MEMORANDUM

TO: Rhode Island Public Utilities Commission

FROM: Bruce R. Oliver, Revilo Hill Associates, on behalf of the Division of Public Utilities and Carriers

DATE: October 8, 2013 (Revised October 10, 2013)

SUBJECT: Review of National Grid's 2013 GCR Filing, Docket 4436.

This memorandum reports on the status of the review by Revilo Hill Associates, Inc. of National Grid's 2013 Annual Gas Cost Recovery filing. Due to the limited time between the filing of the Company's testimony and exhibits and the due date for submission of the Division's assessment of the Company's filing, our assessment is not complete as of this time, and the some of the observations offered below must be considered preliminary.

The Company's September 3, 2013 filing comprises two non-confidential volumes (plus an additional volume which contains confidential material), testimony of three witnesses, and supporting schedules totaling 430 pages. We have prepared and submitted three sets of data requests relating to those materials, but to date, time has permitted the Company's response to most of those requests only in the past few days, and we have had less than one week to review and analyze the content of those responses. Furthermore, I note that we have asked in the past that the Division's review of the Company's filing be facilitated by the Company's provision of the electronic spreadsheet files from which filed schedules are generated at the time of the filing of its Direct Testimony. That has not occurred this year. Rather, only in the last couple days have we started to receive such files. We therefore, reiterate that in the context of the tight time schedule for review of National Grid's annual GCR filings, the importance of early receipt of supporting workpapers and electronic spreadsheet files cannot be overstated.

Based on the information and materials reviewed to date, we offer the following observations:

1. **Overall** National Grid's projected **costs of gas** prior to adjustments and reconciliations for the November 1, 2013 through October 31, 2014 period have **declined** by **nearly $3.5 million or 2.1%** from the levels the Company projected one year earlier in Docket No. 4346. (See Attachment BRO-1, line 24).

    a. The Company's projected total **Fixed Costs** for the 2013-2014 GCR year have **increased** by **$4.8 million or 12.1%** prior to consideration of adjustments and reconciliations. (Attachment BRO-1, line 3).

b. The Company's projected total **Variable Costs** for the 2013-2014 GCR year have **decreased** by **$8.3 million or 6.7%** prior to consideration of adjustments and reconciliations. (Attachment BRO-1, line 15).

2. The Company's determination of the amount of costs it must recover through the GCR for the period from November 1, 2013 through October 31, 2014 adds a number of cost adjustments and reconciliations to its projected costs of gas.

   a. With all cost adjustments and reconciliations considered, the Company's **overall costs of gas** to be recovered through its 2013-14 GCR charges have increased by **$5.1 million** or **3.2%**. (Attachment BRO-1, line 25). Also, the relative magnitudes of the changes in the Company's overall Fixed Costs and Variable Costs relative to those included in the Company's prior year's annual GRC filing are **reversed**.

   b. After all adjustments and reconciliations, the **Fixed Cost** component of National Grid's gas cost recovery requirements for 2013-14 **decline $13.3 million or 29.7%** from the overall Fixed Costs reflected in the Company's 2012-13 annual GCR filing. (Attachment BRO-1, line 12).

   c. After all adjustments and reconciliations, The Company's **Variable Cost** recovery requirement is **$18.4 million or 15.8% above** the level of Variable Cost recovery that National Grid included in its 2012-13 GCR annual GCR filing. (Attachment BRO-1, line 23).

3. The **major drivers** of the swings in Total Fixed and Total Variable costs after adjustments and reconciliations are **large changes** in the **deferred balances** for Fixed Costs and for Variable costs.

   a. In the Company's 2012-13 annual GCR filing, **Deferred Fixed Costs** had an **over-recovery** balance of **$10.7 million.** In this docket, National Grid reflects an **under-recovery** of Fixed Costs in the amount of **$4.2 million**. That change represents a **-$14.9 million net change** in the under (over)-recovery balance to be collected through the GCR for the November 2013 through October 2014 period. (Attachment BRO-1, line 9).

   b. Conversely, the Company's 2012-13 GCR filing reflected a **$10.2 million over-recovery** of **Variable Costs** while its filing in this docket for 2013-14 GCR rates includes **under-recovery of $16.1 million**. This change in the deferred balance for Variable Costs represents a rather dramatic **$26.3 million increase** in National Grid's 2013-14 GCR Variable Cost recovery requirements. (Attachment BRO-1, line 18).

4. The calculations supporting the proposed 2013-14 GCR charges appear to be accurate and consistent with established procedures for computing those charges.

5. Given the Company's cost inputs and its sales and throughput forecasts for the 2013-2014 GCR year, no problems are found in the mathematical computations used to produce the Company's recommended GCR charges.

6. The Gas Cost Reconciliations presented in Attachment AEL-2 are heavily influenced by the $6.8 million[1] upward revision that National Grid made to commodity costs in May 2013. This is the second time in two years that National Grid has made significant upward revisions to its deferred gas costs that included adjustments to costs that were the subject of prior gas cost reconciliation filings.

7. The Company's recent Monthly GCR Deferred Balance reports show comparatively large **negative** Sales volumes in certain months for the Extra Large LLF and HLF sales service classifications that need further explanation. For example, in May 2013 the Company reflects a negative sales volume for Extra Large LLF customers of (71,177) Dth. That equates to more than 40% of the total annual sales volume for the entire class and warrants further explanation.

8. A comparison of the forecasted **normal weather** sales and throughput in Attachment AEL-1, page 11 of 12, to witness Leary's testimony to the Company's sales and throughput forecasts in its two preceding annual GCR filings finds:

    a. A greater than 4% overall increase in forecasted annual sales and throughput requirements. After years of very low or negative growth, the Company's projections in this Docket represent one of the largest forecasted year-to-year increases in total sales and throughput volumes over the last couple of decades.

    b. An **unexpectedly large increase** in projected sales to **Residential Non-Heating** customers. Although the Company's number of Residential Non-Heating customers and its sales to those customers have generally been declining over the last couple of decades, National Grid's forecasted Residential Non-Heating Sales represents an **increase of greater than 153,000 Dth or 27%** over the prior year forecast. The increase projected in Design Winter requirements for the Residential Non-Heating class is **greater than 37%**.

    c. Very large percentage increases in projected Annual Sales & Throughput and Design Winter Sales for Large HLF, Extra Large HLF, and Extra Large LLF rate classifications. For the two Extra Large rate classifications

[1] The referenced $6.8 million adjustment was made to its claimed commodity costs of gas to reflect costs of gas sold to third parties that were "inadvertently omitted" from its reported gas costs. As indicated in National Grid's response to Division Data Request 1-1, regarding the Company's May 20, 2013 filing, those adjustments to the Company's pipeline commodity charges (coupled with adjustments made to the Beginning Balance, working capital and associated interest) resulted in a total upward adjustment to the Company's deferred gas costs of **$7.3 million.**

the forecasted **increases** in Design Winter volumes are **in excess of 125%**.

9. The Company's tariff requires that a high load factor customer have at least 31% of annual gas use in the months of May through October. With projections of greater growth in winter month sales for the Residential Non-Heating class the percentage of gas use for that class in the months of May through October would fall below 31% and would no longer meet the threshold for GCR rate treatment as a high load factor rate classification. Rate equity considerations suggest that this situation should be closely monitored. Also, the Commission should require National Grid to investigate the factors causing the identified change in Residential Non-Heating usage characteristics.

10. Exhibit AEL-1, page 12 of 12, reflects a Design Day Peak for the winter of 2013-14 of **328,454 Dth**. That is 4.27% above the 315,000 Dth Design Day Peak that was forecasted for January 2014 in the Company's March 8, 2012 Long-Range Plan. It is also more than 9,000 Dth or about 3% above the 319,000 Dth that National Grid has forecasted for its Design Day Peak in **2016**. If this forecast is accepted as reliable, then the Company may need additional peak supply resources sooner than expected. In Docket No. 4346, the Division recommended that National Grid be required to provide a new five-year Gas Supply Plan every three years. This requirement is necessary to avoid situations, such as that encountered prior to the preparation of National Grid's last five-year plan, where the Company had progressed beyond the last year of its most recent planning study and the Commission was left with no basis for evaluating the reasonableness of the Company's overall gas supply portfolio. The changes in the Company's forecasted peak requirements identified herein provide further evidence of the need for more frequent review of the Company's long-range gas supply plans.

11. The testimony of National Grid witness McCauley at page 4 of 9 indicates that the Company has earned a calculated GPIP incentive of $453,345 for the reconciliation period (i.e., the nine months ended March 31, 2013). Although the extensive data and computations underlying that determination are still being reviewed, nothing has been identified to date that raises concerns regarding the accuracy of the Company's computed GPIP incentive amount for the nine-month period ended March 31, 2013.[2]

12. Witness McCauley's filed Direct Testimony at page 9, lines 3-5, requests the Commission's approval of a NGPMP incentive to the Company in the amount of $1,482,571.33 for the twelve-month period ended March 31, 2013.

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[2] The Division's assessment of this matter would be greatly facilitated by the receipt of the electronic spreadsheet files used to generate the pages of Attachment SAM-2 to witness McCauley's testimony at the time of the filing.,

13. Witness McCauley's Direct Testimony at pages 9-10 discusses that the Company's proposal for extension of the NGPMP for an additional four years (i.e., through March 2018). As part of his presentation regarding the proposed NGPMP extension, McCauley suggests that the Company should be free to utilize any combination of (1) internal asset management, (2) capacity release arrangements, and (3) external asset management through Asset Management Agreements (AMAs) with third parties that the Company deems appropriate. Although the Division generally supports the requested extension of the NGPMP, I cannot concur with witness McCauley's suggestion that the Commission should be indifferent with respect to the manner in which National Grid chooses to manage its natural pipeline and storage gas assets.

a. When the NGPMP was initiated, National Grid represented that it could provide asset management services more cost-effectively than third parties that offer similar asset management services. In that context, National Grid represented that, through self-management of the Company's gas assets, it could extract greater net asset management benefits for its RI firm service customers.

b. In the last couple of years National Grid has begun outsourcing portions of its gas asset management activities to third parties arguing that the selected third party asset managers can derive greater net asset management revenue from certain assets than National Grid could achieve through internal management of those assets.[3]

c. Third party gas asset managers typically derive their profits from the portion of the expected net revenue they obtain through their management of gas assets that **they do <u>not</u> pay** to the party contracting for their services (e.g., National Grid).

d. The Division has accepted the Company's use of such third-party asset management arrangements as long as they are limited to a comparatively small portion of the Company's overall portfolio of RI natural gas assets.

e. As the portion of the Company's RI natural gas asset portfolio subject to AMAs with third parties increases, the rationale for paying National Grid the current level of incentive on its entire RI portfolio weakens.

f. National Grid has provided no compelling justification for why any incentives should be paid to the Company on revenue derived from third party asset management arrangements. Such incentive payments essentially

[3] The Commission should note that, to date, National Grid has presented no evidence to demonstrate the magnitude of the benefits it derives from AMA's entered into with third parties that it could not achieve through internal management of the same assets. Nor, has the Company provided any evidence that its solicitation of bids for such third-party asset management arrangements has produced competitive results that exceed the benefits it could derive through internal asset management activities.

constitute a requirement for firm service customer in RI to pay twice for the same asset management activities.

14. A significant number of data request responses have been received in the last couple of business days before the submission of this memo which we have not yet had the opportunity to fully review and analyze. If upon further examination of those materials, additional findings of importance surface, we will attempt to supplement the observations provided herein.

Attachment BRO-1
Docket No. 4436

National Grid - RI Gas
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Changes in Projected Costs by GCR Cost Component
With Capacity Release Credits Netted from Fixed Supply Costs

Ln No	GCR Cost Component	Forecasted Annual Cost 2013-14 1/	Forecasted Annual Cost 2012-13 2/	Change 2012-13 to 2013-14 $	%
	FIXED GAS COSTS				
1	Supply Fixed Costs 3/	$ 29,048,581	$ 28,645,415	$ 403,166	1.4%
2	Storage Fixed Costs	$ 15,830,032	$ 11,398,130	$ 4,431,902	38.9%
3	**Total Fixed Costs Before Adjusts & Reconciliations**	**$ 44,878,613**	**$ 40,043,545**	**$ 4,835,068**	**12.1%**
	Adjustments and Reconciliation Amounts				
4	NGPMP Revenue Sharing - Customer Benefit	$ (6,900,000.00)	$ (4,600,000)	$ (2,300,000)	50.0%
5	Removal of FT-2 Storage Demand Costs	$ (1,542,334)	$ (1,178,704)	$ (363,630)	30.8%
6	Allocation of LNG Costs to DAC	$ (1,488,789.58)	$ (622,659)	$ (866,130)	139.1%
7	Supply Related LNG O&M Costs	$ 575,581	$ 618,591	$ (43,010)	-7.0%
8	Working Capital Requirement	$ 260,649	$ 265,525	$ (4,876)	-1.8%
9	Deferred Fixed Costs under/(Over)-Recovered	**$ (4,245,368)**	**$ 10,697,488**	**$ (14,942,856)**	-139.7%
10	Reconciliation of Marketer Fixed Costs	$ (8,205)	$ (374,462)	$ 366,257	-97.8%
11	Total Fixed Costs Adjustments & Reconciliations	$ (13,348,467)	$ 4,805,779	$ (18,154,245)	-377.8%
12	**Adjusted FIXED COST Recovery Requirement**	**$ 31,530,146**	**$ 44,849,324**	**$ (13,319,177)**	**-29.7%**
	VARIABLE GAS COSTS				
13	Supply Variable Costs	$ 103,784,247	$ 107,717,133	$ (3,932,886)	-3.7%
14	Storage Variable Costs	$ 12,062,659	$ 16,438,331	$ (4,375,672)	-26.6%
15	**Total Variable Costs Before Adjusts & Recons**	**$ 115,846,906**	**$ 124,155,464**	**$ (8,308,558)**	**-6.7%**
	Adjustments and Reconciliation Amounts				
16	Balanceing Related LNG Costs (to DAC)	$ -	$ (372,608)	$ 372,608	-100.0%
17	Working Capital Requirement	$ 690,195	$ 823,727	$ (133,532)	-16.2%
18	Deferred Variable Costs under/(Over)-Recovered	**$ 16,104,739**	**$ (10,210,487)**	**$ 26,315,226**	-257.7%
19	Supply Related LNG O&M	$ 572,694	$ 430,129	$ 142,565	33.1%
20	Inventory Financing - LNG	$ 403,203	$ 370,897	$ 32,306	8.7%
21	Inventory Financing - Storage	$ 1,485,211	$ 1,485,575	$ (364)	0.0%
22	Total Variable Costs Adjustments & Reconciliations	$ 19,256,042	$ (7,472,767)	$ 26,728,809	-357.7%
23	**Adjusted VARIABLE COST Recovery Requirement**	**$ 135,102,948**	**$ 116,682,697**	**$ 18,420,251**	**15.8%**
24	**Total Gas Costs BEFORE Adjusts & Recons**	**$ 160,725,519**	**$ 164,199,009**	**$ (3,473,490)**	**-2.1%**
25	**Total Gas Costs AFTER Adjusts & Recons**	**$ 166,633,094**	**$ 161,532,021**	**$ 5,101,074**	**3.2%**

1/ Source: Docket No. 4436, Attachment EDA-1, September 3, 2012, page 1.
2/ Source: Docket No. 4346, Attachment EDA-1, September 4, 2012, page 1.
3/ Net of Capacity Release Credits