BEFORE THE

PUBLIC UTILITIES COMMISSION
OF THE
STATE OF RHODE ISLAND
AND PROVIDENCE PLANTATIONS

IN THE MATTER OF

The National Grid Annual	**)**	
Gas Cost Recovery Charge	**)**	**Docket No. 4199**
Filing	**)**	

DIRECT TESTIMONY OF WITNESS
BRUCE R. OLIVER

On Behalf of

The Division of Public Utilities and Carriers

October 7, 2010

TESTIMONY OF BRUCE R. OLIVER
Docket No. 4199
October 7, 2010

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Exhibits BRO-1 through BRO-7.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Bruce R. Oliver. My business address is 7103 Laketree Drive, Fairfax Station, Virginia, 22039.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am employed by Revilo Hill Associates, Inc., and serve as President of the firm. I manage the firm's business and consulting activities, and I direct its preparation and presentation of economic, utility planning, and policy analyses for our clients.

Q. ON WHOSE BEHALF DO YOU APPEAR IN THIS PROCEEDING?

A. My testimony in this proceeding is presented on behalf of the Division of Public Utilities and Carriers (hereinafter "the Division").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. This testimony addresses issues relating to National Grid (or hereinafter "the Company") Annual Gas Cost Recovery (GCR) filing. This testimony reviews and comments on the content of the September 1, 2010 direct testimony of witnesses Arangio, Nestor, and McCauley, as well as the attachments submitted in support of those testimonies and the Company's responses to data requests.

Q. WHAT EXHIBITS ARE YOU SPONSORING AS PART OF THIS TESTIMONY?

A. Attached to this testimony are seven exhibits. They include:

Exhibit BRO-1	Proposed Changes in GCR Charges by Rate Class
Exhibit BRO-2	Changes in Costs by GCR Cost Component
Exhibit BRO-3	Changes in Forecasted Normal Weather Sales and Throughput
Exhibit BRO-4	Changes in Forecasted Design Winter Throughput
Exhibit BRO-5	Comparison of Forecasted and Actual Throughput by Rate Class
Exhibit BRO-6	U.S. Natural Gas Market Data
Exhibit BRO-7	Division Recommended GCR Charges

II. DISCUSSION OF ISSUES

Q. HOW IS YOUR DISCUSSION OF ISSUES RELATING TO NATIONAL GRID'S GCR FILING IN THIS PROCEEDING ORGANIZED?

A. This discussion is presented in seven sections. **Section A** discusses the changes in GCR charges by rate class that National Grid proposes and analyzes the changes in costs by gas cost component that underlie the Company's proposed GCR charges. **Section B** evaluates the reasonableness of the forecasts of normalized sales and design winter sales that have been relied upon in the development of National Grid's proposed GCR charges. **Section C** provides an assessment of current natural gas market conditions and forward looking natural gas pricing considerations. **Section**

D presents an assessment of (1) the Company's GPIP performance, (2) the incentive calculations that National Grid offers for FY 2008, (3) the reasonableness of the amount of the GPIP incentive that National Grid seeks, and (4) changes that the Company proposes in the language of the GPIP. **Section E** examines the impacts of the Natural Gas Portfolio Management Plan (NGPMP) on the costs subject to recovery through the Company's proposed GCR rates. **Section F** reviews National Grid's reconciliation of its GCR costs and revenue for FY 2009. **Section G** reviews issues associated with the pricing of pipeline alternatives for marketers. **Section H** discusses other matters of concern to the Division.

A. Changes in National Grid's GCR Rates and Gas Costs

Q. HOW DO THE COMPANY'S PROPOSED CHANGES IN GCR CHARGES VARY BY RATE CLASSIFICATION?

A. National Grid's filing proposes reductions in its GCR charges for all rate classifications except the FT-2 Marketer Charge. As shown in **Exhibit BRO-1,** the Company proposes to lower its GCR charges for Residential Heating customers, Small C&I customers, Medium C&I customers, Low Load Factor Large C&I customers, and Low Load Factor Extra Large C&I customers from $1.0801 per therm to **$0.9239 per therm**. That represents a **reduction** of **14.5%**. The Company's September 1, 2010 filing also proposes a GCR **reduction** of **17.5%** for Residential Non-Heating customers and High Load Factor Large and Extra Large

C&I customers. As a result, GCR charges for those customers would also **decline** from $1.0338 per therm to **$0.8929 per therm**. The GCR rate for Natural Gas Vehicles would also decrease from $0.9091 to **$0.7530 per therm** (i.e., a **17.2% reduction**). However, the FT-2 Storage Charge would increase **27.6%** from $0.0337 per therm to **$0.0430 per therm**.

Q. WHY ARE THE PERCENTAGE DECREASES IN GCR CHARGES SHOWN IN EXHIBIT BRO-1 NOT UNIFORM ACROSS RATE CLASSES?

A. Three basic factors contribute to the differences in percentage decreases in GCR charges by rate class that National Grid proposes. Those are:

1. Differences in the rates of change in the size of the GCR cost components; and

2. Differences in the magnitude of over- or under-collections of costs by GCR component; and

3. Differences in the manner in which the five components of GCR costs are allocated among classes.

Q. HAVE THE COMPANY'S GAS COSTS DECREASED UNIFORMILY ACROSS ALL GCR COST COMPONENTS?

A. No. **Exhibit BRO-2, page 1,** compares the Company's updated GCR cost projections by component for the 2010-11 GCR year with the costs that National Grid projected 12 months earlier for the 2009-10 GCR year in Docket No. 4097. As shown on that page, the changes in individual cost components vary widely. Although overall the Company's gas costs (prior to consideration of adjustments and reconciliation factors) have declined by 22.5%, percentage changes in individual cost components range from -37.0% for Storage Variable Product Costs to +9.6% for Storage Fixed Costs.

Q. DOES THE COMPANY EXPLAIN THE LARGE VARIATIONS IN THE CHANGES IN COMPONENTS OF ITS GAS COSTS?

A. Not directly. My review and analysis of the Company's filed testimony and attachments finds that the decline in National Grid's overall gas costs is primarily the result of changes in the Company's Supply Variable Costs and Storage Variable Costs. As indicated in **Exhibit BRO-2, page 1,** reductions in the National Grid's Supply Variable Costs and Storage Variable Product Costs account for of **$60.44 million** or the Company's forecasted **overall decrease of $61.66 million** in its GCR costs. These reductions in Variable Supply Cost are generally attributable to changes in market prices for natural gas that have been experience since the start of the economic recession. In addition, another factor contributing to the reduction in variable costs is the incentive structure provided the Company under the GPIP.[1] Perhaps most important, however, is a sharp decline in National Grid's forecasted sales volumes. In Docket No. 4097 the Company projected **27,254,552 Dth** of total annual Gas Sales for the 2009-10 GCR. In this proceeding, National Grid's forecast of annual Gas Sales and FT-2 Throughput for the 2010-11 GCR period is only **24,256,162** Dth. That represents a **reduction** of **11.0%**. Given that the Company for many years has projected only about 1% per year growth, National Grid's forecasted 11.0% one-year **reduction** in sales volumes represents a substantial change which impacts its overall gas costs, operations, planning, and revenue.

Q. HAVE YOU ASSESSED THE IMPACTS THAT OTHER ADJUSTMENTS AND RECONCILIATIONS HAVE HAD ON NATIONAL GRID'S PROJECTED OVERALL COSTS OF GAS FOR THE 2010-11 GCR YEAR?

A. Yes. **Exhibit BRO-2, page 3**, compares National Grid's projected gas costs for the 2010-11 GCR year with the comparable measures of costs that the Company projected in Docket No. 4097 for its 2009-10 GCR filing. As shown on that page, the referenced adjustments and reconciliation amounts have noticeable impacts on both the Company's overall costs of gas and the distribution of the costs by GCR cost component.

Further, **Exhibit BRO-2, page 3**, illustrates the large swings in other adjustment amounts applicable to the 2009-10 and 2010-11 GCR periods. The net of the changes in such other adjustments is a **$3.9 million decrease** in GCR costs to be collected over the November 2010 to October 2011 period.

Q. DO THE COMPANY'S GAS COSTS BY COST COMPONENT AS SHOWN IN ATTACHMENT EDA-1, PAGE 1, TIE DIRECTLY TO THE STARTING COSTS BY

[1] Further discussion of the GPIP and incentives provided to National Grid under that mechanism will be provided in Section D of this testimony.

GAS COST COMPONENT THAT ARE USED IN THE COMPUTATION OF THE COMPANY'S PROPOSED GCR CHARGES ON PAGES 2-5 OF ATTACHMENT JFN-1?

A. Yes, they do.

Q. DO YOU FIND ANY REASON TO QUESTION THE REASONABLENESS OF THE COMPANY'S FORECASTED GAS COSTS?

A. Given the Company's forecasted sales and throughput requirements I find the Company's projected Variable Gas Supply, Storage Variable Product Costs, and Storage Variable Non-Product Costs to be reasonable. I also find that National Grid has properly priced its Supply Fixed Costs and Storage Fixed Costs based on the demand units that the Company has specified for each of its various sources of supply for the projected 2010-2011 GCR year. However, given the large reductions in annual throughput and Design Winter Requirements that National Grid projects for the coming year, the net decrease of just 2.0% reflected in the combination of the Company's Supply Fixed Costs and Storage Fixed Costs for the 2010-2011 GCR year appears comparatively small. In addition, I have found computational inconsistencies in National Grid's determination of deferred cost balances that I have not been able to fully resolve.

Q. CAN YOU CITE EXAMPLES OF THE INCONSISTENCIES TO WHICH YOU REFER?

A. Yes. First, in witness Nestor's Attachment NG-JNF-1, pages 6-9, the sum of the "Month's Average Balances" for the five categories of gas costs analyzed does not equal the "Month's Average Balances" for the GCR Deferred Summary for the months of March 2010 through August 2010. However, the total for "Interest Applied" does match the sum of the applied interest costs for the five cost categories. In response to an informal inquiry regarding this matter witness Nestor explained that this inconsistency is related to the double counting of certain Storage Variable and Variable Non-Product costs that is referenced in footnote 2 on page 4 of his direct testimony. That note indicates a $695,928 adjustment was made to correct for the double counting.

Although I recognize that the referenced adjustment was made, I have been unable to fully verify that the amount of the adjustment is correct. My investigation has found that important elements of the Company's deferred gas cost balance determinations are calculated outside the spreadsheet file from which the referenced pages of witness Nestor's Attachment NG-JFN-1 were generated and then imported to that file. As a result, the actual data and calculations used to derive many of the deferred gas cost entries have not been provided to, or reviewed by, the Division. In this instance I do not believe that any variation from the amount of the adjustment National Grid has applied would be large, but it is troublesome that the full detail of the supporting calculations cannot be reviewed or replicated.

Second, in a related matter, the Attachment to the Company's response to Division Data Request DIV 2-4 provides corrected entries for "actual" Storage

Variable Product Costs - UG used in computing the Deferred Gas Cost Balance for the months of November 2009 through August 2010. Since actual data for most of the affected months are also reported on page 5 of 14 of Attachment NG-JFN-2, I made the effort to compare the monthly data in for Storage Variable Product Costs that report with the corrected data provide in the attachment to the Company's response to Division Data Request DIV 2-4. Although the corrected monthly entries for Storage Variable Product Costs-UG differed from the amounts on the same line of Attachment NG-JFN-2, page 5 of 14, by amounts ranging as high as $221,573, the totals reflected in these two documents for "Total Storage Variable Product Costs" never differed by more than $1,648 even though all other dollar amounts included in "Total Storage Variable Product Costs" except "Interest Applied" remained unchanged, and changes in "Interest Applied" were comparatively small. Upon further examination of the data in the Company's Deferred Gas Cost Report (Attachment NG-JFN-2), I discovered that the elements of the Storage Variable Product Costs shown in that report **do not equal** the "Total Storage Variable Product Costs." Once again, this appears to be related to Company's use of separate spreadsheet files (not provided to the Division) to compute monthly cost entries (and even certain cost totals) such that the resulting data is imported to the spreadsheets from which witness Nestor's Attachments were printed without the formulae used in the determination of those dollar amounts.

In this instance, however, I note an additional concern. With corrections as large as $200,000 in the Company's actual Storage Variable Product Costs – UG, it should be expected that Underground Storage Inventory balances and Inventory Financing – UG costs would also change. But that is not the case. Rather, the amounts shown for Inventory Financing – UG are the identical by month in Attachment NG-JFN-2 and in the Attachment to Division Data Request DIV 2-4.

Q. ARE THE GCR CHARGES THAT NATIONAL GRID PROPOSES IN ITS SEPTEMBER 1, 2010 FILING PROPERLY COMPUTED?

A. The methods that National Grid uses in its September 1, 2010 filing to compute the GCR charges that it proposes are consistent with those the Company has used, and the Commission has accepted in past GCR filings. With the exceptions cited above, the computations the Company has used to derive the specific charges set forth in witness Nestor's testimony and attachments appear to be mathematically accurate. As a result, the reasonableness of the GCR charges that National Grid proposes is primarily a function of:

(1) The reasonableness of the forecasts of gas throughput requirements upon which the Company relies in this proceeding;

(2) The capacity planning data and analyses which underlie National Grid's determination of resource costs for the projected GCR period; and

(3) Other data inputs and assumptions the Company's has used to compute its projected gas costs including adjustments the Company has made to its deferred gas costs.

B. Forecasted Sales and Throughput

Q. DOES NATIONAL GRID ANTICIPATE SIGNIFICANT CHANGES IN ITS FORECASTED SALES AND THROUGHPUT FOR THE 2010-2011 GCR PERIOD (I.E., NOVEMBER 2010 THROUGH OCTOBER 2011)?

A. Yes, it does. In fact, comparisons of the Company's sales and throughput forecasts for the 2010-2011 GCR period with those National Grid submitted last year in Docket No. 4097 are the most **dramatic** I have seen in nearly 20 years of reviewing gas utility filings in this jurisdiction. As demonstrated in Exhibit BRO-3, pages 1 of 2 and 2 of 2, the Company expects its overall sales volumes to **fall by 11.0%** during the 2010-2011 GCR period from the levels it forecasted just one year ago. Likewise, total FT-2 throughput is expected to **decline 9.7%**. For a utility that has been experiencing a growth rate in the range of 1.0 percent per year over the past decade, this projected one-year decline equates to roughly a full decade of past growth. Although FT-1 throughput volumes are projected to increase, essentially all of the growth is found in the Extra Large High Load Factor C&I class which the Company believes will experience a **33.6% throughput increase**.[2]

Q. DOES NATIONAL GRID ALSO EXPECT LARGE REDUCTIONS IN ITS DESIGN WINTER SALES AND THROUGHPUT REQUIREMENTS?

A. Yes. Exhibit BRO-4, pages 1 of 2 and 2 of 2, compares the changes that the Company forecasts in its Design Winter Requirements for the winter of 2010-2011 relative to those forecasted in Docket No. 4097 for the winter of 2009-2010. Although National Grid's projected reduction in design winter requirements for sales and FT-2 customers is somewhat less than the reduction it has forecasted in its annual sales and throughput for those customers, the overall one-year **decline is 8.67%.**

Q. ARE THESE SUBSTANTIAL CHANGES IN NATIONAL GRID'S FORECASTED SALES AND THROUGHPUT DISCUSSED IN THE COMPANY'S SEPTEMBER 1, 2010 TESTIMONY IN THIS PROCEEDING?

A. Not directly. Witness Nestor who presents the Company's forecasts offers a one-paragraph description of the general methods used to produce the Company's forecasts, but provides no observations regarding the significance of the changes in

[2] The Company's projected throughput increase for the FT-1 Extra Large High Load Factor C&I customers of 1,262,347 Dth exceeds the net throughput change (i.e., 1,255,973 Dth) for the Company's entire FT-1 service including throughput for all categories of Medium, Large and Extra Large FT-1 customers.

forecasted throughput volumes that result from National Grid's application of those forecasting methods.

Likewise, witness Arangio observes at page 14 of her September 1, 2010 testimony, "*Factors that have contributed to the decline in prices can be associated with reduced demand from warmer than normal weather and weak economic conditions, as well as higher than usual production and storage*." But, her testimony is devoid of any explicit discussion of the significance of the Company's forecasted declines in both normal weather and design winter requirements and the impacts of those significant declines on the Company's planning and operations.

I submit that the changes that National Grid forecasts in its Normal Weather and Design Winter throughput requirements are not reflective of "business as usual" conditions and should not be treated as such. Rather the magnitude of the forecasted changes in throughput requirements can be expected to impact a wide array of rate and regulatory policy considerations in this and other proceedings. Therefore, it is critical that this Commission be provided greater understanding of these changes in expected service requirements, as well as their actual and reasonably anticipated impacts on the Company's planning, operations and costs.

Q. DO YOU CHALLENGE THE ACCURACY AND RELIABILITY OF THE FORECAST OF WEATHER NORMAL ANNUAL SALES AND THROUGHPUT THAT WITNESS NESTOR PRESENTS ON BEHALF OF NATIONAL GRID IN THIS PROCEEDING?

A. Forecasts by their very nature are most likely to be inaccurate. However, they should be indicative of the general magnitude and direction of expected changes. Exhibit BRO-5 presents a comparison of the Company's forecast of annual sales and throughput volumes in this proceeding with the Company's reported **actual** volumes for July 2009 through June 2010. Although it should be expected that actual throughput for the period July 2009 through June 2010 was depressed by heating degree days ("HDDs") that were significantly below normal,[3] we find a fairly close correspondence between actual and forecasted volumes.[4] This suggests that a substantial portion of the Company's forecasted reduction in annual sales and throughput requirements for the 2010-2011 GCR year may already be reflected in recent actual results. That said, I have identified some concerns regarding the data and methods the Company has used in its preparation of its forecasts that may undermine the confidence the Commission can place in its results. I must also note that I did not receive supporting detail for the Company's sales and throughput forecasts until shortly before the due date of this testimony. Thus, the time provided for review of that detail has been quite limited. In that context, I reserve the right to supplement this testimony if further relevant findings are subsequently made with respect to the information and analyses underlying the Company's Normal Weather & Design Winter forecasts.

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[3] The data National Grid presents in Attachment NG-JFN-8US in Docket No. 4196 indicates that overall the winter of 2009-2010 was 369 HDDs or 7.7% warmer than normal.

[4] Exhibit BRO-5 shows that National Grid's sales forecast for the 2010-2011 GCR period is within 0.5% of its actual sales for the July 2009 through June 2010 period. Furthermore, the Company's overall throughput forecast in this proceeding is within 0.3% of its reported actual throughput for the period July 2010 through June 2011.

Q. WHAT IMPACT DO THE COMPANY'S THROUGHPUT FORECASTS HAVE ON ITS PROJECTED DESIGN DAY GAS SUPPLY REQUIREMENTS?

A. In the Company's last Long-Range Gas Supply Planning Study (filed in Docket No. 3789), National Grid projected a Design Day Peak for January 2011 of **349,367 Dth**. National Grid's response to Division Data Request DIV 2-10 in this proceeding reflects a forecasted Design Day Peak requirement of **289,700 Dth**. That represents roughly a **reduction** of **59,667 Dth** or **17%** from the Design Day Peak requirement that the Company forecasted in its last Long-Range Gas Supply Planning Study. Moreover, National Grid projects that its available supply to meet Design Day Peak requirements for the winter of 2010-2011 will be 337,603 Dth which provides the Company more than a **16% capacity reserve** over a one-in-one-hundred year Design Day Peak requirement.

I understand that the effects of the economic recession have been substantial and it may difficult to assess whether recession related reductions in service requirements will be temporary or enduring. Also, given the State's focus on energy efficiency, it would appear unlikely that the Company's actual service requirements will return to previously forecasted levels for most rate classes. However, National Grid is well acquainted with risk management techniques, and using such techniques, it should be able to provide this Commission greater quantitative insight regarding the expected costs to ratepayers of continuing to carry excess capacity to address future load uncertainties. A 16% capacity reserve over a one-in-a-hundred year Design Day Peak requirement is substantial. Moreover, the Commission should be sensitive to the fact that the Company may benefit from carrying excess capacity since greater amounts of excess capacity increase the Company's potential to earn incentives under the provisions of its Natural Gas Portfolio Management Program (NGPMP).

C. Natural Gas Market and Gas Supply Portfolio Considerations

Q. HOW HAVE NATURAL GAS MARKET CONDITIONS CHANGED OVER THE LAST YEAR?

A. The two driving forces in U.S. natural gas markets over the last year have been the achievement of all-time high U.S. domestic production levels for natural gas and an economic recession that has depressed growth in overall natural gas consumption. **Exhibit BRO-6, page 1 of 5**, illustrates the recent increase in U.S. natural gas production which has risen steadily since the middle of 2006. The increase in natural gas production is the product of the surge in U.S. natural gas drilling activity which peaked in the summer of 2008 (as shown in **Exhibit BRO-6, page 2 of 5**), but is still having a lagged impact on U.S. production levels. **Exhibit BRO-6, page 1 of 5 and page 3 of 5** depict the impacts that growth in U.S. domestic natural gas production and the slowing of U.S. natural gas demand growth have had on imports of natural gas to the U.S. Both pipeline imports of natural gas (primarily from Canada) and LNG imports have declined and are well below the import levels achieved prior to the economic recession. Although some increase in natural gas import levels can be seen since the fall of 2008, LNG imports for the twelve months ended July 2010 were at only 55% of the peak levels achieved prior to the recession.

Changes in the consumption of natural gas by end-use sector are graphically presented in **Exhibit BRO-6, page 4 of 5**. As demonstrated in that exhibit both Industrial and Electric Power consumption of natural gas have turned noticeably upward over the last 6-8 months, with electric power requirements for natural gas now exceeding the highest levels achieved prior to the economic recession. Although Industrial natural gas consumption remains below pre-recession levels the up turn in Industrial natural gas demand in recent months is significant. On the other hand, Residential and Commercial uses of natural gas have remained relatively flat with no clear upward or downward trends visible (even during the depth of the economic recession).

Q. WHAT IMPACT HAVE THE MARCELLUS SHALE AND THE ROCKIES EXPRESS PIPELINE HAD ON THE GAS MARKET IN NEW ENGLAND?

A. The Marcellus Shale formation that witness Arangio references certainly has considerable potential, but she notes in the Company's response to Division Data Request 1-10, at present the Marcellus Shale represents an immature supply basin. Furthermore, the development of that resource continues to be fraught with controversy. In particular, concerns regarding environmental impacts are raising the costs and slowing the development of Marcellus Shale. Also, there is presently considerable debate regarding the taxation of Marcellus Shale production that will impact the costs to consumers of gas produced from that basin. Although drilling activity in Pennsylvania has increased noticeably over the last couple years, that activity is well below the levels that would be required to have major impacts on eastern U.S. natural gas markets within the next few years.

Completion of the Rockies Express Pipeline offers the potential to bring additional gas supplies into the Central and Eastern U.S. natural gas markets. But, the increase natural gas supplies from Rocky Mountain production areas appears to be offset, at least in part, by declines in Canadian imports. At this point the net effect of those changes on gas markets in New England is at best difficult to assess. National Grid's response to Division Data Request DIV 1-10 indicates the Company is not able to quantitatively assess the effects of either the Rockies Express or Marcellus Shale development on its gas supply for the 2010-11 GCR period. Yet, it asserts "*All signs point to a large increase in the supply in the northeast which for now is exceeding demand growth*." In the context of the substantial decreases in gas use that the Company projects in this proceeding, it appears that the existence of excess supply for northeast markets may be driven more by declining demand than rising supply.

Q. PLEASE COMMENT ON THE LOCAL CAPACITY RESOURCES THAT HAVE BEEN ADDED BY NATIONAL GRID TO ITS GAS SUPPLY PORTFOLIO?

A. Although witness Arangio, at pages 15-16 of her Direct Testimony, discusses new "local" projects that are also expected to provide increased supply to northeast natural gas markets, National Grid's response to Division Data Request DIV 1-11 states, "*To date, the Company has not contracted for any dedicated supplies from any of [the new "local"] projects for use by its Rhode Island customers*."

The Commission should also understand that most of the referenced projects are premised on imports of LNG. However, the addition of LNG terminal capacity does not necessitate the flow of substantial gas volumes. Although substantial LNG import capability has been added, much of the U.S. LNG import capacity is being operated at very low capacity factors.[5] The U.S. Energy Information Administration ("EIA") reports that for calendar year 2009 overall LNG terminal capacity utilization in the U.S. averaged only about **11%**. As previously noted, recent LNG import levels have remained well below levels achieved in 2007[6] even though LNG terminal capacity has nearly doubled since that time.

Furthermore, many of the LNG cargoes that are delivered to eastern U.S. markets can characterized as "cargoes of opportunity." That is they represent shipments of LNG that are only delivered to U.S. ports when spot prices in U.S. markets exceed those in other international markets (particularly Western European

5 Between 2005 and 2009, U.S. LNG terminal capacity has increased more than threefold. Yet, the only LNG terminal in the U.S. to operate at greater than 50% of its capacity was the Distrigas facility in Everett, Massachusetts, which achieved about a 60% capacity factor. Other LNG terminal facilities directly serving the New England region had much lower rates of capacity utilization. The New England Gateway terminal completed in late 2008 had only minor utilization (i.e., approximately 1%) in 2009 while capacity utilization at the Canaport facility (in Canada) was less than a 20%. See EIA's "Natural Gas Year in Review 2009, released July 2010.

6 See **Exhibit BRO-6, page 3**.

markets) which generally are willing to pay noticeable premiums above U.S. market prices. As a result, such cargoes of opportunity may provide added supply to the northeast during periods of high demand, but even those deliveries may be contingent upon prices in New England being high enough to justify diversion of cargoes from European or even Asian markets. In other words, such cargoes of opportunity are likely to be priced well above average gas supply costs and may not constitute reliable sources of peak supply unless used in combination with LNG storage facilities.

Q. SHOULD FURTHER DECREASES IN NATURAL GAS COMMODITY COSTS BE ANTICIPATED IN THE COMING MONTHS?

A. Although some continuing volatility in natural gas prices can be expected, I do not anticipate further dramatic declines in natural gas prices. Future price uncertainties tend to be more associated with when prices will move upward again and how fast and how far they will rise. **Exhibit BRO-6**, **page 5 of 5**, provides the latest natural gas storage data from EIA. That data indicates the levels of natural gas presently in underground storage in the U.S. are above five-year average levels by 6.3% but **below** the levels reported for the comparable week of last year **by 4.6%**. With declines in demand such as those National Grid is forecasting, storage inventories are likely to be adequate for the coming winter. However, extremely cold early winter weather could tighten supplies enough to cause short-term prices to rise.

Importantly, futures prices for natural gas continue to exhibit a strongly "contango" relationship. For example, current prices for January and February of 2011 are in the range of $5.40 per Dth while comparable prices for the winter of 2012 are in the range of $5.80 per Dth. That pricing pattern for natural gas futures continues as we mover forward in time with current future contract prices for January and February of 2015 rising to roughly $6.40 per Dth.

For most of the period since the year 2000, natural gas commodity prices have reflected a "backwardized" relationship in which prices for comparable months became progressively less expensive as one looked further into the future. The current "contango" relationship in natural gas futures prices suggests that the market believes higher natural gas prices will prevail in the future. That is a somewhat different perspective than that offered in Company's testimony and data request responses in this proceeding. As portrayed by National Grid, increased supply from new sources (e.g., the Marcellus Shale, Rockies Express Pipeline, and an array of "local" projects) will produce increased competition and lower prices.

I recognize that prices will respond to supply and demand relationships and that considerable uncertainty remains with respect to future growth in U.S. natural gas demand. However, demand growth can be expected to have substantial impact on future natural gas prices for periods beyond the next six to eight months. **Exhibit BRO-6, page 4 of 5**, depicts changes in annual natural gas utilization by end-use sector over the past decade. As illustrated in the graph on that page, the major drivers of recent changes in natural gas demand have been primarily industrial natural gas use and the use of natural gas for electricity generation. Residential and Commercial uses of natural gas have remained comparatively flat over the last several years despite large market price fluctuations and despite the economic recession. Considering pressures to reduce coal-fired electric generation for environmental reasons and the absence of commitments to the construction of new nuclear plants, natural gas-fired electric generation can be expected to provide a growing share of New England's electric generation needs over the next 5-10 years. Even with aggressive pursuit of renewable generation alternatives and energy efficiency, the use of natural gas in electric power and industrial applications should be expected to grow, and that growth should be expected to place noticeable upward pressure on natural gas prices over the next several years. A continued resurgence of industrial demand for natural gas will only further amplify the upward pressure on natural gas prices.

Rapid development of new domestic gas supplies, such as the Marcellus Shale, offers the greatest hope for moderating the rate of increase in natural gas prices over the next several years. But, the immaturity of that basin and issues associated with its exploitation are not likely to permit the level of expansion needed to dampen upward price pressures. Moreover, if we are to continue to expand U.S. natural gas production, the level of new natural gas drilling activity will need to more closely approximate pre-recession levels. Yet, **Exhibit BRO-6, page 2 of 5**, demonstrates current drilling activity in the U.S. appears to have leveled off at 2003 levels (i.e., less than 1,000 active drilling rigs) which is only equivalent to about 60% of the pre-recession peak.

Q. TO WHAT EXTENT DOES NATIONAL GRID PLAN TO RELY ON LNG DURING THE COMING 2010-2011 WINTER SEASON?

A. National Grid's response to Division Data Request DIV 1-7, provided on September 30, 2010, indicates "*The Company is still in the process of finalizing its needs for the November 1, 2010 through October 31, 2011 time period. Once finalized, the Company will submit its final plan*." Thus, there remains considerable uncertainty regarding the extent to which the Company actually plans to use LNG for any purpose during the coming winter. Yet, from the Company's response to Division Data Request DIV 1-4 we have learned that National Grid anticipates no LNG use in either Newport or Westerly during the coming winter under any planning scenario (i.e., normal winter weather, design winter weather, design day peak, or cold snap) with the availability of service through the Algonquin East to West Project to those areas. No where does the Company offer any insight regarding when use of the LNG facilities in those areas will once again become necessary for the Company's provision of safe and reliable service, particularly given its forecasted declines in both Normal Winter and Design Winter throughput requirements.

D. GPIP Incentive Calculations

Q. DOES THE COMPANY SEEK APPROVAL OF A GAS PROCUREMENT INCENTIVE FOR THE 12 MONTH PERIOD ENDED JUNE 2009?

A. Yes. The September 1, 2010 testimony of witness Stephen McCauley presents National Grid's request for approval of an incentive of **$1,000,000.** Although the incentive calculation methodology for the period July 2009 through June 2010 yields an incentive of **$1,606,937**, the Company recognizes its agreement with the Division that incentive payments be capped at $1,000,000 per year through June 2010.

Q. DO YOU FIND ANY REASON TO QUESTION THE ACCURACY OF THE COMPANY'S GPIP INCENTIVE CALCULATIONS?

A. No, I do not. I have reviewed the supporting detail for the Company's mandatory and discretionary gas purchases for the twelve months ended June 2010, and I find that the Company's incentive calculation is consistent with the terms of the Gas Procurement Incentive Plan (GPIP).

Q. DO YOU AGREE THAT THE AMOUNT OF INCENTIVE RECOVERED BY THE COMPANY FOR THE TWELVE MONTHS ENDED JUNE 2010 SHOULD BE CAPPED AT $1,000,000?

A. Yes, I do. However, with approval of the changes in the GPIP that are set forth in witness McCauley's Attachments SAM-1 and SAM-1a, the $1,000,000 annual cap on GPIP incentives will no longer be applicable going forward.

Q. DO YOU SUPPORT COMMISSION APPROVAL OF THE CHANGES IN THE PROVISIONS OF THE GPIP THAT WITNESS MCCAULEY PRESENTS IN ATTACHMENTS SAM-1 AND SAM-1A?

A. Yes. I have reviewed those changes, and I find them to be consistent with the understanding reached between the Company and the Division. Therefore, I support the Commission's approval of the changes in the GPIP that National Grid presents in this proceeding.

E. Natural Gas Portfolio Management Plan (NGPMP)

Q. DOES THE COMPANY REQUEST APPROVAL OF AN INCENTIVE PAYMENT UNDER THE PROVISIONS OF THE NGPMP?

A. Yes. Witness McCauley's September 1, 2010 testimony at page 7 requests approval of NGPMP incentive payment of **$375,276** for the period April 2009 through March 2010.

Q. IS THE INCENTIVE THAT NATIONAL GRID COMPUTES UNDER THE PROVISIONS OF THE NATURAL GAS PORTFOLIO MANAGEMENT PLAN (NGPMP) APPROPRIATELY COMPUTED?

A. Yes, it is.

Q. HOW DOES THE LEVEL OF NGPMP CREDIT INCLUDED IN THE COMPANY'S GCR FILING IN THIS PROCEEDING COMPARE TO THE ACTUAL NGPMP BENEFITS THAT THE COMPANY REFLECTS FOR THE CAPACITY CREDITS THAT NATIONAL GRID REFLECTED IN LAST YEAR'S GCR FILING?

A. In its GCR rate calculations for this proceeding, the Company as assumed an net customer benefit from the NGPMP for the 2010-2011 GCR year of $2.4 million. Last year in Docket No. 4097, National Grid estimated a $1,000,000 million credit for its in-sourced asset management activities under the NGPMP. However, despite the economic recession and generally weak energy market demand, the Company indicates that it achieved actual NGPMP benefits for ratepayers from the NGPMP of $2,501,102. Although the periods associated with those estimated and actual incentive amounts differ, the actual results achieved were roughly 2.5 times the level of benefit the Company proposed in Docket No. 4097.

Q. DO YOU FIND ANY REASON THAT THE COMMISSION SHOULD WITHHOLD APPROVAL OF THE $375,276 NGPMP INCENTIVE THAT NATIONAL GRID HAS COMPUTED?

A. No, I do not.

Q. IS IT LIKELY THAT THE COMPANY'S ACTUAL NET ASSET MANAGEMENT REVENUE FROM THE NGPMP FOR 2010-11 GCR YEAR WILL EXCEED $1.0 MILLION?

A. Although I do not presume to be able to accurately predict the Company's actual net asset management revenue from the NGPMP program for the coming GCR period, I assess that it is reasonable to anticipate that National Grid will achieve net asset management revenue in excess of the minimum annual guarantee.

Q. IF NET ASSET MANAGEMENT REVENUE IN EXCESS OF THE MINIMUM ANNUAL GUARANTEE IS ACHIEVED, WHAT PORTION OF ANY EXCESS IS CREDITED TO RATEPAYERS?

A. Under the new NGPMP the level of annual guaranteed benefit is set at $1.0 million, but ratepayers will receive 80% of all asset management revenue that the Company derives in excess of $1.0 million.

Q. WHAT LEVEL OF NGPMP CREDITS SHOULD BE ASSUMED IN THE DEVELOPMENT OF PROPOSED GCR CHARGES FOR THE 2010-11 GCR PERIOD?

A. I encourage the Commission to assume annual NGPMP credits to ratepayers of not less $3.4 million annually. A $3.4 million annual credit is consistent with the achievement of $4.0 million of annual net asset management revenue. The Direct Testimony of National Grid witness McCauley at page 7 indicates that nearly $2.9 million of annual net asset management revenue was obtained for the period from April 2009 through March 2010 despite a recession economy and significant declines in energy market prices. With access to increased pipeline capacity from the Algonquin East to West Project and significant reductions in its own customers' throughput requirements, I assess that targeting of a $3.4 million net customer benefit for the coming GCR period is reasonable.

Once again, I note that, in the current market, it is reasonable to expect that annual NGPMP credits will significantly exceed the established $1.0 million minimum guarantee. In that context, the Company's assumption of only $2.4 million of NGPMP credit for the 2010-11 GCR period unnecessarily and inappropriately limits the level of benefit that will be conveyed to the Company's firm service customers over the coming GCR year. Alternatively, I assess that assumption of $4.0 million of net asset management revenue and $3.4 million of NGPMP credits for the Company's ratepayers is reasonable given the considerations I have presented.

Q. WOULD THE ASSUMPTION OF $3.4 MILLION OF NGPMP CREDITS EFFECTIVELY RAISE THE GUARANTEED MINIMUM ANNUAL CREDIT FOR RATEPAYERS SET FORTH IN THE PROVISIONS OF THE NGPMP?

A. No. If the $3.4 million of credits is not achieved, the Company can recover any deficiency plus interest through the GCR reconciliation process. The effective minimum annual credit guarantee remains $1.0 million, and nothing in my proposal is intended to increase the dollar amount of credits for which the Company is at risk.

F. Gas Cost Reconciliations

Q. HAVE YOU REVIEWED THE COMPANY'S RECONCILIATION OF GAS COSTS FOR THE TWELVE MONTHS ENDED JUNE 30, 2010?

A. Yes, I have. Attachment JFN-2 submitted with witness Nestor's September 1, 2010 testimony in this proceeding provides the Company's "Annual Gas Cost Recovery Reconciliation Report." In that reconciliation report, the Company presents its costs and revenue collections by month for each of the major components of its Gas Supply Costs for the twelve months ended June 30, 2010. I have reviewed that document in detail. I have also reviewed additional detail upon which the Company has relied to support those reconciliations that was obtained through discovery.

Q. ARE THE COMPANY'S RECONCILIATIONS MATHEMATICALLY ACCURATE?

A. In general, I find that they are. However, as noted in Section A of this testimony, certain elements of the Company's calculations were not mathematically correct, and apparently those errors were the result of computations performed in another spreadsheet and imported to the files from which the Company's reconciliation report was printed. My expectation is that those errors have no material impact on the results of the Company's gas cost reconciliations. However, I was unable to fully verify that assessment prior to the filing of this testimony.

Q. SHOULD THE COMMISSION ACCEPT THE COMPANY'S ANNUAL GAS COST RECOVERY RECONCILIATON AS FILED?

A. No, it should not. Included in National Grid's gas cost reconciliations is a $6,173,538 adjustment. Of that amount **$1,348,893** is associated with the months of **May and June 2009** which were part of the Company's last Gas Cost Recovery Reconciliation. The current Gas Cost Recovery Reconciliation is intended to address only the period July 1, 2009 through June 30, 2010. The portion of the proposed $6.2 million adjustment that relates to the months of May and June of 2009 is not relevant to the reconciliation period that is subject to review in this proceeding. The Company's reconciliations for the twelve months ended June 30, 2009 were reviewed and accepted in Docket No. 4097 as part of the setting of rates for the current GCR year. As such, that portion of the Company's claimed $6.2

million cost adjustment to gas costs must be viewed as an inappropriate retroactive ratemaking adjustment.

Furthermore, regardless of whether the prior period portion of the Company's $6.2 million adjustment represents retroactive ratemaking, National Grid has failed to provide reasonable proof that the amounts for which the adjustment was made. It has also failed to demonstrate that the amounts claimed as part of its $6.2 million adjustment were not previously included in the gas costs for which National Grid has been provided, or now seeks, recovery. In addition, the Company has disclosed neither: (1) the parties with whom the Company engaged in the subject "netting" transactions; nor (2) quantities and prices upon which the subject transactions were premised.

Additionally, the prior period costs for which the Company now seeks recovery do not appear to constitute costs for which the timing of their recognition was beyond the control of National Grid. Rather, the Company had the opportunity, and the responsibility, to identify errors in its accounting of such costs in the preparation of its 2009 Annual Gas Cost Recovery Reconciliation Report, but did not do so.

Q. WHAT INFORMATION HAS THE COMPANY PRESENTED TO SUPPORT THE $6.2 MILLION ADJUSTMENT THAT IT HAS MADE TO ITS DEFERRED GAS COST BALANCE?

A. National Grid did not address this adjustment in either its August 2, 2010, Annual Gas Cost Recovery Reconciliation or in its September 1, 2010 initial filing in this proceeding. As a result, the only explanation of that adjustment is found in the Company's response to a Division inquiry regarding that adjustment (i.e., the response to Division Data Request DIV 3-1). In that response the Company indicates its $6.2 million adjustment is associated with a netting of transactions where the Company buys and sells to the same vendor. National Grid explains that in such circumstances "*a 'net' invoice is rendered by the Company to the supplier for transactions in which the sale exceeds the purchase, and a 'net' invoice is received by the Company from the supplier for transactions in which the purchase exceeds the sale*." According the Company, the $6.2 million adjustment is a derivative of transactions where the Company issued a "net" invoice, and the gas cost component was inappropriately excluded from the data included in National Grid's gas cost deferred calculations.

National Grid's response to Division Data Request DIV 3-1 also includes a listing of the 15 journal entries that were made between May 18, 2009 and April 20, 2010 to record the dollar amounts upon which the overall $6.2 million adjustment is premised.

Q. HAVE YOU BEEN ABLE TO VERIFY THAT THE JOURNAL ENTRIES LISTED IN NATIONAL GRID'S RESPONSE TO DIVISION DATA REQUEST DIV 3-1

ACTUALLY REFLECT COSTS THAT WERE NOT PROPERLY INCLUDED IN THE COMPANY'S DEFERRED GAS COST BALANCE DETERMINATIONS?

A. No. I find the information provided to be insufficient for that purpose. Although National Grid represents that the adjustment reflects instances in which the Company rendered a "net" invoice, no evidence of the amounts that were netted is provided. Furthermore, nothing in the information provided enables the Division to verify that the referenced costs were not previously included in National Grid's Deferred Gas Cost Balance calculations.

Q. HAS NATIONAL GRID OFFERED ANY FURTHER RATIONALE FOR INCLUDING THE PRIOR PERIOD PORTION OF ITS $6.2 MILLION ADJUSTMENT IN THE GAS COST RECONCILIATIONS SUBJECT TO REVIEW IN THIS PROCEEDING?

A. Yes. In response to Division Data Request DIV 3-3 the Company asserts:

1. The prior period portion of the $6.2 million adjustment should be included in the Company's 2010-2011 GCR rates because they are prudently incurred costs that were excluded due to an oversight.

2. The inclusion of the costs that comprise prior period portion of the Company's $6.2 million adjustment are appropriate for inclusion in National Grid's GCR rates as it is common for items from prior periods such as credits and refunds to be included.

3. Since the Company has included in the current GCR filing refunds received from the Tennessee Pipeline that related to a number of periods prior to July 2009, it is appropriate to include known prior period adjustments to gas costs as well.

Q. HOW DO YOU RESPOND TO THE RATIONALES THAT NATIONAL GRID OFFERS FOR INCLUSION OF THE DISPUTED PRIOR PERIOD COSTS IN ITS PROPOSED 2010-2011 GCR RATES?

A. First, I note the documentation that National Grid has provided for the subject costs is insufficient to determine that either (1) that those costs were prudently incurred or (2) that the subject prior period costs were not previously included in its reported gas costs.

Second, I would urge the Commission to differentiate credits or refunds that National Grid receives from Tennessee Pipeline or any other regulated pipeline supplier from other prior period adjustments to gas costs. It is my understanding that credits and refunds provided by FERC regulated pipelines are subject to the *Filed Rate Doctrine*, and under that doctrine this Commission's discretion regarding the rate treatment of such costs is limited. However, adjustments to costs based on transactions with unregulated entities are not subject to the *Filed Rate Doctrine,* and the Commission is not required to provide a dollar for dollar pass through of such costs or credits. Rather, this Commission has the opportunity, if not the responsibility, to determine the reasonableness and appropriateness of costs that result from transactions with unregulated entities before such costs are included in rates.

Q. ARE YOU AWARE OF ANY PRECEDENTS FOR THE EXCLUSION OF PRIOR PERIOD COSTS BASED ON RETROACTIVE RATEMAKING?

A. Yes. In Docket No. 3832 this Commission rejected a request by Providence Water for recovery of $1.489 million of prior period costs and that determination was upheld by the Supreme Court.

Q. DOESN'T THE COMMISSION'S ORDER IN DOCKET NO. 3832, AT PAGE 60, NOTE AN EXCEPTION TO RETROACTIVE RATEMAKING FOR REVIEWS OF PAST COSTS IN CONJUNCTION WITH A RECONCILIATION TARIFF?

A. Yes. Reconciliation tariffs such as the GCR in this proceeding necessarily require adjustments to rates for costs after they have actually have been incurred. However, the Commission's procedures do not provided for open ended adjustment periods. Rather, a reconciliation period has been defined (i.e., in this case it is the twelve month period ended June 30th of each year), and it for that period when subject to review in the Company's subsequent GCR proceeding that adjustments can and should be made without concern regarding claims of retroactive ratemaking. As set forth in the Company's tariff at RIPUC NG-GAS No. 101, Section 2, Gas Charge, Schedule A, Sheet 2, Third Revision:

> "***The Annual Reconciliation filing will be made by August 1 of each year containing actual data for the twelve months ending June 30 of that year***."

Nothing in that language or any other portion of the Gas Charge section of the Company's tariff provides for consideration of costs from periods prior to the twelve months ending June 30 of the year of the filing in the Company's annual reconciliations. Thus, once each annual reconciliation filing has been accepted and new GCR rates are established which address demonstrated differences between estimated and actual costs, the reconciliation exemption from retroactive ratemaking claims appropriately disappears. To do otherwise would be neither reasonable nor appropriate. Allowing an open ended exemption from retroactive ratemaking claims would subject future ratepayers to never ending exposure to requests for recoveries of prior period costs regardless how far back in time the alleged costs were incurred. I don't believe that has ever been the intent of the GCR mechanism that this Commission has implemented for National Grid.

<u>G. Pricing of Capacity Assignments for Marketers</u>

Q. IN THE COMPANY'S LAST GCR PROCEEDING, ISSUES WERE RAISED BY CERTAIN MARKETERS REGARDING THE PRICING OF CAPACITY ASSIGNED TO MARKETERS. WHAT WAS THE NATURE OF THE MARKETER'S CONCERNS?

A. In Docket No. 4097, National Grid changed its methodology for computing the prices at which capacity would be released to marketers for various pipeline paths. Previously, the Company had used a historical average to determine the basis portion of the WACOG. However, in Docket 4097, National Grid elected instead to use a one-year forward looking forecast of prices. Witness Bachelder, testifying on behalf of Direct, argued: (1) that the change in methodology increased costs to marketers at a time when market prices were declining; and (2) that, in the absence of a mechanism for reconciling forecasted and actual costs, unwarranted subsidization between sales customers and transportation customer could result. Witness Bachelder also noted that use of the three year moving average of actual data makes it easier to predict costs used in multiple year contracts.

Q. HAS NATIONAL GRID MET WITH MARKETERS TO FURTHER DISCUSS ALTERNATIVES FOR PRICING OF CAPACITY THAT THE COMPANY RELEASES TO MARKETERS?

A. Yes. Witness Arangio's September 1, 2010 Direct Testimony in this proceeding at page 8 indicates that the Company met with marketers on July 15, 2010 to discuss the methodology to be used by National Grid in determining the Company's pricing of alternative supply paths for gas marketers.

Q. WHAT WAS THE RESULT OF THE COMPANY'S DISCUSSIONS WITH MARKETERS?

A. Witness Arangio states that a one-year forward looking methodology was agreed to by marketers.

Q. WERE YOU ABLE TO VERIFY THAT IN FACT SUCH AN AGREEMENT WAS REACHED?

A. Yes. In response to Division Data Request 1-1, National Grid has provided e-mail confirmation's from each of the six (6) marketers that were represented at the July 15, 2010 meeting that demonstrate their acceptance of the one-year, forwarding looking pricing methodology.

Q. DID THE DIVISION OR ANY NON-MARKETER INTERESTS OTHER THAN THE COMPANY PARTICIPATE IN THE DECISION TO CHANGE THE METHODOLOGY FOR DETERMINING THE CAPACITY ASSIGNMENT PRICES FOR MARKETERS?

A. No.

Q. DID THE AGREEMENT REGARDING THE CHANGE IN METHODOLOGY FOR PRICING CAPACITY ASSIGNMENTS TO MARKETERS INCLUDE ANY EXPLICIT REFERENCE TO THE ADOPTION OF A MECHANISM TO RECONCILE FORECASTED AND ACTUAL COSTS?

A. No. Thus, witness Bachelder's concerns regarding the potential for inappropriate cost subsidization between sales customers and transportation customers remain unaddressed.

Q. DO YOU OPPOSE THE USE OF THE ONE-YEAR FORWARD LOOKING METHODOLOGY AGREED UPON BY NATIONAL GRID AND THE MARKETERS?

A. I am not opposed to use of a one-year forward looking methodology ***if a mechanism is adopted for reconciliation of forecasted and actual costs***. However, in the absence of such a reconciliation mechanism, I would encourage the Commission to require National Grid to retain its prior three-year historical moving average method. Although witness Bachelder's concerns in Docket No. 4097 appear to be focused primarily on the potential that transportation service customers may be required to subsidize service to sales service customers, I believe the opposite is equally likely and equally inappropriate.

The importance of adopting a reconciliation mechanism where forward looking cost estimates are employed must be recognized. Considering the dramatic changes in natural gas markets that have been experienced over the last few years in terms of expanding supplies and declining usage, the ability of any party to forecast changes in basis prices with reasonable accuracy must be questioned. Therefore, the equitable treatment of all customers necessitates use of a reconciliation mechanism with pricing based on forward looking cost estimates.

H. Other Matters

Q. DO YOU HAVE ANY OTHER GENERAL OBSERVATIONS REGARDING THE COMPANY'S SUPPORT FOR ITS FILING IN THIS PROCEEDING?

A. Yes. Most of the analyses that the Company presents in support of its filing are prepared in electronic spreadsheet format. Although the Division's time for review of these very technical and detailed filings is limited, the electronic spreadsheet files upon which the Company has relied in the development of its testimony and attachments had not been provided to the Division at the time of the initial filing. Considering the highly quantitative and technical nature of much of the information that the Division is called upon to review, delays in the provision of such files impedes the Division's timely analysis of the Company's GCR filing. Furthermore, when the spreadsheet files from which the Company's exhibits were printed were provided, the Division found that numerous important elements of data and analyses relied upon in the preparation of those files were actually computed in other spreadsheets (not provided to the Division) and then imported to the files from which the final exhibits were printed. As a result, key formulas and calculations were effectively hidden from the Division's view. Although the Company has been responsive to Division data requests, there simply is not sufficient time to engage in the multiple rounds of discovery necessary to work through the various levels of spreadsheet references that have been identified. For this reason, I would encourage the Commission to require National Grid to provide the Division copies of all electronic spreadsheet relied upon (either directly or indirectly) in the preparation of its filings at the time each set of documents is filed.

III. SUMMARY OF RECOMMENDATIONS

Q. PLEASE SUMMARIZE THE RECOMMENDATIONS THAT YOU HAVE PRESENTED IN THIS TESTIMONY.

A. My recommendations to the Commission in this proceeding include the following:

1. The Commission should approve the changes to the provisions of the GPIP that National Grid presents in witness McCauley's Attachments SAM-1 and SAM-1a.

2. The Commission should accept National Grid's request to recover $1.0 million in GPIP incentives for the twelve months ended June 30, 2010.

3. The Commission should approve National Grid's computed NGPMP incentive of $375,276 for the period April 2009 through March 2010.

4. The Commission should direct National Grid to include $3.4 million of net customer benefit in its GCR rate calculations for the November 2010 to October 2011 period.

5. If forward looking cost estimates are to be used in the pricing of capacity released to marketers, then this Commission should mandate the adoption of a mechanism for reconciling forecasted used in the development of capacity prices with the actual costs that National Grid incurs.

6. Given the dramatic nature of the Company's forecasted declines in both normal winter and design winter throughput as well as the operational changes that will result from the start-up of service from the Algonquin East to West Project, the Commission should accelerate the timing of the Company's next required long range gas supply planning study and specifically require the Company to address the implications of changes in its Normal Weather and Design Winter throughput forecasts on (1) its near-term and long-term gas supply planning and (2) the expected availability of capacity resources for release or use in the production of asset management credits.

7. The Commission should reject the **$1,348,893** portion of the National Grid's $6.2 million adjustment to gas costs that National Grid has included in its Annual Gas Cost Reconciliation Report for costs purportedly incurred in months prior to July 2009 (i.e., the start of the reconciliation period addressed in this proceeding).

Q. HAVE YOU COMPUTED PROPOSED GCR CHARGES WITH THE COMPANY'S CLAIM OF ROUGHLY $1.35 MILLION OF PRIOR PERIOD HEDGING COSTS EXCLUDED?

A. Yes, I have. **Exhibit BRO-7,** presents the Division's recommended GCR charges for the period November 2010 though October 2011 (page 1 of 4), and supporting calculations for those charges (pages 2 of 4 through 4 of 4). The Division's recommended charges exclude the Company's claimed adjustment for prior period hedging costs as explained in Section F of this Discussion of Issues. They also reflect the Division's recommendation that the assumed NGPMP Customer Benefit be set at $3.4 million, as well as the impact of the Division's recommendation in the current DAC proceeding (Docket No. 4196) that the System Pressure Factor in the DAC be set at zero. With that System Pressure Factor change, the 16.8% of LNG-related costs currently recovered through the DAC would instead be recovered as gas costs through the Company's GCR. The combined effects of these changes, further reduce the proposed GCR charges for all major classes of customers. The GCR charge for Residential Heating, Small C&I, Medium C&I, Large Low Load

Factor, and Extra Large Low Load Factor C&I customers falls to **$0.9160 per therm**, while GCR charges for Residential Non-Heating, Large High Load Factor C&I, and Extra Large High Load Factor C&I customers become **$0.8854 per therm**.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

National Grid - RI Gas

Docket No. 4199

Company Proposed Changes in GCR Charges by Rate Class

Based on NG's Currently Effective Rates and September 1, 2010 GCR Filing

Rate Classification	Current GCR Rate ($/Therm)	NGrid Proposed GCR Rate 1/ ($/Therm)	Increase (Decrease) $ ($/Therm)	Increase (Decrease) %
Residential				
Non-Heating	$1.0338	$0.8529	($0.1809)	-17.5%
LI - Non-Heating	$1.0338	$0.8529	($0.1809)	-17.5%
Heating	$1.0801	$0.9239	($0.1562)	-14.5%
LI - Heating	$1.0801	$0.9239	($0.1562)	-14.5%
Commercial & Industrial				
Small	$1.0801	$0.9239	($0.1562)	-14.5%
Medium	$1.0801	$0.9239	($0.1562)	-14.5%
Large Low Load Factor	$1.0801	$0.9239	($0.1562)	-14.5%
Large High Load Factor	$1.0338	$0.8529	($0.1809)	-17.5%
Extra Large Low Load Factor	$1.0801	$0.9239	($0.1562)	-14.5%
Extra Large High Load Factor	$1.0338	$0.8529	($0.1809)	-17.5%
Natual Gas Vehicles	$0.9091	$0.7530	($0.1561)	-17.2%
FT-2 Storage Service Charge	$0.0337	$0.0430	$0.0093	27.6%

1/ Source: Docket No. 4199, Attachment JFN-1, September 1, 2010, page 1.

National Grid - RI Gas

Docket No. 4199

Changes in Costs by GCR Cost Component

Based on National Grid's September 1, 2009 and September 1, 2010 GCR Filings
Without Adjustments and Reconciliations

GCR Cost Component	Forecasted Annual Cost 2009-10 1/	Forecasted Annual Cost 2010-11 2/	Change $	Change %
Supply Fixed Costs	$ 29,343,973	$ 27,527,751	$ (1,816,222)	-6.2%
Storage Fixed Costs	$ 10,450,090	$ 11,454,439	$ 1,004,349	9.6%
Supply Variable Costs	$ 196,408,852	$ 149,514,232	$ (46,894,620)	-23.9%
Storage Variable Product Costs	$ 36,624,047	$ 23,083,547	$ (13,540,500)	-37.0%
Storage Variable Non-Product Costs	$ 1,128,324	$ 715,645	$ (412,679)	-36.6%
TOTAL	$ 273,955,286	$ 212,295,614	$ (61,659,672)	-22.5%
Total Fixed Costs	$ 39,794,063	$ 38,982,190	$ (811,873)	-2.0%
Total Variable Costs	$ 234,161,223	$ 173,313,424	$ (60,847,799)	-26.0%

1/ Source: Docket No. 4097, Attachment GLB-1, September 1, 2009, pages 2-5.
2/ Source: Docket No. 4199, Attachment JFN-1, September 1, 2010, pages 2-5.

National Grid - RI Gas

Docket No. 4199

Changes in Reconciliation Amounts by Gas Cost Component

Based on National Grid's September 1, 2009 and September 1, 2010 GCR Filings

GCR Cost Component	Forecasted Annual Cost 2009-10 1/	Forecasted Annual Cost 2010-11 2/	Change $	Change %
Supply Fixed Costs	$ 1,584,026	$ (4,680,040)	$ (6,264,066)	-395.5%
Storage Fixed Costs	$ 1,211,860	$ 256,010	$ (955,850)	-78.9%
Supply Variable Costs	$ 45,481,451	$ 13,406,402	$ (32,075,049)	-70.5%
Storage Variable Product Costs	$ (31,689,296)	$ (460,482)	$ 31,228,814	98.5%
Storage Variable Non-Product Costs	$ (4,883,861)	$ (1,794,337)	$ 3,089,524	63.3%
TOTAL	$ 11,704,180	$ 6,727,553	$ (4,976,627)	-42.5%
Total Fixed Costs	$ 2,795,886	$ (4,424,030)	$ (7,219,916)	-258.2%
Total Variable Costs	$ 8,908,294	$ 11,151,583	$ 2,243,289	25.2%

1/ Source: Docket No. 4097, Attachment GLB-1, September 1, 2009, pages 2-5.

2/ Source: Docket No. 4199, Attachment JFN-1, September 1, 2010, pages 2-5.

National Grid - RI Gas

Docket No. 4199

Changes in Other Adjustment Amounts by Gas Cost Component

Based on National Grid's September 1, 2009 and September 1, 2010 GCR Filings

GCR Cost Component	Forecasted Annual Cost 2009-10 1/	Forecasted Annual Cost 2010-11 2/	Change $	Change %
Supply Fixed Costs	$ (781,773)	$ (2,212,974)	$ (1,431,201)	-183.1%
Storage Fixed Costs	$ 203,923	$ 34,896	$ (169,027)	-82.9%
Supply Variable Costs	$ (203,832)	$ (936,629)	$ (732,797)	-359.5%
Storage Variable Product Costs	$ 2,875,223	$ 2,560,849	$ (314,374)	-10.9%
Storage Variable Non-Product Costs	$ 1,660,598	$ 402,305	$ (1,258,293)	-75.8%
TOTAL	$ 3,754,139	$ (151,553)	$ (3,905,692)	-104.0%
Total Fixed Costs	$ (577,850)	$ (2,178,078)	$ (1,600,228)	-276.9%
Total Variable Costs	$ 4,331,989	$ 2,026,525	$ (2,305,464)	-53.2%

1/ Source: Docket No. 4097, Attachment GLB-1, September 1, 2009, pages 2-5.

2/ Source: Docket No. 4199, Attachment JFN-1, September 1, 2010, pages 2-5.

National Grid - RI Gas

Docket No. 4199

Changes in Forecasted Normal Weather Sales and Throughput by Rate Class
For November through October (12 Months)

	Forecasted 2009-10 Throughput 1/ (MMBtu)	Forecasted 2010-11 Throughput 2/ (MMBtu)	Forecasted Change In Throughput (MMBtu)	Change %
Sales				
Residential Non-Heat	650,517	698,210	47,693	7.3%
Residential Heat	17,121,459	16,815,263	(306,196)	-1.8%
Small C&I	2,672,144	1,987,380	(684,764)	-25.6%
Medium C&I	4,405,703	3,252,891	(1,152,812)	-26.2%
Large LLF	1,419,227	862,458	(556,769)	-39.2%
Large HLF	437,759	235,719	(202,040)	-46.2%
Extra Large LLF	234,991	264,369	29,378	12.5%
Extra Large HLF	312,750	139,872	(172,878)	-55.3%
Total Sales	27,254,552	24,256,162	(2,998,390)	-11.0%
FT-2 Throughput				
Medium C&I	738,021	650,002	(88,019)	-11.9%
Large LLF	621,927	606,975	(14,952)	-2.4%
Large HLF	126,864	144,746	17,882	14.1%
Extra Large LLF	16,538	22,796	6,258	37.8%
Extra Large HLF	94,578	18,203	(76,375)	-80.8%
Total FT-2 Throughput	1,597,928	1,442,722	(155,206)	-9.7%
Total Sales & FT-2 Throughput	28,852,480	25,698,884	(3,153,596)	-10.9%
FT-1 Throughput				
Medium C&I	679,681	619,282	(60,399)	-8.9%
Large LLF	906,304	960,238	53,934	6.0%
Large HLF	579,912	622,524	42,612	7.3%
Extra Large LLF	580,971	538,450	(42,521)	-7.3%
Extra Large HLF	3,759,588	5,021,935	1,262,347	33.6%
Total FT-1 Throughput	6,506,456	7,762,429	1,255,973	19.3%
Total Sales FT-1 & FT-2 Throughpu				
Residential Non-Heat	650,517	698,210	47,693	7.3%
Residential Heat	17,121,459	16,815,263	(306,196)	-1.8%
Small C&I	2,672,144	1,987,380	(684,764)	-25.6%
Medium C&I	5,823,405	4,522,175	(1,301,230)	-22.3%
Large LLF	2,947,458	2,429,671	(517,787)	-17.6%
Large HLF	1,144,535	1,002,989	(141,546)	-12.4%
Extra Large LLF	832,500	825,615	(6,885)	-0.8%
Extra Large HLF	4,166,916	5,180,010	1,013,094	24.3%
Total THROUGHPUT	35,358,936	33,461,313	(1,897,623)	-5.4%

1/ Source: Docket No. 4097, Attachment GLB-1, September 1, 2009, page 14.
2/ Source: Docket No. 4199, Attachment JFN-1, September 1, 2010, page 14.

National Grid - RI Gas
Docket No. 4199

Forecasted Normal Weather Sales & Throughput by Month

	Forecasted 2009-10 Throughput (MMBtu) 1/	Forecasted 2010-11 Throughput (MMBtu) 2/	Forecasted Change In Throughput (MMBtu)	Change %
Sales				
November	1,696,390	1,645,083	(51,307)	-3.0%
December	3,092,425	2,830,271	(262,154)	-8.5%
January	4,535,743	4,004,935	(530,808)	-11.7%
February	4,690,914	4,181,709	(509,205)	-10.9%
March	4,061,612	3,765,571	(296,041)	-7.3%
April	2,970,754	2,790,327	(180,427)	-6.1%
May	1,889,993	1,602,241	(287,752)	-15.2%
June	1,147,972	949,867	(198,105)	-17.3%
July	788,472	631,387	(157,085)	-19.9%
August	672,664	518,143	(154,521)	-23.0%
September	733,349	562,453	(170,896)	-23.3%
October	974,264	774,174	(200,090)	-20.5%
Total Sales	27,254,552	24,256,162	(2,998,390)	-11.0%
FT-2 Throughput				
November	95,791	103,208	7,417	7.7%
December	167,042	160,475	(6,567)	-3.9%
January	252,279	214,635	(37,644)	-14.9%
February	244,941	231,207	(13,734)	-5.6%
March	220,406	200,393	(20,013)	-9.1%
April	185,264	171,481	(13,783)	-7.4%
May	126,591	113,420	(13,171)	-10.4%
June	86,855	74,488	(12,367)	-14.2%
July	49,149	36,450	(12,699)	-25.8%
August	50,766	38,449	(12,317)	-24.3%
September	48,629	56,033	7,404	15.2%
October	70,215	42,483	(27,732)	-39.5%
Total FT-2 Throughput	1,597,928	1,442,722	(155,206)	-9.7%
Sales & FT-2 Throughput				
November	1,792,181	1,748,291	(43,890)	-2.4%
December	3,259,467	2,990,746	(268,721)	-8.2%
January	4,788,022	4,219,570	(568,452)	-11.9%
February	4,935,855	4,412,916	(522,939)	-10.6%
March	4,282,018	3,965,964	(316,054)	-7.4%
April	3,156,018	2,961,808	(194,210)	-6.2%
May	2,016,584	1,715,661	(300,923)	-14.9%
June	1,234,827	1,024,355	(210,472)	-17.0%
July	837,621	667,837	(169,784)	-20.3%
August	723,430	556,592	(166,838)	-23.1%
September	781,978	618,486	(163,492)	-20.9%
October	1,044,479	816,657	(227,822)	-21.8%
Total Sales & FT-2	28,852,480	25,698,884	(3,153,596)	-10.9%

1/ Source: Docket No. 4097, Attachment GLB-1, September 1, 2009, page 14.
2/ Source: Docket No. 4199, Attachment JFN-1, September 1, 2010, page 14.

National Grid - RI Gas
Docket No. 4199

Changes in Forecasted Design Winter Sales and Throughput by Rate Class
For November through October (12 Months)

	Forecasted 2009-10 Throughput (MMBtu) 1/	Forecasted 2010-11 Throughput (MMBtu) 2/	Forecasted Change In Throughput (MMBtu)	Change %
Sales				
Residential Non-Heat	343,337	405,772	62,435	18.18%
Residential Heat	13,016,465	13,013,430	(3,035)	-0.02%
Small C&I	2,033,081	1,610,982	(422,099)	-20.76%
Medium C&I	3,261,290	2,416,991	(844,299)	-25.89%
Large LLF	1,160,904	699,149	(461,755)	-39.78%
Large HLF	236,564	144,596	(91,968)	-38.88%
Extra Large LLF	206,077	240,000	33,923	16.46%
Extra Large HLF	155,779	95,670	(60,109)	-38.59%
Total Sales	20,413,497	18,626,590	(1,786,907)	-8.75%
FT-2 Throughput				
Medium C&I	513,626	452,368	(61,258)	-11.93%
Large LLF	457,296	466,071	8,775	1.92%
Large HLF	64,220	73,840	9,620	14.98%
Extra Large LLF	15,000	19,954	4,954	33.03%
Extra Large HLF	49,111	9,791	(39,320)	-80.06%
Total FT-2 Throughput	1,099,253	1,022,024	(77,229)	-7.03%
Sales & FT-2 Throughput				
Residential Non-Heat	343,337	405,772	62,435	18.18%
Residential Heat	13,016,465	13,013,430	(3,035)	-0.02%
Small C&I	2,033,081	1,610,982	(422,099)	-20.76%
Medium C&I	3,774,916	2,869,359	(905,557)	-23.99%
Large LLF	1,618,200	1,165,220	(452,980)	-27.99%
Large HLF	300,784	218,436	(82,348)	-27.38%
Extra Large LLF	221,077	259,954	38,877	17.59%
Extra Large HLF	204,890	105,461	(99,429)	-48.53%
Total Sales & FT-2 Throughput	21,512,750	19,648,614	(1,864,136)	-8.67%

1/ Source: Docket No. 4097, Attachment GLB-1, September 1, 2009, page 15.
2/ Source: Docket No. 4199, Attachment JFN-1, September 1, 2010, page 15.

National Grid - RI Gas
Docket No. 4199

Forecasted Design Winter Sales & Throughput by Month

	Forecasted 2009-10 Throughput 1/ (MMBtu)	Forecasted 2010-11 Throughput 2/ (MMBtu)	Forecasted Throughput Increase (MMBtu)	% Increase
Sales				
November	2,696,056	2,420,992	(275,064)	-10.20%
December	4,482,493	4,098,495	(383,998)	-8.57%
January	4,876,345	4,469,187	(407,158)	-8.35%
February	4,630,437	4,249,392	(381,045)	-8.23%
March	3,728,166	3,388,525	(339,641)	-9.11%
Total Sales	20,413,497	18,626,591	(1,786,906)	-8.75%
FT-2 Throughput				
November	149,266	137,814	(11,452)	-7.67%
December	240,503	223,813	(16,690)	-6.94%
January	260,528	242,711	(17,817)	-6.84%
February	246,806	230,067	(16,739)	-6.78%
March	202,149	187,619	(14,530)	-7.19%
Total FT-2 Throughput	1,099,252	1,022,024	(77,228)	-7.03%
Sales & FT-2 Throughput				
November	2,845,322	2,558,806	(286,516)	-10.07%
December	4,722,996	4,322,308	(400,688)	-8.48%
January	5,136,873	4,711,898	(424,975)	-8.27%
February	4,877,243	4,479,459	(397,784)	-8.16%
March	3,930,315	3,576,144	(354,171)	-9.01%
Total Sales & FT-2	21,512,749	19,648,615	(1,864,134)	-8.67%

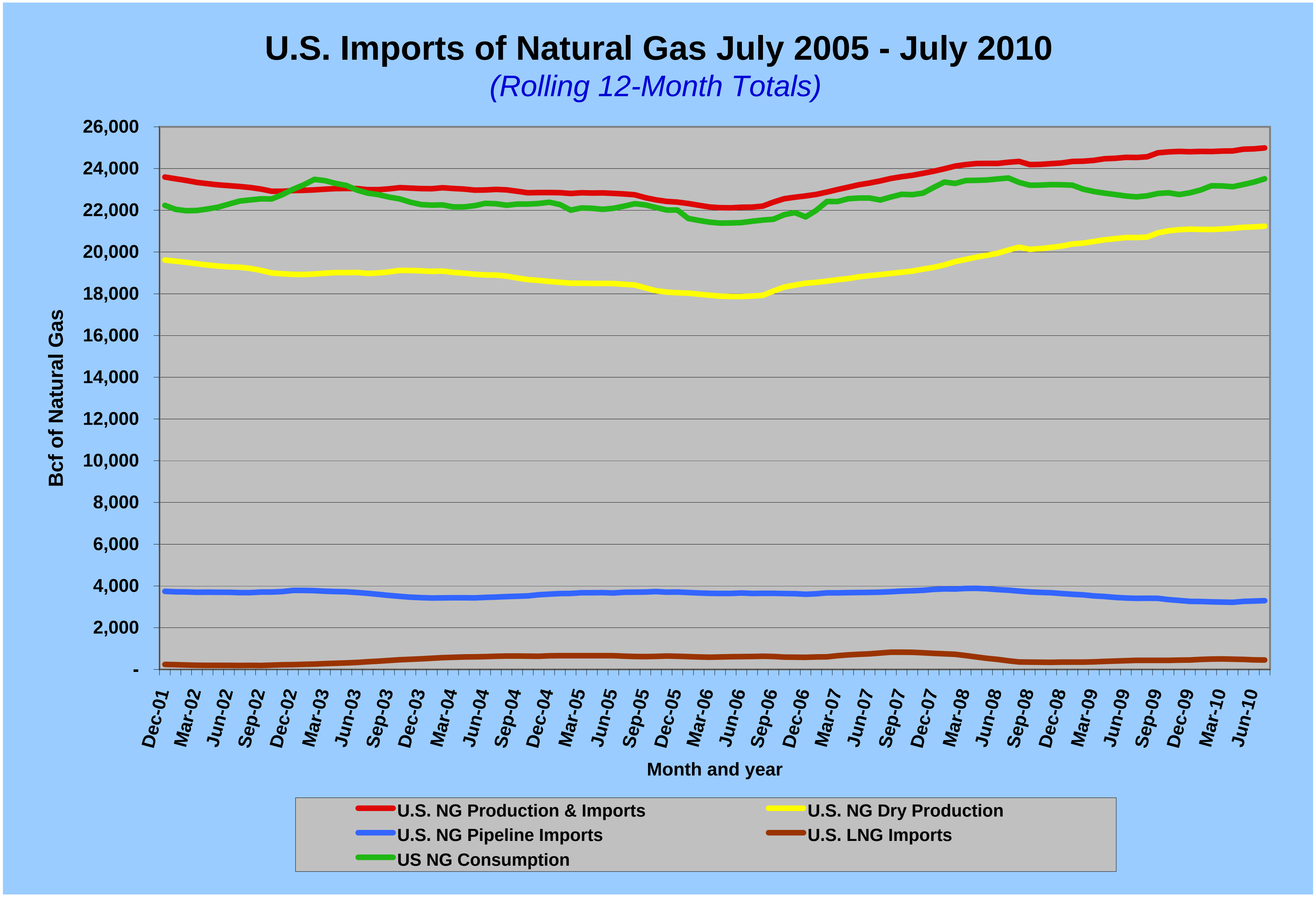
1/ Source: Docket No. 4097, Attachment GLB-1, September 1, 2009, page 15.
2/ Source: Docket No. 4199, Attachment JFN-1, September 1, 2010, page 15.

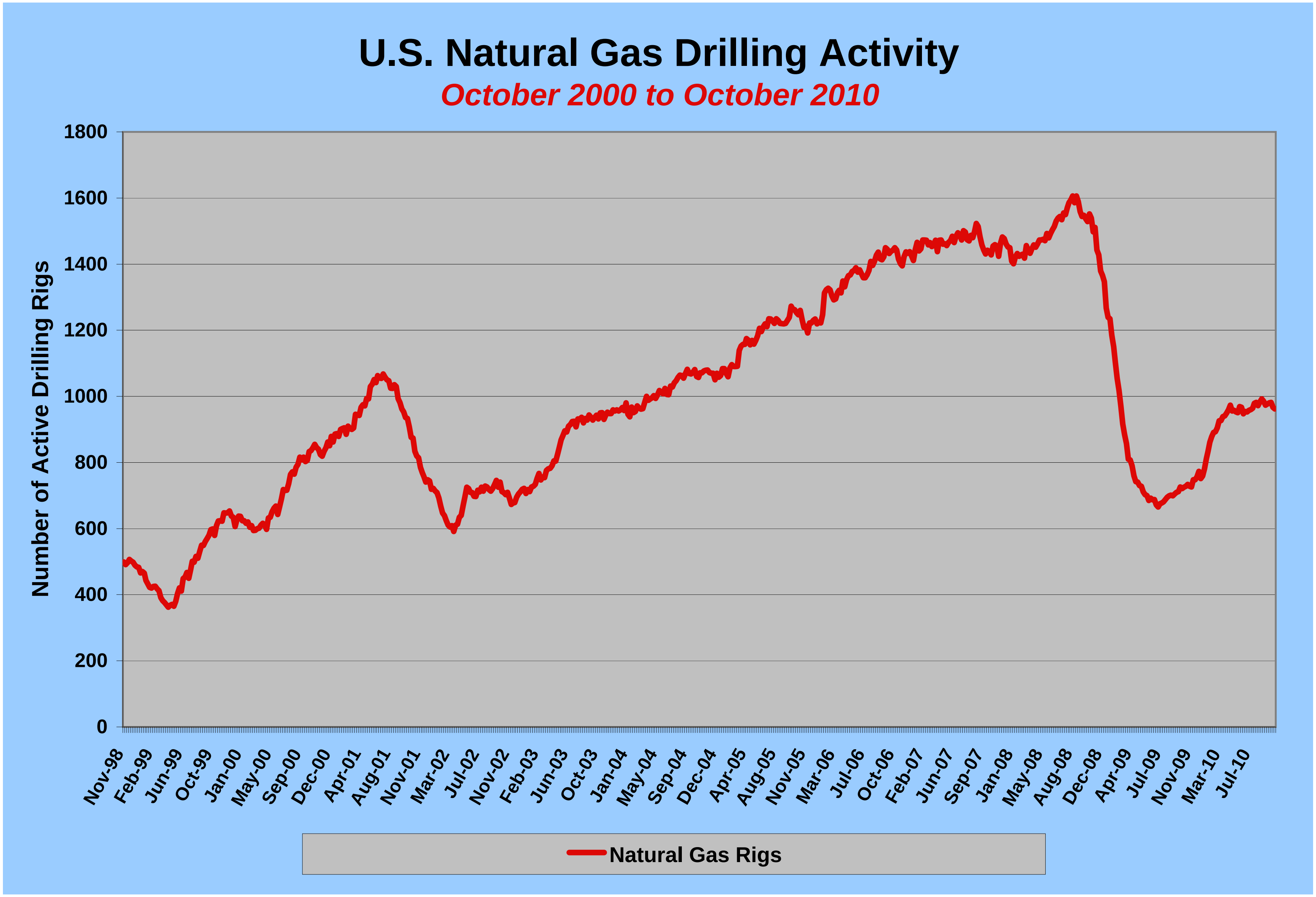
National Grid - RI Gas
Docket No. 4199

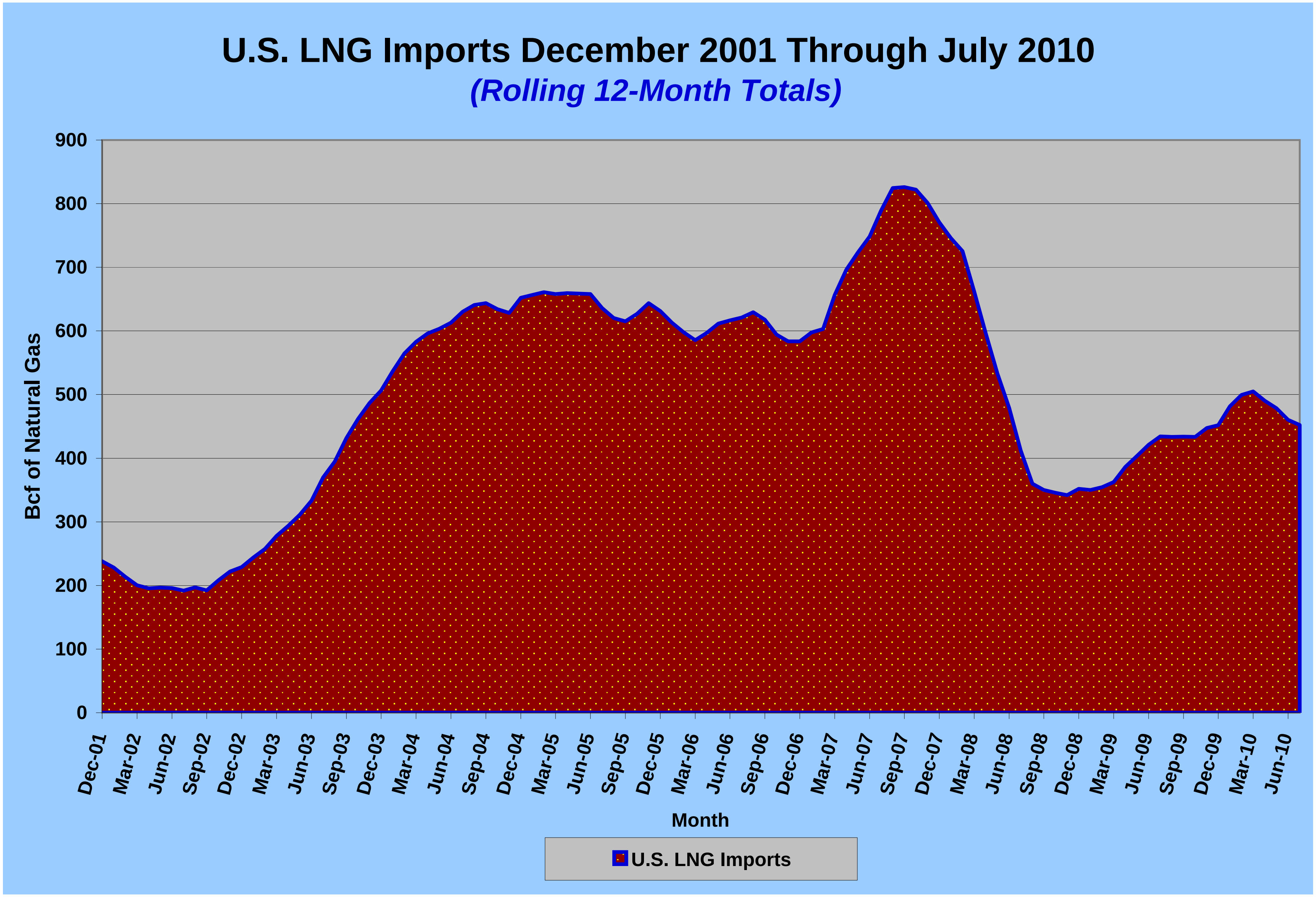
Comparison of Forecasted and Actual Sales and Throughput by Rate Class

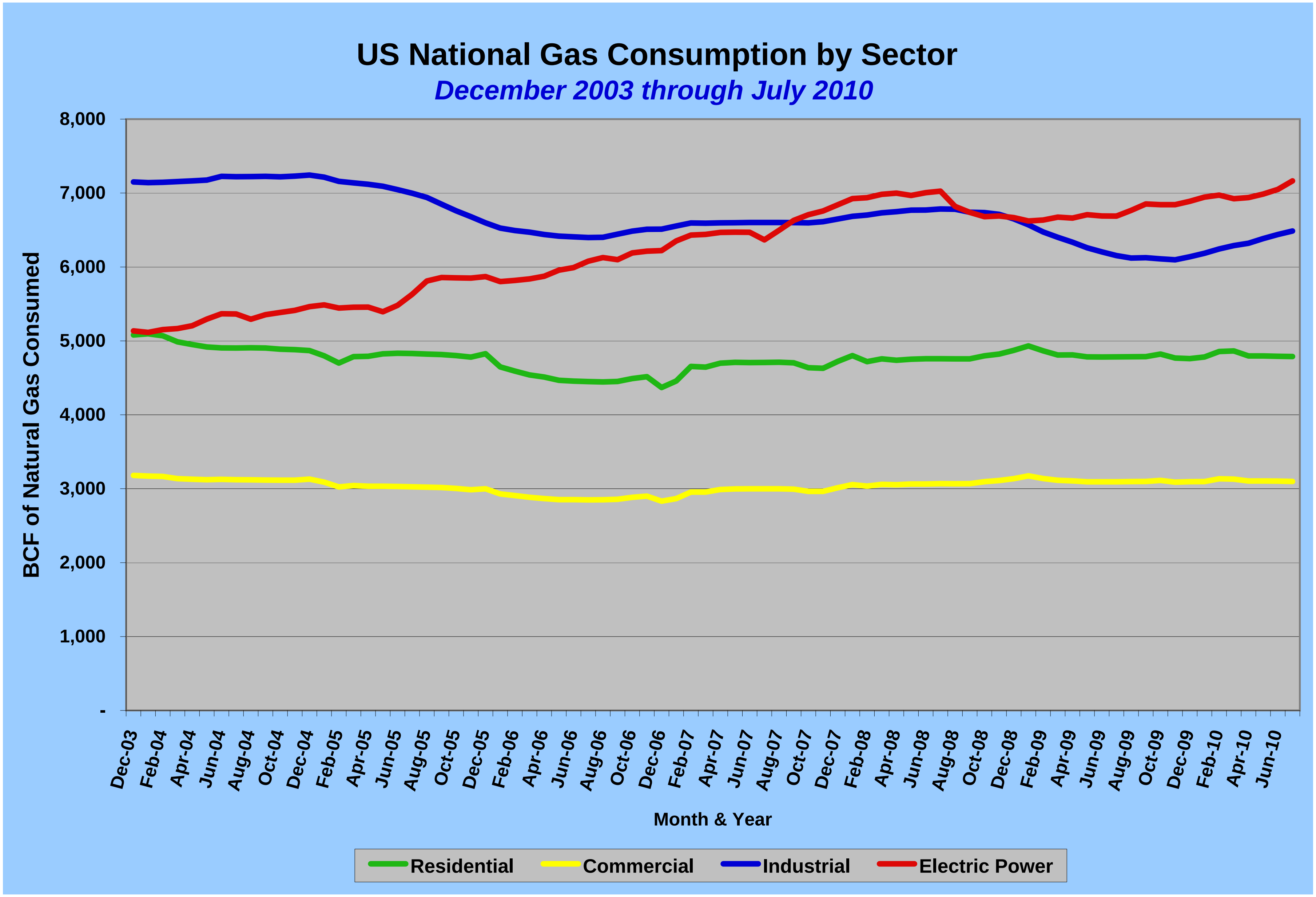
	Actual Jul 09 - Jun 10 Throughput 1/ (MMBtu)		Forecasted 2010-11 Throughput 2/ (MMBtu)	Change in Forecasted Throughput (MMBtu)	% Change
Sales					
Residential Non-Heat	698,968		698,210	(758)	-0.1%
Residential Heat	16,679,421		16,815,263	135,842	0.8%
Small C&I	2,225,030		1,987,380	(237,650)	-10.7%
Medium C&I	3,375,519		3,252,891	(122,628)	-3.6%
Large LLF	736,291		862,458	126,167	17.1%
Large HLF	365,280		235,719	(129,561)	-35.5%
Extra Large LLF	33,849		264,369	230,520	681.0%
Extra Large HLF	262,374		139,872	(122,502)	-46.7%
Total Sales	24,376,731		24,256,162	(120,569)	-0.5%
FT-2 Throughput					
Medium C&I	891,306		650,002	(241,304)	-27.1%
Large LLF	674,479		606,975	(67,504)	-10.0%
Large HLF	178,924		144,746	(34,178)	-19.1%
Extra Large LLF	52,826		22,796	(30,030)	-56.8%
Extra Large HLF	83,176		18,203	(64,973)	-78.1%
Total FT-2 Throughput	1,880,711		1,442,722	(437,989)	-23.3%
Total Sales & FT-2 Throughput	26,257,442		25,698,884	(558,558)	-2.1%
FT-1 Throughput					
Medium C&I	724,106		619,282	(104,824)	-14.5%
Large LLF	999,111		960,238	(38,873)	-3.9%
Large HLF	580,922		622,524	41,602	7.2%
Extra Large LLF	516,063		538,450	22,387	4.3%
Extra Large HLF	4,584,423		5,021,935	437,512	9.5%
Total FT-1 Throughput	7,508,380	3/	7,762,429	357,804	4.8%
Total All Throughput Classifications					
Residential Non-Heat	698,968		698,210	(758)	-0.1%
Residential Heat	16,679,421		16,815,263	135,842	0.8%
Small C&I	2,225,030		1,987,380	(237,650)	-10.7%
Medium C&I	4,990,931		4,522,175	(468,756)	-9.4%
Large LLF	2,409,881		2,429,671	19,790	0.8%
Large HLF	1,125,126		1,002,989	(122,137)	-10.9%
Extra Large LLF	602,738		825,615	222,877	37.0%
Extra Large HLF	4,929,973		5,180,010	250,037	5.1%
Total System Throughput	33,765,822		33,565,068	(98,189)	-0.3%

1/ Source: Docket No. 4199, Attachment JFN-2, September 1, 2010, page 14. Actual sales include TSS volumes.
2/ Source: Docket No. 4199, Attachment JFN-1, September 1, 2010, page 14.
3/ Total includes 103,755 Dth of Default Service throughput.


U.S. Imports of Natural Gas July 2005 - July 2010
(Rolling 12-Month Totals)
Bcf of Natural Gas
26,000
24,000
22,000
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
-
Dec-01
Mar-02
Jun-02
Sep-02
Dec-02
Mar-03
Jun-03
Sep-03
Dec-03
Mar-04
Jun-04
Sep-04
Dec-04
Mar-05
Jun-05
Sep-05
Dec-05
Mar-06
Jun-06
Sep-06
Dec-06
Mar-07
Jun-07
Sep-07
Dec-07
Mar-08
Jun-08
Sep-08
Dec-08
Mar-09
Jun-09
Sep-09
Dec-09
Mar-10
Jun-10
Month and year
U.S. NG Production & Imports
U.S. NG Dry Production
U.S. NG Pipeline Imports
U.S. LNG Imports
US NG Consumption


U.S. Natural Gas Drilling Activity
October 2000 to October 2010
Number of Active Drilling Rigs
0
200
400
600
800
1000
1200
1400
1600
1800
Nov-98
Feb-99
Jun-99
Oct-99
Jan-00
May-00
Sep-00
Dec-00
Apr-01
Aug-01
Nov-01
Mar-02
Jul-02
Nov-02
Feb-03
Jun-03
Oct-03
Jan-04
May-04
Sep-04
Dec-04
Apr-05
Aug-05
Nov-05
Mar-06
Jul-06
Oct-06
Feb-07
Jun-07
Sep-07
Jan-08
May-08
Aug-08
Dec-08
Apr-09
Jul-09
Nov-09
Mar-10
Jul-10
Natural Gas Rigs


U.S. LNG Imports December 2001 Through July 2010
(Rolling 12-Month Totals)
Bcf of Natural Gas
900
800
700
600
500
400
300
200
100
0
Dec-01
Mar-02
Jun-02
Sep-02
Dec-02
Mar-03
Jun-03
Sep-03
Dec-03
Mar-04
Jun-04
Sep-04
Dec-04
Mar-05
Jun-05
Sep-05
Dec-05
Mar-06
Jun-06
Sep-06
Dec-06
Mar-07
Jun-07
Sep-07
Dec-07
Mar-08
Jun-08
Sep-08
Dec-08
Mar-09
Jun-09
Sep-09
Dec-09
Mar-10
Jun-10
Month
U.S. LNG Imports


US National Gas Consumption by Sector
December 2003 through July 2010
BCF of Natural Gas Consumed
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
Dec-03
Feb-04
Apr-04
Jun-04
Aug-04
Oct-04
Dec-04
Feb-05
Apr-05
Jun-05
Aug-05
Oct-05
Dec-05
Feb-06
Apr-06
Jun-06
Aug-06
Oct-06
Dec-06
Feb-07
Apr-07
Jun-07
Aug-07
Oct-07
Dec-07
Feb-08
Apr-08
Jun-08
Aug-08
Oct-08
Dec-08
Feb-09
Apr-09
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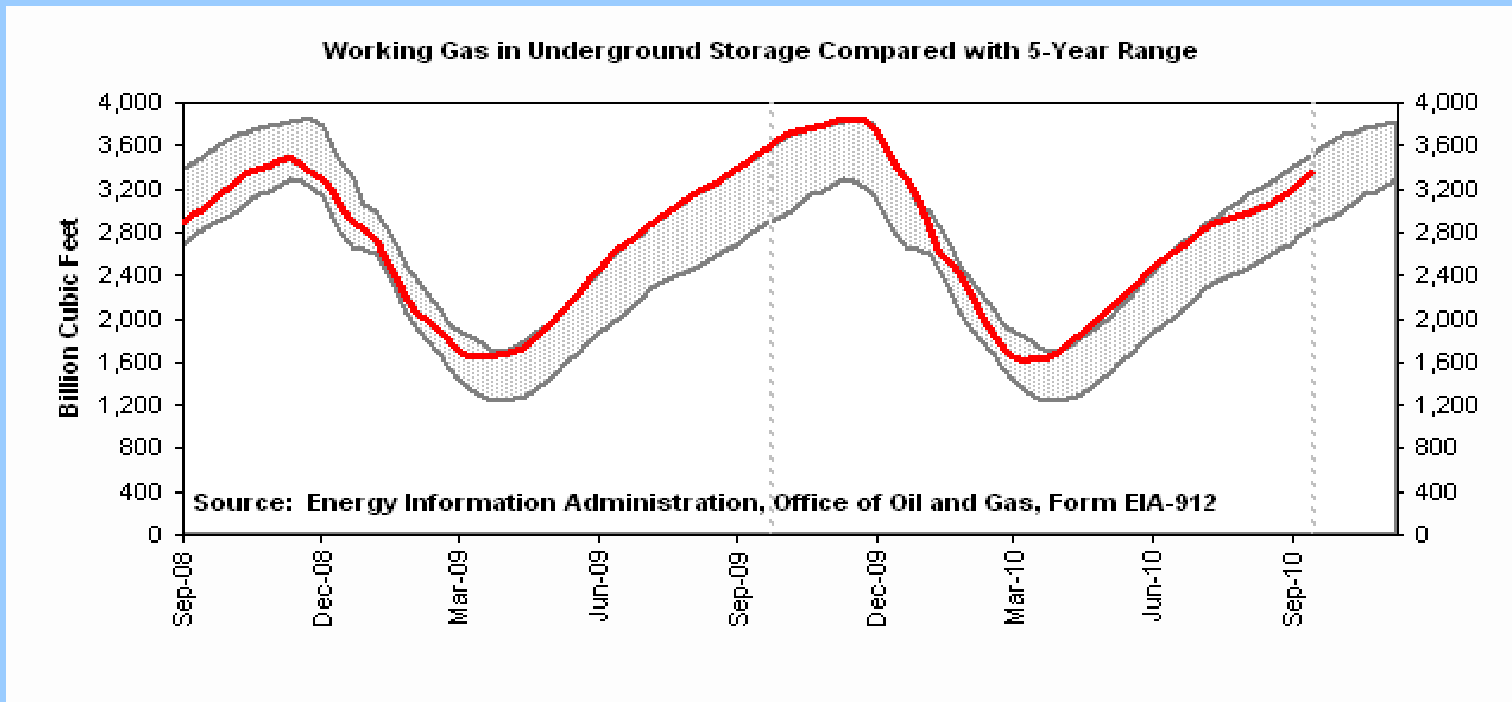
Feb-10
Apr-10
Jun-10
Month & Year
Residential
Commercial
Industrial
Electric Power



Region	Stocks in Billion cubic feet (Bcf)			Historical Comparison			
				Year Ago (09/24/09)		5-Year (2005-2009) Average	
	09/24/10	09/17/10	Change	Stocks (Bcf)	Change	Stocks (Bcf)	Change
East	1,867	1,819	48	1,950	-4.3%	1,845	1.2%
West	497	492	5	488	1.8%	436	14.0%
Producing	1,050	1,029	21	1,142	-8.1%	931	12.8%
Total	3,414	3,340	74	3,580	-4.6%	3,212	6.3%

Exhibit BRO - 7

October 7, 2010

National Grid - RI Gas
Docket No. 4199

Division Recommended Gas Cost Recovery (GCR) Charges
Rates Effective November 1, 2010
($ per Dth)

Line No.	Description (a)	Reference (b)	Residential Non-Heat (c)	Residential Heating (d)	Small C&I (e)	Medium C&I (f)	Large LLF (g)	Large HLF (h)	Extra Large LLF (i)	Extra Large HLF (j)	FT-2 Marketer (k)	NGV (l)
1	Supply Fixed Cost Factor	JFN-1, p. 2	$0.6342	$0.8176	$0.8176	$0.8176	$0.8176	$0.6342	$0.8176	$0.6342	n/a	$0.6342
2	Storage Fixed Cost Factor	JFN-1, p. 3	$0.3725	$0.4883	$0.4883	$0.4883	$0.4883	$0.3725	$0.4883	$0.3725	$0.4554	n/a
3	Supply Variable Cost Factor	BRO-9, p. 2	$6.6224	$6.6224	$6.6224	$6.6224	$6.6224	$6.6224	$6.6224	$6.6224	n/a	$6.6224
4a	Storage Variable Product Cost Factor	JFN-1, p. 5	$1.0382	$1.0382	$1.0382	$1.0382	$1.0382	$1.0382	$1.0382	$1.0382	n/a	n/a
4b	Storage Variable Non-product Cost Factor	JFN-1, p. 5	($0.0263)	($0.0263)	($0.0263)	($0.0263)	($0.0263)	($0.0263)	($0.0263)	($0.0263)	($0.0263)	n/a
5	Total Gas Cost Recovery Charge	(1)+(2)+(3)+(4)	$ 8.6411	$ 8.9403	$ 8.9403	$ 8.9403	$ 8.9403	$ 8.6411	$ 8.9403	$ 8.6411	$ 0.4291	$ 7.2566
6	Uncollectible %	Docket 3943	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%
7	Total GCR Charge Adjusted for Uncollectibles	(5)/[(1)-(6)]	$ 8.8536	$ 9.1602	$ 9.1602	$ 9.1602	$ 9.1602	$ 8.8536	$ 9.1602	$ 8.8536	$ 0.4397	$ 7.4352
8	**GCR Charge on a per therm basis**	(7)/10	**$ 0.8854**	**$ 0.9160**	**$ 0.9160**	**$ 0.9160**	**$ 0.9160**	**$ 0.8854**	**$ 0.9160**	**$ 0.8854**	**$ 0.0440**	**$ 0.7435**
9	Current Effective Rate 11/1/09	Docket 4097	$1.0338	$1.0801	$1.0801	$1.0801	$1.0801	$1.0338	$1.0801	$1.0338	$0.0337	$0.9091
10	Difference	(8)-(9)	$ (0.1484)	$ (0.1641)	$ (0.1641)	$ (0.1641)	$ (0.1641)	$ (0.1484)	$ (0.1641)	$ (0.1484)	$ 0.0103	$ (0.1656)
11	Percent Change	(10)/(9)	-14.4%	-15.2%	-15.2%	-15.2%	-15.2%	-14.4%	-15.2%	-14.4%	30.5%	-18.2%

National Grid - RI Gas
Docket No. 4199

Gas Cost Recovery (GCR)
Division Adjusted Supply Fixed Cost Calculation ($ per therm)

Ln No	Description	Reference	Amount As Filed By Company	Division Adjustment	Adjusted Amount	Residential Heating	Small C&I	Medium C&I	Large LLF	Extra Large LLF	Low Load Factor Total	Residential Non-Heat	Large HLF	Extra Large HLF	High Load Factor Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	Supply Fixed Costs	EDA-1	$ 27,527,751		$27,527,751										
2	Less:														
3	NGPMP Customer Benefit	BRO	$ 2,400,000	$1,000,000	$ 3,400,000										
4	Interruptible Costs		$ -		$ -										
5	Non-Firm Sales Costs		$ -		$ -										
6	Off-System Sales Margin		$ -		$ -										
7	Refunds		$ -		$ -										
8	Total Credits	Sum[(3)-(7)]	$ 2,400,000	$1,000,000	$ 3,400,000										
9	Plus:														
10	Working Capital Requirement	JFN-1, p. 10	$ 187,026		$ 187,026										
11	Reconciliation Amount	JFN-1, p. 8	$ (4,680,040)	$ -	$ (4,680,040)										
12	Total Additions	(10) + (11)	$ (4,493,014)	$ -	$ (4,493,014)										
13	Total Storage Fixed Costs	(1) - (8) + (12)	$ 20,634,737	$ (1,000,000)	**$19,634,737**										
14	Design Winter Sales (Dth) %	JFN-1, p. 15				69.86%	8.65%	12.98%	3.75%	1.29%	96.53%	2.18%	0.78%	0.51%	3.47%
15	Allocated Storage Fixed Costs	(13) x (14)				$ 13,717,770	$1,698,175	$ 2,547,808	$ 736,990	$ 252,990	$ 18,953,733	$ 427,734	$ 152,422	$100,848	$ 681,004
16	Sales (Dth) Nov 10 - Oct 11	JFN-1, p. 14	25,698,884			16,815,263	1,987,380	3,252,891	862,458	264,369	23,182,361	698,210	235,719	139,872	1,073,801
17	Supply Fixed Cost Factor	(15)/(16)									**$ 0.8176**				**$ 0.6342**

National Grid - RI Gas

Docket No. 4199

Gas Cost Recovery (GCR)
Division Adjusted Storage Fixed Cost Calculation ($ per therm)

Ln No	Description	Reference	Amount As Filed By Company	Division Adjustment	Adjusted Amount	Residential Heating	Small C&I	Medium C&I	Large LLF	Extra Large LLF	Low Load Factor Total	Residential Non-Heat	Large HLF	Extra Large HLF	High Load Factor Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	Storage Fixed Costs	EDA-1	$ 11,454,439		$11,454,439										
2	Less:														
3	LNG Demand to DAC	EAD-2/Dkt 3943	$661,228	($661,228)	$ -										
4	Credits		$0		$ -										
5	Refunds		$0		$ -										
6	Total Credits	Sum[(3)-(5)]	$661,228	($661,228)	$ -										
7	Plus:														
8	Supply Related LNG O&M Costs	pg. 8	$ 618,591		$ 618,591										
9	Working Capital Requirement	pg. 6	$ 77,533	$ -	$ 77,533										
10	Reconciliation Amount	pg. 6	$ 256,010	$ -	$ 256,010										
11	Total Additions	(10) + (11)	$ 952,134	$ -	$ 952,134										
12	Total Storage Fixed Costs	(1) -(8) + (12)	$ 11,745,345	$ 661,228	$12,406,573										
13	Design Winter Throughput (Dt) %	JFN-1, p. 15				66.23%	8.20%	14.60%	5.93%	1.32%	96.29%	2.07%	1.11%	0.54%	3.71%
14	Allocated Storage Fixed Costs	(12) x (13)				$ 8,216,970	$1,017,210	$ 1,811,777	$ 735,746	$ 164,141	$ 11,945,844	$ 256,214	$ 137,925	$ 66,590	$ 460,729
15	Throughput (DTh) Nov 10 - Oct 11	JFN-1, p. 14	25,698,884			16,815,263	1,987,380	3,902,893	1,469,433	287,165	24,462,134	698,210	380,465	158,075	1,236,750
16	Storage Fixed Cost Factor	(15)/(16)									**$ 0.4883**				**$ 0.3725**

National Grid - RI Gas

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Gas Cost Recovery (GCR)
Division Adjusted Variable Supply Cost Calculation ($ per therm)

Ln No	Description	Reference	Amount As Filed By Company	Division Adjustment	Adjusted Amount
	(a)	(b)	(c)		
1	Variable Supply Costs	EDA-1	$ 149,514,232		$ 149,514,232
2	Less:				
3	Non-Firm Sales Costs		$0		$ -
4	Variable Delivery Storage Costs	JFN-1, p 4	$0		$ -
5	Variable Injection Storage Costs	JFN-1, p 4	$0		$ -
6	Fuel Costs Allocated to Storage	EDA-2	$323,191		$ 323,191
7	Refunds (Tennessee Pipeline PCB)		$1,627,056		$ 1,627,056
8	Total Credits	Sum[(3)-(7)]	$1,950,246		$ 1,950,246
9	Plus:				
10	Working Capital Requirement	pg. 8	$ 1,013,618		$ 1,013,618
11	Reconciliation Amount	pg. 6	$ 13,406,402	$ (1,348,893)	$ 12,057,509
12	Total Additions	(10) + (11)	$ 14,420,020	$ (1,348,893)	$ 13,071,127
13	Total Supply Fixed Costs	(1) -(8) + (12)	$ 161,984,006	$ (1,348,893)	$ 160,635,112
14	Sales (Dt) Nov 2009 - Oct 2010	JFN-1, p.14	24,256,162		24,256,162
15	Variable Supply Cost Factor	(15)/(16)	**$6.6781**		**$6.6224**

National Grid - RI Gas

Docket No. 4199

Gas Cost Recovery (GCR)
Division Adjusted Storage Variable Cost Calculation ($ per therm)

Ln No	Description	Reference	Amount As Filed By Company	Division Adjustment	Adjusted Amount
	(a)	(b)	(c)		
1	Storage Variable Costs	EDA-1	$ 23,083,547	$ -	$ 23,083,547
2	Less:				
3	Balancing Related LNG Costs (to DAC)		$ 349,551	$ (349,551)	$ -
4	Refunds		$ -		$ -
5	Total Credits	Sum[(3)-(7)]	$ 349,551	$ (349,551)	$ -
6	Plus:				
7	Supply Related LNG O&M	Dkt 3943	$ 430,129	$ -	
8	Working Capital	JFN-1, p.11	$ 157,379	$ -	$ 157,379
9	Inventory Financing - LNG	JFN-1, p.13	$ 478,213	$ -	$ 478,213
10	Inventory Financing - Storage	JFN-1, p.13	$ 1,844,679	$ 96,562	$ 1,941,241
11	Reconciliation Amount	JFN-1, p.9	$ (460,482)	$ -	$ (460,482)
12	Total Additions	(10) + (11)	$ 635,592	$ -	$ 635,592
13	Total Supply Fixed Costs	(1) -(8) + (12)	$ 23,369,588	$ 349,551	$ 23,719,139
14	Sales (Dt) Nov 2009 - Oct 2010	JFN-1, p.14	24,256,162		24,256,162
15	Storage Variable Cost Factor	(15)/(16)	**$0.9634**		**$0.9779**