDNY / KEDLI

Projected Gas Storage Inventory

Twelve Months Ended March 2023

Market Area	Forecast Apr-2022	Forecast May-2022	Forecast Jun-2022	Forecast Jul-2022	Forecast Aug-2022	Forecast Sep-2022	Forecast Oct-2022	Forecast Nov-2022	Forecast Dec-2022	Forecast Jan-2023	Forecast Feb-2023	Forecast Mar-2023
Dth												
Beginning Inventory	996,000	4,709,000	15,039,000	24,574,000	33,669,000	42,741,000	51,580,000	59,865,000	58,224,000	45,829,000	27,053,000	12,085,000
Injections	3,713,000	10,331,000	9,534,000	9,096,000	9,071,000	8,839,000	8,285,000	1,523,000	5,000	-	-	7,000
Withdrawals	-	-	-	-	-	-	-	3,164,000	12,400,000	18,776,000	14,969,000	9,601,000
EndingBalance	4,709,000	15,039,000	24,574,000	33,669,000	42,741,000	51,580,000	59,865,000	58,224,000	45,829,000	27,053,000	12,085,000	2,491,000
$												
Beginning Inventory	$ 2,090,000	$ 9,930,000	$ 30,099,000	$ 48,563,000	$ 65,476,000	$ 82,341,000	$ 97,102,000	$ 111,711,000	$ 108,887,000	$ 85,792,000	$ 50,713,000	$ 22,874,000
Injections	$ 7,840,000	$ 20,169,000	$ 18,465,000	$ 16,913,000	$ 16,864,000	$ 14,762,000	$ 14,608,000	$ 3,031,000	$ 11,000	$ -	$ -	$ 17,000
Withdrawals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,854,000	$ 23,106,000	$ 35,079,000	$ 27,839,000	$ 17,949,000
EndingBalance	$ 9,930,000	$ 30,099,000	$ 48,563,000	$ 65,476,000	$ 82,341,000	$ 97,102,000	$ 111,711,000	$ 108,887,000	$ 85,792,000	$ 50,713,000	$ 22,874,000	$ 4,942,000
Average Rate	$ 2.1087	$ 2.0014	$ 1.9762	$ 1.9447	$ 1.9265	$ 1.8826	$ 1.8660	$ 1.8701	$ 1.8720	$ 1.8746	$ 1.8928	$ 1.9839

Gulf Coast	Forecast Apr-2022	Forecast May-2022	Forecast Jun-2022	Forecast Jul-2022	Forecast Aug-2022	Forecast Sep-2022	Forecast Oct-2022	Forecast Nov-2022	Forecast Dec-2022	Forecast Jan-2023	Forecast Feb-2023	Forecast Mar-2023
Dth												
Beginning Inventory	2,553,000	2,767,000	3,397,000	3,611,000	3,833,000	3,833,000	4,047,000	4,053,000	4,053,000	4,053,000	4,053,000	4,053,000
Injections	214,000	629,000	214,000	222,000	-	214,000	5,000	-	-	-	-	-
Withdrawals	-	-	-	-	-	-	-	-	-	-	-	1,500,000
EndingBalance	2,767,000	3,397,000	3,611,000	3,833,000	3,833,000	4,047,000	4,053,000	4,053,000	4,053,000	4,053,000	4,053,000	2,553,000
$												
Beginning Inventory	$ 6,472,000	$ 7,011,000	$ 8,590,000	$ 9,132,000	$ 9,694,000	$ 9,694,000	$ 10,235,000	$ 10,249,000	$ 10,249,000	$ 10,249,000	$ 10,249,000	$ 10,249,000
Injections	$ 539,000	$ 1,579,000	$ 542,000	$ 562,000	$ -	$ 541,000	$ 13,000	$ -	$ -	$ -	$ -	$ -
Withdrawals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,792,000
EndingBalance	$ 7,011,000	$ 8,590,000	$ 9,132,000	$ 9,694,000	$ 9,694,000	$ 10,235,000	$ 10,249,000	$ 10,249,000	$ 10,249,000	$ 10,249,000	$ 10,249,000	$ 6,456,000
Average Rate	$ 2.5338	$ 2.5287	$ 2.5289	$ 2.5291	$ 2.5291	$ 2.5290	$ 2.5287	$ 2.5287	$ 2.5287	$ 2.5287	$ 2.5287	$ 2.5288

LNG	Forecast Apr-2022	Forecast May-2022	Forecast Jun-2022	Forecast Jul-2022	Forecast Aug-2022	Forecast Sep-2022	Forecast Oct-2022	Forecast Nov-2022	Forecast Dec-2022	Forecast Jan-2023	Forecast Feb-2023	Forecast Mar-2023
Dth												
Beginning Inventory	1,574,000	1,509,000	1,664,000	1,665,000	1,597,000	1,530,000	1,680,000	1,680,000	1,680,000	1,653,000	1,626,000	1,601,000
Injections	-	223,000	66,000	-	-	216,000	68,000	26,000	-	-	-	-
Withdrawals	66,000	68,000	66,000	68,000	68,000	66,000	68,000	26,000	27,000	27,000	24,000	27,000
EndingBalance	1,509,000	1,664,000	1,665,000	1,597,000	1,530,000	1,680,000	1,680,000	1,680,000	1,653,000	1,626,000	1,601,000	1,574,000
$												
Beginning Inventory	$ 3,038,000	$ 2,912,000	$ 3,183,000	$ 3,177,000	$ 3,048,000	$ 2,919,000	$ 3,127,000	$ 3,112,000	$ 3,111,000	$ 3,061,000	$ 3,011,000	$ 2,966,000
Injections	$ -	$ 401,000	$ 120,000	$ -	$ -	$ 332,000	$ 110,000	$ 48,000	$ -	$ -	$ -	$ -
Withdrawals	$ 126,000	$ 130,000	$ 125,000	$ 129,000	$ 129,000	$ 123,000	$ 126,000	$ 49,000	$ 50,000	$ 50,000	$ 45,000	$ 50,000
EndingBalance	$ 2,912,000	$ 3,183,000	$ 3,177,000	$ 3,048,000	$ 2,919,000	$ 3,127,000	$ 3,112,000	$ 3,111,000	$ 3,061,000	$ 3,011,000	$ 2,966,000	$ 2,915,000
Average Rate	$ 1.9298	$ 1.9129	$ 1.9081	$ 1.9086	$ 1.9078	$ 1.8613	$ 1.8524	$ 1.8518	$ 1.8518	$ 1.8518	$ 1.8526	$ 1.8520

Exhibit_(EDA-4)
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KEDNY / KEDLI

Projected Gas Storage Inventory

Twelve Months Ended March 2024

Market Area	Forecast Apr-2023	Forecast May-2023	Forecast Jun-2023	Forecast Jul-2023	Forecast Aug-2023	Forecast Sep-2023	Forecast Oct-2023	Forecast Nov-2023	Forecast Dec-2023	Forecast Jan-2024	Forecast Feb-2024	Forecast Mar-2024
Dth												
Beginning Inventory	2,491,000	4,981,000	15,181,000	24,701,000	34,082,000	43,027,000	51,866,000	59,893,000	58,224,000	45,579,000	26,924,000	11,481,000
Injections	2,617,000	10,200,000	9,520,000	9,381,000	8,945,000	8,839,000	8,026,000	1,483,000	5,000	-	-	9,000
Withdrawals	127,000	-	-	-	-	-	-	3,151,000	12,650,000	18,655,000	15,443,000	9,366,000
EndingBalance	4,981,000	15,181,000	24,701,000	34,082,000	43,027,000	51,866,000	59,893,000	58,224,000	45,579,000	26,924,000	11,481,000	2,123,000
$												
Beginning Inventory	$ 4,942,000	$ 10,352,000	$ 30,893,000	$ 50,066,000	$ 68,252,000	$ 85,553,000	$ 101,113,000	$ 116,051,000	$ 113,056,000	$ 88,570,000	$ 52,389,000	$ 22,506,000
Injections	$ 5,650,000	$ 20,541,000	$ 19,172,000	$ 18,187,000	$ 17,301,000	$ 15,560,000	$ 14,938,000	$ 3,095,000	$ 11,000	$ -	$ 1,000	$ 21,000
Withdrawals	$ 240,000	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,089,000	$ 24,498,000	$ 36,181,000	$ 29,884,000	$ 18,183,000
EndingBalance	$ 10,352,000	$ 30,893,000	$ 50,066,000	$ 68,252,000	$ 85,553,000	$ 101,113,000	$ 116,051,000	$ 113,056,000	$ 88,570,000	$ 52,389,000	$ 22,506,000	$ 4,344,000
Average Rate	$ 2.0783	$ 2.0350	$ 2.0269	$ 2.0026	$ 1.9884	$ 1.9495	$ 1.9376	$ 1.9417	$ 1.9432	$ 1.9458	$ 1.9603	$ 2.0462

Gulf Coast	Forecast Apr-2023	Forecast May-2023	Forecast Jun-2023	Forecast Jul-2023	Forecast Aug-2023	Forecast Sep-2023	Forecast Oct-2023	Forecast Nov-2023	Forecast Dec-2023	Forecast Jan-2024	Forecast Feb-2024	Forecast Mar-2024
Dth												
Beginning Inventory	2,553,000	2,987,000	3,616,000	3,831,000	4,053,000	4,053,000	4,053,000	4,053,000	4,053,000	4,053,000	4,053,000	4,053,000
Injections	434,000	629,000	214,000	222,000	-	-	-	-	-	-	-	-
Withdrawals	-	-	-	-	-	-	-	-	-	-	-	1,500,000
EndingBalance	2,987,000	3,616,000	3,831,000	4,053,000	4,053,000	4,053,000	4,053,000	4,053,000	4,053,000	4,053,000	4,053,000	2,553,000
$												
Beginning Inventory	$ 6,456,000	$ 7,575,000	$ 9,188,000	$ 9,743,000	$ 10,319,000	$ 10,319,000	$ 10,319,000	$ 10,319,000	$ 10,319,000	$ 10,319,000	$ 10,319,000	$ 10,319,000
Injections	$ 1,119,000	$ 1,614,000	$ 554,000	$ 577,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Withdrawals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,819,000
EndingBalance	$ 7,575,000	$ 9,188,000	$ 9,743,000	$ 10,319,000	$ 10,319,000	$ 10,319,000	$ 10,319,000	$ 10,319,000	$ 10,319,000	$ 10,319,000	$ 10,319,000	$ 6,501,000
Average Rate	$ 2.5360	$ 2.5409	$ 2.5432	$ 2.5460	$ 2.5460	$ 2.5460	$ 2.5460	$ 2.5460	$ 2.5460	$ 2.5460	$ 2.5460	$ 2.5464

LNG	Forecast Apr-2023	Forecast May-2023	Forecast Jun-2023	Forecast Jul-2023	Forecast Aug-2023	Forecast Sep-2023	Forecast Oct-2023	Forecast Nov-2023	Forecast Dec-2023	Forecast Jan-2024	Forecast Feb-2024	Forecast Mar-2024
Dth												
Beginning Inventory	1,574,000	1,609,000	1,947,000	1,983,000	1,932,000	1,956,000	2,284,000	2,296,000	2,298,000	2,261,000	1,282,000	1,248,000
Injections	112,000	419,000	114,000	30,000	105,000	405,000	93,000	37,000	-	-	-	-
Withdrawals	78,000	80,000	78,000	80,000	80,000	78,000	80,000	35,000	37,000	979,000	34,000	37,000
EndingBalance	1,609,000	1,947,000	1,983,000	1,932,000	1,956,000	2,284,000	2,296,000	2,298,000	2,261,000	1,282,000	1,248,000	1,211,000
$												
Beginning Inventory	$ 2,915,000	$ 2,988,000	$ 3,618,000	$ 3,687,000	$ 3,592,000	$ 3,631,000	$ 4,146,000	$ 4,160,000	$ 4,167,000	$ 4,100,000	$ 2,316,000	$ 2,254,000
Injections	$ 218,000	$ 780,000	$ 213,000	$ 54,000	$ 188,000	$ 659,000	$ 160,000	$ 71,000	$ -	$ -	$ -	$ -
Withdrawals	$ 145,000	$ 150,000	$ 145,000	$ 150,000	$ 149,000	$ 143,000	$ 146,000	$ 64,000	$ 66,000	$ 1,784,000	$ 62,000	$ 66,000
EndingBalance	$ 2,988,000	$ 3,618,000	$ 3,687,000	$ 3,592,000	$ 3,631,000	$ 4,146,000	$ 4,160,000	$ 4,167,000	$ 4,100,000	$ 2,316,000	$ 2,254,000	$ 2,188,000
Average Rate	$ 1.8571	$ 1.8582	$ 1.8593	$ 1.8592	$ 1.8563	$ 1.8152	$ 1.8118	$ 1.8133	$ 1.8134	$ 1.8066	$ 1.8061	$ 1.8068

Exhibit_(EDA-4)
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Exhibit __ (EDA-5)

KEDNY/KEDLI Purchased Gas Expense for the Twelve Months Ending ("TME") December 31, 2018

KEDNY / KEDLI

Purchased Gas Expense

Twelve Months Ended December 31, 2018
(in thousands of dollars)

	Jan-2018	Feb-2018	Mar-2018	Apr-2018	May-2018	Jun-2018	Jul-2018	Aug-2018	Sep-2018	Oct-2018	Nov-2018	Dec-2018	Total TME Dec 2018
Purchased Take - MDT	24,980	17,311	21,351	25,275	17,826	16,183	15,612	13,653	13,638	17,928	20,258	22,167	226,182
Variable Cost	$ 203,709	$ 44,560	$ 53,070	$ 61,885	$ 40,489	$ 34,271	$ 37,410	$ 33,504	$ 33,954	$ 48,570	$ 76,985	$ 90,950	$ 759,356
Fixed Costs	$ 32,678	$ 31,101	$ 30,673	$ 28,748	$ 30,099	$ 29,084	$ 31,506	$ 30,246	$ 29,381	$ 27,481	$ 27,826	$ 32,004	$ 360,825
Total Invoice Cost	$ 236,386	$ 75,661	$ 83,742	$ 90,632	$ 70,588	$ 63,354	$ 68,916	$ 63,750	$ 63,335	$ 76,050	$ 104,811	$ 122,954	$ 1,120,181
Minus Injections to Storage & LNG	$ (451)	$ (4,501)	$ (8,445)	$ (18,417)	$ (26,344)	$ (22,642)	$ (24,964)	$ (22,190)	$ (22,191)	$ (20,179)	$ (6,386)	$ (1,410)	$ (178,121)
Plus Withdrawls from Storage & LNG	$ 38,713	$ 31,666	$ 32,461	$ 3,270	$ 481	$ 146	$ 4,147	$ 986	$ 688	$ 9,177	$ 22,118	$ 24,897	$ 168,751
Total Purchased Gas Expense	$ 274,649	$ 102,826	$ 107,758	$ 75,485	$ 44,725	$ 40,859	$ 48,099	$ 42,547	$ 41,832	$ 65,048	$ 120,543	$ 146,441	$ 1,110,811
<u>WACOG per Dth</u>													
Unitized Variable Gas Cost	$ 8.15	$ 2.57	$ 2.49	$ 2.45	$ 2.27	$ 2.12	$ 2.40	$ 2.45	$ 2.49	$ 2.71	$ 3.80	$ 4.10	
Underground Storage "In Ground" WACOG	$ 2.00	$ 2.00	$ 2.01	$ 2.12	$ 2.17	$ 2.14	$ 2.20	$ 2.25	$ 2.29	$ 2.35	$ 2.36	$ 2.36	
LNG WACOG	$ 2.03	$ 2.03	$ 2.03	$ 2.04	$ 2.06	$ 2.06	$ 2.06	$ 2.06	$ 2.07	$ 2.12	$ 2.13	$ 2.13	

<u>Note</u>: No hedging costs/credits included.

Exhibit_(EDA-5)
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Exhibit __ (EDA-6)

KEDNY/KEDLI Forecast of Variable Gas Expense for the TME March 31, 2021, 2022, 2023 and 2024

KEDNY / KEDLI

Forecast of Variable Gas Expense

Twelve Months Ended March 2021
(in thousands of dollars)

	Apr-2020	May-2020	Jun-2020	Jul-2020	Aug-2020	Sep-2020	Oct-2020	Nov-2020	Dec-2020	Jan-2021	Feb-2021	Mar-2021	Total TME Mar 2021
Purchased "Wellhead" Volume - MDT	22,138	20,891	17,425	16,325	16,695	18,044	22,373	23,818	32,454	37,565	32,212	28,126	288,066
Delivered Volume - MDT	21,859	20,557	17,096	15,988	16,367	17,705	22,009	23,467	31,912	36,913	31,743	27,735	283,351
HH NYMEX (8/27/15)	$ 2.56	$ 2.50	$ 2.53	$ 2.57	$ 2.57	$ 2.55	$ 2.57	$ 2.62	$ 2.80	$ 2.92	$ 2.86	$ 2.71	
Total "Wellhead" Cost of Purchased Gas	$ 43,074	$ 37,602	$ 30,622	$ 27,819	$ 28,782	$ 28,898	$ 37,538	$ 41,715	$ 42,217	$ 42,608	$ 37,035	$ 38,614	$ 436,525
Total Pipeline Variable Cost	$ 4,881	$ 4,743	$ 4,578	$ 4,395	$ 4,148	$ 4,292	$ 4,008	$ 4,494	$ 5,368	$ 5,961	$ 5,182	$ 5,065	$ 57,114
Total Variable Cost	$ 47,955	$ 42,345	$ 35,200	$ 32,214	$ 32,930	$ 33,190	$ 41,546	$ 46,209	$ 47,585	$ 48,569	$ 42,217	$ 43,679	$ 493,639
"Wellhead" WACOG per Dth	$ 1.95	$ 1.80	$ 1.76	$ 1.70	$ 1.72	$ 1.60	$ 1.68	$ 1.75	$ 1.30	$ 1.13	$ 1.15	$ 1.37	
Delivered Unit Cost of Total Flowing Supply Purchases	$ 2.19	$ 2.06	$ 2.06	$ 2.01	$ 2.01	$ 1.87	$ 1.89	$ 1.97	$ 1.49	$ 1.32	$ 1.33	$ 1.57	

Twelve Months Ended March 2022
(in thousands of dollars)

	Apr-2021	May-2021	Jun-2021	Jul-2021	Aug-2021	Sep-2021	Oct-2021	Nov-2021	Dec-2021	Jan-2022	Feb-2022	Mar-2022	Total TME Mar 2021
Purchased "Wellhead" Volume - MDT	21,735	21,853	17,580	16,633	16,298	17,909	22,129	23,256	33,161	38,376	32,919	28,693	290,543
Delivered Volume - MDT	21,454	21,492	17,270	16,291	15,972	17,572	21,770	22,916	32,590	37,715	32,427	28,314	285,784
HH NYMEX (8/27/15)	$ 2.47	$ 2.44	$ 2.47	$ 2.51	$ 2.53	$ 2.52	$ 2.55	$ 2.61	$ 2.79	$ 2.91	$ 2.86	$ 2.76	
Total "Wellhead" Cost of Purchased Gas	$ 39,849	$ 36,629	$ 29,084	$ 26,202	$ 26,029	$ 26,728	$ 35,713	$ 37,012	$ 44,156	$ 41,058	$ 40,203	$ 36,469	$ 419,130
Total Pipeline Variable Cost	$ 4,831	$ 4,633	$ 4,372	$ 4,311	$ 3,831	$ 3,449	$ 3,838	$ 4,316	$ 5,196	$ 5,790	$ 5,044	$ 5,027	$ 54,640
Total Variable Cost	$ 44,680	$ 41,262	$ 33,456	$ 30,513	$ 29,860	$ 30,177	$ 39,551	$ 41,328	$ 49,352	$ 46,848	$ 45,247	$ 41,496	$ 473,770
"Wellhead" WACOG per Dth	$ 1.83	$ 1.68	$ 1.65	$ 1.58	$ 1.60	$ 1.49	$ 1.61	$ 1.59	$ 1.33	$ 1.07	$ 1.22	$ 1.27	
Delivered Unit Cost of Total Flowing Supply Purchases	$ 2.08	$ 1.92	$ 1.94	$ 1.87	$ 1.87	$ 1.72	$ 1.82	$ 1.80	$ 1.51	$ 1.24	$ 1.40	$ 1.47	

Exhibit_(EDA-6)
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KEDNY / KEDLI

Forecast of Variable Gas Expense

Twelve Months Ended March 2023
(in thousands of dollars)

	Apr-2022	May-2022	Jun-2022	Jul-2022	Aug-2022	Sep-2022	Oct-2022	Nov-2022	Dec-2022	Jan-2023	Feb-2023	Mar-2023	Total TME Mar 2023
Purchased "Wellhead" Volume - MDT	21,949	22,010	17,720	16,532	16,386	18,014	22,481	24,142	33,864	39,169	33,603	29,262	295,132
Delivered Volume - MDT	21,711	21,652	17,410	16,210	16,078	17,679	22,126	23,793	33,263	38,510	33,107	28,888	290,427
HH NYMEX (8/27/15)	$ 2.52	$ 2.50	$ 2.53	$ 2.56	$ 2.57	$ 2.56	$ 2.59	$ 2.65	$ 2.81	$ 2.92	$ 2.87	$ 2.78	
Total "Wellhead" Cost of Purchased Gas	$ 39,954	$ 36,606	$ 28,915	$ 25,974	$ 25,798	$ 26,115	$ 35,536	$ 38,424	$ 45,943	$ 48,893	$ 41,863	$ 36,703	$ 430,723
Total Pipeline Variable Cost	$ 4,670	$ 4,622	$ 4,345	$ 3,903	$ 3,718	$ 3,390	$ 3,734	$ 4,343	$ 5,151	$ 5,696	$ 4,984	$ 4,981	$ 53,538
Total Variable Cost	$ 44,624	$ 41,228	$ 33,260	$ 29,877	$ 29,516	$ 29,505	$ 39,270	$ 42,767	$ 51,094	$ 54,589	$ 46,847	$ 41,684	$ 484,261
"Wellhead" WACOG per Dth	$ 1.82	$ 1.66	$ 1.63	$ 1.57	$ 1.57	$ 1.45	$ 1.58	$ 1.59	$ 1.36	$ 1.25	$ 1.25	$ 1.25	
Delivered Unit Cost of Total Flowing Supply Purchases	$ 2.06	$ 1.90	$ 1.91	$ 1.84	$ 1.84	$ 1.67	$ 1.77	$ 1.80	$ 1.54	$ 1.42	$ 1.42	$ 1.44	

Twelve Months Ended March 2024
(in thousands of dollars)

	Apr-2023	May-2023	Jun-2023	Jul-2023	Aug-2023	Sep-2023	Oct-2023	Nov-2023	Dec-2023	Jan-2024	Feb-2024	Mar-2024	Total TME Mar 2024
Purchased "Wellhead" Volume - MDT	21,638	22,491	17,916	17,000	16,514	17,981	22,561	24,640	34,670	40,128	35,802	29,942	301,283
Delivered Volume - MDT	21,361	22,133	17,605	16,672	16,206	17,649	22,208	24,291	34,054	39,443	35,263	29,572	296,458
HH NYMEX (8/27/15)	$ 2.56	$ 2.55	$ 2.59	$ 2.63	$ 2.65	$ 2.65	$ 2.68	$ 2.75	$ 2.90	$ 3.01	$ 2.97	$ 2.89	
Total "Wellhead" Cost of Purchased Gas	$ 40,235	$ 38,691	$ 30,436	$ 27,939	$ 27,059	$ 27,298	$ 37,571	$ 41,462	$ 49,319	$ 49,536	$ 48,811	$ 40,967	$ 459,324
Total Pipeline Variable Cost	$ 4,943	$ 4,814	$ 4,543	$ 4,178	$ 3,853	$ 3,548	$ 3,902	$ 4,518	$ 5,349	$ 5,885	$ 5,371	$ 5,184	$ 56,088
Total Variable Cost	$ 45,178	$ 43,505	$ 34,979	$ 32,117	$ 30,912	$ 30,846	$ 41,473	$ 45,980	$ 54,668	$ 55,421	$ 54,182	$ 46,150	$ 515,411
"Wellhead" WACOG per Dth	$ 1.86	$ 1.72	$ 1.70	$ 1.64	$ 1.64	$ 1.52	$ 1.67	$ 1.68	$ 1.42	$ 1.23	$ 1.36	$ 1.37	
Delivered Unit Cost of Total Flowing Supply Purchases	$ 2.11	$ 1.97	$ 1.99	$ 1.93	$ 1.91	$ 1.75	$ 1.87	$ 1.89	$ 1.61	$ 1.41	$ 1.54	$ 1.56	

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Exhibit __ (EDA-7)

KEDNY/KEDLI Forecast of Purchased Gas Expense for the TME March 31, 2021, 2022, 2023 and 2024

KEDNY / KEDLI

Forecast of Purchased Gas Expense

Twelve Months Ended March 2021
(in thousands of dollars)

	Apr-2020	May-2020	Jun-2020	Jul-2020	Aug-2020	Sep-2020	Oct-2020	Nov-2020	Dec-2020	Jan-2021	Feb-2021	Mar-2021	Total TME Mar 2021
Delivered Volume - MDT	21,859	20,557	17,096	15,988	16,367	17,705	22,009	23,467	31,912	36,913	31,743	27,735	283,351
Variable Cost	$ 47,955	$ 42,345	$ 35,200	$ 32,214	$ 32,930	$ 33,190	$ 41,546	$ 46,209	$ 47,585	$ 48,569	$ 42,217	$ 43,679	$ 493,639
Fixed Costs	$ 36,746	$ 37,476	$ 36,746	$ 37,476	$ 37,476	$ 36,746	$ 37,476	$ 37,475	$ 57,716	$ 57,716	$ 53,911	$ 54,577	$ 521,534
Total Invoice Cost	$ 84,701	$ 79,821	$ 71,946	$ 69,690	$ 70,406	$ 69,936	$ 79,022	$ 83,684	$ 105,301	$ 106,285	$ 96,128	$ 98,256	$ 1,015,173
Minus Injections to Storage	$ (8,715)	$ (21,888)	$ (20,158)	$ (18,764)	$ (19,297)	$ (17,968)	$ (16,241)	$ (3,271)	$ (12)	$ -	$ -	$ (40)	$ (126,354)
Plus Withdrawls from Storage	$ 1,137	$ 172	$ 166	$ 171	$ 170	$ 162	$ 165	$ 5,328	$ 26,335	$ 40,558	$ 32,408	$ 19,892	$ 126,664
Total Purchased Gas Expense	$ 77,123	$ 58,105	$ 51,954	$ 51,097	$ 51,279	$ 52,130	$ 62,946	$ 85,741	$ 131,624	$ 146,843	$ 128,536	$ 118,108	$ 1,015,483
WACOG per Dth													
Delivered Unit Cost of Total Flowing Supply Purchases	$ 2.19	$ 2.06	$ 2.06	$ 2.01	$ 2.01	$ 1.87	$ 1.89	$ 1.97	$ 1.49	$ 1.32	$ 1.33	$ 1.57	
Underground Storage "In Ground" WACOG	$ 2.43	$ 2.23	$ 2.17	$ 2.14	$ 2.11	$ 2.08	$ 2.05	$ 2.05	$ 2.06	$ 2.09	$ 2.20	$ 2.49	
LNG WACOG	$ 2.13	$ 2.13	$ 2.13	$ 2.13	$ 2.10	$ 2.06	$ 2.04	$ 2.04	$ 2.04	$ 2.04	$ 2.04	$ 2.04	

Twelve Months Ended March 2022
(in thousands of dollars)

	Apr-2021	May-2021	Jun-2021	Jul-2021	Aug-2021	Sep-2021	Oct-2021	Nov-2021	Dec-2021	Jan-2022	Feb-2022	Mar-2022	Total TME Mar 2021
Delivered Volume - MDT	21,454	21,492	17,270	16,291	15,972	17,572	21,770	22,916	32,590	37,715	32,427	28,314	285,784
Variable Cost	$ 44,680	$ 41,262	$ 33,456	$ 30,513	$ 29,860	$ 30,177	$ 39,551	$ 41,328	$ 49,352	$ 46,848	$ 45,247	$ 41,496	$ 473,770
Fixed Costs	$ 52,586	$ 53,844	$ 52,586	$ 53,844	$ 53,844	$ 52,586	$ 53,844	$ 53,083	$ 54,532	$ 54,532	$ 50,727	$ 54,345	$ 640,349
Total Invoice Cost	$ 97,266	$ 95,106	$ 86,042	$ 84,357	$ 83,704	$ 82,763	$ 93,395	$ 94,411	$ 103,884	$ 101,380	$ 95,974	$ 95,841	$ 1,114,119
Minus Injections to Storage	$ (8,595)	$ (21,943)	$ (19,217)	$ (18,095)	$ (17,155)	$ (16,000)	$ (14,835)	$ (2,210)	$ (11)	$ -	$ -	$ (18)	$ (118,079)
Plus Withdrawls from Storage	$ 20	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,286	$ 22,763	$ 38,751	$ 28,433	$ 21,845	$ 117,098
Total Purchased Gas Expense	$ 88,691	$ 73,163	$ 66,825	$ 66,262	$ 66,549	$ 66,763	$ 78,560	$ 97,487	$ 126,636	$ 140,131	$ 124,407	$ 117,667	$ 1,113,138
WACOG per Dth													
Delivered Unit Cost of Total Flowing Supply Purchases	$ 2.08	$ 1.92	$ 1.94	$ 1.87	$ 1.87	$ 1.72	$ 1.82	$ 1.80	$ 1.51	$ 1.24	$ 1.40	$ 1.47	
Underground Storage "In Ground" WACOG	$ 2.30	$ 2.11	$ 2.06	$ 2.02	$ 1.99	$ 1.95	$ 1.93	$ 1.93	$ 1.95	$ 1.98	$ 2.08	$ 2.41	
LNG WACOG	$ 2.04	$ 2.02	$ 2.01	$ 2.01	$ 2.01	$ 1.96	$ 1.95	$ 1.95	$ 1.95	$ 1.93	$ 1.93	$ 1.93	

Exhibit_(EDA-7)
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KEDNY / KEDLI

Forecast of Purchased Gas Expense

Twelve Months Ended March 2023
(in thousands of dollars)

	Apr-2022	May-2022	Jun-2022	Jul-2022	Aug-2022	Sep-2022	Oct-2022	Nov-2022	Dec-2022	Jan-2023	Feb-2023	Mar-2023	Total TME Mar 2023
Delivered Volume - MDT	21,711	21,652	17,410	16,210	16,078	17,679	22,126	23,793	33,263	38,510	33,107	28,888	290,427
Variable Cost	$ 44,624	$ 41,228	$ 33,260	$ 29,877	$ 29,516	$ 29,505	$ 39,270	$ 42,767	$ 51,094	$ 54,589	$ 46,847	$ 41,684	$ 484,261
Fixed Costs	$ 52,586	$ 53,844	$ 52,586	$ 53,844	$ 53,844	$ 52,586	$ 53,844	$ 52,439	$ 53,888	$ 53,888	$ 50,083	$ 53,701	$ 637,130
Total Invoice Cost	$ 97,210	$ 95,072	$ 85,846	$ 83,721	$ 83,360	$ 82,091	$ 93,114	$ 95,206	$ 104,982	$ 108,477	$ 96,930	$ 95,385	$ 1,121,391
Minus Injections to Storage	$ (8,379)	$ (21,971)	$ (19,073)	$ (17,475)	$ (16,864)	$ (15,519)	$ (14,689)	$ (3,057)	$ (11)	$ -	$ -	$ (17)	$ (117,055)
Plus Withdrawls from Storage	$ 66	$ 68	$ 66	$ 68	$ 68	$ 66	$ 68	$ 5,880	$ 23,133	$ 35,106	$ 27,863	$ 21,768	$ 114,220
Total Purchased Gas Expense	$ 88,897	$ 73,169	$ 66,839	$ 66,314	$ 66,564	$ 66,638	$ 78,493	$ 98,029	$ 128,104	$ 143,583	$ 124,793	$ 117,136	$ 1,118,556
WACOG per Dth													
Delivered Unit Cost of Total Flowing Supply Purchases	$ 2.06	$ 1.90	$ 1.91	$ 1.84	$ 1.84	$ 1.67	$ 1.77	$ 1.80	$ 1.54	$ 1.42	$ 1.42	$ 1.44	
Underground Storage "In Ground" WACOG	$ 2.27	$ 2.10	$ 2.05	$ 2.00	$ 1.98	$ 1.93	$ 1.91	$ 1.91	$ 1.93	$ 1.96	$ 2.05	$ 2.26	
LNG WACOG	$ 1.93	$ 1.91	$ 1.91	$ 1.91	$ 1.91	$ 1.86	$ 1.85	$ 1.85	$ 1.85	$ 1.85	$ 1.85	$ 1.85	

Twelve Months Ended March 2024
(in thousands of dollars)

	Apr-2023	May-2023	Jun-2023	Jul-2023	Aug-2023	Sep-2023	Oct-2023	Nov-2023	Dec-2023	Jan-2024	Feb-2024	Mar-2024	Total TME Mar 2024
Delivered Volume - MDT	21,711	21,652	17,410	16,210	16,078	17,679	22,126	23,793	33,263	38,510	33,107	28,888	290,427
Variable Cost	$ 44,624	$ 41,228	$ 33,260	$ 29,877	$ 29,516	$ 29,505	$ 39,270	$ 42,767	$ 51,094	$ 54,589	$ 46,847	$ 41,684	$ 484,261
Fixed Costs	$ 51,942	$ 53,200	$ 51,942	$ 53,200	$ 53,200	$ 51,942	$ 53,200	$ 52,439	$ 53,888	$ 50,416	$ 48,103	$ 50,229	$ 623,700
Total Invoice Cost	$ 96,566	$ 94,428	$ 85,202	$ 83,077	$ 82,716	$ 81,447	$ 92,470	$ 95,206	$ 104,982	$ 105,005	$ 94,950	$ 91,913	$ 1,107,961
Minus Injections to Storage	$ (6,987)	$ (22,935)	$ (19,939)	$ (18,818)	$ (17,489)	$ (16,219)	$ (15,098)	$ (3,166)	$ (11)	$ -	$ (1)	$ (21)	$ (120,684)
Plus Withdrawls from Storage	$ 385	$ 150	$ 145	$ 150	$ 149	$ 143	$ 146	$ 6,153	$ 24,564	$ 37,965	$ 29,946	$ 22,068	$ 121,964
Total Purchased Gas Expense	$ 89,964	$ 71,643	$ 65,408	$ 64,409	$ 65,376	$ 65,371	$ 77,518	$ 98,193	$ 129,535	$ 142,970	$ 124,895	$ 113,960	$ 1,109,241
WACOG per Dth													
Delivered Unit Cost of Total Flowing Supply Purchases	$ 2.06	$ 1.90	$ 1.91	$ 1.84	$ 1.84	$ 1.67	$ 1.77	$ 1.80	$ 1.54	$ 1.42	$ 1.42	$ 1.44	
Underground Storage "In Ground" WACOG	$ 2.25	$ 2.13	$ 2.10	$ 2.06	$ 2.04	$ 1.99	$ 1.98	$ 1.98	$ 1.99	$ 2.02	$ 2.11	$ 2.32	
LNG WACOG	$ 1.86	$ 1.86	$ 1.86	$ 1.86	$ 1.86	$ 1.82	$ 1.81	$ 1.81	$ 1.81	$ 1.81	$ 1.81	$ 1.81	

Exhibit_(EDA-7)
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Exhibit __ (EDA-8)

KEDNY & KEDLI Estimated Marginal Commodity Cost of Gas

KEDNY
Estimated Marginal Commodity Cost of Gas
For Period: November 1, 2020 through March 31, 2021
($ / dt)

Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Winter (Nov-Mar) Average
$ 2.67	$ 3.37	$ 5.64	$ 5.54	$ 2.86	$ 4.02

KEDLI
Estimated Marginal Commodity Cost of Gas
For Period: November 1, 2020 through March 31, 2021
($ / dt)

Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Winter (Nov-Mar) Average
$ 2.67	$ 3.37	$ 5.64	$ 5.54	$ 2.86	$ 4.02

Exhibit __ (EDA-9)

KEDNY & KEDLI Estimated Annualized Marginal Capacity Cost of Gas

KEDNY
Estimated Annualized Marginal Capacity Cost of Gas
For Period: November 1, 2020 through March 31, 2021
Units ($ per dt)

Marginal Supplies	Peak Day Quantity dt/day	Annual Capacity Costs Cost $	Annual Capacity Costs Quantity dt	Annual Capacity Costs Unitized $/dt	Peak Day Capacity Costs $/dt
Transco NESE Project	400,000	$ 176,880,000	134,000,000	$1.32	$442.20
15 Day City Gate Peaking Supplies	160,468	$ 8,856,378	2,407,020	$3.68	$55.19
Grand Total	**560,468**	**185,736,378**	**136,407,020**	**$1.36**	**$331.40**

Annualized Marginal Capacity Cost of Gas

Peak Day Capacity Cost	**$331.40**	**per dt**
Ratio: Peak Day Requirements to Annual Normalized Firm Sales	**1 to 72**	**dt**
Annual Marginal Capacity Cost	**$4.48**	**per dt**

KEDLI
Estimated Annualized Marginal Capacity Cost of Gas
For Period: November 1, 2016 through March 31, 2017
Units ($ per dt)

Marginal Supplies	Peak Day Quantity dt/day		Annual Capacity Costs Cost $	Quantity dt	Unitized $/dt	Peak Day Capacity Costs $/dt
DTI New Market Project	400,000	$	176,880,000	146,000,000	$1.21	$442.20
15 Day City Gate Peaking Supplies	160,468	$	8,856,378	2,407,020	$3.68	$55.19
Grand Total	**560,468**		**185,736,378**	**148,407,020**	**$1.25**	**$331.40**

Annualized Marginal Capacity Cost of Gas

Peak Day Capacity Cost	$331.40	per dt
Ratio: Peak Day Requirements to Annual Normalized Firm Sales	1 to 72	dt
Annual Marginal Capacity Cost	$4.48	per dt

Exhibit __ (EDA-10)

KEDNY & KEDLI Non-Migration Capacity Release Revenues

KEDNY & KEDLI Non-Migration Capacity Release Revenues

KEDNY

	Total Margin	Customer Share	Nat Grid Share
Apr 14-Mar 15	$4,392,667	$3,733,767	$658,900
Apr 15-Mar 16	$5,278,667	$4,486,867	$791,800
Apr 16-Mar 17	$4,898,667	$4,163,867	$734,800
Apr 17-Mar 18	$3,538,000	$3,007,300	$530,700
Apr 18-Jan 19	$4,380,000	$3,723,000	$657,000
Total:	**$22,488,000**	**$19,114,800**	**$3,373,200**

KEDLI

	Total Margin	Customer Share	Nat Grid Share
Apr 14-Mar 15	$3,148,667	$2,676,367	$472,300
Apr 15-Mar 16	$3,318,000	$2,820,300	$497,700
Apr 16-Mar 17	$3,304,000	$2,808,400	$495,600
Apr 17-Mar 18	$2,364,000	$2,009,400	$354,600
Apr 18-Jan 19	$2,891,333	$2,457,633	$433,700
Total:	**$15,026,000**	**$12,772,100**	**$2,253,900**

Exhibit __ (EDA-11)

KEDNY & KEDLI Off-System Sales ("OSS") Transaction Revenues

KEDNY & KEDLI OSS Transaction Revenues

KEDNY

		Total Margin	Customer Share	Nat Grid Share
Apr 14-Mar 15	OSS Sales	$14,983,333	$12,735,833	$2,247,500
	Capacity Release	$4,392,667	$3,733,767	$658,900
	AMA's	$14,934,667	$12,694,467	$2,240,200
	Total	**$34,310,667**	**$29,164,067**	**$5,146,600**
Apr 15-Mar 16	OSS Sales	$28,524,000	$24,245,400	$4,278,600
	Capacity Release	$5,278,667	$4,486,867	$791,800
	AMA's	$13,758,000	$11,694,300	$2,063,700
	Total	**$47,560,667**	**$40,426,567**	**$7,134,100**
Apr 16-Mar 17	OSS Sales	$14,092,000	$11,978,200	$2,113,800
	Capacity Release	$4,898,667	$4,163,867	$734,800
	AMA's	$11,064,000	$9,404,400	$1,659,600
	Total	**$30,054,667**	**$25,546,467**	**$4,508,200**
Apr 17-Mar 18	OSS Sales	$20,882,000	$17,749,700	$3,132,300
	Capacity Release	$3,538,000	$3,007,300	$530,700
	AMA's	$9,731,333	$8,271,633	$1,459,700
	Total	**$34,151,333**	**$29,028,633**	**$5,122,700**
Apr 18-Jan 19	OSS Sales	$13,009,333	$11,057,933	$1,951,400
	Capacity Release	$4,380,000	$3,723,000	$657,000
	AMA's	$7,186,667	$6,108,667	$1,078,000
	Total	**$24,576,000**	**$20,889,600**	**$3,686,400**
	Grand Total:	**$170,653,333**	**$145,055,333**	**$25,598,000**

KEDLI

		Total Margin	Customer Share	Nat Grid Share
Apr 14-Mar 15	OSS Sales	$9,972,667	$8,476,767	$1,495,900
	Capacity Release	$3,148,667	$2,676,367	$472,300
	AMA's	$10,210,000	$8,678,500	$1,531,500
	Total	**$23,331,333**	**$19,831,633**	**$3,499,700**
Apr 15-Mar 16	OSS Sales	$17,931,333	$15,241,633	$2,689,700
	Capacity Release	$3,318,000	$2,820,300	$497,700
	AMA's	$8,648,667	$7,351,367	$1,297,300
	Total	**$29,898,000**	**$25,413,300**	**$4,484,700**
Apr 16-Mar 17	OSS Sales	$9,426,667	$8,012,667	$1,414,000
	Capacity Release	$3,304,000	$2,808,400	$495,600
	AMA's	$7,487,333	$6,364,233	$1,123,100
	Total	**$20,218,000**	**$17,185,300**	**$3,032,700**
Apr 17-Mar 18	OSS Sales	$14,121,333	$12,003,133	$2,118,200
	Capacity Release	$2,364,000	$2,009,400	$354,600
	AMA's	$7,402,933	$6,437,333	$965,600
	Total	**$23,888,267**	**$20,449,867**	**$3,438,400**
Apr 18-Jan 19	OSS Sales	$8,532,000	$7,252,200	$1,279,800
	Capacity Release	$2,891,333	$2,457,633	$433,700
	AMA's	$4,755,333	$4,042,033	$713,300
	Total	**$16,178,667**	**$13,751,867**	**$2,426,800**
	Grand Total:	**$113,514,267**	**$96,631,967**	**$16,882,300**