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NH PUBLIC UTILITIES COMMISSION

July 20, 2012

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Debra A. Howland, Executive Director and Secretary
New Hampshire Public Utilities Commission
21 S. Fruit Street, Suite 10
Concord, NH 03301-2429

RE: Docket No. DG 12-131

Dear Director Howland:

On behalf of Northern Utilities, Inc. (the "Company"), enclosed is an original and six copies of the Company's "Report Concerning the Allocation of Gas Supply Resources Between Northern's Maine and New Hampshire Divisions and the Calculation of the Monthly Gas Supply Commodity Cost Allocator."

Thank you for your attention to this matter.

Sincerely,

Gary Epler
Attorney for Northern Utilities, Inc.

cc: Rorie Hollenberg, Office of Consumer Advocate
Service List (by e-mail only)

Gary Epler
Chief Regulatory Counsel

6 Liberty Lane West
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Northern Utilities, Inc.

DG 12-131

Table of Contents

15. Summary of Allocation Adjustment Calculation – Peak Period - May 2008 through April 2011 (By Month)
16. Summary of Allocation Adjustment Calculation – Off-Peak Period - November 2008 through October 2011 (By Month)
17. Total Impact by Division, by Period, and by Type of Revision

NORTHERN UTILITIES, INC.

REPORT CONCERNING THE ALLOCATION OF GAS SUPPLY RESOURCES BETWEEN NORTHERN'S MAINE AND NEW HAMPSHIRE DIVISIONS AND THE CALCULATION OF THE MONTHLY GAS SUPPLY COMMODITY COST ALLOCATOR

I. EXECUTIVE SUMMARY

During the course of preparing its 2011-2012 Winter Season Cost of Gas ("COG") filing for New Hampshire and its 2011-2012 Peak Period Cost of Gas Factor ("CGF") filing for Maine in 2011, Northern Utilities, Inc. ("Northern" or "the Company") discovered an inconsistency in the allocation of its gas supply resource costs ("Resource Costs") between its Maine and New Hampshire Divisions. Shortly thereafter, the Company determined the allocation of Resource Costs to its Maine and New Hampshire Divisions required revision with regards to the inclusion of the Maine Division's company-managed sales volumes in its monthly gas supply commodity cost allocator ("the Allocator"). As a result, in November 2011, Northern updated the Allocator, and, in its 2012 Summer Season COG/Off-Peak Season CGF filings, included monthly Allocation Adjustments to its 2011 Summer/Off-Peak COG/CGF Reconciliations. At this point, the Company continued its research to determine the impact on the inter-state allocation of Resource Costs between New Hampshire and Maine resulting from the exclusion of the Maine Division's company-managed sales volumes from the Allocator from December 2008 to October 2011.

This report is the result of that research effort. It provides a background to the calculation and allocation of Resource Costs, an explanation as to why Northern excluded Maine Division company-managed sales volumes in the determination of the allocation of Resource Costs between New Hampshire and Maine in its COG/CGF filings during the period December 2008 through October 2011, and, lastly, provides a recalculation of Resource Costs and other associated cost elements to be allocated between Northern's New Hampshire and Maine Divisions.

The report concludes that the exclusion of the Maine Division's company-managed sales volumes from the allocation in the COG/CGF filings occurred during this period, even though a correction to the allocation formula to include these volumes had been introduced by Northern's predecessor owner's regulatory reporting group in its Maine Division CGF proceeding, Docket No. 2008-343, during the summer of 2008. The correction to the allocation formula, however, was never memorialized in either an internal Company procedures manual or in the regulatory order issued in Docket No. 2008-343 in October of 2008, and therefore the updated allocation formula was not communicated to the regulatory reporting group at Northern during the 2008-2009 transition from the predecessor owner to Unitil. Accordingly, when Northern was acquired by Unitil in December 2008, the Company carried forward the predecessor owner's uncorrected regulatory reporting formulas until Northern's recent determination that the Allocator had not been updated to conform with what had been presented in Docket No. 2008-343.

A recalculation of resource and other associated costs, based on allocation factors that include Northern's Maine Division's company-managed volumes, for the period December 2008 to October 2011 would result in a net decrease/credit to the New Hampshire division's COG of ($4,130,679) and a net increase/charge to the Maine division's CGF of $4,136,640. Detail providing support for the derivation of this recalculation is provided in Section IV, below.

Unlike a typical LDC, Northern has two divisions, located in separate states, but which are served by an integrated resource portfolio. Any reallocation of the costs of the portfolio between the divisions results in offsetting adjustments between the divisions: Northern does not profit or realize any financial benefit from the allocation or, when appropriate, reallocation of costs. An incorrect allocation of costs results in each division's COG/CGF improperly reflecting the cost of serving its respective customers. In order to correctly reflect the cost of service, any reallocation, therefore, must be made to the costs, and ultimately, the rates of both divisions. Accordingly, Northern recommends that the New Hampshire and Maine Public Utilities Commissions ("Commissions") address and resolve this matter jointly as they have in the prior proceedings such as those for the Modified Proportional Responsibility ("PR") Allocator ("Modified PR Allocator") and Northern's recent Integrated Resource Plan ("IRP") filing

II. BACKGROUND

A. NORTHERN'S RESOURCE COSTS

What are the Resource Costs of a typical natural gas local distribution company (LDC)?

Resource Costs for a typical LDC result from purchases of upstream interstate pipeline transportation and storage services, purchases of gas supplies to be consumed by customers and use of the LDC's on-system peaking facilities, like LNG.

Resource Costs are separated into two functional categories; demand and commodity. Demand-related costs are based on the maximum daily volume to be used or contracted for. Commodity-related costs are based on the daily volume used. Resource Costs are further separated into two seasons

How are the LDC's Resource Costs collected?

For the most part, LDCs recover their Resource Costs through COG Adjustment Clauses. LDCs aggregate their estimated Resource Costs and derive a per unit COG rate to be charged to bundled sales customers consuming the LDC's gas supplies in the upcoming seasonal period. COG rates may differ by customer class. An LDC's actual Resource Costs are reconciled in seasonal COG Reconciliations.

In recent years, Northern has incurred approximately $30 million annually in actual Resource Costs for each division, New Hampshire and Maine. The Company's annual Resource Costs can vary widely depending on the market price for gas supplies.

Are Resource Costs mitigated?

Yes. LDCs mitigate demand-related Resource Costs by assigning and/or releasing specific capacity contract shares and their respective costs to customers migrating from bundled sales service to distribution-only service, their third-party suppliers or their marketers ("Marketers").

For Northern, capacity contract shares and costs are assigned and/or released on voluntary and mandatory bases as discussed below. Collection of these mitigated costs is discussed below also.

B. ALLOCATING NORTHERN'S RESOURCE COSTS TO THE DIVISIONS

How does Northern allocate its Resource Costs to the Maine and New Hampshire Divisions?

As previously noted, Northern has an integrated resource (capacity and gas supply) portfolio that serves the two divisions located in separate states. Therefore, the Company must allocate its Resource Costs to each division in an appropriate manner.[1] The Company uses separate methods to allocate its demand- and commodity-related Resource Costs to the Maine and New Hampshire Divisions.

Northern uses the Modified Proportional Responsibility ("PR") Allocator to allocate expected and actual <u>demand-related</u> upstream interstate pipeline transportation and storage services costs and gas supply costs. The use of the PR Allocator was agreed to pursuant to settlement agreements approved in Maine Docket Nos. 2005-087 and 2005-273 and New Hampshire Docket No. DG05-080. The PR Allocator splits demand costs over the entire gas year, November through October, and is based on each division's expected design-year sendout and projected costs. For the gas year beginning November 2011, the PR Allocator assigned 52.62% of Northern's demand-related costs to the Maine Division and 47.38% to the New Hampshire Division.

For allocating expected and actual demand- and commodity-related on-system LNG peaking facility costs, Northern uses the fixed amounts approved by the respective state

[1] As noted above, cost allocation for Northern is a Zero-Sum Game. This means, if +$1 is reallocated to the Maine Division, then -$1 is reallocated to the New Hampshire Division.

Commissions in the Company's latest rate case proceedings. For the Maine Division these annual costs are $780,867; for the New Hampshire Division the costs are $719,362.

Northern uses each division's relative share of total expected (normal year) or actual sendout to allocate expected and actual commodity-related upstream interstate pipeline transportation and storage services costs and gas supply costs. The derivation of these allocators is explained below.

Please define "sendout."

Sendout is the volume (and makeup) of gas supply dispatched to meet the needs of Northern's firm bundled and company-managed sales customers, company use, and lost and unaccounted for ("LAUF") gas.

How is sendout used to allocate Northern's commodity-related costs to the Maine and New Hampshire Divisions?

Northern's expected and actual commodity-related interstate pipeline transportation and storage services costs and gas supply costs are allocated to the divisions based on each division's relative share of total sendout. Expected sendout is used to allocate expected commodity-related costs for COG/CGF ratemaking purposes, while actual sendout is used to allocate actual commodity-related costs for COG/CGF Reconciliation purposes.

C. CAPACITY ASSIGNMENT AND CAPACITY RELEASE

Please provide an overview of Northern's capacity assignment and capacity release transactions?

As mentioned above, Northern mitigates its Resource Costs by assigning and/or releasing capacity to migrating customers or their Marketers. Capacity assignment and releases refer to the transfer and use of an LDC's actual resources held within a gas supply and capacity portfolio. There are significant differences between these two cost mitigation transactions.

Capacity *release* transactions were mandated by the Federal Energy Regulatory Commission ("FERC") in the early 1990s. Capacity releases allow the holder of interstate pipeline and storage contracts ("the Shipper") to voluntarily release any portion of their capacity contracts to another party ("the Replacement Shipper"). Typically, unless prearranged at the maximum recourse rate, released capacity has been subject to competitive bids and awarded to the highest bidder. Upon release of a capacity contract or a portion thereof, the Replacement Shipper is held responsible for conducting business (nominations, balancing, etc.) with the pipeline or storage company that directly bills the Replacement Shipper for the released capacity and credits the Shipper. After such credits, the Shipper pays any balance due the pipeline.[2] In the Northeast, LDCs, like Northern, voluntarily release capacity in non-peak periods when bundled sales customer daily demands are below maximum daily contract quantity capacity levels. Capacity releases mitigate the Company's total demand-related Resource Costs.

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[2] This balance reflects any difference between what the Shipper and Replacement Shipper pay for the contract service. During some months of the year Replacement Shippers may pay a discounted price for the contract service.

Capacity *assignment* transactions differ from capacity release transactions in that the Marketer is required or mandated by state PUC retail-choice programs to accept assignment of and pay for a portion of the LDC's gas capacity and supply portfolio. Capacity assignment programs were established by PUCs to address customer migration from bundled sales.

In the mid-to-late 1990s, commercial and industrial ("C&I") customers began switching or migrating from the LDC's bundled sales service to distribution-only service. This migration resulted in the LDC's remaining bundled sales customers, who were mostly residential customers, being allocated upstream pipeline and storage capacity originally acquired to serve the C&I customers who had migrated to distribution only service. In order to protect remaining bundled sales customers from higher costs, PUCs mandated that migrating C&I customers (or their Marketers) be assigned a portion of the LDC's capacity (by release, if possible) and pay for this portion of the LDC's capacity and gas supply resources.

Capacity assignment transactions allow an LDC to include its on-system LNG and propane facilities in the assignment, as well as Canadian pipeline transportation and storage capacity contracts that are not releasable within the regulatory jurisdiction of Canada's National Energy Board. As with capacity release, capacity assignment mitigates Northern's total demand-related Resource Costs.

D. THE NEW HAMPSHIRE AND MAINE DIVISION CAPACITY ASSIGNMENT PROGRAMS

Please compare the capacity assignment programs of the New Hampshire and Maine Divisions

In November 2000, in Docket Nos. DG 00-046 and DG 00-063, the New Hampshire PUC instituted a mandatory capacity assignment program for all bundled sales customers who migrate to distribution-only service after January 1, 2001. Under this program, the volume of capacity assigned is equal to the amount required to meet the migrating customer's Total Contract Quantity ("TCQ"), which is their expected design day load. This program utilizes a "slice of the system" approach where the migrating customer or Marketer is assigned capacity in slices. Each slice is comprised of one or more resources that comprise a capacity path.[3] In this assignment, upstream pipeline transportation and storage contracts that can be released are released; assignments of contracts and on-system capacity that are not released are company-managed assignments.

The Maine Division's mandatory capacity assignment program was approved in Docket Nos. 2005-087 and 2005-273. It went into effect on January 1, 2006. This program has several key differences from the New Hampshire Division's program. The first difference is that customers who migrate from bundled sales are assigned a TCQ equal to

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[3] A capacity path provides a route by which a gas supply travels from its source to Northern's service territory. For example, Northern's "Tennessee's Long Haul Capacity Path" is comprised of two segments (Segment 1: Tennessee's supply region through Tennessee Pipeline up to Granite State Pipeline; and Segment 2: Granite State Pipeline to Northern delivery points) whereas, Northern's "Washington-10 Capacity Path" is comprised of comprised of six segments (Segment 1: Washington-10 Storage; Segment 2: Vector Pipeline from Washington-10 Storage; Segment 3: Union Gas Pipeline from Vector; Segment 4: TransCanada Pipeline from Union; Segment 5: PNGTS Pipeline from TransCanada; and Segment 6: Granite State Pipeline to Northern delivery points).

only 50 percent of their design day demand (the remaining capacity needed on the design day is the responsibility of the customer or their Marketer). The second difference is that the entire TCQ is made up of capacity assigned from three specific capacity paths, all of which are managed by the Company.[4] A third difference is that the program is in effect only during five of the six Peak Period months, November through March.

How does the Company manage capacity that is assigned buy not released?

As noted above, some of Northern's capacity and supply resource portfolio and Resource Costs are not under FERC jurisdiction, such as the Canadian transportation contracts and the Company's on-system LNG resources. Thus, these resources cannot be released. Pursuant to the two states' retail choice programs, these resources are assigned to Marketers, but they are managed by the Company and, accordingly, are referred to as "company-managed" resources.[5]

On any day, a Marketer can submit to Northern a nomination up to the assigned volume, seeking delivery of a gas supply from any one of the Company's company-managed resources. Northern will deliver a gas supply to the Marketer at the Company's city gate. Final delivery to the customer is made via the Company's distribution system. To complete this capacity assignment transaction, Northern directly bills the Marketer for this supply purchase.

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[4] These paths are comprised of the Washington 10 Capacity Path and two Peaking Capacity Paths which are typically Winter Season delivered supplies.

[5] The Company notes that if any particular resource in a capacity path cannot be released, Northern will make the entire path company-managed. For instance, the Washington-10 Capacity Path includes non-releasable TransCanada contracts. Thus, this capacity path is company-managed.

How is the sales price of company-managed supply derived by Northern?

The sales price consists of a demand charge and a commodity charge. These charges are derived differently for the New Hampshire and Maine Divisions.

In the New Hampshire Division, the demand charges for company-managed supply are based on the demand costs of each pipeline, storage and peaking contract resource assigned to the Marketer. In the Maine Division, there is a single demand charge determined by taking Maine's share of total annual demand costs and dividing it by its share of total capacity. This annual cost is then converted to a five-month demand charge (November through March). The Company provides detailed calculations for both the Maine and New Hampshire Division demand charges in the Winter/Peak COG/GAF filings.

The derivation of the New Hampshire Division's commodity charge for company-managed supply is based on the commodity costs for each capacity path's cost of gas, variable transportation charges and the costs of fuel loss. In the Maine Division, the commodity charge for company-managed supply is based on the actual costs for the available path. These costs are then blended with the commodity costs from the capacity paths that are not assigned, such as Tennessee production area capacity. This blending is designed to have Maine Division Marketers pay the same price for supply as if they used all resources on Northern's system (i.e. a slice of the system approach).

How is the revenue received by Northern from company-managed supply sales accounted for in the COG Reconciliation?

The revenue received from the sale of company-managed supply for both the Maine and New Hampshire Divisions is listed as line items in Northern's seasonal COG Reconciliations. Specifically, this monthly revenue appears in FORM III, Schedule 4 of the Reconciliation filing as a credit to monthly gas supply demand and commodity costs.

How are the costs incurred by Northern for company-managed supply accounted for in the COG Reconciliation?

Each day, Northern purchases enough gas supply to meet the needs of all bundled sales customers, including company-managed sales volume. Thus, the Company's monthly invoices from its gas suppliers include purchases used to make company-managed sales. These invoices make up the gas supply commodity costs included in Northern's seasonal COG Reconciliations. Specifically, these monthly costs appear in FORM III, Schedule 4 of the Reconciliation filing as charges to gas supply commodity costs. However, because company-managed costs are included in the Company's aggregated commodity purchases, they are not listed as a separate line item. Therefore, in order to properly assign the company-managed costs to each division, they are allocated pursuant to a formula, termed the "Allocator."

III. DERIVATION OF THE ALLOCATOR

How has the Allocator been derived since December 2008?

In August 2008, prior to the anticipated transition of ownership, NiSource provided to Unitil personnel written instructions listing the components to be used in deriving the Allocator, including a list of components.

These instructions provided that the Allocator of actual total Company monthly gas supply commodity costs between the two divisions is to be derived using the current month COG volumes plus Company Use volumes, Company-managed volumes (for New Hampshire only) and Unaccounted For volumes (New Hampshire 1%; Maine 2%) less Interruptible Volumes, with a BTU adjustment for Maine Division Mcf volume.

Northern used this derivation of the Allocator until November 2011.

What caused Northern to question the derivation of the Allocator?

As described above, company-managed sales volumes are made to Marketers in both divisions from Northern's overall gas supply purchases. However, the Allocator used for the period December 2008 through October 2011 included company-managed volumes for the New Hampshire Division only, and not the Maine Division. In preparing its 2011-2012 Winter Season COG filing, the regulatory reporting group at Northern questioned why there appeared to be an inconsistency as to why the Maine Division company-managed volume was not included in the Allocator. The inclusion of only New Hampshire Division company-managed volume in the derivation of the Allocator omits the supply purchased by the Company for the Maine's Division's company-managed sales. In other words, excluding Maine Division company-managed sales volumes from the Allocator results in the New Hampshire Division being allocated a higher percentage of actual monthly gas supply commodity costs, unless the Maine Division company-managed sales volume is accounted for elsewhere.

Has Northern been able to determine whether Maine Division company-managed sales volumes are accounted for elsewhere in other Maine Division sales volumes, so as to justify its exclusion as a line item in the derivation of the Allocator?

No. The Company reviewed numerous COG/CGF filings as well as accounting documents transferred from NiSource to Unitil in order to determine if there was any information that would explain why New Hampshire Division company-managed volume only is included in the derivation of the Allocator. The Company was unable to find an explanation. Based on this review, the Company has concluded that the Maine Division company-managed sales volumes are not accounted for in any of the other monthly sales components, and therefore should not be excluded as a line item in the Allocator.

In the course of its investigation, the Company discovered that this issue had been raised previously by Northern prior to its acquisition by Unitil. The cover letters to Northern's 2007-2008 Winter/Peak Period COG Reconciliations, dated September 15, 2008 for the New Hampshire Division and August 15, 2008 for the Maine Division, mention the inadvertent omission of the Maine Division's company-managed volumes from the Allocators. These letters (and the accompanying COG/CGF Reconciliations) are included in Appendix A.

The transcripts from the 2008 Off-Peak Period Maine Division CGF proceeding, Docket No. 2008-343, includes a discussion of the Maine Division company-managed volumes being inadvertently omitted in the initial calculation of the Allocator (page 45-64).[6] A copy of the transcript pages is included as Appendix B. Although this issue was raised just prior to Unitil's acquisition of Northern, the correction for the omission of the Maine Division company-managed volumes from the calculation of the Allocator was not memorialized in any Northern procedures manual, or in the regulatory order issued in Docket No. 2008-343 in October of 2008, and therefore the updated allocation formula was not communicated to the regulatory reporting group at Northern during the 2008-2009 transition from the predecessor owner to Unitil.

IV. RECALCULATION OF THE HISTORIC COG/CGF RECONCILIATIONS

Has the Company revised the historic monthly Allocators for the period from December 2008 through October 2011 to account for Northern's Maine Divisions company-managed volumes?

Yes. The monthly Allocators have been revised and used to rerun the COG/CGF Reconciliations for the six seasonal periods for each division since December 2008.

Have there been any other changes or revisions made to the derivation of the Allocator since 2008, that are included in these recalculations?

[6] The Maine PUC's order approving Northern's CGF filing in Docket No. 2008-343, issued on October 28, 2008, does not include any discussion of or reference to this issue, although the corrected allocation resulted in an increase to Northern's Maine Division CGF of approximately $3.2 million. Similarly, the regulatory order for the Northern's New Hampshire COG proceeding for the same period, Order No. 24,912 in Docket DG 08-115, in which a credit to the COG of the same amount was applied as a result of the inclusion of the Maine Division's company-managed supply volumes, does not contain any discussion of or reference to this issue.

Beginning in November 2010, Northern made a revision to each division's monthly LAUF[7] gas supply percentage and volume to reflect the actual 4-year historical rolling-average LAUF percentage, as calculated for the Winter/Peak Period COG/CGF and used throughout the gas year. Before then, Northern used fixed estimated LAUF percentages (for the New Hampshire Division 1%; for the Maine Division 2%) to determine each month's LAUF volume includable in the Allocator. The current LAUF rates are 1.17% for the Maine Division and 0.87% for the New Hampshire Division.

The Company also revised its New Hampshire Division's company-managed volumes from December 2008 through March 2009 to include additional volumes that had been inadvertently omitted.

Please provide a summary of the impact of the recalculations on the COG/CGF Reconciliations for both divisions.

Please see Schedule 1, which provides a summary of the recalculation of seasonal COG/CGF Reconciliations. As shown on Schedule 1, page 2, line 88, the total impact would be a credit to Northern's New Hampshire Division of $4,130,679 and a charge to the Maine Division of $4,136,640.

Attached as Schedules 2 through 13 are the original COG/CGF reconciliations[8] for each period and each division, as well as the recalculated COG/CGF reconciliations which are based on allocation factors that include the Maine Division's company-managed

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[7] An adjustment was also made to remove company-managed volumes from the LAUF calculation, as those volumes are net of LAUF.
[8] As originally filed, with only minor corrections.

volumes. Attached as Schedule 14 are the recast monthly Allocators. Attached as Schedules 15 and 16 are the derivations of the Allocation Adjustments to each division's monthly gas supply commodity costs included in the recalculated COG/CGF Reconciliations. Lastly, attached as Schedule 17 is a summary of each division's total impact by period and by type of revision (company managed, LAUF, etc.)

Why do the resulting recalculations for each division not precisely offset each other?

The recalculated amounts are not precisely offsetting due to division specific COG/CGF Reconciliation carrying charge, working capital, and bad debt allowance rates.

V. RECOMMENDATION FOR RESOLUTION OF THIS MATTER

How does the Company propose to solve this matter?

As Northern's two divisions, located in separate states, are served by an integrated resource portfolio, any reallocation of COG/CGF costs of the portfolio between the divisions is a zero sum game. Northern did not profit from nor realize any financial benefit from the original allocation of Resource Costs, and will not gain any benefit from a reallocation of these costs. An incorrect allocation of costs results in each division's COG/CGF improperly reflecting the cost of serving its respective customers. In order to correctly reflect these COG/CGF costs, any reallocation, therefore, must be made to the costs, and ultimately, the rates of both divisions. Accordingly, Northern recommends that the New Hampshire and Maine Commissions address and resolve this matter jointly as they have in past proceedings such as those for the Modified PR Allocator and Northern's Recent Integrated Resource Plan ("IRP") filing.

Does this conclude the Company's Report?

Yes.

Appendix A

Cover Letters to the New Hampshire and Maine Commissions and Accompanying 2007-2008 Winter /Peak Period COG / CGF Reconciliations

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NiSource
Corporate Services

September 15, 2008

Ms. Debra Howland
Executive Director and Secretary
State of New Hampshire
Public Utilities Commission
21 S. Fruit St.
Concord, NH 03301

Re: **Northern Utilities, Inc. – New Hampshire Division, 2007-2008 Winter Period Cost of Gas (COG) Adjustment Reconciliation - Revised**

Dear Ms. Howland:

Attached are an original and eight copies of Northern Utilities' 2007-2008 Winter Period COG reconciliation analysis. The objective of this analysis is to identify the causes of the Winter Period 2007-2008 over-collection. This revision to the 2007-2008 Winter Period Cost of Gas (COG) Adjustment Reconciliation reflects a corrected level of Capacity Reserve Charge credits off-set by a like amount in the Adjusted Bill Adjustment. These revisions are summarized in Schedule 2. Also, Schedule 3 reflects the amount of the CRC monthly credits as required by Commission Order No. 24,687 in Docket DG 06-033 dated October 27, 2006. There also was a revision in the Environmental Response Costs (ERC) reconciliation to reflect an omission of a layer of costs from the 2007-2008 ERC rate.

Form III, Schedules 1 through 5 of the filing, attached, contain the accounting of six months of costs assigned to the winter period, along with the monthly gas cost collections. The schedules illustrate the Company's over-collection of $688,600. Schedule 1, page 1, provides the summary of the winter period ending balance. Schedule 2 shows the deferred gas cost activity, allowable costs and revenues for the period May 2007 through May 2008, including $80,100 in net interest. Schedule 3, page 1, shows the summary of winter period gas cost collections, while Schedule 3, pages 2 through 8 illustrates the gas cost collections for each individual month. Schedule 4, pages 1 and 2, shows the monthly detail of purchase gas costs allocated to the winter period. Schedule 4 Re-Allocation reflects the re-allocation of commodity costs from the New Hampshire Division to the Maine Division primarily due to the inadvertent omission of Company Managed volumes from the calculation. Schedule 5 presents the purchased and made volumes in Dekatherms ("Dths"), as well as sales volumes by Residential and Commercial/Industrial customer classification for the annual period of May 2007 through April 2008. The resulting difference between sendout and sales volumes is shown for this twelve-month period

Attachment A presents the reconciliation of the working capital costs allowable based on direct gas costs. The under-collection of $10,235 will be reflected on Revised Page 39 of Northern's Tariff No. 10 as an addition to the costs used to calculate the COG rate.

Attachment B shows the reconciliation of the bad debt expenses, which are allowed based on gas costs and the working capital allowance. The under-collection of $22,359 will also be reflected on Revised Page 39 of Northern's Tariff No. 10 as an addition to the costs used in calculating the COG rate.

Attachment C presents the interruptible profits by month. A total of $30,338 of interruptible profits has been recognized for May 2007-April 2008. The $30,338 has been deducted from the 2007-2008 Winter Period Costs.

Attachment D reconciles the Environmental Response Costs as well as a true-up of the estimates used for July-October 2007 and an estimate for July-October 2008.

Attachment E reconciles the RLIAP program costs and recoveries. The projected under recovery of $5,626 will be reflected in a revision to the RLIAP recovery rate of $0.0020 per therm.

Attachment F details the sales variance analysis. Of the 303,608 MMBtu less than forecasted sales variance, warmer than normal weather resulted in a 66,140 MMBtu decrease in sales, leaving weather normalized sales variance of 237,668 MMBtu. The remaining sales variance is the result of less than forecasted customer counts and a decrease in the average usage per customer.

Attachment G reconciles the refund passback of a refund received on January 31, 2007.

Please do not hesitate to contact me if you have any questions regarding these reconciliation schedules.

Sincerely,

Ronald D. Gibbons
Manager of Regulatory Accounting

Attachments

cc: Ann Ross, Esq., Office of the Consumer Advocate
Joseph A. Ferro, Northern Utilities, Inc.
Patricia M. French, Esq., NCS

FORM III
Schedule 1

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2007-08 WINTER PERIOD RECONCILIATION - Revised
November 2007 - April 2008

	AMOUNT	
Winter Period Beg. Balance	$ (2,678,727)	SCHEDULE 2
Less: Reported Collections	$ (33,489,751)	SCHEDULE 3
Less: Adjusted Bill Adjustment	$ (61,862)	SCHEDULE 2
Add: Cost of Gas Adjustments	$ 35,461,640	SCHEDULE 2
Add: Interest	$ 80,100	SCHEDULE 2
Winter Period Ending Balance	$ (688,600)	

FORM III
Schedule 2

NORTHERN UTILTIES, INC. - NEW HAMPSHIRE DIVISION
2007-08 WINTER PERIOD RECONCILIATION - Revised
SCHEDULE 2: ADJUSTMENTS TO REPORTED PEAK PERIOD ACCOUNTS
May 2007 - May 2008
Acct 191.20

WINTER PERIOD	May 2007	June	July	August	September	October	November	December	January 2008	February	March	April	May	Total
Winter Period Account Beginning Balance	$ (2,678,727)	$ (2,396,210)	$ (2,051,479)	$ (1,662,112)	$ (1,296,944)	$ (923,335)	$ (545,751)	$ 3,313,256	$ 4,194,338	$ 4,439,919	$ 4,244,786	$ 4,065,598	$ 1,283,810	$ (2,678,727)
Plus: Cost of Firm Gas (Schedule 4)	$ 281,549	$ 359,967	$ 402,089	$ 375,305	$ 381,214	$ 382,618	$ 5,297,051	$ 6,517,400	$ 7,067,273	$ 6,359,268	$ 5,998,341	$ 2,055,930	$ (16,366)	$ 35,461,640
Less: Reported Collections (Schedule 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,447,526)	$ (5,658,565)	$ (6,840,667)	$ (6,572,275)	$ (6,176,992)	$ (4,832,202)	$ (1,961,524)	$(33,489,751)
Less: Adjusted Bill Adjustment							$ -	$ (3,471)	$ (7,923)	$ (9,181)	$ (26,427)	$ (18,855)	$ 3,995	$ (61,862)
Winter Period Ending Balance	$ (2,397,178)	$ (2,036,243)	$ (1,649,390)	$ (1,286,807)	$ (915,729)	$ (540,718)	$ 3,303,775	$ 4,168,619	$ 4,413,021	$ 4,217,731	$ 4,039,709	$ 1,270,470	$ (690,084)	$ (768,700)
Month's Average Balance	$ (2,537,952)	$ (2,216,226)	$ (1,850,435)	$ (1,474,459)	$ (1,106,336)	$ (732,027)	$ 1,379,012	$ 3,740,937	$ 4,303,679	$ 4,328,825	$ 4,142,247	$ 2,668,034	$ 296,863	
Interest Rate (Prime Rate)	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	7.50%	7.50%	7.50%	6.00%	6.00%	
Interest Applied	$ 968	$ (15,237)	$ (12,722)	$ (10,137)	$ (7,606)	$ (5,033)	$ 9,481	$ 25,719	$ 26,898	$ 27,055	$ 25,889	$ 13,340	$ 1,484	$ 80,100
Winter Period Account Ending Balance	$ (2,396,210)	$ (2,051,479)	$ (1,662,112)	$ (1,296,944)	$ (923,335)	$ (545,751)	$ 3,313,256	$ 4,194,338	$ 4,439,919	$ 4,244,786	$ 4,065,598	$ 1,283,810	$ (688,600)	$ (688,600)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2007-08 WINTER RECONCILIATION - Revised
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2007 - April 2008

GAS COST RECOVERY FOR THE PERIOD OF :	November 2007 - April 2008									
	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms) - November - April (old)	12,020,242	157,313	931,435	6,500,619	1,639,911	5,429,565	367,150	713,702	3,960,346	31,720,283
Sales (therms) - April (new) - May	1,168,785	24,326	146,364	544,006	243,344	535,517	32,225	78,521	468,301	3,241,388
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate										
November - April (old)	$1.1314	$1.1314	$1.0505	$1.1993	$1.0505	$1.1993	$1.0505	$1.1993	$0.0000	
April (new) - May	$1.3436	$1.3436	$1.2465	$1.4115	$1.2465	$1.4115	$1.2465	$1.4115	$0.0000	
Prior Period Reconciliation	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	$0.0000	
Working Captal Allowance	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0000	
Supplier Refund	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	$0.0000	
Bad Debt Allowance	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0000	
Capacity Reserve Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.00551	
Total Billed Rate										
November - April (old)	$1.0610	$1.0610	$0.9801	$1.1289	$0.9801	$1.1289	$0.9801	$1.1289	$0.00551	
April (new) - May	$1.2732	$1.2732	$1.1761	$1.3411	$1.1761	$1.3411	$1.1761	$1.3411	$0.00551	
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate										
November - April (old)	$13,599,701	$177,984	$978,473	$7,796,192	$1,722,727	$6,511,677	$385,691	$855,943	$0	$32,028,388
April (new) - May	$1,570,379	$32,684	$182,442	$767,864	$303,328	$755,882	$40,169	$110,833	$0	$3,763,581
Prior Period Reconciliation	($1,005,004)	($13,841)	($82,128)	($536,800)	($143,504)	($454,539)	($30,432)	($60,367)	$0	($2,326,616)
Working Captal Allowance	$23,740	$327	$1,940	$12,680	$3,390	$10,737	$719	$1,426	$0	$54,959
Supplier Refund	($6,595)	($91)	($539)	($3,522)	($942)	($2,983)	($200)	($396)	$0	($15,267)
Bad Debt Allowance	$59,351	$817	$4,850	$31,701	$8,475	$26,843	$1,797	$3,565	$0	$137,399
Capacity Reserve Charge	$0	$0	$0	$0	$0	$0	$0	$0	$24,402	$24,402
Total Peak COG Revenues										
November - April (old)	$12,753,476	$166,909	$912,900	$7,338,548	$1,607,277	$6,129,435	$359,844	$805,699	$21,822	$30,095,910
April (new) - May	$1,488,097	$30,972	$172,138	$729,566	$286,197	$718,181	$37,900	$105,305	$2,580	$3,570,936
Total Peak Billed Rate for Winter 2007-2008	$14,241,573	$197,881	$1,085,038	$8,068,115	$1,893,474	$6,847,617	$397,744	$911,003	$24,402	$33,666,846
Working Captal Allowance										($54,959)
Supplier Refund										$15,267
Bad Debt Allowance										($137,399)
Total Gas Cost Collections										$33,489,754

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2007-08 WINTER RECONCILIATION - Revised
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2007 - April 2008

FORM III
Schedule 3
Page 2 of 8

GAS COST RECOVERY FOR THE MONTH OF : November 2007 Prorated

	Res. Heat & NH	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	412,340	6,373	46,653	225,794	124,644	381,697	68,059	78,963	280,094	1,624,616
										1,624,616
									Sales	1,344,521
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate	$1.1314	$1.1314	$1.0505	$1.1993	$1.0505	$1.1993	$1.0505	$1.1993	$ -	
Prior Period Reconciliation	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	$ -	
Working Captal Allowance	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$ -	
Supplier Refund	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	$ -	
Bad Debt Allowance	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$ -	
Capacity Reserve Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$ 0.00551	
Total Billed Rate	$1.0610	$1.0610	$0.9801	$1.1289	$0.9801	$1.1289	$0.9801	$1.1289	$ 0.00551	
Peak Period Demand/Commodity Recovery Revenues										
Demand & Commodity	$ 466,521	$ 7,210	$ 49,009	$ 270,795	$ 130,938	$ 457,769	$ 71,495	$ 94,701	$ -	$ 1,548,438
Prior Period Reconciliation	$ (31,420)	$ (486)	$ (3,555)	$ (17,206)	$ (9,498)	$ (29,085)	$ (5,186)	$ (6,017)	$ -	$ (102,453)
Working Captal Allowance	$ 742	$ 11	$ 84	$ 406	$ 224	$ 687	$ 123	$ 142	$ -	$ 2,420
Supplier Refund	$ (206)	$ (3)	$ (23)	$ (113)	$ (62)	$ (191)	$ (34)	$ (39)	$ -	$ (672)
Bad Debt Allowance	$ 1,856	$ 29	$ 210	$ 1,016	$ 561	$ 1,718	$ 306	$ 355	$ -	$ 6,050
Capacity Reserve Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,543	$ 1,543
Total Peak COG Revenues	$ 437,493	$ 6,761	$ 45,725	$ 254,899	$ 122,163	$ 430,897	$ 66,704	$ 89,142	$ 1,543	$ 1,455,327
Check (Total Billed Sales Rate * Therms)	$ 437,493	$ 6,761	$ 45,725	$ 254,899	$ 122,163	$ 430,897	$ 66,704	$ 89,142	$ 1,543	$ 1,455,327

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2007-08 WINTER RECONCILIATION - Revised
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2007 - April 2008

GAS COST RECOVERY FOR THE MONTH OF : December 2007

	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	2,168,421	32,147	170,253	1,186,009	329,251	1,085,168	105,113	171,477	744,653	5,992,492
										7,472,553
									Sales	5,247,839
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate	$1.1314	$1.1314	$1.0505	$1.1993	$1.0505	$1.1993	$1.0505	$1.1993	$ -	
Prior Period Reconciliation	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	$ -	
Working Captal Allowance	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$ -	
Supplier Refund	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	$ -	
Bad Debt Allowance	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$ -	
Capacity Reserve Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$ 0.00551	
Total Billed Rate	$1.0610	$1.0610	$0.9801	$1.1289	$0.9801	$1.1289	$0.9801	$1.1289	$ 0.00551	
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity	$ 2,453,352	$ 36,371	$ 178,851	$ 1,422,381	$ 345,878	$ 1,301,442	$ 110,421	$ 205,652	$ -	$ 6,054,348
Prior Period Reconciliation	$ (165,234)	$ (2,450)	$ (12,973)	$ (90,374)	$ (25,089)	$ (82,690)	$ (8,010)	$ (13,067)	$ -	$ (399,885)
Working Captal Allowance	$ 3,903	$ 58	$ 306	$ 2,135	$ 593	$ 1,953	$ 189	$ 309	$ -	$ 9,446
Supplier Refund	$ (1,084)	$ (16)	$ (85)	$ (593)	$ (165)	$ (543)	$ (53)	$ (86)	$ -	$ (2,624)
Bad Debt Allowance	$ 9,758	$ 145	$ 766	$ 5,337	$ 1,482	$ 4,883	$ 473	$ 772	$ -	$ 23,615
Capacity Reserve Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,103	$ 4,103
Total Peak COG Revenues	$ 2,300,695	$ 34,108	$ 166,865	$ 1,338,886	$ 322,699	$ 1,225,046	$ 103,021	$ 193,580	$ 4,103	$ 5,689,003
Check (Total Billed Sales Rate * Therms)	2,300,695	34,108	166,865	1,338,886	322,699	1,225,046	103,021	193,580	4,103	5,689,003

Revised
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FORM III
Schedule 3
Page 4 of 8

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2007-08 WINTER RECONCILIATION - Revised
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2007 - April 2008

GAS COST RECOVERY FOR THE MONTH OF : January 2008

	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	2,744,489	35,421	230,580	1,531,133	359,149	1,239,744	71,163	130,441	894,482	7,236,602
										9,176,920
									Sales	6,342,120
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate	$1.1314	$1.1314	$1.0505	$1.1993	$1.0505	$1.1993	$1.0505	$1.1993	$ -	
Prior Period Reconciliation	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	$ -	
Working Captal Allowance	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$ -	
Supplier Refund	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	$ -	
Bad Debt Allowance	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$ -	
Capacity Reserve Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$ 0.00551	
Total Billed Rate	$1.0610	$1.0610	$0.9801	$1.1289	$0.9801	$1.1289	$0.9801	$1.1289	$ 0.00551	
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity	$ 3,105,115	$ 40,075	$ 242,224	$ 1,836,288	$ 377,286	$ 1,486,825	$ 74,757	$ 156,438	$ -	$ 7,319,008
Prior Period Reconciliation	$ (209,130)	$ (2,699)	$ (17,570)	$ (116,672)	$ (27,367)	$ (94,468)	$ (5,423)	$ (9,940)	$ -	$ (483,270)
Working Captal Allowance	$ 4,940	$ 64	$ 415	$ 2,756	$ 646	$ 2,232	$ 128	$ 235	$ -	$ 11,416
Supplier Refund	$ (1,372)	$ (18)	$ (115)	$ (766)	$ (180)	$ (620)	$ (36)	$ (65)	$ -	$ (3,171)
Bad Debt Allowance	$ 12,350	$ 159	$ 1,038	$ 6,890	$ 1,616	$ 5,579	$ 320	$ 587	$ -	$ 28,540
Capacity Reserve Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,929	$ 4,929
Total Peak COG Revenues	$ 2,911,903	$ 37,582	$ 225,991	$ 1,728,496	$ 352,002	$ 1,399,547	$ 69,747	$ 147,255	$ 4,929	$ 6,877,451
Check (Total Billed Sales Rate * Therms)	$ 2,911,903	$ 37,582	$ 225,991	$ 1,728,496	$ 352,002	$ 1,399,547	$ 69,747	$ 147,255	$ 4,929	$ 6,877,451

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2007-08 WINTER RECONCILIATION - Revised
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2007 - April 2008

FORM III
Schedule 3
Page 7 of 8

GAS COST RECOVERY FOR THE MONTH OF : April 2008 Old

	Res. Heat	Res NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (therms)	1,562,861	19,940	116,351	705,407	143,237	431,669	7,543	26,359	323,478	3,336,845
										5,392,449
									Sales	3,013,367
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate	$1.1314	$1.1314	$1.0505	$1.1993	$1.0505	$1.1993	$1.0505	$1.1993	$ -	
Prior Period Reconciliation	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	$ -	
Working Captal Allowance	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$ -	
Supplier Refund	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	$ -	
Bad Debt Allowance	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$ -	
Capacity Reserve Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$ 0.00551	
Total Billed Rate	$1.0610	$1.0610	$0.9801	$1.1289	$0.9801	$1.1289	$ 0.9801	$ 1.1289	$ 0.00551	
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity	$ 1,768,221	$ 22,560	$ 122,227	$ 845,995	$ 150,470	$ 517,701	$ 7,923	$ 31,613	$ -	$ 3,466,710
Prior Period Reconciliation	$ (119,090)	$ (1,519)	$ (8,866)	$ (53,752)	$ (10,915)	$ (32,893)	$ (575)	$ (2,009)	$ -	$ (229,619)
Working Captal Allowance	$ 2,813	$ 36	$ 209	$ 1,270	$ 258	$ 777	$ 14	$ 47	$ -	$ 5,424
Supplier Refund	$ (781)	$ (10)	$ (58)	$ (353)	$ (72)	$ (216)	$ (4)	$ (13)	$ -	$ (1,507)
Bad Debt Allowance	$ 7,033	$ 90	$ 524	$ 3,174	$ 645	$ 1,943	$ 34	$ 119	$ -	$ 13,560
Capacity Reserve Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,782	$ 1,782
Total Peak COG Revenues	$ 1,658,195	$ 21,157	$ 114,036	$ 796,334	$ 140,386	$ 487,311	$ 7,392	$ 29,757	$ 1,782	$ 3,256,351
Check (Total Billed Sales Rate * Therms)	$ 1,658,195	$ 21,157	$ 114,036	$ 796,334	$ 140,386	$ 487,311	$ 7,392	$ 29,757	$ 1,782	$ 3,256,351

GAS COST RECOVERY FOR THE MONTH OF : April 2008 New

	Res. Heat	Res NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	395,235	7,754	54,531	246,473	130,163	313,038	24,621	66,585	289,329	1,527,728
										1,527,728
									Sales	1,238,399
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate	$1.3436	$1.3436	$1.2465	$1.4115	$1.2465	$1.4115	$1.2465	$1.4115	$ -	
Prior Period Reconciliation	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	$ -	
Working Captal Allowance	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$ -	
Supplier Refund	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	$ -	
Bad Debt Allowance	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$ -	
Capacity Reserve Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$ 0.00551	
Total Billed Rate	$1.2732	$1.2732	$1.1761	$1.3411	$1.1761	$1.3411	$1.1761	$1.3411	$ 0.00551	
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity	$ 531,038	$ 10,418	$ 67,972	$ 347,896	$ 162,248	$ 441,853	$ 30,689	$ 93,984	$ -	$ 1,686,100
Prior Period Reconciliation	$ (30,117)	$ (591)	$ (4,155)	$ (18,781)	$ (9,918)	$ (23,854)	$ (1,876)	$ (5,074)	$ -	$ (94,366)
Working Captal Allowance	$ 711	$ 14	$ 98	$ 444	$ 234	$ 563	$ 44	$ 120	$ -	$ 2,229
Supplier Refund	$ (198)	$ (4)	$ (27)	$ (123)	$ (65)	$ (157)	$ (12)	$ (33)	$ -	$ (619)
Bad Debt Allowance	$ 1,779	$ 35	$ 245	$ 1,109	$ 586	$ 1,409	$ 111	$ 300	$ -	$ 5,573
Capacity Reserve Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,594	$ 1,594
Total Peak COG Revenues	$ 503,213	$ 9,872	$ 64,133	$ 330,544	$ 153,085	$ 419,815	$ 28,956	$ 89,297	$ 1,594	$ 1,600,511
Check (Total Billed Sales Rate * Therms)	$ 503,213	$ 9,872	$ 64,133	$ 330,544	$ 153,085	$ 419,815	$ 28,956	$ 89,297	$ 1,594	$ 1,600,511

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2007-08 WINTER RECONCILIATION - Revised
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2007 - April 2008

Form III
Schedule 3
Page 8 of 8

GAS COST RECOVERY FOR THE MONTH OF :

May 2008 Prorated

	Res. Heat	Res NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (Therms)	773,549.6	16,572.2	91,832.9	297,533.4	113,180.5	222,478.5	7,604.6	11,936.4	178,971.9	1,713,660
										3,309,271
									Sales	1,534,688
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity Rate	$1.3436	$1.3436	$1.2465	$1.4115	$1.2465	$1.4115	$1.2465	$1.4115	$ -	
Prior Period Reconciliation	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	($0.0762)	$ -	
Working Captal Allowance	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$ -	
Supplier Refund	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	($0.0005)	$ -	
Bad Debt Allowance	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$0.0045	$ -	
Capacity Reserve Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$ 0.00551	
Total Billed Rate	$1.2732	$1.2732	$1.1761	$1.3411	$1.1761	$1.3411	$1.1761	$1.3411	$ 0.00551	
Peak Period Demand/Commodity Recovery Rate										
Demand & Commodity	$ 1,039,341	$ 22,266	$ 114,470	$ 419,968	$ 141,079	$ 314,028	$ 9,479	$ 16,848	$ -	$ 2,077,481
Prior Period Reconciliation	$ (58,944)	$ (1,263)	$ (6,998)	$ (22,672)	$ (8,624)	$ (16,953)	$ (579)	$ (910)	$ -	$ (116,943)
Working Captal Allowance	$ 1,392	$ 30	$ 165	$ 536	$ 204	$ 400	$ 14	$ 21	$ -	$ 2,762
Supplier Refund	$ (387)	$ (8)	$ (46)	$ (149)	$ (57)	$ (111)	$ (4)	$ (6)	$ -	$ (767)
Bad Debt Allowance	$ 3,481	$ 75	$ 413	$ 1,339	$ 509	$ 1,001	$ 34	$ 54	$ -	$ 6,906
Capacity Reserve Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 986	$ 986
Total Peak COG Revenues	$ 984,883	$ 21,100	$ 108,005	$ 399,022	$ 133,112	$ 298,366	$ 8,944	$ 16,008	$ 986	$ 1,970,425
Check (Total Billed Sales Rate * Therms)	$ 984,883	$ 21,100	$ 108,005	$ 399,022	$ 133,112	$ 298,366	$ 8,944	$ 16,008	$ 986	$ 1,970,425

Docket No. DG 12-131
APPENDIX A
Page 11 of 45

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2007-2008 PEAK PERIOD
COST OF GAS ADJUSTMENT RESULTS
November 2007 - April 2008

FORM III
Schedule 4
Page 1 of 2

WINTER RELATED COSTS INCURRED IN SUMMER '07 DEFERRED TO WINTER 2007-08

	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	End of Period Adjustments	Total Winter
nmodity Costs:														
erta Northeast Gas Limited	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,009	$ 1,072	$ 1,142	$ 1,020	$ 1,103	$ 1,121	$ -	$ 6,467
Energy										$ 46,740	$ -	$ 2,970,725	$ -	$ 3,017,465
gill, Incorporated	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ 790,517	$ -	$ 790,517
vron Texaco Natural Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
onial Energy Inc	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,852	$ -	$ -	$ -	$ 6,852
istellation Power Source Inc	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 276,451	$ -	$ 276,451
al Energy Resources	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
rigas of Mass	$ -	$ -	$ -	$ -	$ -	$ -	$ 151,991	$ 466,815	$ 364,815	$ 465,465	$ 1,327,477	$ -	$ -	$ 2,776,563
e	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 60,122	$ -	$ -	$ -	$ 60,122
era Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ 155,345	$ 135,564	$ 126,987	$ 126,718	$ 147,177	$ -	$ -	$ 691,790
Ex Trade	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,152	$ 5,293	$ 5,640	$ 5,385	$ 5,450	$ 465,099	$ -	$ 492,019
ky	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
grys Energy Services	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 203,843	$ 808,977	$ 719,785	$ 573,831	$ 88,721	$ -	$ 2,395,157
is Dreyfus	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
guire Cook Inlet, LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 512,745	$ 183,021	$ -	$ 695,766
ssPower	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
rill Lynch Commodities	$ -	$ -	$ -	$ -	$ -	$ -	$ 680,221	$ 761,892	$ 761,830	$ 760,178	$ 935,077	$ 1,001,156	$ -	$ 4,900,354
en Marketing USA Inc	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
R Energy Services	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
theast Gas Marketing	$ -	$ -	$ -	$ -	$ -	$ -	$ 240,623	$ 258,701	$ 288,980	$ 270,276	$ 320,443	$ 347,629	$ -	$ 1,726,652
ples Energy Wholesale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
npra	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
uent Energy Management, LP	$ -	$ -	$ -	$ -	$ -	$ -	$ 104,882	$ 113,051	$ 126,244	$ 118,037	$ 139,873	$ 151,686	$ -	$ 753,773
thwest Energy LP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
iaska Marketing Canada	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,685	$ -	$ -	$ -	$ 18,685
iaska Marketing Ventures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,628	$ -	$ -	$ -	$ 6,628
J Portfolio Mgmt Co	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
S AG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 106,791	$ -	$ 106,791
Customs	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,077	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,077
hdrawal Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,350,111	$ 3,605,137	$ 3,570,775	$ 2,804,169	$ 1,578,070	$ 184	$ -	$ 13,908,446
Inventory Injections	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,026,702)	$ -	$ (3,026,702)
rruptible Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ (22,271)	$ -	$ -	$ -	$ -	$ (6,667)	$ -	$ (28,937)
Traditional Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (404,494)	$ -	$ (404,494)
OBA Adj.	$ -	$ -	$ -	$ -	$ -	$ -	$ 16,314	$ (79,086)	$ 173,467	$ 291,930	$ 105,924	$ (311,207)	$ (46,601)	$ 150,741
nsportation Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,976	$ 7,575	$ 7,860	$ 9,784	$ 7,917	$ 5,073	$ 796	$ 42,981
npany Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ (12,783)	$ (16,389)	$ (3,744)	$ (15,034)	$ (17,519)	$ (19,400)	$ -	$ (84,868)
3 Bolloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 534	$ 7,883	$ 22,476	$ 5,471	$ 9,912	$ 5,792	$ 517	$ 52,584
3 Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 746	$ 725	$ 18,485	$ -	$ -	$ -	$ 19,956
or Period Adjustments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (32,353)	$ (13,652)	$ 28,404	$ (10,559)	$ 10,160	$ (271,123)	$ (289,124)
System Sales Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
npany Use	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,166)	$ (2,749)	$ (4,339)	$ (4,323)	$ (4,280)	$ (3,037)	$ -	$ (19,894)
nsportation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,481)	$ (8,998)	$ 121,785	$ (11,956)	$ 18,280	$ 57,577	$ -	$ 174,208
dging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 62,190	$ 188,390	$ 218,421	$ 104,295	$ (1,035)	$ (373,725)	$ -	$ 198,537
pane	$ -	$ -	$ -	$ -	$ -	$ -	$ (482)	$ (66,850)	$ (85,172)	$ (260,284)	$ (204,326)	$ (136,195)	$ (59,253)	$ (812,561)
entory Finance Charges	$ 34,664	$ 41,377	$ 47,271	$ 53,139	$ 57,991	$ 58,564	$ 52,776	$ 40,562	$ 25,887	$ 9,894	$ 2,597	$ 3,892	$ -	$ 428,614
rage Commodity	$ 171	$ 4,638	$ 433	$ 235	$ 231	$ 206	$ 16,923	$ 24,956	$ 24,666	$ 18,812	$ 10,982	$ 227	$ (6)	$ 102,474
mmodity Re-Allocation							$ (251,369)	$ (586,657)	$ (897,390)	$ (647,477)	$ (822,740)	$ (52,526)	$ -	$ (3,258,159)
al Commodity Costs	$ 34,835	$ 46,015	$ 47,703	$ 53,374	$ 58,222	$ 58,770	$ 3,570,575	$ 5,028,396	$ 5,646,380	$ 4,958,062	$ 4,636,398	$ 2,131,872	$ (375,671)	$ 25,894,931

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2007-2008 PEAK PERIOD
COST OF GAS ADJUSTMENT RESULTS
November 2007 - April 2008

FORM III
Schedule 4
Page 2 of 2

WINTER RELATED COSTS INCURRED IN SUMMER '07 DEFERRED TO WINTER 2007-08

	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	End of Period	Total Winter
eline Reservation														
onquin	16,201	16,238	16,220	16,220	16,238	16,186	16,049	16,011	15,992	16,013	15,948	15,949	-	193,264
minion	-	-	-	-	-	-	-	-	-	-	-	-	-	-
anite	62,889	62,856	62,889	62,889	63,104	63,104	62,575	62,515	62,491	62,467	62,461	62,435	-	752,676
quois	20,952	20,982	20,982	20,982	20,982	20,922	20,714	20,684	20,651	20,612	20,579	20,549	-	249,593
tional Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGTS (DEM)	14,013	14,013	14,013	14,013	14,013	14,013	815,518	815,518	815,518	815,518	815,518	13,905	-	4,175,572
nnessee Gas (El Paso)	138,482	138,623	138,694	138,692	138,694	138,361	136,936	136,790	133,397	133,154	132,925	133,201	-	1,637,948
xas Eastern	3,350	3,350	3,475	3,374	3,374	3,385	3,359	3,358	3,358	3,387	3,387	3,364	-	40,524
xas Gas Transmission Company	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ansco	583	-	-	-	-	-	(30)	-	-	-	-	-	-	554
ctor Limited	1,248	1,248	1,248	1,248	1,248	1,248	1,238	1,238	1,238	1,238	1,238	1,238	-	14,913
ctor LP	24,781	24,781	24,781	24,781	24,781	24,781	24,590	24,590	24,590	24,590	24,590	89,971	-	361,610
-Managed	(3,847)	(4,099)	(3,967)	(4,027)	(4,012)	(3,907)	(4,039)	(5,168)	(4,497)	(4,564)	(4,905)	(5,066)	-	(52,099)
ior Period Adj.	-	22,352	(4,516)	23,288	23,064	23,978	294	23,385	41,536	73,390	46,543	46,501	320,254	640,068
tal Pipeline Reservation	278,654	300,344	273,819	301,461	301,485	302,070	1,077,205	1,098,920	1,114,273	1,145,805	1,118,284	382,047	320,254	8,014,622
oduct Demand														
anite Demand Purchases	-	-	-		-	-	-	-	-	-	-	-	-	-
strigas of Massachusetts	100,884	100,884	100,884	100,884	100,884	100,884	-	103,671	103,671	103,671	103,671	103,671	-	1,123,664
ke	-	-	-	-	-	-	107,070	107,070	107,070	107,070	107,070	107,070	-	642,418
sky	-	-	-	-	-	-	-	-	-	-	-	-	-	-
naska Marketing Canada	20,184	19,533	20,184	20,184	19,533	20,184	-	-	-	-	-	-	-	119,800
ior Period Adjustments	-	887	2,031	1,043	2,315	3,672	2,715	103,671	-	-	-	-	(107,070)	9,265
tal Product Demand	121,068	121,304	123,099	122,111	122,732	124,740	109,785	314,413	210,741	210,741	210,741	210,741	(107,070)	1,895,146
orage Pipeline Transportation and Demand Reservation														
gonquin	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-Energy	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Paso Energy (Tennessee Gas)	4,660	4,669	4,669	4,669	4,669	4,661	4,617	4,609	4,600	4,591	4,583	4,575	-	55,574
TE Energy	153,893	154,751	187,519	187,519	188,377	187,519	518,715	519,566	525,559	523,856	525,559	(25,536)	-	3,647,299
quois	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NGTS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
xas Eastern	115	115	115	115	115	116	115	115	115	116	116	116	-	1,385
xas Gas	-	-	-	-	-	(111)	-	-	-	-	-	-	-	(111)
ational Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NG Transmission - Dominion	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ompany Managed	(19,823)	(20,512)	(19,581)	(21,325)	(21,325)	(21,325)	(25,374)	(544,161)	(532,162)	(575,838)	(583,856)	(612,097)	-	(2,997,380)
rior Period Adjustment	-	51,641	56,445	26,598	25,220	31,054	43,234	24,718	14,746	27,408	24,174	25,025	146,121	496,385
otal Storage and Demand Reservation	138,845	190,665	229,168	197,577	197,057	201,915	541,307	4,848	12,858	(19,867)	(29,425)	(607,917)	146,121	1,203,152
otal Fixed Demand	538,567	612,312	626,086	621,149	621,275	628,725	1,728,297	1,418,181	1,337,872	1,336,679	1,299,600	(15,129)	359,306	11,112,920
ransp. Charges	-	-	-	-	-	-	-	-	-	-	-	-	-	-
on-Traditional Sales Margin	(1,377)	(1,863)	(1,618)	(1,602)	(1,656)	(6,031)	-	-	-	-	-	(37,657)	-	(51,804)
terruptible Profits	(103)	(10)	(147)	1	(10)	(929)	(26,482)	-	-	-	-	(2,761)	-	(30,440)
apacity Release	(108,663)	(114,776)	(88,226)	(116,135)	(115,134)	(116,436)	(76,567)	(78,073)	(91,773)	(73,685)	(73,144)	(99,349)	-	(1,151,961)
apacity Mitigation	-	-	-	228	228	227	228	299	860	(9,219)	7,292	(4,038)	-	(3,895)
roduction and Storage	-	-	-	-	-	-	88,672	130,457	152,701	129,434	112,546	72,863	-	686,673
iscellaneous Overhead	-	-	-	-	-	-	12,334	18,146	21,240	18,004	15,655	10,135	-	95,514
ransp. Demand Revenues	(6)	(8)	(7)	(7)	(7)	(6)	(6)	(6)	(7)	(6)	(7)	(7)	-	(80)
otal Demand Costs	428,417	495,655	536,089	503,634	504,695	505,550	1,726,476	1,489,003	1,420,894	1,401,206	1,361,943	(75,942)	359,306	10,656,927
emand Costs Transferred to Summer Period	181,703	181,703	181,703	181,703	181,703	181,703	-	-	-	-	-	-	-	1,090,218
et Demand Costs For Winter Period	246,714	313,952	354,386	321,932	322,993	323,847	1,726,476	1,489,003	1,420,894	1,401,206	1,361,943	(75,942)	359,306	9,566,709
otal Gas Cost for Winter Period	281,549	359,967	402,089	375,305	381,214	382,618	5,297,051	6,517,400	7,067,273	6,359,268	5,998,341	2,055,930	(16,366)	35,461,640

Dctober includes Supplier refund for Texas Gas ($110.69)

Northern Utiltiies

New Hampshire Division

Winter 07-08

FORM III
Schedule 4
Re-Allocation

	November 2007	December	January 2008	February	March	April	
Tariff Sales	2,419,372	5,247,839	6,342,120	6,088,195	5,723,894	4,251,766	
Current Unbilled	2,389,920	3,731,368	3,560,205	3,399,704	3,260,255	1,845,183	
Prior Unbilled	(1,128,719)	(2,389,920)	(3,731,368)	(3,560,205)	(3,399,704)	(3,260,255)	
Tariff Sales Volumes---therms	3,680,573	6,589,287	6,170,957	5,927,694	5,584,445	2,836,694	
Tariff Sales Volumes---Dth	368,057	658,929	617,096	592,769	558,445	283,669	
--includes billed and net unbilled							
Plus: Company Use	100	235	299	282	285	206	
Plus: Co-Managed	58,519	64,924	94,588	85,303	77,579	2,234	
Subtotal	426,676	724,088	711,983	678,354	636,309	286,109	
Unacounted for estimate	101%	101%	101%	101%	101%	101%	
Volumes for allocation	430,943	731,329	719,103	685,138	642,672	288,970	
Maine Division							
Tariff Sales	2,093,267	4,404,789	4,626,911	4,922,184	4,510,695	2,944,959	
Current Unbilled	1,317,085	2,237,906	2,193,171	2,033,942	2,052,850	1,167,223	
Prior Unbilled	(725,516)	(1,317,085)	(2,237,906)	(2,193,171)	(2,033,942)	(2,052,850)	
Tariff Sales Volumes---Ccf	2,684,836	5,325,610	4,582,176	4,762,955	4,529,603	2,059,332	
Tariff Sales Volumes---Mcf	268,484	532,561	458,218	476,296	452,960	205,933	
--includes billed and net unbilled							
Plus: Company Use	185	309	276	584	271	150	
Plus: Co-Managed	163,122	229,828	253,711	222,424	222,901	-	
Subtotal---Mcf	431,791	762,698	712,205	699,304	676,132	206,083	
Maine conversion factor	1.059	1.048	1.051	1.050	1.067	1.075	
Subtotal---Dth	457,266	799,308	748,527	734,269	721,433	221,539	
Unacounted for estimate	102%	102%	102%	102%	102%	102%	
Volumes for allocation	466,412	815,294	763,498	748,954	735,862	225,970	
New Hampshire New Commodity Allocation %	48.024%	47.286%	48.503%	47.775%	46.620%	56.117%	
Maine New Commodity Allocation %	51.976%	52.714%	51.497%	52.225%	53.380%	43.883%	
New Hampshire Old Commodity Allocation %	51.522%	52.927%	56.403%	53.848%	54.498%	57.230%	
Maine Old Commodity Allocation %	48.478%	47.073%	43.597%	46.152%	45.502%	42.770%	
New Commodity Allocation Costs							
New Hampshire	$3,563,993	$5,028,396	$5,646,380	$4,853,768	$4,636,398	$2,132,388	$25,861,323
Maine	$3,857,041	$5,164,943	$4,884,850	$4,664,204	$4,866,661	$839,953	$24,277,652
Old Commodity Allocation Costs							
New Hampshire	$3,815,362	$5,615,053	$6,543,770	$5,501,245	$5,459,138	$2,184,914	$29,119,482
Maine	$3,605,661	$4,578,196	$3,987,277	$4,016,590	$4,043,754	$787,414	$21,018,892
Difference In Commodity Allocation Costs							
New Hampshire	($251,369)	($586,657)	($897,390)	($647,477)	($822,740)	($52,526)	($3,258,159)
Maine	$251,380	$586,747	$897,573	$647,614	$822,907	$52,539	$3,258,760
	$11	$90	$183	$137	$167	$13	$601

Attachment A

NORTHERN UTILITIES
NEW HAMPSHIRE DIVISION
DEFERRED WINTER PERIOD WORKING CAPITAL
ALLOWANCE ON PURCHASED GAS COSTS
April 30, 2008

WINTER PERIOD - Acct 182.11

	BEGINNING BALANCE*	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
MAY 07 (Summer)	**(2,669)**	535	0.1900%	0	535	(2,134)	(2,402)	8.25%	(17)	(2,151)
JUNE	(2,151)	684	0.1900%	0	684	(1,467)	(1,809)	8.25%	(12)	(1,479)
JULY	(1,479)	764	0.1900%	0	764	(715)	(1,097)	8.25%	(8)	(723)
AUGUST	(723)	713	0.1900%	0	713	(10)	(366)	8.25%	(3)	(12)
SEPTEMBER	(12)	724	0.1900%	0	724	712	350	8.25%	2	715
OCTOBER	715	727	0.1900%	0	727	1,442	1,078	8.25%	7	1,449
NOVEMBER	1,449	10,064	0.1900%	(2,420)	7,644	9,093	5,271	8.25%	36	9,130
DECEMBER	9,130	12,383	0.1900%	(9,446)	2,937	12,066	10,598	8.25%	73	12,139
JANUARY 2008	12,139	13,428	0.1900%	(11,416)	2,012	14,151	13,145	7.50%	82	14,233
FEBRUARY	14,233	12,083	0.1900%	(10,959)	1,124	15,357	14,795	7.50%	92	15,450
MARCH	15,450	11,397	0.1900%	(10,303)	1,094	16,544	15,997	7.50%	100	16,644
APRIL	16,644	3,906	0.1900%	(7,653)	(3,747)	12,897	14,770	6.00%	74	12,971
MAY 08 (Winter)	12,971	(31)	0.1900%	(2,762)	(2,794)	10,177	11,574	6.00%	58	10,235

*Beginning Balance for May 2007 (Summer) approved in DG07-033, get from tariff pg 39
** Working Capital Allowance Calculated by taking Eligible Gas Costs from Sch 4 and multiplying by Working Capital Percentage

Attachment B

NORTHERN UTILITIES, INC
NEW HAMPSHIRE DIVISION
BAD DEBT EXPENSE
CALCULATION OF COLLECTION ALLOWANCE
April 30, 2008

WINTER PERIOD - Acct 182.16

	BEG. BAL*	BAD DEBT ALLOWANCE	% ALLOWED BAD DEBT	BAD DEBT COLLECTION	DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B = Allowed Gas Cost * C	C	(D)	E = B + (D)	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
MAY 07 (Summer)	(1,552)	1,269	0.45%	0	1,269	(283)	(917)	8.25%	(6)	(289)
JUNE	(289)	1,623	0.45%	0	1,623	1,334	523	8.25%	4	1,338
JULY	1,338	1,813	0.45%	0	1,813	3,150	2,244	8.25%	15	3,166
AUGUST	3,166	1,692	0.45%	0	1,692	4,858	4,012	8.25%	28	4,886
SEPTEMBER	4,886	1,719	0.45%	0	1,719	6,604	5,745	8.25%	39	6,644
OCTOBER	6,644	1,725	0.45%	0	1,725	8,369	7,506	8.25%	52	8,420
NOVEMBER	8,420	23,882	0.45%	(6,050)	17,832	26,252	17,336	8.25%	119	26,371
DECEMBER	26,371	29,384	0.45%	(23,615)	5,769	32,140	29,256	8.25%	201	32,341
JANUARY 2008	32,341	31,863	0.45%	(28,540)	3,324	35,665	34,003	7.50%	213	35,877
FEBRUARY	35,877	28,671	0.45%	(27,397)	1,274	37,151	36,514	7.50%	228	37,380
MARCH	37,380	27,044	0.45%	(25,758)	1,286	38,666	38,023	7.50%	238	38,904
APRIL	38,904	9,269	0.45%	(19,133)	(9,864)	29,040	33,972	6.00%	170	29,210
MAY 08 (Winter)	29,210	(74)	0.45%	(6,906)	(6,980)	22,230	25,720	6.00%	129	22,359

*Beginning Balance for May 2007 approved in DG07-033, get from tariff pg 39
**Bad Debt Allowance Calc by multiplying Bad Debt % by Gas Cost on Sch 4 and Working Capital Allowance on Attachment A

Northern Utilities, Inc. - New Hampshire Division
Environmental Response Costs
June 2007 through October 2008

Attachment D
Page 1 of 1

	Beginning Balance	Firm Sales and Transportation (therms)	ERC Recovery/Passback Rate	Current ERC Recoveries/ Passbacks	Ending Balance
JUNE 2007 (act)	$ 109,723	2,665,422	$ 0.0083	$ 22,123	$ 87,600
JULY (act)	$ 87,600	2,325,630	$ 0.0083	$ 19,303	$ 68,298
AUGUST (act)	$ 68,298	2,179,948	$ 0.0083	$ 18,094	$ 50,204
SEPTEMBER (act)	$ 50,204	2,412,730	$ 0.0083	$ 20,026	$ 30,178
OCTOBER (act)	$ 30,178	2,670,590	$ 0.0083	$ 22,166	$ 8,012
NOV (Summer) (act)	$ 8,012	2,678,108	$ 0.0083	$ 22,228	$ (14,216)
NOV (Winter) (act)	$ 454,216	1,624,616	$ 0.0052	$ 8,448	$ 445,768
DECEMBER (act)	$ 445,768	7,472,553	$ 0.0052	$ 38,857	$ 406,911
JANUARY 2008 (act)	$ 406,911	9,176,920	$ 0.0052	$ 47,720	$ 359,191
FEBRUARY (act)	$ 359,191	8,793,148	$ 0.0052	$ 45,724	$ 313,467
MAR (act)	$ 313,467	8,444,432	$ 0.0052	$ 43,911	$ 269,555
APR (act)	$ 269,555	6,920,177	$ 0.0052	$ 35,985	$ 233,571
MAY (act)	$ 233,571	4,247,427	$ 0.0052	$ 22,087	$ 211,484
JUNE (act)	$ 211,484	2,727,206	$ 0.0052	$ 14,181	$ 197,302
JULY (est)	$ 197,302	2,342,550	$ 0.0052	$ 12,181	$ 185,121
AUGUST (est)	$ 185,121	2,195,910	$ 0.0052	$ 11,419	$ 173,702
SEPTEMBER (est)	$ 173,702	2,844,710	$ 0.0052	$ 14,792	$ 158,910
OCTOBER (est)	$ 158,910	4,327,460	$ 0.0052	$ 22,503	$ 136,407

Attachment C

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2007 - 08 WINTER PERIOD RECONCILIATION
INTERRUPTIBLE PROFIT SCHEDULE
Summary May 2007 - April 2008

	May 2007	June	July	August	September	October	November	December	January 2008	February	March	April	Total
Total Interruptible Sales	$448	$53	$162	$42	$26	$2,184	$64,548	$0	$0	$0	$0	$ 14,408	$81,871
Less: Emergency Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$ -	$0
Interruptible Sales	$448	$53	$162	$42	$26	$2,184	$64,548	$0	$0	$0	$0	$14,408	$81,871
Total Interruptible Costs	$345	$42	$132	$29	$16	$1,255	$38,066	$0	$0	$0	$0	$11,647	$51,533
Total Interruptible Profits	$103	$10	$30	$13	$10	$929	$26,482	$0	$0	$0	$0	$2,761	$30,338
Emergency Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Emergency Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Emer Sales Margin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Inter & Emer Margin	$103	$10	$30	$13	$10	$929	$26,482	$0	$0	$0	$0	$2,761	$30,338
Total Passback Profit	$103	$10	$30	$13	$10	$929	$26,482	$0	$0	$0	$0	$2,761	$30,338

Attachment E

NORTHERN UTILITIES
NEW HAMPSHIRE DIVISION
RLIAP Reconciliation

October 31, 2008

	Beginning Balance	Program Costs	RLIAP Recoveries	Ending Balance	Average Monthly Balance	Interest Rate	Interest	Ending Balance w/Interest
	A	B	C	D = A + B - C	E = (A +D) / 2	F	G = E * (F / 12)	H = D + G
June 2007	$ (64,279)	$ 12,502	$ 13,327	$ (65,104)	$ (64,692)	8.25%	$ (445)	$ (65,549)
July 2007	$ (65,549)	$ 8,829	$ 11,628	$ (68,348)	$ (66,949)	8.25%	$ (460)	$ (68,808)
August 2007	$ (68,808)	$ 7,905	$ 10,900	$ (71,803)	$ (70,306)	8.25%	$ (483)	$ (72,286)
September 2007	$ (72,286)	$ 7,856	$ 12,064	$ (76,494)	$ (74,390)	8.25%	$ (511)	$ (77,005)
October 2007	$ (77,005)	$ 8,256	$ 13,353	$ (82,102)	$ (79,553)	8.25%	$ (547)	$ (82,649)
November 2007	$ (82,649)	$ 17,611	$ 16,640	$ (81,678)	$ (82,163)	8.25%	$ (565)	$ (82,243)
December 2007	$ (82,243)	$ 24,867	$ 14,945	$ (72,321)	$ (77,282)	8.25%	$ (531)	$ (72,852)
January 2008	$ (72,852)	$ 32,341	$ 18,354	$ (58,865)	$ (65,858)	7.50%	$ (412)	$ (59,277)
February 2008	$ (59,277)	$ 35,928	$ 17,586	$ (40,935)	$ (50,106)	7.50%	$ (313)	$ (41,248)
March 2008	$ (41,248)	$ 33,927	$ 16,889	$ (24,210)	$ (32,729)	7.50%	$ (205)	$ (24,415)
April 2008	$ (24,415)	$ 33,448	$ 13,840	$ (4,807)	$ (14,611)	6.00%	$ (73)	$ (4,880)
May 2008	$ (4,880)	$ 18,999	$ 8,495	$ 5,624	$ 372	6.00%	$ 2	$ 5,626

NORTHERN UTILITIES, NEW HAMPSHIRE DIVISION
Sales Variance Analysis
Winter 2007-2008 Period

Attachment F
Page 1 of 2

	Nov	December	January	February	March	April	TOTAL	
recasted Sales Activity	414,859	609,511	713,213	604,770	526,055	341,098	3,209,506	
tual Sales	420,252	574,513	557,501	531,696	497,858	323,878	2,905,698	
ference	5,393	(34,998)	(155,712)	(73,074)	(28,197)	(17,220)	(303,808)	
d: volume difference due to weather								
rmalized Sales Activity	370,158	545,639	651,912	576,886	509,153	318,090	2,971,838	
tual Sales	420,252	574,513	557,501	531,696	497,858	323,878	2,905,698	
	50,094	28,874	(94,411)	(45,190)	(11,295)	5,788	(66,140)	
tal Variance cl weather effect)	(44,701)	(63,872)	(61,301)	(27,884)	(16,902)	(23,008)	(237,668)	-7.41%
riance-difference due to meter count							(67,578)	
-difference in load pattern							(236,230)	
							(303,808)	

Attachment F
Page 2 of 2

NORTHERN UTILITIES, NEW HAMPSHIRE DIVISION
Sales Variance Analysis
Winter 2007-2008 Period

	NORMAL MMBtu			METERS		
	2007-2008 Forecast	2007-2008 Actual	Difference	2007-2008 Forecast	2007-2008 Actual	Difference
ıs Heat	1,268,872	1,249,770	(19,102)	117,602	117,335	(267)
ɜs General	19,042	18,093	(949)	10,676	10,199	(477)
ɔtal Res	1,287,914	1,267,863	(20,051)	128,278	127,534	(744)
40	697,626	663,211	(34,415)	27,249	25,483	(1,766)
50	112,259	105,633	(6,626)	6,293	5,662	(631)
41	646,657	567,160	(79,497)	2,372	2,185	(187)
51	216,343	184,941	(31,402)	1,153	1,024	(129)
42	110,524	76,852	(33,672)	67	61	(6)
52	138,183	40,038	(98,145)	54	33	(21)
ɔtal C & I	1,921,592	1,637,835	(283,757)	37,188	34,448	(2,740)
ɔtal	3,209,506	2,905,698	(303,808)	165,466	161,982	(3,484)

	NORMAL AVERAGE USE			Change in Sales Due to Change In:			Total Chg	
	2007-2008 Forecast	2007-2008 Actual	Difference	Meter Count	Load Pattern		MMBtu	% difference
ɜs Heat	10.79	10.65	(0.14)	(2,881)	(16,221)	(19,102)	(19,102)	-1.51%
ɜs General	1.78	1.77	(0.01)	(851)	(98)	(949)	(949)	-4.98%
otal Res	10.04	9.94	(0.10)	(7,470)	(12,581)	(20,051)	(20,051)	-1.56%
-40	25.60	26.03	0.42	(45,213)	10,798	(34,415)	(34,415)	-4.93%
-50	17.84	18.66	0.82	(11,256)	4,630	(6,626)	(6,626)	-5.90%
-41	272.62	259.57	(13.05)	(50,980)	(28,517)	(79,497)	(79,497)	-12.29%
-51	187.63	180.61	(7.03)	(24,205)	(7,197)	(31,402)	(31,402)	-14.51%
-42	1,649.61	1,259.87	(389.74)	(9,898)	(23,774)	(33,672)	(33,672)	-30.47%
-52	2,558.94	1,213.27	(1,345.67)	(53,738)	(44,407)	(98,145)	(98,145)	-71.03%
ɔtal C & I	51.67	47.55	(4.12)	(141,576)	(142,181)	(283,757)	(283,757)	-14.77%
ɔtal	19.40	17.94	(1.46)	(67,578)	(236,230)	(303,808)	(303,808)	-9.47%

Attachment G

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
REFUND PASSBACK CALCULATION FOR THE PERIOD NOV 2007 - APR 2008

	Beginng Month Balance	Refund Pass Back	Refunds	End of Month Balance	Average Balance	Annual Interest Rate	Monthly Interest Amount	Principal & Interest Balance	Actual Sales (ccf)
January 31, 2007	$0	$0	($18,779)	($18,779)	($9,389)	8.25%	($65)	($18,843)	
February	($18,843)	$0	$0	($18,843)	($18,843)	8.25%	($130)	($18,973)	
March	($18,973)	$0	$0	($18,973)	($18,973)	8.25%	($130)	($19,103)	
April	($19,103)	$0	$0	($19,103)	($19,103)	8.25%	($131)	($19,235)	
May	($19,235)	$0	$0	($19,235)	($19,235)	8.25%	($132)	($19,367)	
June	($19,367)	$0	$0	($19,367)	($19,367)	8.25%	($133)	($19,500)	
July	($19,500)	$0	$0	($19,500)	($19,500)	8.25%	($134)	($19,634)	
August (act)	($19,634)	$0	$0	($19,634)	($19,634)	8.25%	($135)	($19,769)	
September (act)	($19,769)	$0	$0	($19,769)	($19,769)	8.25%	($136)	($19,905)	
October (act)	($19,905)	$0	$0	($19,905)	($19,905)	8.25%	($137)	($20,042)	
November (act)	($20,042)	($672)	$0	($19,370)	($19,706)	8.25%	($135)	($19,505)	1,344,521
December (act)	($19,505)	($2,624)	$0	($16,881)	($18,193)	8.25%	($125)	($17,006)	5,247,839
January 2008 (act)	($17,006)	($3,171)	$0	($13,835)	($15,421)	7.50%	($96)	($13,932)	6,342,120
February (act)	($13,932)	($3,044)	$0	($10,888)	($12,410)	7.50%	($78)	($10,965)	6,088,195
March (act)	($10,965)	($2,862)	$0	($8,103)	($9,534)	7.50%	($60)	($8,163)	5,723,894
April (act)	($8,163)	($2,126)	$0	($6,037)	($7,100)	6.00%	($35)	($6,072)	4,251,766
May (Winter) (act)	($6,072)	($767)	$1	($5,304)	($5,688)	6.00%	($28)	($5,332)	1,534,688
Total			($18,778)				($1,263)		28,998,335

Refund Passback Rate	
Total Refunds	$ (20,041)
Interest	$ (847)
Refund Passback Amount	$ (20,888)
/ Total Sales	57,263,958
= Passback Rate (R1d)	($0.0005)

NiSource
Corporate Services

August 15, 2008

Ms. Karen Geraghty
Administrative Director
Maine Public Utilities Commission
242 State Street
Augusta, Maine 04333

Re: Northern Utilities, Inc. 2007-2008 Peak Period Cost of Gas Reconciliation

Dear Ms. Geraghty:

In accordance with Section 5.09: Reconciliation Adjustment – Account 175 of the Company's currently effective Cost of Gas Factor ("CGF") Clause, Section V of the tariff, approved by the Commission on September 3, 1999, in Docket No. 97-393, the Company is filing herewith, an original and six copies of Northern Utilities, Inc. Peak period 2007-2008 reconciliation filing. This seasonal reconciliation filing covers the accounting for the Peak period costs from May 1, 2007 through May 31, 2008 and collections from November 1, 2007 through April 30, 2008.

In this filing, Schedules 1 through 5 contain the accounting of twelve months costs assigned to the Peak period and six months of Peak period collections. The schedules illustrate the Company's over-collection of Peak Demand costs of $7,480,450 and under-collection of Peak Commodity costs of $5,896,579 for a net over-collection of $1,583,871. Schedule 1, page 1, provides the summary of the twelve months reconciliation of Peak Demand, while page 2 of Schedule 1 provides the summary of the Peak Commodity. Schedule 2 shows the deferred gas cost activity, allowable costs, revenues and interest on the monthly balances for the period May 2007 through May 2008. Schedule 3, page 1, shows the summary of Peak period gas cost collections, while Schedule 3, pages 2 through 8 illustrate the gas cost collections for each individual month. Schedule 4, pages 1 and 2, shows the monthly detail of purchase gas costs allocated to the Peak season during the period November 2007 through April 2008. Schedule 4 Re-Allocation reflects the re-allocation of commodity costs from the New Hampshire Division to the Maine Division primarily due to the inadvertent omission of Company Managed volumes from the calculation. Schedule 5 presents the purchased and made volumes in Dekatherms ("Dths"), as well as sales volumes by Residential and Commercial/Industrial customer classification for the annual period of May 2007 through April 2008. The resulting difference between sendout and sales volumes is shown for this twelve-month period.

Attachment A presents the interruptible profits by month. A total of $96,175 of interruptible profits has be recognized for May 2007 through April 2008. The $96,175 represents 90% of the total interruptible profit of $106,861. The Company has retained the remaining 10% of interruptible profits. A total of $96,175 has been deducted from the Peak Period Demand Costs found on Form III, Schedule 4, Pages 1 and 2. There were no emergency sales during the period.

Attachment B shows the Deferred Working Capital balances remaining at the end of the winter period for Peak Demand and Peak Commodity. An over-collection of $23,977 remains for Peak Demand and an under-collection of $26,360 remains for Peak Commodity resulting in a total net under-collection of $2,383.

Attachment C contains the calculation of the Bad Debt Collection Allowance. This schedule shows, at the end of the 2007-2008 peak season an under-collection of $7,872.

Attachment D details the sales variance analysis. Of the (74,422) Mcf less-than-forecasted sales variance, warmer than normal weather resulted in a 159,833 Mcf decrease in sales, leaving a weather normalized sales variance of 85,411 Mcf greater-than-forecast. The residential classes' normalized sales were greater-than-forecasted by 16,418 Mcf, while the Commercial and Industrial ("C&I") categories had greater-than-forecasted normalized sales of 68,993 Mcf. The residential class variance is due to a lower-than-forecast average use attributing to lower-than-forecast sales of 3,242 Mcf, partially off-set by a higher than forecast number of meters of 19,660 Mcf. The greater-than-forecast C&I sales variance is due increased average use of 357,038 Mcf, partially off-set by a lower-than-forecast meter variance of 288,045 Mcf.

Attachment E reconciles the refund passback of a refund received on January 31, 2007.

Please do not hesitate to contact me if you have any questions regarding these reconciliation schedules.

Sincerely,

Ronald D. Gibbons
Manager, Regulatory Accounting

Enclosures
cc: Wayne Jortner, Esquire
Patricia M. French, Esquire
Joseph A. Ferro

FORM III
Schedule 1
Page 1 of 2

NORTHERN UTILITIES, INC. - MAINE DIVISION
2007-08 PEAK PERIOD RECONCILIATION
SCHEDULE 1: PEAK DEMAND SUMMARY
November 2007 - April 2008

	AMOUNT	
Peak Demand Beg. Balance	$ (3,208,051)	SCHEDULE 2
Less: Rev. Billed via Demand CGF	$ (8,697,079)	SCHEDULE 3
Less: Return to Sales Service Fees (Through April 2008)	$0	
Add: Cost of Firm Gas Allowable (Demand)	$ 4,549,834	SCHEDULE 2
Add: Interest	$ (125,154)	SCHEDULE 2
Peak Demand Ending Balance	$ (7,480,450)	

NORTHERN UTILITIES, INC. - MAINE DIVISION
2007-08 PEAK PERIOD RECONCILIATION
SCHEDULE 1: PEAK COMMODITY SUMMARY
November 2007 - April 2008

	AMOUNT	
Peak Commodity Beg. Balance	$ 2,983,298	SCHEDULE 2
Less: Rev. Billed via Commodity CGF	$ (21,767,808)	SCHEDULE 3
Add: Cost of Firm Gas Allowable (Commodity)	$ 24,422,928	SCHEDULE 2
Add: Adj. bill adjustment	$ 9,082	SCHEDULE 2
Add: Interest	$ 249,079	SCHEDULE 2
Peak Commodity Ending Balance	$ 5,896,579	SCHEDULE 2
Net Peak Commodity Ending Balance	$ 5,896,579	
	$ (1,583,871)	

FORM III
Schedule 2

NORTHERN UTILITIES, INC. - MAINE DIVISION
2007-08 PEAK PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED PEAK PERIOD ACCOUNTS
May 2007 - May 2008

Line	Description	May 2007	June	July	August	September	October	November	December	January 2008	February	March	April	May	Total
1	PEAK DEMAND - ACCOUNT 191.20														
2	Peak Demand Account Beginning Balance	$ (3,208,051)	$ (2,980,276)	$ (2,697,372)	$ (2,376,650)	$ (2,088,198)	$ (1,803,546)	$ (1,494,910)	$ (232,233)	$ (832,637)	$ (1,960,916)	$ (3,598,465)	$ (5,091,616)	$ (7,495,677)	$ (3,208,051)
3	Plus: Cost of Gas Allowable (Schedule 4)	$ 227,243	$ 296,498	$ 332,934	$ 299,346	$ 294,179	$ 316,205	$ 1,759,825	$ 1,014,704	$ 592,642	$ 199,829	$ 178,286	$ (1,320,158)	$ 358,301	$ 4,549,834
4	Less: Base Gas Rev. Applied (Schedule 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ (493,341)	$ (1,612,740)	$ (1,714,707)	$ (1,827,967)	($1,658,638)	($1,067,299)	($322,386)	$ (8,697,079)
5	Preliminary Ending Balance	$ (2,980,808)	$ (2,683,778)	$ (2,364,438)	$ (2,077,304)	$ (1,794,018)	$ (1,487,341)	$ (228,427)	$ (830,268)	$ (1,954,703)	$ (3,589,053)	$ (5,078,817)	$ (7,479,074)	$ (7,459,762)	
6	Month's Average Balance ((Line 1 + Line 5) / 2)	$ (3,094,429)	$ (2,832,027)	$ (2,530,905)	$ (2,226,977)	$ (1,941,108)	$ (1,645,444)	$ (861,669)	$ (531,251)	$ (1,393,670)	$ (2,774,985)	$ (4,338,641)	$ (6,285,345)	$ (7,477,720)	
7	Interest Rate (Short Term Borrowing Rate)	5.62%	5.76%	5.79%	5.87%	5.89%	5.52%	5.30%	5.35%	5.35%	4.07%	3.54%	3.17%	3.32%	
8	Interest Applied (Line 6 * (Line 7 / 12))	$ 532	$ (13,594)	$ (12,212)	$ (10,894)	$ (9,528)	$ (7,569)	$ (3,806)	$ (2,368)	$ (6,213)	$ (9,412)	$ (12,799)	$ (16,604)	$ (20,688)	$ (125,154)
9	Peak Demand Account Ending Balance (Line 5 + Line 8)	$ (2,980,276)	$ (2,697,372)	$ (2,376,650)	$ (2,088,198)	$ (1,803,546)	$ (1,494,910)	$ (232,233)	$ (832,637)	$ (1,960,916)	$ (3,598,465)	$ (5,091,616)	$ (7,495,677)	$ (7,480,450)	$ (7,480,450)
10	PEAK COMMODITY - ACCOUNT 191.19														
11	Peak Commodity Account Beginning Balance	$ 2,983,298	$ 3,017,589	$ 3,076,268	$ 3,137,948	$ 3,205,777	$ 3,278,749	$ 3,351,654	$ 5,965,618	$ 7,110,518	$ 7,780,503	$ 8,042,172	$ 8,820,584	$ 6,941,732	$ 2,983,298
12	Plus: Cost of Gas Allowable	$ 34,211	$ 44,089	$ 46,724	$ 52,351	$ 57,098	$ 57,690	$ 3,863,168	$ 5,164,943	$ 4,884,850	$ 4,753,970	$ 4,866,660	$ 839,565	$ (242,391)	$ 24,422,928
13	Less: Base Gas Rev. Applied	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,269,734)	$ (4,051,221)	($4,247,449)	($4,518,647)	($4,145,058)	($2,709,513)	($826,187)	$ (21,767,808)
14	Less: Adjusted Bill Adjustment								$ 2,093	$ (537)	$ (442)	$ 31,974	$ (29,696)	$ 5,690	$ 9,082
15	Preliminary Ending Balance	$ 3,017,509	$ 3,061,678	$ 3,122,992	$ 3,190,299	$ 3,262,874	$ 3,336,439	$ 5,945,088	$ 7,081,434	$7,747,382	$8,015,384	$8,795,748	$6,920,940	$5,878,844	
16	Month's Average Balance ((Line 11 + Line 15) / 2)	$ 3,000,404	$ 3,039,634	$ 3,099,630	$ 3,164,123	$ 3,234,325	$ 3,307,594	$ 4,648,371	$ 6,523,526	$ 7,428,950	$ 7,897,944	$ 8,418,960	$ 7,870,762	$ 6,410,288	
17	Interest Rate (Short Term Borrowing Rate)	5.62%	5.76%	5.79%	5.87%	5.89%	5.52%	5.30%	5.35%	5.35%	4.07%	3.54%	3.17%	3.32%	
18	Interest Applied (Line 16 * (Line 17 / 12))	$ 80	$ 14,590	$ 14,956	$ 15,478	$ 15,875	$ 15,215	$ 20,530	$ 29,084	$ 33,121	$ 26,787	$ 24,836	$ 20,792	$ 17,735	$ 249,079
19	Peak Commodity Account Ending Balance (Line 16 + Line 18)	$ 3,017,589	$ 3,076,268	$ 3,137,948	$ 3,205,777	$ 3,278,749	$ 3,351,654	$ 5,965,618	$ 7,110,518	$ 7,780,503	$ 8,042,172 1/	$ 8,820,584	$ 6,941,732	$ 5,896,579	$ 5,896,579

Line	Description	May 2007	June	July	August	September	October	November	December	January 2008	February	March	April	May	Total
20	STIPULATION DEMAND CHARGE														
21	Stipulation Demand Charge Account Beg. Balance	$ 255,476	$ 255,534	$ 248,054	$ 241,482	$ 235,140	$ 228,520	$ 201,525	$ 188,377	$ 173,402	$ 154,874	$ 135,472	$ 117,445	$ 100,372	$ 255,476
22	Plus: Cost of Gas Allowable (Schedule 4)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Less: Base Gas Rev. Applied (Schedule 3)	($1,136)	$ (8,686)	$ (7,750)	($7,505)	($7,755)	($27,982)	($14,007)	($15,780)	$ (19,258)	$ (19,894)	($18,399)	($17,361)	($11,885)	$ (177,398)
24	Preliminary Ending Balance	$ 254,340	$ 246,848	$ 240,304	$ 233,977	$ 227,385	$ 200,538	$ 187,518	$ 172,597	$ 154,144	$ 134,981	$ 117,073	$ 100,084	$ 88,486	
25	Month's Average Balance ((Line 21 + Line 24) / 2)	$ 254,908	$ 251,191	$ 244,179	$ 237,729	$ 231,262	$ 214,529	$ 194,521	$ 180,487	$ 163,773	$ 144,928	$ 126,272	$ 108,765	$ 94,429	
26	Interest Rate (Short Term Borrowing Rate)	5.62%	5.76%	5.79%	5.87%	5.89%	5.52%	5.30%	5.35%	5.35%	4.07%	3.54%	3.17%	3.32%	
27	Interest Applied (Line 25 * (Line 26 / 12))	$ 1,194	$ 1,206	$ 1,178	$ 1,163	$ 1,135	$ 987	$ 859	$ 805	$ 730	$ 492	$ 373	$ 287	$ 261	$ 10,669
28	Interest Previously Applied	$ -													$ -
29	Stipulation Demand Charge Account Ending Balan (Line 24 + Line 27)	$ 255,534	$ 248,054	$ 241,482	$ 235,140	$ 228,520	$ 201,525	$ 188,377	$ 173,402	$ 154,874	$ 135,472	$ 117,445	$ 100,372	$ 88,748	$ 88,748
30-31	Peak Demand Account Ending Balance, including Stipulation Demand Charge (Line 9 + Line 29)	$ (2,724,742)	$ (2,449,318)	$ (2,135,168)	$ (1,853,058)	$ (1,575,026)	$ (1,293,385)	$ (43,856)	$ (659,235)	$ (1,806,042)	$ (3,462,993)	$ (4,974,171)	$ (7,395,306)	$ (7,391,703)	

*Interest was calculated on the Demand/Commodity Balance during the prior Peak Period reconciliation/filing and is included above in the beginning balance for May. The interest calculated above (Interest Applied) is only calculated on the Off Peak Costs (Sch 4) deferred to Peak.
1/ Includes Hedging from Sch 4, not booked by Accounting. Should show up in Accounting for March

NORTHERN UTILITIES, INC. - MAINE DIVISION
2007-08 PEAK PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2007 - April 2008

GAS COST RECOVERY FOR THE PERIOD OF :

	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (CCF)	7,256,704	400,417	1,160,285	6,653,514	1,213,937	5,801,477	660,760	536,480	31,556,676	55,240,248
									Sales	23,683,572
Peak Period Demand Recovery Rates										
Demand Costs	$0.4257	$0.4257	$0.3305	$0.5178	$0.3305	$0.5178	$0.3305	$0.5178	$0.0000	
Reconciliation Adj.	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	$0.0000	
Working Capital Allowance DMD	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0000	
SDC	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0033	
Capacity Reserve Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0015	
Energy Efficiency	$0.0234	$0.0234	$0.0078	$0.0078	$0.0078	$0.0078	$0.0078	$0.0078	$0.0078	
Total Billed Peak Demand Rate	$0.3517	$0.3517	$0.2409	$0.4282	$0.2409	$0.4282	$0.2409	$0.4282	$0.0126	
Peak Period Commodity Recovery Rates										
Commodity Costs	$0.8241	$0.8241	$0.8702	$0.8190	$0.8702	$0.8190	$0.8702	$0.8190	$0.0000	
Working Capital Allowance CMD	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0000	
Reconciliation Adj.	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0000	
Bad Debt	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0000	
Total Billed Peak Commodity Rate	$0.9331	$0.9331	$0.9792	$0.9280	$0.9792	$0.9280	$0.9792	$0.9280	$0.0000	
Total Billed Peak Period Rate	$1.2848	$1.2848	$1.2201	$1.3562	$1.2201	$1.3562	$1.2201	$1.3562	$0.0126	
Peak Period Demand Recovery Revenues										
Demand Costs	$3,089,179	$170,457	$383,474	$3,445,189	$401,206	$3,004,005	$218,381	$277,789	$0	$10,989,681
Reconciliation Adj.	($716,962)	($39,561)	($114,636)	($657,367)	($119,937)	($573,186)	($65,283)	($53,004)	$0	($2,339,937)
Working Capital Allowance DMD	$10,159	$561	$1,624	$9,315	$1,700	$8,122	$925	$751	$0	$33,157
SDC	$0	$0	$0	$0	$0	$0	$0	$0	$104,137	$104,137
Capacity Reserve Charge	$0	$0	$0	$0	$0	$0	$0	$0	$47,335	$47,335
Energy Efficiency	$169,807	$9,370	$9,050	$51,897	$9,469	$45,252	$5,154	$4,185	$246,142	$550,325
Total Demand Gas Cost Recovery Revenues	$2,552,183	$140,826	$279,513	$2,849,034	$292,437	$2,484,192	$159,177	$229,721	$397,614	$9,384,698
Peak Period Commodity Recovery Revenues										
Commodity Costs	$5,980,250	$329,983	$1,009,680	$5,449,228	$1,056,368	$4,751,409	$574,994	$439,377	$0	$19,591,288
Working Capital Allowance CMD	$29,752	$1,642	$4,757	$27,279	$4,977	$23,786	$2,709	$2,200	$0	$97,103
Reconciliation Adj.	$666,891	$36,798	$106,630	$611,458	$111,561	$533,156	$60,724	$49,302	$0	$2,176,520
Bad Debt	$94,337	$5,205	$15,084	$86,496	$15,781	$75,419	$8,590	$6,974	$0	$307,886
Total Commodity Gas Cost Recovery Revenue	$6,771,231	$373,629	$1,136,151	$6,174,461	$1,188,687	$5,383,770	$647,016	$497,853	$0	$22,172,797
Total Gas Cost Recovery Revenues	$9,323,414	$514,455	$1,415,663	$9,023,495	$1,481,125	$7,867,962	$806,194	$727,574	$397,614	$31,557,495

Demand	
Demand Costs	$10,989,681
Reconciliation Adj.	($2,339,937)
Capacity Reserve Charge	$47,335
	$8,697,079
Commodity	
Commodity Costs	$19,591,288
Reconciliation Adj.	$2,176,520
	$21,767,808
Total Demand and Commodity	$30,464,887

FORM III
Schedule 3
Page 2 of 8

NORTHERN UTILITIES, INC. - MAINE DIVISION
2007-08 PEAK PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2007 - April 2008

GAS COST RECOVERY FOR THE MONTH OF :	November 2007		Prorated							
	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (CCF)	340,570	17,947	82,917	328,667	134,244	376,174	55,853	40,209	472,808	1,849,389 1,849,389 1,376,580
Peak Period Demand Recovery Rates										
Demand Costs	$0.4257	$0.4257	$0.3305	$0.5178	$0.3305	$0.5178	$0.3305	$0.5178	$0.0000	
Reconciliation Adj.	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	$0.0000	
Working Capital Allowance DMD	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0000	
SDC	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0033	
Capacity Reserve Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0015	
Energy Efficiency	$0.0234	$0.0234	$0.0078	$0.0078	$0.0078	$0.0078	$0.0078	$0.0078	$0.0078	
Total Billed Peak Demand Rate	$0.3517	$0.3517	$0.2409	$0.4282	$0.2409	$0.4282	$0.2409	$0.4282	$0.0126	
Peak Period Commodity Recovery Rates										
Commodity Costs	$0.8241	$0.8241	$0.8702	$0.8190	$0.8702	$0.8190	$0.8702	$0.8190	$0.0000	
Working Capital Allowance CMD	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0000	
Reconciliation Adj.	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0000	
Bad Debt	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0000	
Total Billed Peak Commodity Rate	$0.9331	$0.9331	$0.9792	$0.9280	$0.9792	$0.9280	$0.9792	$0.9280	$0.0000	
Peak Period Demand Recovery Revenues										
Demand Costs	$144,981	$7,640	$27,404	$170,184	$44,368	$194,783	$18,460	$20,820	$0	$628,638
Reconciliation Adj.	($33,648)	($1,773)	($8,192)	($32,472)	($13,263)	($37,166)	($5,518)	($3,973)	$0	($136,006)
Working Capital Allowance DMD	$477	$25	$116	$460	$188	$527	$78	$56	$0	$1,927
SDC	$0	$0	$0	$0	$0	$0	$0	$0	$1,560	$1,560
Capacity Reserve Charge	$0	$0	$0	$0	$0	$0	$0	$0	$709	$709
Energy Efficiency	$7,969	$420	$647	$2,564	$1,047	$2,934	$436	$314	$3,688	$20,018
Total Demand Gas Cost Recovery	$119,779	$6,312	$19,975	$140,735	$32,339	$161,078	$13,455	$17,217	$5,957	$516,847
Peak Period Commodity Recovery Revenues										
Commodity Costs	$280,664	$14,790	$72,154	$269,178	$116,819	$308,086	$48,604	$32,931	$0	$ 1,143,226
Working Capital Allowance CMD	$1,396	$74	$340	$1,348	$550	$1,542	$229	$165	$0	$ 5,644
Reconciliation Adj.	$31,298	$1,649	$7,620	$30,205	$12,337	$34,570	$5,133	$3,695	$0	$ 126,508
Bad Debt	$4,427	$233	$1,078	$4,273	$1,745	$4,890	$726	$523	$0	$ 17,896
Total Commodity Gas Cost Recovery	$317,786	$16,746	$81,192	$305,003	$131,451	$349,089	$54,692	$37,314	$0	$ 1,293,273
Total Demand and Commodity Gas Cost Recovery	$437,565	$23,058	$101,167	$445,738	$163,791	$510,167	$68,147	$54,531	$5,957	$1,810,120
Check (Total Rate * Volumes)	$437,565	$23,058	$101,167	$445,738	$163,791	$510,167	$68,147	$54,531	$5,957	$1,810,120

FORM III
Schedule 3
Page 3 of 8

NORTHERN UTILITIES, INC. - MAINE DIVISION
2007-08 PEAK PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2007 - April 2008

GAS COST RECOVERY FOR THE MONTH OF :	December 2007									
	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (CCF)	1,271,813	59,022	288,432	1,279,031	218,686	1,067,201	120,054	100,550	4,781,756	9,186,545 9,186,545 4,404,789
Peak Period Demand Recovery Rates										
Demand Costs	$0.4257	$0.4257	$0.3305	$0.5178	$0.3305	$0.5178	$0.3305	$0.5178	$0.0000	
Reconciliation Adj.	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	$0.0000	
Working Capital Allowance DMD	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0000	
SDC	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0033	
Capacity Reserve Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0015	
Energy Efficiency	$0.0234	$0.0234	$0.0078	$0.0078	$0.0078	$0.0078	$0.0078	$0.0078	$0.0078	
Total Billed Peak Demand Rate	$0.3517	$0.3517	$0.2409	$0.4282	$0.2409	$0.4282	$0.2409	$0.4282	$0.0126	
Peak Period Commodity Recovery Rates										
Commodity Costs	$0.8241	$0.8241	$0.8702	$0.8190	$0.8702	$0.8190	$0.8702	$0.8190	$0.0000	
Working Capital Allowance CMD	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0000	
Reconciliation Adj.	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0000	
Bad Debt	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0000	
Total Billed Peak Commodity Rate	$0.9331	$0.9331	$0.9792	$0.9280	$0.9792	$0.9280	$0.9792	$0.9280	$0.0000	
Peak Period Demand Recovery Revenues										
Demand Costs	$541,411	$25,126	$95,327	$662,282	$72,276	$552,597	$39,678	$52,065	$0	$ 2,040,761
Reconciliation Adj.	($125,655)	($5,831)	($28,497)	($126,368)	($21,606)	($105,439)	($11,861)	($9,934)	$0	$ (435,193)
Working Capital Allowance DMD	$1,781	$83	$404	$1,791	$306	$1,494	$168	$141	$0	$ 6,167
SDC	$0	$0	$0	$0	$0	$0	$0	$0	$15,780	$ 15,780
Capacity Reserve Charge	$0	$0	$0	$0	$0	$0	$0	$0	$7,173	$ 7,173
Energy Efficiency	$29,760	$1,381	$2,250	$9,976	$1,706	$8,324	$936	$784	$37,298	$ 92,416
Total Demand Gas Cost Recovery	$447,297	$20,758	$69,483	$547,681	$52,681	$456,975	$28,921	$43,056	$60,250	$ 1,727,103
Peak Period Commodity Recovery Revenues										
Commodity Costs	$1,048,101	$48,640	$250,994	$1,047,526	$190,301	$874,038	$104,471	$82,350	$0	$ 3,646,421
Working Capital Allowance CMD	$5,214	$242	$1,183	$5,244	$897	$4,376	$492	$412	$0	$ 18,060
Reconciliation Adj.	$116,880	$5,424	$26,507	$117,543	$20,097	$98,076	$11,033	$9,241	$0	$ 404,800
Bad Debt	$16,534	$767	$3,750	$16,627	$2,843	$13,874	$1,561	$1,307	$0	$ 57,262
Total Commodity Gas Cost Recovery	$1,186,729	$55,073	$282,433	$1,186,941	$214,137	$990,363	$117,557	$93,310	$0	$ 4,126,543
Total Demand and Commodity Gas Cost Recovery	$1,634,025	$75,831	$351,916	$1,734,622	$266,819	$1,447,338	$146,478	$136,366	$60,250	$5,853,645
Check (Total Rate * Volumes)	$1,634,025	$75,831	$351,916	$1,734,622	$266,819	$1,447,338	$146,478	$136,366	$60,250	$5,853,645

Docket No. DG 12-131
APPENDIX A
Page 30 of 45

NORTHERN UTILITIES, INC. - MAINE DIVISION
2007-08 PEAK PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2007 - April 2008

GAS COST RECOVERY FOR THE MONTH OF : January 2008

	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (CCF)	1,464,497	70,693	153,240	1,384,364	207,968	1,125,229	126,410	94,510	5,835,628	10,462,539
										10,462,539
										4,626,911
Peak Period Demand Recovery Rates										
Demand Costs	$0.4257	$0.4257	$0.3305	$0.5178	$0.3305	$0.5178	$0.3305	$0.5178	$0.0000	
Reconciliation Adj.	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	$0.0000	
Working Capital Allowance DMD	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0000	
SDC	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0033	
Capacity Reserve Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0015	
Energy Efficiency	$0.0234	$0.0234	$0.0078	$0.0078	$0.0078	$0.0078	$0.0078	$0.0078	$0.0078	
Total Billed Peak Demand Rate	$0.3517	$0.3517	$0.2409	$0.4282	$0.2409	$0.4282	$0.2409	$0.4282	$0.0126	
Peak Period Commodity Recovery Rates										
Commodity Costs	$0.8241	$0.8241	$0.8702	$0.8190	$0.8702	$0.8190	$0.8702	$0.8190	$0.0000	
Working Capital Allowance CMD	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0000	
Reconciliation Adj.	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0000	
Bad Debt	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0000	
Total Billed Peak Commodity Rate	$0.9331	$0.9331	$0.9792	$0.9280	$0.9792	$0.9280	$0.9792	$0.9280	$0.0000	
Peak Period Demand Recovery Revenues										
Demand Costs	$623,436	$30,094	$50,646	$716,824	$68,733	$582,644	$41,779	$48,937	$0	$ 2,163,093
Reconciliation Adj.	($144,692)	($6,984)	($15,140)	($136,775)	($20,547)	($111,173)	($12,489)	($9,338)	$0	$ (457,139)
Working Capital Allowance DMD	$2,050	$99	$215	$1,938	$291	$1,575	$177	$132	$0	$ 6,478
SDC	$0	$0	$0	$0	$0	$0	$0	$0	$19,258	$ 19,258
Capacity Reserve Charge	$0	$0	$0	$0	$0	$0	$0	$0	$8,753	$ 8,753
Energy Efficiency	$34,269	$1,654	$1,195	$10,798	$1,622	$8,777	$986	$737	$45,518	$ 105,557
Total Demand Gas Cost Recovery	$515,064	$24,863	$36,916	$592,785	$50,099	$481,823	$30,452	$40,469	$73,529	$1,845,999
Peak Period Commodity Recovery Revenues										
Commodity Costs	$1,206,892	$58,258	$133,349	$1,133,794	$180,974	$921,563	$110,002	$77,404	$0	$3,822,236
Working Capital Allowance CMD	$6,004	$290	$628	$5,676	$853	$4,613	$518	$387	$0	$18,970
Reconciliation Adj.	$134,587	$6,497	$14,083	$127,223	$19,112	$103,409	$11,617	$8,685	$0	$425,213
Bad Debt	$19,038	$919	$1,992	$17,997	$2,704	$14,628	$1,643	$1,229	$0	$60,150
Total Commodity Gas Cost Recovery	$1,366,522	$65,964	$150,053	$1,284,690	$203,642	$1,044,213	$123,781	$87,705	$0	$4,326,569
Total Demand and Commodity Gas Cost Recovery	$1,881,586	$90,826	$186,968	$1,877,474	$253,742	$1,526,036	$154,233	$128,174	$73,529	$6,172,568
Check (Total Rate * Volumes)	$1,881,586	$90,826	$186,968	$1,877,474	$253,742	$1,526,036	$154,233	$128,174	$73,529	$6,172,568

NORTHERN UTILITIES, INC. - MAINE DIVISION
2007-08 PEAK PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2007 - April 2008

GAS COST RECOVERY FOR THE MONTH OF : February 2008	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (CCF)	1,498,701	71,578	204,211	1,417,972	255,880	1,298,587	67,663	107,592	6,028,369	10,950,553
										10,950,553
										4,922,184
Peak Period Demand Recovery Rates										
Demand Costs	$0.4257	$0.4257	$0.3305	$0.5178	$0.3305	$0.5178	$0.3305	$0.5178	$0.0000	
Reconciliation Adj.	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	$0.0000	
Working Capital Allowance DMD	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0000	
SDC	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0033	
Capacity Reserve Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0015	
Energy Efficiency	$0.0234	$0.0234	$0.0078	$0.0078	$0.0078	$0.0078	$0.0078	$0.0078	$0.0078	
Total Billed Peak Demand Rate	$0.3517	$0.3517	$0.2409	$0.4282	$0.2409	$0.4282	$0.2409	$0.4282	$0.0126	
Peak Period Commodity Recovery Rates										
Commodity Costs	$0.8241	$0.8241	$0.8702	$0.8190	$0.8702	$0.8190	$0.8702	$0.8190	$0.0000	
Working Capital Allowance CMD	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0000	
Reconciliation Adj.	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0000	
Bad Debt	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0000	
Total Billed Peak Commodity Rate	$0.9331	$0.9331	$0.9792	$0.9280	$0.9792	$0.9280	$0.9792	$0.9280	$0.0000	
Peak Period Demand Recovery Revenues										
Demand Costs	$637,997	$30,471	$67,492	$734,226	$84,568	$672,408	$22,363	$55,711	$0	$ 2,305,236
Reconciliation Adj.	($148,072)	($7,072)	($20,176)	($140,096)	($25,281)	($128,300)	($6,685)	($10,630)	$0	$ (486,312)
Working Capital Allowance DMD	$2,098	$100	$286	$1,985	$358	$1,818	$95	$151	$0	$ 6,891
SDC	$0	$0	$0	$0	$0	$0	$0	$0	$19,894	$ 19,894
Capacity Reserve Charge	$0	$0	$0	$0	$0	$0	$0	$0	$9,043	$ 9,043
Energy Efficiency	$35,070	$1,675	$1,593	$11,060	$1,996	$10,129	$528	$839	$47,021	$ 109,911
Total Demand Gas Cost Recovery	$527,093	$25,174	$49,194	$607,176	$61,641	$556,055	$16,300	$46,071	$75,957	$ 1,964,662
Peak Period Commodity Recovery Revenues										
Commodity Costs	$1,235,079	$58,987	$177,704	$1,161,319	$222,667	$1,063,543	$58,880	$88,118	$0	$4,066,298
Working Capital Allowance CMD	$6,145	$293	$837	$5,814	$1,049	$5,324	$277	$441	$0	$20,181
Reconciliation Adj.	$137,731	$6,578	$18,767	$130,312	$23,515	$119,340	$6,218	$9,888	$0	$452,349
Bad Debt	$19,483	$931	$2,655	$18,434	$3,326	$16,882	$880	$1,399	$0	$63,988
Total Commodity Gas Cost Recovery	$1,398,438	$66,789	$199,963	$1,315,878	$250,558	$1,205,089	$66,256	$99,845	$0	$4,602,816
Total Demand and Commodity Gas Cost Recovery	$1,925,531	$91,963	$249,158	$1,923,054	$312,199	$1,761,144	$82,556	$145,916	$75,957	$6,567,478
Check (Total Rate * Volumes)	$1,925,531	$91,963	$249,158	$1,923,054	$312,199	$1,761,144	$82,556	$145,916	$75,957	$6,567,478

FORM III
Schedule 3
Page 6 of 8

NORTHERN UTILITIES, INC. - MAINE DIVISION
2007-08 PEAK PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2007 - April 2008

GAS COST RECOVERY FOR THE MONTH OF : March 2008	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (CCF)	1,377,691	84,834	189,202	1,294,898	167,614	1,068,103	204,047	124,406	5,575,602	10,086,397 10,086,397 4,510,795
Peak Period Demand Recovery Rates										
Demand Costs	$0.4257	$0.4257	$0.3305	$0.5178	$0.3305	$0.5178	$0.3305	$0.5178	$0.0000	
Reconciliation Adj.	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	$0.0000	
Working Capital Allowance DMD	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0000	
SDC	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0033	
Capacity Reserve Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0015	
Energy Efficiency	$0.0234	$0.0234	$0.0078	$0.0078	$0.0078	$0.0078	$0.0078	$0.0078	$0.0078	
Total Peak Period Demand Recovery Rate	$0.3517	$0.3517	$0.2409	$0.4282	$0.2409	$0.4282	$0.2409	$0.4282	$0.0126	
Peak Period Commodity Recovery Rates										
Commodity Costs	$0.8241	$0.8241	$0.8702	$0.8190	$0.8702	$0.8190	$0.8702	$0.8190	$0.0000	
Working Capital Allowance CMD	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0000	
Reconciliation Adj.	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0000	
Bad Debt	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0000	
Total Peak Period Commodity Recovery Rate	$0.9331	$0.9331	$0.9792	$0.9280	$0.9792	$0.9280	$0.9792	$0.9280	$0.0000	
Peak Period Demand Recovery Revenues										
Demand Costs	$586,483	$36,114	$62,531	$670,498	$55,396	$553,064	$67,438	$64,417	$0	$2,095,941
Reconciliation Adj.	($136,116)	($8,382)	($18,693)	($127,936)	($16,560)	($105,529)	($20,160)	($12,291)	$0	($445,667)
Working Capital Allowance DMD	$1,929	$119	$265	$1,813	$235	$1,495	$286	$174	$0	$6,315
SDC	$0	$0	$0	$0	$0	$0	$0	$0	$18,399	$18,399
Capacity Reserve Charge	$0	$0	$0	$0	$0	$0	$0	$0	$8,363	$8,363
Energy Efficiency	$32,238	$1,985	$1,476	$10,100	$1,307	$8,331	$1,592	$970	$43,490	$101,489
Total Demand Gas Cost Recovery	$484,534	$29,836	$45,579	$554,475	$40,378	$457,362	$49,155	$53,271	$70,253	$1,784,842
Peak Period Commodity Recovery Revenues										
Commodity Costs	$1,135,355	$69,912	$164,644	$1,060,521	$145,858	$874,776	$177,562	$101,889	$0	$3,730,516
Working Capital Allowance CMD	$5,649	$348	$776	$5,309	$687	$4,379	$837	$510	$0	$18,494
Reconciliation Adj.	$126,610	$7,796	$17,388	$119,001	$15,404	$98,159	$18,752	$11,433	$0	$414,542
Bad Debt	$17,910	$1,103	$2,460	$16,834	$2,179	$13,885	$2,653	$1,617	$0	$58,640
Total Commodity Gas Cost Recovery	$1,285,523	$79,159	$185,267	$1,201,665	$164,128	$991,200	$199,803	$115,449	$0	$4,222,193
Total Demand and Commodity Gas Cost Recovery	$1,770,057	$108,995	$230,845	$1,756,141	$204,506	$1,448,561	$248,958	$168,719	$70,253	$6,007,035
Check (Total Rate * Volumes)	$1,770,057	$108,995	$230,845	$1,756,141	$204,506	$1,448,561	$248,958	$168,719	$70,253	$6,007,035

FORM III
Schedule 3
Page 7 of 8

NORTHERN UTILITIES, INC. - MAINE DIVISION
2007-08 PEAK PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2007 - April 2008

GAS COST RECOVERY FOR THE MONTH OF : April 2008	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (CCF)	967,792	66,218	159,446	709,651	187,559	717,180	76,366	60,747	5,260,885	8,205,844 8,205,844 2,944,959
Peak Period Demand Recovery Rates										
Demand Costs	$0.4257	$0.4257	$0.3305	$0.5178	$0.3305	$0.5178	$0.3305	$0.5178	$0.0000	
Reconciliation Adj.	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	$0.0000	
Working Capital Allowance DMD	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0000	
SDC	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0033	
Capacity Reserve Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0015	
Energy Efficiency	$0.0234	$0.0234	$0.0078	$0.0078	$0.0078	$0.0078	$0.0078	$0.0078	$0.0078	
Total Peak Period Demand Recovery Rate	$0.3517	$0.3517	$0.2409	$0.4282	$0.2409	$0.4282	$0.2409	$0.4282	$0.0126	
Peak Period Commodity Recovery Rates										
Commodity Costs	$0.8241	$0.8241	$0.8702	$0.8190	$0.8702	$0.8190	$0.8702	$0.8190	$0.0000	
Working Capital Allowance CMD	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0000	
Reconciliation Adj.	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0000	
Bad Debt	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0000	
Total Peak Period Commodity Recovery Rate	$0.9331	$0.9331	$0.9792	$0.9280	$0.9792	$0.9280	$0.9792	$0.9280	$0.0000	
Peak Period Demand Recovery Revenues										
Demand Costs	$411,989	$28,189	$52,697	$367,457	$61,988	$371,356	$25,239	$31,455	$0	$1,350,370
Reconciliation Adj.	($95,618)	($6,542)	($15,753)	($70,114)	($18,531)	($70,857)	($7,545)	($6,002)	$0	($290,962)
Working Capital Allowance DMD	$1,355	$93	$223	$994	$263	$1,004	$107	$85	$0	$4,123
SDC	$0	$0	$0	$0	$0	$0	$0	$0	$17,361	$17,361
Capacity Reserve Charge	$0	$0	$0	$0	$0	$0	$0	$0	$7,891	$7,891
Energy Efficiency	$22,646	$1,550	$1,244	$5,535	$1,463	$5,594	$596	$474	$41,035	$80,136
Total Demand Gas Cost Recovery	$340,372	$23,289	$38,411	$303,873	$45,183	$307,096	$18,397	$26,012	$66,287	$1,168,919
Peak Period Commodity Recovery Revenues										
Commodity Costs	$797,557	$54,570	$138,750	$581,204	$163,214	$587,370	$66,454	$49,752	$0	$2,438,871
Working Capital Allowance CMD	$3,968	$271	$654	$2,910	$769	$2,940	$313	$249	$0	$12,074
Reconciliation Adj.	$88,940	$6,085	$14,653	$65,217	$17,237	$65,909	$7,018	$5,583	$0	$270,642
Bad Debt	$12,581	$861	$2,073	$9,225	$2,438	$9,323	$993	$790	$0	$38,284
Total Commodity Gas Cost Recovery	$903,047	$61,788	$156,130	$658,556	$183,658	$665,543	$74,778	$56,373	$0	$2,759,872
Total Demand and Commodity Gas Cost Recovery	$1,243,419	$85,077	$194,540	$962,429	$228,841	$972,640	$93,174	$82,385	$66,287	$3,928,791
Check (Total Rate * Volumes)	$1,243,419	$85,077	$194,540	$962,429	$228,841	$972,640	$93,174	$82,385	$66,287	$3,928,791

FORM III
Schedule 3
Page 8 of 8

NORTHERN UTILITIES, INC. - MAINE DIVISION
2007-08 PEAK PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2007 - April 2008

May 2008 Prorated

GAS COST RECOVERY FOR THE MONTH OF :	Res. Heat	Res. NH	G-50	G-40	G-51	G-41	G-52	G-42	Transportation	Total
Sales (CCF)	335,640	30,125	82,837	238,930	41,986	149,003	10,367	8,466	3,601,628	4,498,982 4,498,982 897,354
Peak Period Demand Recovery Rates										
Demand Costs	$0.4257	$0.4257	$0.3305	$0.5178	$0.3305	$0.5178	$0.3305	$0.5178	$0.0000	
Reconciliation Adj.	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	($0.0988)	$0.0000	
Working Capital Allowance DMD	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0000	
SDC	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0033	
Capacity Reserve Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0015	
Energy Efficiency	$0.0234	$0.0234	$0.0078	$0.0078	$0.0078	$0.0078	$0.0078	$0.0078	$0.0078	
Total Billed Peak Demand Rate	$0.3517	$0.3517	$0.2409	$0.4282	$0.2409	$0.4282	$0.2409	$0.4282	$0.0126	
Peak Period Commodity Recovery Rates										
Commodity Costs	$0.8241	$0.8241	$0.8702	$0.8190	$0.8702	$0.8190	$0.8702	$0.8190	$0.0000	
Working Capital Allowance CMD	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0000	
Reconciliation Adj.	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0919	$0.0000	
Bad Debt	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0000	
Total Billed Peak Commodity Rate	$0.9331	$0.9331	$0.9792	$0.9280	$0.9792	$0.9280	$0.9792	$0.9280	$0.0000	
Peak Period Demand Recovery Revenues										
Demand Costs	$142,882	$12,824	$27,377	$123,718	$13,876	$77,154	$3,426	$4,384	$0	$405,642
Reconciliation Adj.	($33,161)	($2,976)	($8,184)	($23,606)	($4,148)	($14,721)	($1,024)	($836)	$0	($88,659)
Working Capital Allowance DMD	$470	$42	$116	$335	$59	$209	$15	$12	$0	$1,256
SDC	$0	$0	$0	$0	$0	$0	$0	$0	$11,885	$11,885
Capacity Reserve Charge	$0	$0	$0	$0	$0	$0	$0	$0	$5,402	$5,402
Energy Efficiency	$7,854	$705	$646	$1,864	$327	$1,162	$81	$66	$28,093	$40,798
Total Demand Gas Cost Recovery	$118,045	$10,595	$19,955	$102,310	$10,114	$63,803	$2,497	$3,625	$45,381	$376,325
Peak Period Commodity Recovery Revenues										
Commodity Costs	$276,601	$24,826	$72,084	$195,684	$36,536	$122,033	$9,021	$6,934	$0	$743,720
Working Capital Allowance CMD	$1,376	$124	$340	$980	$172	$611	$43	$35	$0	$3,679
Reconciliation Adj.	$30,845	$2,768	$7,613	$21,958	$3,859	$13,693	$953	$778	$0	$82,467
Bad Debt	$4,363	$392	$1,077	$3,106	$546	$1,937	$135	$110	$0	$11,666
Total Commodity Gas Cost Recovery	$313,186	$28,110	$81,114	$221,727	$41,113	$138,274	$10,151	$7,856	$0	$841,531
Total Demand and Commodity Gas Cost Recovery	$431,230	$38,705	$101,069	$324,037	$51,227	$202,077	$12,649	$11,481	$45,381	$1,217,857
Check (Total Rate * Volumes)	$431,230	$38,705	$101,069	$324,037	$51,227	$202,077	$12,649	$11,481	$45,381	$1,217,857

FORM III
Schedule 4
Page 1 of 2

NORTHERN UTILITIES, INC. - MAINE DIVISION
2007-2008 PEAK PERIOD
COST OF GAS ADJUSTMENT RESULTS

WINTER RELATED COSTS INCURRED IN SUMMER '07 DEFERRED TO WINTER 2007-08

dity Costs:	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	End of Period Adjustments	Winter
a Northeast Gas Limited	-	-	-	-	-	-	950	953	883	874	921.2	838	-	5,419
nergy	-	-	-	-	-	-	-	-	-	40,060	-	2,220,136	-	2,260,195
il, Incorporated	-	-	-	-	-	-	-	-	-	-	-	590,783	-	590,783
ron	-	-	-	-	-	-	-	-	-	-	-	-	-	-
nial Energy	-	-	-	-	-	-	-	-	-	5,873	-	206,602	-	212,475
tellation	-	-	-	-	-	-	-	-	-	-	-	-	-	-
l Energy Resources	-	-	-	-	-	-	-	-	-	-	-	-	-	-
igas	-	-	-	-	-	-	143,009	415,185	281,986	398,935	1,108,348	-	-	2,347,462
e	-	-	-	-	-	-	-	-	-	51,528	-	347,586	-	399,114
ra Energy	-	-	-	-	-	-	146,165	120,570	98,155	-	122,882	-	-	487,772
Ex Trade	-	-	-	-	-	-	4,848	4,707	4,360	108,606	4,550	-	-	127,071
ky	-	-	-	-	-	-	-	-	-	4,615	-	-	-	4,615
grys Energy Services	-	-	-	-	-	-	-	181,298	625,304	616,905	479,107	66,304	-	1,968,918
is Dreyfus	-	-	-	-	-	-	-	-	-	-	-	-	-	-
quire Cook Inlet	-	-	-	-	-	-	-	-	-	-	428,105	136,779	-	564,884
ssPower	-	-	-	-	-	-	-	-	-	-	-	-	-	-
rill Lynch Commodities	-	-	-	-	-	-	640,021	677,627	588,861	651,524	780,721	748,202	-	4,086,957
ken Marketing USA Inc	-	-	-	-	-	-	-	-	-	-	-	-	-	-
R Energy Services	-	-	-	-	-	-	-	-	-	-	-	-	-	-
rtheast Gas Marketing	-	-	-	-	-	-	226,403	230,089	223,369	231,645	267,547	259,796	-	1,438,848
oples Energy Marketing	-	-	-	-	-	-	-	-	-	-	-	-	-	-
quent Energy Management LP	-	-	-	-	-	-	98,684	100,547	97,581	101,166	116,784	113,361	-	628,123
uthwest Energy LP	-	-	-	-	-	-	-	-	-	-	-	-	-	-
naska Energy Canada	-	-	-	-	-	-	-	-	-	16,015	-	-	-	16,015
naska Energy Ventures	-	-	-	-	-	-	-	-	-	5,681	-	-	-	5,681
U Portfolio Mgmt Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BS AG	-	-	-	-	-	-	-	-	-	-	-	79,809	-	79,809
S Customs Convenience Bill	-	-	-	-	-	-	19,077	-	-	-	-	-	-	19,077
ompany Use	-	-	-	-	-	-	(1,959)	(3,432)	(4,366)	(9,122)	(3,997)	(2,066)	-	(24,942)
ansportation Charges	-	-	-	-	-	-	(2,334)	(8,003)	94,135	(10,247)	15,262	43,030	-	131,843
edging Costs 1/	-	-	-	-	-	-	58,818	167,927	169,847	89,766	(704)	(279,600)	-	206,055
ropane	-	-	-	-	-	-	(310)	166	651	681	24	(23)	-	1,189
o-Managed Propane	-	-	-	-	-	-	-	(492,732)	(1,145,239)	(928,911)	(707,341)	(623,708)		(3,897,931)
torage Injection	-	-	-	-	-	-	-	-	-	-	-	(2,261,969)	-	(2,261,969)
torage Withdrawals	-	-	-	-	-	-	2,211,224	3,206,411	2,760,051	2,403,364	1,317,574	137	-	11,898,762
NG Boiloff	-	-	-	-	-	-	502	8,282	18,805	21,033	9,116	4,674	-	62,412
iel OBJ Adj	-	-	-	-	-	-	15,350	(70,339)	134,082	250,204	88,439	(232,577)	(40,362)	144,797
ransportation Commodity	-	-	-	-	-	-	3,741	6,737	6,075	8,218	6,669	3,959	596	35,996
lon Traditional Sales	-	-	-	-	-	-	-	-	-	-	-	(302,294)	-	(302,294)
nterruptible Gas Costs	-	-	-	-	-	-	(20,955)	-	-	-	-	(4,982)	-	(25,937)
nventory Finance Charges	34,032	40,623	46,409	52,170	56,933	57,496	52,629	40,449	25,815	9,866	2,590	3,879	-	422,890
Prior Period Adj	-	-	-	-	-	-	-	(30,441)	(12,142)	21,955	(9,050)	8,483	(202,621)	(223,816)
Co-Managed	-	-	-	-	-	-	-	-	-	-	7,036	(340,283)	-	(333,247)
Storage Commodity	180	3,466	315	181	164	193	15,925	22,195	19,065	16,124	9,169	169	(4)	87,142
Commodity Re-Allocation	-	-	-	-	-	-	251,380	586,747	897,573	647,614	822,907	52,539	-	3,258,760
Total Commodity Costs	$ 34,211	$ 44,089	$ 46,724	$ 52,351	$ 57,098	$ 57,690	$ 3,863,168	$ 5,164,943	$ 4,884,850	$ 4,753,970	$ 4,866,660	$ 839,565	$ (242,391)	$ 24,422,928

1/ February hedging not booked during close. Should show as an adj during March close.

FORM III
Schedule 4
Page 2 of 2

NORTHERN UTILITIES, INC. - MAINE DIVISION
2007-2008 PEAK PERIOD
COST OF GAS ADJUSTMENT RESULTS

WINTER RELATED COSTS INCURRED IN SUMMER '07 DEFERRED TO WINTER 2007-08

	May 2007	June	July	August	Sept	Oct	Nov	Dec	January 2008	February	March	April	End of Period Adjustments	Winter
ne Reservation														
quin	$ 15,906	$ 15,942	$ 15,924	$ 15,924	$ 15,942	$ 15,890	$ 16,004	$ 15,966	$ 15,947	$ 15,968	$ 15,904	$ 15,905	$ -	$ 191,222
ion	$ -	$ -	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
le	$ 61,743	$ 61,710	$ 61,743	$ 61,743	$ 61,953	61,953	$ 62,400	$ 62,340	$ 62,316	$ 62,292	$ 62,287	$ 62,261	$ -	$ 744,741
ois	$ 20,570	$ 20,600	$ 20,600	$ 20,600	$ 20,600	20,541	$ 20,656	$ 20,627	$ 20,594	$ 20,555	$ 20,521	$ 20,492	$ -	$ 246,953
nal Fuel	$ 13,758	$ -	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,758
TS	$ 135,958	$ 13,758	$ 13,758	$ 13,758	$ 13,758	13,758	$ 813,238	$ 813,238	$ 813,238	$ 813,238	$ 813,238	$ 13,866	$ -	$ 4,284,799
essee Gas (El Pas)	$ 3,289	$ 136,095	$ 136,165	$ 136,164	$ 136,165	135,838	$ 136,554	$ 136,407	$ 133,024	$ 132,781	$ 132,553	$ 132,828	$ -	$ 1,487,864
as Eastern	$ -	$ 3,289	$ 3,412	$ 3,313	$ 3,313	3,324	$ 3,350	$ 3,349	$ 3,349	$ 3,378	$ 3,378	$ 3,355	$ -	$ 36,808
as Gas	$ 573	$ -	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 573
nsco	$ -	$ -	$ -	$ -	$ -	-	$ (29)	$ -	$ -	$ -	$ -	$ -	$ -	$ (29)
tor Limited	$ 1,225	$ 1,225	$ 1,225	$ 1,225	$ 1,225	1,225	$ 1,234	$ 1,234	$ 1,234	$ 1,234	$ 1,234	$ 1,234	$ -	$ 14,755
tor LP	$ 24,330	$ 24,330	$ 24,330	$ 24,330	$ 24,330	24,330	$ 24,521	$ 24,521	$ 24,521	$ 24,521	$ 24,521	$ 89,719	$ -	$ 358,303
npany Managed	$ -	$ -	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
r Period Adjustments	$ -	$ 21,945	$ (4,434)	$ 22,864	$ 22,643	23,541	$ 289	$ 23,320	$ 41,420	$ 73,185	$ 46,413	$ 46,371	$ 319,359	$ 636,913
al Pipeline Reservation	$ 277,350	$ 298,893	$ 272,721	$ 299,918	$ 299,927	$ 300,399	$ 1,078,217	$ 1,101,001	$ 1,115,642	$ 1,147,152	$ 1,120,049	$ 386,031	$ 319,359	$ 8,016,659
oduct Demand														
trigas	$ 99,045	$ 99,045	$ 99,045	$ 99,045	$ 99,045	99,045	$ 106,770	$ 103,382	$ 103,382	$ 103,382	$ 103,382	$ 103,382	$ -	$ 1,217,949
ke Energy	$ -	$ -	$ -	$ -	$ -	-	$ -	$ 106,770	$ 106,770	$ 106,770	$ 106,770	$ 106,770	$ -	$ 533,852
sky	$ -	$ -	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
naska Marketing Group	$ 19,816	$ 19,176	$ 19,816	$ 19,816	$ 19,176	19,816	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 117,615
ior Period Adj	$ -	$ 870	$ 1,994	$ 1,024	$ 2,273	3,605	$ 2,666	$ 103,382	$ -	$ -	$ -	$ -	$ (106,770)	$ 9,043
tal Product Demand	$ 118,861	$ 119,092	$ 120,855	$ 119,885	$ 120,494	$ 122,465	$ 109,436	$ 313,533	$ 210,152	$ 210,152	$ 210,152	$ 210,152	$ (106,770)	$ 1,878,459
orage Pipeline Transportation and Demand Reservation														
gonquin	$ -	$ -	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
o-Energy	$ -	$ -	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Paso Energy (Tennessee Gas)	$ 4,575	$ 4,584	$ 4,584	$ 4,584	$ 4,584	4,576	$ 4,604	$ 4,596	$ 4,587	$ 4,578	$ 4,570	$ 4,562	$ -	$ 54,986
TE Energy	$ 151,087	$ 151,929	$ 184,101	$ 184,101	$ 184,943	184,101	$ 517,265	$ 518,114	$ 524,089	$ 522,392	$ 524,089	$ (25,464)	$ -	$ 3,620,745
oquois	$ -	$ -	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
NGTS	$ -	$ -	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
exas Eastern	$ 113	$ 113	$ 113	$ 113	$ 113	114	$ 115	$ 115	$ 115	$ 115	$ 115	$ 115	$ -	$ 1,370
exas Gas	$ -	$ -	$ -	$ -	$ -	(109)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (109)
lational Fuel	$ -	$ -	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
CNG Transmission - Dominion	$ -	$ -	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Company Managed	$ -	$ -	$ -	$ -	$ -	-	$ -	$ (993,292)	$ (1,335,189)	$ (1,758,184)	$ (1,735,997)	$ (1,863,861)	$ -	$ (7,686,523)
Prior Period Adjustment	$ -	$ 50,700	$ 55,416	$ 26,108	$ 24,761	30,487	$ 42,446	$ 24,649	$ 14,700	$ 27,332	$ 24,106	$ 24,955	$ 145,712	$ 491,372
Total Storage and Demand Reservation	$ 155,775	$ 207,326	$ 244,214	$ 214,906	$ 214,401	$ 219,169	$ 564,430	$ (445,818)	$ (791,698)	$ (1,203,767)	$ (1,183,116)	$ (1,859,693)	$ 145,712	$ (3,518,159)
Total Fixed Demand	$ 551,986	$ 625,311	$ 637,790	$ 634,709	$ 634,823	$ 642,033	$ 1,752,083	$ 968,717	$ 534,096	$ 153,537	$ 147,084	$ (1,263,510)	$ 358,301	$ 6,376,960
Transp. Charges	$ -	$ -	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	-		$ -
Non-Traditional Sales Margin	$ (1,459)	$ (974)	$ (1,218)	$ (1,235)	$ (1,181)	(5,614)	$ -	$ -	$ -	$ -	$ -	(28,142)		$ (39,823)
Interruptible Profits	$ (14,427)	$ (13,704)	$ (15,541)	$ (18,816)	$ (25,133)	(4,609)	$ (3,960)	$ -	$ -	$ -	$ -	(13)		$ (96,202)
Capacity Release	$ (103,552)	$ (108,834)	$ (82,794)	$ (110,010)	$ (109,027)	(110,302)	$ (72,402)	$ (74,185)	$ (82,165)	$ (73,479)	$ (72,940)	(99,071)		$ (1,098,761)
Capacity Exchange	$ -	$ -	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	-	-	$ -
Production and Storage	$ -	$ -	$ -	$ -	$ -	-	$ 84,110	$ 120,178	$ 140,716	$ 119,777	$ 104,147	70,584	$ -	$ 639,512
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	-	$	$ -
Transp. Demand Revenues	$ (6)	$ (4)	$ (5)	$ (5)	$ (5)	(6)	$ (6)	$ (6)	$ (5)	$ (6)	$ (5)	(5)		$ (64)
Total Demand Costs	$ 432,541	$ 501,796	$ 538,232	$ 504,644	$ 499,477	$ 521,503	$ 1,759,825	$ 1,014,704	$ 592,642	$ 199,829	$ 178,286	$ (1,320,158)	$ 358,301	$ 5,781,622
Demand Costs Transferred to Summer Period	$ 205,298	$ 205,298	$ 205,298	$ 205,298	$ 205,298	205,298	$ -	$ -	$ -	$ -	$ -	-	$ -	$ 1,231,788
Net Demand Costs For Winter Period	$ 227,243	$ 296,498	$ 332,934	$ 299,346	$ 294,179	$ 316,205	$ 1,759,825	$ 1,014,704	$ 592,642	$ 199,829	$ 178,286	$ (1,320,158)	$ 358,301	$ 4,549,834
TOTAL FIRM GAS COSTS	$ 261,454	$ 340,587	$ 379,657	$ 351,697	$ 351,277	$ 373,894	$ 5,522,993	$ 6,179,648	$ 5,477,491	$ 4,953,800	$ 5,044,947	$ (480,592)	$ 115,910	$ 28,972,762

Northern Utiltiies

Maine Division

Winter 07-08

FORM III
Schedule 4
Re-Allocation

	November 2007	December	January 2008	February	March	April	
Tariff Sales	2,419,372	5,247,839	6,342,120	6,088,195	5,723,894	4,251,766	
Current Unbilled	2,389,920	3,731,368	3,560,205	3,399,704	3,260,255	1,845,183	
Prior Unbilled	(1,128,719)	(2,389,920)	(3,731,368)	(3,560,205)	(3,399,704)	(3,260,255)	
Tariff Sales Volumes---therms	3,680,573	6,589,287	6,170,957	5,927,694	5,584,445	2,836,694	
Tariff Sales Volumes---Dth	368,057	658,929	617,096	592,769	558,445	283,669	
--includes billed and net unbilled							
Plus: Company Use	100	235	299	282	285	206	
Plus: Co-Managed	58,519	64,924	94,588	85,303	77,579	2,234	
Subtotal	426,676	724,088	711,983	678,354	636,309	286,109	
Unacounted for estimate	101%	101%	101%	101%	101%	101%	
Volumes for allocation	430,943	731,329	719,103	685,138	642,672	288,970	
Maine Division							
Tariff Sales	2,093,267	4,404,789	4,626,911	4,922,184	4,510,695	2,944,959	
Current Unbilled	1,317,085	2,237,906	2,193,171	2,033,942	2,052,850	1,167,223	
Prior Unbilled	(725,516)	(1,317,085)	(2,237,906)	(2,193,171)	(2,033,942)	(2,052,850)	
Tariff Sales Volumes---Ccf	2,684,836	5,325,610	4,582,176	4,762,955	4,529,603	2,059,332	
Tariff Sales Volumes---Mcf	268,484	532,561	458,218	476,296	452,960	205,933	
--includes billed and net unbilled							
Plus: Company Use	185	309	276	584	271	150	
Plus: Co-Managed	163,122	229,828	253,711	222,424	222,901	-	
Subtotal---Mcf	431,791	762,698	712,205	699,304	676,132	206,083	
Maine conversion factor	1.059	1.048	1.051	1.050	1.067	1.075	
Subtotal---Dth	457,266	799,308	748,527	734,269	721,433	221,539	
Unacounted for estimate	102%	102%	102%	102%	102%	102%	
Volumes for allocation	466,412	815,294	763,498	748,954	735,862	225,970	
New Hampshire New Commodity Allocation %	48.024%	47.286%	48.503%	47.775%	46.620%	56.117%	
Maine New Commodity Allocation %	51.976%	52.714%	51.497%	52.225%	53.380%	43.883%	
New Hampshire Old Commodity Allocation %	51.522%	52.927%	56.403%	53.848%	54.498%	57.230%	
Maine Old Commodity Allocation %	48.478%	47.073%	43.597%	46.152%	45.502%	42.770%	
<u>New Commodity Allocation Costs</u>							
New Hampshire	$3,563,993	$5,028,396	$5,646,380	$4,853,768	$4,636,398	$2,132,388	$25,861,323
Maine	$3,857,041	$5,164,943	$4,884,850	$4,664,204	$4,866,661	$839,953	$24,277,652
<u>Old Commodity Allocation Costs</u>							
New Hampshire	$3,815,362	$5,615,053	$6,543,770	$5,501,245	$5,459,138	$2,184,914	$29,119,482
Maine	$3,605,661	$4,578,196	$3,987,277	$4,016,590	$4,043,754	$787,414	$21,018,892
<u>Difference in Commodity Allocation Costs</u>							
New Hampshire	($251,369)	($586,657)	($897,390)	($647,477)	($822,740)	($52,526)	($3,258,159)
Maine	$251,380	$586,747	$897,573	$647,614	$822,907	$52,539	$3,258,760
	$11	$90	$183	$137	$167	$13	$601

Schedule 5

	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	TME
Maine													
Throughput IN													
BTU Factor	1.074	1.061	1.054	1.051	1.07	1.047	1.058	1.049	1.052	1.049	1.067	1.076	
GST Meter Throughput (MCF)	373,744	289,308	277,524	288,948	295,288	413,355	661,222	864,436	856,259	799,317	711,641	443,246	
Kittery Meter (MCF)	46,338	43,261	50,299	49,437	47,399	56,976	82,707	106,587	119,763	123,022	124,501	93,383	
GST Meter Throughpurt (DTH)	401,401	306,956	292,510	303,684	315,958	432,783	699,573	906,793	900,784	838,484	759,321	476,933	
Kittery Meter (DTH)	*49,789*	*45,933*	*53,028*	*50,251*	*50,724*	*59,654*	*87,504*	*111,810*	*125,991*	*129,050*	*132,843*	*100,480*	
Cotton Road (Lewiston)(DTH)			*0*	*2,115*	*450*	*859*	*31,369*	*157,892*	*151,884*	*142,082*	*151,905*	*90,017*	
LNG/Propane	*1,566*	*1,464*	*973*	*1,159*	*811*	*1,041*	*931*	*1,101*	*6,058*	*5,214*	*1,514*	*1,182*	
Total Throughput	452,756	354,353	346,511	357,209	367,943	494,337	819,377	1,177,596	1,184,717	1,114,830	1,045,583	668,612	
Throughput OUT													
Residential Gas													
Charged	68,470	38,566	28,135	24,977	26,434	32,197	68,565	139,473	161,350	164,881	156,053	111,137	
Uncharged Current	29,333	21,058	28,148	20,034	22,497	30,914	60,944	92,158	91,806	85,468	84,066	48,361	
Uncharged Prior	-51,890	-29,333	-21,058	-28,148	-20,034	-22,497	-30,914	-60,944	-92,158	-91,806	-85,468	-84,066	
Total Residential Gas	**45,913**	**30,291**	**35,225**	**16,863**	**28,897**	**40,614**	**98,595**	**170,687**	**160,998**	**158,543**	**154,651**	**75,432**	
Interruptible	**10,405**	**11,767**	**7,461**	**7,033**	**7,584**	**661**	**663**	**0**	**0**	**0**	**0**	**1**	
Commercial/Industrial Gas													
Charged	124,975	66,674	64,182	57,979	59,859	76,580	153,114	322,150	324,940	351,950	325,250	205,427	
Uncharged Current	78,596	36,081	31,234	32,705	35,620	44,902	78,535	142,375	138,696	128,096	134,973	77,116	
Uncharged Prior	-68,098	-78,596	-36,081	-31,234	-32,705	-35,620	-44,902	-78,535	-142,375	-138,696	-128,096	-134,973	
Total C/I Gas	**135,473**	**24,159**	**59,335**	**59,450**	**62,774**	**85,862**	**186,747**	**385,990**	**321,261**	**341,350**	**332,127**	**147,570**	
Transportation													
Charged	390,276	283,528	252,279	253,546	264,514	266,796	371,564	501,128	613,325	632,979	594,917	565,545	
Uncharged Current	300,630	228,429	235,692	119,421	247,802	311,193	419,852	530,284	551,430	509,922	518,540	385,493	
Uncharged Prior	-354,750	-300,630	-228,429	-235,692	-119,421	-247,802	-311,193	-419,852	-530,284	-551,430	-509,922	-518,540	
Total Transportation	**336,156**	**211,327**	**259,542**	**137,275**	**392,895**	**330,187**	**480,223**	**611,560**	**634,471**	**591,471**	**603,535**	**432,498**	
Company Use	**790**	**1,416**	**540**	**126**	**135**	**551**	**1,901**	**3,171**	**263**	**557**	**258**	**141**	
Total Throughput OUT	**528,737**	**278,960**	**362,103**	**220,747**	**492,285**	**457,875**	**768,129**	**1,171,408**	**1,116,993**	**1,091,921**	**1,090,571**	**655,642**	8,235,371
Total Throughput IN	**452,756**	**354,353**	**346,511**	**357,209**	**367,943**	**494,337**	**819,377**	**1,177,596**	**1,184,717**	**1,114,830**	**1,045,583**	**668,612**	8,383,823
Difference IN/OUT	-75,981	75,393	-15,592	136,462	-124,342	36,462	51,248	6,188	67,724	22,909	-44,988	12,970	148,452
%	-16.78%	21.28%	-4.50%	38.20%	-33.79%	7.38%	6.25%	0.53%	5.72%	2.05%	-4.30%	1.94%	**1.77%**

Attachment A

NORTHERN UTILITIES, INC. - MAINE DIVISION
2007-08 PEAK PERIOD RECONCILIATION
INTERRUPTIBLE PROFIT SCHEDULE
Summary May 2007 - April 2008

	May 2007	June	July	August	September	October	November	December	January 2008	February	March	April	Total
Total Interruptible Sales	$98,703	$112,955	$72,575	$70,135	$73,765	$9,666	$9,559	$0	$0	$0	$0	$0	$447,358
Less: Emergency Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Interruptible Sales	$98,703	$112,955	$72,575	$70,135	$73,765	$9,666	$9,559	$0	$0	$0	$0	$0	$447,358
Total Interruptible Costs	$82,672	$97,728	$55,324	$49,228	$45,839	$4,545	$5,159	$0	$0	$0	$0	$0	$340,497
Total Interruptible Profits	$16,030	$15,226	$17,251	$20,907	$27,926	$5,121	$4,400	$0	$0	$0	$0	$0	$106,861
Emergency Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Emergency Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Emer Sales Margin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Inter & Emer Margin	$16,030	$15,226	$17,251	$20,907	$27,926	$5,121	$4,400	$0	$0	$0	$0	$0	$106,861
10% Profit	$1,603	$1,523	$1,725	$2,091	$2,793	$512	$440	$0	$0	$0	$0	$0	$10,686
90% Profit	$14,427	$13,704	$15,526	$18,816	$25,133	$4,609	$3,960	$0	$0	$0	$0	$0	$96,175
100% Profit (Emergency Sales)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Passback Profit	$14,427	$13,704	$15,526	$18,816	$25,133	$4,609	$3,960	$0	$0	$0	$0	$0	$96,175

NORTHERN UTILITIES
MAINE DIVISION
DEFERRED OFF PEAK WORKING CAPITAL
ALLOWANCE ON PURCHASED GAS COSTS
Period Ending April 30, 2008

PEAK DEMAND - ACCOUNT 182.13

	BEGINNING BALANCE	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	1	2	3	(4)	5 = 2 + (4)	6 = 1 + 5	7 = (1+ 6) / 2	8	9 = (8 * 7) / 12	10 = 6 + 9
MAY 07(Summer)	(10,519)	998	0.4410%	0	998	(9,521)	(10,020)	5.62%	(47)	(9,567)
JUNE	(9,567)	1,308	0.4410%	0	1,308	(8,260)	(8,914)	5.76%	(43)	(8,303)
JULY	(8,303)	1,468	0.4410%	0	1,468	(6,834)	(7,569)	5.79%	(37)	(6,871)
AUGUST	(6,871)	1,320	0.4410%	0	1,320	(5,551)	(6,211)	5.87%	(30)	(5,581)
SEPTEMBER	(5,581)	1,297	0.4410%	0	1,297	(4,284)	(4,933)	5.89%	(24)	(4,308)
OCTOBER	(4,308)	1,394	0.4410%	0	1,394	(2,914)	(3,611)	5.52%	(17)	(2,930)
NOVEMBER	(2,930)	7,761	0.4410%	(1,927)	5,834	2,903	(13)	5.30%	(0)	2,903
DECEMBER	2,903	4,475	0.4410%	(6,167)	(1,692)	1,211	2,057	5.35%	9	1,221
JANUARY 2008	1,221	2,614	0.4410%	(6,478)	(3,864)	(2,644)	(711)	5.35%	(3)	(2,647)
FEBRUARY	(2,647)	881	0.4410%	(6,891)	(6,010)	(8,657)	(5,652)	4.07%	(19)	(8,676)
MARCH	(8,676)	786	0.4410%	(6,315)	(5,529)	(14,205)	(11,440)	3.54%	(34)	(14,238)
APRIL	(14,238)	(5,822)	0.4410%	(4,123)	(9,945)	(24,183)	(19,211)	3.17%	(51)	(24,234)
MAY 08 (Winter)	(24,234)	1,580	0.4410%	(1,256)	324	(23,910)	(24,072)	3.32%	(67)	(23,977)
Check	(10,519)	20,061			(13,096)	(106,847)			(362)	(23,977)

MAINE DIVISION
DEFERRED OFF PEAK WORKING CAPITAL
ALLOWANCE ON PURCHASED GAS COSTS
Period Ending April 30, 2008

PEAK COMMODITY - ACCOUNT 182.11

	BEGINNING BALANCE	WKG CAP ALLOWANCE**	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	1	2	3	(4)	5 = 2 + (4)	6 = 1 + 5	7 = (1+ 6) / 2	8	9 = (8 * 7) / 12	10 = 6 + 9
May 07 (Summer)	14,532	151	0.4410%	0	151	14,683	14,607	5.62%	68	14,751
June	14,751	194	0.4410%	0	194	14,946	14,848	5.76%	71	15,017
July	15,017	206	0.4410%	0	206	15,223	15,120	5.79%	73	15,296
August	15,296	231	0.4410%	0	231	15,527	15,411	5.87%	75	15,602
September	15,602	252	0.4410%	0	252	15,854	15,728	5.89%	77	15,931
October	15,931	254	0.4410%	0	254	16,186	16,058	5.52%	74	16,260
November	16,260	17,037	0.4410%	(5,644)	11,393	27,652	21,956	5.30%	97	27,749
December	27,749	22,777	0.4410%	(18,060)	4,718	32,467	30,108	5.35%	134	32,601
January 2008	32,601	21,542	0.4410%	(18,970)	2,572	35,173	33,887	5.35%	151	35,324
February	35,324	20,965	0.4410%	(20,181)	784	36,108	35,716	4.07%	121	36,229
March	36,229	21,462	0.4410%	(18,494)	2,968	39,197	37,713	3.54%	111	39,308
April	39,308	3,702	0.4410%	(12,074)	(8,372)	30,936	35,122	3.17%	93	31,029
May 08 (Winter)	31,029	(1,069)	0.4410%	(3,679)	(4,748)	26,281	28,655	3.32%	79	26,360
Check	14,532	107,705		(97,103)	10,602	320,232			1,226	26,360

** Working Capital Allowance Calculated by taking Eligible Gas Costs from Sch 4 and multiplying by Working Capital Percentage

Attachment C

NORTHERN UTILITIES, INC
MAINE DIVISION
BAD DEBT EXPENSE
CALCULATION OF COLLECTION ALLOWANCE
April 30, 2008
Account 182.16

DEFERRED ACCT

	BEG. BAL *		MAINE GAS COSTS PER BOOKS ALLOWED FOR BAD DEBT **	% ALLOWED BAD DEBT	ACTUAL BAD DEBT ALLOWANCE		ACTUAL BAD DEBT COLLECTION	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	1		2	3	4 = 2 * 3		5	6 = 4 + 5	7 = 1 + 6	8 = (1 + 7) / 2	9	10 = 8 * (9 / 12)	11 = 7 + 10
MAY 07 (Summer)	$5,369	$	262,604	1.06%	$2,784	$	-	$2,784	$8,153	$6,761	5.62%	$32	$8,184
JUNE	$8,184	$	342,089	1.06%	$3,626	$	-	$3,626	$11,810	$9,997	5.76%	$48	$11,858
JULY	$11,858	$	381,331	1.06%	$4,042	$	-	$4,042	$15,901	$13,879	5.79%	$67	$15,967
AUGUST	$15,967	$	353,248	1.06%	$3,744	$	-	$3,744	$19,712	$17,840	5.87%	$87	$19,799
SEPTEMBER	$19,799	$	352,826	1.06%	$3,740	$	-	$3,740	$23,539	$21,669	5.89%	$106	$23,645
OCTOBER	$23,645	$	375,543	1.06%	$3,981	$	-	$3,981	$27,626	$25,636	5.52%	$118	$27,744
NOVEMBER	$27,744	$	5,647,791	1.06%	$59,867	$	(17,896)	$41,971	$69,715	$48,730	5.30%	$215	$69,930
DECEMBER	$69,930	$	6,206,900	1.06%	$65,793	$	(57,262)	$8,531	$78,461	$74,196	5.35%	$331	$78,792
JANUARY 2008	$78,792	$	5,501,647	1.06%	$58,317	$	(60,150)	($1,832)	$76,960	$77,876	5.35%	$347	$77,307
FEBRUARY	$77,307	$	4,975,646	1.06%	$52,742		($63,988)	($11,247)	$66,060	$71,684	4.07%	$243	$66,303
MARCH	$66,303	$	5,067,195	1.06%	$53,712		($58,640)	($4,928)	$61,375	$63,839	3.54%	$188	$61,564
APRIL	$61,564	$	(482,712)	1.06%	($5,117)		($38,284)	($43,401)	$18,163	$39,863	3.17%	$105	$18,268
MAY 08 (Winter)	$18,268	$	116,421	1.06%	$1,234		($11,666)	($10,432)	$7,836	$13,052	3.32%	$36	$7,872
Check	$5,369				$308,466		($307,886)	$579				$1,924	$7,872

** Working Capital Allowance from "Working Capital Summary" worksheet

Northern Utilities, Inc. - Maine Division
Winter 2007-2008 Period

Attachment D
Page 1 of 2

	November	December	January 2008	February	March	April	Total
ecast Sales	301,766	431,169	504,856	429,731	373,655	253,240	2,294,417
ual Sales	321,088	439,648	423,188	404,497	381,064	250,510	2,219,995
erence	19,322	8,479	(81,668)	(25,234)	7,409	(2,730)	(74,422)
:							
ume Variance due to Weather							
mal Calendar Month Sales	316,928	449,552	514,264	455,080	389,457	254,547	2,379,828
ual Sales	321,088	439,648	423,188	404,497	381,064	250,510	2,219,995
ather Variance	4,160	(9,904)	(91,076)	(50,583)	(8,393)	(4,037)	159,833
al Variance Excluding Weather	23,482	(1,425)	(172,744)	(75,817)	(984)	(6,767)	85,411
iance-change in meter count							(268,385)
-change in load pattern							353,796
							85,411

Northern Utilities, Inc. - Maine Division
Winter 2007-2008 Period

Attachment D
Page 2 of 2

	2007-08 Normal Calendar Mcf	2007-08 Forecasted Mcf	CHANGE in Mcf	2007-08 Actual Meters	2007-08 Forecasted Meters	CHANGE in Meters
s Heat	734,668	717,789	16,879	75,341	73,565	1,776
s Non Heat	41,266	41,727	(461)	31,146	31,783	(637)
ıtal Res	**775,934**	**759,516**	**16,418**	**106,487**	**105,348**	**1,139**
ʌ Annual Use, Low Peak Period Use (G-50)	113,996	111,669	2,327	10,188	12,240	(2,052)
ʌ Annual Use, High Peak Period Use (G-40)	669,896	670,235	(339)	26,688	31,441	(4,753)
ːdium Annual Use, Low Peak Period Use (G-51)	123,836	123,765	71	846	1,032	(186)
ːdium Annual Use, High Peak Period Use (G-41)	575,861	526,607	49,254	2,154	2,323	(169)
ʒh Annual Use, Low Peak Period Use (G-52)	66,955	58,315	8,640	43	72	(29)
ʒh Annual Use, Low Peak Period Use (G-42)	53,350	44,310	9,040	34	21	13
ɔtal Commercial and Industrial	**1,603,894**	**1,534,901**	**68,993**	**39,953**	**47,129**	**(7,176)**
tal Company	**2,379,828**	**2,294,417**	**85,411**	**146,440**	**152,477**	**(6,037)**

	2007-08 Normalized Avg Use	2007-08 Forecasted Avg Use	CHANGE in Avg Use	CHANGE IN SALES DUE TO CHANGE IN Meter Count	CHANGE IN SALES DUE TO CHANGE IN Load Pattern	TOTAL CHANGE MCF	PERCENT CHANGE
ɜs Heat	9.75	9.76	(0.01)	17,316	(437)	16,879	2.35%
ɜs Non Heat	1.32	1.31	0.01	2,344	(2,805)	(461)	-1.10%
otal Res	7.29	7.21	0.08	19,660	(3,242)	16,418	2.16%
ıw Annual Use, Low Peak Period Use (G-50)	11.19	9.12	2.07	(22,962)	25,289	2,327	2.08%
ıw Annual Use, High Peak Period Use (G-40)	25.10	21.32	3.78	(119,300)	118,961	(339)	-0.05%
ɜdium Annual Use, Low Peak Period Use (G-51)	146.38	119.93	26.45	(27,227)	27,298	71	0.06%
ɜdium Annual Use, High Peak Period Use (G-41)	267.34	226.69	40.65	(45,180)	94,434	49,254	9.35%
gh Annual Use, Low Peak Period Use (G-52)	1,557.09	809.93	747.16	(45,156)	53,796	8,640	14.82%
gh Annual Use, Low Peak Period Use (G-42)	1,569.12	2,110.00	(540.88)	20,399	(11,359)	9,040	20.40%
otal Commercial and Industrial	40.14	32.57	7.57	(288,045)	357,038	68,993	4.49%
ɔtal Company	16.25	15.05	1.20	(268,385)	353,796	85,411	3.72%

Attachment E

NORTHERN UTILITIES, INC.
MAINE DIVISION
REFUND PASSBACK CALCULATION FOR THE PERIOD NOVEMBER 2007 - APRIL 2008
Account 265.41

		Beginng Month Balance	Refund Pass Back	Refunds	End of Month Balance	Average Balance	Annual Interest Rate	Monthly Interest Amount	Principal & Interest Balance	Total Sales
January 31, 2007	(act)	$ -	$ -	$ (14,653)	$ (14,653)	$ (473)	5.71%	$ (27)	$ (14,680)	
February	(act)	$ (14,680)	$ -	$ -	$ (14,680)	$ (14,680)	5.73%	$ (70)	$ (14,750)	
March	(act)	$ (14,750)	$ -	$ -	$ (14,750)	$ (14,750)	5.73%	$ (70)	$ (14,821)	
April	(act)	$ (14,821)	$ -	$ -	$ (14,821)	$ (14,821)	5.68%	$ (70)	$ (14,891)	
May	(act)	$ (14,891)	$ -	$ -	$ (14,891)	$ (14,891)	5.62%	$ (70)	$ (14,961)	
June	(act)	$ (14,961)	$ -	$ -	$ (14,961)	$ (14,961)	5.76%	$ (72)	$ (15,033)	
July	(act)	$ (15,033)	$ -	$ -	$ (15,033)	$ (15,033)	5.79%	$ (73)	$ (15,105)	
August	(act)	$ (15,105)	$ -	$ -	$ (15,105)	$ (15,105)	5.87%	$ (74)	$ (15,179)	
September	(act)	$ (15,179)	$ -	$ -	$ (15,179)	$ (15,179)	5.89%	$ (75)	$ (15,254)	
October	(act)	$ (15,254)	$ -	$ -	$ (15,254)	$ (15,255)	5.52%	$ (70)	$ (15,323)	
November	(act)	**$ (15,323)**	$ (964)	$ -	$ (14,359)	$ (14,841)	5.30%	$ (66)	$ (14,425)	1,376,580
December	(act)	$ (14,425)	$ (3,083)	$ -	$ (11,341)	$ (12,883)	5.35%	$ (57)	$ (11,399)	4,404,789
January 2008	(act)	$ (11,399)	$ (3,239)	$ -	$ (8,160)	$ (9,779)	5.35%	$ (44)	$ (8,203)	4,626,911
February	(act)	$ (8,203)	$ (3,446)	$ -	$ (4,758)	$ (6,481)	4.07%	$ (22)	$ (4,780)	4,922,184
March	(act)	$ (4,780)	$ (3,158)	$ -	$ (1,622)	$ (3,201)	3.54%	$ (9)	$ (1,632)	4,510,795
April	(act)	$ (1,632)	$ (2,061)	$ -	$ 430	$ (601)	3.17%	$ (2)	$ 428	2,944,959
May	(act)	$ 428	$ (628)	$ -	$ 1,056	$ 742	3.32%	$ 2	$ 1,058	897,354

Refund Passback Rate*		
Total Refunds (Projected @ 10/31/07)	$	(15,324)
Interest (11/1/07 - 4/30/08)	$	(207)
Refund Passback Amount	$	(15,531)
Total Sales (11/1/07 - 4/31/08)		22,944,170
Passback Rate	$	(0.0007)

*As determined in Docket No. 07-400

Appendix B

Pages 46 -54 of Transcript from the Maine Division's 2008 Off-Peak Period CGF Proceeding

It could be a marketer. It could be another utility. It doesn't have to be Bay State.

MS. MACLENNAN: Okay.

MR. DAFONTE: It just happened to work out with Bay State because of the existing agency and exchange agreement that Northern, Bay State, and Granite were part of.

MS. MACLENNAN: Okay. Okay, great. Thank you. I guess I may as well ask this question even though it occurs to me that it would have been better asked in the acquisition docket. But are there any capacity or commodity contracts that Northern holds that will become stranded, in effect, by the acquisition and spin-off to Unitil?

MR. DAFONTE: No, there won't.

MS. MACLENNAN: Okay. Good.

MS. SMITH: I think you might have asked something along those lines --

MS. MACLENNAN: Okay.

MS. SMITH: -- in the acquisition case. So --

MS. MACLENNAN: Okay.

MS. SMITH: You ready to move on to the other?

MS. MACLENNAN: Yeah.

MS. SMITH: Tom's here, and --

MS. MACLENNAN: We're going to move onto the New Hampshire-Maine allocation issue (inaudible) you wanted to sit in on.

MR. AUSTIN: Oh, okay.

MS. SMITH: I have one question before we go into that. The reconciliation moving -- the adjustment moving three million to Maine from New Hampshire, and that was the response of ADR 1-11, does that have to do -- and the only reason I'm going to ask this is because I want -- I'm thinking it does with the capacity allocation issue that we talked about in -- we asked about in data request 1-6, we were asking about the change in the allocation of the capacity costs, why basically in the summer months it was so much lower for Maine to New Hampshire. I'm just wondering if -- if that's the reason for this adjustment that you were talking about?

MR. GIBBONS: Yes.

MS. SMITH: Okay. Okay. Now, maybe this is in part because I was not heavily involved in the case that dealt with capacity assignment provisions, I guess I was slightly wondering why there's such an impact on the commodity cost allocators, but no impact on the demand cost allocators, and -- because in my mind, the capacity assignment meant capacity assignment of capacity on pipelines. But Carol says it also included assignment of some of your actual commodity costs, as well?

MR. FERRO: No. The --

MS. MACLENNAN: I didn't say that. I said there's a question.

MS. SMITH: Okay.

MR. FERRO: Should I proceed?

MS. SMITH: Yes.

MS. MACLENNAN: Please. Sorry.

MR. FERRO: The dockets that you're referring to in the capacity assignment was just that: capacity. Commodity cost allocations has always based on some assessment of what the firm send out of the two divisions are, what are the volumes that are being dispatched to each division to satisfy Northern's obligation to provide commodity to its customers.

And through the capacity assignment arrangement, it does impact commodity requirements both in Maine and New Hampshire divisions, but became a new requirement, and a significant requirement, with respect to commodity in the Maine division starting in January 2006. And that's because upon the agreement in those dockets, we agreed to satisfy capacity assignment with company-managed resources. And company-managed resources provides for sort of a virtual assignment of resources where Northern Utilities dispatches, and therefore, provides the commodity for the suppliers to satisfy their customers.

So it obviously flows into the assessment of commodity cost allocation factors between the two divisions because some of the volumes, commodity purchases, whether it's pulling out of storage MCN for company managed or Duke, DOMAC, those resources that Northern dispatches is associated with company-managed assignment. So if one is trying to capture the volumes to satisfy firm demand, one has to capture those commodity volumes to satisfy company-managed.

MS. SMITH: So just -- so in looking at the allocators, is it actually that the -- because I was looking at it that summer supply was less in Maine. Is it actually that winter supply is more and that's why the allocators are different? I mean, I'm trying to figure out as to why we go from, you know, around 50 percent to 52 percent in certain months to down as low as 30 percent to 70 percent.

MR. FERRO: I'm sorry. Can you tell me what schedule you're --

MS. SMITH: I'm looking at schedule -- it's on page 60 of the filing.

MR. FERRO: Page --

MS. SMITH: The simplified market-based allocators.

MR. GIBBONS: The winter months would include the estimated company-managed estimates of the allocations November through March.

MS. SMITH: Uh-huh.

MR. GIBBONS: And then that program ends in Maine from April through October.

MR. FERRO: Yeah. The send-out model, Lucretia, has to recognize that it needs to dispatch volumes in Maine to satisfy company managed, and this schedule reflects that. And certainly you can see that Maine's allocation factors are higher in the winter than in the summer, at least in part due to the company-managed requirements in Maine solely in the winter.

MS. SMITH: Okay.

MS. MACLENNAN: You can continue if you'd like. I need to take a break.

MS. SMITH: Okay.

MR. GIBBONS: So we put those -- we have to put those costs into the Maine reconciliation, but then those are offset by company-managed commodity credits.

MR. FERRO: Excuse me. Off the record, is it okay we continue to --

MS. SMITH: Yeah, she said to go ahead, so --

MR. FERRO: Oh, I'm sorry, I didn't hear that. Okay. Sorry.

MS. SMITH: No, that's all right. I was debating that, as well. Okay, so there's -- I'm trying to get -- where would I see what you just told me?

MR. GIBBONS: The credits?

MS. SMITH: Yeah.

MR. GIBBONS: The credits are -- you would see those on page 38, which is the tariff page.

MS. SMITH: Okay.

MR. GIBBONS: The volumes associated with that assigned transportation is included and is reflective of the --

MS. SMITH: Okay. So that $2 million that's assigned to -- that's on the first line, that's peak demand?

MR. GIBBONS: Yes.

MS. SMITH: And then there's 12 million assigned transportation costs that's commodity?

MR. GIBBONS: Yes.

MS. SMITH: Okay. So the allocator is allocating more dollars to Maine, but then when we go through the tariff pages and are assigning it to classes, some of those dollars are being assigned to the transport customers; is that correct?

MR. GIBBONS: Yes.

MS. SMITH: Okay.

MS. MACLENNAN: Sorry.

MS. SMITH: That's all right. So what happened with the reconciliation? I guess I'm -- we've moved three million to Maine from New Hampshire.

MR. GIBBONS: The original -- when the costs came through originally, the allocation did not reflect the fact that these costs had to be assigned to Maine November through March because the credits were coming through also to offset t hose. You were getting the credits but you weren't getting the up-front costs associated with that. The gas that was being assigned through the company-managed program --

MS. SMITH: Uh-huh.

MR. GIBBONS: -- was not getting -- it was not being allocated to Maine.

MS. MACLENNAN: I'm sorry, if I cover ground you've already covered. But you're probably not surprised that we were surprised to see such a large dollar amount suddenly appear in your reconciliation without much explanation. Was it that the company overlooked this particular part of the calculation --

MR. GIBBONS: Yes.

MS. MACLENNAN: -- January '06 to the present?

MR. GIBBONS: It did not get in -- winter '07-'08 it did not get into the calculation of the allocation.

MS. MACLENNAN: So it's a one-season error?

MR. GIBBONS: It did not -- you were receiving the credits but the costs were not in on Maine's books. You were only receiving the credit side of things.

MS. SMITH: Let me just see if -- because this will bring -- hopefully bring Carol up to date but will also make sure I understand what was just stated. The allocation to Maine in total the allocators are higher because of the Maine send out because of the assignment of capacity management is higher. But when it goes -- comes to the allocation to actual customers on the tariff sheet, some of it is assigned directly to transport customers so, therefore, those costs aren't being assigned to the sales-only customers. Is that correct?

MR. FERRO: Yes. As it was last year -- if you look at last year's winter cost of gas, just what you say, Lucretia, that is, we back out the associated costs of commodity and capacity to the capacity assigned customers, and the net is charged to sales customers. But then when we -- as we proceeded in that period in the real world, we bill the supplier for company-managed resources. Some of is capacity, some is commodity. That is credited through the cost of gas in our accounting.

But when we were taking a look at the send outs, say, in November '07 or December '07 and we were assigning total Northern commodity costs to the Maine division and the New Hampshire division, we were developing allocation factors that excluded Northern's requirement to send out gas to satisfy company-managed resources to the transportation customers of Maine. And once Ron discovered that, we had -- we had to reverse the calculation. And what Ron was saying is the credit really is the charges that we bill the suppliers and ran that revenue through the cost of gas in the Maine division, that's the credit. The cost side of it is just allocating commodity costs to the Maine division associated with that requirement. That's what was not being done, the allocation of commodity costs associated with that requirement in the Maine division.

MS. SMITH: So if I were to look at the allocation tab in my filing from last year, which is still in my office, as is every filing since I've been here, I would not see this differential that I'm seeing this year?

MR. FERRO: You should not. If we modeled this correctly last year, you should --

MS. SMITH: Or you modeled incorrectly?

MR. FERRO: No, I don't think we modeled it incorrectly.

MS. SMITH: (Inaudible).

MR. FERRO: We modeled it correctly. We accounted it for it incorrectly, if you will. We modeled -- I think the person who runs out send out model, he did not --

MR. GIBBONS: I think you would see these same allocations last year.

MR. FERRO: That's the point I'm making. That's right.

MS. SMITH: Okay.

MR. FERRO: That's right. That's the point making. He modeled it correctly and, therefore, he was -- he was satisfying company-managed resources last year. So on a projected basis, they're not forecasts. The commodity allocation factor should have represented reasonably accurate assessment of the split.

MS. SMITH: Okay.

MR. FERRO: But then when we accounted for it in the real world, actual basis, we did not reflect the company-managed commodity requirements in the Maine division by way of allocating total Northern commodity requirements. The commodity allocation factors did not recognize the additional Maine demand for company-managed resources.

MR. JORTNER: Was there a reciprocal error made in the New Hampshire filing or was this only an error made in the Maine filing?

MR. GIBBONS: No, a reciprocating amount was in New Hampshire.

MR. JORTNER: So you had to correct the New Hampshire as well?

MR. GIBBONS: Yes. Now --

MR. JORTNER: By the same exact amount?

MR. GIBBONS: Yes. Now, you would not have seen the adjustment line in the reconciliation in the prior winter. Let's say the accounting department makes the allocation calculation based on actuals. They do not use these allocators --

MS. SMITH: Okay.

MR. GIBBONS: -- when they post commodity costs.

MS. SMITH: Okay.

MR. GIBBONS: They use the actuals. So, therefore, if the company managed were taken under consideration when the allocations were made originally, coming through this winter, there would be no need for the reallocation line because that $3.2 million in costs would be spread throughout the commodity costs on the reconciliation. You would not see a line for an extra allocation because of the company-managed and all that.

MS. SMITH: Okay.

MR. GIBBONS: They would be -- it would be included in the allocation amount and they would be spread amongst --

MS. SMITH: Because --

MR. GIBBONS: -- costs.

MS. SMITH: -- because they would have used these percentages or something along those --

MR. GIBBONS: Something similar.

MS. SMITH: -- percentages in booking it?

MR. GIBBONS: Something similar to that.

MS. SMITH: Something similar to that?

MR. GIBBONS: Yes.

MS. SMITH: So instead what they used to book it did not reflect the company-managed that's being added for Maine; is that --

MR. GIBBONS: Not originally.

MS. SMITH: Not originally, which caused the need of the $3 million reconciliation. But is it -- I guess I'm trying to figure out is it really a reconciliation as so much that it's a -- if the accounting had been correct each month, you know, your build up, you're saying we wouldn't have seen --

MS. MACLENNAN: The correction.

MS. SMITH: It's a correction within that so that you didn't have to go back and recalculate each month's?

MR. GIBBONS: Right, it was just --

MS. SMITH: Is that really what it is?

MR. GIBBONS: Yes, it would have just flowed through as it usually does.

MS. SMITH: Okay. So it's more that the individual months on the sheets weren't accurate, not that we're getting $3 million of costs that New Hampshire paid for in a prior period.

MR. GIBBONS: No. No. And it was done in this manner -- I made the decision to do it in this manner to preserve the audit trail --

MS. SMITH: Okay.

MR. GIBBONS: -- for when you do the audit because if you were to look at the allocated cover sheets and the invoices and such, you will see allocations like what is in the reconciliation. If I'd gone through and put the correct allocations on the spreadsheets and re-spread the dollars and made it look like you're accustomed to seeing, if you went and looked a the allocations between the two jurisdictions, two divisions --

MS. SMITH: Okay.

MR. GIBBONS: -- it wouldn't have tied out. The total costs to Northern are the same as the split between the two. So --

MS. SMITH: And the split between the two is really -- really what was estimated close to what -- other than, you know, the changes in costs and things, but the theory behind in the end is what was estimated when you made the filing for 2007-2008 winter period?

MR. GIBBONS: Yes, it should be.

MS. SMITH: Okay.

MS. MACLENNAN: Just so I fully understand. I think I understand the basic explanation for -- which is that Maine has a higher percentage of managed resources assigned to suppliers than does New Hampshire?

MR. GIBBONS: Yes.

MS. MACLENNAN: So there has to be a -- in your calculation of commodity allocation by jurisdiction, you have to somehow add in, for this one category of commodity, that difference?

MR. GIBBONS: Yes. And if you look at the reconciliation on page 136, two-thirds of the way down, you'll see company-managed propane which really is company-managed peaking resources or just company managed, and follow that across, you'll see a $3.9 million credit. The credits were --

are already in the commodity cost schedule. And those are not allocated. Those are division-by-division actual credits. Those are not part of the allocation process.

MS. SMITH: What page did you say, Ron?

MR. GIBBONS: 136.

MS. SMITH: Okay. I have it now.

MR. GIBBONS: 13 lines up or so.

MS. SMITH: Okay.

MR. FERRO: The three million nine dollar number right, Ron?

MR. GIBBONS: Yes.

MS. SMITH: Yeah.

MS. MACLENNAN: This seemed to come out of the blue for me and it could be my faulty memory, but I don't -- didn't think I recalled a discussion during the negotiations of the allocations between states for capacity assignment including this item, that there would be an acknowledgment of different -- I understand the logic but it wasn't something that rang a bell for me. Is that because I overlooked it or is this something that sort of bubbled up to everyone's -- New Hampshire's consciousness so the company is accommodating it, let's say.

MR. FERRO: No. You didn't overlook it. It was not an issue because this was a capacity-related docket, and no one was proposing to change the methodology of allocating commodity costs --

MS. MACLENNAN: Okay.

MR. FERRO: -- which is based on each division's firm send out requirements, volumes/commodity requirements. And that was not of issue.

MS. MACLENNAN: Okay. So this has really evolved out of the CGF commodity aspect?

MR. FERRO: That's correct.

MS. MACLENNAN: And -- but was it brought to your attention by the New Hampshire staff, say, in last year's -- last winter's CGF or this winter's CGF or did you just discover it, think it through yourselves?

MR. FERRO: I'll let Ron speak --

MS. MACLENNAN: Okay.

MR. FERRO: I mean, we haven't even discussed this with New Hampshire. I mean, this was discovered by Ron recently.

MS. MACLENNAN: Okay.

MR. GIBBONS: I discovered it doing the reconciliations because I had an enormous over collection in Maine, and a -- and a very large under collection in New Hampshire.

MS. MACLENNAN: Okay.

MR. GIBBONS: So that's how it came to light.

MS. MACLENNAN: I see.

MR. FERRO: Carol, you might not need this simple illustration and I think you understand it, but very simply, if we had a hundred dollars worth of commodity costs, and without reflecting the company-managed requirements in the Maine division, we allocated only 40 percent of that hundred dollars to Maine and 60 percent to New Hampshire and then realized the 60/40 split should have been 50/50 if we reflected company-managed resources.

MS. MACLENNAN: Uh-huh.

MR. FERRO: That instead of $40 being allocated to Maine, we should have allocated $50 to Maine; instead of 60 to New Hampshire, 50 to New Hampshire. That’s the $10 adjustment that he’s providing there.

MS. MACLENNAN: Okay.

MS. SMITH: And the reason it’s done in one lump sum is for the audit trail, so we didn’t have to ask him every month why is this number different, why is this number different, so we have -- all the numbers will match how they accounted for it.

MS. MACLENNAN: Uh-huh.

MS. SMITH: And then they’ll have the one true up, which reflects how it was proposed in last year’s filing.

MS. MACLENNAN: Just a question on why Maine has more company-managed assignment to suppliers than New Hampshire. Is that --

MR. FERRO: Well, two fold.

MS. MACLENNAN: Okay.

MR. FERRO: Certainly the unique provisions in the Maine capacity assignment is that we provide them with capacity only in the five months of November through March --

MS. MACLENNAN: Uh-huh.

MR. FERRO: -- while in New Hampshire it's year round. But secondly that all capacity assignment and, therefore, all capacity requirements that the suppliers need in Maine are satisfied by company managed, while in New Hampshire a good share of it is long-haul pipeline, as well as some company-managed storage and peaking.

So it's the entire requirement in Maine is satisfied by company managed while just a portion of New Hampshire's requirement is satisfied by company managed.

MS. MACLENNAN: And -- and why is that, again, Joe? Is it -- why isn't company-managed divided between the states equally? Why is there a particular designation of only company managed to Maine and a portion of New Hampshire's overall to New Hampshire?

MR. FERRO: Well, like any other requirement, you look at New Hampshire's firm demand --

MS. MACLENNAN: Uh-huh.

MR. FERRO: -- sales and company assignment, and Maine's firm demand, firm sales, and company -- and -- and -- and capacity assignment, excuse me. And so when you add -- if you isolate the pieces, the capacity assignment piece in Maine is made up of different -- solely company managed, a different component that New Hampshire. It has pipeline and a little company managed.

MS. MACLENNAN: But I'm asking why.

MR. FERRO: It's the tariff provisions in both -- both divisions; that is, New Hampshire gets a slice of the system every month --

MS. MACLENNAN: Okay.

MR. FERRO: -- while we had agreed upon, settled upon in Maine --

MS. MACLENNAN: Okay.

MR. FERRO: -- that they don't get a slice. They get specific resources.

MS. MACLENNAN: Okay. Good. That's all I was getting at.

MR. FERRO: Okay.

MS. MACLENNAN: Sorry I didn't remember that.

MR. GIBBONS: Well, the agreement also -- New Hampshire had a cut off back in '02 --

MR. FERRO: That's another element to this --

MR. GIBBONS: -- '03, whereas Maine was --
MR. FERRO: Right.
MR. GIBBONS: -- 50 percent of the firm transportation.
MR. FERRO: That's another element to this but that's -- that is just who was assigned capacity and who was not. And in New Hampshire I believe it was March 2001 grandfathered date; that is, all customers who switched to transportation service after that date was non-grandfathered or capacity assigned while the prior ones were.
MS. MACLENNAN: I remember that.
MR. GIBBONS: And the Maine division credits are much larger than the New Hampshire division credits.
MS. SMITH: So you have certain pipeline, gas, if you will, that New Hampshire transportation customers or commodity, they get a slice of that. How are -- and that's not at all reflected in any of these allocation factors or anything like that? What I'm trying to figure out is we have total Northern costs --
MR. FERRO: Right.
MS. SMITH: -- which include -- are those costs of that pipeline supply in that total Northern cost?
MR. FERRO: There's no commodity assignment associated with those resources --
MS. SMITH: Okay.

MR. FERRO: -- both in Maine -- well, Maine doesn't get any capacity assignment, but New Hampshire there's -- we just release the capacity to the suppliers to satisfy their long-haul pipeline needs.

MS. SMITH: Okay.

MR. FERRO: They buy their own gas. We don't dispatch for them or buy gas. So that's not part of Northern's send out.

MS. SMITH: Okay.

MR. FERRO: That's what we're trying to capture here, Northern's send out requirements. And only company managed affects Northern's send out requirements.

MS. MACLENNAN: Great. Now this makes sense. Thank you. Do you have any questions?

MS. SMITH: Well, that's wasn't as painful as I expected it to be.

MS. MACLENNAN: No.

MS. SMITH: I don't know that I have anything else on the cost of gas stuff specifically.

MS. MACLENNAN: When are you going to move to the ERC --

MS. SMITH: Oh, the ERC questions. On ADR number 1-9 and 1-10 --

MS. FRENCH: Sorry that it didn't occur to me to bring him up here.

Schedule 1

Summary of Original and Revised Seasonal Reconciliations

Northern Utilities, Inc.
Summary of Variable Commodity Allocation Adjustments related to Company Managed Gas and LAUF

		New Hampshire			Maine			
Line #	Description	As Filed	Updated	Change	As Filed	Updated	Change	Reference for Updated Amounts
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	*Peak - May 2008- Apr 2009:*							
2	Commodity Costs	$ 28,851,058	$ 28,029,008	$ (822,050)	$ 21,736,533	$ 22,558,583	$ 822,050	Sch 2, pps.5, 13 and Sch 5, pps.6, 20
3	Demand Costs	$ 11,159,762	$ 11,159,762	$ -	$ 11,019,798	$ 11,019,798	$ -	Sch 2, pps.6, 14 and Sch 5, pps.7, 21
4	Interest on Over/Under Balance	$ 59,253	$ 51,804	$ (7,449)	$ 64,728	$ 74,030	$ 9,302	Sch 2, pps.3, 11 and Sch 5, pps.4, 18
5	Working Capital	$ 27,190	$ 26,714	$ (476)	$ 144,455	$ 148,081	$ 3,626	Sch 2, pps.7, 15 and Sch 5, pps.11, 25
6	Interest on Over/Under Balance	$ 118	$ 113	$ (5)	$ 632	$ 673	$ 41	Sch 2, pps.7, 15 and Sch 5, pps.11, 25
7	Bad Debt	$ 180,171	$ 176,470	$ (3,701)	$ 348,748	$ 357,500	$ 8,752	Sch 2, pps.8, 16 and Sch 5, pps.12, 26
8	Interest on Over/Under Balance	$ 1,251	$ 1,218	$ (33)	$ 1,546	$ 1,645	$ 99	Sch 2, pps.8, 16 and Sch 5, pps.12, 26
9	Totals - Peak Period - 2008/2009	$ 40,278,803	$ 39,445,089	$ (833,714)	$ 33,316,440	$ 34,160,310	$ 843,870	
10	*Peak - May 2009- Apr 2010:*							
11	Commodity Costs	$ 16,507,551	$ 15,281,412	$ (1,226,139)	$ 12,405,739	$ 13,631,878	$ 1,226,139	Sch 3, pps.5, 16 and Sch 6, pps.6, 20
12	Demand Costs	$ 10,650,190	$ 10,650,190	$ -	$ 10,921,727	$ 10,921,727	$ -	Sch 3, pps.6, 17 and Sch 6, pps.8, 22
13	Interest on Over/Under Balance	$ 110,619	$ 73,599	$ (37,020)	$ (18,711)	$ 7,414	$ 26,125	Sch 3, pps.3, 14 and Sch 6, p.4, 18
14	Working Capital	$ 15,317	$ 14,625	$ (692)	$ 102,874	$ 108,281	$ 5,407	Sch 3, pps.8, 19 and Sch 6, pps.11, 25
15	Interest on Over/Under Balance	$ (1,366)	$ (1,389)	$ (23)	$ 196	$ 311	$ 115	Sch 3, pps.8, 19 and Sch 6, pps.11, 25
16	Bad Debt	$ 122,279	$ 116,758	$ (5,521)	$ 248,362	$ 261,416	$ 13,054	Sch 3, pps.9, 20 and Sch 6, pps.12, 26
17	Interest on Over/Under Balance	$ 1,338	$ 1,168	$ (170)	$ 384	$ 662	$ 278	Sch 3, pps.9, 20 and Sch 6, pps.12, 26
18	Totals - Peak Period - 2009/2010	$ 27,405,928	$ 26,136,363	$ (1,269,565)	$ 23,660,571	$ 24,931,689	$ 1,271,118	
19	*Peak - May 2010- Apr 2011:*							
20	Commodity Costs	$ 16,690,300	$ 14,784,852	$ (1,905,447)	$ 10,305,839	$ 12,211,286	$ 1,905,447	Sch 4, pps.5, 16 and Sch 7, pps.6, 20
21	Demand Costs	$ 14,353,569	$ 14,353,569	$ -	$ 14,211,538	$ 14,211,538	$ -	Sch 4, pps.6, 17 and Sch 7, pps.8, 22
22	Interest on Over/Under Balance	$ 138,949	$ 55,976	$ (82,973)	$ 17,918	$ 75,480	$ 57,562	Sch 4, pps.3, 14 and Sch 7, pps.4, 18
23	Working Capital	$ 17,509	$ 16,434	$ (1,075)	$ 108,122	$ 116,525	$ 8,403	Sch 4, pps.8, 19 and Sch 7, pps.11, 25
24	Interest on Over/Under Balance	$ (2,285)	$ (2,334)	$ (49)	$ 188	$ 441	$ 253	Sch 4, pps.8, 19 and Sch 7, pps.11, 25
25	Bad Debt	$ 139,776	$ 131,197	$ (8,579)	$ 261,030	$ 281,317	$ 20,287	Sch 4, pps.9, 20 and Sch 7, pps.12, 26
26	Interest on Over/Under Balance	$ 278	$ (99)	$ (377)	$ 351	$ 963	$ 612	Sch 4, pps.9, 20 and Sch 7, pps.12, 26
27	Totals - Peak Period - 2010/2011	$ 31,338,096	$ 29,339,595	$ (1,998,500)	$ 24,904,985	$ 26,897,549	$ 1,992,564	
28	**Totals - All peak periods**	**$ 99,022,827**	**$ 94,921,047**	**$ (4,101,779)**	**$ 81,881,996**	**$ 85,989,548**	**$ 4,107,552**	
29	*Off Peak - Nov 2008- Oct 2009:*							
30	Commodity Costs	$ 3,977,459	$ 3,980,481	$ 3,022	$ 3,595,126	$ 3,592,104	$ (3,022)	Sch 8, pps.5, 16 and Sch 11, pps.6, 18
31	Demand Costs	$ 1,468,086	$ 1,468,086	$ -	$ 1,285,602	$ 1,285,602	$ -	Sch 8, pps.6, 17 and Sch 11, pps.7, 19
32	Interest on Over/Under Balance	$ 12,420	$ 12,438	$ 18	$ 6,350	$ 6,339	$ (11)	Sch 8, pps.3, 14 and Sch 11, pps.4, 16
33	Working Capital	$ 3,070	$ 3,071	$ 1	$ 21,524	$ 21,511	$ (13)	Sch 8, pps.8, 19 and Sch 11, pps.9, 21
34	Interest on Over/Under Balance	$ 79	$ 79	$ -	$ (13)	$ (13)	$ -	Sch 8, pps.8, 19 and Sch 11, pps.9, 21
35	Bad Debt	$ 24,519	$ 24,532	$ 13	$ 51,964	$ 51,932	$ (32)	Sch 8, pps.9, 20 and Sch 11, pps.10, 22
36	Interest on Over/Under Balance	$ 306	$ 306	$ -	$ (21)	$ (21)	$ -	Sch 8, pps.9, 20 and Sch 11, pps.10, 22
37	Totals - Off-Peak Period - 2008/2009	$ 5,485,939	$ 5,488,993	$ 3,054	$ 4,960,532	$ 4,957,454	$ (3,078)	
38	*Off Peak - Nov 2009- Oct 2010:*							
39	Commodity Costs	$ 3,895,166	$ 3,863,740	$ (31,426)	$ 3,377,317	$ 3,408,742	$ 31,426	Sch 9, pps.5, 16 and Sch 12, pps.6, 18
40	Demand Costs	$ 1,086,474	$ 1,086,474	$ -	$ 1,020,599	$ 1,020,599	$ 0	Sch 9, pps.6, 17 and Sch 12, pps.7, 19
41	Interest on Over/Under Balance	$ (5,937)	$ (6,304)	$ (367)	$ 3,010	$ 3,272	$ 262	Sch 9, pps.3, 14 and Sch 12, pps.4, 16
42	Working Capital	$ 2,810	$ 2,792	$ (18)	$ 19,395	$ 19,533	$ 138	Sch 9, pps.8, 19 and Sch 12, pps.9, 21
43	Interest on Over/Under Balance	$ (261)	$ (261)	$ -	$ 20	$ 22	$ 2	Sch 9, pps.8, 19 and Sch 12, pps.9, 21
44	Bad Debt	$ 22,430	$ 22,289	$ (141)	$ 46,823	$ 47,158	$ 335	Sch 9, pps.9, 20 and Sch 12, pps.10, 22
45	Interest on Over/Under Balance	$ (73)	$ (75)	$ (2)	$ 22	$ 25	$ 3	Sch 9, pps.9, 20 and Sch 12, pps.10, 22
46	Totals - Off-Peak Period - 2009/2010	$ 5,000,609	$ 4,968,655	$ (31,954)	$ 4,467,186	$ 4,499,352	$ 32,166	
47	**Subtotal**	**$ 10,486,548**	**$ 10,457,648**	**$ (28,900)**	**$ 9,427,718**	**$ 9,456,806**	**$ 29,088**	
48	*Off Peak - Nov 2010- Oct 2011:*	***Note - The following correction has already been done in Nov10-Nov11 filing as $10,385, change due to treatment of Hedging.***						
49	Commodity Costs	$ 2,964,431	$ 2,974,843	$ 10,413	$ 2,664,627	$ 2,654,215	$ (10,413)	Sch 10, pps.5, 16 and Sch 13, pps.6, 18
50	Demand Costs	$ 1,253,424	$ 1,253,424	$ 0	$ 1,267,915	$ 1,267,915	$ -	Sch 10, pps.6, 17 and Sch 13, pps.7, 19
51	Interest on Over/Under Balance	$ (8,994)	$ (9,832)	$ (838)	$ (3,763)	$ (3,196)	$ 567	Sch 10, pps.3, 14 and Sch 13, pps.4, 16
52	Working Capital	$ 2,379	$ 2,385	$ 6	$ 17,343	$ 17,297	$ (46)	Sch 10, pps.8, 19 and Sch 13, pps.9, 21
53	Interest on Over/Under Balance	$ (196)	$ (197)	$ (1)	$ 10	$ 12	$ 2	Sch 10, pps.8, 19 and Sch 13, pps.9, 21
54	Bad Debt	$ 18,991	$ 19,038	$ 47	$ 41,869	$ 41,758	$ (111)	Sch 10, pps.9, 20 and Sch 13, pps.10, 22
55	Interest on Over/Under Balance	$ 37	$ 33	$ (4)	$ 34	$ 40	$ 6	Sch 10, pps.9, 20 and Sch 13, pps.10, 22
56	Totals - Off-Peak Period - 2010/2011	$ 4,230,072	$ 4,239,695	$ 9,623	$ 3,988,035	$ 3,978,040	$ (9,995)	
57	**Totals - All Off-Peak periods**	**$ 14,716,620**	**$ 14,697,343**	**$ (19,277)**	**$ 13,415,753**	**$ 13,434,846**	**$ 19,094**	

Northern Utilities, Inc.
Summary of Variable Commodity Allocation Adjustments related to Company Managed Gas and LAUF (cont.)

		New Hampshire			Maine			
	Description	As Filed	Updated	Change	As Filed	Updated	Change	Reference
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
58	**Summaries by Season [1]:**							
59	*Peak - All periods:*							
60	**Commodity Costs**	**$ 62,048,909**	**$ 58,095,272**	**$ (3,953,636)**	**$ 44,448,111**	**$ 48,401,747**	**$ 3,953,636**	L.2 + L.11 + L.20
61	Demand Costs	$ 36,163,521	$ 36,163,521	$ -	$ 36,153,063	$ 36,153,063	$ -	L.3 + L.12 + L.21
62	Interest on Over/Under Balance	$ 308,821	$ 181,379	$ (127,442)	$ 63,935	$ 156,924	$ 92,989	L.4 + L.13 + L.22
63	Working Capital	$ 60,016	$ 57,773	$ (2,243)	$ 355,451	$ 372,887	$ 17,436	L.5 + L.14 + L.23
64	Interest on Over/Under Balance	$ (3,533)	$ (3,610)	$ (77)	$ 1,016	$ 1,425	$ 409	L.6 + L.15 + L.24
65	Bad Debt	$ 442,226	$ 424,425	$ (17,801)	$ 858,140	$ 900,233	$ 42,093	L.7 + L.16 + L.25
66	Interest on Over/Under Balance	$ 2,867	$ 2,287	$ (580)	$ 2,281	$ 3,270	$ 989	L.8 + L.17 + L.26
67	Totals - Peak Period - All Periods	$ 99,022,827	$ 94,921,047	$ (4,101,779)	$ 81,881,996	$ 85,989,548	$ 4,107,552	
68	*Off-Peak - All periods:*							
69	**Commodity Costs**	**$ 10,837,056**	**$ 10,819,064**	**$ (17,991)**	**$ 9,637,070**	**$ 9,655,061**	**$ 17,991**	L.30 + L.39 + L.49
70	Demand Costs	$ 3,807,984	$ 3,807,984	$ 0	$ 3,574,116	$ 3,574,116	$ 0	L.31 + L.40 + L.50
71	Interest on Over/Under Balance	$ (2,511)	$ (3,698)	$ (1,187)	$ 5,597	$ 6,415	$ 818	L.32 + L.41 + L.51
72	Working Capital	$ 8,259	$ 8,248	$ (11)	$ 58,262	$ 58,341	$ 79	L.33 + L.42 + L.52
73	Interest on Over/Under Balance	$ (378)	$ (379)	$ (1)	$ 17	$ 21	$ 4	L.34 + L.43 + L.53
74	Bad Debt	$ 65,940	$ 65,859	$ (81)	$ 140,656	$ 140,848	$ 192	L.35 + L.44 + L.54
75	Interest on Over/Under Balance	$ 270	$ 264	$ (6)	$ 35	$ 44	$ 9	L.36 + L.45 + L.55
76	Totals - Off-Peak Period - All Periods	$ 14,716,620	$ 14,697,343	$ (19,277)	$ 13,415,753	$ 13,434,846	$ 19,094	
77	*Both Seasons - All periods:*							
78	**Commodity Costs**	**$ 72,885,964**	**$ 68,914,337**	**$ (3,971,627)**	**$ 54,085,180**	**$ 58,056,807**	**$ 3,971,627**	L.60 + L.69
79	Demand Costs	$ 39,971,505	$ 39,971,505	$ 0	$ 39,727,179	$ 39,727,179	$ 0	L.61 + L.70
80	Interest on Over/Under Balance	$ 306,310	$ 177,681	$ (128,629)	$ 69,532	$ 163,339	$ 93,807	L.62 + L.71
81	Working Capital	$ 68,275	$ 66,021	$ (2,254)	$ 413,713	$ 431,228	$ 17,515	L.63 + L.72
82	Interest on Over/Under Balance	$ (3,911)	$ (3,989)	$ (78)	$ 1,033	$ 1,446	$ 413	L.64 + L.73
83	Bad Debt	$ 508,166	$ 490,284	$ (17,882)	$ 998,796	$ 1,041,081	$ 42,285	L.65 + L.74
84	Interest on Over/Under Balance	$ 3,137	$ 2,551	$ (586)	$ 2,316	$ 3,314	$ 998	L.66 + L.75
85	Totals - Off-Peak Period - All Periods	$ 113,739,446	$ 109,618,390	$ (4,121,056)	$ 95,297,749	$ 99,424,394	$ 4,126,646	
86	Subtotal - All periods	$ 113,739,446	$ 109,618,390	$ (4,121,056)	$ 95,297,749	$ 99,424,394	$ 4,126,646	L.67 + L.76
87	Less: Off Peak 2011 already filed	$ 4,230,072	$ 4,239,695	$ 9,623	$ 3,988,035	$ 3,978,040	$ (9,995)	L. 56
88	**Total - All periods not yet filed**	**$ 109,509,375**	**$ 105,378,695**	**$ (4,130,679)**	**$ 91,309,714**	**$ 95,446,354**	**$ 4,136,640**	**L. 86 - L. 87**
89	*Interest - All Reconciling Mechanisms:*							
90	Peak	$ 308,155	$ 180,056	$ (128,099)	$ 67,232	$ 161,619	$ 94,387	L.62 + L.64 + L.66
91	Off Peak	$ (2,619)	$ (3,813)	$ (1,194)	$ 5,649	$ 6,480	$ 831	L.71 + L.73 + L.75

Schedule 2

New Hampshire Division
Original and Revised 2008-2009 Winter Period Reconciliation

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2008-09 WINTER PERIOD RECONCILIATION
May 2008 - April 2009

Original Reconciliation - Conformed

FORM III
Schedule 1
REV (3-4-10)
Conformed to Current Presentation

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2008-09 WINTER PERIOD RECONCILIATION
SCHEDULE 1: PEAK PERIOD SUMMARY
May 2008 - April 2009

	AMOUNT	
Winter Period Beg. Balance	$ (707,623)	SCHEDULE 2
Less: Reported Collections	$ (37,294,395)	SCHEDULE 3
Less: Reclass Supplier Refund	$ (5,270)	SCHEDULE 2
Add: Cost of Gas Adjustments	$ 40,010,820	SCHEDULE 2
Add: Capacity Reserve Charge Rev. from Summer	$ 3,347	SCHEDULE 2
Add: Interest	$ 59,253	SCHEDULE 2
Winter Period Ending Balance	$ 2,066,132	

FORM III
Schedule 2
REV (3-4-10)
Conformed to Current Presentation

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2008-09 WINTER PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED PEAK PERIOD ACCOUNTS
May 2008 - May 2009
Acct 191.20

	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Total
WINTER PERIOD													
Winter Period Account Beginning Balance	$ (707,623)	$ (825,602)	$ (174,447)	$ 88,209	$ 1,074,115	$ 1,518,856	$ 1,931,971	$ 2,422,024	$ 4,335,781	$ 3,181,399	$ 2,536,129	$ 2,177,448	$ (707,623)
Plus: Cost of Firm Gas (Schedule 4)(1)	$ (120,689)	$ 658,101	$ 262,275	$ 983,213	$ 438,876	$ 407,833	$ 4,767,023	$ 8,085,110	$ 9,907,318	$ 6,705,531	$ 5,157,054	$ 2,759,174	$ 40,010,820
Less: Reported Collections (Schedule 3)(2)	$ -	$ -	$ -	$ -	$ -	$ -	($4,284,156)	($6,181,503)	($11,071,866)	($7,358,533)	($5,522,108)	($2,876,228)	$ (37,294,395)
Plus: Capacity Reserve Charge Revenues from Summer	$ 2,955	$ 403	$ 561	$ 277	$ 474	$ (1,264)	$ (58)	$ -	$ -	$ -	$ -	$ -	$ 3,347
Less: Reclass Supplier Refund		$ (5,270)											$ (5,270)
Winter Period Ending Balance	$ (825,357)	$ (172,368)	$ 88,388	$ 1,071,699	$ 1,513,466	$ 1,925,426	$ 2,414,779	$ 4,325,631	$ 3,171,234	$ 2,528,397	$ 2,171,074	$ 2,060,395	
Month's Average Balance	$ (766,490)	$ (498,985)	$ (43,029)	$ 579,954	$ 1,293,791	$ 1,722,141	$ 2,173,375	$ 3,373,828	$ 3,753,507	$ 2,854,898	$ 2,353,601	$ 2,118,922	
Interest Rate (Prime Rate)	5.00%	5.00%	5.00%	5.00%	5.00%	4.56%	4.00%	3.61%	3.25%	3.25%	3.25%	3.25%	
Interest Applied	$ (245)	$ (2,079)	$ (179)	$ 2,416	$ 5,391	$ 6,544	$ 7,245	$ 10,150	$ 10,166	$ 7,732	$ 6,374	$ 5,739	$ 59,253
Winter Period Account Ending Balance	$ (825,602)	$ (174,447)	$ 88,209	$ 1,074,115	$ 1,518,856	$ 1,931,971	$ 2,422,024	$ 4,335,781	$ 3,181,399	$ 2,536,129	$ 2,177,448	$ 2,066,133	$ 2,066,132

Explanation of adjustments necessary to change to accrual accounting effective November 1, 2008 in compliance with the Commission's Order No. 25,038

October 2008 Ending Balance	
Winter Period	$1,931,971
Summer Period	<u>$2,032,076</u>
TOTAL (Order 25,038 Pg.4)	$3,964,047
Less October Unbilled Revenue included in November's Summer Revenues	<u>$1,506,169</u>
November 2008 Adjusted Opening Balances	
Winter Period (no adjustment required)	$1,931,971
Summer Period (full $1.5 million adjustment required)	<u>$525,907</u>
TOTAL (Order 25,038 Pg.4)	$2,457,878

(1) May-09 costs reflect April actual costs received in May and changes necessary to revise April estimates to actual costs.
(2) Reported collections for Dec-08 & Jan-09 are corrected figures. This results in a change in reported collections for these two months; however, there is no net impact on total reported collections for the period.

FORM III
Schedule 3
REV (3-4-10)
Conformed to Current Presentation

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2008-09 WINTER RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS(1)
November 2008 - April 2009

	November	December(2)	January 2009(2)	February	March	April	May	Total
Accrued Revenue	$3,079,685	$35,676	$1,605,991	($1,124,470)	($1,020,000)	($1,265,810)	($1,311,072)	$0
Billed Revenue	$1,204,471	$6,145,827	$9,465,875	$8,483,003	$6,542,109	$4,142,038	$1,242,642	$37,225,965
Calendarized Revenue	**$4,284,156**	**$6,181,503**	**$11,071,866**	**$7,358,533**	**$5,522,108**	**$2,876,228**	**($68,430)**	**$37,225,965**

(1) Revenue figures reflect the transition to accrual accounting as required by Commission Order No. 25,038, dated October 30, 2009 in docket DG 07-033.
(2) Accrued revenues for Dec-08 & Jan-09 are corrected figures. This results in a change in accrued and calendarized revenues for these two months; however, there is no net impact on total revenues for the period.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2008-2009 PEAK PERIOD
COST OF GAS ADJUSTMENT RESULTS
November 2008 - April 2009

FORM III
Schedule 4
Page 1 of 2

REV (3-4-10)
Conformed to Current Presentation

WINTER RELATED COSTS INCURRED IN SUMMER '08 DEFERRED TO WINTER 2008-09

	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Total Winter
Commodity Costs:													
Alberta Northeast Gas Limited	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,566	$ -	$ -	$ -	$ -	$ -	$ 2,566
BP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 49,715	$ 85,483	$ -	$ 95,702	$ 230,900
BG Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,380	$ 24,622	$ 20,917	$ (2,591)	$ 27,495	$ 83,823
Colonial Energy Inc	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,292	$ 24,292	$ -	$ -	$ -	$ -	$ 48,585
Conoco Phillips	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 933,489	$ 317,180	$ 387,314	$ 1,637,983
Distrigas of Mass	$ -	$ -	$ -	$ -	$ -	$ -	$ 257,063	$ 257,015	$ 176,305	$ 423,491	$ 42,799	$ 20,393	$ 1,177,065
Emera Canada	$ -	$ -	$ -	$ -	$ -	$ -	$ 122,083	$ 100,634	$ 172,273	$ 131,731	$ 83,821	$ 213,671	$ 824,213
FedEx Trade	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,174						$ 5,174
FPL/NextEra	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 78,895	$ 141,386	$ 72,854	$ 96,820	$ 389,955
Integrys	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Northeast Gas Marketing	$ -	$ -	$ -	$ -	$ -	$ -	$ 217,372	$ 217,002	$ 245,426	$ 233,055	$ 165,788	$ 149,882	$ 1,228,526
Sequent Energy Management, LP	$ -	$ -	$ -	$ -	$ -	$ -	$ 615,762	$ 620,588	$ 704,724	$ 661,858	$ 476,426	$ -	$ 3,079,357
Sprague Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 37,159	$ 37,159
Tenaska Marketing Ventures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,605	$ 14,622	$ -	$ -	$ 37,227
Tennessee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Texas Eastern Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 59	$ 59
United Energy Trading	$ -	$ -	$ -	$ -	$ -	$ -	$ 28,768	$ 28,768	$ -	$ -	$ -	$ -	$ 57,536
	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,273,080	$ 1,261,680	$ 1,474,565	$ 2,646,032	$ 1,156,277	$ 1,028,495	**$ 8,840,129**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,433,794	$ 2,736,685	$ 1,490,040	$ 1,022,022	$ 517,082	$ 7,199,623
Commodity Cost Reversals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,275,610)	$ (1,433,794)	$ (2,736,685)	$ (1,490,040)	$ (1,022,022)	$ (7,958,151)
Subtotal - Supply	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,273,080	$ 1,419,863	$ 2,777,456	$ 1,399,387	$ 688,259	$ 523,555	**$ 8,081,601**
Withdrawal Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,270,234	$ 4,034,698	$ 4,849,388	$ 3,538,004	$ 2,543,943	$ 962,204	$ 18,198,471
Interruptible Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ (31,164)	$ (7,818)	$ -	$ -	$ -	$ (2,328)	$ (41,310)
Non Traditional Sales	$ (33,079)	$ (15,195)	$ -	$ -	$ -	$ -	$ (13,514)	$ -	$ -	$ -	$ -	$ -	$ (61,788)
Net OBA Adj.	$ -	$ -	$ -	$ -	$ -	$ -	$ (352,941)	$ 122,165	$ (4,092)	$ (11,822)	$ (44,346)	$ (870)	$ (291,906)
Transportation Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,136	$ 3,808	$ 8,821	$ 3,876	$ 3,292	$ 5,982	$ 29,915
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ (8,837)	$ (10,001)	$ (17,760)	$ (18,059)	$ (16,400)	$ (16,782)	$ (87,839)
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,910	$ -	$ 2,023	$ 18	$ 6,905	$ 8,786	$ 21,643
Prior Period Adjustments	$ -	$ -	$ -	$ 273,086	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 273,086
Transportation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 42,521	$ 64,809	$ 34,173	$ 81,200	$ (19,738)	$ (29,546)	$ 173,421
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 244,516	$ 357,301	$ 474,693	$ 580,332	$ 525,569	$ 778,238	$ 2,960,650
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ 548	$ (67,152)	$ (121,986)	$ (263,123)	$ (109,513)	$ (104,739)	$ (665,965)
Inventory Finance Charges	$ 11,905	$ 22,418	$ 30,593	$ 30,166	$ 41,998	$ 59,351	$ 53,246	$ 2,901	$ 3,157	$ 2,254	$ 1,490	$ 624	$ 260,102
Storage Commodity	$ 226	$ 228	$ 232	$ 207	$ (29)	$ (31)	$ 146	$ -	$ -	$ -	$ -	$ -	$ 979
Prior Period Adjustment													
Subtotal - Supply	$ (20,948)	$ 7,451	$ 30,825	$ 303,458	$ 41,969	$ 59,319	$ 2,212,803	$ 4,500,711	$ 5,228,418	$ 3,912,679	$ 2,891,202	$ 1,601,569	**$ 20,769,457**
Total Commodity Costs	**$ (20,948)**	**$ 7,451**	**$ 30,825**	**$ 303,458**	**$ 41,969**	**$ 59,319**	**$ 3,485,883**	**$ 5,920,575**	**$ 8,005,874**	**$ 5,312,066**	**$ 3,579,461**	**$ 2,125,124**	**$ 28,851,058**

(1) May-09 costs reflect April actual costs received in May and changes necessary to revise April estimates to actual costs.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2008-2009 PEAK PERIOD
COST OF GAS ADJUSTMENT RESULTS
November 2008 - April 2009

FORM III
Schedule 4
Page 2 of 2

REV (3-4-10)
Conformed to Current Presentation

WINTER RELATED COSTS INCURRED IN SUMMER '08 DEFERRED TO WINTER 2008-09

	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Total Winter
Pipeline Reservation													
Algonquin	$ 15,967	$ 15,988	$ 16,004	$ 16,076	$ 16,094	$ 16,051	$ 16,064	$ 16,073	$ 16,111	$ 16,029	$ 16,059	$ 16,638	$ 193,155
BG Energy	$ -	$ 285,399	$ -	$ 285,399	$ 285,399	$ 285,399	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,141,596
Granite	$ 62,411	$ 62,460	$ 62,460	$ 62,509	$ 62,595	$ 62,595	$ -	$ -	$ -	$ -	$ -	$ -	$ 375,029
Iroquois	$ 20,612	$ 20,612	$ 20,675	$ 20,790	$ 20,790	$ 20,751	$ 21,076	$ 20,726	$ 20,838	$ 20,703	$ 20,703	$ 21,707	$ 249,981
PNGTS (DEM)	$ 13,905	$ 13,905	$ 13,905	$ 13,905	$ 13,905	$ 13,905	$ 815,844	$ 875,687	$ 875,687	$ 875,687	$ 875,687	$ 875,687	$ 5,277,707
Tennessee Gas (El Paso)	$ 133,142	$ 133,141	$ 133,563	$ 134,286	$ 134,286	$ 134,060	$ 27,997	$ 134,221	$ 134,626	$ 133,751	$ 133,751	$ 140,197	$ 1,507,019
Texas Eastern	$ 3,364	$ 3,364	$ 3,364	$ 3,364	$ 3,364	$ 3,364	$ 3,390	$ 3,390	$ 3,392	$ 3,392	$ 3,395	$ 3,395	$ 40,539
Transcanada (Emera, Sequent, BG Energy)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 280,916	$ 277,083	$ 228,264	$ 227,143	$ 239,223	$ 1,252,628
Vector Limited	$ 1,238	$ 1,238	$ 1,238	$ 1,238	$ 1,238	$ 1,238	$ 1,238	$ 1,220	$ 1,201	$ 1,212	$ 1,152	$ 1,236	$ 14,686
Vector LP	$ 89,971	$ 89,971	$ 89,971	$ 89,971	$ 89,971	$ 89,971	$ 129,055	$ 129,055	$ 129,055	$ 129,055	$ 129,055	$ 129,055	$ 1,314,153
Co-Managed (includes Off System Sales)	$ (5,041)	$ (5,630)	$ (5,484)	$ (5,484)	$ (4,762)	$ (4,762)	$ (5,436)	$ -	$ -	$ -	$ -	$ -	$ (36,600)
Prior Period Adjustment	$ -	$ 313,821	$ 47,125	$ 324,536	$ 31,874	$ 3,178	$ (9,590)	$ -	$ -	$ -	$ -	$ -	$ 710,944
Total Pipeline Reservation	**$ 335,568**	**$ 934,268**	**$ 382,819**	**$ 946,590**	**$ 654,754**	**$ 625,749**	**$ 999,637**	**$ 1,461,288**	**$ 1,457,991**	**$ 1,408,093**	**$ 1,406,944**	**$ 1,427,137**	**$ 12,040,839**
Product Demand													
Granite Demand Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,486	$ 136,351	$ 82,944	$ 82,489	$ 82,637	$ 82,533	$ 470,440
Alberta Northeast Gas Ltd.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,476	$ (5,651)	$ 1,114	$ 1,022	$ 1,453	$ (587)
Distrigas of Massachusetts	$ 103,671	$ 103,671	$ 103,671	$ 103,671	$ 103,671	$ 103,671	$ 105,189	$ 116,012	$ 116,012	$ 116,012	$ 116,012	$ 116,012	$ 1,307,280
FPL/NextEra (formerly Duke)	$ -	$ -	$ -	$ -	$ -	$ -	$ 146,198	$ 146,198	$ 145,555	$ 145,555	$ 146,198	$ 146,198	$ 875,900
NEGM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 358	$ 370	$ 370	$ 335	$ 370	$ 1,804
Prior Period Adjustment	$ -	$ -	$ -	$ 653	$ (653)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Product Demand	**$ 103,671**	**$ 103,671**	**$ 103,671**	**$ 104,325**	**$ 103,018**	**$ 103,671**	**$ 254,873**	**$ 400,395**	**$ 339,230**	**$ 345,540**	**$ 346,204**	**$ 346,566**	**$ 2,654,837**
Storage Pipeline Transportation and Demand Reservation													
Tennessee Gas Pipeline	$ 4,592	$ 4,592	$ 4,609	$ 4,634	$ 4,634	$ 4,626	$ 4,644	$ 4,651	$ 4,138	$ 4,617	$ 4,617	$ 4,847	$ 55,203
Washington 10 (BG Energy)	$ -	$ -	$ 120,585	$ 120,585	$ 120,585	$ 120,585	$ 120,633	$ 120,633	$ 120,633	$ 120,633	$ 120,633	$ 120,633	$ 1,206,142
PNGTS (2)	$ -	$ -	$ -	$ -	$ -	$ (10,436)	$ -	$ -	$ -	$ -	$ -	$ -	$ (10,436)
Texas Eastern	$ 116	$ 116	$ 116	$ 116	$ 116	$ 116	$ 116	$ 87	$ 87	$ 87	$ 87	$ 88	$ 1,245
Company Managed	$ (53,505)	$ (54,834)	$ (47,001)	$ (48,041)	$ (40,243)	$ (40,243)	$ (338,421)	$ (146,347)	$ (177,661)	$ (396,399)	$ (189,803)	$ (158,997)	$ (1,691,495)
Prior Period Adjustment	$ -	$ 120,585	$ 120,585	$ 789	$ (790)	$ (0)	$ (0)	$ -	$ -	$ -	$ -	$ -	$ 241,170
Total Storage and Demand Reservation	**$ (48,798)**	**$ 70,459**	**$ 198,894**	**$ 78,083**	**$ 84,303**	**$ 74,649**	**$ (213,028)**	**$ (20,975)**	**$ (52,802)**	**$ (271,061)**	**$ (64,466)**	**$ (33,429)**	**$ (198,171)**
Demand Cost Estimates							$ -	$ 1,917,907	$ 2,139,331	$ 2,139,331	$ 2,139,331	$ 1,093,496	$ 9,429,396
Demand Cost Reversals							$ -	$ (1,391,444)	$ (1,917,907)	$ (2,139,331)	$ (2,139,331)	$ (2,139,331)	$ (9,727,344)
Total Fixed Demand	**$ 390,442**	**$ 1,108,398**	**$ 685,385**	**$ 1,128,998**	**$ 842,075**	**$ 804,069**	**$ 1,041,482**	**$ 2,367,171**	**$ 1,965,844**	**$ 1,482,572**	**$ 1,688,682**	**$ 694,439**	**$ 14,199,557**
Non-Traditional Sales Margin	$ (3,376)	$ (20,384)	$ (56,371)	$ (54,217)	$ (50,285)	$ (54,240)	$ -	$ -	$ -	$ -	$ -	$ -	$ (238,872)
Interruptible Profits	$ (3,259)	$ (3,364)	$ (2,347)	$ (883)	$ -	$ (4,192)	$ (12,171)	$ (4,237)	$ -	$ -	$ -	$ -	$ (30,454)
Capacity Release	$ (195,033)	$ (144,594)	$ (111,120)	$ (110,039)	$ (110,778)	$ (113,018)	$ 39,454	$ (122,028)	$ (227,160)	$ (233,820)	$ (240,159)	$ (243,285)	$ (1,811,582)
Capacity Mitigation	$ (4,234)	$ (5,126)	$ 178	$ 175	$ 175	$ 175	$ (4,950)	$ (6,305)	$ (6,013)	$ (5,665)	$ (3,796)	$ (11,584)	$ (46,970)
Production and Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 86,999	$ 125,353	$ 148,075	$ 132,440	$ 117,018	$ 76,789	$ 686,674
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,787	$ 16,984	$ 20,062	$ 17,944	$ 15,854	$ 10,404	$ 93,035
Transp. Demand Revenues	$ (6)	$ (7)	$ (2)	$ (7)	$ (6)	$ (7)	$ (6)	$ (6)	$ (6)	$ (6)	$ (6)	$ (6)	$ (70)
Prior Period Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ 118,546	$ -	$ -	$ -	$ -	$ -	$ 118,546
Demand Cost Estimates - Capacity Release							$ -	$ (227,718)	$ (227,075)	$ (227,075)	$ (227,075)	$ (119,782)	$ (1,028,725)
Demand Cost Reversals - Capacity Release							$ -	$ 15,322	$ 227,718	$ 227,075	$ 227,075	$ 227,075	$ 924,265
Total Demand Costs	**$ 184,534**	**$ 934,924**	**$ 515,723**	**$ 964,028**	**$ 681,181**	**$ 632,787**	**$ 1,281,141**	**$ 2,164,536**	**$ 1,901,445**	**$ 1,393,465**	**$ 1,577,592**	**$ 634,050**	**$ 12,865,404**
Demand Costs Transferred to Summer Period	$ 284,274	$ 284,274	$ 284,274	$ 284,274	$ 284,274	$ 284,274	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,705,642
Net Demand Costs For Winter Period	**$ (99,740)**	**$ 650,650**	**$ 231,449**	**$ 679,755**	**$ 396,907**	**$ 348,514**	**$ 1,281,141**	**$ 2,164,536**	**$ 1,901,445**	**$ 1,393,465**	**$ 1,577,592**	**$ 634,050**	**$ 11,159,762**
Total Gas Cost for Winter Period	**$ (120,689)**	**$ 658,101**	**$ 262,275**	**$ 983,213**	**$ 438,876**	**$ 407,833**	**$ 4,767,023**	**$ 8,085,110**	**$ 9,907,318**	**$ 6,705,531**	**$ 5,157,054**	**$ 2,759,174**	**$ 40,010,820**

(1) May-09 costs reflect April actual costs received in May and changes necessary to revise April estimates to actual costs.
(2) Supplier Refund.

Attachment A
REV (3-4-10)
Conformed to Current Presentation

NORTHERN UTILITIES
NEW HAMPSHIRE DIVISION
DEFERRED WINTER PERIOD WORKING CAPITAL
ALLOWANCE ON PURCHASED GAS COSTS
April 30, 2009

WINTER PERIOD - Acct 182.11

	BEGINNING BALANCE(1)	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE(2)	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
MAY 08 (Summer)	10,154	(229)	0.1900%	0	(229)	9,925	10,040	5.00%	(1)	9,924
June	9,924	1,250	0.1900%	0	1,250	11,174	10,549	5.00%	44	11,218
July	11,218	498	0.1900%	0	498	11,717	11,468	5.00%	48	11,764
August	11,764	1,868	0.1900%	0	1,868	13,633	12,698	5.00%	53	13,685
September	13,685	834	0.1900%	0	834	14,519	14,102	5.00%	59	14,578
October	14,578	775	0.1900%	0	775	15,353	14,966	4.56%	57	15,410
November(3)	12,647	3,307	0.0694%	(7,545)	(4,238)	8,410	10,529	4.00%	35	8,445
December	8,445	5,062	0.0626%	(13,034)	(7,973)	472	4,459	3.61%	13	486
January 2009	486	5,584	0.0564%	(15,823)	(10,239)	(9,753)	(4,633)	3.25%	(13)	(9,765)
February	(9,765)	3,779	0.0564%	(12,437)	(8,658)	(18,423)	(14,094)	3.25%	(38)	(18,461)
March	(18,461)	2,907	0.0564%	(11,097)	(8,190)	(26,652)	(22,557)	3.25%	(61)	(26,713)
April	(26,713)	1,555	0.0564%	(5,920)	(4,365)	(31,078)	(28,896)	3.25%	(78)	(31,156)
Totals		27,190		(65,856)					118	

(1) Beginning Balance for May 2008 (Summer) approved in DG 08-115.
(2) Working Capital Allowance Calculated by taking Eligible Gas Costs from Sch 4 and multiplying by Working Capital Percentage through October 2008.
Working Capital Allowance Calculated by taking Eligible Gas Costs from Sch 4 and multiplying by (6.33/365)*Interest Rate for November 2008 and beyond.
(3) November 2008 beginning balance reduced by $2,762.35 to account for transition to accrual accounting as required by Commission Order No. 25,038, dated October 30, 2009 in docket DG 07-033.

Attachment B
REV (3-4-10)
Conformed to Current Presentation

NORTHERN UTILITIES, INC
NEW HAMPSHIRE DIVISION
BAD DEBT EXPENSE
CALCULATION OF COLLECTION ALLOWANCE
April 30, 2009

WINTER PERIOD - Acct 182.16

	BEGINNING BALANCE(1)	BAD DEBT ALLOWANCE	% ALLOWED BAD DEBT(2)	BAD DEBT COLLECTION	DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B = Allowed Gas Cost * C	C	(D)	E = B + (D)	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
May 08 (Summer)	22,157	(544)	0.45%	0	(544)	21,612	21,884	5.00%	0	21,612
June	21,612	2,967	0.45%	0	2,967	24,579	23,096	5.00%	96	24,676
July	24,676	1,182	0.45%	0	1,182	25,858	25,267	5.00%	105	25,963
August	25,963	4,433	0.45%	0	4,433	30,396	28,180	5.00%	117	30,514
September	30,514	1,979	0.45%	0	1,979	32,492	31,503	5.00%	131	32,624
October	32,624	1,839	0.45%	0	1,839	34,462	33,543	4.56%	127	34,590
November(3)	28,202	21,466	0.45%	$ (17,832)	3,634	31,836	30,019	4.00%	100	31,936
December	31,936	36,406	0.45%	$ (30,809)	5,597	37,533	34,735	3.61%	104	37,638
January 2009	37,638	44,608	0.45%	$ (37,399)	7,209	44,847	41,242	3.25%	112	44,959
February	44,959	30,192	0.45%	$ (29,397)	795	45,753	45,356	3.25%	123	45,876
March	45,876	23,220	0.45%	$ (26,230)	(3,010)	42,866	44,371	3.25%	120	42,987
April	42,987	12,423	0.45%	$ (13,994)	(1,570)	41,416	42,201	3.25%	114	41,531
Totals		180,171		(155,660)					1,251	

(1) Beginning Balance for May 2008 (Summer) approved in DG 08-115.
(2) Bad Debt Allowance Calculated by taking Eligible Gas Costs from Sch 4 and Working Capital Allowance on Attachment A and multiplying by Bad Debt %.
(3) November 2008 beginning balance reduced by $6,387.92 to account for transition to accrual accounting as required by Commission Order No. 25,038, dated October 30, 2009 in docket DG 07-033.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2008-09 WINTER PERIOD RECONCILIATION
May 2008 - April 2009

Recalculated Reconciliation

FORM III
Schedule 1
Updated July 2012

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2008-09 WINTER PERIOD RECONCILIATION
SCHEDULE 1: PEAK PERIOD SUMMARY
May 2008 - April 2009

	AMOUNT	
Winter Period Beg. Balance	$ (707,623)	SCHEDULE 2
Less: Reported Collections	$ (37,294,395)	SCHEDULE 3
Less: Reclass Supplier Refund	$ (5,270)	SCHEDULE 2
Add: Cost of Firm Gas Allowable	$ 39,188,770	SCHEDULE 2
Add: Capacity Reserve Charge Rev. from Summer	$ 3,347	SCHEDULE 2
Add: Interest	$ 51,804	SCHEDULE 2
Winter Period Ending Balance	$ 1,236,634	

FORM III
Schedule 2
Updated July 2012

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2008-09 WINTER PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED PEAK PERIOD ACCOUNTS
May 2008 - April 2009
Acct 191.20

WINTER PERIOD	May 2008	June	July	August	September	October	November	December	January 2009	February	March	April	Total
Winter Period Account Beginning Balance	$ (707,623)	$ (825,602)	$ (174,447)	$ 88,209	$ 1,074,115	$ 1,518,856	$ 1,931,971	$ 2,422,024	$ 4,135,159	$ 2,633,564	$ 1,774,490	$ 1,359,497	$ (707,623)
Plus: Cost of Firm Gas (Schedule 4)(1)	$ (120,689)	$ 658,101	$ 262,275	$ 983,213	$ 438,876	$ 407,833	$ 4,767,023	$ 7,884,790	$ 9,561,117	$ 6,493,498	$ 5,102,877	$ 2,749,855	$ 39,188,770
Less: Reported Collections (Schedule 3)(2)	$ -	$ -	$ -	$ -	$ -	$ -	($4,284,156)	($6,181,503)	($11,071,866)	($7,358,533)	($5,522,108)	($2,876,228)	$(37,294,395)
Plus: Capacity Reserve Charge Revenues from Summe	$ 2,955	$ 403	$ 561	$ 277	$ 474	$ (1,264)	$ (58)	$ -	$ -	$ -	$ -	$ -	$ 3,347
Less: Reclass Supplier Refund		$ (5,270)											$ (5,270)
Winter Period Ending Balance	$ (825,357)	$ (172,368)	$ 88,388	$ 1,071,699	$ 1,513,466	$ 1,925,426	$ 2,414,779	$ 4,125,311	$ 2,624,410	$ 1,768,528	$ 1,355,258	$ 1,233,124	$ 1,184,829
Month's Average Balance	$ (766,490)	$ (498,985)	$ (43,029)	$ 579,954	$ 1,293,791	$ 1,722,141	$ 2,173,375	$ 3,273,668	$ 3,379,785	$ 2,201,046	$ 1,564,874	$ 1,296,310	
Interest Rate (Prime Rate)	5.00%	5.00%	5.00%	5.00%	5.00%	4.56%	4.00%	3.61%	3.25%	3.25%	3.25%	3.25%	
Interest Applied	$ (245)	$ (2,079)	$ (179)	$ 2,416	$ 5,391	$ 6,544	$ 7,245	$ 9,848	$ 9,154	$ 5,961	$ 4,238	$ 3,511	$ 51,804
Winter Period Account Ending Balance	$ (825,602)	$ (174,447)	$ 88,209	$ 1,074,115	$ 1,518,856	$ 1,931,971	$ 2,422,024	$ 4,135,159	$ 2,633,564	$ 1,774,490	$ 1,359,497	$ 1,236,635	$ 1,236,634

Explanation of adjustments necessary to change to accrual accounting effective November 1, 2008 in compliance with the Commission's Order No. 25,038

October 2008 Ending Balance	
Winter Period	$1,931,971
Summer Period	$2,032,076
TOTAL (Order 25,038 Pg.4)	$3,964,047
Less October Unbilled Revenue included in November's Summer Revenues	$1,506,169
November 2008 Adjusted Opening Balances	
Winter Period (no adjustment required)	$1,931,971
Summer Period (full $1.5 million adjustment required)	$525,907
TOTAL (Order 25,038 Pg.4)	$2,457,878

(1) May-09 costs reflect April actual costs received in May and changes necessary to revise April estimates to actual costs.
(2) Reported collections for Dec-08 & Jan-09 are corrected figures. This results in a change in reported collections for these two months; however, there is no net impact on total reported collections for the period.

FORM III
Schedule 3

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2008-09 WINTER RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS(1)
November 2008 - April 2009

	November	December(2)	January 2009(2)	February	March	April	Total
Accrued Revenue	$3,079,685	$35,676	$1,605,991	($1,124,470)	($1,020,000)	($1,265,810)	$1,311,072
Billed Revenue	$1,204,471	$6,145,827	$9,465,875	$8,483,003	$6,542,109	$4,142,038	$35,983,322
Calendarized Revenue	**$4,284,156**	**$6,181,503**	**$11,071,866**	**$7,358,533**	**$5,522,108**	**$2,876,228**	**$37,294,395**

(1) Revenue figures reflect the transition to accrual accounting as required by Commission Order No. 25,038, dated October 30, 2009 in docket DG 07-033.

(2) Accrued revenues for Dec-08 & Jan-09 are corrected figures. This results in a change in accrued and calendarized revenues for these two months; however, there is no net impact on total revenues for the period.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2008-2009 PEAK PERIOD
COST OF GAS ADJUSTMENT RESULTS
May 2008 - April 2009

FORM III
Schedule 4
Page 1 of 2

Updated July 2012

WINTER RELATED COSTS INCURRED IN SUMMER '08 DEFERRED TO WINTER 2008-0

	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Total
Commodity Costs:													
Alberta Northeast Gas Limited	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,566	$ -	$ -	$ -	$ -	$ -	**$ 2,566**
BP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 49,715	$ 85,483	$ -	$ 95,702	**$ 230,900**
BG Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,380	$ 24,622	$ 20,917	$ (2,591)	$ 27,495	**$ 83,823**
Colonial Energy Inc	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,292	$ 24,292	$ -	$ -	$ -	$ -	**$ 48,585**
Conoco Phillips	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 933,489	$ 317,180	$ 387,314	**$ 1,637,983**
Distrigas of Mass	$ -	$ -	$ -	$ -	$ -	$ -	$ 257,063	$ 257,015	$ 176,305	$ 423,491	$ 42,799	$ 20,393	**$ 1,177,065**
Emera Canada	$ -	$ -	$ -	$ -	$ -	$ -	$ 122,083	$ 100,634	$ 172,273	$ 131,731	$ 83,821	$ 213,671	**$ 824,213**
FedEx Trade	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,174						**$ 5,174**
FPL/NextEra	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 78,895	$ 141,386	$ 72,854	$ 96,820	**$ 389,955**
Integrys	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Northeast Gas Marketing	$ -	$ -	$ -	$ -	$ -	$ -	$ 217,372	$ 217,002	$ 245,426	$ 233,055	$ 165,788	$ 149,882	**$ 1,228,526**
Sequent Energy Management, LP	$ -	$ -	$ -	$ -	$ -	$ -	$ 615,762	$ 620,588	$ 704,724	$ 661,858	$ 476,426	$ -	**$ 3,079,357**
Sprague Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 37,159	**$ 37,159**
Tenaska Marketing Ventures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,605	$ 14,622	$ -	$ -	**$ 37,227**
Tennessee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Texas Eastern Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 59	**$ 59**
United Energy Trading	$ -	$ -	$ -	$ -	$ -	$ -	$ 28,768	$ 28,768	$ -	$ -	$ -	$ -	**$ 57,536**
Subtotal	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,273,080	$ 1,261,680	$ 1,474,565	$ 2,646,032	$ 1,156,277	$ 1,028,495	**$ 8,840,129**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,433,794	$ 2,736,685	$ 1,490,040	$ 1,022,022	$ 517,082	**$ 7,199,623**
Commodity Cost Reversals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,275,610)	$ (1,433,794)	$ (2,736,685)	$ (1,490,040)	$ (1,022,022)	**$ (7,958,151)**
Subtotal - Supply	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,273,080	$ 1,419,863	$ 2,777,456	$ 1,399,387	$ 688,259	$ 523,555	**$ 8,081,601**
Withdrawal Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,270,234	$ 4,034,698	$ 4,849,388	$ 3,538,004	$ 2,543,943	$ 962,204	**$ 18,198,471**
Interruptible Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ (31,164)	$ (7,818)	$ -	$ -	$ -	$ (2,328)	**$ (41,310)**
Non Traditional Sales	$ (33,079)	$ (15,195)	$ -	$ -	$ -	$ -	$ (13,514)	$ -	$ -	$ -	$ -	$ -	**$ (61,788)**
Net OBA Adj.	$ -	$ -	$ -	$ -	$ -	$ -	$ (352,941)	$ 122,165	$ (4,092)	$ (11,822)	$ (44,346)	$ (870)	**$ (291,906)**
Transportation Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,136	$ 3,808	$ 8,821	$ 3,876	$ 3,292	$ 5,982	**$ 29,915**
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ (8,837)	$ (10,001)	$ (17,760)	$ (18,059)	$ (16,400)	$ (16,782)	**$ (87,839)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,910	$ -	$ 2,023	$ 18	$ 6,905	$ 8,786	**$ 21,643**
Prior Period Adjustments	$ -	$ -	$ -	$ 273,086	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 273,086**
Transportation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 42,521	$ 64,809	$ 34,173	$ 81,200	$ (19,738)	$ (29,546)	**$ 173,421**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 244,516	$ 357,301	$ 474,693	$ 580,332	$ 525,569	$ 778,238	**$ 2,960,650**
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ 548	$ (67,152)	$ (121,986)	$ (263,123)	$ (109,513)	$ (104,739)	**$ (665,965)**
Inventory Finance Charges	$ 11,905	$ 22,418	$ 30,593	$ 30,166	$ 41,998	$ 59,351	$ 53,246	$ 2,901	$ 3,157	$ 2,254	$ 1,490	$ 624	**$ 260,102**
Storage Commodity	$ 226	$ 228	$ 232	$ 207	$ (29)	$ (31)	$ 146	$ -	$ -	$ -	$ -	$ -	**$ 979**
Allocation Adjustments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (200,320)	$ (346,202)	$ (212,033)	$ (54,176)	$ (9,319)	**$ (822,050)**
Subtotal - Supply	$ (20,948)	$ 7,451	$ 30,825	$ 303,458	$ 41,969	$ 59,319	$ 2,212,803	$ 4,300,391	$ 4,882,216	$ 3,700,646	$ 2,837,026	$ 1,592,250	**$ 19,947,407**
Total Commodity Costs	**$ (20,948)**	**$ 7,451**	**$ 30,825**	**$ 303,458**	**$ 41,969**	**$ 59,319**	**$ 3,485,883**	**$ 5,720,254**	**$ 7,659,672**	**$ 5,100,033**	**$ 3,525,285**	**$ 2,115,805**	**$ 28,029,008**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2008-2009 PEAK PERIOD
COST OF GAS ADJUSTMENT RESULTS
May 2008 - April 2009

FORM III
Schedule 4
Page 2 of 2

Updated July 2012

WINTER RELATED COSTS INCURRED IN SUMMER '08 DEFERRED TO WINTER 2008-0

	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Total
Pipeline Reservation													
Algonquin	$ 15,967	$ 15,988	$ 16,004	$ 16,076	$ 16,094	$ 16,051	$ 16,064	$ 16,073	$ 16,111	$ 16,029	$ 16,059	$ 16,638	**$ 193,155**
BG Energy	$ -	$ 285,399	$ -	$ 285,399	$ 285,399	$ 285,399	$ -	$ -	$ -	$ -	$ -	$ -	**$ 1,141,596**
Granite	$ 62,411	$ 62,460	$ 62,460	$ 62,509	$ 62,595	$ 62,595	$ -	$ -	$ -	$ -	$ -	$ -	**$ 375,029**
Iroquois	$ 20,612	$ 20,612	$ 20,675	$ 20,790	$ 20,790	$ 20,751	$ 21,076	$ 20,726	$ 20,838	$ 20,703	$ 20,703	$ 21,707	**$ 249,981**
PNGTS (DEM)	$ 13,905	$ 13,905	$ 13,905	$ 13,905	$ 13,905	$ 13,905	$ 815,844	$ 875,687	$ 875,687	$ 875,687	$ 875,687	$ 875,687	**$ 5,277,707**
Tennessee Gas (El Paso)	$ 133,142	$ 133,141	$ 133,563	$ 134,286	$ 134,286	$ 134,060	$ 27,997	$ 134,221	$ 134,626	$ 133,751	$ 133,751	$ 140,197	**$ 1,507,019**
Texas Eastern	$ 3,364	$ 3,364	$ 3,364	$ 3,364	$ 3,364	$ 3,364	$ 3,390	$ 3,390	$ 3,392	$ 3,392	$ 3,395	$ 3,395	**$ 40,539**
Transcanada (Emera, Sequent, BG Energy)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 280,916	$ 277,083	$ 228,264	$ 227,143	$ 239,223	**$ 1,252,628**
Vector Limited	$ 1,238	$ 1,238	$ 1,238	$ 1,238	$ 1,238	$ 1,238	$ 1,238	$ 1,220	$ 1,201	$ 1,212	$ 1,152	$ 1,236	**$ 14,686**
Vector LP	$ 89,971	$ 89,971	$ 89,971	$ 89,971	$ 89,971	$ 89,971	$ 129,055	$ 129,055	$ 129,055	$ 129,055	$ 129,055	$ 129,055	**$ 1,314,153**
Co-Managed (includes Off System Sales)	$ (5,041)	$ (5,630)	$ (5,484)	$ (5,484)	$ (4,762)	$ (4,762)	$ (5,436)	$ -	$ -	$ -	$ -	$ -	**$ (36,600)**
Prior Period Adjustment	$ -	$ 313,821	$ 47,125	$ 324,536	$ 31,874	$ 3,178	$ (9,590)	$ -	$ -	$ -	$ -	$ -	**$ 710,944**
Total Pipeline Reservation	**$ 335,568**	**$ 934,268**	**$ 382,819**	**$ 946,590**	**$ 654,754**	**$ 625,749**	**$ 999,637**	**$ 1,461,288**	**$ 1,457,991**	**$ 1,408,093**	**$ 1,406,944**	**$ 1,427,137**	**$ 12,040,839**
Product Demand													
Granite Demand Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,486	$ 136,351	$ 82,944	$ 82,489	$ 82,637	$ 82,533	**$ 470,440**
Alberta Northeast Gas Ltd.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,476	$ (5,651)	$ 1,114	$ 1,022	$ 1,453	**$ (587)**
Distrigas of Massachusetts	$ 103,671	$ 103,671	$ 103,671	$ 103,671	$ 103,671	$ 103,671	$ 105,189	$ 116,012	$ 116,012	$ 116,012	$ 116,012	$ 116,012	**$ 1,307,280**
FPL/NextEra (formerly Duke)	$ -	$ -	$ -	$ -	$ -	$ -	$ 146,198	$ 146,198	$ 145,555	$ 145,555	$ 146,198	$ 146,198	**$ 875,900**
NEGM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 358	$ 370	$ 370	$ 335	$ 370	**$ 1,804**
Prior Period Adjustment	$ -	$ -	$ -	$ 653	$ (653)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Total Product Demand	**$ 103,671**	**$ 103,671**	**$ 103,671**	**$ 104,325**	**$ 103,018**	**$ 103,671**	**$ 254,873**	**$ 400,395**	**$ 339,230**	**$ 345,540**	**$ 346,204**	**$ 346,566**	**$ 2,654,837**
Storage Pipeline Transportation and Demand Reservation													
Tennessee Gas Pipeline	$ 4,592	$ 4,592	$ 4,609	$ 4,634	$ 4,634	$ 4,626	$ 4,644	$ 4,651	$ 4,138	$ 4,617	$ 4,617	$ 4,847	**$ 55,203**
Washington 10 (BG Energy)	$ -	$ -	$ 120,585	$ 120,585	$ 120,585	$ 120,585	$ 120,633	$ 120,633	$ 120,633	$ 120,633	$ 120,633	$ 120,633	**$ 1,206,142**
PNGTS (2)	$ -	$ -	$ -	$ -	$ -	$ (10,436)	$ -	$ -	$ -	$ -	$ -	$ -	**$ (10,436)**
Texas Eastern	$ 116	$ 116	$ 116	$ 116	$ 116	$ 116	$ 116	$ 87	$ 87	$ 87	$ 87	$ 88	**$ 1,245**
Company Managed	$ (53,505)	$ (54,834)	$ (47,001)	$ (48,041)	$ (40,243)	$ (40,243)	$ (338,421)	$ (146,347)	$ (177,661)	$ (396,399)	$ (189,803)	$ (158,997)	**$ (1,691,495)**
Prior Period Adjustment	$ -	$ 120,585	$ 120,585	$ 789	$ (790)	$ (0)	$ (0)	$ -	$ -	$ -	$ -	$ -	**$ 241,170**
Total Storage and Demand Reservation	**$ (48,798)**	**$ 70,459**	**$ 198,894**	**$ 78,083**	**$ 84,303**	**$ 74,649**	**$ (213,028)**	**$ (20,975)**	**$ (52,802)**	**$ (271,061)**	**$ (64,466)**	**$ (33,429)**	**$ (198,171)**
Demand Cost Estimates							$ -	$ 1,917,907	$ 2,139,331	$ 2,139,331	$ 2,139,331	$ 1,093,496	**$ 9,429,396**
Demand Cost Reversals							$ -	$ (1,391,444)	$ (1,917,907)	$ (2,139,331)	$ (2,139,331)	$ (2,139,331)	**$ (9,727,344)**
Total Fixed Demand	**$ 390,442**	**$ 1,108,398**	**$ 685,385**	**$ 1,128,998**	**$ 842,075**	**$ 804,069**	**$ 1,041,482**	**$ 2,367,171**	**$ 1,965,844**	**$ 1,482,572**	**$ 1,688,682**	**$ 694,439**	**$ 14,199,557**
Non-Traditional Sales Margin	$ (3,376)	$ (20,384)	$ (56,371)	$ (54,217)	$ (50,285)	$ (54,240)	$ -	$ -	$ -	$ -	$ -	$ -	**$ (238,872)**
Interruptible Profits	$ (3,259)	$ (3,364)	$ (2,347)	$ (883)	$ -	$ (4,192)	$ (12,171)	$ (4,237)	$ -	$ -	$ -	$ -	**$ (30,454)**
Capacity Release	$ (195,033)	$ (144,594)	$ (111,120)	$ (110,039)	$ (110,778)	$ (113,018)	$ 39,454	$ (122,028)	$ (227,160)	$ (233,820)	$ (240,159)	$ (243,285)	**$ (1,811,582)**
Capacity Mitigation	$ (4,234)	$ (5,126)	$ 178	$ 175	$ 175	$ 175	$ (4,950)	$ (6,305)	$ (6,013)	$ (5,665)	$ (3,796)	$ (11,584)	**$ (46,970)**
Production and Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 86,999	$ 125,353	$ 148,075	$ 132,440	$ 117,018	$ 76,789	**$ 686,674**
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,787	$ 16,984	$ 20,062	$ 17,944	$ 15,854	$ 10,404	**$ 93,035**
Transp. Demand Revenues	$ (6)	$ (7)	$ (2)	$ (7)	$ (6)	$ (7)	$ (6)	$ (6)	$ (6)	$ (6)	$ (6)	$ (6)	**$ (70)**
Prior Period Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ 118,546	$ -	$ -	$ -	$ -	$ -	**$ 118,546**
Demand Cost Estimates - Capacity Release							$ -	$ (227,718)	$ (227,075)	$ (227,075)	$ (227,075)	$ (119,782)	**$ (1,028,725)**
Demand Cost Reversals - Capacity Release							$ -	$ 15,322	$ 227,718	$ 227,075	$ 227,075	$ 227,075	**$ 924,265**
Total Demand Costs	**$ 184,534**	**$ 934,924**	**$ 515,723**	**$ 964,028**	**$ 681,181**	**$ 632,787**	**$ 1,281,141**	**$ 2,164,536**	**$ 1,901,445**	**$ 1,393,465**	**$ 1,577,592**	**$ 634,050**	**$ 12,865,404**
Demand Costs Transferred to Summer Peri	$ 284,274	$ 284,274	$ 284,274	$ 284,274	$ 284,274	$ 284,274	$ -	$ -	$ -	$ -	$ -	$ -	**$ 1,705,642**
Net Demand Costs For Winter Period	**$ (99,740)**	**$ 650,650**	**$ 231,449**	**$ 679,755**	**$ 396,907**	**$ 348,514**	**$ 1,281,141**	**$ 2,164,536**	**$ 1,901,445**	**$ 1,393,465**	**$ 1,577,592**	**$ 634,050**	**$ 11,159,762**
Total Gas Cost for Winter Period	**$ (120,689)**	**$ 658,101**	**$ 262,275**	**$ 983,213**	**$ 438,876**	**$ 407,833**	**$ 4,767,023**	**$ 7,884,790**	**$ 9,561,117**	**$ 6,493,498**	**$ 5,102,877**	**$ 2,749,855**	**$ 39,188,770**

(2) Supplier Refund.

Attachment A
Updated July 2012

NORTHERN UTILITIES
NEW HAMPSHIRE DIVISION
DEFERRED WINTER PERIOD WORKING CAPITAL
ALLOWANCE ON PURCHASED GAS COSTS
May 2008 - April 2009

WINTER PERIOD - Acct 182.11

	BEGINNING BALANCE(1)	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE(2)	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
May 08 (Summer)	10,154	(229)	0.1900%	0	(229)	9,925	10,040	5.00%	(1)	9,924
June	9,924	1,250	0.1900%	0	1,250	11,174	10,549	5.00%	44	11,218
July	11,218	498	0.1900%	0	498	11,717	11,468	5.00%	48	11,764
August	11,764	1,868	0.1900%	0	1,868	13,633	12,698	5.00%	53	13,685
September	13,685	834	0.1900%	0	834	14,519	14,102	5.00%	59	14,578
October	14,578	775	0.1900%	0	775	15,353	14,966	4.56%	57	15,410
November(3)	12,647	3,307	0.0694%	(7,545)	(4,238)	8,410	10,529	4.00%	35	8,445
December	8,445	4,936	0.0626%	(13,034)	(8,098)	347	4,396	3.61%	13	360
January 2009	360	5,389	0.0564%	(15,823)	(10,434)	(10,073)	(4,857)	3.25%	(13)	(10,087)
February	(10,087)	3,660	0.0564%	(12,437)	(8,777)	(18,864)	(14,475)	3.25%	(39)	(18,903)
March	(18,903)	2,876	0.0564%	(11,097)	(8,221)	(27,124)	(23,014)	3.25%	(62)	(27,187)
April	(27,187)	1,550	0.0564%	(5,920)	(4,370)	(31,557)	(29,372)	3.25%	(80)	(31,637)
Totals		26,714		(65,856)					113	

(1) Beginning Balance for May 2008 (Summer) approved in DG 08-115.
(2) Working Capital Allowance Calculated by taking Eligible Gas Costs from Sch 4 and multiplying by Working Capital Percentage through October 2008.
Working Capital Allowance Calculated by taking Eligible Gas Costs from Sch 4 and multiplying by (6.33/365)*Interest Rate for November 2008 and beyond.
(3) November 2008 beginning balance reduced by $2,762.35 to account for transition to accrual accounting as required by Commission Order No. 25,038, dated October 30, 2009 in docket DG 07-033.

Attachment B
Updated July 2012

NORTHERN UTILITIES, INC
NEW HAMPSHIRE DIVISION
BAD DEBT EXPENSE
CALCULATION OF COLLECTION ALLOWANCE
May 2008 - April 2009

WINTER PERIOD - Acct 182.16

	BEGINNING BALANCE(1)	BAD DEBT ALLOWANCE	% ALLOWED BAD DEBT(2)	BAD DEBT COLLECTION	DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B = Allowed Gas Cost * C	C	(D)	E = B + (D)	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
May 08 (Summer)	22,157	(544)	0.45%	0	(544)	21,612	21,884	5.00%	0	21,612
June	21,612	2,967	0.45%	0	2,967	24,579	23,096	5.00%	96	24,676
July	24,676	1,182	0.45%	0	1,182	25,858	25,267	5.00%	105	25,963
August	25,963	4,433	0.45%	0	4,433	30,396	28,180	5.00%	117	30,514
September	30,514	1,979	0.45%	0	1,979	32,492	31,503	5.00%	131	32,624
October	32,624	1,839	0.45%	0	1,839	34,462	33,543	4.56%	127	34,590
November(3)	28,202	21,466	0.45%	$ (17,832)	3,634	31,836	30,019	4.00%	100	31,936
December	31,936	35,504	0.45%	$ (30,809)	4,695	36,631	34,284	3.61%	103	36,734
January 2009	36,734	43,049	0.45%	$ (37,399)	5,650	42,385	39,560	3.25%	107	42,492
February	42,492	29,237	0.45%	$ (29,397)	(160)	42,332	42,412	3.25%	115	42,447
March	42,447	22,976	0.45%	$ (26,230)	(3,254)	39,193	40,820	3.25%	111	39,304
April	39,304	12,381	0.45%	$ (13,994)	(1,612)	37,691	38,498	3.25%	104	37,796
Totals		176,470		(155,660)					1,218	

(1) Beginning Balance for May 2008 (Summer) approved in DG 08-115.
(2) Bad Debt Allowance Calculated by taking Eligible Gas Costs from Sch 4 and Working Capital Allowance on Attachment A and multiplying by Bad Debt %.
(3) November 2008 beginning balance reduced by $6,387.92 to account for transition to accrual accounting as required by Commission Order No. 25,038, dated October 30, 2009 in docket DG 07-033.

Schedule 3

New Hampshire Division
Original and Revised 2009-2010 Winter Period Reconciliation

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009-10 WINTER PERIOD RECONCILIATION
May 2009 - April 2010

Original Reconciliation

FORM III
Schedule 1
Conformed to Current Presentation

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009-2010 WINTER PERIOD RECONCILIATION
SCHEDULE 1: SUMMARY OF WINTER PERIOD BALANCE
November 2009 - April 2010

	AMOUNT	
Winter Period Beg. Balance	$2,066,132	SCHEDULE 2
Less: Reported Collections	($26,807,090)	SCHEDULE 2
Less: Billing Adjustment	$0	SCHEDULE 2
Add: Cost of Firm Gas Allowable	$27,157,741	SCHEDULE 4
Add: Interest	$110,619	SCHEDULE 2
Winter Period Ending Balance	$2,527,403	

FORM III
Schedule 2
Conformed to Current Presentation

NORTHERN UTILTIES, INC. - NEW HAMPSHIRE DIVISION
2009-10 WINTER PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED SUMMER PERIOD ACCOUNTS
May 2009 - April 2010
Acct 191.10

	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
WINTER PERIOD													
Winter Period Account Beginning Balance(1)	$ 2,066,132	$ 2,464,908	$ 2,959,005	$ 3,165,364	$ 3,634,791	$ 4,213,161	$ 4,557,492	$ 5,394,761	$ 5,457,786	$ 3,076,566	$ 1,876,431	$ 1,802,212	$ 2,066,132
Plus: Cost of Firm Gas (Schedule 4)	$ 324,218	$ 499,289	$ 202,141	$ 463,098	$ 583,812	$ 340,706	$ 3,461,034	$ 5,515,279	$ 5,103,627	$ 4,387,573	$ 3,966,842	$ 2,310,122	$ 27,157,741
Less: Reported Collections (Schedule 3)	$ 68,430	$ (12,527)	$ (4,064)	$ (2,866)	$ (16,056)	$ (8,236)	$ (2,637,223)	$ (5,466,931)	$ (7,496,388)	$ (5,594,406)	$ (4,046,036)	$ (1,590,786)	$ (26,807,090)
Less: Billing Adjustment													
Winter Period Account Ending Balance	$ 2,458,780	$ 2,951,670	$ 3,157,082	$ 3,625,595	$ 4,202,548	$ 4,545,631	$ 5,381,302	$ 5,443,109	$ 3,065,025	$ 1,869,733	$ 1,797,237	$ 2,521,548	$ 2,416,784
Month's Average Balance	$ 2,262,456	$ 2,708,289	$ 3,058,043	$ 3,395,480	$ 3,918,669	$ 4,379,396	$ 4,969,397	$ 5,418,935	$ 4,261,405	$ 2,473,149	$ 1,836,834	$ 2,161,880	
Interest Rate (Prime Rate)	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
Interest Applied	$ 6,127	$ 7,335	$ 8,282	$ 9,196	$ 10,613	$ 11,861	$ 13,459	$ 14,676	$ 11,541	$ 6,698	$ 4,975	$ 5,855	$ 110,619
Winter Period Account Ending Balance w/int	$ 2,464,908	$ 2,959,005	$ 3,165,364	$ 3,634,791	$ 4,213,161	$ 4,557,492	$ 5,394,761	$ 5,457,786	$ 3,076,566	$ 1,876,431	$ 1,802,212	$ 2,527,403	$ 2,527,403

(1) Beginning balance for May-09 from Revised 2008-09 Winter Period Cost of Gas Adjustment Reconciliation in docket DG 08-115, dated March 4, 2009.

FORM III
Schedule 3
Conformed to Current Presentation

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009-10 WINTER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS(1)
May 2009 - April 2010

	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
Accrued Revenue	$ (1,311,072)						$ 1,671,036	$ 1,496,137	$ 140,433	$ (343,134)	$ (716,828)	$ (1,425,408)	$ (488,835)
Billed Revenue	$ 1,242,642	$ 12,527	$ 4,064	$ 2,866	$ 16,056	$ 8,236	$ 966,188	$ 3,970,794	$ 7,355,955	$ 5,937,540	$ 4,762,863	$ 3,016,194	$ 27,295,925
Calendarized Revenue	**$ (68,430)**	**$ 12,527**	**$ 4,064**	**$ 2,866**	**$ 16,056**	**$ 8,236**	**$ 2,637,223**	**$ 5,466,931**	**$ 7,496,388**	**$ 5,594,406**	**$ 4,046,036**	**$ 1,590,786**	**$ 26,807,090**

(1) Revenue figures reflect the transition to accrual accounting as required by Commission Order No. 25,038, dated October 30, 2009 in DG 07-033.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009-10 WINTER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO WINTER PERIOD
May 2009 - April 2010

Conformed to Current Presentation

Commodity Costs:	**May-09 (Actual)**	**Jun-09 (Actual)**	**Jul-09 (Actual)**	**Aug-09 (Actual)**	**Sep-09 (Actual)**	**Oct-09 (Actual)**	**Nov-09 (Actual)**	**Dec-09 (Actual)**	**Jan-10 (Actual)**	**Feb-10 (Actual)**	**Mar-10 (Actual)**	**Apr-10 (Actual)**	**Total Winter**
BG Energy	$ 34,182	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,662	$ -	$ -	$ 31,403	**$ 74,248**
Boss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,928	$ -	$ -	$ -	**$ 12,928**
BP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 52,755	$ 615,705	$ 1,520,629	$ 823,812	$ -	**$ 3,012,900**
Classic	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 92	$ -	$ -	**$ 92**
Distrigas of Mass	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 100,357	$ 251,243	$ 327,297	$ 299,197	$ 333,212	**$ 1,311,307**
DTE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 398,780	$ -	$ -	$ -	$ -	**$ 398,780**
Emera Energy	$ 67,194	$ -	$ -	$ -	$ -	$ -	$ -	$ 120,652	$ 149,959	$ 114,759	$ 117,063	$ 101,123	**$ 670,750**
FPL/NextEra	$ 62,478	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,130	$ -	$ -	$ -	**$ 72,608**
Iberdrola	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 760,290	$ 726,122	$ 628,066	$ -	**$ 2,114,478**
Integrys	$ 5,032	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 5,032**
J. P. Morgan	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,705	$ -	$ -	$ -	$ -	**$ 12,705**
Louis Dreyfus Electric Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,243	$ -	**$ 7,243**
Macquarie Cook Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,042,914	$ 9,657	$ -	$ -	**$ 1,052,571**
National Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Northeast Gas Marketing	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 180,861	$ 205,686	$ 269,427	$ 222,108	$ -	**$ 878,081**
Sequent Energy Management, LP	$ 394,997	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,970	$ -	$ -	$ -	$ -	**$ 398,967**
South Jersey	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 214,587	$ -	$ -	$ -	$ -	**$ 214,587**
Spark	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,004	$ -	$ -	$ -	**$ 13,004**
Sprague Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 38,977	$ -	**$ 38,977**
Tennessee	$ 885	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,333	$ 7,809	$ 7,964	$ 25,260	$ 12,304	**$ 61,555**
Subtotal	$ 564,769	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,092,000	$ 3,078,330	$ 2,975,947	$ 2,161,725	$ 478,042	**$ 10,350,813**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,080,518	$ 2,970,078	$ 2,999,574	$ 2,210,204	$ 472,450	$ 908,200	**$ 10,641,024**
Commodity Cost Reversals	$ (517,082)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,080,518)	$ (2,970,078)	$ (2,999,574)	$ (2,210,204)	$ (472,450)	**$ (10,249,907)**
Subtotal	$ 47,686	$ -	$ -	$ -	$ -	$ -	$ 1,080,518	$ 2,981,560	$ 3,107,825	$ 2,186,577	$ 423,971	$ 913,792	**$ 10,741,931**
Withdrawal Charges	$ 108	$ 2,801	$ 2,273	$ 3,064	$ -	$ 4,088	$ 5,007	$ 100,799	$ 1,171,362	$ 1,644,641	$ 1,125,338	$ 10,539	**$ 4,070,020**
Interruptible Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,649	$ -	$ -	$ -	**$ 7,649**
Non Traditional Sales	$ (58,807)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (71,930)	$ (958,751)	$ (1,694,948)	$ -	**$ (2,784,436)**
Net OBA Adj	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,022	$ 13,478	$ 7,907	$ (4,850)	$ (3,845)	$ (81)	**$ 21,632**
Company Managed	$ -	$ -	$ (8,779)	$ -	$ -	$ -	$ -	$ (13,437)	$ (283,247)	$ (273,692)	$ (235,583)	$ (243,681)	**$ (1,058,418)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,706	$ -	$ -	$ -	$ -	$ -	**$ 3,706**
Transportation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 101,847	$ 593,753	$ 834,653	$ 703,532	$ 500,280	$ 278,881	**$ 3,012,946**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 391,680	$ 497,797	$ 359,604	$ 415,832	$ 551,773	$ 668,016	**$ 2,884,703**
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Inventory Finance Charges	$ 512	$ 431	$ 514	$ 815	$ 898	$ 938	$ 1,088	$ 1,130	$ 920	$ 556	$ 302	$ 209	**$ 8,312**
Prior Period Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Subtotal	$ (58,187)	$ 3,231	$ (5,991)	$ 3,879	$ 898	$ 5,027	$ 512,351	$ 1,193,520	$ 2,026,918	$ 1,527,268	$ 243,317	$ 713,885	**$ 6,166,115**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,243,562)	$ (1,932,442)	$ (243,681)	$ (400,495)	**$ (3,820,180)**
Commodity Cost Reversals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,243,562	$ 1,932,442	$ 243,681	**$ 3,419,685**
Subtotal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,243,562)	$ (688,880)	$ 1,688,761	$ (156,814)	**$ (400,495)**
Total Commodity Costs	**$ (10,501)**	**$ 3,231**	**$ (5,991)**	**$ 3,879**	**$ 898**	**$ 5,027**	**$ 1,592,869**	**$ 4,175,080**	**$ 3,891,181**	**$ 3,024,966**	**$ 2,356,050**	**$ 1,470,863**	**$ 16,507,551**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009-10 WINTER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO WINTER PERIOD
May 2009 - April 2010

Conformed to Current Presentation

Demand Costs	May-09 (Actual)	Jun-09 (Actual)	Jul-09 (Actual)	Aug-09 (Actual)	Sep-09 (Actual)	Oct-09 (Actual)	Nov-09 (Actual)	Dec-09 (Actual)	Jan-10 (Actual)	Feb-10 (Actual)	Mar-10 (Actual)	Apr-10 (Actual)	Total Winter
Pipeline Reservation													
Algonquin	$ 16,627	$ 16,583	$ 16,641	$ 16,673	$ -	$ 33,316	$ 16,671	$ 15,722	$ 15,767	$ 15,767	$ 15,767	$ 15,767	**$ 195,302**
BG Energy	$ 204,893	$ 211,309	$ 213,511	$ 217,940	$ 221,483	$ 233,893	$ 228,130	$ 213,086	$ 221,372	$ 305,309	$ 312,580	$ 319,133	**$ 2,902,641**
Granite	$ 82,533	$ 82,533	$ 82,533	$ 82,533	$ 82,533	$ 82,628	$ 78,289	$ 78,375	$ 78,375	$ 78,375	$ 78,400	$ 78,400	**$ 965,504**
Emera	$ 20,421	$ 19,920	$ 21,221	$ 21,340	$ 21,170	$ 21,484	$ 21,734	$ 20,850	$ 20,664	$ 29,988	$ 36,680	$ 31,506	**$ 286,978**
Iberdrola	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 48,939	$ 30,801	$ 33,994	$ 34,571	**$ 148,305**
Iroquois	$ 21,707	$ 21,707	$ 21,707	$ 21,707	$ 21,707	$ 21,707	$ 21,707	$ 20,567	$ 20,567	$ 20,567	$ 20,567	$ 20,567	**$ 254,787**
J.P. Morgan	$ -	$ -	$ -	$ -	$ -	$ -	$ 128,153	$ -	$ -	$ -	$ -	$ -	**$ 128,153**
PNGTS (DEM)	$ 15,098	$ 15,098	$ 15,098	$ 15,098	$ 15,098	$ 15,098	$ 15,098	$ 829,709	$ 829,709	$ 829,709	$ 829,709	$ 829,709	**$ 4,254,230**
Sequent	$ 22,226	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 22,226**
Spectra	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,014	$ -	$ -	$ -	$ -	$ -	**$ 17,014**
Tennessee Gas (El Paso)	$ 140,197	$ 140,197	$ 137,622	$ 137,622	$ 135,736	$ 137,622	$ 137,622	$ 46,404	$ 130,396	$ 130,396	$ 130,396	$ 102,900	**$ 1,507,107**
Texas Eastern	$ 3,395	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,707	$ 6,497	$ -	**$ 19,598**
Vector LP	$ 91,274	$ 91,322	$ 91,340	$ 91,357	$ 91,204	$ 91,654	$ 91,421	$ 123,617	$ 123,656	$ 122,705	$ 122,755	$ 122,777	**$ 1,255,083**
Co-Managed (includes Off System Sales)	$ (5,524)	$ (5,631)	$ (5,587)	$ -	$ (11,527)	$ -	$ (10,551)	$ -	$ -	$ (229,041)	$ -	$ -	**$ (267,860)**
Prior Period Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Total Pipeline Reservation	$ 612,846	$ 593,037	$ 594,086	$ 604,269	$ 577,405	$ 637,401	$ 745,288	$ 1,348,331	$ 1,489,445	$ 1,344,283	$ 1,587,346	$ 1,555,330	**$ 11,689,068**
Product Demand													
Alberta Northeast Gas Ltd.	$ 1,147	$ 1,155	$ 1,223	$ 1,672	$ 1,189	$ 1,146	$ 1,283	$ 1,235	$ 1,067	$ 1,044	$ 1,089	$ 1,066	**$ 14,316**
Distrigas of Massachusetts	$ 116,012	$ 116,012	$ 116,012	$ 116,012	$ 116,012	$ 116,012	$ 116,012	$ 99,140	$ 99,140	$ 99,140	$ 99,140	$ 99,140	**$ 1,307,786**
FPL/NextEra	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 162,997	$ 162,997	$ 162,997	$ 162,997	$ 162,997	**$ 814,983**
NEGM	$ 358	$ 370	$ 358	$ 370	$ 370	$ 358	$ 370	$ 340	$ 351	$ 351	$ 317	$ 351	**$ 4,266**
LNG used to vaporize	$ (39,958)	$ (43,633)	$ -	$ -	$ -	$ (44,082)	$ (45,029)	$ -	$ -	$ -	$ -	$ -	**$ (172,702)**
Prior Period Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Total Product Demand	$ 77,560	$ 73,905	$ 117,594	$ 118,055	$ 117,572	$ 73,435	$ 72,636	$ 263,711	$ 263,554	$ 263,531	$ 263,542	$ 263,553	**$ 1,968,648**
Storage Pipeline Transportation and Demand Reservation													
Spectra	$ -	$ -	$ -	$ -	$ -	$ -	$ 435	$ -	$ -	$ -	$ -	$ -	**$ 435**
Tennessee Gas Pipeline	$ 4,632	$ 4,632	$ 4,632	$ 4,847	$ 4,847	$ 4,847	$ 4,847	$ 4,593	$ 4,593	$ 4,593	$ 4,593	$ 4,593	**$ 56,248**
Washington 10 (BG Energy)	$ 120,633	$ 120,633	$ 120,633	$ 120,633	$ 120,633	$ 120,633	$ -	$ 114,300	$ 114,300	$ 114,300	$ 114,300	$ 114,300	**$ 1,295,298**
Texas Eastern	$ 88	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 248	$ 165	$ -	**$ 501**
Company Managed	$ -	$ -	$ (44,167)	$ (91,004)	$ -	$ -	$ -	$ (246,597)	$ (273,254)	$ (273,452)	$ (268,438)	$ (265,617)	**$ (1,462,528)**
Prior Period Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Total Storage and Demand Reservation	$ 125,353	$ 125,265	$ 81,098	$ 34,477	$ 125,481	$ 125,481	$ 5,283	$ (127,705)	$ (154,362)	$ (154,311)	$ (149,380)	$ (146,725)	**$ (110,046)**
Demand Cost Estimates	$ 1,093,496	$ 1,093,496	$ 800,208	$ 800,208	$ 937,830	$ 800,208	$ 1,834,817	$ 1,755,720	$ 1,482,990	$ 1,488,004	$ 1,487,979	$ 663,217	**$ 14,238,175**
Demand Cost Reversals	$ (1,093,496)	$ (1,093,496)	$ (1,093,496)	$ (800,208)	$ (800,208)	$ (937,830)	$ (800,208)	$ (1,834,817)	$ (1,755,720)	$ (1,482,990)	$ (1,488,004)	$ (1,487,979)	**$ (14,668,453)**
Total Fixed Demand	$ 815,759	$ 792,208	$ 499,490	$ 756,801	$ 958,079	$ 698,695	$ 1,857,816	$ 1,405,241	$ 1,325,908	$ 1,458,518	$ 1,701,483	$ 847,396	**$ 13,117,392**
Interruptible Profits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Amortization of PNGTS Rate Case Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 41,206	$ 41,206	$ 41,206	$ 41,206	$ 41,206	$ -	**$ 206,029**
Capacity Release	$ (235,351)	$ (45,131)	$ (44,064)	$ (46,590)	$ (113,612)	$ (112,384)	$ (39,815)	$ (229,706)	$ (270,306)	$ (260,100)	$ (254,880)	$ (249,185)	**$ (1,901,126)**
Capacity Mitigation	$ (6,218)	$ (11,531)	$ -	$ (11,521)	$ (22,081)	$ (11,161)	$ (10,773)	$ (6,961)	$ (7,419)	$ (7,362)	$ (7,436)	$ (7,436)	**$ (109,898)**
Production and Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 114,446	$ 114,446	$ 114,446	$ 114,446	$ 114,446	$ 114,446	**$ 686,673**
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,974	$ 15,974	$ 15,974	$ 15,974	$ 15,974	$ 15,974	**$ 95,845**
Transp. Demand Revenues	$ -	$ (18)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ (18)**
Prior Period Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Demand Cost Estimates - Capacity Release	$ (119,782)	$ (119,782)	$ (127,604)	$ (127,604)	$ (127,604)	$ (127,604)	$ (238,292)	$ (238,292)	$ (245,654)	$ (245,728)	$ (245,728)	$ (127,663)	**$ (2,091,338)**
Demand Cost Reversals - Capacity Release	$ 119,782	$ 119,782	$ 119,782	$ 127,604	$ 127,604	$ 127,604	$ 127,604	$ 238,292	$ 238,292	$ 245,654	$ 245,728	$ 245,728	**$ 2,083,457**
Total Demand Costs	**$ 574,190**	**$ 735,528**	**$ 447,603**	**$ 698,690**	**$ 822,385**	**$ 575,150**	**$ 1,868,165**	**$ 1,340,199**	**$ 1,212,446**	**$ 1,362,607**	**$ 1,610,792**	**$ 839,259**	$ 12,087,015
Demand Costs Transferred to Summer Perioc	$ (239,471)	$ (239,471)	$ (239,471)	$ (239,471)	$ (239,471)	$ (239,471)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,436,825)
Net Demand Costs For Winter Period	**$ 334,719**	**$ 496,058**	**$ 208,133**	**$ 459,219**	**$ 582,915**	**$ 335,679**	**$ 1,868,165**	**$ 1,340,199**	**$ 1,212,446**	**$ 1,362,607**	**$ 1,610,792**	**$ 839,259**	**$ 10,650,190**
Total Gas Costs	**$ 324,218**	**$ 499,289**	**$ 202,141**	**$ 463,098**	**$ 583,812**	**$ 340,706**	**$ 3,461,034**	**$ 5,515,279**	**$ 5,103,627**	**$ 4,387,573**	**$ 3,966,842**	**$ 2,310,122**	**$ 27,157,741**

FORM III
Schedule 5

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009 - 2010 WINTER PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
May 2009 - April 2010

New Hampshire	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
Throughput IN													
BTU Factor	1.058	1.043	1.046	1.029	1.05	1.042	1.037	1.04053	1.042	1.044	1.039	1.03975	
GST Meter Throughput (MCF)	318,202	259,715	275,694	259,076	278,578	460,252	528,094	880,611	977,063	812,599	665,946	416,782	6,132,612
Salem Meter (MCF)	13,740	10,711	11,098	10,145	11,353	21,545	27,009	56,707	61,967	49,058	34,966	18,950	327,249
GST Meter Throughpurt (DTH)	336,658	270,883	288,376	266,589	292,507	479,583	547,633	916,302	1,018,100	848,353	691,918	433,349	6,390,251
Salem Meter (DTH)	14,537	11,172	11,609	10,439	11,921	22,450	28,008	59,005	64,570	51,217	36,330	19,703	340,960
LNG/Propane													0
Total Throughput	351,195	282,054	299,984	277,028	304,428	502,032	575,642	975,307	1,082,669	899,570	728,248	453,052	6,731,210
Throughput OUT													
Residential Gas													
Charged	91,409	45,514	54,713	33,949	34,637	53,953	114,181	153,165	320,901	266,164	208,617	154,085	1,531,288
Uncharged Current	40,334	10,780	19,977	21,823	32,708	47,772	71,699	132,901	139,568	126,626	96,640	71,183	812,011
Uncharged Prior	-57,682	-40,334	-10,780	-19,977	-21,823	-32,708	-47,772	-71,699	-132,901	-139,568	-126,626	-96,640	-798,510
Total Residential Gas	**74,060**	**15,960**	**63,910**	**35,795**	**45,522**	**69,016**	**138,108**	**214,367**	**327,568**	**253,222**	**178,631**	**128,628**	1,544,788
Interruptible	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	0
Commercial/Industrial Gas													
Charged	95,223	92,202	53,650	54,112	54,903	82,024	134,296	213,173	371,131	308,200	236,761	162,214	1,857,888
Uncharged Current	41,496	33,674	21,433	33,488	37,652	56,218	81,951	157,742	163,939	151,115	114,042	75,149	967,898
Uncharged Prior	-65,679	-41,496	-33,674	-21,433	-33,488	-37,652	-56,218	-81,951	-157,742	-163,939	-151,115	-114,042	-958,429
Total C/I Gas	**71,040**	**84,379**	**41,409**	**66,168**	**59,067**	**100,589**	**160,029**	**288,963**	**377,329**	**295,376**	**199,688**	**123,321**	1,867,358
Transportation													
Charged	205,707	194,417	194,706	180,110	199,077	252,958	274,355	362,827	418,102	374,369	348,655	274,469	3,279,751
Uncharged Current	16,613	42,700	40,205	12,581	70,882	101,472	110,691	186,138	147,132	139,598	124,303	85,504	1,077,819
Uncharged Prior	-21,875	-16,613	-42,700	-40,205	-12,581	-70,882	-101,472	-110,691	-186,138	-147,132	-139,598	-124,303	-1,014,190
Total Transportation	**200,445**	**220,504**	**192,210**	**152,485**	**257,379**	**283,547**	**283,574**	**438,274**	**379,095**	**366,836**	**333,359**	**235,670**	**3,343,380**
Company Use	**88**	**47**	**5**	**1**	**7**	**21**	**38**	**81**	**137**	**118**	**76**	**49**	**666**
Total Throughput OUT	**345,633**	**320,891**	**297,533**	**254,449**	**361,975**	**453,174**	**581,750**	**941,685**	**1,084,129**	**915,550**	**711,754**	**487,669**	**6,756,192**
Total Throughput IN	**351,195**	**282,054**	**299,984**	**277,028**	**304,428**	**502,032**	**575,642**	**975,307**	**1,082,669**	**899,570**	**728,248**	**453,052**	**6,731,210**
Difference IN/OUT	5,562	-38,836	2,451	22,579	-57,547	48,859	-6,108	33,622	-1,460	-15,980	16,494	-34,616	-24,982
%													-0.37%

Attachment A
Conformed to Current Presentation

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
DEFERRED PEAK WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
Period Ending April 30, 2010

OFF-PEAK PERIOD - Acct 182.21

		BEGINNING BALANCE(1)	WORKING CAP ALLOWANCE(2)	WORKING CAP PERCENTAGE	WORKING CAP COLLECTIONS	WORKING CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
		A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
May 2009	$	(28,876)	183	0.0564%	147	330	(28,546)	(28,711)	3.25%	(78)	(28,623)
June	$	(28,623)	282	0.0564%	-	282	(28,342)	(28,482)	3.25%	(77)	(28,419)
July	$	(28,419)	114	0.0564%	(0)	114	(28,305)	(28,362)	3.25%	(77)	(28,382)
August	$	(28,382)	261	0.0564%	(0)	261	(28,121)	(28,251)	3.25%	(77)	(28,197)
September	$	(28,197)	329	0.0564%	(6)	323	(27,874)	(28,036)	3.25%	(76)	(27,950)
October	$	(27,950)	192	0.0564%	(5)	187	(27,763)	(27,857)	3.25%	(75)	(27,839)
November	$	(27,839)	1,952	0.0564%	(6,275)	(4,323)	(32,162)	(30,000)	3.25%	(81)	(32,243)
December	$	(32,243)	3,111	0.0564%	(13,017)	(9,907)	(42,149)	(37,196)	3.25%	(101)	(42,250)
January 2010	$	(42,250)	2,878	0.0564%	(18,330)	(15,451)	(57,701)	(49,976)	3.25%	(135)	(57,837)
February	$	(57,837)	2,475	0.0564%	(14,266)	(11,792)	(69,628)	(63,732)	3.25%	(173)	(69,801)
March	$	(69,801)	2,237	0.0564%	(9,837)	(7,600)	(77,401)	(73,601)	3.25%	(199)	(77,600)
April	$	(77,600)	1,303	0.0564%	(6,553)	(5,250)	(82,850)	(80,225)	3.25%	(217)	(83,068)
Totals			15,317		(68,143)					(1,366)	

(1) The beginning balance for May-09 from Revised 2008-09 Winter Period Cost of Gas Adjustment Reconciliation in docket DG 08-115, dated March 4, 2009, has been reduced by $538.08 for an adjustment made by NiSource prior to Unitil ownership. In addition, the amount of $2,762.35 has been added back to reverse an adjustment made in the prior winter period reconciliation as this amount pertains to the summer period (See Attachment A, Footnote 3). These two changes combined with a small change in interest as a result yields a starting balance of ($28,876).
(2) Working Capital Allowance Calculated by taking Eligible Gas Costs from Sch 4 and multiplying by (6.33/365)*Interest Rate.

Attachment B
Conformed to Current Presentation

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
BAD DEBT EXPENSE - CALCULATION OF COLLECTION ALLOWANCE
Period Ending April 30, 2010

OFF-PEAK PERIOD - Acct 182.22

	BEGINNING BALANCE(1)	BAD DEBT ALLOWANCE(2)	% ALLOWED BAD DEBT	BAD DEBT COLLECTIONS	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
May 2009	46,749	1,460	0.45%	348	1,808	48,557	47,653	3.25%	129	48,686
June	48,686	2,248	0.45%	0	2,248	50,934	49,810	3.25%	135	51,069
July	51,069	910	0.45%	(0)	910	51,979	51,524	3.25%	140	52,119
August	52,119	2,085	0.45%	(0)	2,085	54,203	53,161	3.25%	144	54,347
September	54,347	2,629	0.45%	(15)	2,614	56,961	55,654	3.25%	151	57,112
October	57,112	1,534	0.45%	(13)	1,521	58,633	57,872	3.25%	157	58,790
November	58,790	15,583	0.45%	(15,940)	(357)	58,433	58,611	3.25%	159	58,592
December	58,592	24,833	0.45%	(33,042)	(8,209)	50,383	54,487	3.25%	148	50,530
January 2010	50,530	22,979	0.45%	(46,531)	(23,552)	26,979	38,754	3.25%	105	27,083
February	27,083	19,755	0.45%	(36,217)	(16,462)	10,622	18,853	3.25%	51	10,673
March	10,673	17,861	0.45%	(24,968)	(7,107)	3,566	7,119	3.25%	19	3,585
April	3,585	10,401	0.45%	(16,634)	(6,232)	(2,647)	469	3.25%	1	(2,646)
Totals		122,279		(173,012)					1,338	

(1) The beginning balance for May-09 from Revised 2008-09 Winter Period Cost of Gas Adjustment Reconciliation in docket DG 08-115, dated March 4, 2009, has been reduced by $1,276.81 for an adjustment made by NiSource prior to Unitil ownership. In addition, the amount of $6,387.92 has been added back to reverse an adjustment made in the prior winter period reconciliation as this amount pertains to the summer period (See Attachment A, Footnote 3). These two changes combined with a small change in interest as a result yields a starting balance of $46,749.
(2) Bad Debt Allowance calculated by multiplying Bad Debt % by Gas Cost on Schedule 4 and Working Capital Allowance on Attachment A.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
WINTER 2009 - 2010

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	TOTAL
Forecast Calendar Month Sales	259,755	451,329	631,824	625,692	525,469	390,952	2,885,021
Actual Sales	254,579	363,628	691,982	574,357	445,323	441,292	2,771,161
Difference	(5,176)	(87,701)	60,158	(51,335)	(80,146)	50,340	(113,860)
Add:							
Volume Variance due to Weather							
Normal Cal. Month Actual Sales	298,137	503,331	704,897	548,597	378,318	251,950	2,685,229
Actual Sales	254,579	363,628	691,982	574,357	445,323	441,292	2,771,161
Weather Variance	43,558	139,703	12,915	(25,760)	(67,005)	(189,342)	(85,932)
Total Variance Excluding Weather (excl weather effect)	38,382	52,002	73,073	(77,095)	(147,151)	(139,002)	(199,792)
Variance-difference due to meter count							(141,263)
-difference in load pattern							27,403
SALES							(113,860)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
WINTER 2009 - 2010

	NORMAL MMBtu			METERS		
	2009-10 Forecast	2009-10 Actual	Difference	2009-10 Forecast	2009-10 Actual	Difference
Res Heat	1,272,586	1,341,110	68,524	121,032	121,602	570
Res General	19,689	24,362	4,673	9,510	9,828	318
Total Res	1,292,275	1,365,472	73,197	130,542	131,430	888
G-40	687,262	588,608	(98,654)	28,135	25,518	(2,617)
G-50	94,010	92,977	(1,033)	6,064	5,500	(564)
G-41	567,659	502,726	(64,933)	2,569	2,330	(239)
G-51	172,943	134,779	(38,164)	1,119	1,015	(104)
G-42	50,540	80,819	30,279	112	102	(10)
G-52	20,331	5,779	(14,552)	22	20	(2)
Total C & I	1,592,745	1,405,688	(187,057)	38,021	34,485	(3,536)
Total Company	2,885,021	2,771,160	(113,860)	168,563	165,915	(2,648)

	NORMAL AVERAGE USE			Change in Sales Due to Change In:			
	2009-10 Forecast	2009-10 Actual	Difference	Meter Count	Load Pattern	Total Chg MMBtu	% Difference
Res Heat	10.51	11.03	0.51	5,993	62,531	68,524	5.38%
Res General	2.07	2.48	0.41	658	4,015	4,673	23.73%
Total Res	12.58	13.51	0.92	6,652	66,545	73,197	5.66%
G-40	24.43	23.07	(1.36)	(63,926)	(34,728)	(98,654)	-14.35%
G-50	15.50	16.90	1.40	(8,744)	7,711	(1,033)	-1.10%
G-41	220.96	215.76	(5.20)	(52,811)	(12,122)	(64,933)	-11.44%
G-51	154.55	132.79	(21.76)	(16,073)	(22,091)	(38,164)	-22.07%
G-42	451.25	792.34	341.09	(4,513)	34,792	30,279	59.91%
G-52	924.14	288.95	(635.19)	(1,848)	(12,704)	(14,552)	-71.58%
Total C & I	41.89	40.76	(1.13)	(147,915)	(39,142)	(187,057)	-11.74%
Total Company	17.12	16.70	(0.41)	(141,263)	27,403	(113,860)	-3.95%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009-10 WINTER PERIOD RECONCILIATION
May 2009 - April 2010

Recalculated Reconciliation

FORM III
Schedule 1
Updated July 2012

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009-2010 WINTER PERIOD RECONCILIATION
SCHEDULE 1: SUMMARY OF WINTER PERIOD BALANCE
May 2009 - April 2010

	AMOUNT	
Winter Period Beg. Balance	$1,236,634	SCHEDULE 2
Less: Reported Collections	($26,807,090)	SCHEDULE 2
Less: Billing Adjustment	$0	SCHEDULE 2
Add: Cost of Firm Gas Allowable	$25,931,602	SCHEDULE 4
Add: Interest	$73,599	SCHEDULE 2
Winter Period Ending Balance	$434,746	

FORM III
Schedule 2
Updated July 2012

NORTHERN UTILTIES, INC. - NEW HAMPSHIRE DIVISION
2009-10 WINTER PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED SUMMER PERIOD ACCOUNTS
May 2009 - April 2010
Acct 191.10

	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
WINTER PERIOD													
Winter Period Account Beginning Balance(1)	$ 1,236,634	$ 1,633,135	$ 2,125,364	$ 2,329,374	$ 2,797,095	$ 3,373,196	$ 3,715,452	$ 4,538,260	$ 4,463,560	$ 1,619,803	$ 30,561	$ (249,675)	$ 1,236,634
Plus: Cost of Firm Gas (Schedule 4)	$ 324,190	$ 499,673	$ 202,050	$ 463,655	$ 583,812	$ 340,906	$ 3,448,870	$ 5,380,057	$ 4,644,404	$ 4,002,933	$ 3,766,096	$ 2,274,957	$ 25,931,602
Less: Reported Collections (Schedule 3)	$ 68,430	$ (12,527)	$ (4,064)	$ (2,866)	$ (16,056)	$ (8,236)	$ (2,637,223)	$ (5,466,931)	$ (7,496,388)	$ (5,594,406)	$ (4,046,036)	$ (1,590,786)	$ (26,807,090)
Less: Billing Adjustment													
Winter Period Account Ending Balance	$ 1,629,254	$ 2,120,281	$ 2,323,350	$ 2,790,162	$ 3,364,851	$ 3,705,866	$ 4,527,099	$ 4,451,386	$ 1,611,576	$ 28,329	$ (249,379)	$ 434,495	$ 361,147
Month's Average Balance	$ 1,432,944	$ 1,876,708	$ 2,224,357	$ 2,559,768	$ 3,080,973	$ 3,539,531	$ 4,121,275	$ 4,494,823	$ 3,037,568	$ 824,066	$ (109,409)	$ 92,410	
Interest Rate (Prime Rate)	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
Interest Applied	$ 3,881	$ 5,083	$ 6,024	$ 6,933	$ 8,344	$ 9,586	$ 11,162	$ 12,173	$ 8,227	$ 2,232	$ (296)	$ 250	$ 73,599
Winter Period Account Ending Balance w/int	$ 1,633,135	$ 2,125,364	$ 2,329,374	$ 2,797,095	$ 3,373,196	$ 3,715,452	$ 4,538,260	$ 4,463,560	$ 1,619,803	$ 30,561	$ (249,675)	$ 434,746	$ 434,746

(1) Beginning balance for May-09 from Revised 2008-09 Winter Period Cost of Gas Adjustment Reconciliation in docket DG 08-115, dated March 4, 2009.

FORM III
Schedule 3

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009-10 WINTER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS(1)
May 2009 - April 2010

	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
Accrued Revenue	$ (1,311,072)						$1,671,036	$1,496,137	$ 140,433	$ (343,134)	$ (716,828)	$ (1,425,408)	$ (488,835)
Billed Revenue	$ 1,242,642	$ 12,527	$ 4,064	$ 2,866	$ 16,056	$ 8,236	$ 966,188	$3,970,794	$7,355,955	$5,937,540	$4,762,863	$ 3,016,194	$ 27,295,925
Calendarized Revenue	**$ (68,430)**	**$ 12,527**	**$ 4,064**	**$ 2,866**	**$ 16,056**	**$ 8,236**	**$2,637,223**	**$5,466,931**	**$7,496,388**	**$5,594,406**	**$4,046,036**	**$ 1,590,786**	**$ 26,807,090**

(1) Revenue figures reflect the transition to accrual accounting as required by Commission Order No. 25,038, dated October 30, 2009 in DG 07-033.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009-10 WINTER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO WINTER PERIOD
May 2009 - April 2010

FORM III
Schedule 4
Page 1 of 2

Updated July 2012

Commodity Costs:	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
BG Energy	$ 34,182	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,662	$ -	$ -	$ 31,403	**$ 74,248**
Boss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,928	$ -	$ -	$ -	**$ 12,928**
BP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 52,755	$ 615,705	$ 1,520,629	$ 823,812	$ -	**$ 3,012,900**
Classic	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 92	$ -	$ -	**$ 92**
Distrigas of Mass	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 100,357	$ 251,243	$ 327,297	$ 299,197	$ 333,212	**$ 1,311,307**
DTE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 398,780	$ -	$ -	$ -	$ -	**$ 398,780**
Emera Energy	$ 67,194	$ -	$ -	$ -	$ -	$ -	$ -	$ 120,652	$ 149,959	$ 114,759	$ 117,063	$ 101,123	**$ 670,750**
FPL/NextEra	$ 62,478	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,130	$ -	$ -	$ -	**$ 72,608**
Iberdrola	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 760,290	$ 726,122	$ 628,066	$ -	**$ 2,114,478**
Integrys	$ 5,032	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 5,032**
J. P. Morgan	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,705	$ -	$ -	$ -	$ -	**$ 12,705**
Louis Dreyfus Electric Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,243	$ -	**$ 7,243**
Macquarie Cook Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,042,914	$ 9,657	$ -	$ -	**$ 1,052,571**
National Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Northeast Gas Marketing	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 180,861	$ 205,686	$ 269,427	$ 222,108	$ -	**$ 878,081**
Sequent Energy Management, LP	$ 394,997	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,970	$ -	$ -	$ -	$ -	**$ 398,967**
South Jersey	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 214,587	$ -	$ -	$ -	$ -	**$ 214,587**
Spark	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,004	$ -	$ -	$ -	**$ 13,004**
Sprague Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 38,977	$ -	**$ 38,977**
Tennessee	$ 885	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,333	$ 7,809	$ 7,964	$ 25,260	$ 12,304	**$ 61,555**
Subtotal	$ 564,769	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,092,000	$ 3,078,330	$ 2,975,947	$ 2,161,725	$ 478,042	**$ 10,350,813**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,080,518	$ 2,970,078	$ 2,999,574	$ 2,210,204	$ 472,450	$ 908,200	**$ 10,641,024**
Commodity Cost Reversals	$ (517,082)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,080,518)	$ (2,970,078)	$ (2,999,574)	$ (2,210,204)	$ (472,450)	**$ (10,249,907)**
Subtotal	$ 47,686	$ -	$ -	$ -	$ -	$ -	$ 1,080,518	$ 2,981,560	$ 3,107,825	$ 2,186,577	$ 423,971	$ 913,792	**$ 10,741,931**
Withdrawal Charges	$ 108	$ 2,801	$ 2,273	$ 3,064	$ -	$ 4,088	$ 5,007	$ 100,799	$ 1,171,362	$ 1,644,641	$ 1,125,338	$ 10,539	**$ 4,070,020**
Interruptible Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,649	$ -	$ -	$ -	**$ 7,649**
Non Traditional Sales	$ (58,807)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (71,930)	$ (958,751)	$ (1,694,948)	$ -	**$ (2,784,436)**
Net OBA Adj	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,022	$ 13,478	$ 7,907	$ (4,850)	$ (3,845)	$ (81)	**$ 21,632**
Company Managed	$ -	$ -	$ (8,779)	$ -	$ -	$ -	$ -	$ (13,437)	$ (283,247)	$ (273,692)	$ (235,583)	$ (243,681)	**$ (1,058,418)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,706	$ -	$ -	$ -	$ -	$ -	**$ 3,706**
Transportation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 101,847	$ 593,753	$ 834,653	$ 703,532	$ 500,280	$ 278,881	**$ 3,012,946**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 391,680	$ 497,797	$ 359,604	$ 415,832	$ 551,773	$ 668,016	**$ 2,884,703**
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Inventory Finance Charges	$ 512	$ 431	$ 514	$ 815	$ 898	$ 938	$ 1,088	$ 1,130	$ 920	$ 556	$ 302	$ 209	**$ 8,312**
Allocation Adjustments	$ (28)	$ 384	$ (91)	$ 557	$ (0)	$ 200	$ (12,164)	$ (135,223)	$ (459,223)	$ (384,641)	$ (200,746)	$ (35,165)	**$ (1,226,139)**
Subtotal	$ (58,215)	$ 3,615	$ (6,083)	$ 4,436	$ 898	$ 5,227	$ 500,187	$ 1,058,298	$ 1,567,695	$ 1,142,628	$ 42,571	$ 678,720	**$ 4,939,976**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,243,562)	$ (1,932,442)	$ (243,681)	$ (400,495)	**$ (3,820,180)**
Commodity Cost Reversals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,243,562	$ 1,932,442	$ 243,681	**$ 3,419,685**
Subtotal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,243,562)	$ (688,880)	$ 1,688,761	$ (156,814)	**$ (400,495)**
Total Commodity Costs	**$ (10,529)**	**$ 3,615**	**$ (6,083)**	**$ 4,436**	**$ 898**	**$ 5,227**	**$ 1,580,705**	**$ 4,039,858**	**$ 3,431,958**	**$ 2,640,326**	**$ 2,155,304**	**$ 1,435,698**	**$ 15,281,412**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009-10 WINTER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO WINTER PERIOD
May 2009 - April 2010

Updated July 2012

Demand Costs

	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
Pipeline Reservation													
Algonquin	$ 16,627	$ 16,583	$ 16,641	$ 16,673	$ -	$ 33,316	$ 16,671	$ 15,722	$ 15,767	$ 15,767	$ 15,767	$ 15,767	**$ 195,302**
BG Energy	$ 204,893	$ 211,309	$ 213,511	$ 217,940	$ 221,483	$ 233,893	$ 228,130	$ 213,086	$ 221,372	$ 305,309	$ 312,580	$ 319,133	**$ 2,902,641**
Granite	$ 82,533	$ 82,533	$ 82,533	$ 82,533	$ 82,533	$ 82,628	$ 78,289	$ 78,375	$ 78,375	$ 78,375	$ 78,400	$ 78,400	**$ 965,504**
Emera	$ 20,421	$ 19,920	$ 21,221	$ 21,340	$ 21,170	$ 21,484	$ 21,734	$ 20,850	$ 20,664	$ 29,988	$ 36,680	$ 31,506	**$ 286,978**
Iberdrola	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 48,939	$ 30,801	$ 33,994	$ 34,571	**$ 148,305**
Iroquois	$ 21,707	$ 21,707	$ 21,707	$ 21,707	$ 21,707	$ 21,707	$ 21,707	$ 20,567	$ 20,567	$ 20,567	$ 20,567	$ 20,567	**$ 254,787**
J.P. Morgan	$ -	$ -	$ -	$ -	$ -	$ -	$ 128,153	$ -	$ -	$ -	$ -	$ -	**$ 128,153**
PNGTS (DEM)	$ 15,098	$ 15,098	$ 15,098	$ 15,098	$ 15,098	$ 15,098	$ 15,098	$ 829,709	$ 829,709	$ 829,709	$ 829,709	$ 829,709	**$ 4,254,230**
Sequent	$ 22,226	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 22,226**
Spectra	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,014	$ -	$ -	$ -	$ -	$ -	**$ 17,014**
Tennessee Gas (El Paso)	$ 140,197	$ 140,197	$ 137,622	$ 137,622	$ 135,736	$ 137,622	$ 137,622	$ 46,404	$ 130,396	$ 130,396	$ 130,396	$ 102,900	**$ 1,507,107**
Texas Eastern	$ 3,395	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,707	$ 6,497	$ -	**$ 19,598**
Vector LP	$ 91,274	$ 91,322	$ 91,340	$ 91,357	$ 91,204	$ 91,654	$ 91,421	$ 123,617	$ 123,656	$ 122,705	$ 122,755	$ 122,777	**$ 1,255,083**
Co-Managed (includes Off System Sale	$ (5,524)	$ (5,631)	$ (5,587)	$ -	$ (11,527)	$ -	$ (10,551)	$ -	$ -	$ (229,041)	$ -	$ -	**$ (267,860)**
Prior Period Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Total Pipeline Reservation	$ 612,846	$ 593,037	$ 594,086	$ 604,269	$ 577,405	$ 637,401	$ 745,288	$ 1,348,331	$ 1,489,445	$ 1,344,283	$ 1,587,346	$ 1,555,330	**$ 11,689,068**
Product Demand													
Alberta Northeast Gas Ltd.	$ 1,147	$ 1,155	$ 1,223	$ 1,672	$ 1,189	$ 1,146	$ 1,283	$ 1,235	$ 1,067	$ 1,044	$ 1,089	$ 1,066	**$ 14,316**
Distrigas of Massachusetts	$ 116,012	$ 116,012	$ 116,012	$ 116,012	$ 116,012	$ 116,012	$ 116,012	$ 99,140	$ 99,140	$ 99,140	$ 99,140	$ 99,140	**$ 1,307,786**
FPL/NextEra	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 162,997	$ 162,997	$ 162,997	$ 162,997	$ 162,997	**$ 814,983**
NEGM	$ 358	$ 370	$ 358	$ 370	$ 370	$ 358	$ 370	$ 340	$ 351	$ 351	$ 317	$ 351	**$ 4,266**
LNG used to vaporize	$ (39,958)	$ (43,633)	$ -	$ -	$ -	$ (44,082)	$ (45,029)	$ -	$ -	$ -	$ -	$ -	**$ (172,702)**
Prior Period Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Total Product Demand	$ 77,560	$ 73,905	$ 117,594	$ 118,055	$ 117,572	$ 73,435	$ 72,636	$ 263,711	$ 263,554	$ 263,531	$ 263,542	$ 263,553	**$ 1,968,648**
Storage Pipeline Transportation and Demand Reservation													
Spectra	$ -	$ -	$ -	$ -	$ -	$ -	$ 435	$ -	$ -	$ -	$ -	$ -	**$ 435**
Tennessee Gas Pipeline	$ 4,632	$ 4,632	$ 4,632	$ 4,847	$ 4,847	$ 4,847	$ 4,847	$ 4,593	$ 4,593	$ 4,593	$ 4,593	$ 4,593	**$ 56,248**
Washington 10 (BG Energy)	$ 120,633	$ 120,633	$ 120,633	$ 120,633	$ 120,633	$ 120,633	$ -	$ 114,300	$ 114,300	$ 114,300	$ 114,300	$ 114,300	**$ 1,295,298**
Texas Eastern	$ 88	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 248	$ 165	$ -	**$ 501**
Company Managed	$ -	$ -	$ (44,167)	$ (91,004)	$ -	$ -	$ -	$ (246,597)	$ (273,254)	$ (273,452)	$ (268,438)	$ (265,617)	**$ (1,462,528)**
Prior Period Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Total Storage and Demand Reservati	$ 125,353	$ 125,265	$ 81,098	$ 34,477	$ 125,481	$ 125,481	$ 5,283	$ (127,705)	$ (154,362)	$ (154,311)	$ (149,380)	$ (146,725)	**$ (110,046)**
Demand Cost Estimates	$ 1,093,496	$ 1,093,496	$ 800,208	$ 800,208	$ 937,830	$ 800,208	$ 1,834,817	$ 1,755,720	$ 1,482,990	$ 1,488,004	$ 1,487,979	$ 663,217	**$ 14,238,175**
Demand Cost Reversals	$ (1,093,496)	$ (1,093,496)	$ (1,093,496)	$ (800,208)	$ (800,208)	$ (937,830)	$ (800,208)	$ (1,834,817)	$ (1,755,720)	$ (1,482,990)	$ (1,488,004)	$ (1,487,979)	**$ (14,668,453)**
Total Fixed Demand	$ 815,759	$ 792,208	$ 499,490	$ 756,801	$ 958,079	$ 698,695	$ 1,857,816	$ 1,405,241	$ 1,325,908	$ 1,458,518	$ 1,701,483	$ 847,396	**$ 13,117,392**
Interruptible Profits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Amortization of PNGTS Rate Case Cos	$ -	$ -	$ -	$ -	$ -	$ -	$ 41,206	$ 41,206	$ 41,206	$ 41,206	$ 41,206	$ -	**$ 206,029**
Capacity Release	$ (235,351)	$ (45,131)	$ (44,064)	$ (46,590)	$ (113,612)	$ (112,384)	$ (39,815)	$ (229,706)	$ (270,306)	$ (260,100)	$ (254,880)	$ (249,185)	**$ (1,901,126)**
Capacity Mitigation	$ (6,218)	$ (11,531)	$ -	$ (11,521)	$ (22,081)	$ (11,161)	$ (10,773)	$ (6,961)	$ (7,419)	$ (7,362)	$ (7,436)	$ (7,436)	**$ (109,898)**
Production and Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 114,446	$ 114,446	$ 114,446	$ 114,446	$ 114,446	$ 114,446	**$ 686,673**
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,974	$ 15,974	$ 15,974	$ 15,974	$ 15,974	$ 15,974	**$ 95,845**
Transp. Demand Revenues	$ -	$ (18)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ (18)**
Prior Period Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Demand Cost Estimates - Capacity Rel	$ (119,782)	$ (119,782)	$ (127,604)	$ (127,604)	$ (127,604)	$ (127,604)	$ (238,292)	$ (238,292)	$ (245,654)	$ (245,728)	$ (245,728)	$ (127,663)	**$ (2,091,338)**
Demand Cost Reversals - Capacity Rel	$ 119,782	$ 119,782	$ 119,782	$ 127,604	$ 127,604	$ 127,604	$ 127,604	$ 238,292	$ 238,292	$ 245,654	$ 245,728	$ 245,728	**$ 2,083,457**
Total Demand Costs	**$ 574,190**	**$ 735,528**	**$ 447,603**	**$ 698,690**	**$ 822,385**	**$ 575,150**	**$ 1,868,165**	**$ 1,340,199**	**$ 1,212,446**	**$ 1,362,607**	**$ 1,610,792**	**$ 839,259**	$ 12,087,015
Demand Costs Transferred to Summ	$ (239,471)	$ (239,471)	$ (239,471)	$ (239,471)	$ (239,471)	$ (239,471)	$ -	$ -	$ -	$ -	$ -	$ -	**$ (1,436,825)**
Net Demand Costs For Winter Perioc	**$ 334,719**	**$ 496,058**	**$ 208,133**	**$ 459,219**	**$ 582,915**	**$ 335,679**	**$ 1,868,165**	**$ 1,340,199**	**$ 1,212,446**	**$ 1,362,607**	**$ 1,610,792**	**$ 839,259**	**$ 10,650,190**
Total Gas Costs	**$ 324,190**	**$ 499,673**	**$ 202,050**	**$ 463,655**	**$ 583,812**	**$ 340,906**	**$ 3,448,870**	**$ 5,380,057**	**$ 4,644,404**	**$ 4,002,933**	**$ 3,766,096**	**$ 2,274,957**	**$ 25,931,602**

FORM III
Schedule 5

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009 - 2010 WINTER PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
May 2009 - April 2010

New Hampshire	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
Throughput IN													
BTU Factor	1.058	1.043	1.046	1.029	1.05	1.042	1.037	1.04053	1.042	1.044	1.039	1.03975	
GST Meter Throughput (MCF)	318,202	259,715	275,694	259,076	278,578	460,252	528,094	880,611	977,063	812,599	665,946	416,782	6,132,612
Salem Meter (MCF)	13,740	10,711	11,098	10,145	11,353	21,545	27,009	56,707	61,967	49,058	34,966	18,950	327,249
GST Meter Throughput (DTH)	336,658	270,883	288,376	266,589	292,507	479,583	547,633	916,302	1,018,100	848,353	691,918	433,349	6,390,251
Salem Meter (DTH)	14,537	11,172	11,609	10,439	11,921	22,450	28,008	59,005	64,570	51,217	36,330	19,703	340,960
LNG/Propane													0
Total Throughput	351,195	282,054	299,984	277,028	304,428	502,032	575,642	975,307	1,082,669	899,570	728,248	453,052	6,731,210
Throughput OUT													
Residential Gas													
Charged	91,409	45,514	54,713	33,949	34,637	53,953	114,181	153,165	320,901	266,164	208,617	154,085	1,531,288
Uncharged Current	40,334	10,780	19,977	21,823	32,708	47,772	71,699	132,901	139,568	126,626	96,640	71,183	812,011
Uncharged Prior	-57,682	-40,334	-10,780	-19,977	-21,823	-32,708	-47,772	-71,699	-132,901	-139,568	-126,626	-96,640	-798,510
Total Residential Gas	**74,060**	**15,960**	**63,910**	**35,795**	**45,522**	**69,016**	**138,108**	**214,367**	**327,568**	**253,222**	**178,631**	**128,628**	1,544,788
Interruptible	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	0
Commercial/Industrial Gas													
Charged	95,223	92,202	53,650	54,112	54,903	82,024	134,296	213,173	371,131	308,200	236,761	162,214	1,857,888
Uncharged Current	41,496	33,674	21,433	33,488	37,652	56,218	81,951	157,742	163,939	151,115	114,042	75,149	967,898
Uncharged Prior	-65,679	-41,496	-33,674	-21,433	-33,488	-37,652	-56,218	-81,951	-157,742	-163,939	-151,115	-114,042	-958,429
Total C/I Gas	**71,040**	**84,379**	**41,409**	**66,168**	**59,067**	**100,589**	**160,029**	**288,963**	**377,329**	**295,376**	**199,688**	**123,321**	1,867,358
Transportation													
Charged	205,707	194,417	194,706	180,110	199,077	252,958	274,355	362,827	418,102	374,369	348,655	274,469	3,279,751
Uncharged Current	16,613	42,700	40,205	12,581	70,882	101,472	110,691	186,138	147,132	139,598	124,303	85,504	1,077,819
Uncharged Prior	-21,875	-16,613	-42,700	-40,205	-12,581	-70,882	-101,472	-110,691	-186,138	-147,132	-139,598	-124,303	-1,014,190
Total Transportation	**200,445**	**220,504**	**192,210**	**152,485**	**257,379**	**283,547**	**283,574**	**438,274**	**379,095**	**366,836**	**333,359**	**235,670**	**3,343,380**
Company Use	**88**	**47**	**5**	**1**	**7**	**21**	**38**	**81**	**137**	**118**	**76**	**49**	**666**
Total Throughput OUT	**345,633**	**320,891**	**297,533**	**254,449**	**361,975**	**453,174**	**581,750**	**941,685**	**1,084,129**	**915,550**	**711,754**	**487,669**	**6,756,192**
Total Throughput IN	**351,195**	**282,054**	**299,984**	**277,028**	**304,428**	**502,032**	**575,642**	**975,307**	**1,082,669**	**899,570**	**728,248**	**453,052**	**6,731,210**
Difference IN/OUT	5,562	-38,836	2,451	22,579	-57,547	48,859	-6,108	33,622	-1,460	-15,980	16,494	-34,616	-24,982
%													-0.37%

Attachment A
Updated July 2012

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
DEFERRED WINTER WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
May 2009 - April 2010

WINTER PERIOD - Acct 182.11

		BEGINNING BALANCE(1)	WORKING CAP ALLOWANCE(2)	WORKING CAP PERCENTAGE	WORKING CAP COLLECTIONS	WORKING CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
		A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
May 2009	$	(29,412)	183	0.0564%	147	330	(29,082)	(29,247)	3.25%	(79)	(29,161)
June	$	(29,161)	282	0.0564%	-	282	(28,880)	(29,021)	3.25%	(79)	(28,958)
July	$	(28,958)	114	0.0564%	(0)	114	(28,844)	(28,901)	3.25%	(78)	(28,923)
August	$	(28,923)	262	0.0564%	(0)	261	(28,661)	(28,792)	3.25%	(78)	(28,739)
September	$	(28,739)	329	0.0564%	(6)	323	(28,416)	(28,578)	3.25%	(77)	(28,494)
October	$	(28,494)	192	0.0564%	(5)	187	(28,307)	(28,400)	3.25%	(77)	(28,384)
November	$	(28,384)	1,945	0.0564%	(6,275)	(4,330)	(32,713)	(30,549)	3.25%	(83)	(32,796)
December	$	(32,796)	3,034	0.0564%	(13,017)	(9,983)	(42,779)	(37,788)	3.25%	(102)	(42,881)
January 2010	$	(42,881)	2,619	0.0564%	(18,330)	(15,710)	(58,591)	(50,736)	3.25%	(137)	(58,729)
February	$	(58,729)	2,258	0.0564%	(14,266)	(12,009)	(70,737)	(64,733)	3.25%	(175)	(70,913)
March	$	(70,913)	2,124	0.0564%	(9,837)	(7,713)	(78,626)	(74,769)	3.25%	(203)	(78,828)
April	$	(78,828)	1,283	0.0564%	(6,553)	(5,270)	(84,098)	(81,463)	3.25%	(221)	(84,319)
Totals			14,625		(68,143)					(1,389)	

(1) The beginning balance for May-09 from Revised 2008-09 Winter Period Cost of Gas Adjustment Reconciliation in docket DG 08-115, dated March 4, 2009, has been reduced by $538.08 for an adjustment made by NiSource prior to Unitil ownership. In addition, the amount of $2,762.35 has been added back to reverse an adjustment made in the prior winter period reconciliation as this amount pertains to the summer period (See Attachment A, Footnote 3). These two changes combined with a small change in interest as a result yields a starting balance of ($29,412).
(2) Working Capital Allowance Calculated by taking Eligible Gas Costs from Sch 4 and multiplying by (6.33/365)*Interest Rate.

Attachment B
Updated July 2012

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
BAD DEBT EXPENSE - CALCULATION OF COLLECTION ALLOWANCE
May 2009 - April 2010

OFF-PEAK PERIOD - Acct 182.16

	BEGINNING BALANCE(1)	BAD DEBT ALLOWANCE(2)	% ALLOWED BAD DEBT	BAD DEBT COLLECTIONS	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
May 2009	42,907	1,460	0.45%	348	1,808	44,714	43,811	3.25%	119	44,833
June	44,833	2,250	0.45%	0	2,250	47,083	45,958	3.25%	124	47,207
July	47,207	910	0.45%	(0)	909	48,117	47,662	3.25%	129	48,246
August	48,246	2,088	0.45%	(0)	2,087	50,333	49,289	3.25%	133	50,467
September	50,467	2,629	0.45%	(15)	2,614	53,080	51,773	3.25%	140	53,220
October	53,220	1,535	0.45%	(13)	1,522	54,743	53,981	3.25%	146	54,889
November	54,889	15,529	0.45%	(15,940)	(411)	54,477	54,683	3.25%	148	54,626
December	54,626	24,224	0.45%	(33,042)	(8,818)	45,808	50,217	3.25%	136	45,944
January 2010	45,944	20,912	0.45%	(46,531)	(25,619)	20,324	33,134	3.25%	90	20,414
February	20,414	18,023	0.45%	(36,217)	(18,194)	2,220	11,317	3.25%	31	2,251
March	2,251	16,957	0.45%	(24,968)	(8,011)	(5,760)	(1,755)	3.25%	(5)	(5,765)
April	(5,765)	10,243	0.45%	(16,634)	(6,390)	(12,155)	(8,960)	3.25%	(24)	(12,179)
Totals		116,758		(173,012)					1,168	

(1) The beginning balance for May-09 from Revised 2008-09 Winter Period Cost of Gas Adjustment Reconciliation in docket DG 08-115, dated March 4, 2009, has been reduced by $1,276.81 for an adjustment made by NiSource prior to Unitil ownership. In addition, the amount of $6,387.92 has been added back to reverse an adjustment made in the prior winter period reconciliation as this amount pertains to the summer period (See Attachment A, Footnote 3). These two changes combined with a small change in interest as a result yields a starting balance of $42,907.
(2) Bad Debt Allowance calculated by multiplying Bad Debt % by Gas Cost on Schedule 4 and Working Capital Allowance on Attachment A.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
WINTER 2009 - 2010

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	TOTAL
Forecast Calendar Month Sales	259,755	451,329	631,824	625,692	525,469	390,952	2,885,021
Actual Sales	254,579	363,628	691,982	574,357	445,323	441,292	2,771,161
Difference	(5,176)	(87,701)	60,158	(51,335)	(80,146)	50,340	(113,860)
Add:							
Volume Variance due to Weather							
Normal Cal. Month Actual Sales	298,137	503,331	704,897	548,597	378,318	251,950	2,685,229
Actual Sales	254,579	363,628	691,982	574,357	445,323	441,292	2,771,161
Weather Variance	43,558	139,703	12,915	(25,760)	(67,005)	(189,342)	(85,932)
Total Variance Excluding Weather (excl weather effect)	38,382	52,002	73,073	(77,095)	(147,151)	(139,002)	(199,792)
Variance-difference due to meter count							(141,263)
-difference in load pattern							27,403
SALES							(113,860)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
WINTER 2009 - 2010

	NORMAL MMBtu			METERS		
	2009-10 Forecast	2009-10 Actual	Difference	2009-10 Forecast	2009-10 Actual	Difference
Res Heat	1,272,586	1,341,110	68,524	121,032	121,602	570
Res General	19,689	24,362	4,673	9,510	9,828	318
Total Res	1,292,275	1,365,472	73,197	130,542	131,430	888
G-40	687,262	588,608	(98,654)	28,135	25,518	(2,617)
G-50	94,010	92,977	(1,033)	6,064	5,500	(564)
G-41	567,659	502,726	(64,933)	2,569	2,330	(239)
G-51	172,943	134,779	(38,164)	1,119	1,015	(104)
G-42	50,540	80,819	30,279	112	102	(10)
G-52	20,331	5,779	(14,552)	22	20	(2)
Total C & I	1,592,745	1,405,688	(187,057)	38,021	34,485	(3,536)
Total Company	2,885,021	2,771,160	(113,860)	168,563	165,915	(2,648)

	NORMAL AVERAGE USE			Change in Sales Due to Change In:			
	2009-10 Forecast	2009-10 Actual	Difference	Meter Count	Load Pattern	Total Chg MMBtu	% Difference
Res Heat	10.51	11.03	0.51	5,993	62,531	68,524	5.38%
Res General	2.07	2.48	0.41	658	4,015	4,673	23.73%
Total Res	12.58	13.51	0.92	6,652	66,545	73,197	5.66%
G-40	24.43	23.07	(1.36)	(63,926)	(34,728)	(98,654)	-14.35%
G-50	15.50	16.90	1.40	(8,744)	7,711	(1,033)	-1.10%
G-41	220.96	215.76	(5.20)	(52,811)	(12,122)	(64,933)	-11.44%
G-51	154.55	132.79	(21.76)	(16,073)	(22,091)	(38,164)	-22.07%
G-42	451.25	792.34	341.09	(4,513)	34,792	30,279	59.91%
G-52	924.14	288.95	(635.19)	(1,848)	(12,704)	(14,552)	-71.58%
Total C & I	41.89	40.76	(1.13)	(147,915)	(39,142)	(187,057)	-11.74%
Total Company	17.12	16.70	(0.41)	(141,263)	27,403	(113,860)	-3.95%

Schedule 4

New Hampshire Division
Original and Revised 2010-2011 Winter Period Reconciliation

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010-11 WINTER PERIOD RECONCILIATION
May 2010 - April 2011

Original Reconciliation

FORM III
Schedule 1

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010-2011 WINTER PERIOD RECONCILIATION
SCHEDULE 1: SUMMARY OF WINTER PERIOD BALANCE
May 2010 - April 2011

	AMOUNT	
Winter Period Beg. Balance	$2,527,403	SCHEDULE 2
Less: Reported Collections	($32,736,593)	SCHEDULE 2
Add: Cost of Firm Gas Allowable	$31,043,868	SCHEDULE 4
Add: Interest	$138,949	SCHEDULE 2
Winter Period Ending Balance	$973,628	

FORM III
Schedule 2

NORTHERN UTILTIES, INC. - NEW HAMPSHIRE DIVISION
2010-2011 WINTER PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED WINTER PERIOD ACCOUNTS
May 2010 - April 2011
Acct 191.20

	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
WINTER PERIOD													
Winter Period Account Beginning Balance	$ 2,527,403	$ 2,960,838	$ 3,830,779	$ 4,148,746	$ 4,817,956	$ 5,378,432	$ 5,928,075	$ 6,528,993	$ 6,435,669	$ 4,898,490	$ 3,305,320	$ 1,390,024	$ 2,527,403
Plus: Cost of Firm Gas (Schedule 4)	$ 426,013	$ 857,257	$ 308,045	$ 655,977	$ 545,138	$ 533,511	$ 3,164,233	$ 5,445,662	$ 6,473,214	$ 5,246,244	$ 5,006,539	$ 2,382,035	$ 31,043,868
Less: Reported Collections (Schedule 3)	$ 0	$ 3,499	$ (869)	$ 1,107	$ 1,549	$ 842	$ (2,580,162)	$ (5,556,519)	$ (8,025,720)	$ (6,850,509)	$ (6,928,185)	$ (2,801,628)	$ (32,736,593)
Less: Billing Adjustment													
Winter Period Account Ending Balance	$ 2,953,416	$ 3,821,594	$ 4,137,955	$ 4,805,830	$ 5,364,643	$ 5,912,785	$ 6,512,147	$ 6,418,136	$ 4,883,162	$ 3,294,226	$ 1,383,674	$ 970,431	$ 834,678
Month's Average Balance	$ 2,740,410	$ 3,391,216	$ 3,984,367	$ 4,477,288	$ 5,091,300	$ 5,645,609	$ 6,220,111	$ 6,473,564	$ 5,659,415	$ 4,096,358	$ 2,344,497	$ 1,180,227	
Interest Rate (Prime Rate)	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
Interest Applied	$ 7,422	$ 9,185	$ 10,791	$ 12,126	$ 13,789	$ 15,290	$ 16,846	$ 17,533	$ 15,328	$ 11,094	$ 6,350	$ 3,196	$ 138,949
Winter Period Account Ending Balance w/int	$ 2,960,838	$ 3,830,779	$ 4,148,746	$ 4,817,956	$ 5,378,432	$ 5,928,075	$ 6,528,993	$ 6,435,669	$ 4,898,490	$ 3,305,320	$ 1,390,024	$ 973,628	$ 973,628

FORM III
Schedule 3

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010-2011 WINTER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2010 - April 2011

	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
Accrued Revenue	$ (822,237)	$ -	$ -	$ -	$ -	$ -	$ 1,768,173	$ 1,169,565	$ 1,127,732	$ (813,839)	$ 756,635	$ (1,767,915)	$ 1,418,115
Billed Revenue	$ 822,236	$ (3,499)	$ 869	$ (1,107)	$ (1,549)	$ (842)	$ 811,989	$ 4,386,954	$ 6,897,988	$ 7,664,347	$ 6,171,550	$ 4,569,542	$ 31,318,478
Calendarized Revenue	**$ (0)**	**$ (3,499)**	**$ 869**	**$ (1,107)**	**$ (1,549)**	**$ (842)**	**$ 2,580,162**	**$ 5,556,519**	**$ 8,025,720**	**$ 6,850,509**	**$ 6,928,185**	**$ 2,801,628**	**$ 32,736,593**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010-2011 WINTER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO WINTER PERIOD
May 2010 - April 2011

Commodity Costs:	**May-10 (Actual)**	**Jun-10 (Actual)**	**Jul-10 (Actual)**	**Aug-10 (Actual)**	**Sep-10 (Actual)**	**Oct-10 (Actual)**	**Nov-10 (Actual)**	**Dec-10 (Actual)**	**Jan-11 (Actual)**	**Feb-11 (Actual)**	**Mar-11 (Actual)**	**Apr-11 (Actual)**	**Total Winter**
BG Energy Merchants, LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 711,103	$ 514,493	$ 474,328	$ 470,883	**$ 2,170,806**
Distrigas of Massachusetts, LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 101,484	$ 228,317	$ 260,990	$ 283,826	$ 260,545	**$ 1,135,162**
Emera Energy Services, Inc.	$ 279,072	$ 3,925	$ -	$ -	$ -	$ -	$ -	$ 65,357	$ 385,878	$ 417,401	$ 420,810	$ 178,742	**$ 1,751,185**
FPL Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 38,074	$ 234,196	$ 98,827	$ -	**$ 371,097**
JP Morgan Ventures Energy Corp	$ 349,226	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 349,226**
Louis Dreyfus Electric Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,057	$ 206,923	$ -	$ -	$ -	**$ 217,980**
Macquarie Cook Energy, LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 37,713	$ -	$ -	$ -	$ -	**$ 37,713**
National Energy & Trade	$ 174,613	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 55,518	$ 118,375	$ 76,393	$ 23,281	**$ 448,180**
Portland Natural Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,176	$ -	$ 697	**$ 4,873**
Repsol	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 96,553	$ 227,153	$ 63,760	**$ 387,466**
South Jersey Resources	$ 11,649	$ -	$ -	$ -	$ -	$ -	$ 11,402	$ -	$ -	$ -	$ -	$ 5,906	**$ 28,957**
Spark Energy Gas, LP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 148,819	$ -	$ 361,732	$ -	$ 393,903	**$ 904,454**
Sprague Energy Corp.	$ 90,521	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 90,521**
Tennessee Gas Pipeline Co	$ 1,897	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,336	$ 5,849	$ 4,192	$ 2,121	$ 3,126	**$ 18,521**
Virginia Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 201,699	$ 43,648	**$ 245,347**
Misc	$ -	$ -	$ -	$ -	$ (1,983)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ (1,983)**
Subtotal	$ 906,977	$ 3,925	$ -	$ -	$ (1,983)	$ -	$ 11,402	$ 365,766	$ 1,631,662	$ 2,012,108	$ 1,785,157	$ 1,444,491	**$ 8,159,504**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 739,132	$ 1,657,574	$ 2,165,594	$ 1,717,909	$ 1,448,855	$ 1,209,861	**$ 8,938,925**
Commodity Cost Reversals	$ (908,200)	$ -	$ -	$ -	$ -	$ -	$ -	$ (739,132)	$ (1,657,574)	$ (2,165,594)	$ (1,717,909)	$ (1,448,855)	**$ (8,637,264)**
Subtotal	$ (1,223)	$ 3,925	$ -	$ -	$ (1,983)	$ -	$ 750,534	$ 1,284,207	$ 2,139,682	$ 1,564,423	$ 1,516,103	$ 1,205,497	**$ 8,461,165**
Withdrawal Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 982,785	$ 2,454,160	$ 2,544,470	$ 1,576,288	$ 1,213,681	$ 870	**$ 8,772,254**
ATV		$ -					$ (30,606)	$ 72,894	$ 111,901	$ 85,224	$ 102,352	$ 22,329	**$ 364,093**
Non Traditional Sales	$ (425,015)	$ -	$ -	$ -	$ -	$ -	$ (4,520)	$ (2,316)	$ (848,206)	$ (141,454)	$ (129,906)	$ (27,350)	**$ (1,578,766)**
Net OBA Adj	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,250	$ 1,739	$ 11,720	$ 31,076	$ (188)	$ 7,938	**$ 62,534**
Company Managed	$ (20,480)	$ -	$ -	$ -	$ -	$ -	$ -	$ (34,309)	$ (341,851)	$ (402,896)	$ (336,167)	$ (246,181)	**$ (1,381,885)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,008	$ 6,370	$ 7,304	$ 1,225	$ 3,279	$ 4,889	**$ 27,075**
Transportation Charges	$ 47,189	$ 160,076	$ (213,177)	$ 117,743	$ -	$ -	$ -	$ 3,498	$ 95,263	$ 28,758	$ 92,402	$ 69,554	**$ 401,304**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 117,625	$ 404,041	$ 147,924	$ 167,138	$ 198,755	$ 212,179	**$ 1,247,662**
Inventory Finance Charges	$ 404	$ 579	$ 774	$ 957	$ 1,048	$ 1,087	$ 1,095	$ 1,060	$ 727	$ 355	$ 183	$ 46	**$ 8,312**
Subtotal	$ (397,903)	$ 160,654	$ (212,403)	$ 118,699	$ 1,048	$ 1,087	$ 1,080,636	$ 2,907,137	$ 1,729,251	$ 1,345,713	$ 1,144,390	$ 44,273	**$ 7,922,583**
Sales for Resale Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ (388,606)	$ (1,181,189)	$ (631,980)	$ (388,103)	$ (273,531)	$ (93,943)	**$ (2,957,352)**
Sales for Resale Reversals	$ 400,495	$ -	$ -	$ -	$ -	$ -	$ -	$ 388,606	$ 1,181,189	$ 631,980	$ 388,103	$ 273,531	**$ 3,263,904**
Subtotal	$ 400,495	$ -	$ -	$ -	$ -	$ -	$ (388,606)	$ (792,583)	$ 549,208	$ 243,877	$ 114,573	$ 179,587	**$ 306,552**
Total Commodity Costs	**$ 1,370**	**$ 164,579**	**$ (212,403)**	**$ 118,699**	**$ (935)**	**$ 1,087**	**$ 1,442,565**	**$ 3,398,761**	**$ 4,418,142**	**$ 3,154,012**	**$ 2,775,065**	**$ 1,429,358**	**$ 16,690,300**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010-2011 WINTER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO WINTER PERIOD
May 2010 - April 2011

Demand Costs

	May-10 (Actual)	Jun-10 (Actual)	Jul-10 (Actual)	Aug-10 (Actual)	Sep-10 (Actual)	Oct-10 (Actual)	Nov-10 (Actual)	Dec-10 (Actual)	Jan-11 (Actual)	Feb-11 (Actual)	Mar-11 (Actual)	Apr-11 (Actual)	Total Winter
Pipeline Reservation													
Algonquin Gas Transmission	$ 15,767	$ 15,770	$ 15,767	$ 15,767	$ 15,767	$ 15,767	$ 15,767	$ 16,159	$ 16,159	$ 16,159	$ 16,159	$ 16,159	**$ 191,172**
BG Energy Merchants, LLC	$ 332,323	$ 344,837	$ 335,961	$ 336,539	$ 342,174	$ 344,671	$ 346,402	$ 351,934	$ 345,595	$ 357,811	$ 366,325	$ 536,412	**$ 4,340,983**
Emera Energy Services, Inc.	$ -	$ 60,549	$ 30,609	$ 30,045	$ 30,979	$ 31,034	$ -	$ 31,046	$ -	$ -	$ -	$ -	**$ 214,262**
Granite State Gas Transmission, Inc.	$ 78,400	$ 78,400	$ 78,412	$ 78,412	$ 78,433	$ 78,414	$ 80,364	$ 80,262	$ 134,845	$ 134,781	$ 134,737	$ 134,695	**$ 1,170,156**
Iroquois Gas Transmision System	$ 20,567	$ 20,567	$ 20,567	$ 20,567	$ 20,567	$ 20,567	$ 20,567	$ 21,079	$ 21,079	$ 21,079	$ -	$ 42,158	**$ 249,366**
Portland Natural Gas Transmission	$ 14,305	$ 14,305	$ 14,305	$ 14,305	$ 14,305	$ 14,305	$ 14,309	$ 850,338	$ 1,248,914	$ 1,249,025	$ 1,248,914	$ 1,248,914	**$ 5,946,245**
Tennessee Gas Pipeline Co	$ 130,396	$ 130,396	$ 102,900	$ 130,396	$ 130,396	$ 102,900	$ 130,396	$ 133,638	$ 76,183	$ 133,638	$ 133,638	$ 76,183	**$ 1,411,058**
Texas Eastern Transmission		$ 3,261	$ 9,784	$ 3,261	$ 3,254	$ 3,254	$ 3,254	$ 3,335	$ 3,336	$ 3,336	$ 3,305	$ 3,304	**$ 42,686**
Union Gas Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,429	$ 7,228	$ 7,274	$ 7,356	**$ 36,286**
Vector Pipeline LP	$ 85,737	$ 85,734	$ 85,745	$ 85,736	$ 85,752	$ 85,781	$ 85,789	$ 125,834	$ 125,856	$ 125,858	$ 125,858	$ 125,920	**$ 1,229,601**
Total Pipeline Reservation	$ 677,496	$ 753,820	$ 694,050	$ 715,029	$ 721,629	$ 696,694	$ 696,849	$ 1,613,624	$ 1,986,395	$ 2,048,915	$ 2,036,210	$ 2,191,101	**$ 14,831,814**
Product Demand													
Alberta Northeast Gas Ltd.	$ 1,022	$ 1,025	$ 1,142	$ 1,351	$ 1,186	$ 1,087	$ 1,104	$ 1,136	$ 1,210	$ -	$ 2,235	$ -	**$ 12,500**
Distrigas of Massachusetts	$ 99,140	$ 99,140	$ 99,140	$ 99,140	$ 99,140	$ 99,140	$ 99,140	$ 96,998	$ 107,849	$ 107,849	$ 107,849	$ 107,849	**$ 1,222,370**
FPL/NextEra	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 187,969	$ 187,969	$ 187,969	$ 187,969	$ 187,969	**$ 939,846**
Total Product Demand	$ 100,162	$ 100,165	$ 100,281	$ 100,491	$ 100,326	$ 100,227	$ 100,244	$ 286,103	$ 297,028	$ 295,818	$ 298,053	$ 295,818	**$ 2,174,716**
Storage Pipeline Transportation and Demand Reservation													
Tennessee Gas Pipeline	$ 4,593	$ 4,593	$ 4,593	$ 4,593	$ 4,593	$ 4,593	$ 4,593	$ 4,707	$ 4,707	$ 4,707	$ 4,707	$ 4,707	**$ 55,684**
Washington 10 (BG Energy)	$ 114,300	$ 114,300	$ 114,300	$ 114,300	$ 114,300	$ 114,300	$ 114,300	$ 117,141	$ 117,141	$ 117,141	$ 117,141	$ 117,141	**$ 1,385,803**
Texas Eastern	$ -	$ 83	$ 249	$ 83	$ 83	$ 83	$ 83	$ 84	$ 84	$ 84	$ 83	$ 84	**$ 1,083**
Company Managed	$ (152,105)	$ (80,108)	$ (76,076)	$ (76,668)	$ (76,162)	$ (79,868)	$ (80,220)	$ (295,491)	$ (360,493)	$ (367,839)	$ (384,681)	$ (418,937)	**$ (2,448,647)**
Total Storage and Demand Reservation	$ (33,212)	$ 38,868	$ 43,065	$ 42,306	$ 42,813	$ 39,107	$ 38,756	$ (173,558)	$ (238,561)	$ (245,907)	$ (262,749)	$ (297,005)	**$ (1,006,077)**
Demand Cost Estimates	$ 668,427	$ 783,265	$ 787,966	$ 781,710	$ 778,004	$ 789,086	$ 1,659,762	$ 1,965,329	$ 1,962,205	$ 1,941,756	$ 2,085,801	$ 854,320	**$ 15,057,632**
Demand Cost Reversals	$ (663,217)	$ (668,427)	$ (783,265)	$ (787,966)	$ (781,710)	$ (778,004)	$ (789,086)	$ (1,659,762)	$ (1,965,329)	$ (1,962,205)	$ (1,941,756)	$ (2,085,801)	**$ (14,866,529)**
Total Fixed Demand	$ 749,655	$ 1,007,690	$ 842,097	$ 851,572	$ 861,062	$ 847,110	$ 1,706,525	$ 2,031,736	$ 2,041,738	$ 2,078,378	$ 2,215,558	$ 958,433	**$ 16,191,555**
Amortization of PNGTS Rate Case Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 30,657	$ 30,657	$ 30,657	$ 30,657	$ 30,657	$ 30,657	**$ 183,943**
Capacity Release	$ (127,117)	$ (129,921)	$ (136,339)	$ (129,346)	$ (129,032)	$ (129,089)	$ (129,330)	$ (99,858)	$ (167,802)	$ (134,599)	$ (132,565)	$ (137,207)	**$ (1,582,206)**
Capacity Mitigation	$ (8,963)	$ (9,007)	$ (8,971)	$ (8,973)	$ (9,005)	$ (9,259)	$ (9,260)	$ (12,186)	$ (12,623)	$ (12,343)	$ (12,501)	$ (12,491)	**$ (125,583)**
Production and Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 114,446	$ 114,446	$ 114,446	$ 114,446	$ 114,446	$ 114,446	**$ 686,673**
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 16,389	$ 16,389	$ 16,389	$ 16,389	$ 16,389	$ 16,389	**$ 98,333**
Demand Cost Estimates - Capacity Release	$ (140,258)	$ (140,005)	$ (140,007)	$ (139,645)	$ (140,261)	$ (140,262)	$ (148,021)	$ (182,303)	$ (150,036)	$ (150,730)	$ (151,240)	$ (168,788)	**$ (1,791,556)**
Demand Cost Reversals - Capacity Release	$ 127,663	$ 140,258	$ 140,005	$ 140,007	$ 139,645	$ 140,261	$ 140,262	$ 148,021	$ 182,303	$ 150,036	$ 150,730	$ 151,240	**$ 1,750,431**
Total Demand Costs	**$ 600,980**	**$ 869,015**	**$ 696,785**	**$ 713,615**	**$ 722,410**	**$ 708,761**	**$ 1,721,668**	**$ 2,046,901**	**$ 2,055,072**	**$ 2,092,232**	**$ 2,231,473**	**$ 952,678**	$ 15,411,591
Demand Costs Transferred to Summer Perioc	$ (176,337)	$ (176,337)	$ (176,337)	$ (176,337)	$ (176,337)	$ (176,337)	$ -	$ -	$ -	$ -	$ -	$ -	**$ (1,058,022)**
Net Demand Costs For Winter Period	**$ 424,643**	**$ 692,678**	**$ 520,448**	**$ 537,278**	**$ 546,073**	**$ 532,424**	**$ 1,721,668**	**$ 2,046,901**	**$ 2,055,072**	**$ 2,092,232**	**$ 2,231,473**	**$ 952,678**	**$ 14,353,569**
Total Gas Costs	**$ 426,013**	**$ 857,257**	**$ 308,045**	**$ 655,977**	**$ 545,138**	**$ 533,511**	**$ 3,164,233**	**$ 5,445,662**	**$ 6,473,214**	**$ 5,246,244**	**$ 5,006,539**	**$ 2,382,035**	**$ 31,043,868**

FORM III
Schedule 5

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010-2011 WINTER PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
May 2010 - April 2011

New Hampshire	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
Throughput IN													
BTU Factor	1.038	1.039	1.033	1.036	1.039	1.041	1.039	1.039	1.046	1.049	1.048	1.041	
GST Meter Throughput (MCF)	312,869	265,598	249,025	269,606	273,645	427,825	569,708	849,169	1,045,428	914,419	780,093	493,361	6,450,746
Salem Meter (MCF)	12,766	9,904	9,385	9,959	10,496	18,586	31,154	57,324	67,178	57,567	45,512	25,940	355,771
GST Meter Throughpurt (DTH)	324,758	275,956	257,243	279,312	284,317	445,366	591,927	882,287	1,093,518	959,226	817,537	513,589	6,725,035
Salem Meter (DTH)	13,251	10,290	9,695	10,318	10,905	19,348	32,369	59,560	70,268	60,388	47,697	27,004	371,092
LNG/Propane													
Total Throughput	338,009	286,247	266,938	289,629	295,222	464,714	624,296	941,846	1,163,786	1,019,613	865,234	540,592	7,096,126
Throughput OUT													
Residential Gas													
Charged	89,805	48,593	37,542	31,398	35,343	45,287	107,248	195,796	291,469	327,102	254,646	192,084	1,656,313
Uncharged Current	24,753	17,120	17,902	18,960	24,555	50,075	80,135	148,473	168,349	135,111	164,902	93,513	943,847
Uncharged Prior	-71,183	-24,753	-17,120	-17,902	-18,960	-24,555	-50,075	-80,135	-148,473	-168,349	-135,111	-164,902	-921,517
Total Residential Gas	**43,375**	**40,960**	**38,324**	**32,457**	**40,938**	**70,806**	**137,308**	**264,134**	**311,345**	**293,864**	**284,436**	**120,695**	1,678,643
Interruptible	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	0
Commercial/Industrial Gas													
Charged	100,468	56,259	50,821	48,982	52,749	63,675	121,973	208,217	342,640	350,674	278,007	203,456	1,877,921
Uncharged Current	33,010	24,405	24,409	28,929	31,853	48,382	82,007	151,318	195,063	145,510	181,239	100,855	1,046,979
Uncharged Prior	-75,149	-33,010	-24,405	-24,409	-28,929	-31,853	-48,382	-82,007	-151,318	-195,063	-145,510	-181,239	-1,021,274
Total C/I Gas	**58,329**	**47,654**	**50,825**	**53,502**	**55,673**	**80,204**	**155,597**	**277,528**	**386,386**	**301,121**	**313,736**	**123,071**	1,903,627
Transportation													
Charged	210,279	200,287	183,338	202,932	206,761	246,364	292,350	379,482	438,660	419,294	396,434	311,797	3,487,978
Uncharged Current	55,335	55,311	49,937	65,560	74,219	115,721	133,472	208,493	192,682	145,148	206,752	127,983	1,430,613
Uncharged Prior	-85,504	-55,335	-55,311	-49,937	-65,560	-74,219	-115,721	-133,472	-208,493	-192,682	-145,148	-206,752	-1,388,134
Total Transportation	**180,110**	**200,263**	**177,964**	**218,555**	**215,420**	**287,866**	**310,101**	**454,503**	**422,849**	**371,760**	**458,038**	**233,029**	**3,530,457**
Company Use	**25**	**7**	**2**	**2**	**6**	**17**	**37**	**85**	**145**	**141**	**104**	**76**	**647**
Total Throughput OUT	**281,838**	**288,884**	**267,115**	**304,515**	**312,038**	**438,894**	**603,044**	**996,250**	**1,120,725**	**966,886**	**1,056,314**	**476,871**	**7,113,374**
Total Throughput IN	**338,009**	**286,247**	**266,938**	**289,629**	**295,222**	**464,714**	**624,296**	**941,846**	**1,163,786**	**1,019,613**	**865,234**	**540,592**	**7,096,126**
Difference IN/OUT	56,171	-2,638	-178	-14,886	-16,815	25,820	21,252	-54,404	43,061	52,727	-191,080	63,721	-17,248
%													-0.24%

Attachment A

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
DEFERRED PEAK WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
Period Ending April 30, 2011

PEAK PERIOD - Acct 182.11

	BEGINNING BALANCE	WORKING CAP ALLOWANCE(1)	WORKING CAP PERCENTAGE	WORKING CAP COLLECTIONS	WORKING CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
May 2010	$ (83,068)	240	0.0564%	553	794	(82,274)	(82,671)	3.25%	(224)	(82,498)
June	$ (82,498)	483	0.0564%	13	497	(82,001)	(82,250)	3.25%	(223)	(82,224)
July	$ (82,224)	174	0.0564%	(2)	171	(82,053)	(82,138)	3.25%	(222)	(82,275)
August	$ (82,275)	370	0.0564%	2	372	(81,903)	(82,089)	3.25%	(222)	(82,125)
September	$ (82,125)	307	0.0564%	4	311	(81,814)	(81,970)	3.25%	(222)	(82,036)
October	$ (82,036)	301	0.0564%	2	303	(81,733)	(81,884)	3.25%	(222)	(81,954)
November	$ (81,954)	1,785	0.0564%	2,594	4,379	(77,576)	(79,765)	3.25%	(216)	(77,792)
December	$ (77,792)	3,071	0.0564%	5,681	8,752	(69,039)	(73,415)	3.25%	(199)	(69,238)
January 2011	$ (69,238)	3,651	0.0564%	7,962	11,613	(57,625)	(63,432)	3.25%	(172)	(57,797)
February	$ (57,797)	2,959	0.0564%	6,539	9,498	(48,298)	(53,048)	3.25%	(144)	(48,442)
March	$ (48,442)	2,824	0.0564%	6,580	9,404	(39,039)	(43,740)	3.25%	(118)	(39,157)
April	$ (39,157)	1,343	0.0564%	2,687	4,030	(35,127)	(37,142)	3.25%	(101)	(35,228)
Totals		17,509		32,616					(2,285)	

(1) Working Capital Allowance calculated by taking monthly Total Gas Costs from Sch 4, page 2 of 2, and multiplying by (6.33/365)*Interest Rate.

Attachment B

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
BAD DEBT EXPENSE - CALCULATION OF COLLECTION ALLOWANCE
Period Ending April 30, 2011

PEAK PERIOD - Acct 182.16

	BEGINNING BALANCE	BAD DEBT ALLOWANCE(1)	% ALLOWED BAD DEBT	BAD DEBT COLLECTIONS	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
May 2010	(2,646)	1,918	0.45%	1,405	3,323	677	(985)	3.25%	(3)	674
June	674	3,860	0.45%	34	3,894	4,568	2,621	3.25%	7	4,575
July	4,575	1,387	0.45%	(6)	1,381	5,956	5,266	3.25%	14	5,970
August	5,970	2,954	0.45%	6	2,959	8,930	7,450	3.25%	20	8,950
September	8,950	2,455	0.45%	10	2,465	11,415	10,182	3.25%	28	11,442
October	11,442	2,402	0.45%	6	2,408	13,850	12,646	3.25%	34	13,885
November	13,885	14,247	0.45%	(11,119)	3,128	17,013	15,449	3.25%	42	17,054
December	17,054	24,519	0.45%	(24,293)	226	17,281	17,168	3.25%	46	17,327
January 2011	17,327	29,146	0.45%	(34,004)	(4,858)	12,469	14,898	3.25%	40	12,509
February	12,509	23,621	0.45%	(27,957)	(4,335)	8,174	10,342	3.25%	28	8,202
March	8,202	22,542	0.45%	(28,113)	(5,571)	2,631	5,417	3.25%	15	2,646
April	2,646	10,725	0.45%	(11,442)	(717)	1,929	2,288	3.25%	6	1,935
Totals		139,776		(135,473)					278	

(1) Bad Debt Allowance calculated by multiplying % Allowed Bad Debt by monthly Total Gas Cost on Sch 4, page 2 of 2, and Working Capital Allowance on Attachment A

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
WINTER 2010 - 2011

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL
Forecast Calendar Month Sales	304,710	472,252	638,023	542,998	525,753	319,160	2,802,896
Actual Sales	229,220	404,014	634,109	677,776	532,653	395,540	2,873,312
Difference	(75,490)	(68,238)	(3,914)	134,778	6,900	76,380	70,416
Add:							
Volume Variance due to Weather							
Normal Cal. Month Actual Sales	227,914	395,404	632,020	644,907	537,921	386,609	2,824,775
Actual Sales	229,220	404,014	634,109	677,776	532,653	395,540	2,873,312
Weather Variance	(1,306)	(8,610)	(2,089)	(32,869)	5,268	(8,931)	(48,537)
Total Variance Excluding Weather (excl weather effect)	(76,796)	(76,848)	(6,003)	101,909	12,168	67,449	21,879
Variance-difference due to meter count							(11,493)
-difference in load pattern							81,911
SALES							70,417

Attachment E
Page 2 of 2

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
WINTER 2010 - 2011

	NORMAL MMBtu			METERS		
	2010-11 Forecast	2010-11 Actual	Difference	2010-11 Forecast	2010-11 Actual	Difference
Res Heat	1,281,543	1,343,369	61,826	123,762	123,390	(372)
Res General	21,981	24,975	2,994	9,600	9,655	55
Total Res	1,303,524	1,368,344	64,820	133,362	133,045	(317)
G-40	625,444	676,391	50,948	27,128	26,987	(141)
G-50	93,945	101,417	7,473	5,761	5,731	(30)
G-41	564,013	527,995	(36,019)	3,386	3,368	(18)
G-51	140,222	138,471	(1,751)	1,406	1,399	(7)
G-42	69,689	55,613	(14,077)	181	180	(1)
G-52	6,058	5,081	(977)	167	166	(1)
Total C & I	1,499,371	1,504,968	5,598	38,028	37,831	(197) .
Total Company	2,802,895	2,873,312	70,417	171,390	170,876	(514)

	NORMAL AVERAGE USE			Change in Sales Due to Change In:			
	2010-11 Forecast	2010-11 Actual	Difference	Meter Count	Load Pattern	Total Chg MMBtu	% Difference
Res Heat	10.35	10.89	0.53	(3,852)	65,678	61,826	4.82%
Res General	2.29	2.59	0.30	126	2,868	2,994	13.62%
Total Res	12.64	13.47	0.83	(3,726)	68,546	64,820	4.97%
G-40	23.06	25.06	2.01	(3,240)	54,188	50,948	8.15%
G-50	16.31	17.70	1.39	(487)	7,959	7,473	7.95%
G-41	166.59	156.77	(9.83)	(2,922)	(33,097)	(36,019)	-6.39%
G-51	99.71	98.98	(0.73)	(726)	(1,025)	(1,751)	-1.25%
G-42	385.16	308.96	(76.20)	(361)	(13,716)	(14,077)	-20.20%
G-52	36.30	30.61	(5.69)	(31)	(945)	(977)	-16.12%
Total C & I	39.43	39.78	0.35	(7,767)	13,365	5,598	0.37%
Total Company	16.35	16.82	0.46	(11,493)	81,911	70,417	2.51%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010-11 WINTER PERIOD RECONCILIATION
May 2010 - April 2011

Recalculated Reconciliation

FORM III
Schedule 1
Updated July 2012

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010-2011 WINTER PERIOD RECONCILIATION
SCHEDULE 1: SUMMARY OF WINTER PERIOD BALANCE
May 2010 - April 2011

	AMOUNT	
Winter Period Beg. Balance	$434,746	SCHEDULE 2
Less: Reported Collections	($32,736,593)	SCHEDULE 2
Add: Cost of Firm Gas Allowable	$29,138,421	SCHEDULE 4
Add: Interest	$55,976	SCHEDULE 2
Winter Period Ending Balance	($3,107,451)	

FORM III
Schedule 2
Updated July 2012

NORTHERN UTILTIES, INC. - NEW HAMPSHIRE DIVISION
2010-2011 WINTER PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED WINTER PERIOD ACCOUNTS
May 2010 - April 2011
Acct 191.20

	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
WINTER PERIOD													
Winter Period Account Beginning Balance	$ 434,746	$ 862,475	$ 1,726,793	$ 2,159,218	$ 2,823,040	$ 3,378,055	$ 3,922,280	$ 4,432,175	$ 3,812,109	$ 1,738,448	$ (291,454)	$ (2,530,760)	$ 434,746
Plus: Cost of Firm Gas (Schedule 4)	$ 425,974	$ 857,318	$ 428,039	$ 655,977	$ 545,080	$ 533,510	$ 3,078,759	$ 4,925,304	$ 5,944,553	$ 4,818,650	$ 4,692,695	$ 2,232,562	$ 29,138,421
Less: Reported Collections (Schedule 3)	$ 0	$ 3,499	$ (869)	$ 1,107	$ 1,549	$ 842	$ (2,580,162)	$ (5,556,519)	$ (8,025,720)	$ (6,850,509)	$ (6,928,185)	$ (2,801,628)	$ (32,736,593)
Less: Billing Adjustment													
Winter Period Account Ending Balance	$ 860,720	$ 1,723,291	$ 2,153,963	$ 2,816,302	$ 3,369,669	$ 3,912,407	$ 4,420,877	$ 3,800,960	$ 1,730,942	$ (293,411)	$ (2,526,944)	$ (3,099,826)	$ (3,163,427)
Month's Average Balance	$ 647,733	$ 1,292,883	$ 1,940,378	$ 2,487,760	$ 3,096,354	$ 3,645,231	$ 4,171,578	$ 4,116,567	$ 2,771,525	$ 722,519	$ (1,409,199)	$ (2,815,293)	
Interest Rate (Prime Rate)	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
Interest Applied	$ 1,754	$ 3,502	$ 5,255	$ 6,738	$ 8,386	$ 9,873	$ 11,298	$ 11,149	$ 7,506	$ 1,957	$ (3,817)	$ (7,625)	$ 55,976
Winter Period Account Ending Balance w/int	$ 862,475	$ 1,726,793	$ 2,159,218	$ 2,823,040	$ 3,378,055	$ 3,922,280	$ 4,432,175	$ 3,812,109	$ 1,738,448	$ (291,454)	$ (2,530,760)	$ (3,107,451)	$ (3,107,451)

FORM III
Schedule 3

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010-2011 WINTER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2010 - April 2011

	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
Accrued Revenue	$ (822,237)	$ -	$ -	$ -	$ -	$ -	$ 1,768,173	$ 1,169,565	$ 1,127,732	$ (813,839)	$ 756,635	$ (1,767,915)	$ 1,418,115
Billed Revenue	$ 822,236	$ (3,499)	$ 869	$ (1,107)	$ (1,549)	$ (842)	$ 811,989	$ 4,386,954	$ 6,897,988	$ 7,664,347	$ 6,171,550	$ 4,569,542	$ 31,318,478
Calendarized Revenue	**$ (0)**	**$ (3,499)**	**$ 869**	**$ (1,107)**	**$ (1,549)**	**$ (842)**	**$ 2,580,162**	**$ 5,556,519**	**$ 8,025,720**	**$ 6,850,509**	**$ 6,928,185**	**$ 2,801,628**	**$ 32,736,593**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010-2011 WINTER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO WINTER PERIOD
May 2010 - April 2011

FORM III
Schedule 4
Page 1 of 2

Updated July 2012

Commodity Costs:	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
BG Energy Merchants, LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 711,103	$ 514,493	$ 474,328	$ 470,883	**$ 2,170,806**
Distrigas of Massachusetts, LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 101,484	$ 228,317	$ 260,990	$ 283,826	$ 260,545	**$ 1,135,162**
Emera Energy Services, Inc.	$ 279,072	$ 3,925	$ -	$ -	$ -	$ -	$ -	$ 65,357	$ 385,878	$ 417,401	$ 420,810	$ 178,742	**$ 1,751,185**
FPL Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 38,074	$ 234,196	$ 98,827	$ -	**$ 371,097**
JP Morgan Ventures Energy Corp	$ 349,226	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 349,226**
Louis Dreyfus Electric Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,057	$ 206,923	$ -	$ -	$ -	**$ 217,980**
Macquarie Cook Energy, LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 37,713	$ -	$ -	$ -	$ -	**$ 37,713**
National Energy & Trade	$ 174,613	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 55,518	$ 118,375	$ 76,393	$ 23,281	**$ 448,180**
Portland Natural Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,176	$ -	$ 697	**$ 4,873**
Repsol	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 96,553	$ 227,153	$ 63,760	**$ 387,466**
South Jersey Resources	$ 11,649	$ -	$ -	$ -	$ -	$ -	$ 11,402	$ -	$ -	$ -	$ -	$ 5,906	**$ 28,957**
Spark Energy Gas, LP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 148,819	$ -	$ 361,732	$ -	$ 393,903	**$ 904,454**
Sprague Energy Corp.	$ 90,521	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 90,521**
Tennessee Gas Pipeline Co	$ 1,897	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,336	$ 5,849	$ 4,192	$ 2,121	$ 3,126	**$ 18,521**
Virginia Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 201,699	$ 43,648	**$ 245,347**
Misc	$ -	$ -	$ -	$ -	$ (1,983)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ (1,983)**
Subtotal	$ 906,977	$ 3,925	$ -	$ -	$ (1,983)	$ -	$ 11,402	$ 365,766	$ 1,631,662	$ 2,012,108	$ 1,785,157	$ 1,444,491	**$ 8,159,504**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 739,132	$ 1,657,574	$ 2,165,594	$ 1,717,909	$ 1,448,855	$ 1,209,861	**$ 8,938,925**
Commodity Cost Reversals	$ (908,200)	$ -	$ -	$ -	$ -	$ -	$ -	$ (739,132)	$ (1,657,574)	$ (2,165,594)	$ (1,717,909)	$ (1,448,855)	**$ (8,637,264)**
Subtotal - Supply	$ (1,223)	$ 3,925	$ -	$ -	$ (1,983)	$ -	$ 750,534	$ 1,284,207	$ 2,139,682	$ 1,564,423	$ 1,516,103	$ 1,205,497	**$ 8,461,165**
Withdrawal Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 982,785	$ 2,454,160	$ 2,544,470	$ 1,576,288	$ 1,213,681	$ 870	**$ 8,772,254**
ATV		$ -					$ (30,606)	$ 72,894	$ 111,901	$ 85,224	$ 102,352	$ 22,329	**$ 364,093**
Non Traditional Sales	$ (425,015)	$ -	$ -	$ -	$ -	$ -	$ (4,520)	$ (2,316)	$ (848,206)	$ (141,454)	$ (129,906)	$ (27,350)	**$ (1,578,766)**
Net OBA Adj	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,250	$ 1,739	$ 11,720	$ 31,076	$ (188)	$ 7,938	**$ 62,534**
Company Managed	$ (20,480)	$ -	$ -	$ -	$ -	$ -	$ -	$ (34,309)	$ (341,851)	$ (402,896)	$ (336,167)	$ (246,181)	**$ (1,381,885)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,008	$ 6,370	$ 7,304	$ 1,225	$ 3,279	$ 4,889	**$ 27,075**
Transportation Charges	$ 47,189	$ 160,076	$ (213,177)	$ 117,743	$ -	$ -	$ -	$ 3,498	$ 95,263	$ 28,758	$ 92,402	$ 69,554	**$ 401,304**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 117,625	$ 404,041	$ 147,924	$ 167,138	$ 198,755	$ 212,179	**$ 1,247,662**
Inventory Finance Charges	$ 404	$ 579	$ 774	$ 957	$ 1,048	$ 1,087	$ 1,095	$ 1,060	$ 727	$ 355	$ 183	$ 46	**$ 8,312**
Allocation Adjustments	$ (38)	$ 61	$ 119,993	$ (0)	$ (58)	$ (0)	$ (85,474)	$ (520,359)	$ (528,660)	$ (427,595)	$ (313,844)	$ (149,473)	**$ (1,905,447)**
Subtotal	$ (397,941)	$ 160,715	$ (92,410)	$ 118,699	$ 990	$ 1,086	$ 995,162	$ 2,386,778	$ 1,200,591	$ 918,118	$ 830,546	$ (105,200)	**$ 6,017,136**
Sales for Resale Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ (388,606)	$ (1,181,189)	$ (631,980)	$ (388,103)	$ (273,531)	$ (93,943)	**$ (2,957,352)**
Sales for Resale Reversals	$ 400,495	$ -	$ -	$ -	$ -	$ -	$ -	$ 388,606	$ 1,181,189	$ 631,980	$ 388,103	$ 273,531	**$ 3,263,904**
Subtotal	$ 400,495	$ -	$ -	$ -	$ -	$ -	$ (388,606)	$ (792,583)	$ 549,208	$ 243,877	$ 114,573	$ 179,587	**$ 306,552**
Total Commodity Costs	**$ 1,331**	**$ 164,640**	**$ (92,410)**	**$ 118,699**	**$ (993)**	**$ 1,086**	**$ 1,357,091**	**$ 2,878,403**	**$ 3,889,481**	**$ 2,726,417**	**$ 2,461,221**	**$ 1,279,884**	**$ 14,784,852**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010-2011 WINTER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO WINTER PERIOD
May 2010 - April 2011

Demand Costs

	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
Pipeline Reservation													
Algonquin Gas Transmission	$ 15,767	$ 15,770	$ 15,767	$ 15,767	$ 15,767	$ 15,767	$ 15,767	$ 16,159	$ 16,159	$ 16,159	$ 16,159	$ 16,159	**$ 191,172**
BG Energy Merchants, LLC	$ 332,323	$ 344,837	$ 335,961	$ 336,539	$ 342,174	$ 344,671	$ 346,402	$ 351,934	$ 345,595	$ 357,811	$ 366,325	$ 536,412	**$ 4,340,983**
Emera Energy Services, Inc.	$ -	$ 60,549	$ 30,609	$ 30,045	$ 30,979	$ 31,034	$ -	$ 31,046	$ -	$ -	$ -	$ -	**$ 214,262**
Granite State Gas Transmission, Inc.	$ 78,400	$ 78,400	$ 78,412	$ 78,412	$ 78,433	$ 78,414	$ 80,364	$ 80,262	$ 134,845	$ 134,781	$ 134,737	$ 134,695	**$ 1,170,156**
Iroquois Gas Transmision System	$ 20,567	$ 20,567	$ 20,567	$ 20,567	$ 20,567	$ 20,567	$ 20,567	$ 21,079	$ 21,079	$ 21,079	$ -	$ 42,158	**$ 249,366**
Portland Natural Gas Transmission	$ 14,305	$ 14,305	$ 14,305	$ 14,305	$ 14,305	$ 14,305	$ 14,309	$ 850,338	$ 1,248,914	$ 1,249,025	$ 1,248,914	$ 1,248,914	**$ 5,946,245**
Tennessee Gas Pipeline Co	$ 130,396	$ 130,396	$ 102,900	$ 130,396	$ 130,396	$ 102,900	$ 130,396	$ 133,638	$ 76,183	$ 133,638	$ 133,638	$ 76,183	**$ 1,411,058**
Texas Eastern Transmission		$ 3,261	$ 9,784	$ 3,261	$ 3,254	$ 3,254	$ 3,254	$ 3,335	$ 3,336	$ 3,336	$ 3,305	$ 3,304	**$ 42,686**
Union Gas Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,429	$ 7,228	$ 7,274	$ 7,356	**$ 36,286**
Vector Pipeline LP	$ 85,737	$ 85,734	$ 85,745	$ 85,736	$ 85,752	$ 85,781	$ 85,789	$ 125,834	$ 125,856	$ 125,858	$ 125,858	$ 125,920	**$ 1,229,601**
Total Pipeline Reservation	$ 677,496	$ 753,820	$ 694,050	$ 715,029	$ 721,629	$ 696,694	$ 696,849	$ 1,613,624	$ 1,986,395	$ 2,048,915	$ 2,036,210	$ 2,191,101	**$ 14,831,814**
Product Demand													
Alberta Northeast Gas Ltd.	$ 1,022	$ 1,025	$ 1,142	$ 1,351	$ 1,186	$ 1,087	$ 1,104	$ 1,136	$ 1,210	$ -	$ 2,235	$ -	**$ 12,500**
Distrigas of Massachusetts	$ 99,140	$ 99,140	$ 99,140	$ 99,140	$ 99,140	$ 99,140	$ 99,140	$ 96,998	$ 107,849	$ 107,849	$ 107,849	$ 107,849	**$ 1,222,370**
FPL/NextEra	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 187,969	$ 187,969	$ 187,969	$ 187,969	$ 187,969	**$ 939,846**
Total Product Demand	$ 100,162	$ 100,165	$ 100,281	$ 100,491	$ 100,326	$ 100,227	$ 100,244	$ 286,103	$ 297,028	$ 295,818	$ 298,053	$ 295,818	**$ 2,174,716**
Storage Pipeline Transportation and Demand Reservation													
Tennessee Gas Pipeline	$ 4,593	$ 4,593	$ 4,593	$ 4,593	$ 4,593	$ 4,593	$ 4,593	$ 4,707	$ 4,707	$ 4,707	$ 4,707	$ 4,707	**$ 55,684**
Washington 10 (BG Energy)	$ 114,300	$ 114,300	$ 114,300	$ 114,300	$ 114,300	$ 114,300	$ 114,300	$ 117,141	$ 117,141	$ 117,141	$ 117,141	$ 117,141	**$ 1,385,803**
Texas Eastern	$ -	$ 83	$ 249	$ 83	$ 83	$ 83	$ 83	$ 84	$ 84	$ 84	$ 83	$ 84	**$ 1,083**
Company Managed	$ (152,105)	$ (80,108)	$ (76,076)	$ (76,668)	$ (76,162)	$ (79,868)	$ (80,220)	$ (295,491)	$ (360,493)	$ (367,839)	$ (384,681)	$ (418,937)	**$ (2,448,647)**
Total Storage and Demand Reservation	$ (33,212)	$ 38,868	$ 43,065	$ 42,306	$ 42,813	$ 39,107	$ 38,756	$ (173,558)	$ (238,561)	$ (245,907)	$ (262,749)	$ (297,005)	**$ (1,006,077)**
Demand Cost Estimates	$ 668,427	$ 783,265	$ 787,966	$ 781,710	$ 778,004	$ 789,086	$ 1,659,762	$ 1,965,329	$ 1,962,205	$ 1,941,756	$ 2,085,801	$ 854,320	**$ 15,057,632**
Demand Cost Reversals	$ (663,217)	$ (668,427)	$ (783,265)	$ (787,966)	$ (781,710)	$ (778,004)	$ (789,086)	$ (1,659,762)	$ (1,965,329)	$ (1,962,205)	$ (1,941,756)	$ (2,085,801)	**$ (14,866,529)**
Total Fixed Demand	$ 749,655	$ 1,007,690	$ 842,097	$ 851,572	$ 861,062	$ 847,110	$ 1,706,525	$ 2,031,736	$ 2,041,738	$ 2,078,378	$ 2,215,558	$ 958,433	**$ 16,191,555**
Amortization of PNGTS Rate Case Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 30,657	$ 30,657	$ 30,657	$ 30,657	$ 30,657	$ 30,657	**$ 183,943**
Capacity Release	$ (127,117)	$ (129,921)	$ (136,339)	$ (129,346)	$ (129,032)	$ (129,089)	$ (129,330)	$ (99,858)	$ (167,802)	$ (134,599)	$ (132,565)	$ (137,207)	**$ (1,582,206)**
Capacity Mitigation	$ (8,963)	$ (9,007)	$ (8,971)	$ (8,973)	$ (9,005)	$ (9,259)	$ (9,260)	$ (12,186)	$ (12,623)	$ (12,343)	$ (12,501)	$ (12,491)	**$ (125,583)**
Production and Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 114,446	$ 114,446	$ 114,446	$ 114,446	$ 114,446	$ 114,446	**$ 686,673**
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 16,389	$ 16,389	$ 16,389	$ 16,389	$ 16,389	$ 16,389	**$ 98,333**
Demand Cost Estimates - Cap Rel	$ (140,258)	$ (140,005)	$ (140,007)	$ (139,645)	$ (140,261)	$ (140,262)	$ (148,021)	$ (182,303)	$ (150,036)	$ (150,730)	$ (151,240)	$ (168,788)	**$ (1,791,556)**
Demand Cost Reversals - Cap Rel	$ 127,663	$ 140,258	$ 140,005	$ 140,007	$ 139,645	$ 140,261	$ 140,262	$ 148,021	$ 182,303	$ 150,036	$ 150,730	$ 151,240	**$ 1,750,431**
Total Demand Costs	**$ 600,980**	**$ 869,015**	**$ 696,785**	**$ 713,615**	**$ 722,410**	**$ 708,761**	**$ 1,721,668**	**$ 2,046,901**	**$ 2,055,072**	**$ 2,092,232**	**$ 2,231,473**	**$ 952,678**	**$ 15,411,591**
Demand Costs Transferred to Summer Perio	$ (176,337)	$ (176,337)	$ (176,337)	$ (176,337)	$ (176,337)	$ (176,337)	$ -	$ -	$ -	$ -	$ -	$ -	**$ (1,058,022)**
Net Demand Costs For Winter Period	**$ 424,643**	**$ 692,678**	**$ 520,448**	**$ 537,278**	**$ 546,073**	**$ 532,424**	**$ 1,721,668**	**$ 2,046,901**	**$ 2,055,072**	**$ 2,092,232**	**$ 2,231,473**	**$ 952,678**	**$ 14,353,569**
Total Gas Costs	**$ 425,974**	**$ 857,318**	**$ 428,039**	**$ 655,977**	**$ 545,080**	**$ 533,510**	**$ 3,078,759**	**$ 4,925,304**	**$ 5,944,553**	**$ 4,818,650**	**$ 4,692,695**	**$ 2,232,562**	**$ 29,138,421**

FORM III
Schedule 5

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010-2011 WINTER PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
May 2010 - April 2011

New Hampshire	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
Throughput IN													
BTU Factor	1.038	1.039	1.033	1.036	1.039	1.041	1.039	1.039	1.046	1.049	1.048	1.041	
GST Meter Throughput (MCF)	312,869	265,598	249,025	269,606	273,645	427,825	569,708	849,169	1,045,428	914,419	780,093	493,361	6,450,746
Salem Meter (MCF)	12,766	9,904	9,385	9,959	10,496	18,586	31,154	57,324	67,178	57,567	45,512	25,940	355,771
GST Meter Throughpurt (DTH)	324,758	275,956	257,243	279,312	284,317	445,366	591,927	882,287	1,093,518	959,226	817,537	513,589	6,725,035
Salem Meter (DTH)	13,251	10,290	9,695	10,318	10,905	19,348	32,369	59,560	70,268	60,388	47,697	27,004	371,092
LNG/Propane													
Total Throughput	338,009	286,247	266,938	289,629	295,222	464,714	624,296	941,846	1,163,786	1,019,613	865,234	540,592	7,096,126
Throughput OUT													
Residential Gas													
Charged	89,805	48,593	37,542	31,398	35,343	45,287	107,248	195,796	291,469	327,102	254,646	192,084	1,656,313
Uncharged Current	24,753	17,120	17,902	18,960	24,555	50,075	80,135	148,473	168,349	135,111	164,902	93,513	943,847
Uncharged Prior	-71,183	-24,753	-17,120	-17,902	-18,960	-24,555	-50,075	-80,135	-148,473	-168,349	-135,111	-164,902	-921,517
Total Residential Gas	**43,375**	**40,960**	**38,324**	**32,457**	**40,938**	**70,806**	**137,308**	**264,134**	**311,345**	**293,864**	**284,436**	**120,695**	1,678,643
Interruptible	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	0
Commercial/Industrial Gas													
Charged	100,468	56,259	50,821	48,982	52,749	63,675	121,973	208,217	342,640	350,674	278,007	203,456	1,877,921
Uncharged Current	33,010	24,405	24,409	28,929	31,853	48,382	82,007	151,318	195,063	145,510	181,239	100,855	1,046,979
Uncharged Prior	-75,149	-33,010	-24,405	-24,409	-28,929	-31,853	-48,382	-82,007	-151,318	-195,063	-145,510	-181,239	-1,021,274
Total C/I Gas	**58,329**	**47,654**	**50,825**	**53,502**	**55,673**	**80,204**	**155,597**	**277,528**	**386,386**	**301,121**	**313,736**	**123,071**	1,903,627
Transportation													
Charged	210,279	200,287	183,338	202,932	206,761	246,364	292,350	379,482	438,660	419,294	396,434	311,797	3,487,978
Uncharged Current	55,335	55,311	49,937	65,560	74,219	115,721	133,472	208,493	192,682	145,148	206,752	127,983	1,430,613
Uncharged Prior	-85,504	-55,335	-55,311	-49,937	-65,560	-74,219	-115,721	-133,472	-208,493	-192,682	-145,148	-206,752	-1,388,134
Total Transportation	**180,110**	**200,263**	**177,964**	**218,555**	**215,420**	**287,866**	**310,101**	**454,503**	**422,849**	**371,760**	**458,038**	**233,029**	**3,530,457**
Company Use	**25**	**7**	**2**	**2**	**6**	**17**	**37**	**85**	**145**	**141**	**104**	**76**	**647**
Total Throughput OUT	**281,838**	**288,884**	**267,115**	**304,515**	**312,038**	**438,894**	**603,044**	**996,250**	**1,120,725**	**966,886**	**1,056,314**	**476,871**	**7,113,374**
Total Throughput IN	**338,009**	**286,247**	**266,938**	**289,629**	**295,222**	**464,714**	**624,296**	**941,846**	**1,163,786**	**1,019,613**	**865,234**	**540,592**	**7,096,126**
Difference IN/OUT	56,171	-2,638	-178	-14,886	-16,815	25,820	21,252	-54,404	43,061	52,727	-191,080	63,721	-17,248
%													-0.24%

Attachment A
Updated July 2012

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
DEFERRED WINTER WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
May 2010 - April 2011

WINTER PERIOD - Acct 182.11

		BEGINNING BALANCE	WORKING CAP ALLOWANCE(1)	WORKING CAP PERCENTAGE	WORKING CAP COLLECTIONS	WORKING CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
		A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
May 2010	$	(84,319)	240	0.0564%	553	794	(83,526)	(83,922)	3.25%	(227)	(83,753)
June	$	(83,753)	484	0.0564%	13	497	(83,256)	(83,504)	3.25%	(226)	(83,482)
July	$	(83,482)	241	0.0564%	(2)	239	(83,243)	(83,362)	3.25%	(226)	(83,469)
August	$	(83,469)	370	0.0564%	2	372	(83,096)	(83,283)	3.25%	(226)	(83,322)
September	$	(83,322)	307	0.0564%	4	311	(83,011)	(83,166)	3.25%	(225)	(83,236)
October	$	(83,236)	301	0.0564%	2	303	(82,933)	(83,084)	3.25%	(225)	(83,158)
November	$	(83,158)	1,736	0.0564%	2,594	4,330	(78,827)	(80,992)	3.25%	(219)	(79,046)
December	$	(79,046)	2,778	0.0564%	5,681	8,459	(70,587)	(74,817)	3.25%	(203)	(70,790)
January 2011	$	(70,790)	3,353	0.0564%	7,962	11,315	(59,475)	(65,133)	3.25%	(176)	(59,652)
February	$	(59,652)	2,718	0.0564%	6,539	9,257	(50,394)	(55,023)	3.25%	(149)	(50,543)
March	$	(50,543)	2,647	0.0564%	6,580	9,227	(41,317)	(45,930)	3.25%	(124)	(41,441)
April	$	(41,441)	1,259	0.0564%	2,687	3,946	(37,496)	(39,468)	3.25%	(107)	(37,602)
Totals			16,434		32,616					(2,334)	

(1) Working Capital Allowance calculated by taking monthly Total Gas Costs from Sch 4, page 2 of 2, and multiplying by (6.33/365)*Interest Rate.

Attachment B
Updated July 2012

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
BAD DEBT EXPENSE - CALCULATION OF COLLECTION ALLOWANCE
May 2010 - April 2011

WINTER PERIOD - Acct 182.16

	BEGINNING BALANCE	BAD DEBT ALLOWANCE(1)	% ALLOWED BAD DEBT	BAD DEBT COLLECTIONS	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
May 2010	(12,179)	1,918	0.45%	1,405	3,323	(8,857)	(10,518)	3.25%	(28)	(8,885)
June	(8,885)	3,860	0.45%	34	3,894	(4,991)	(6,938)	3.25%	(19)	(5,010)
July	(5,010)	1,927	0.45%	(6)	1,921	(3,089)	(4,049)	3.25%	(11)	(3,100)
August	(3,100)	2,954	0.45%	6	2,959	(140)	(1,620)	3.25%	(4)	(145)
September	(145)	2,454	0.45%	10	2,464	2,320	1,088	3.25%	3	2,323
October	2,323	2,402	0.45%	6	2,408	4,731	3,527	3.25%	10	4,740
November	4,740	13,862	0.45%	(11,119)	2,743	7,484	6,112	3.25%	17	7,500
December	7,500	22,176	0.45%	(24,293)	(2,117)	5,384	6,442	3.25%	17	5,401
January 2011	5,401	26,766	0.45%	(34,004)	(7,239)	(1,838)	1,782	3.25%	5	(1,833)
February	(1,833)	21,696	0.45%	(27,957)	(6,261)	(8,093)	(4,963)	3.25%	(13)	(8,107)
March	(8,107)	21,129	0.45%	(28,113)	(6,984)	(15,090)	(11,599)	3.25%	(31)	(15,122)
April	(15,122)	10,052	0.45%	(11,442)	(1,390)	(16,512)	(15,817)	3.25%	(43)	(16,555)
Totals		131,197		(135,473)					(99)	

(1) Bad Debt Allowance calculated by multiplying % Allowed Bad Debt by monthly Total Gas Cost on Sch 4, page 2 of 2, and Working Capital Allowance on Attachment A

Attachment E
Page 1 of 2

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
WINTER 2010 - 2011

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL
Forecast Calendar Month Sales	304,710	472,252	638,023	542,998	525,753	319,160	2,802,896
Actual Sales	229,220	404,014	634,109	677,776	532,653	395,540	2,873,312
Difference	(75,490)	(68,238)	(3,914)	134,778	6,900	76,380	70,416
Add:							
Volume Variance due to Weather							
Normal Cal. Month Actual Sales	227,914	395,404	632,020	644,907	537,921	386,609	2,824,775
Actual Sales	229,220	404,014	634,109	677,776	532,653	395,540	2,873,312
Weather Variance	(1,306)	(8,610)	(2,089)	(32,869)	5,268	(8,931)	(48,537)
Total Variance Excluding Weather (excl weather effect)	(76,796)	(76,848)	(6,003)	101,909	12,168	67,449	21,879
Variance-difference due to meter count							(11,493)
-difference in load pattern							81,911
SALES							70,417

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
WINTER 2010 - 2011

	NORMAL MMBtu			METERS		
	2010-11 Forecast	2010-11 Actual	Difference	2010-11 Forecast	2010-11 Actual	Difference
Res Heat	1,281,543	1,343,369	61,826	123,762	123,390	(372)
Res General	21,981	24,975	2,994	9,600	9,655	55
Total Res	1,303,524	1,368,344	64,820	133,362	133,045	(317)
G-40	625,444	676,391	50,948	27,128	26,987	(141)
G-50	93,945	101,417	7,473	5,761	5,731	(30)
G-41	564,013	527,995	(36,019)	3,386	3,368	(18)
G-51	140,222	138,471	(1,751)	1,406	1,399	(7)
G-42	69,689	55,613	(14,077)	181	180	(1)
G-52	6,058	5,081	(977)	167	166	(1)
Total C & I	1,499,371	1,504,968	5,598	38,028	37,831	(197) .
Total Company	2,802,895	2,873,312	70,417	171,390	170,876	(514)

	NORMAL AVERAGE USE			Change in Sales Due to Change In:			
	2010-11 Forecast	2010-11 Actual	Difference	Meter Count	Load Pattern	Total Chg MMBtu	% Difference
Res Heat	10.35	10.89	0.53	(3,852)	65,678	61,826	4.82%
Res General	2.29	2.59	0.30	126	2,868	2,994	13.62%
Total Res	12.64	13.47	0.83	(3,726)	68,546	64,820	4.97%
G-40	23.06	25.06	2.01	(3,240)	54,188	50,948	8.15%
G-50	16.31	17.70	1.39	(487)	7,959	7,473	7.95%
G-41	166.59	156.77	(9.83)	(2,922)	(33,097)	(36,019)	-6.39%
G-51	99.71	98.98	(0.73)	(726)	(1,025)	(1,751)	-1.25%
G-42	385.16	308.96	(76.20)	(361)	(13,716)	(14,077)	-20.20%
G-52	36.30	30.61	(5.69)	(31)	(945)	(977)	-16.12%
Total C & I	39.43	39.78	0.35	(7,767)	13,365	5,598	0.37%
Total Company	16.35	16.82	0.46	(11,493)	81,911	70,417	2.51%

Schedule 5

Maine Division
Original and Revised 2008-2009 Peak Period Reconciliation

NORTHERN UTILITIES, INC. - MAINE DIVISION
2008-09 PEAK PERIOD RECONCILIATION
May 2008 - April 2009

Original Reconciliation

FORM III
Schedule 1
Page 1 of 2
Revised (8-13-10)

NORTHERN UTILITIES, INC. - MAINE DIVISION
2008-09 PEAK PERIOD RECONCILIATION
SCHEDULE 1: PEAK DEMAND SUMMARY
November 2008 - April 2009

		AMOUNT	
Peak Demand Beg. Balance (including Stipulation Demand)	$	(6,915,647)	SCHEDULE 2
Less: Rev. Billed via Demand CGF (including Capacity Release)	$	(6,103,436)	SCHEDULE 3
Add: Cost of Firm Gas Allowable (Demand)	$	11,019,798	SCHEDULE 2
Less: Adjustment for Del to Sales Fee	$	(1,839)	SCHEDULE 2
Add: Reclass of Supplier Refund Balance	$	1,058	SCHEDULE 2
Add: Adjustment prior to Unitil ownership	$	8,236	SCHEDULE 2
Add: Interest	$	(128,503)	SCHEDULE 2
Peak Demand Ending Balance	$	(2,120,334)	

FORM III
Schedule 1
Page 2 of 2
Revised (8-13-10)

NORTHERN UTILITIES, INC. - MAINE DIVISION
2008-09 PEAK PERIOD RECONCILIATION
SCHEDULE 1: PEAK COMMODITY SUMMARY
November 2008 - April 2009

		AMOUNT	
Peak Commodity Beg. Balance	$	5,896,579	SCHEDULE 2
Less: Rev. Billed via Commodity CGF	$	(27,317,064)	SCHEDULE 3
Add: Cost of Firm Gas Allowable (Commodity)	$	21,736,533	SCHEDULE 2
Add: Adjusted Bill Adjustment	$	-	SCHEDULE 2
Add: Interest	$	193,232	SCHEDULE 2
Less: Interest Previously Applied	$	-	SCHEDULE 2
Peak Commodity Ending Balance	$	509,280	SCHEDULE 2
Net Peak Demand and Commodity Ending Balance	$	(1,611,054)	

FORM III
Schedule 2
Revised (8-13-10)

NORTHERN UTILITIES, INC. - MAINE DIVISION
2008-09 PEAK PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED PEAK PERIOD ACCOUNTS
May 2008 - April 2009

		May 2008	June	July	August	September	October	November	December	January 2009	February	March	April	Total
1	**PEAK DEMAND - ACCOUNT 191.20**													
2	Peak Demand Account Beginning Balance	(7,004,395)	(7,025,688)	(6,319,540)	(6,034,350)	(5,306,305)	(4,884,571)	(4,499,643)	(3,346,569)	(2,578,406)	(2,762,386)	(2,593,855)	(2,260,102)	(7,004,395)
3	Plus: Cost of Gas Allowable (Schedule 4)	(20,496)	726,618	304,905	745,997	439,325	396,708	1,412,023	1,809,160	1,299,020	1,510,802	1,551,278	844,459	11,019,798
4	Less: Base Gas Rev. Applied (Schedule 3)	-	-	-	-	-	-	(246,871)	(1,033,910)	(1,474,489)	(1,333,462)	(1,209,382)	(679,993)	(5,978,106)
5	Less: Capacity Reserve Charge Revenues from Summer	(424)	(4,121)	(3,634)	(3,119)	(3,638)	(3,832)	-	-	-	-	-	-	(18,768)
6	Adjustment for Del to Sales Fee included in 07-08 balance	(345)	(303)	(298)	(298)	(298)	(298)	-	-	-	-	-	-	(1,839)
7	Reclass of Supplier Refund Balance	-	1,058	-	-	-	-	-	-	-	-	-	-	1,058
8	Adjustment 2/	-	-	-	-	-	8,236	-	-	-	-	-	-	8,236
9	**Preliminary Ending Balance**	**(7,025,660)**	**(6,302,436)**	**(6,018,568)**	**(5,291,770)**	**(4,870,917)**	**(4,483,756)**	**(3,334,491)**	**(2,571,319)**	**(2,753,874)**	**(2,585,045)**	**(2,251,959)**	**(2,095,637)**	**(1,974,016)**
10	Month's Average Balance ((Line 1 + Line 5) / 2)	(7,015,027)	(6,664,062)	(6,169,054)	(5,663,060)	(5,088,611)	(4,684,163)	(3,917,067)	(2,958,944)	(2,666,140)	(2,673,716)	(2,422,907)	(2,177,870)	
11	Interest Rate (Short Term Borrowing Rate)	3.32%	3.08%	3.07%	3.08%	3.22%	4.07%	3.70%	2.87%	3.83%	3.95%	4.03%	4.46%	
12	Interest Applied (Line 6 * (Line 7 / 12))	(28)	(17,104)	(15,782)	(14,535)	(13,654)	(15,887)	(12,078)	(7,087)	(8,512)	(8,810)	(8,143)	(8,096)	**(129,717)**
13	Interest Previously Applied*	-	-	-	-	-	-	-	-	-	-	-	-	**-**
14	**Peak Demand Account Ending Balance** (Line 5 + Line 10)	**(7,025,688)**	**(6,319,540)**	**(6,034,350)**	**(5,306,305)**	**(4,884,571)**	**(4,499,643)**	**(3,346,569)**	**(2,578,406)**	**(2,762,386)**	**(2,593,855)**	**(2,260,102)**	**(2,103,733)**	**(2,103,733)**
15	**PEAK COMMODITY - ACCOUNT 191.19**													
16	Peak Commodity Account Beginning Balance	5,896,579	5,879,980	5,906,407	5,945,127	6,204,844	6,263,403	6,343,906	8,461,316	8,648,800	7,913,221	5,024,463	2,570,754	5,896,579
17	Plus: Cost of Gas Allowable	(16,576)	11,320	23,579	244,145	41,853	59,159	3,263,283	4,903,357	5,973,738	3,145,653	3,047,644	1,039,377	21,736,533
18	Less: Base Gas Rev. Applied (Schedule 3)	-	-	-	-	-	-	(1,168,662)	(4,736,339)	(6,735,712)	(6,055,691)	(5,514,095)	(3,106,566)	(27,317,064)
19	Adjusted Bill Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
20	**Preliminary Ending Balance**	**5,880,003**	**5,891,300**	**5,929,986**	**6,189,272**	**6,246,698**	**6,322,562**	**8,438,527**	**8,628,335**	**7,886,826**	**5,003,184**	**2,558,012**	**503,565**	**316,048**
21	Month's Average Balance ((Line 12 + Line 16) / 2)	5,888,291	5,885,640	5,918,196	6,067,199	6,225,771	6,292,983	7,391,216	8,544,825	8,267,813	6,458,202	3,791,238	1,537,160	
22	Interest Rate (Short Term Borrowing Rate)	3.32%	3.08%	3.07%	3.08%	3.22%	4.07%	3.70%	2.87%	3.83%	3.95%	4.03%	4.46%	
23	Interest Applied (Line 17 * (Line 18 / 12))	(23)	15,106	15,141	15,572	16,706	21,344	22,790	20,465	26,395	21,280	12,742	5,714	**193,232**
24	Interest Previously Applied													**-**
25	**Peak Commodity Account Ending Balance** (Line 16 + Line 19)	**5,879,980**	**5,906,407**	**5,945,127**	**6,204,844**	**6,263,403**	**6,343,906**	**8,461,316**	**8,648,800**	**7,913,221**	**5,024,463**	**2,570,754**	**509,280**	**509,280**

		May 2008	June	July	August	September	October	November	December	January 2009	February	March	April	Total
26	**STIPULATION DEMAND CHARGE**													
27	Stipulation Demand Charge Account Beg. Balance	88,748	88,748	79,899	72,098	65,413	57,573	49,324	38,522	29,483	17,545	4,553	(6,550)	88,748
28	Plus: Cost of Gas Allowable (Schedule 4)	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Less: Base Gas Rev. Applied (Schedule 3)	-	(9,065)	(7,995)	(6,862)	(8,004)	(8,430)	(10,936)	(9,121)	(12,012)	(13,028)	(11,100)	(10,007)	(106,562)
30	Adjusted Bill Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
31	**Preliminary Ending Balance**	**88,748**	**79,683**	**71,904**	**65,236**	**57,408**	**49,143**	**38,387**	**29,401**	**17,470**	**4,517**	**(6,547)**	**(16,558)**	**(17,814)**
32	Month's Average Balance ((Line 23 + Line 26) / 2)	88,748	84,215	75,901	68,667	61,410	53,358	43,855	33,962	23,476	11,031	(997)	(11,554)	
33	Interest Rate (Short Term Borrowing Rate)	3.32%	3.08%	3.07%	3.08%	3.22%	4.07%	3.70%	2.87%	3.83%	3.95%	4.03%	4.46%	
34	Interest Applied (Line 27 * (Line 28 / 12))	-	216	194	176	165	181	135	81	75	36	(3)	(43)	**1,214**
35	Interest Previously Applied													**-**
36	**Stipulation Demand Charge Account Ending Balance** (Line 26 + Line 29)	**88,748**	**79,899**	**72,098**	**65,413**	**57,573**	**49,324**	**38,522**	**29,483**	**17,545**	**4,553**	**(6,550)**	**(16,601)**	**(16,601)**

		May 2008	June	July	August	September	October	November	December	January 2009	February	March	April
37	**Peak Demand Account Ending Balance, including**												
38	**Stipulation Demand Charge** (Line 10 + Line 31)	**(6,936,940)**	**(6,239,642)**	**(5,962,252)**	**(5,240,893)**	**(4,826,998)**	**(4,450,319)**	**(3,308,046)**	**(2,548,923)**	**(2,744,841)**	**(2,589,302)**	**(2,266,653)**	**(2,120,334)**
		1/											

***Interest was calculated on the Demand/Commodity Balance during the prior Peak Period reconciliation/filing and is included above in the beginning balance for May. The interest calculated above (Interest Applied) is only calculated on the Off Peak Costs (Sch 4) deferred to Peak.**

1/Beginning balances updated to tie to Winter 07-08 ending balance as filed on August 15, 2008 and then on October 20.

FORM III
Schedule 3
Revised (8-13-10)

NORTHERN UTILITIES, INC. - MAINE DIVISION
2008-09 PEAK PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS - DEMAND REVENUE
May 2008 - April 2009

	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Total
Accrued Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Billed Demand Revenue	$ 424	$ 4,121	$ 3,634	$ 3,119	$ 3,638	$ 3,832	$ 246,871	$ 1,033,910	$ 1,474,489	$ 1,333,462	$ 1,209,382	$ 679,993	$ 5,996,874
Stipulation Demand Charge	$ -	$ 9,065	$ 7,995	$ 6,862	$ 8,004	$ 8,430	$ 10,936	$ 9,121	$ 12,012	$ 13,028	$ 11,100	$ 10,007	$ 106,562
Calendarized Revenue	**$ 424**	**$ 13,186**	**$ 11,629**	**$ 9,981**	**$ 11,643**	**$ 12,262**	**$ 257,808**	**$ 1,043,031**	**$ 1,486,501**	**$ 1,346,490**	**$ 1,220,482**	**$ 690,000**	**$ 6,103,436**

NORTHERN UTILITIES, INC. - MAINE DIVISION
2008-09 PEAK PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS - COMMODITY REVENUE
May 2008 - April 2009

	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Total
Accrued Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Billed Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,168,662	$ 4,736,339	$ 6,735,712	$ 6,055,691	$ 5,514,095	$ 3,106,566	$ 27,317,064
Calendarized Revenue	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,168,662**	**$ 4,736,339**	**$ 6,735,712**	**$ 6,055,691**	**$ 5,514,095**	**$ 3,106,566**	**$ 27,317,064**

NORTHERN UTILITIES, INC. - MAINE DIVISION
2008-09 PEAK PERIOD RECONCILIATION
COST OF GAS ADJUSTMENT RESULTS
November 2008 - April 2009
WINTER RELATED COSTS INCURRED IN SUMMER '08 DEFERRED TO WINTER 2008-09

FORM III
Schedule 4
Page 1 of 2
Revised (8-13-10)

	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Winter
Commodity Costs:													
Alberta Northeast Gas Limited	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,393	$ -	$ -	$ -	$ -	$ -	$ 2,393
Algonquin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 25	$ 25
BG Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,480	$ 22,215	$ 17,144	$ (2,117)	$ 24,937	$ 74,659
BP Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 44,855	$ 70,067	$ -	$ 86,798	$ 201,720
Colonial Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,658	$ 22,658	$ -	$ -	$ -	$ -	$ 45,315
Conoco Phillips	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 765,138	$ 259,219	$ 351,279	$ 1,375,636
Distrigas	$ -	$ -	$ -	$ -	$ -	$ -	$ 239,762	$ 239,718	$ 159,070	$ 347,116	$ 34,978	$ 18,496	$ 1,039,140
Emera Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ 113,867	$ 93,861	$ 159,347	$ 107,974	$ 68,503	$ 193,792	$ 737,344
FedEx Trade	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,826	$ -	$ -	$ -	$ -	$ -	$ 4,826
FPL (Nextera)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 71,183	$ 115,888	$ 59,541	$ 87,812	$ 334,423
Northeast Gas Marketing	$ -	$ -	$ -	$ -	$ -	$ -	$ 202,743	$ 202,398	$ 221,434	$ 191,025	$ 135,492	$ 135,938	$ 1,089,030
Sequent Energy Management LP	$ -	$ -	$ -	$ -	$ -	$ -	$ 574,321	$ 578,822	$ 635,833	$ 542,495	$ 389,364	$ -	$ 2,720,835
Sprague Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 33,701	$ 33,701
Tenaska Energy Ventures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,395	$ 11,985	$ -	$ -	$ 32,380
Tennessee Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,217	$ 3,551	$ 3,448	$ 3,177	$ 2,690	$ 5,400	$ 20,483
Texas Eastern Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 54	$ 54
United	$ -	$ -	$ -	$ -	$ -	$ -	$ 26,832	$ 26,832	$ -	$ -	$ -	$ -	$ 53,664
Subtotal	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,189,619.04**	**$ 1,180,320.65**	**$ 1,337,778.85**	**$ 2,172,007.81**	**$ 947,669.33**	**$ 938,231.80**	**$ 7,765,627.48**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,293,606	$ 2,243,135	$ 967,750	$ 926,936.12	$ 361,751	$ 5,793,178
Commodity Cost Reversals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,189,760)	$ (1,293,606)	$ (2,243,135)	$ (967,750.03)	$ (926,936)	$ (6,621,187)
Subtotal	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 103,846.17**	**$ 949,529.17**	**$ (1,275,384.99)**	**$ (40,813.91)**	**$ (565,185.60)**	**$ (828,009.16)**
Withdrawal Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,116,298	$ 3,645,421	$ 3,974,834	$ 2,891,376	$ 2,307,252	$ 673,368	$ 15,608,550
Interruptible Gas Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ (29,066)	$ (9,231)	$ -	$ -	$ -	$ (1,629)	$ (39,926)
Non Traditional Sales	$ (28,643)	$ (11,203)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (39,846)
Net OBJ Adj	$ -	$ -	$ -	$ -	$ -	$ -	$ (329,188)	$ 110,222	$ (3,354)	$ (9,662)	$ (40,220)	$ (609)	$ (272,810)
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ (12,118)	$ -	$ 9,215	$ (42,012)	$ 3,492	$ 13,103	$ (28,322)
Storage Commodity	$ 196	$ 168	$ 178	$ 173.25	$ (28)	$ (26)							$ 661
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,786	$ -	$ 1,658	$ 15	$ 6,263	$ 6,147	$ 19,868
Transportation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 39,660	$ 58,474	$ 28,010	$ 66,367	$ (17,902)	$ (20,390)	$ 154,219
Transportation Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 597	$ -	$ -	$ -	$ 597
Hedging Costs 1/	$ -	$ -	$ -	$ -	$ -	$ -	$ 228,727	$ 322,373	$ 389,084	$ 474,282	$ 476,672	$ 544,455	$ 2,435,593
LPG Process	$ -	$ -	$ -	$ -	$ -	$ -	$ 511	$ (510,687)	$ (716,202)	$ (1,133,178)	$ (596,120)	$ (548,551)	$ (3,504,226)
Inventory Finance Charges	$ 11,871	$ 22,355	$ 23,401	$ 30,421	$ 41,881	$ 59,185	$ 53,055	$ 2,618	$ 2,588	$ 1,842	$ 1,351	$ 437	$ 251,005
Prior Period Adj	$ -	$ -	$ -	$ 213,551	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 213,551
Total Commodity Costs	**$ (16,576)**	**$ 11,320**	**$ 23,579**	**$ 244,145**	**$ 41,853**	**$ 59,159**	**$ 3,263,283**	**$ 4,903,357**	**$ 5,973,738**	**$ 3,145,653**	**$ 3,047,644**	**$ 1,039,377**	**$ 21,736,533**

1/ Prior period adj for August 2008 is for April 2008 invoice that was originally billed to BSG instead of NU.

NORTHERN UTILITIES, INC. - MAINE DIVISION
2008-09 PEAK PERIOD RECONCILIATION
COST OF GAS ADJUSTMENT RESULTS
November 2008 - April 2009
WINTER RELATED COSTS INCURRED IN SUMMER '08 DEFERRED TO WINTER 2008-09

FORM III
Schedule 4
Page 2 of 2
Revised (8-13-10)

	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Winter
Pipeline Reservation													
Algonquin	15,922	15,944	15,758	16,031	16,049	16,006	16,007	16,015	16,053	15,972	16,002	16,500	192,259
BG Energy	-	284,601	-	284,601	284,601	284,601	-	225,679	226,797	188,033	187,102	198,146	2,164,161
Emera	-	-	-	-	-	-	-	28,952	24,141	18,392	18,671	18,621	108,777
Granite	62,237	62,285	61,499	62,334	62,420	62,420	-	135,861	82,646	82,192	82,340	82,236	838,470
1/PPA to correct July demand alloc. % granite	-	-	-	786	-	-	-	-	-	-	-	-	786
Iroquois	20,554	20,554	20,357	20,732	20,732	20,693	21,000	20,651	20,838	20,628	20,628	21,629	248,997
PNGTS	13,866	13,866	13,691	13,866	13,866	13,866	812,912	872,540	872,540	872,540	872,540	872,540	5,258,633
Sequent	-	-	-	-	-	-	-	25,276	25,074	21,019	20,553	21,674	113,596
Tennessee Gas (El Pas)	132,769	132,769	131,509	133,910	133,911	133,685	27,896	133,739	134,142	133,270	133,270	139,693	1,500,563
Texas Eastern	-	3,355	3,312	3,355	3,355	3,355	3,378	3,378	3,380	3,380	3,382	3,382	37,012
Texas Gas	3,355	-	-	-	-	-	-	-	-	-	-	-	3,355
Vector Limited	1,234	1,234	1,219	1,234	1,234	1,234	1,234	-	-	-	-	-	8,625
Vector LP	89,719	89,719	88,587	89,719	89,719	89,719	128,591	129,807	129,787	129,799	129,738	129,822	1,314,729
Company Managed	-	-	-	-	-	-	3,474	-	-	-	-	-	3,474
1/PPA to correct July demand alloc. %	-	-	-	3,507	-	-	-	-	-	-	-	-	3,507
Prior Period Adjustments	-	312,943	46,993	323,629	31,785	3,169	(9,564)	-	-	-	-	-	708,956
Total Pipeline Reservation	**339,657**	**937,270**	**382,925**	**953,705**	**657,672**	**628,748**	**1,004,928**	**1,591,898**	**1,535,398**	**1,485,226**	**1,484,228**	**1,504,245**	**12,505,899**
Product Demand													
Alberta Northeast	-	-	-	-	-	-	-	1,471	(5,631)	1,110	1,018	1,448	(584)
Distrigas	103,382	103,382	102,077	103,382	103,382	103,382	104,811	115,596	115,596	115,596	115,596	115,596	1,301,774
FPL/Nextera	-	-	-	-	-	-	145,672	-	145,031	145,031	145,672	145,672	727,080
NEGM	-	-	-	-	-	-	-	357	369	369	333	369	1,797
LNG	-	-	-	-	-	-	115	(243,878)	(330,710)	(619,914)	(311,422)	(290,175)	(1,795,984)
1/PPA to correct July demand alloc. %	-	-	-	1,304	-	-	-	-	-	-	-	-	1,304
Prior Period Adj	-	-	-	651	(651)	-	-	-	-	-	-	-	-
Total Product Demand	**103,382**	**103,382**	**102,077**	**105,337**	**102,730**	**103,382**	**250,598**	**(126,455)**	**(75,345)**	**(357,808)**	**(48,803)**	**(27,091)**	**235,387**
Storage Pipeline Transportation and Demand Reservation													
El Paso Energy (Tennessee Gas)	4,579	4,579	4,538	4,621	4,621	4,613	4,627	4,634	4,123	4,600	4,600	4,830	54,968
PNGTS 2/	-	-	-	-	-	(10,407)	-	-	-	-	-	-	(10,407)
Texas Eastern	115	115	114	115	115	115	-	87	87	87	87	87	1,124
Washington 10 - BG Energy	-	-	118,731	120,248	120,248	120,248	120,200	120,200	120,200	120,200	120,200	120,200	1,200,675
Company Managed	-	(7,796)	-	-	-	-	(268,906)	-	-	-	-	-	(276,702)
1/PPA to correct July demand alloc. %	-	-	-	1,577	-	-	-	-	-	-	-	-	1,577
Prior Period Adjustment	-	120,248	120,248	787	(787)	(0)	(0)	-	-	-	-	-	240,496
Total Storage and Demand Reservation	**4,694**	**117,146**	**243,631**	**127,349**	**124,198**	**114,570**	**(144,079)**	**124,921**	**124,410**	**124,887**	**124,887**	**125,117**	**1,211,732**
Subtotal	**447,733**	**1,157,798**	**728,633**	**1,186,391**	**884,600**	**846,700**	**1,111,447**	**1,590,364**	**1,584,464**	**1,252,304**	**1,560,312**	**1,602,271**	**13,953,017**
Demand Cost Estimates	-	-	-	-	-	-	-	1,586,015	1,281,644	1,556,644	1,601,644	859,568	6,885,515
Demand Cost Reversals	-	-	-	-	-	-	-	(1,240,771)	(1,586,015)	(1,281,644)	(1,556,644)	(1,601,644)	(7,266,718)
Subtotal	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**345,243.93**	**(304,371.00)**	**275,000.00**	**45,000.00**	**(742,076.00)**	**(381,203.07)**
Total Fixed Demand	**447,733**	**1,157,798**	**728,633**	**1,186,391**	**884,600**	**846,700**	**1,111,447**	**1,935,608**	**1,280,093**	**1,527,304**	**1,605,312**	**860,195**	**13,571,814**
Interruptible Profits	(2,537)	(3,683)	(8,765)	(20,181)	(22,626)	(28,869)	(7,658)	(17)	-	-	-	(2,269)	(96,605)
Capacity Release	(194,488)	(144,189)	(103,566)	(104,630)	(105,357)	(107,589)	39,356	(121,590)	(226,344)	(232,980)	(239,296)	(241,460)	(1,782,133)
Production and Storage	-	-	-	-	-	-	86,756	123,061	140,774	124,574	106,611	69,680	651,456
LNG/LPG Prod & Storage	-	-	-	-	-	-	64,008	90,794	103,863	91,910	78,657	51,410	480,642
Non-Traditional Sales Margin	(2,923)	(15,028)	(43,121)	(45,275)	(49,011)	(45,252)	-	-	-	-	-	-	(200,610)
1/PPA to correct July demand alloc. % Cap Rel	-	-	-	(2,028)	-	-	-	-	-	-	-	-	(2,028)
Transp. Demand Revenues	(6)	(5)	(1)	(5)	(6)	(5)	(6)	(6)	(6)	(6)	(6)	(6)	(64)
Prior Period Adjustment	-	-	-	-	-	-	118,120	1,150	-	-	-	-	119,270
Subtotal	(199,953)	(162,905)	(155,453)	(172,119)	(177,000)	(181,716)	300,576	93,392	18,287	(16,502)	(54,034)	(122,644)	(830,072)
Demand Cost Estimates - Capacity Release	-	-	-	-	-	-	-	(226,899)	(226,259)	(226,259)	(226,259)	(119,351)	(1,025,027)
Demand Cost Reversals - Capacity Release	-	-	-	-	-	-	-	7,059	226,899	226,259	226,259	226,259	912,735
Subtotal	-	-	-	-	-	-	-	(219,840)	640	-	-	106,908	(112,292)
Total Demand Costs	**247,780**	**994,893**	**573,180**	**1,014,272**	**707,600**	**664,984**	**1,412,023**	**1,809,160**	**1,299,020**	**1,510,802**	**1,551,278**	**844,459**	**12,629,450**
Demand Costs Transferred to Summer Period	268,275	268,275	268,275	268,275	268,275	268,275	-	-	-	-	-	-	**1,609,652**
Net Demand Costs For Winter Period	**(20,496)**	**726,618**	**304,905**	**745,997**	**439,325**	**396,708**	**1,412,023**	**1,809,160**	**1,299,020**	**1,510,802**	**1,551,278**	**844,459**	**11,019,798**
TOTAL FIRM GAS COSTS	**(37,072)**	**737,938**	**328,484**	**990,142**	**481,178**	**455,867**	**4,675,306**	**6,712,517**	**7,272,758**	**4,656,456**	**4,598,921**	**1,883,836**	**32,756,331**

1/Accounting calc 49.3% demand allocation for July instead of 49.93%
2/Supplier refund from PNGTS

FORM III
Schedule 5

NORTHERN UTILITIES, INC. - MAINE DIVISION
2008-09 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
May 2008 - April 2009

	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Total
Maine													
Throughput IN													
BTU Factor	1.077	1.059	1.059	1.05	1.069	1.058	1.050	1.049	1.038	1.038	1.042	1.044	
GST Meter Throughput (MCF)	294,553	207,061	189,696	204,107	236,313	413,711	573,246	823,030	1,085,298	777,310	724,644	436,305	5,965,274
Kittery Meter (MCF)	54,025	43,149	46,007	45,512	46,920	64,366	93,642	122,039	138,443	122,552	124,353	95,094	996,102
GST Meter Throughpurt (DTH)	317,234	219,278	200,888	214,312	252,619	437,706	601,908	863,358	1,126,539	806,848	755,079	455,502	6,251,272
Kittery Meter (DTH)	58,185	45,695	48,721	47,788	50,157	68,099	98,324	128,019	143,704	127,209	129,576	99,278	1,044,755
Cotton Road (Lewiston)(DTH)	77,490	84,341	77,731	77,318	66,214	73,686	92,617	154,585	186,528	168,014	136,986	81,507	1,277,017
LNG/Propane	1,131	1,541	1,439	1,606	1,299	989	800	1,036	794	814	1,268	1,446	14,163
Total Throughput	454,040	350,854	328,779	341,024	370,289	580,480	793,649	1,146,998	1,457,565	1,102,885	1,022,909	637,734	8,587,207
Throughput OUT													
Residential Gas													
Charged	60,655	31,079	24,245	22,473	25,572	37,652	66,620	135,800	206,476	192,347	166,446	105,256	1,074,621
Uncharged Current	31,003	20,110	18,485	19,945	24,999	43,085	67,000	42,346	99,461	87,869	69,728	29,217	553,248
Uncharged Prior	-48,361	-31,003	-20,110	-18,485	-19,945	-24,999	-43,085	-67,000	-42,346	-99,461	-87,869	-69,728	-572,392
Total Residential Gas	**43,297**	**20,186**	**22,620**	**23,933**	**30,626**	**55,738**	**90,535**	**111,146**	**263,591**	**180,754**	**148,305**	**64,746**	**1,055,477**
Interruptible	**1,826**	**2,628**	**4,776**	**4,406**	**4,236**	**5,165**	**3,452**	**10**	**0**	**0**	**0**	**0**	**26,499**
Commercial/Industrial Gas													
Charged	113,636	67,342	55,615	58,991	68,563	89,955	135,788	284,237	382,918	336,601	317,804	169,155	2,080,605
Uncharged Current	53,585	40,657	45,568	44,333	41,865	65,442	139,000	101,365	186,026	150,259	131,280	38,421	1,037,801
Uncharged Prior	-44,902	-53,585	-40,657	-45,568	-44,333	-41,865	-65,442	-139,000	-101,365	-186,026	-150,259	-131,280	-1,044,281
Total C/I Gas	**122,319**	**54,414**	**60,526**	**57,756**	**66,095**	**113,532**	**209,346**	**246,602**	**467,580**	**300,833**	**298,825**	**76,297**	**2,074,124**
Transportation													
Charged	418,333	290,636	256,570	218,120	259,293	270,022	365,111	611,165	733,616	615,292	605,788	425,771	5,069,717
Uncharged Current	279,867	231,522	216,070	217,776	237,869	321,787	398,728	447,691	522,278	429,312	426,473	307,605	4,036,978
Uncharged Prior	-311,193	-279,867	-231,522	-216,070	-217,776	-237,869	-321,787	-398,728	-447,691	-522,278	-429,312	-426,473	-4,040,566
Total Transportation	**387,007**	**242,291**	**241,118**	**219,826**	**279,386**	**353,940**	**442,052**	**660,128**	**808,203**	**522,326**	**602,949**	**306,903**	**5,066,129**
Company Use	**35**	**12**	**11**	**20**	**10**	**35**	**128**	**770**	**1,035**	**909**	**875**	**427**	**4,266**
Total Throughput OUT	**554,484**	**319,531**	**329,051**	**305,941**	**380,353**	**528,410**	**745,513**	**1,018,655**	**1,540,409**	**1,004,822**	**1,050,953**	**448,373**	**8,226,495**
Total Throughput IN	**454,040**	**350,854**	**328,779**	**341,024**	**370,289**	**580,480**	**793,649**	**1,146,998**	**1,457,565**	**1,102,885**	**1,022,909**	**637,734**	**8,587,207**
Difference IN/OUT	-100,444	31,323	-272	35,083	-10,064	52,070	48,136	128,343	-82,843	98,063	-28,045	189,361	360,712
%													4.20%

Attachment A

NORTHERN UTILITIES, INC. - MAINE DIVISION
2008-09 PEAK PERIOD RECONCILIATION
INTERRUPTIBLE PROFIT SCHEDULE
Summary May 2008 - April 2009

	May 2008	June	July	August	September	October	November	December	January 2009	February	March	April	Total
Total Interruptible Sales	$24,466	$38,516	$76,738	$66,813	$63,125	$73,672	$41,110	$124	$0	$0	$0	$6,477	$391,042
Less: Emergency Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Interruptible Sales	$24,466	$38,516	$76,738	$66,813	$63,125	$73,672	$41,110	$124	$0	$0	$0	$6,477	$391,042
Total Interruptible Costs	$21,648	$34,425	$66,999	$44,389	$37,985	$41,595	$32,601	$105	$0	$0	$0	$3,956	$283,702
Total Interruptible Profits	$2,819	$4,092	$9,739	$22,424	$25,139	$32,077	$8,509	$19	$0	$0	$0	$2,521	$107,340
Emergency Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Emergency Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Emer Sales Margin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Inter & Emer Margin	$2,819	$4,092	$9,739	$22,424	$25,139	$32,077	$8,509	$19	$0	$0	$0	$2,521	$107,340
10% Profit	$282	$409	$974	$2,242	$2,514	$3,208	$851	$2	$0	$0	$0	$252	$10,734
90% Profit	$2,537	$3,683	$8,765	$20,181	$22,626	$28,869	$7,658	$17	$0	$0	$0	$2,269	$96,606
100% Profit (Emergency Sales)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Passback Profit	$2,537	$3,683	$8,765	$20,181	$22,626	$28,869	$7,658	$17	$0	$0	$0	$2,269	$96,606

NORTHERN UTILITIES
MAINE DIVISION
DEFERRED PEAK WORKING CAPITAL
ALLOWANCE ON PURCHASED GAS COSTS
Period Ending April 30, 2009

PEAK DEMAND - ACCOUNT 182.13

	BEGINNING BALANCE	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	1	2	3	(4)	5 = 2 + (4)	6 = 1 + 5	7 = (1+ 6) / 2	8	9 = (8 * 7) / 12	10 = 6 + 9
May 08 (Summer)	(21,829)	(90)	0.4410%	0	(90)	(21,919)	(21,874)	3.32%	0	(21,919)
June	(21,919)	3,204	0.4410%	0	3,204	(18,715)	(20,317)	3.08%	(52)	(18,767)
July	(18,767)	1,345	0.4410%	0	1,345	(17,423)	(18,095)	3.07%	(46)	(17,469)
August	(17,469)	3,290	0.4410%	0	3,290	(14,179)	(15,824)	3.08%	(41)	(14,220)
September	(14,220)	1,937	0.4410%	0	1,937	(12,282)	(13,251)	3.22%	(36)	(12,318)
October	(12,318)	1,749	0.4410%	0	1,749	(10,568)	(11,443)	4.07%	(39)	(10,607)
November	(10,607)	6,227	0.4410%	(998)	5,229	(5,378)	(7,992)	3.70%	(25)	(5,402)
December	(5,402)	7,978	0.4410%	(3,999)	3,980	(1,423)	(3,412)	2.87%	(8)	(1,431)
January	(1,431)	5,729	0.4410%	(5,679)	50	(1,381)	(1,406)	3.83%	(4)	(1,385)
February	(1,385)	6,663	0.4410%	(5,096)	1,567	182	(602)	3.95%	(2)	180
March	180	6,841	0.4410%	(4,647)	2,194	2,374	1,277	4.03%	4	2,378
April	2,378	3,724	0.4410%	(2,624)	1,100	3,479	2,928	4.46%	11	3,490
Totals		48,597		(23,041)					(238)	

NORTHERN UTILITIES
MAINE DIVISION
DEFERRED PEAK WORKING CAPITAL
ALLOWANCE ON PURCHASED GAS COSTS
Period Ending April 30, 2009

PEAK COMMODITY - ACCOUNT 182.11

	BEGINNING BALANCE	WKG CAP ALLOWANCE**	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	1	2	3	(4)	5 = 2 + (4)	6 = 1 + 5	7 = (1+ 6) / 2	8	9 = (8 * 7) / 12	10 = 6 + 9
May 08 (Summer)	26,360	(73)	0.4410%	0	(73)	26,287	26,323	3.32%	0	26,287
June	26,287	50	0.4410%	0	50	26,336	26,311	3.08%	68	26,404
July	26,404	104	0.4410%	0	104	26,508	26,456	3.07%	68	26,576
August	26,576	1,077	0.4410%	0	1,077	27,652	27,114	3.08%	70	27,722
September	27,722	185	0.4410%	0	185	27,906	27,814	3.22%	75	27,981
October	27,981	261	0.4410%	0	261	28,242	28,112	4.07%	95	28,337
November	28,337	14,391	0.4410%	(5,187)	9,204	37,541	32,939	3.70%	102	37,643
December	37,643	21,624	0.4410%	(20,794)	830	38,473	38,058	2.87%	91	38,564
January	38,564	26,344	0.4410%	(29,528)	(3,184)	35,380	36,972	3.83%	118	35,498
February	35,498	13,872	0.4410%	(26,498)	(12,626)	22,872	29,185	3.95%	96	22,968
March	22,968	13,440	0.4410%	(24,164)	(10,724)	12,244	17,606	4.03%	59	12,303
April	12,303	4,584	0.4410%	(13,643)	(9,059)	3,244	7,773	4.46%	29	3,273
Totals		95,858		(119,815)					870	
Combined Totals		144,455		(142,856)					632	

Attachment C

NORTHERN UTILITIES, INC
MAINE DIVISION
BAD DEBT EXPENSE
CALCULATION OF COLLECTION ALLOWANCE
April 30, 2009

DEFERRED ACCT - Acct 182.16

	BEG. BAL *	MAINE GAS COSTS PER BOOKS ALLOWED FOR BAD DEBT **	% ALLOWED BAD DEBT	ACTUAL BAD DEBT ALLOWANCE	ACTUAL BAD DEBT COLLECTION	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	1	2	3	4 = 2 * 3	5	6 = 4 + 5	7 = 1 + 6	8 = (1 + 7) / 2	9	10 = 8 * (9 / 12)	11 = 7 + 10
May 08 (Summer)	$13,057	$ (37,235)	1.06%	($395)	$ -	($395)	$12,662	$12,859	3.32%	$0	$12,662
June	$12,662	$ 741,192	1.06%	$7,857	$ -	$7,857	$20,519	$16,590	3.08%	$43	$20,561
July	$20,561	$ 329,932	1.06%	$3,497	$ -	$3,497	$24,058	$22,310	3.07%	$57	$24,116
August	$24,116	$ 994,509	1.06%	$10,542	$ -	$10,542	$34,657	$29,386	3.08%	$75	$34,733
September	$34,733	$ 483,300	1.06%	$5,123	$ -	$5,123	$39,856	$37,294	3.22%	$100	$39,956
October	$39,956	$ 457,878	1.06%	$4,854	$ -	$4,854	$44,809	$42,383	4.07%	$144	$44,953
November	$44,953	$ 4,695,924	1.06%	$49,777	$ (15,163)	$34,614	$79,567	$62,260	3.70%	$192	$79,759
December	$79,759	$ 6,742,119	1.06%	$71,466	$ (60,782)	$10,685	$90,443	$85,101	2.87%	$204	$90,647
January 09	$90,647	$ 7,304,831	1.06%	$77,431	$ (86,314)	($8,883)	$81,765	$86,206	3.83%	$275	$82,040
February	$82,040	$ 4,676,991	1.06%	$49,576	$ (77,456)	($27,880)	$54,160	$68,100	3.95%	$224	$54,384
March	$54,384	$ 4,619,203	1.06%	$48,964	$ (70,634)	($21,670)	$32,714	$43,549	4.03%	$146	$32,860
April	$32,860	$ 1,892,143	1.06%	$20,057	$ (39,879)	($19,822)	$13,038	$22,949	4.46%	$85	$13,124
Totals				$348,748	($350,227)					$1,546	

Northern Utilities, Inc. - Maine Division
Winter 2008-2009 Period

	November	December	January 2009	February	March	April	Total
Forecasted Sales Activity:	316,872	449,474	514,170	455,001	389,390	254,504	2,379,411
Actual Winter 2008-2009 Period	192,951	400,417	567,816	509,583	464,731	262,379	2,397,878
Difference	(123,921)	(49,057)	53,646	54,582	75,341	7,875	18,467
Add:							
Volume Variance due to Weather							
Normal Calendar Month Sales	191,520	380,504	532,718	491,183	453,308	254,645	2,303,878
Actual Sales	192,951	400,417	567,816	509,583	464,731	262,379	2,397,878
Weather Variance	1,432	19,912	35,098	18,401	11,423	7,735	(94,000)
Total Variance Excluding Weather	(122,489)	(29,145)	88,744	72,983	86,764	15,610	(75,533)
Variance-change in meter count							(205,798)
-change in load pattern							148,193
							(57,605)

Northern Utilities, Inc. - Maine Division
Winter 2008-2009 Period

	2008-09 Normal Calendar Mcf	2008-09 Forecasted Mcf	CHANGE in Mcf	2008-09 Actual Meters	2008-09 Forecasted Meters	CHANGE in Meters
	---------	---------	---------	-------------	-------------	-------------
Res Heat	761,156	732,843	28,313	80,457	75,773	4,684
Res Non Heat	49,118	41,163	7,955	30,023	31,325	(1,302)
Total Res	**810,274**	**774,006**	**36,268**	**110,480**	**107,098**	**3,382**
Low Annual Use, Low Peak Period Use (G-50)	119,665	114,104	5,561	9,523	11,820	(2,297)
Low Annual Use, High Peak Period Use (G-40)	683,798	670,525	13,273	27,213	30,964	(3,751)
Medium Annual Use, Low Peak Period Use (G-51)	79,614	123,953	(44,339)	620	981	(361)
Medium Annual Use, High Peak Period Use (G-41)	500,763	576,403	(75,640)	2,142	2,500	(358)
High Annual Use, Low Peak Period Use (G-52)	45,257	67,019	(21,762)	49	43	6
High Annual Use, Low Peak Period Use (G-42)	82,435	53,401	29,034	43	34	9
Total Commercial and Industrial	**1,511,532**	**1,605,405**	**(93,873)**	**39,590**	**46,342**	**(6,752)**
Total Company	**2,321,806**	**2,379,411**	**(57,605)**	**150,070**	**153,440**	**(3,370)**

	2007-08 Normalized Avg Use	2007-08 Forecasted Avg Use	CHANGE in Avg Use	CHANGE IN SALES DUE TO CHANGE IN Meter Count	Load Pattern	TOTAL CHANGE MCF	PERCENT CHANGE
	-------------	-------------	-------------	---------------	---------------	-------	-------
Res Heat	9.46	9.67	(0.21)	44,311	(15,998)	28,313	3.86%
Res Non Heat	1.64	1.31	0.33	7,682	273	7,955	19.33%
Total Res	7.33	7.23	0.10	51,993	(15,725)	36,268	4.69%
Low Annual Use, Low Peak Period Use (G-50)	12.57	9.65	2.92	(28,873)	34,434	5,561	4.87%
Low Annual Use, High Peak Period Use (G-40)	25.13	21.65	3.48	(94,263)	107,536	13,273	1.98%
Medium Annual Use, Low Peak Period Use (G-51)	128.41	126.35	2.06	(46,356)	2,017	(44,339)	-35.77%
Medium Annual Use, High Peak Period Use (G-41)	233.78	230.56	3.22	(83,693)	8,053	(75,640)	-13.12%
High Annual Use, Low Peak Period Use (G-52)	923.61	1,558.58	(634.97)	5,542	(27,304)	(21,762)	-32.47%
High Annual Use, Low Peak Period Use (G-42)	1,917.09	1,570.62	346.47	17,254	11,780	29,034	54.37%
Total Commercial and Industrial	38.18	34.64	3.54	(257,791)	163,918	(93,873)	-5.85%
Total Company	15.47	15.51	(0.04)	(205,798)	148,193	(57,605)	-2.42%

NORTHERN UTILITIES, INC. - MAINE DIVISION
2008-09 PEAK PERIOD RECONCILIATION
May 2008 - April 2009

Recalculated Reconciliation

FORM III
Schedule 1
Page 1 of 2
Updated July 2012

NORTHERN UTILITIES, INC. - MAINE DIVISION
2008-09 PEAK PERIOD RECONCILIATION
SCHEDULE 1: PEAK DEMAND SUMMARY
May 2008 - April 2009

		AMOUNT	
Peak Demand Beg. Balance (including Stipulation Demand)	$	(6,915,647)	SCHEDULE 2
Less: Rev. Billed via Demand CGF (including Capacity Release)	$	(6,103,436)	SCHEDULE 3
Add: Cost of Firm Gas Allowable (Demand)	$	11,019,798	SCHEDULE 2
Less: Adjustment for Del to Sales Fee	$	(1,839)	SCHEDULE 2
Add: Reclass of Supplier Refund Balance	$	1,058	SCHEDULE 2
Add: Adjustment prior to Unitil ownership	$	8,236	SCHEDULE 2
Add: Interest	$	(128,503)	SCHEDULE 2
Peak Demand Ending Balance	$	(2,120,334)	

FORM III
Page 2 of 2
Updated July 2012

NORTHERN UTILITIES, INC. - MAINE DIVISION
2008-09 PEAK PERIOD RECONCILIATION
SCHEDULE 1: PEAK COMMODITY SUMMARY
May 2008 - April 2009

		AMOUNT	
Peak Commodity Beg. Balance	$	5,896,579	SCHEDULE 2
Less: Rev. Billed via Commodity CGF	$	(27,317,064)	SCHEDULE 3
Add: Cost of Firm Gas Allowable (Commodity)	$	22,558,583	SCHEDULE 2
Add: Adjusted Bill Adjustment	$	-	SCHEDULE 2
Add: Interest	$	202,534	SCHEDULE 2
Less: Interest Previously Applied	$	-	SCHEDULE 2
Peak Commodity Ending Balance	$	1,340,632	SCHEDULE 2
Net Peak Demand and Commodity Ending Balance	$	(779,702)	

Updated July 2012 | FORM III
Schedule 2

NORTHERN UTILITIES, INC. - MAINE DIVISION
2008-09 PEAK PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED PEAK PERIOD ACCOUNTS
May 2008 - April 2009

Line		May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Total
1	**PEAK DEMAND - ACCOUNT 191.20**													
2	Peak Demand Account Beginning Balance	(7,004,395)	(7,025,688)	(6,319,540)	(6,034,350)	(5,306,305)	(4,884,571)	(4,499,643)	(3,346,569)	(2,578,406)	(2,762,386)	(2,593,855)	(2,260,102)	(7,004,395)
3	Plus: Cost of Gas Allowable (Schedule 4)	(20,496)	726,618	304,905	745,997	439,325	396,708	1,412,023	1,809,160	1,299,020	1,510,802	1,551,278	844,459	11,019,798
4	Less: Base Gas Rev. Applied (Schedule 3)	-	-	-	-	-	-	(246,871)	(1,033,910)	(1,474,489)	(1,333,462)	(1,209,382)	(679,993)	(5,978,106)
5	Less: Capacity Reserve Charge Revenues from Summer	(424)	(4,121)	(3,634)	(3,119)	(3,638)	(3,832)	-	-	-	-	-	-	(18,768)
6	Adjustment for Del to Sales Fee included in 07-08 balance	(345)	(303)	(298)	(298)	(298)	(298)	-	-	-	-	-	-	(1,839)
7	Reclass of Supplier Refund Balance	-	1,058	-	-	-	-	-	-	-	-	-	-	1,058
8	Adjustment 2/	-	-	-	-	-	8,236	-	-	-	-	-	-	8,236
9	**Preliminary Ending Balance**	**(7,025,660)**	**(6,302,436)**	**(6,018,568)**	**(5,291,770)**	**(4,870,917)**	**(4,483,756)**	**(3,334,491)**	**(2,571,319)**	**(2,753,874)**	**(2,585,045)**	**(2,251,959)**	**(2,095,637)**	**(1,974,016)**
10	Month's Average Balance ((Line 1 + Line 5) / 2)	(7,015,027)	(6,664,062)	(6,169,054)	(5,663,060)	(5,088,611)	(4,684,163)	(3,917,067)	(2,958,944)	(2,666,140)	(2,673,716)	(2,422,907)	(2,177,870)	
11	Interest Rate (Short Term Borrowing Rate)	3.32%	3.08%	3.07%	3.08%	3.22%	4.07%	3.70%	2.87%	3.83%	3.95%	4.03%	4.46%	
12	Interest Applied (Line 6 * (Line 7 / 12))	(28)	(17,104)	(15,782)	(14,535)	(13,654)	(15,887)	(12,078)	(7,087)	(8,512)	(8,810)	(8,143)	(8,096)	**(129,717)**
13	Interest Previously Applied*	-	-	-	-	-	-	-	-	-	-	-	-	**-**
14	**Peak Demand Account Ending Balance** (Line 5 + Line 10)	**(7,025,688)**	**(6,319,540)**	**(6,034,350)**	**(5,306,305)**	**(4,884,571)**	**(4,499,643)**	**(3,346,569)**	**(2,578,406)**	**(2,762,386)**	**(2,593,855)**	**(2,260,102)**	**(2,103,733)**	**(2,103,733)**
15	**PEAK COMMODITY - ACCOUNT 191.19**													
16	Peak Commodity Account Beginning Balance	5,896,579	5,879,980	5,906,407	5,945,127	6,204,844	6,263,403	6,343,906	8,461,316	8,849,360	8,461,176	5,786,606	3,389,726	5,896,579
17	Plus: Cost of Gas Allowable	(16,576)	11,320	23,579	244,145	41,853	59,159	3,263,283	5,103,678	6,319,940	3,357,686	3,101,820	1,048,696	22,558,583
18	Less: Base Gas Rev. Applied (Schedule 3)	-	-	-	-	-	-	(1,168,662)	(4,736,339)	(6,735,712)	(6,055,691)	(5,514,095)	(3,106,566)	(27,317,064)
19	Adjusted Bill Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
20	**Preliminary Ending Balance**	**5,880,003**	**5,891,300**	**5,929,986**	**6,189,272**	**6,246,698**	**6,322,562**	**8,438,527**	**8,828,655**	**8,433,588**	**5,763,171**	**3,374,331**	**1,331,856**	**1,138,098**
21	Month's Average Balance ((Line 12 + Line 16) / 2)	5,888,291	5,885,640	5,918,196	6,067,199	6,225,771	6,292,983	7,391,216	8,644,986	8,641,474	7,112,174	4,580,469	2,360,791	
22	Interest Rate (Short Term Borrowing Rate)	3.32%	3.08%	3.07%	3.08%	3.22%	4.07%	3.70%	2.87%	3.83%	3.95%	4.03%	4.46%	
23	Interest Applied (Line 17 * (Line 18 / 12))	(23)	15,106	15,141	15,572	16,706	21,344	22,790	20,705	27,588	23,435	15,394	8,776	**202,534**
24	Interest Previously Applied													**-**
25	**Peak Commodity Account Ending Balance** (Line 16 + Line 19)	**5,879,980**	**5,906,407**	**5,945,127**	**6,204,844**	**6,263,403**	**6,343,906**	**8,461,316**	**8,849,360**	**8,461,176**	**5,786,606**	**3,389,726**	**1,340,632**	**1,340,632**
26	**STIPULATION DEMAND CHARGE**													Total
27	Stipulation Demand Charge Account Beg. Balance	88,748	88,748	79,899	72,098	65,413	57,573	49,324	38,522	29,483	17,545	4,553	(6,550)	88,748
28	Plus: Cost of Gas Allowable (Schedule 4)	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Less: Base Gas Rev. Applied (Schedule 3)	-	(9,065)	(7,995)	(6,862)	(8,004)	(8,430)	(10,936)	(9,121)	(12,012)	(13,028)	(11,100)	(10,007)	(106,562)
30	Adjusted Bill Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
31	**Preliminary Ending Balance**	**88,748**	**79,683**	**71,904**	**65,236**	**57,408**	**49,143**	**38,387**	**29,401**	**17,470**	**4,517**	**(6,547)**	**(16,558)**	**(17,814)**
32	Month's Average Balance ((Line 23 + Line 26) / 2)	88,748	84,215	75,901	68,667	61,410	53,358	43,855	33,962	23,476	11,031	(997)	(11,554)	
33	Interest Rate (Short Term Borrowing Rate)	3.32%	3.08%	3.07%	3.08%	3.22%	4.07%	3.70%	2.87%	3.83%	3.95%	4.03%	4.46%	
34	Interest Applied (Line 27 * (Line 28 / 12))	-	216	194	176	165	181	135	81	75	36	(3)	(43)	**1,214**
35	Interest Previously Applied													**-**
36	**Stipulation Demand Charge Account Ending Balance** (Line 26 + Line 29)	**88,748**	**79,899**	**72,098**	**65,413**	**57,573**	**49,324**	**38,522**	**29,483**	**17,545**	**4,553**	**(6,550)**	**(16,601)**	**(16,601)**
37	**Peak Demand Account Ending Balance, including**													
38	**Stipulation Demand Charge** (Line 10 + Line 31)	**(6,936,940)**	**(6,239,642)**	**(5,962,252)**	**(5,240,893)**	**(4,826,998)**	**(4,450,319)**	**(3,308,046)**	**(2,548,923)**	**(2,744,841)**	**(2,589,302)**	**(2,266,653)**	**(2,120,334)**	
		1/												

*Interest was calculated on the Demand/Commodity Balance during the prior Peak Period reconciliation/filing and is included above in the beginning balance for May. The interest calculated above (Interest Applied) is only calculated on the Off Peak Costs (Sch 4) deferred to Peak.

1/Beginning balances updated to tie to Winter 07-08 ending balance as filed on August 15, 2008 and then on October 20.
2/An amount of $8,236 has been added back to account for an adjustment made by NiSource prior to Unitil ownership.

FORM III
Schedule 3

NORTHERN UTILITIES, INC. - MAINE DIVISION
2008-09 PEAK PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS - DEMAND REVENUE
May 2008 - April 2009

	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Total
Accrued Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Billed Demand Revenue	$ 424	$ 4,121	$ 3,634	$ 3,119	$ 3,638	$ 3,832	$ 246,871	$ 1,033,910	$ 1,474,489	$ 1,333,462	$ 1,209,382	$ 679,993	**$ 5,996,874**
Stipulation Demand Charge	$ -	$ 9,065	$ 7,995	$ 6,862	$ 8,004	$ 8,430	$ 10,936	$ 9,121	$ 12,012	$ 13,028	$ 11,100	$ 10,007	**$ 106,562**
Calendarized Revenue	**$ 424**	**$ 13,186**	**$ 11,629**	**$ 9,981**	**$ 11,643**	**$ 12,262**	**$ 257,808**	**$ 1,043,031**	**$ 1,486,501**	**$ 1,346,490**	**$ 1,220,482**	**$ 690,000**	**$ 6,103,436**

NORTHERN UTILITIES, INC. - MAINE DIVISION
2008-09 PEAK PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS - COMMODITY REVENUE
May 2008 - April 2009

	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Total
Accrued Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Billed Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,168,662	$ 4,736,339	$ 6,735,712	$ 6,055,691	$ 5,514,095	$ 3,106,566	**$ 27,317,064**
Calendarized Revenue	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,168,662**	**$ 4,736,339**	**$ 6,735,712**	**$ 6,055,691**	**$ 5,514,095**	**$ 3,106,566**	**$ 27,317,064**

NORTHERN UTILITIES, INC. - MAINE DIVISION
2008-09 PEAK PERIOD RECONCILIATION
COST OF GAS ADJUSTMENT RESULTS
May 2008 - April 2009

FORM III
Schedule 4
Page 1 of 2

Updated July 2012

WINTER RELATED COSTS INCURRED IN SUMMER '08 DEFERRED TO WINTER 2008-09

	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Total
Commodity Costs:													
Alberta Northeast Gas Limited	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,393	$ -	$ -	$ -	$ -	$ -	$ 2,393
Algonquin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 25	$ 25
BG Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,480	$ 22,215	$ 17,144	$ (2,117)	$ 24,937	$ 74,659
BP Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 44,855	$ 70,067	$ -	$ 86,798	$ 201,720
Colonial Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,658	$ 22,658	$ -	$ -	$ -	$ -	$ 45,315
Conoco Phillips	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 765,138	$ 259,219	$ 351,279	$ 1,375,636
Distrigas	$ -	$ -	$ -	$ -	$ -	$ -	$ 239,762	$ 239,718	$ 159,070	$ 347,116	$ 34,978	$ 18,496	$ 1,039,140
Emera Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ 113,867	$ 93,861	$ 159,347	$ 107,974	$ 68,503	$ 193,792	$ 737,344
FedEx Trade	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,826	$ -	$ -	$ -	$ -	$ -	$ 4,826
FPL (Nextera)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 71,183	$ 115,888	$ 59,541	$ 87,812	$ 334,423
Northeast Gas Marketing	$ -	$ -	$ -	$ -	$ -	$ -	$ 202,743	$ 202,398	$ 221,434	$ 191,025	$ 135,492	$ 135,938	$ 1,089,030
Sequent Energy Management LP	$ -	$ -	$ -	$ -	$ -	$ -	$ 574,321	$ 578,822	$ 635,833	$ 542,495	$ 389,364	$ -	$ 2,720,835
Sprague Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 33,701	$ 33,701
Tenaska Energy Ventures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,395	$ 11,985	$ -	$ -	$ 32,380
Tennessee Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,217	$ 3,551	$ 3,448	$ 3,177	$ 2,690	$ 5,400	$ 20,483
Texas Eastern Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 54	$ 54
United	$ -	$ -	$ -	$ -	$ -	$ -	$ 26,832	$ 26,832	$ -	$ -	$ -	$ -	$ 53,664
Subtotal	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,189,619**	**$ 1,180,321**	**$ 1,337,779**	**$ 2,172,008**	**$ 947,669**	**$ 938,232**	**$ 7,765,627**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,293,606	$ 2,243,135	$ 967,750	$ 926,936.12	$ 361,751	$ 5,793,178
Commodity Cost Reversals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,189,760)	$ (1,293,606)	$ (2,243,135)	$ (967,750.03)	$ (926,936)	$ (6,621,187)
Subtotal	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**103,846**	**949,529**	**(1,275,385)**	**(40,814)**	**(565,186)**	**(828,009)**
Withdrawal Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,116,298	$ 3,645,421	$ 3,974,834	$ 2,891,376	$ 2,307,252	$ 673,368	$ 15,608,550
Interruptible Gas Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ (29,066)	$ (9,231)	$ -	$ -	$ -	$ (1,629)	$ (39,926)
Non Traditional Sales	$ (28,643)	$ (11,203)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (39,846)
Net OBJ Adj	$ -	$ -	$ -	$ -	$ -	$ -	$ (329,188)	$ 110,222	$ (3,354)	$ (9,662)	$ (40,220)	$ (609)	$ (272,810)
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ (12,118)	$ -	$ 9,215	$ (42,012)	$ 3,492	$ 13,103	$ (28,322)
Storage Commodity	$ 196	$ 168	$ 178	$ 173.25	$ (28)	$ (26)							$ 661
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,786	$ -	$ 1,658	$ 15	$ 6,263	$ 6,147	$ 19,868
Transportation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 39,660	$ 58,474	$ 28,010	$ 66,367	$ (17,902)	$ (20,390)	$ 154,219
Transportation Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 597	$ -	$ -	$ -	$ 597
Hedging Costs 1/	$ -	$ -	$ -	$ -	$ -	$ -	$ 228,727	$ 322,373	$ 389,084	$ 474,282	$ 476,672	$ 544,455	$ 2,435,593
LPG Process	$ -	$ -	$ -	$ -	$ -	$ -	$ 511	$ (510,687)	$ (716,202)	$ (1,133,178)	$ (596,120)	$ (548,551)	$ (3,504,226)
Inventory Finance Charges	$ 11,871	$ 22,355	$ 23,401	$ 30,421	$ 41,881	$ 59,185	$ 53,055	$ 2,618	$ 2,588	$ 1,842	$ 1,351	$ 437	$ 251,005
Prior Period Adj	$ -	$ -	$ -	$ 213,551	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 213,551
Allocation Adjustments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 200,320	$ 346,202	$ 212,033	$ 54,176	$ 9,319	$ 822,050
Total Commodity Costs	**$ (16,576)**	**$ 11,320**	**$ 23,579**	**$ 244,145**	**$ 41,853**	**$ 59,159**	**$ 3,263,283**	**$ 5,103,678**	**$ 6,319,940**	**$ 3,357,686**	**$ 3,101,820**	**$ 1,048,696**	**$ 22,558,583**

1/ Prior period adj for August 2008 is for April 2008 invoice that was originally billed to BSG instead of NU.

NORTHERN UTILITIES, INC. - MAINE DIVISION
2008-09 PEAK PERIOD RECONCILIATION
COST OF GAS ADJUSTMENT RESULTS
May 2008 - April 2009

FORM III
Schedule 4
Page 2 of 2

WINTER RELATED COSTS INCURRED IN SUMMER '08 DEFERRED TO WINTER 2008-09

	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Total
Pipeline Reservation													
Algonquin	15,922	15,944	15,758	16,031	16,049	16,006	16,007	16,015	16,053	15,972	16,002	16,500	192,259
BG Energy	-	284,601	-	284,601	284,601	284,601	-	225,679	226,797	188,033	187,102	198,146	2,164,161
Emera	-	-	-	-	-	-	-	28,952	24,141	18,392	18,671	18,621	108,777
Granite	62,237	62,285	61,499	62,334	62,420	62,420	-	135,861	82,646	82,192	82,340	82,236	838,470
1/PPA to correct July demand alloc. % gra	-	-	-	786	-	-	-	-	-	-	-	-	786
Iroquois	20,554	20,554	20,357	20,732	20,732	20,693	21,000	20,651	20,838	20,628	20,628	21,629	248,997
PNGTS	13,866	13,866	13,691	13,866	13,866	13,866	812,912	872,540	872,540	872,540	872,540	872,540	5,258,633
Sequent	-	-	-	-	-	-	-	25,276	25,074	21,019	20,553	21,674	113,596
Tennessee Gas (El Pas)	132,769	132,769	131,509	133,910	133,911	133,685	27,896	133,739	134,142	133,270	133,270	139,693	1,500,563
Texas Eastern	-	3,355	3,312	3,355	3,355	3,355	3,378	3,378	3,380	3,380	3,382	3,382	37,012
Texas Gas	3,355	-	-	-	-	-	-	-	-	-	-	-	3,355
Vector Limited	1,234	1,234	1,219	1,234	1,234	1,234	1,234	-	-	-	-	-	8,625
Vector LP	89,719	89,719	88,587	89,719	89,719	89,719	128,591	129,807	129,787	129,799	129,738	129,822	1,314,729
Company Managed	-	-	-	-	-	-	3,474	-	-	-	-	-	3,474
1/PPA to correct July demand alloc. %	-	-	-	3,507	-	-	-	-	-	-	-	-	3,507
Prior Period Adjustments	-	312,943	46,993	323,629	31,785	3,169	(9,564)	-	-	-	-	-	708,956
Total Pipeline Reservation	**339,657**	**937,270**	**382,925**	**953,705**	**657,672**	**628,748**	**1,004,928**	**1,591,898**	**1,535,398**	**1,485,226**	**1,484,228**	**1,504,245**	**12,505,899**
Product Demand													
Alberta Northeast	-	-	-	-	-	-	-	1,471	(5,631)	1,110	1,018	1,448	(584)
Distrigas	103,382	103,382	102,077	103,382	103,382	103,382	104,811	115,596	115,596	115,596	115,596	115,596	1,301,774
FPL/Nextera	-	-	-	-	-	-	145,672	-	145,031	145,031	145,672	145,672	727,080
NEGM	-	-	-	-	-	-	-	357	369	369	333	369	1,797
LNG	-	-	-	-	-	-	115	(243,878)	(330,710)	(619,914)	(311,422)	(290,175)	(1,795,984)
1/PPA to correct July demand alloc. %	-	-	-	1,304	-	-	-	-	-	-	-	-	1,304
Prior Period Adj	-	-	-	651	(651)	-	-	-	-	-	-	-	-
Total Product Demand	**103,382**	**103,382**	**102,077**	**105,337**	**102,730**	**103,382**	**250,598**	**(126,455)**	**(75,345)**	**(357,808)**	**(48,803)**	**(27,091)**	**235,387**
Storage Pipeline Transportation and Demand Reservation													
El Paso Energy (Tennessee Gas)	4,579	4,579	4,538	4,621	4,621	4,613	4,627	4,634	4,123	4,600	4,600	4,830	54,968
PNGTS 2/	-	-	-	-	-	(10,407)	-	-	-	-	-	-	(10,407)
Texas Eastern	115	115	114	115	115	115	-	87	87	87	87	87	1,124
Washington 10 - BG Energy	-	-	118,731	120,248	120,248	120,248	120,200	120,200	120,200	120,200	120,200	120,200	1,200,675
Company Managed	-	(7,796)	-	-	-	-	(268,906)	-	-	-	-	-	(276,702)
1/PPA to correct July demand alloc. %	-	-	-	1,577	-	-	-	-	-	-	-	-	1,577
Prior Period Adjustment	-	120,248	120,248	787	(787)	(0)	(0)	-	-	-	-	-	240,496
Total Storage and Demand Reservation	**4,694**	**117,146**	**243,631**	**127,349**	**124,198**	**114,570**	**(144,079)**	**124,921**	**124,410**	**124,887**	**124,887**	**125,117**	**1,211,732**
Subtotal	**447,733**	**1,157,798**	**728,633**	**1,186,391**	**884,600**	**846,700**	**1,111,447**	**1,590,364**	**1,584,464**	**1,252,304**	**1,560,312**	**1,602,271**	**13,953,017**
Demand Cost Estimates	-	-	-	-	-	-	-	1,586,015	1,281,644	1,556,644	1,601,644	859,568	6,885,515
Demand Cost Reversals	-	-	-	-	-	-	-	(1,240,771)	(1,586,015)	(1,281,644)	(1,556,644)	(1,601,644)	(7,266,718)
Subtotal	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**345,243.93**	**(304,371.00)**	**275,000.00**	**45,000.00**	**(742,076.00)**	**(381,203.07)**
Total Fixed Demand	**447,733**	**1,157,798**	**728,633**	**1,186,391**	**884,600**	**846,700**	**1,111,447**	**1,935,608**	**1,280,093**	**1,527,304**	**1,605,312**	**860,195**	**13,571,814**
Interruptible Profits	(2,537)	(3,683)	(8,765)	(20,181)	(22,626)	(28,869)	(7,658)	(17)	-	-	-	(2,269)	(96,605)
Capacity Release	(194,488)	(144,189)	(103,566)	(104,630)	(105,357)	(107,589)	39,356	(121,590)	(226,344)	(232,980)	(239,296)	(241,460)	(1,782,133)
Production and Storage	-	-	-	-	-	-	86,756	123,061	140,774	124,574	106,611	69,680	651,456
LNG/LPG Prod & Storage	-	-	-	-	-	-	64,008	90,794	103,863	91,910	78,657	51,410	480,642
Non-Traditional Sales Margin	(2,923)	(15,028)	(43,121)	(45,275)	(49,011)	(45,252)	-	-	-	-	-	-	(200,610)
1/PPA to correct July demand alloc. % Ca	-	-	-	(2,028)	-	-	-	-	-	-	-	-	(2,028)
Transp. Demand Revenues	(6)	(5)	(1)	(5)	(6)	(5)	(6)	(6)	(6)	(6)	(6)	(6)	(64)
Prior Period Adjustment	-	-	-	-	-	-	118,120	1,150	-	-	-	-	119,270
Subtotal	(199,953)	(162,905)	(155,453)	(172,119)	(177,000)	(181,716)	300,576	93,392	18,287	(16,502)	(54,034)	(122,644)	(830,072)
Demand Cost Estimates - Capacity Releas	-	-	-	-	-	-	-	(226,899)	(226,259)	(226,259)	(226,259)	(119,351)	(1,025,027)
Demand Cost Reversals - Capacity Releas	-	-	-	-	-	-	-	7,059	226,899	226,259	226,259	226,259	912,735
Subtotal	-	-	-	-	-	-	-	(219,840)	640	-	-	106,908	(112,292)
Total Demand Costs	**247,780**	**994,893**	**573,180**	**1,014,272**	**707,600**	**664,984**	**1,412,023**	**1,809,160**	**1,299,020**	**1,510,802**	**1,551,278**	**844,459**	**12,629,450**
Demand Costs Transferred to Summer Pe	268,275	268,275	268,275	268,275	268,275	268,275	-	-	-	-	-	-	**1,609,652**
Net Demand Costs For Winter Period	**(20,496)**	**726,618**	**304,905**	**745,997**	**439,325**	**396,708**	**1,412,023**	**1,809,160**	**1,299,020**	**1,510,802**	**1,551,278**	**844,459**	**11,019,798**
TOTAL FIRM GAS COSTS	**(37,072)**	**737,938**	**328,484**	**990,142**	**481,178**	**455,867**	**4,675,306**	**6,912,837**	**7,618,960**	**4,868,488**	**4,653,098**	**1,893,155**	**33,578,381**

1/Accounting calc 49.3% demand allocation for July instead of 49.93%

2/Supplier refund from PNGTS

FORM III
Schedule 5

NORTHERN UTILITIES, INC. - MAINE DIVISION
2008-09 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
May 2008 - April 2009

	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Total
Maine													
Throughput IN													
BTU Factor	1.077	1.059	1.059	1.05	1.069	1.058	1.050	1.049	1.038	1.038	1.042	1.044	
GST Meter Throughput (MCF)	294,553	207,061	189,696	204,107	236,313	413,711	573,246	823,030	1,085,298	777,310	724,644	436,305	5,965,274
Kittery Meter (MCF)	54,025	43,149	46,007	45,512	46,920	64,366	93,642	122,039	138,443	122,552	124,353	95,094	996,102
GST Meter Throughpurt (DTH)	317,234	219,278	200,888	214,312	252,619	437,706	601,908	863,358	1,126,539	806,848	755,079	455,502	6,251,272
Kittery Meter (DTH)	58,185	45,695	48,721	47,788	50,157	68,099	98,324	128,019	143,704	127,209	129,576	99,278	1,044,755
Cotton Road (Lewiston)(DTH)	77,490	84,341	77,731	77,318	66,214	73,686	92,617	154,585	186,528	168,014	136,986	81,507	1,277,017
LNG/Propane	1,131	1,541	1,439	1,606	1,299	989	800	1,036	794	814	1,268	1,446	14,163
Total Throughput	454,040	350,854	328,779	341,024	370,289	580,480	793,649	1,146,998	1,457,565	1,102,885	1,022,909	637,734	8,587,207
Throughput OUT													
Residential Gas													
Charged	60,655	31,079	24,245	22,473	25,572	37,652	66,620	135,800	206,476	192,347	166,446	105,256	1,074,621
Uncharged Current	31,003	20,110	18,485	19,945	24,999	43,085	67,000	42,346	99,461	87,869	69,728	29,217	553,248
Uncharged Prior	-48,361	-31,003	-20,110	-18,485	-19,945	-24,999	-43,085	-67,000	-42,346	-99,461	-87,869	-69,728	-572,392
Total Residential Gas	**43,297**	**20,186**	**22,620**	**23,933**	**30,626**	**55,738**	**90,535**	**111,146**	**263,591**	**180,754**	**148,305**	**64,746**	**1,055,477**
Interruptible	**1,826**	**2,628**	**4,776**	**4,406**	**4,236**	**5,165**	**3,452**	**10**	**0**	**0**	**0**	**0**	**26,499**
Commercial/Industrial Gas													
Charged	113,636	67,342	55,615	58,991	68,563	89,955	135,788	284,237	382,918	336,601	317,804	169,155	2,080,605
Uncharged Current	53,585	40,657	45,568	44,333	41,865	65,442	139,000	101,365	186,026	150,259	131,280	38,421	1,037,801
Uncharged Prior	-44,902	-53,585	-40,657	-45,568	-44,333	-41,865	-65,442	-139,000	-101,365	-186,026	-150,259	-131,280	-1,044,281
Total C/I Gas	**122,319**	**54,414**	**60,526**	**57,756**	**66,095**	**113,532**	**209,346**	**246,602**	**467,580**	**300,833**	**298,825**	**76,297**	**2,074,124**
Transportation													
Charged	418,333	290,636	256,570	218,120	259,293	270,022	365,111	611,165	733,616	615,292	605,788	425,771	5,069,717
Uncharged Current	279,867	231,522	216,070	217,776	237,869	321,787	398,728	447,691	522,278	429,312	426,473	307,605	4,036,978
Uncharged Prior	-311,193	-279,867	-231,522	-216,070	-217,776	-237,869	-321,787	-398,728	-447,691	-522,278	-429,312	-426,473	-4,040,566
Total Transportation	**387,007**	**242,291**	**241,118**	**219,826**	**279,386**	**353,940**	**442,052**	**660,128**	**808,203**	**522,326**	**602,949**	**306,903**	**5,066,129**
Company Use	**35**	**12**	**11**	**20**	**10**	**35**	**128**	**770**	**1,035**	**909**	**875**	**427**	**4,266**
Total Throughput OUT	**554,484**	**319,531**	**329,051**	**305,941**	**380,353**	**528,410**	**745,513**	**1,018,655**	**1,540,409**	**1,004,822**	**1,050,953**	**448,373**	**8,226,495**
Total Throughput IN	**454,040**	**350,854**	**328,779**	**341,024**	**370,289**	**580,480**	**793,649**	**1,146,998**	**1,457,565**	**1,102,885**	**1,022,909**	**637,734**	**8,587,207**
Difference IN/OUT	-100,444	31,323	-272	35,083	-10,064	52,070	48,136	128,343	-82,843	98,063	-28,045	189,361	360,712
%													4.20%

Attachment A

NORTHERN UTILITIES, INC. - MAINE DIVISION
2008-09 PEAK PERIOD RECONCILIATION
INTERRUPTIBLE PROFIT SCHEDULE
May 2008 - April 2009

	May 2008	June	July	August	September	October	November	December	January 2009	February	March	April	Total
Total Interruptible Sales	$24,466	$38,516	$76,738	$66,813	$63,125	$73,672	$41,110	$124	$0	$0	$0	$6,477	$391,042
Less: Emergency Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Interruptible Sales	$24,466	$38,516	$76,738	$66,813	$63,125	$73,672	$41,110	$124	$0	$0	$0	$6,477	$391,042
Total Interruptible Costs	$21,648	$34,425	$66,999	$44,389	$37,985	$41,595	$32,601	$105	$0	$0	$0	$3,956	$283,702
Total Interruptible Profits	$2,819	$4,092	$9,739	$22,424	$25,139	$32,077	$8,509	$19	$0	$0	$0	$2,521	$107,340
Emergency Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Emergency Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Emer Sales Margin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Inter & Emer Margin	$2,819	$4,092	$9,739	$22,424	$25,139	$32,077	$8,509	$19	$0	$0	$0	$2,521	$107,340
10% Profit	$282	$409	$974	$2,242	$2,514	$3,208	$851	$2	$0	$0	$0	$252	$10,734
90% Profit	$2,537	$3,683	$8,765	$20,181	$22,626	$28,869	$7,658	$17	$0	$0	$0	$2,269	$96,606
100% Profit (Emergency Sales)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Passback Profit	$2,537	$3,683	$8,765	$20,181	$22,626	$28,869	$7,658	$17	$0	$0	$0	$2,269	$96,606

Updated July 2012 Attachment B
Page 1 of 2

NORTHERN UTILITIES
MAINE DIVISION
DEFERRED PEAK WORKING CAPITAL
ALLOWANCE ON PURCHASED GAS COSTS
May 2008 - April 2009

PEAK DEMAND - ACCOUNT 182.13

	BEGINNING BALANCE	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	1	2	3	(4)	5 = 2 + (4)	6 = 1 + 5	7 = (1+ 6) / 2	8	9 = (8 * 7) / 12	10 = 6 + 9
May 08 (Summer)	(21,829)	(90)	0.4410%	0	(90)	(21,919)	(21,874)	3.32%	0	(21,919)
June	(21,919)	3,204	0.4410%	0	3,204	(18,715)	(20,317)	3.08%	(52)	(18,767)
July	(18,767)	1,345	0.4410%	0	1,345	(17,423)	(18,095)	3.07%	(46)	(17,469)
August	(17,469)	3,290	0.4410%	0	3,290	(14,179)	(15,824)	3.08%	(41)	(14,220)
September	(14,220)	1,937	0.4410%	0	1,937	(12,282)	(13,251)	3.22%	(36)	(12,318)
October	(12,318)	1,749	0.4410%	0	1,749	(10,568)	(11,443)	4.07%	(39)	(10,607)
November	(10,607)	6,227	0.4410%	(998)	5,229	(5,378)	(7,992)	3.70%	(25)	(5,402)
December	(5,402)	7,978	0.4410%	(3,999)	3,980	(1,423)	(3,412)	2.87%	(8)	(1,431)
January	(1,431)	5,729	0.4410%	(5,679)	50	(1,381)	(1,406)	3.83%	(4)	(1,385)
February	(1,385)	6,663	0.4410%	(5,096)	1,567	182	(602)	3.95%	(2)	180
March	180	6,841	0.4410%	(4,647)	2,194	2,374	1,277	4.03%	4	2,378
April	2,378	3,724	0.4410%	(2,624)	1,100	3,479	2,928	4.46%	11	3,490
Totals		48,597		(23,041)					(238)	

Updated July 2012 Attachment B
Page 2 of 2

NORTHERN UTILITIES
MAINE DIVISION
DEFERRED PEAK WORKING CAPITAL
ALLOWANCE ON PURCHASED GAS COSTS
May 2008 - April 2009

PEAK COMMODITY - ACCOUNT 182.11

	BEGINNING BALANCE	WKG CAP ALLOWANCE**	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	1	2	3	(4)	5 = 2 + (4)	6 = 1 + 5	7 = (1+ 6) / 2	8	9 = (8 * 7) / 12	10 = 6 + 9
May 08 (Summer)	26,360	(73)	0.4410%	0	(73)	26,287	26,323	3.32%	0	26,287
June	26,287	50	0.4410%	0	50	26,336	26,311	3.08%	68	26,404
July	26,404	104	0.4410%	0	104	26,508	26,456	3.07%	68	26,576
August	26,576	1,077	0.4410%	0	1,077	27,652	27,114	3.08%	70	27,722
September	27,722	185	0.4410%	0	185	27,906	27,814	3.22%	75	27,981
October	27,981	261	0.4410%	0	261	28,242	28,112	4.07%	95	28,337
November	28,337	14,391	0.4410%	(5,187)	9,204	37,541	32,939	3.70%	102	37,643
December	37,643	22,507	0.4410%	(20,794)	1,713	39,356	38,499	2.87%	92	39,448
January	39,448	27,871	0.4410%	(29,528)	(1,657)	37,791	38,619	3.83%	123	37,914
February	37,914	14,807	0.4410%	(26,498)	(11,691)	26,223	32,069	3.95%	106	26,329
March	26,329	13,679	0.4410%	(24,164)	(10,485)	15,844	21,086	4.03%	71	15,915
April	15,915	4,625	0.4410%	(13,643)	(9,018)	6,897	11,406	4.46%	42	6,939
Totals		99,483		(119,815)					911	

** Working Capital Allowance Calculated by taking Eligible Gas Costs from Sch 4 and multiplying by Working Capital Percentage

Beginning balance for May 08 (Summer) should tie to Ending balance for May 08 (Winter) from the Winter 07-08 Reconciliation as filed in Docket No. 2008-343

Combined Totals	148,081	(142,856)	673	

Updated July 2012 Attachment C

NORTHERN UTILITIES, INC
MAINE DIVISION
BAD DEBT EXPENSE
CALCULATION OF COLLECTION ALLOWANCE
May 2008 - April 2009

DEFERRED ACCT - Acct 182.16

	BEG. BAL *	MAINE GAS COSTS PER BOOKS ALLOWED FOR BAD DEBT **	% ALLOWED BAD DEBT	ACTUAL BAD DEBT ALLOWANCE	ACTUAL BAD DEBT COLLECTION	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	1	2	3	4 = 2 * 3	5	6 = 4 + 5	7 = 1 + 6	8 = (1 + 7) / 2	9	10 = 8 * (9 / 12)	11 = 7 + 10
May 08 (Summer)	$13,057	$ (37,235)	1.06%	($395)	$ -	($395)	$12,662	$12,859	3.32%	$0	$12,662
June	$12,662	$ 741,192	1.06%	$7,857	$ -	$7,857	$20,519	$16,590	3.08%	$43	$20,561
July	$20,561	$ 329,932	1.06%	$3,497	$ -	$3,497	$24,058	$22,310	3.07%	$57	$24,116
August	$24,116	$ 994,509	1.06%	$10,542	$ -	$10,542	$34,657	$29,386	3.08%	$75	$34,733
September	$34,733	$ 483,300	1.06%	$5,123	$ -	$5,123	$39,856	$37,294	3.22%	$100	$39,956
October	$39,956	$ 457,878	1.06%	$4,854	$ -	$4,854	$44,809	$42,383	4.07%	$144	$44,953
November	$44,953	$ 4,695,924	1.06%	$49,777	$ (15,163)	$34,614	$79,567	$62,260	3.70%	$192	$79,759
December	$79,759	$ 6,943,323	1.06%	$73,599	$ (60,782)	$12,817	$92,576	$86,168	2.87%	$206	$92,783
January 09	$92,783	$ 7,652,559	1.06%	$81,117	$ (86,314)	($5,197)	$87,586	$90,184	3.83%	$288	$87,874
February	$87,874	$ 4,889,959	1.06%	$51,834	$ (77,456)	($25,623)	$62,251	$75,063	3.95%	$247	$62,498
March	$62,498	$ 4,673,618	1.06%	$49,540	$ (70,634)	($21,093)	$41,405	$51,952	4.03%	$175	$41,580
April	$41,580	$ 1,901,503	1.06%	$20,156	$ (39,879)	($19,723)	$21,857	$31,718	4.46%	$118	$21,975
Totals				$357,500	($350,227)					$1,645	

** Working Capital Allowance from "Working Capital Summary" worksheet
Beginning balance for May 08 (Summer) should tie to Ending balance for May 08 (Winter) from the Winter 07-08 Reconciliation as filed in Docket No. 2008-343

Northern Utilities, Inc. - Maine Division
Winter 2008-2009 Period

	November	December	January 2009	February	March	April	Total
Forecasted Sales Activity:	316,872	449,474	514,170	455,001	389,390	254,504	2,379,411
Actual Winter 2008-2009 Period	192,951	400,417	567,816	509,583	464,731	262,379	2,397,878
Difference	(123,921)	(49,057)	53,646	54,582	75,341	7,875	18,467
Add:							
Volume Variance due to Weather							
Normal Calendar Month Sales	191,520	380,504	532,718	491,183	453,308	254,645	2,303,878
Actual Sales	192,951	400,417	567,816	509,583	464,731	262,379	2,397,878
Weather Variance	1,432	19,912	35,098	18,401	11,423	7,735	(94,000)
Total Variance Excluding Weather	(122,489)	(29,145)	88,744	72,983	86,764	15,610	(75,533)
Variance-change in meter count							(205,798)
-change in load pattern							148,193
							(57,605)

Northern Utilities, Inc. - Maine Division
Winter 2008-2009 Period

Attachment D
Page 2 of 2

	2008-09 Normal Calendar Mcf	2008-09 Forecasted Mcf	CHANGE in Mcf	2008-09 Actual Meters	2008-09 Forecasted Meters	CHANGE in Meters
Res Heat	761,156	732,843	28,313	80,457	75,773	4,684
Res Non Heat	49,118	41,163	7,955	30,023	31,325	(1,302)
Total Res	**810,274**	**774,006**	**36,268**	**110,480**	**107,098**	**3,382**
Low Annual Use, Low Peak Period Use (G-50)	119,665	114,104	5,561	9,523	11,820	(2,297)
Low Annual Use, High Peak Period Use (G-40)	683,798	670,525	13,273	27,213	30,964	(3,751)
Medium Annual Use, Low Peak Period Use (G-51)	79,614	123,953	(44,339)	620	981	(361)
Medium Annual Use, High Peak Period Use (G-41)	500,763	576,403	(75,640)	2,142	2,500	(358)
High Annual Use, Low Peak Period Use (G-52)	45,257	67,019	(21,762)	49	43	6
High Annual Use, Low Peak Period Use (G-42)	82,435	53,401	29,034	43	34	9
Total Commercial and Industrial	**1,511,532**	**1,605,405**	**(93,873)**	**39,590**	**46,342**	**(6,752)**
Total Company	**2,321,806**	**2,379,411**	**(57,605)**	**150,070**	**153,440**	**(3,370)**

	2007-08 Normalized Avg Use	2008-09 Forecasted Avg Use	CHANGE in Avg Use	CHANGE IN SALES DUE TO CHANGE IN Meter Count	Load Pattern	TOTAL CHANGE MCF	PERCENT CHANGE
Res Heat	9.46	9.67	(0.21)	44,311	(15,998)	28,313	3.86%
Res Non Heat	1.64	1.31	0.33	7,682	273	7,955	19.33%
Total Res	7.33	7.23	0.10	51,993	(15,725)	36,268	4.69%
Low Annual Use, Low Peak Period Use (G-50)	12.57	9.65	2.92	(28,873)	34,434	5,561	4.87%
Low Annual Use, High Peak Period Use (G-40)	25.13	21.65	3.48	(94,263)	107,536	13,273	1.98%
Medium Annual Use, Low Peak Period Use (G-51)	128.41	126.35	2.06	(46,356)	2,017	(44,339)	-35.77%
Medium Annual Use, High Peak Period Use (G-41)	233.78	230.56	3.22	(83,693)	8,053	(75,640)	-13.12%
High Annual Use, Low Peak Period Use (G-52)	923.61	1,558.58	(634.97)	5,542	(27,304)	(21,762)	-32.47%
High Annual Use, Low Peak Period Use (G-42)	1,917.09	1,570.62	346.47	17,254	11,780	29,034	54.37%
Total Commercial and Industrial	38.18	34.64	3.54	(257,791)	163,918	(93,873)	-5.85%
Total Company	15.47	15.51	(0.04)	(205,798)	148,193	(57,605)	-2.42%

Schedule 6

Maine Division
Original and Revised 2009-2010 Peak Period Reconciliation

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009-10 PEAK PERIOD RECONCILIATION
May 2009 - April 2010

Original Reconciliation

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009-10 PEAK PERIOD RECONCILIATION
SCHEDULE 1: PEAK DEMAND SUMMARY
November 2009 - April 2010

		AMOUNT	
Peak Demand Beginning Balance	$	(2,120,334)	SCHEDULE 2
Less: Cost of Firm Gas Revenue (Demand)	$	(8,369,062)	SCHEDULE 2
Add: Cost of Firm Gas Allowable (Demand)	$	10,921,727	SCHEDULE 2
Add: Interest	$	(7,409)	SCHEDULE 2
Peak Demand Ending Balance	$	424,922	

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009-10 PEAK PERIOD RECONCILIATION
SCHEDULE 1: PEAK COMMODITY SUMMARY
November 2009 - April 2010

		AMOUNT	
Peak Commodity Beginning Balance	$	509,280	SCHEDULE 2
Less: Cost of Firm Gas Revenue (Commodity)	$	(14,488,324)	SCHEDULE 2
Add: Cost of Firm Gas Allowable (Commodity)	$	12,405,739	SCHEDULE 2
Add: Interest	$	(11,303)	SCHEDULE 2
Peak Commodity Ending Balance	$	(1,584,608)	
Net Peak Demand and Commodity Ending Balance	$	(1,159,686)	

FORM III
Schedule 2

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009-10 PEAK PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED PEAK PERIOD ACCOUNTS
May 2009 - April 2010

		May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
1	**PEAK DEMAND - ACCOUNT 191.20**													
2	Peak Demand Account Beginning Balance (1)	$ (2,120,334)	$ (1,962,588)	$ (1,389,557)	$ (878,855)	$ (323,082)	$ 274,861	$ 637,479	$ 1,264,318	$ 901,147	$ (45,395)	$ (178,670)	$ 10,568	$ (2,120,334)
3	Plus: Cost of Gas Demand Allowable (Schedule 4)	$ 391,895	$ 583,213	$ 516,695	$ 559,988	$ 609,382	$ 366,718	$ 1,427,665	$ 1,426,235	$ 1,122,272	$ 1,446,841	$ 1,418,332	$ 1,052,491	$ 10,921,727
4	Less: Cost of Gas Demand Revenue (Schedule 3)	$ (227,167)	$ (7,297)	$ (4,062)	$ (3,203)	$ (11,399)	$ (4,916)	$ (802,599)	$ (1,791,418)	$ (2,069,610)	$ (1,579,907)	$ (1,228,938)	$ (638,546)	$ (8,369,062)
5	**Preliminary Ending Balance**	**$ (1,955,605)**	**$ (1,386,672)**	**$ (876,924)**	**$ (322,070)**	**$ 274,902**	**$ 636,663**	**$ 1,262,545**	**$ 899,134**	**$ (46,190)**	**$ (178,462)**	**$ 10,725**	**$ 424,513**	**$ 432,331**
6	Month's Average Balance ((Line 2 + Line 5) / 2)	$ (2,037,969)	$ (1,674,630)	$ (1,133,241)	$ (600,462)	$ (24,090)	$ 455,762	$ 950,012	$ 1,081,726	$ 427,479	$ (111,928)	$ (83,972)	$ 217,541	
7	Interest Rate (Short Term Borrowing Rate)	4.112%	2.067%	2.044%	2.022%	1.998%	2.148%	2.240%	2.233%	2.232%	2.229%	2.236%	2.255%	
8	Interest Applied (Line 6 * (Line 7 / 12))	$ (6,983)	$ (2,885)	$ (1,930)	$ (1,012)	$ (40)	$ 816	$ 1,773	$ 2,013	$ 795	$ (208)	$ (156)	$ 409	$ (7,409)
9	**Peak Demand Account Ending Balance**	**$ (1,962,588)**	**$ (1,389,557)**	**$ (878,855)**	**$ (323,082)**	**$ 274,861**	**$ 637,479**	**$ 1,264,318**	**$ 901,147**	**$ (45,395)**	**$ (178,670)**	**$ 10,568**	**$ 424,922**	**$ 424,922**

(1) Peak Period Ending Balance of ($1,940,916) approved by Commission Order dated October 28, 2009, in Docket No. 2009-250. This figure has been revised as a result of revisions to the prior period reconciliation.

		May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
10	**PEAK COMMODITY - ACCOUNT 191.19**													
11	Peak Commodity Account Beginning Balance (1)	$ 509,280	$ (513,457)	$ (511,069)	$ (536,659)	$ (539,139)	$ (540,944)	$ (537,008)	$ (487,168)	$ 178,106	$ 263,990	$ (799,555)	$ (1,708,807)	$ 509,280
12	Plus: Cost of Gas Commodity Allowable (Schedule 4)	$ (7,236)	$ 3,270	$ 3,642	$ 3,614	$ 597	$ 4,921	$ 1,415,797	$ 3,603,056	$ 3,485,232	$ 1,536,254	$ 1,144,867	$ 1,211,724	$ 12,405,739
13	Less: Cost of Gas Commodity Revenue (Schedule 3)	$ (1,015,493)	$ -	$ (28,342)	$ (5,188)	$ (1,504)	$ (21)	$ (1,365,003)	$ (2,937,494)	$ (3,399,758)	$ (2,599,302)	$ (2,051,785)	$ (1,084,434)	$ (14,488,324)
14	**Preliminary Ending Balance**	**$ (513,450)**	**$ (510,187)**	**$ (535,768)**	**$ (538,233)**	**$ (540,045)**	**$ (536,044)**	**$ (486,213)**	**$ 178,393**	**$ 263,579**	**$ (799,058)**	**$ (1,706,472)**	**$ (1,581,516)**	**$ (1,573,305)**
15	Month's Average Balance ((Line 10 + Line 15) / 2)	$ (2,085)	$ (511,822)	$ (523,418)	$ (537,446)	$ (539,592)	$ (538,494)	$ (511,611)	$ (154,388)	$ 220,843	$ (267,534)	$ (1,253,014)	$ (1,645,161)	
16	Interest Rate (Short Term Borrowing Rate)	4.112%	2.067%	2.044%	2.022%	1.998%	2.148%	2.240%	2.233%	2.232%	2.229%	2.236%	2.255%	
17	Interest Applied (Line 16 * (Line 17 / 12))	$ (7)	$ (882)	$ (892)	$ (906)	$ (898)	$ (964)	$ (955)	$ (287)	$ 411	$ (497)	$ (2,334)	$ (3,092)	$ (11,303)
18	**Peak Commodity Account Ending Balance**	**$ (513,457)**	**$ (511,069)**	**$ (536,659)**	**$ (539,139)**	**$ (540,944)**	**$ (537,008)**	**$ (487,168)**	**$ 178,106**	**$ 263,990**	**$ (799,555)**	**$ (1,708,807)**	**$ (1,584,608)**	**$ (1,584,608)**

(1) Peak Period Ending Balance of $49,627 approved by Commission Order dated October 28, 2009, in Docket No. 2009-250. This figure has been revised as a result of revisions to the prior period reconciliation.

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009-10 PEAK PERIOD RECONCILIATION
SCHEDULE 3: BILLED REVENUE
May 2009 - April 2010

FORM III
Schedule 3

	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
Demand Revenue:													
Accrued Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ 456,693	$ 526,047	$ (35,169)	$ (123,175)	$ (99,386)	$ (300,601)	$ 424,409
Billed Revenue	$ 227,167	$ 7,297	$ 4,062	$ 3,203	$ 11,399	$ 4,916	$ 345,906	$ 1,265,372	$ 2,104,778	$ 1,703,083	$ 1,328,324	$ 939,147	$ 7,944,654
Calendarized Revenue	**$ 227,167**	**$ 7,297**	**$ 4,062**	**$ 3,203**	**$ 11,399**	**$ 4,916**	**$ 802,599**	**$ 1,791,418**	**$ 2,069,610**	**$ 1,579,907**	**$ 1,228,938**	**$ 638,546**	**$ 8,369,062**
Commodity Revenue:													
Accrued Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ 774,943	$ 842,004	$ (52,139)	$ (196,079)	$ (149,402)	$ (497,941)	$ 721,385
Billed Revenue	$ 1,015,493	$ -	$ 28,342	$ 5,188	$ 1,504	$ 21	$ 590,060	$ 2,095,490	$ 3,451,897	$ 2,795,382	$ 2,201,187	$ 1,582,375	$ 13,766,939
Calendarized Revenue	**$ 1,015,493**	**$ -**	**$ 28,342**	**$ 5,188**	**$ 1,504**	**$ 21**	**$ 1,365,003**	**$ 2,937,494**	**$ 3,399,758**	**$ 2,599,302**	**$ 2,051,785**	**$ 1,084,434**	**$ 14,488,324**
Total Revenue	**$ 1,242,659**	**$ 7,297**	**$ 32,404**	**$ 8,392**	**$ 12,903**	**$ 4,937**	**$ 2,167,602**	**$ 4,728,913**	**$ 5,469,368**	**$ 4,179,210**	**$ 3,280,722**	**$ 1,722,980**	**$ 22,857,386**

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009-10 PEAK PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO PEAK PERIOD
May 2009 - April 2010

Commodity Costs	**May-09 (Actual)**	**Jun-09 (Actual)**	**Jul-09 (Actual)**	**Aug-09 (Actual)**	**Sep-09 (Actual)**	**Oct-09 (Actual)**	**Nov-09 (Actual)**	**Dec-09 (Actual)**	**Jan-10 (Actual)**	**Feb-10 (Actual)**	**Mar-10 (Actual)**	**Apr-10 (Actual)**	**Total Peak**
BG Energy Merchants, LLC	$ 23,914	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,358	$ -	$ -	$ 22,897	**$ 54,169**
Boss Energy, LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,981	$ -	$ -	$ -	**$ 10,981**
BP Energy Marketing Corp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 46,901	$ 522,982	$ 1,156,252	$ 609,082	$ -	**$ 2,335,216**
Classic Energy, LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 78	$ -	$ -	**$ 78**
Distrigas of Massachusetts, LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 89,220	$ 213,407	$ 248,869	$ 221,211	$ 242,954	**$ 1,015,660**
DTE Energy Trading, Inc.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 354,528	$ -	$ -	$ -	$ -	**$ 354,528**
Emera Energy Services, Inc.	$ 47,009	$ -	$ -	$ -	$ -	$ -	$ -	$ 107,263	$ 127,376	$ 87,260	$ 88,168	$ 73,732	**$ 530,808**
Iberdrola Renewables	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 645,792	$ 552,127	$ 464,375	$ -	**$ 1,662,294**
Integrys Energy Services, Inc.	$ 3,520	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 3,520**
JP Morgan Ventures Energy Corp	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,295	$ -	$ -	$ -	$ -	**$ 11,295**
Louis Dreyfus Electric Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,507	$ -	**$ 5,507**
Macquarie Cook Energy, LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 885,854	$ 7,343	$ -	$ -	**$ 893,197**
NextEra Energy Power Marketing, LLC	$ 43,710	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,605	$ -	$ -	$ -	**$ 52,314**
Northeast Gas Markets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 160,791	$ 174,710	$ 204,866	$ 164,215	$ -	**$ 704,581**
Sequent Energy Management, LP	$ 276,339	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,530	$ -	$ -	$ -	$ -	**$ 279,869**
South Jersey Resources	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 190,775	$ -	$ -	$ -	$ -	**$ 190,775**
Spark Energy Gas, LP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,046	$ -	$ -	$ -	**$ 11,046**
Sprague Energy Corp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 28,818	$ -	**$ 28,818**
Tennessee Gas Pipeline Co	$ 619	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,519	$ 6,633	$ 6,056	$ 18,676	$ 8,971	**$ 47,474**
Subtotal	**$ 395,112**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 970,821**	**$ 2,614,743**	**$ 2,262,851**	**$ 1,600,050**	**$ 348,553**	**$ 8,192,130**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 960,614	$ 2,609,637	$ 2,144,478	$ 681,982	$ 350,770	$ 743,844	**$ 7,491,326**
Commodity Cost Reversals	$ (361,751)	$ -	$ -	$ -	$ -	$ -	$ -	$ (960,614)	$ (2,609,637)	$ (2,144,478)	$ (681,982)	$ (350,770)	**$ (7,109,232)**
Subtotal	**$ (361,751)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 960,614**	**$ 1,649,023**	**$ (465,159)**	**$ (1,462,496)**	**$ (331,213)**	**$ 393,074**	**$ 382,094**
Withdrawal Charges	$ 76	$ 2,791	$ 2,265	$ 3,053	$ -	$ 4,074	$ 4,452	$ 85,619	$ 890,666	$ 1,215,884	$ 820,519	$ 8,233	**$ 3,037,628**
Interruptible Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,816	$ -	$ -	$ -	**$ 5,816**
Non Traditional Sales	$ (41,142)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (61,098)	$ (729,013)	$ (1,253,152)	$ -	**$ (2,084,403)**
Net OBA Adj.	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,021	$ 11,449	$ 6,012	$ (3,586)	$ (2,803)	$ (66)	**$ 19,027**
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (44,486)	$ (417,106)	$ (577,070)	$ (457,556)	$ (318,705)	**$ (1,814,923)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,295	$ -	$ -	$ -	$ -	$ -	**$ 3,295**
Transportation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 90,545	$ 504,335	$ 634,746	$ 520,481	$ 365,304	$ 230,371	**$ 2,345,783**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 348,653	$ 423,423	$ 274,513	$ 308,062	$ 402,950	$ 549,474	**$ 2,307,074**
Propane	$ -	$ 154	$ 822	$ -	$ -	$ -	$ (749)	$ 1,913	$ 1,399	$ 729	$ 548	$ 619	**$ 5,434**
Inventory Finance Charges	$ 468	$ 325	$ 555	$ 562	$ 597	$ 847	$ 967	$ 959	$ 700	$ 411	$ 220	$ 172	**$ 6,784**
Subtotal	**$ (40,598)**	**$ 3,270**	**$ 3,642**	**$ 3,614**	**$ 597**	**$ 4,921**	**$ 455,183**	**$ 983,212**	**$ 1,335,647**	**$ 735,899**	**$ (123,970)**	**$ 470,097**	**$ 3,831,515**
Total Commodity Costs	**$ (7,236)**	**$ 3,270**	**$ 3,642**	**$ 3,614**	**$ 597**	**$ 4,921**	**$ 1,415,797**	**$ 3,603,056**	**$ 3,485,232**	**$ 1,536,254**	**$ 1,144,867**	**$ 1,211,724**	**$ 12,405,739**

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009-10 PEAK PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO PEAK PERIOD
May 2009 - April 2010

<u>Demand Costs</u>	May-09 (Actual)	Jun-09 (Actual)	Jul-09 (Actual)	Aug-09 (Actual)	Sep-09 (Actual)	Oct-09 (Actual)	Nov-09 (Actual)	Dec-09 (Actual)	Jan-10 (Actual)	Feb-10 (Actual)	Mar-10 (Actual)	Apr-10 (Actual)	Total Peak
Pipeline Reservation													
Algonquin Gas Transmission	$ 16,567	$ 16,524	$ 16,581	$ 16,613	$ -	$ 33,196	$ 16,611	$ 17,405	$ 17,455	$ 17,455	$ 17,455	$ 17,455	**$ 203,317**
BG Energy Merchants, LLC	$ 204,157	$ 210,550	$ 212,744	$ 217,157	$ 220,687	$ 233,053	$ 233,053	$ 235,894	$ 245,067	$ 337,988	$ 346,038	$ 353,292	**$ 3,049,681**
Emera Energy Services, Inc.	$ 20,347	$ 19,849	$ 21,145	$ 21,263	$ 21,094	$ 21,407	$ 21,656	$ 23,082	$ 22,876	$ 33,198	$ 39,949	$ 34,878	**$ 300,743**
Granite State Gas Transmission, Inc.	$ 82,236	$ 82,236	$ 82,236	$ 82,236	$ 82,236	$ 82,331	$ 86,669	$ 86,764	$ 86,764	$ 86,764	$ 86,792	$ 86,792	**$ 1,014,054**
Iberdrola Renewables	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 54,178	$ 34,098	$ 37,633	$ 38,271	**$ 164,179**
Iroquois Gas Transmision System	$ 21,629	$ 21,629	$ 21,629	$ 21,629	$ 21,629	$ 21,629	$ 21,629	$ 22,769	$ 22,769	$ 22,769	$ 22,769	$ 22,769	**$ 265,249**
JP Morgan Ventures Energy Corp	$ -	$ -	$ -	$ -	$ -	$ -	$ 127,692	$ -	$ -	$ -	$ -	$ -	**$ 127,692**
Portland Natural Gas Transmission	$ 15,044	$ 15,044	$ 15,044	$ 15,044	$ 15,044	$ 15,044	$ 15,044	$ 918,519	$ 918,519	$ 918,519	$ 918,519	$ 918,519	**$ 4,697,900**
Sequent Energy Management, LP	$ 22,146	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 22,146**
Spectra Energy Corp	$ -	$ -	$ -	$ -	$ -	$ -	$ 16,953	$ -	$ -	$ -	$ -	$ -	**$ 16,953**
Tennessee Gas Pipeline Co	$ 139,693	$ 139,693	$ 137,127	$ 137,127	$ 135,248	$ 137,127	$ 137,127	$ 60,663	$ 144,353	$ 144,353	$ 144,353	$ 116,956	**$ 1,573,821**
Texas Eastern Transmission	$ 3,382	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,746	$ 7,192	$ -	**$ 21,321**
Vector Pipeline LP	$ 90,946	$ 90,994	$ 91,012	$ 91,029	$ 90,877	$ 91,324	$ 91,092	$ 136,848	$ 136,892	$ 135,840	$ 135,895	$ 135,919	**$ 1,318,667**
Co-Managed and Off System Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,835)	$ -	$ -	$ (228,218)	$ -	$ -	**$ (233,053)**
Subtotal	**$ 616,148**	**$ 596,517**	**$ 597,518**	**$ 602,098**	**$ 586,815**	**$ 635,110**	**$ 762,691**	**$ 1,501,945**	**$ 1,648,872**	**$ 1,513,511**	**$ 1,756,594**	**$ 1,724,851**	$ 12,542,670
Product Demand													
Alberta Northeast Gas Ltd.	$ 1,143	$ 1,151	$ 1,219	$ 1,666	$ 1,185	$ 1,142	$ 1,278	$ 1,368	$ 1,181	$ 1,156	$ 1,205	$ 1,180	**$ 14,873**
Distrigas of Massachusetts, LLC	$ 115,596	$ 115,596	$ 115,596	$ 115,596	$ 115,596	$ 115,596	$ 115,596	$ 109,751	$ 109,751	$ 109,751	$ 109,751	$ 109,751	**$ 1,357,926**
NextEra Energy Power Marketing, LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 180,443	$ 180,443	$ 180,443	$ 180,443	$ 180,443	**$ 902,217**
Northeast Gas Markets	$ 357	$ 369	$ 357	$ 369	$ 369	$ 357	$ 369	$ 376	$ 388	$ 388	$ 351	$ 388	**$ 4,440**
Subtotal	**$ 117,095**	**$ 117,116**	**$ 117,171**	**$ 117,630**	**$ 117,149**	**$ 117,095**	**$ 117,243**	**$ 291,938**	**$ 291,764**	**$ 291,739**	**$ 291,751**	**$ 291,763**	$ 2,279,455
Storage Pipeline Transportation and Demand Reservation													
BG Energy Merchants, LLC	$ 120,200	$ 120,200	$ 120,200	$ 120,200	$ 120,200	$ 120,200	$ -	$ 126,534	$ 126,534	$ 126,534	$ 126,534	$ 126,534	**$ 1,353,869**
Spectra Energy Corp	$ -	$ -	$ -	$ -	$ -	$ -	$ 434	$ -	$ -	$ -	$ -	$ -	**$ 434**
Tennessee Gas Pipeline	$ 4,615	$ 4,615	$ 4,615	$ 4,830	$ 4,830	$ 4,830	$ 4,830	$ 5,084	$ 5,084	$ 5,084	$ 5,084	$ 5,084	**$ 58,586**
Texas Eastern Transmission	$ 87	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 275	$ 183	$ -	**$ 545**
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (628,058)	$ (643,014)	$ (632,650)	$ (640,048)	$ (639,423)	**$ (3,183,193)**
Subtotal	**$ 124,902**	**$ 124,815**	**$ 124,815**	**$ 125,030**	**$ 125,030**	**$ 125,030**	**$ 5,264**	**$ (496,440)**	**$ (511,395)**	**$ (500,757)**	**$ (508,247)**	**$ (507,805)**	$ (1,769,759)
Demand Cost Estimates	$ 839,568	$ 839,568	$ 797,334	$ 797,334	$ 934,462	$ 797,334	$ 1,331,211	$ 1,443,648	$ 1,311,797	$ 1,539,399	$ 1,504,996	$ 994,565	**$ 13,131,215**
Demand Cost Reversals	$ (859,568)	$ (839,568)	$ (839,568)	$ (797,334)	$ (797,334)	$ (934,462)	$ (797,334)	$ (1,331,211)	$ (1,443,648)	$ (1,311,797)	$ (1,539,399)	$ (1,504,996)	**$ (12,996,218)**
Subtotal	**$ (20,000)**	**$ -**	**$ (42,234)**	**$ -**	**$ 137,128**	**$ (137,128)**	**$ 533,877**	**$ 112,437**	**$ (131,851)**	**$ 227,602**	**$ (34,403)**	**$ (510,431)**	$ 134,997
Total Fixed Demand	**$ 838,145**	**$ 838,448**	**$ 797,270**	**$ 844,758**	**$ 966,122**	**$ 740,107**	**$ 1,419,074**	**$ 1,409,880**	**$ 1,297,389**	**$ 1,532,095**	**$ 1,505,695**	**$ 998,378**	**$ 13,187,362**

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009-10 PEAK PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO PEAK PERIOD
May 2009 - April 2010

Other Demand Costs	**May-09 (Actual)**	**Jun-09 (Actual)**	**Jul-09 (Actual)**	**Aug-09 (Actual)**	**Sep-09 (Actual)**	**Oct-09 (Actual)**	**Nov-09 (Actual)**	**Dec-09 (Actual)**	**Jan-10 (Actual)**	**Feb-10 (Actual)**	**Mar-10 (Actual)**	**Apr-10 (Actual)**	**Total Peak**
Interruptible Profits	$ (1,496)	$ -	$ (17,675)	$ (27,472)	$ (30,150)	$ (48,638)	$ -	$ -	$ -	$ -	$ -	$ -	**$ (125,432)**
Capacity Release	$ (234,505)	$ (44,968)	$ (44,858)	$ (47,049)	$ (116,341)	$ (114,502)	$ (41,806)	$ (170,695)	$ (362,166)	$ (272,304)	$ (274,412)	$ (265,329)	**$ (1,988,936)**
Production and Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 106,942	$ 106,942	$ 106,942	$ 106,942	$ 106,942	$ 106,942	**$ 641,654**
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 80,107	$ 80,107	$ 80,107	$ 80,107	$ 80,107	$ 80,107	**$ 480,642**
Transp. Demand Revenues	$ -	$ (18)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ (18)**
Subtotal	$ (236,001)	$ (44,986)	$ (62,533)	$ (74,521)	$ (146,491)	$ (163,140)	$ 145,243	$ 16,354	$ (175,117)	$ (85,254)	$ (87,363)	$ (78,280)	**$ (992,090)**
Capacity Release Estimates	$ (119,351)	$ (119,351)	$ (127,145)	$ (127,145)	$ (127,145)	$ (127,145)	$ (263,798)	$ (263,798)	$ (263,798)	$ (263,798)	$ (263,798)	$ (131,405)	**$ (2,197,677)**
Capacity Release Reversals	$ 119,351	$ 119,351	$ 119,351	$ 127,145	$ 127,145	$ 127,145	$ 127,145	$ 263,798	$ 263,798	$ 263,798	$ 263,798	$ 263,798	**$ 2,185,623**
Subtotal	$ -	$ -	$ (7,794)	$ -	$ -	$ -	$ (136,653)	$ -	$ -	$ -	$ -	$ 132,393	**$ (12,054)**
Total Demand Costs	**$ 602,144**	**$ 793,461**	**$ 726,943**	**$ 770,237**	**$ 819,631**	**$ 576,967**	**$ 1,427,665**	**$ 1,426,235**	**$ 1,122,272**	**$ 1,446,841**	**$ 1,418,332**	**$ 1,052,491**	**$ 12,183,219**
Demand Costs Transferred to Off Peal	$ (210,249)	$ (210,249)	$ (210,249)	$ (210,249)	$ (210,249)	$ (210,249)	$ -	$ -	$ -	$ -	$ -	$ -	**$ (1,261,492)**
Net Demand Costs For Peak Period	**$ 391,895**	**$ 583,213**	**$ 516,695**	**$ 559,988**	**$ 609,382**	**$ 366,718**	**$ 1,427,665**	**$ 1,426,235**	**$ 1,122,272**	**$ 1,446,841**	**$ 1,418,332**	**$ 1,052,491**	**$ 10,921,727**
Total Gas Costs	**$ 384,659**	**$ 586,483**	**$ 520,337**	**$ 563,603**	**$ 609,979**	**$ 371,639**	**$ 2,843,462**	**$ 5,029,291**	**$ 4,607,504**	**$ 2,983,095**	**$ 2,563,199**	**$ 2,264,216**	**$ 23,327,466**

FORM III
Schedule 5

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009-10 PEAK PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
May 2009 - April 2010

	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
Maine													
Throughput IN													
BTU Factor	1.068	1.047	1.056	1.022	1.054	1.0498	1.043	1.04354	1.043	1.045	1.04869	1.04978	
GST Meter Throughput (MCF)	315,350	262,374	243,827	234,846	229,378	403,099	507,050	835,228	890,230	703,595	564,701	394,783	5,584,461
Kittery Meter (MCF)	58,567	48,524	53,025	49,244	50,689	63,360	89,080	120,178	128,573	114,728	118,070	86,859	980,897
GST Meter Throughput (DTH)	336,794	274,706	257,481	240,013	241,764	423,173	528,853	871,594	928,510	735,257	592,196	414,435	5,844,776
Kittery Meter (DTH)	62,550	50,805	55,994	50,327	53,426	66,515	92,910	125,411	134,102	119,891	123,819	91,183	1,026,933
Cotton Road (Lewiston)(DTH)	44,584	32,997	32,760	34,060	75,004	93,008	89,983	148,885	187,409	166,726	152,016	61,625	1,119,057
LNG/Propane	952	1,068	1,139	1,495	1,323	1,097	863	825	1,018	1,062	1,311	1,466	13,619
Total Throughput	444,879	359,575	347,375	325,895	371,518	583,794	712,610	1,146,714	1,251,039	1,022,936	869,342	568,709	8,004,385
Throughput OUT													
Residential Gas													
Charged	56,461	22,684	49,411	21,758	24,033	39,237	78,764	114,202	206,234	169,145	131,164	97,552	1,010,647
Uncharged Current	22,514	2,109	17,517	13,812	20,920	34,608	22,514	92,643	89,141	78,142	67,962	42,176	504,059
Uncharged Prior	-29,217	-22,514	-2,109	-17,517	-13,812	-20,920	-34,608	-22,514	-92,643	-89,141	-78,142	-67,962	-491,100
Total Residential Gas	**49,758**	**2,279**	**64,819**	**18,053**	**31,142**	**52,925**	**66,671**	**184,330**	**202,732**	**158,146**	**120,984**	**71,765**	**1,023,605**
Interruptible	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Commercial/Industrial Gas													
Charged	112,209	83,467	66,893	110,730	77,805	87,814	140,996	228,668	362,528	292,022	232,086	163,484	1,958,702
Uncharged Current	44,764	29,462	23,049	26,073	26,344	55,542	78,012	162,681	157,805	137,669	123,900	71,128	936,428
Uncharged Prior	-38,421	-44,764	-29,462	-23,049	-26,073	-26,344	-55,542	-78,012	-162,681	-157,805	-137,669	-123,900	-903,722
Total C/I Gas	**118,552**	**68,164**	**60,481**	**113,754**	**78,075**	**117,012**	**163,466**	**313,337**	**357,651**	**271,886**	**218,317**	**110,712**	**1,991,408**
Transportation													
Charged	318,773	267,430	241,386	289,592	231,949	343,039	424,558	577,854	685,209	592,960	522,065	411,220	4,906,035
Uncharged Current	28,601	77,564	69,107	27,300	125,449	167,050	71,142	293,812	232,929	214,679	212,900	136,064	1,656,598
Uncharged Prior	-25,609	-28,601	-77,564	-69,107	-27,300	-125,449	-167,050	-71,142	-293,812	-232,929	-214,679	-212,900	-1,546,143
Total Transportation	**321,766**	**316,393**	**232,928**	**247,784**	**330,098**	**384,640**	**328,650**	**800,524**	**624,327**	**574,710**	**520,287**	**334,384**	**5,016,491**
Company Use	**1,278**	**297**	**150**	**153**	**60**	**290**	**440**	**535**	**1,144**	**870**	**802**	**693**	**6,711**
Total Throughput OUT	**491,354**	**387,134**	**358,379**	**379,743**	**439,375**	**554,867**	**559,227**	**1,298,726**	**1,185,855**	**1,005,612**	**860,390**	**517,554**	**8,038,215**
Total Throughput IN	**444,879**	**359,575**	**347,375**	**325,895**	**371,518**	**583,794**	**712,610**	**1,146,714**	**1,251,039**	**1,022,936**	**869,342**	**568,709**	**8,004,385**
Difference IN/OUT	-46,475	-27,559	-11,005	-53,848	-67,858	28,927	153,383	-152,011	65,184	17,324	8,953	51,155	-33,831
%													-0.42%

Attachment A

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009-10 PEAK PERIOD RECONCILIATION
INTERRUPTIBLE PROFIT SCHEDULE
Summary May 2009 - April 2010

	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
Total Interruptible Sales	$2,294	$2,410	$35,571	$44,897	$45,425	$76,658	$0	$0	$0	$0	$0	$0	$207,255
Less: Emergency Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Interruptible Sales	$2,294	$2,410	$35,571	$44,897	$45,425	$76,658	$0	$0	$0	$0	$0	$0	$207,255
Total Interruptible Costs	$631	$662	$15,932	$14,373	$11,925	$22,615	$0	$0	$0	$0	$0	$0	$66,138
Total Interruptible Profits	$1,663	$1,748	$19,639	$30,524	$33,500	$54,043	$0	$0	$0	$0	$0	$0	$141,117
Emergency Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Emergency Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Emer Sales Margin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Inter & Emer Margin	$1,663	$1,748	$19,639	$30,524	$33,500	$54,043	$0	$0	$0	$0	$0	$0	$141,117
10% Profit	$166	$175	$1,964	$3,052	$3,350	$5,404	$0	$0	$0	$0	$0	$0	$14,112
90% Profit	$1,497	$1,573	$17,675	$27,472	$30,150	$48,639	$0	$0	$0	$0	$0	$0	$127,005
100% Profit (Emergency Sales)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Passback Profit	$1,497	$1,573	$17,675	$27,472	$30,150	$48,639	$0	$0	$0	$0	$0	$0	$127,005

Attachment B

NORTHERN UTILITIES, INC. - MAINE DIVISION
DEFERRED PEAK WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
Period Ending April 30, 2010

PEAK DEMAND - ACCOUNT 182.13

	BEGINNING BALANCE	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	(D)	E = B + (D)	F = A + E	G = (A + F) / 2	H	I = G * (H/12)	J = F + I
MAY 2009	3,490	1,728	0.4410%	(857)	871	4,361	3,925	4.11%	13	4,374
JUNE	4,374	2,572	0.4410%	0	2,572	6,946	5,660	2.07%	10	6,956
JULY	6,956	2,279	0.4410%	(23)	2,255	9,211	8,083	2.04%	14	9,225
AUGUST	9,225	2,470	0.4410%	(4)	2,465	11,690	10,457	2.02%	18	11,707
SEPTEMBER	11,707	2,687	0.4410%	(1)	2,686	14,393	13,050	2.00%	22	14,415
OCTOBER	14,415	1,617	0.4410%	(0)	1,617	16,032	15,223	2.15%	27	16,059
NOVEMBER	16,059	6,296	0.4410%	(4,711)	1,585	17,644	16,852	2.24%	31	17,676
DECEMBER	17,676	6,290	0.4410%	(10,199)	(3,909)	13,767	15,721	2.23%	29	13,796
JANUARY 2010	13,796	4,949	0.4410%	(11,806)	(6,856)	6,940	10,368	2.23%	19	6,959
FEBRUARY	6,959	6,381	0.4410%	(9,022)	(2,642)	4,317	5,638	2.23%	10	4,328
MARCH	4,328	6,255	0.4410%	(7,101)	(847)	3,481	3,904	2.24%	7	3,488
APRIL	3,488	4,641	0.4410%	(3,743)	899	4,387	3,937	2.26%	7	4,394
Totals		48,165		(47,468)					209	

PEAK COMMODITY - ACCOUNT 182.11

	BEGINNING BALANCE	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	(D)	E = B + (D)	F = A + E	G = (A + F) / 2	H	I = G * (H/12)	J = F + I
MAY 2009	3,273	(32)	0.4410%	(4,458)	(4,490)	(1,217)	1,028	4.11%	4	(1,214)
JUNE	(1,214)	14	0.4410%	0	14	(1,199)	(1,206)	2.07%	(2)	(1,201)
JULY	(1,201)	16	0.4410%	(122)	(106)	(1,308)	(1,254)	2.04%	(2)	(1,310)
AUGUST	(1,310)	16	0.4410%	(22)	(6)	(1,316)	(1,313)	2.02%	(2)	(1,318)
SEPTEMBER	(1,318)	3	0.4410%	(7)	(4)	(1,322)	(1,320)	2.00%	(2)	(1,325)
OCTOBER	(1,325)	22	0.4410%	(0)	22	(1,303)	(1,314)	2.15%	(2)	(1,305)
NOVEMBER	(1,305)	6,244	0.4410%	(5,784)	460	(846)	(1,075)	2.24%	(2)	(848)
DECEMBER	(848)	15,889	0.4410%	(12,522)	3,368	2,520	836	2.23%	2	2,522
JANUARY 2010	2,522	15,370	0.4410%	(14,488)	881	3,403	2,963	2.23%	6	3,409
FEBRUARY	3,409	6,775	0.4410%	(11,075)	(4,300)	(891)	1,259	2.23%	2	(889)
MARCH	(889)	5,049	0.4410%	(8,722)	(3,673)	(4,563)	(2,726)	2.24%	(5)	(4,568)
APRIL	(4,568)	5,344	0.4410%	(4,594)	750	(3,818)	(4,193)	2.26%	(8)	(3,826)
Totals		54,709		(61,795)					(13)	
Combined Totals		102,874		(109,263)					196	

NORTHERN UTILITIES, INC - MAINE DIVISION
DEFERRED PEAK 2009-10 BAD DEBT CALCULATION OF COLLECTION ALLOWANCE
Period Ending April 30, 2010

ACCOUNT 182.16

	BEG. BAL	MAINE GAS COSTS PER BOOKS ALLOWED FOR BAD DEBT	BAD DEBT % ALLOWED	ACTUAL BAD DEBT ALLOWANCE(1)	ACTUAL BAD DEBT COLLECTION	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	(E)	F = D + (E)	G = A + F	H = (A+G)/2	I = G*(H/12)	J = F + I	
MAY 2009	13,124	386,355	1.06%	4,095	(13,032)	(8,937)	4,187	8,656	4.11%	30	4,217
JUNE	4,217	589,069	1.06%	6,244	0	6,244	10,461	7,339	2.07%	13	10,474
JULY	10,474	522,632	1.06%	5,540	(357)	5,182	15,656	13,065	2.04%	22	15,678
AUGUST	15,678	566,088	1.06%	6,001	(66)	5,935	21,613	18,646	2.02%	31	21,645
SEPTEMBER	21,645	612,669	1.06%	6,494	(19)	6,475	28,120	24,882	2.00%	41	28,161
OCTOBER	28,161	373,278	1.06%	3,957	(0)	3,956	32,118	30,139	2.15%	54	32,172
NOVEMBER	32,172	2,856,001	1.06%	30,274	(25,507)	4,766	36,938	34,555	2.24%	65	37,003
DECEMBER	37,003	5,051,470	1.06%	53,546	(55,169)	(1,624)	35,379	36,191	2.23%	67	35,446
JANUARY 2010	35,446	4,627,823	1.06%	49,055	(63,852)	(14,797)	20,649	28,048	2.23%	52	20,701
FEBRUARY	20,701	2,996,250	1.06%	31,760	(48,801)	(17,041)	3,661	12,181	2.23%	23	3,683
MARCH	3,683	2,574,503	1.06%	27,290	(38,421)	(11,132)	(7,448)	(1,883)	2.24%	(4)	(7,452)
APRIL	(7,452)	2,274,201	1.06%	24,107	(20,240)	3,867	(3,585)	(5,519)	2.26%	(10)	(3,596)
Totals				248,362	(265,465)					384	

(1) Bad Debt Allowance calculated by multiplying Bad Debt % Allowed times Gas Cost on Schedule 4 and Working Capital Allowance on Attachment B.

Attachment D
Page 1 of 2

NORTHERN UTILITIES - MAINE DIVISION
SALES VARIANCE ANALYSIS
PEAK PERIOD 2009-10

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
Forecast Calendar Month Sales	213,468	389,436	512,470	527,142	455,588	290,176	2,388,280
Actual Calendar Month Sales	92,586	329,992	544,935	441,214	346,779	332,632	2,088,138
Difference	(120,882)	(59,444)	32,465	(85,928)	(108,809)	42,456	(300,142)
Add:							
Volume Variance due to Weather							
Normal Calendar Month Sales	242,310	462,129	536,935	410,173	322,434	170,100	2,144,082
Actual Calendar Month Sales	92,586	329,992	544,935	441,214	346,779	332,632	2,088,138
Weather Variance	149,724	132,137	(8,000)	(31,041)	(24,345)	(162,532)	55,944
Total Variance Excluding Weather	28,842	72,693	24,465	(116,969)	(133,154)	(120,076)	(244,198)
Variance-change in meter count							554
-change in load pattern							(300,692)
							(300,138)

Attachment D
Page 2 of 2

NORTHERN UTILITIES - MAINE DIVISION
SALES VARIANCE ANALYSIS
PEAK PERIOD 2009-10

	Normal Mcf			Meters		
	2009-10 Actual	2009-10 Forecast	Difference	2009-10 Actual	2009-10 Forecast	Difference
Res Heat	694,452	788,819	(94,367)	82,504	82,476	28
Res Non Heat	55,028	46,240	8,788	30,091	29,238	853
Total Res	**749,480**	**835,059**	**(85,579)**	**112,595**	**111,714**	**881**
G-50	106,789	114,663	(7,874)	9,636	9,646	(10)
G-40	589,270	695,748	(106,478)	31,316	31,348	(32)
G-51	70,213	80,420	(10,207)	1,358	1,359	(1)
G-41	436,281	526,102	(89,821)	4,566	4,571	(5)
G-52	29,220	41,820	(12,600)	236	236	-
G-42	106,888	94,467	12,421	162	162	-
Total Commercial and Industrial	**1,338,661**	**1,553,220**	**(214,559)**	**47,274**	**47,322**	**(48)**
Total Company	2,088,141	2,388,279	(300,138)	159,869	159,036	833

	Normal Average Use			Change in Sales Due to Change in:			
	2009-10 Actual	2009-10 Forecast	Difference	Meter Count	Load Pattern	Total Change Mcf	% Difference
Res Heat	8.42	9.56	(1.14)	236	(94,603)	(94,367)	-11.96%
Res Non Heat	1.83	1.58	0.25	1,561	7,227	8,788	19.01%
Total Res	**6.66**	**7.47**	**(0.81)**	**1,797**	**(87,376)**	**(85,579)**	**-10.25%**
G-50	11.08	11.89	(0.81)	(111)	(7,763)	(7,874)	-6.87%
G-40	18.82	22.19	(3.37)	(602)	(105,876)	(106,478)	-15.30%
G-51	51.70	59.18	(7.48)	(52)	(10,155)	(10,207)	-12.69%
G-41	95.55	115.10	(19.55)	(478)	(89,343)	(89,821)	-17.07%
G-52	123.81	177.20	(53.39)	-	(12,600)	(12,600)	-30.13%
G-42	659.80	583.13	76.67	-	12,421	12,421	13.15%
Total Commercial and Industrial	**28.32**	**32.82**	**(4.50)**	**(1,243)**	**(213,316)**	**(214,559)**	**-13.81%**
Total Company	13.06	15.02	(1.96)	554	(300,692)	(300,138)	-12.57%

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009-10 PEAK PERIOD RECONCILIATION
May 2009 - April 2010

Recalculated Reconciliation

FORM III
Schedule 1
Page 1 of 2
Updated July 2012

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009-10 PEAK PERIOD RECONCILIATION
SCHEDULE 1: PEAK DEMAND SUMMARY
May 2009 - April 2010

		AMOUNT	
Peak Demand Beginning Balance	$	(2,120,334)	SCHEDULE 2
Less: Cost of Firm Gas Revenue (Demand)	$	(8,369,062)	SCHEDULE 2
Add: Cost of Firm Gas Allowable (Demand)	$	10,921,727	SCHEDULE 2
Add: Interest	$	(7,409)	SCHEDULE 2
Peak Demand Ending Balance	$	424,922	

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009-10 PEAK PERIOD RECONCILIATION
SCHEDULE 1: PEAK COMMODITY SUMMARY
May 2009 - April 2010

		AMOUNT	
Peak Commodity Beginning Balance	$	1,340,632	SCHEDULE 2
Less: Cost of Firm Gas Revenue (Commodity)	$	(14,488,324)	SCHEDULE 2
Add: Cost of Firm Gas Allowable (Commodity)	$	13,631,878	SCHEDULE 2
Add: Interest	$	14,823	SCHEDULE 2
Peak Commodity Ending Balance	$	499,008	
Net Peak Demand and Commodity Ending Balance	$	923,930	

FORM III
Updated July 2012 Schedule 2

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009-10 PEAK PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED PEAK PERIOD ACCOUNTS
May 2009 - April 2010

		May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
1	**PEAK DEMAND - ACCOUNT 191.20**													
2	Peak Demand Account Beginning Balance (1)	$ (2,120,334)	$ (1,962,588)	$ (1,389,557)	$ (878,855)	$ (323,082)	$ 274,861	$ 637,479	$ 1,264,318	$ 901,147	$ (45,395)	$ (178,670)	$ 10,568	$ (2,120,334)
3	Plus: Cost of Gas Demand Allowable (Schedule 4)	$ 391,895	$ 583,213	$ 516,695	$ 559,988	$ 609,382	$ 366,718	$ 1,427,665	$ 1,426,235	$ 1,122,272	$ 1,446,841	$ 1,418,332	$ 1,052,491	$ 10,921,727
4	Less: Cost of Gas Demand Revenue (Schedule 3)	$ (227,167)	$ (7,297)	$ (4,062)	$ (3,203)	$ (11,399)	$ (4,916)	$ (802,599)	$ (1,791,418)	$ (2,069,610)	$ (1,579,907)	$ (1,228,938)	$ (638,546)	$ (8,369,062)
5	**Preliminary Ending Balance**	**$ (1,955,605)**	**$ (1,386,672)**	**$ (876,924)**	**$ (322,070)**	**$ 274,902**	**$ 636,663**	**$ 1,262,545**	**$ 899,134**	**$ (46,190)**	**$ (178,462)**	**$ 10,725**	**$ 424,513**	**$ 432,331**
6	Month's Average Balance ((Line 2 + Line 5) / 2)	$ (2,037,969)	$ (1,674,630)	$ (1,133,241)	$ (600,462)	$ (24,090)	$ 455,762	$ 950,012	$ 1,081,726	$ 427,479	$ (111,928)	$ (83,972)	$ 217,541	
7	Interest Rate (Short Term Borrowing Rate)	4.112%	2.067%	2.044%	2.022%	1.998%	2.148%	2.240%	2.233%	2.232%	2.229%	2.236%	2.255%	
8	Interest Applied (Line 6 * (Line 7 / 12))	$ (6,983)	$ (2,885)	$ (1,930)	$ (1,012)	$ (40)	$ 816	$ 1,773	$ 2,013	$ 795	$ (208)	$ (156)	$ 409	$ (7,409)
9	**Peak Demand Account Ending Balance**	**$ (1,962,588)**	**$ (1,389,557)**	**$ (878,855)**	**$ (323,082)**	**$ 274,861**	**$ 637,479**	**$ 1,264,318**	**$ 901,147**	**$ (45,395)**	**$ (178,670)**	**$ 10,568**	**$ 424,922**	**$ 424,922**

(1) Peak Period Ending Balance of ($1,940,916) approved by Commission Order dated October 28, 2009, in Docket No. 2009-250. This figure has been revised as a result of revisions to the prior period reconciliation.

		May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
10	**PEAK COMMODITY - ACCOUNT 191.19**													
11	Peak Commodity Account Beginning Balance (1)	$ 1,340,632	$ 320,772	$ 324,213	$ 300,136	$ 298,509	$ 298,099	$ 303,337	$ 366,920	$ 1,169,132	$ 1,716,509	$ 1,040,659	$ 335,769	$ 1,340,632
12	Plus: Cost of Gas Commodity Allowable (Schedule 4)	$ (7,209)	$ 2,886	$ 3,734	$ 3,057	$ 597	$ 4,721	$ 1,427,961	$ 3,738,279	$ 3,944,454	$ 1,920,895	$ 1,345,613	$ 1,246,889	$ 13,631,878
13	Less: Cost of Gas Commodity Revenue (Schedule 3)	$ (1,015,493)	$ -	$ (28,342)	$ (5,188)	$ (1,504)	$ (21)	$ (1,365,003)	$ (2,937,494)	$ (3,399,758)	$ (2,599,302)	$ (2,051,785)	$ (1,084,434)	$ (14,488,324)
14	**Preliminary Ending Balance**	**$ 317,930**	**$ 323,658**	**$ 299,605**	**$ 298,005**	**$ 297,602**	**$ 302,799**	**$ 366,295**	**$ 1,167,704**	**$ 1,713,828**	**$ 1,038,101**	**$ 334,488**	**$ 498,224**	**$ 484,185**
15	Month's Average Balance ((Line 10 + Line 15) / 2)	$ 829,281	$ 322,215	$ 311,909	$ 299,070	$ 298,056	$ 300,449	$ 334,816	$ 767,312	$ 1,441,480	$ 1,377,305	$ 687,574	$ 416,997	
16	Interest Rate (Short Term Borrowing Rate)	4.112%	2.067%	2.044%	2.022%	1.998%	2.148%	2.240%	2.233%	2.232%	2.229%	2.236%	2.255%	
17	Interest Applied (Line 16 * (Line 17 / 12))	$ 2,842	$ 555	$ 531	$ 504	$ 496	$ 538	$ 625	$ 1,428	$ 2,681	$ 2,558	$ 1,281	$ 784	$ 14,823
18	**Peak Commodity Account Ending Balance**	**$ 320,772**	**$ 324,213**	**$ 300,136**	**$ 298,509**	**$ 298,099**	**$ 303,337**	**$ 366,920**	**$ 1,169,132**	**$ 1,716,509**	**$ 1,040,659**	**$ 335,769**	**$ 499,008**	**$ 499,008**

(1) Peak Period Ending Balance of $49,627 approved by Commission Order dated October 28, 2009, in Docket No. 2009-250. This figure has been revised as a result of revisions to the prior period reconciliation.

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009-10 PEAK PERIOD RECONCILIATION
SCHEDULE 3: BILLED REVENUE
May 2009 - April 2010

FORM III
Schedule 3

	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
Demand Revenue:													
Accrued Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ 456,693	$ 526,047	$ (35,169)	$ (123,175)	$ (99,386)	$ (300,601)	$ 424,409
Billed Revenue	$ 227,167	$ 7,297	$ 4,062	$ 3,203	$ 11,399	$ 4,916	$ 345,906	$ 1,265,372	$ 2,104,778	$ 1,703,083	$ 1,328,324	$ 939,147	$ 7,944,654
Calendarized Revenue	**$ 227,167**	**$ 7,297**	**$ 4,062**	**$ 3,203**	**$ 11,399**	**$ 4,916**	**$ 802,599**	**$ 1,791,418**	**$ 2,069,610**	**$ 1,579,907**	**$ 1,228,938**	**$ 638,546**	**$ 8,369,062**
Commodity Revenue:													
Accrued Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ 774,943	$ 842,004	$ (52,139)	$ (196,079)	$ (149,402)	$ (497,941)	$ 721,385
Billed Revenue	$ 1,015,493	$ -	$ 28,342	$ 5,188	$ 1,504	$ 21	$ 590,060	$ 2,095,490	$ 3,451,897	$ 2,795,382	$ 2,201,187	$ 1,582,375	$ 13,766,939
Calendarized Revenue	**$ 1,015,493**	**$ -**	**$ 28,342**	**$ 5,188**	**$ 1,504**	**$ 21**	**$ 1,365,003**	**$ 2,937,494**	**$ 3,399,758**	**$ 2,599,302**	**$ 2,051,785**	**$ 1,084,434**	**$ 14,488,324**
Total Revenue	**$ 1,242,659**	**$ 7,297**	**$ 32,404**	**$ 8,392**	**$ 12,903**	**$ 4,937**	**$ 2,167,602**	**$ 4,728,913**	**$ 5,469,368**	**$ 4,179,210**	**$ 3,280,722**	**$ 1,722,980**	**$ 22,857,386**

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009-10 PEAK PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO PEAK PERIOD
May 2009 - April 2010

FORM III
Schedule 4
Page 1 of 3

Updated July 2012

Commodity Costs	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
BG Energy Merchants, LLC	$ 23,914	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,358	$ -	$ -	$ 22,897	**$ 54,169**
Boss Energy, LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,981	$ -	$ -	$ -	**$ 10,981**
BP Energy Marketing Corp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 46,901	$ 522,982	$ 1,156,252	$ 609,082	$ -	**$ 2,335,216**
Classic Energy, LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 78	$ -	$ -	**$ 78**
Distrigas of Massachusetts, LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 89,220	$ 213,407	$ 248,869	$ 221,211	$ 242,954	**$ 1,015,660**
DTE Energy Trading, Inc.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 354,528	$ -	$ -	$ -	$ -	**$ 354,528**
Emera Energy Services, Inc.	$ 47,009	$ -	$ -	$ -	$ -	$ -	$ -	$ 107,263	$ 127,376	$ 87,260	$ 88,168	$ 73,732	**$ 530,808**
Iberdrola Renewables	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 645,792	$ 552,127	$ 464,375	$ -	**$ 1,662,294**
Integrys Energy Services, Inc.	$ 3,520	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 3,520**
JP Morgan Ventures Energy Corp	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,295	$ -	$ -	$ -	$ -	**$ 11,295**
Louis Dreyfus Electric Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,507	$ -	**$ 5,507**
Macquarie Cook Energy, LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 885,854	$ 7,343	$ -	$ -	**$ 893,197**
NextEra Energy Power Marketing, LLC	$ 43,710	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,605	$ -	$ -	$ -	**$ 52,314**
Northeast Gas Markets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 160,791	$ 174,710	$ 204,866	$ 164,215	$ -	**$ 704,581**
Sequent Energy Management, LP	$ 276,339	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,530	$ -	$ -	$ -	$ -	**$ 279,869**
South Jersey Resources	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 190,775	$ -	$ -	$ -	$ -	**$ 190,775**
Spark Energy Gas, LP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,046	$ -	$ -	$ -	**$ 11,046**
Sprague Energy Corp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 28,818	$ -	**$ 28,818**
Tennessee Gas Pipeline Co	$ 619	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,519	$ 6,633	$ 6,056	$ 18,676	$ 8,971	**$ 47,474**
Subtotal	**$ 395,112**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 970,821**	**$ 2,614,743**	**$ 2,262,851**	**$ 1,600,050**	**$ 348,553**	**$ 8,192,130**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 960,614	$ 2,609,637	$ 2,144,478	$ 681,982	$ 350,770	$ 743,844	**$ 7,491,326**
Commodity Cost Reversals	$ (361,751)	$ -	$ -	$ -	$ -	$ -	$ -	$ (960,614)	$ (2,609,637)	$ (2,144,478)	$ (681,982)	$ (350,770)	**$ (7,109,232)**
Subtotal	**$ (361,751)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 960,614**	**$ 1,649,023**	**$ (465,159)**	**$ (1,462,496)**	**$ (331,213)**	**$ 393,074**	**$ 382,094**
Withdrawal Charges	$ 76	$ 2,791	$ 2,265	$ 3,053	$ -	$ 4,074	$ 4,452	$ 85,619	$ 890,666	$ 1,215,884	$ 820,519	$ 8,233	**$ 3,037,628**
Interruptible Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,816	$ -	$ -	$ -	**$ 5,816**
Non Traditional Sales	$ (41,142)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (61,098)	$ (729,013)	$ (1,253,152)	$ -	**$ (2,084,403)**
Net OBA Adj.	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,021	$ 11,449	$ 6,012	$ (3,586)	$ (2,803)	$ (66)	**$ 19,027**
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (44,486)	$ (417,106)	$ (577,070)	$ (457,556)	$ (318,705)	**$ (1,814,923)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,295	$ -	$ -	$ -	$ -	$ -	**$ 3,295**
Transportation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 90,545	$ 504,335	$ 634,746	$ 520,481	$ 365,304	$ 230,371	**$ 2,345,783**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 348,653	$ 423,423	$ 274,513	$ 308,062	$ 402,950	$ 549,474	**$ 2,307,074**
Propane	$ -	$ 154	$ 822	$ -	$ -	$ -	$ (749)	$ 1,913	$ 1,399	$ 729	$ 548	$ 619	**$ 5,434**
Inventory Finance Charges	$ 468	$ 325	$ 555	$ 562	$ 597	$ 847	$ 967	$ 959	$ 700	$ 411	$ 220	$ 172	**$ 6,784**
Allocation Adjustments	$ 28	$ (384)	$ 91	$ (557)	$ 0	$ (200)	$ 12,164	$ 135,223	$ 459,223	$ 384,641	$ 200,746	$ 35,165	**$ 1,226,139**
Subtotal	**$ (40,570)**	**$ 2,886**	**$ 3,734**	**$ 3,057**	**$ 597**	**$ 4,721**	**$ 467,347**	**$ 1,118,434**	**$ 1,794,870**	**$ 1,120,539**	**$ 76,776**	**$ 505,262**	**$ 5,057,653**
Total Commodity Costs	**$ (7,209)**	**$ 2,886**	**$ 3,734**	**$ 3,057**	**$ 597**	**$ 4,721**	**$ 1,427,961**	**$ 3,738,279**	**$ 3,944,454**	**$ 1,920,895**	**$ 1,345,613**	**$ 1,246,889**	**$ 13,631,878**

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009-10 PEAK PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO PEAK PERIOD
May 2009 - April 2010

Demand Costs	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
Pipeline Reservation													
Algonquin Gas Transmission	$ 16,567	$ 16,524	$ 16,581	$ 16,613	$ -	$ 33,196	$ 16,611	$ 17,405	$ 17,455	$ 17,455	$ 17,455	$ 17,455	$ 203,317
BG Energy Merchants, LLC	$ 204,157	$ 210,550	$ 212,744	$ 217,157	$ 220,687	$ 233,053	$ 233,053	$ 235,894	$ 245,067	$ 337,988	$ 346,038	$ 353,292	$ 3,049,681
Emera Energy Services, Inc.	$ 20,347	$ 19,849	$ 21,145	$ 21,263	$ 21,094	$ 21,407	$ 21,656	$ 23,082	$ 22,876	$ 33,198	$ 39,949	$ 34,878	$ 300,743
Granite State Gas Transmission, Inc.	$ 82,236	$ 82,236	$ 82,236	$ 82,236	$ 82,236	$ 82,331	$ 86,669	$ 86,764	$ 86,764	$ 86,764	$ 86,792	$ 86,792	$ 1,014,054
Iberdrola Renewables	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 54,178	$ 34,098	$ 37,633	$ 38,271	$ 164,179
Iroquois Gas Transmision System	$ 21,629	$ 21,629	$ 21,629	$ 21,629	$ 21,629	$ 21,629	$ 21,629	$ 22,769	$ 22,769	$ 22,769	$ 22,769	$ 22,769	$ 265,249
JP Morgan Ventures Energy Corp	$ -	$ -	$ -	$ -	$ -	$ -	$ 127,692	$ -	$ -	$ -	$ -	$ -	$ 127,692
Portland Natural Gas Transmission	$ 15,044	$ 15,044	$ 15,044	$ 15,044	$ 15,044	$ 15,044	$ 15,044	$ 918,519	$ 918,519	$ 918,519	$ 918,519	$ 918,519	$ 4,697,900
Sequent Energy Management, LP	$ 22,146	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,146
Spectra Energy Corp	$ -	$ -	$ -	$ -	$ -	$ -	$ 16,953	$ -	$ -	$ -	$ -	$ -	$ 16,953
Tennessee Gas Pipeline Co	$ 139,693	$ 139,693	$ 137,127	$ 137,127	$ 135,248	$ 137,127	$ 137,127	$ 60,663	$ 144,353	$ 144,353	$ 144,353	$ 116,956	$ 1,573,821
Texas Eastern Transmission	$ 3,382	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,746	$ 7,192	$ -	$ 21,321
Vector Pipeline LP	$ 90,946	$ 90,994	$ 91,012	$ 91,029	$ 90,877	$ 91,324	$ 91,092	$ 136,848	$ 136,892	$ 135,840	$ 135,895	$ 135,919	$ 1,318,667
Co-Managed and Off System Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,835)	$ -	$ -	$ (228,218)	$ -	$ -	$ (233,053)
Subtotal	**$ 616,148**	**$ 596,517**	**$ 597,518**	**$ 602,098**	**$ 586,815**	**$ 635,110**	**$ 762,691**	**$ 1,501,945**	**$ 1,648,872**	**$ 1,513,511**	**$ 1,756,594**	**$ 1,724,851**	**$ 12,542,670**
Product Demand													
Alberta Northeast Gas Ltd.	$ 1,143	$ 1,151	$ 1,219	$ 1,666	$ 1,185	$ 1,142	$ 1,278	$ 1,368	$ 1,181	$ 1,156	$ 1,205	$ 1,180	$ 14,873
Distrigas of Massachusetts, LLC	$ 115,596	$ 115,596	$ 115,596	$ 115,596	$ 115,596	$ 115,596	$ 115,596	$ 109,751	$ 109,751	$ 109,751	$ 109,751	$ 109,751	$ 1,357,926
NextEra Energy Power Marketing, LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 180,443	$ 180,443	$ 180,443	$ 180,443	$ 180,443	$ 902,217
Northeast Gas Markets	$ 357	$ 369	$ 357	$ 369	$ 369	$ 357	$ 369	$ 376	$ 388	$ 388	$ 351	$ 388	$ 4,440
Subtotal	**$ 117,095**	**$ 117,116**	**$ 117,171**	**$ 117,630**	**$ 117,149**	**$ 117,095**	**$ 117,243**	**$ 291,938**	**$ 291,764**	**$ 291,739**	**$ 291,751**	**$ 291,763**	**$ 2,279,455**
Storage Pipeline Transportation and Demand Reservation													
BG Energy Merchants, LLC	$ 120,200	$ 120,200	$ 120,200	$ 120,200	$ 120,200	$ 120,200	$ -	$ 126,534	$ 126,534	$ 126,534	$ 126,534	$ 126,534	$ 1,353,869
Spectra Energy Corp	$ -	$ -	$ -	$ -	$ -	$ -	$ 434	$ -	$ -	$ -	$ -	$ -	$ 434
Tennessee Gas Pipeline	$ 4,615	$ 4,615	$ 4,615	$ 4,830	$ 4,830	$ 4,830	$ 4,830	$ 5,084	$ 5,084	$ 5,084	$ 5,084	$ 5,084	$ 58,586
Texas Eastern Transmission	$ 87	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 275	$ 183	$ -	$ 545
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (628,058)	$ (643,014)	$ (632,650)	$ (640,048)	$ (639,423)	$ (3,183,193)
Subtotal	**$ 124,902**	**$ 124,815**	**$ 124,815**	**$ 125,030**	**$ 125,030**	**$ 125,030**	**$ 5,264**	**$ (496,440)**	**$ (511,395)**	**$ (500,757)**	**$ (508,247)**	**$ (507,805)**	**$ (1,769,759)**
Demand Cost Estimates	$ 839,568	$ 839,568	$ 797,334	$ 797,334	$ 934,462	$ 797,334	$ 1,331,211	$ 1,443,648	$ 1,311,797	$ 1,539,399	$ 1,504,996	$ 994,565	$ 13,131,215
Demand Cost Reversals	$ (859,568)	$ (839,568)	$ (839,568)	$ (797,334)	$ (797,334)	$ (934,462)	$ (797,334)	$ (1,331,211)	$ (1,443,648)	$ (1,311,797)	$ (1,539,399)	$ (1,504,996)	$ (12,996,218)
Subtotal	**$ (20,000)**	**$ -**	**$ (42,234)**	**$ -**	**$ 137,128**	**$ (137,128)**	**$ 533,877**	**$ 112,437**	**$ (131,851)**	**$ 227,602**	**$ (34,403)**	**$ (510,431)**	**$ 134,997**
Total Fixed Demand	**$ 838,145**	**$ 838,448**	**$ 797,270**	**$ 844,758**	**$ 966,122**	**$ 740,107**	**$ 1,419,074**	**$ 1,409,880**	**$ 1,297,389**	**$ 1,532,095**	**$ 1,505,695**	**$ 998,378**	**$ 13,187,362**

FORM III
Schedule 4
Page 3 of 3

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009-10 PEAK PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO PEAK PERIOD
May 2009 - April 2010

	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
Other Demand Costs													
Interruptible Profits	$ (1,496)	$ -	$ (17,675)	$ (27,472)	$ (30,150)	$ (48,638)	$ -	$ -	$ -	$ -	$ -	$ -	**$ (125,432)**
Capacity Release	$ (234,505)	$ (44,968)	$ (44,858)	$ (47,049)	$ (116,341)	$ (114,502)	$ (41,806)	$ (170,695)	$ (362,166)	$ (272,304)	$ (274,412)	$ (265,329)	**$ (1,988,936)**
Production and Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 106,942	$ 106,942	$ 106,942	$ 106,942	$ 106,942	$ 106,942	**$ 641,654**
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 80,107	$ 80,107	$ 80,107	$ 80,107	$ 80,107	$ 80,107	**$ 480,642**
Transp. Demand Revenues	$ -	$ (18)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ (18)**
Subtotal	$ (236,001)	$ (44,986)	$ (62,533)	$ (74,521)	$ (146,491)	$ (163,140)	$ 145,243	$ 16,354	$ (175,117)	$ (85,254)	$ (87,363)	$ (78,280)	**$ (992,090)**
Capacity Release Estimates	$ (119,351)	$ (119,351)	$ (127,145)	$ (127,145)	$ (127,145)	$ (127,145)	$ (263,798)	$ (263,798)	$ (263,798)	$ (263,798)	$ (263,798)	$ (131,405)	**$ (2,197,677)**
Capacity Release Reversals	$ 119,351	$ 119,351	$ 119,351	$ 127,145	$ 127,145	$ 127,145	$ 127,145	$ 263,798	$ 263,798	$ 263,798	$ 263,798	$ 263,798	**$ 2,185,623**
Subtotal	$ -	$ -	$ (7,794)	$ -	$ -	$ -	$ (136,653)	$ -	$ -	$ -	$ -	$ 132,393	**$ (12,054)**
Total Demand Costs	**$ 602,144**	**$ 793,461**	**$ 726,943**	**$ 770,237**	**$ 819,631**	**$ 576,967**	**$ 1,427,665**	**$ 1,426,235**	**$ 1,122,272**	**$ 1,446,841**	**$ 1,418,332**	**$ 1,052,491**	**$ 12,183,219**
Demand Costs Transferred to Off Peal	$ (210,249)	$ (210,249)	$ (210,249)	$ (210,249)	$ (210,249)	$ (210,249)	$ -	$ -	$ -	$ -	$ -	$ -	**$ (1,261,492)**
Net Demand Costs For Peak Period	**$ 391,895**	**$ 583,213**	**$ 516,695**	**$ 559,988**	**$ 609,382**	**$ 366,718**	**$ 1,427,665**	**$ 1,426,235**	**$ 1,122,272**	**$ 1,446,841**	**$ 1,418,332**	**$ 1,052,491**	**$ 10,921,727**
Total Gas Costs	**$ 384,687**	**$ 586,098**	**$ 520,428**	**$ 563,045**	**$ 609,980**	**$ 371,439**	**$ 2,855,625**	**$ 5,164,513**	**$ 5,066,727**	**$ 3,367,735**	**$ 2,763,945**	**$ 2,299,381**	**$ 24,553,604**

FORM III
Schedule 5

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009-10 PEAK PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
May 2009 - April 2010

	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
Maine													
Throughput IN													
BTU Factor	1.068	1.047	1.056	1.022	1.054	1.0498	1.043	1.04354	1.043	1.045	1.04869	1.04978	
GST Meter Throughput (MCF)	315,350	262,374	243,827	234,846	229,378	403,099	507,050	835,228	890,230	703,595	564,701	394,783	5,584,461
Kittery Meter (MCF)	58,567	48,524	53,025	49,244	50,689	63,360	89,080	120,178	128,573	114,728	118,070	86,859	980,897
GST Meter Throughput (DTH)	336,794	274,706	257,481	240,013	241,764	423,173	528,853	871,594	928,510	735,257	592,196	414,435	5,844,776
Kittery Meter (DTH)	62,550	50,805	55,994	50,327	53,426	66,515	92,910	125,411	134,102	119,891	123,819	91,183	1,026,933
Cotton Road (Lewiston)(DTH)	44,584	32,997	32,760	34,060	75,004	93,008	89,983	148,885	187,409	166,726	152,016	61,625	1,119,057
LNG/Propane	952	1,068	1,139	1,495	1,323	1,097	863	825	1,018	1,062	1,311	1,466	13,619
Total Throughput	444,879	359,575	347,375	325,895	371,518	583,794	712,610	1,146,714	1,251,039	1,022,936	869,342	568,709	8,004,385
Throughput OUT													
Residential Gas													
Charged	56,461	22,684	49,411	21,758	24,033	39,237	78,764	114,202	206,234	169,145	131,164	97,552	1,010,647
Uncharged Current	22,514	2,109	17,517	13,812	20,920	34,608	22,514	92,643	89,141	78,142	67,962	42,176	504,059
Uncharged Prior	-29,217	-22,514	-2,109	-17,517	-13,812	-20,920	-34,608	-22,514	-92,643	-89,141	-78,142	-67,962	-491,100
Total Residential Gas	**49,758**	**2,279**	**64,819**	**18,053**	**31,142**	**52,925**	**66,671**	**184,330**	**202,732**	**158,146**	**120,984**	**71,765**	**1,023,605**
Interruptible	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Commercial/Industrial Gas													
Charged	112,209	83,467	66,893	110,730	77,805	87,814	140,996	228,668	362,528	292,022	232,086	163,484	1,958,702
Uncharged Current	44,764	29,462	23,049	26,073	26,344	55,542	78,012	162,681	157,805	137,669	123,900	71,128	936,428
Uncharged Prior	-38,421	-44,764	-29,462	-23,049	-26,073	-26,344	-55,542	-78,012	-162,681	-157,805	-137,669	-123,900	-903,722
Total C/I Gas	**118,552**	**68,164**	**60,481**	**113,754**	**78,075**	**117,012**	**163,466**	**313,337**	**357,651**	**271,886**	**218,317**	**110,712**	**1,991,408**
Transportation													
Charged	318,773	267,430	241,386	289,592	231,949	343,039	424,558	577,854	685,209	592,960	522,065	411,220	4,906,035
Uncharged Current	28,601	77,564	69,107	27,300	125,449	167,050	71,142	293,812	232,929	214,679	212,900	136,064	1,656,598
Uncharged Prior	-25,609	-28,601	-77,564	-69,107	-27,300	-125,449	-167,050	-71,142	-293,812	-232,929	-214,679	-212,900	-1,546,143
Total Transportation	**321,766**	**316,393**	**232,928**	**247,784**	**330,098**	**384,640**	**328,650**	**800,524**	**624,327**	**574,710**	**520,287**	**334,384**	**5,016,491**
Company Use	**1,278**	**297**	**150**	**153**	**60**	**290**	**440**	**535**	**1,144**	**870**	**802**	**693**	**6,711**
Total Throughput OUT	**491,354**	**387,134**	**358,379**	**379,743**	**439,375**	**554,867**	**559,227**	**1,298,726**	**1,185,855**	**1,005,612**	**860,390**	**517,554**	**8,038,215**
Total Throughput IN	**444,879**	**359,575**	**347,375**	**325,895**	**371,518**	**583,794**	**712,610**	**1,146,714**	**1,251,039**	**1,022,936**	**869,342**	**568,709**	**8,004,385**
Difference IN/OUT	-46,475	-27,559	-11,005	-53,848	-67,858	28,927	153,383	-152,011	65,184	17,324	8,953	51,155	-33,831
%													-0.42%

Attachment A

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009-10 PEAK PERIOD RECONCILIATION
INTERRUPTIBLE PROFIT SCHEDULE
Summary May 2009 - April 2010

	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
Total Interruptible Sales	$2,294	$2,410	$35,571	$44,897	$45,425	$76,658	$0	$0	$0	$0	$0	$0	$207,255
Less: Emergency Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Interruptible Sales	$2,294	$2,410	$35,571	$44,897	$45,425	$76,658	$0	$0	$0	$0	$0	$0	$207,255
Total Interruptible Costs	$631	$662	$15,932	$14,373	$11,925	$22,615	$0	$0	$0	$0	$0	$0	$66,138
Total Interruptible Profits	$1,663	$1,748	$19,639	$30,524	$33,500	$54,043	$0	$0	$0	$0	$0	$0	$141,117
Emergency Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Emergency Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Emer Sales Margin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Inter & Emer Margin	$1,663	$1,748	$19,639	$30,524	$33,500	$54,043	$0	$0	$0	$0	$0	$0	$141,117
10% Profit	$166	$175	$1,964	$3,052	$3,350	$5,404	$0	$0	$0	$0	$0	$0	$14,112
90% Profit	$1,497	$1,573	$17,675	$27,472	$30,150	$48,639	$0	$0	$0	$0	$0	$0	$127,005
100% Profit (Emergency Sales)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Passback Profit	$1,497	$1,573	$17,675	$27,472	$30,150	$48,639	$0	$0	$0	$0	$0	$0	$127,005

Updated July 2012 Attachment B

NORTHERN UTILITIES, INC. - MAINE DIVISION
DEFERRED PEAK WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
May 2009 - April 2010

PEAK DEMAND - ACCOUNT 182.13

	BEGINNING BALANCE	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	(D)	E = B + (D)	F = A + E	G = (A + F) / 2	H	I = G * (H/12)	J = F + I
MAY 2009	3,490	1,728	0.4410%	(857)	871	4,361	3,925	4.11%	13	4,374
JUNE	4,374	2,572	0.4410%	0	2,572	6,946	5,660	2.07%	10	6,956
JULY	6,956	2,279	0.4410%	(23)	2,255	9,211	8,083	2.04%	14	9,224
AUGUST	9,224	2,470	0.4410%	(4)	2,465	11,689	10,457	2.02%	18	11,707
SEPTEMBER	11,707	2,687	0.4410%	(1)	2,686	14,393	13,050	2.00%	22	14,415
OCTOBER	14,415	1,617	0.4410%	(0)	1,617	16,032	15,223	2.15%	27	16,059
NOVEMBER	16,059	6,296	0.4410%	(4,711)	1,585	17,644	16,852	2.24%	31	17,676
DECEMBER	17,676	6,290	0.4410%	(10,199)	(3,909)	13,767	15,721	2.23%	29	13,796
JANUARY 2010	13,796	4,949	0.4410%	(11,806)	(6,856)	6,940	10,368	2.23%	19	6,959
FEBRUARY	6,959	6,381	0.4410%	(9,022)	(2,642)	4,317	5,638	2.23%	10	4,328
MARCH	4,328	6,255	0.4410%	(7,101)	(847)	3,481	3,904	2.24%	7	3,488
APRIL	3,488	4,641	0.4410%	(3,743)	899	4,387	3,937	2.26%	7	4,394
TOTALS		48,165		(47,468)					209	

PEAK COMMODITY - ACCOUNT 182.11

	BEGINNING BALANCE	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	(D)	E = B + (D)	F = A + E	G = (A + F) / 2	H	I = G * (H/12)	J = F + I
MAY 2009	6,939	(32)	0.4410%	(4,458)	(4,490)	2,449	4,694	4.11%	16	2,465
JUNE	2,465	13	0.4410%	0	13	2,478	2,471	2.07%	4	2,482
JULY	2,482	16	0.4410%	(122)	(106)	2,376	2,429	2.04%	4	2,380
AUGUST	2,380	13	0.4410%	(22)	(9)	2,371	2,376	2.02%	4	2,375
SEPTEMBER	2,375	3	0.4410%	(7)	(4)	2,371	2,373	2.00%	4	2,375
OCTOBER	2,375	21	0.4410%	(0)	21	2,396	2,386	2.15%	4	2,400
NOVEMBER	2,400	6,297	0.4410%	(5,784)	513	2,914	2,657	2.24%	5	2,919
DECEMBER	2,919	16,486	0.4410%	(12,522)	3,964	6,883	4,901	2.23%	9	6,892
JANUARY 2010	6,892	17,395	0.4410%	(14,488)	2,907	9,799	8,345	2.23%	16	9,814
FEBRUARY	9,814	8,471	0.4410%	(11,075)	(2,604)	7,210	8,512	2.23%	16	7,226
MARCH	7,226	5,934	0.4410%	(8,722)	(2,788)	4,438	5,832	2.24%	11	4,449
APRIL	4,449	5,499	0.4410%	(4,594)	905	5,354	4,901	2.26%	9	5,363
TOTALS		60,117		(61,795)					102	
COMBINED TOTALS		108,281		(109,263)					311	

Updated July 2012 Attachment C

NORTHERN UTILITIES, INC - MAINE DIVISION
DEFERRED PEAK 2009-10 BAD DEBT CALCULATION OF COLLECTION ALLOWANCE
May 2009 - April 2010

ACCOUNT 182.16

	BEG. BAL	MAINE GAS COSTS PER BOOKS ALLOWED FOR BAD DEBT	BAD DEBT % ALLOWED	ACTUAL BAD DEBT ALLOWANCE(1)	ACTUAL BAD DEBT COLLECTION	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	(E)	F = D + (E)	G = A + F	H = (A+G)/2	I = G*(H/12)	J = F + I	
MAY 2009	21,975	386,383	1.06%	4,096	(13,032)	(8,936)	13,039	17,507	4.11%	60	13,099
JUNE	13,099	588,683	1.06%	6,240	0	6,240	19,339	16,219	2.07%	28	19,367
JULY	19,367	522,723	1.06%	5,541	(357)	5,183	24,550	21,958	2.04%	37	24,587
AUGUST	24,587	565,528	1.06%	5,995	(66)	5,929	30,516	27,552	2.02%	46	30,563
SEPTEMBER	30,563	612,670	1.06%	6,494	(19)	6,475	37,038	33,800	2.00%	56	37,094
OCTOBER	37,094	373,077	1.06%	3,955	(0)	3,954	41,048	39,071	2.15%	70	41,118
NOVEMBER	41,118	2,868,219	1.06%	30,403	(25,507)	4,896	46,014	43,566	2.24%	81	46,096
DECEMBER	46,096	5,187,289	1.06%	54,985	(55,169)	(184)	45,911	46,003	2.23%	86	45,997
JANUARY 2010	45,997	5,089,071	1.06%	53,944	(63,852)	(9,908)	36,089	41,043	2.23%	76	36,166
FEBRUARY	36,166	3,382,587	1.06%	35,855	(48,801)	(12,945)	23,220	29,693	2.23%	55	23,275
MARCH	23,275	2,776,134	1.06%	29,427	(38,421)	(8,994)	14,281	18,778	2.24%	35	14,316
APRIL	14,316	2,309,521	1.06%	24,481	(20,240)	4,241	18,557	16,436	2.26%	31	18,588
TOTALS				261,416	(265,465)					662	

(1) Bad Debt Allowance calculated by multiplying Bad Debt % Allowed times Gas Cost on Schedule 4 and Working Capital Allowance on Attachment B.

Attachment D
Page 1 of 2

NORTHERN UTILITIES - MAINE DIVISION
SALES VARIANCE ANALYSIS
PEAK PERIOD 2009-10

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
Forecast Calendar Month Sales	213,468	389,436	512,470	527,142	455,588	290,176	2,388,280
Actual Calendar Month Sales	92,586	329,992	544,935	441,214	346,779	332,632	2,088,138
Difference	(120,882)	(59,444)	32,465	(85,928)	(108,809)	42,456	(300,142)
Add:							
Volume Variance due to Weather							
Normal Calendar Month Sales	242,310	462,129	536,935	410,173	322,434	170,100	2,144,082
Actual Calendar Month Sales	92,586	329,992	544,935	441,214	346,779	332,632	2,088,138
Weather Variance	149,724	132,137	(8,000)	(31,041)	(24,345)	(162,532)	55,944
Total Variance Excluding Weather	28,842	72,693	24,465	(116,969)	(133,154)	(120,076)	(244,198)

Variance-change in meter count	554
-change in load pattern	(300,692)
	(300,138)

Attachment D
Page 2 of 2

NORTHERN UTILITIES - MAINE DIVISION
SALES VARIANCE ANALYSIS
PEAK PERIOD 2009-10

	Normal Mcf			Meters		
	2009-10 Actual	**2009-10 Forecast**	**Difference**	**2009-10 Actual**	**2009-10 Forecast**	**Difference**
Res Heat	694,452	788,819	(94,367)	82,504	82,476	28
Res Non Heat	55,028	46,240	8,788	30,091	29,238	853
Total Res	**749,480**	**835,059**	**(85,579)**	**112,595**	**111,714**	**881**
G-50	106,789	114,663	(7,874)	9,636	9,646	(10)
G-40	589,270	695,748	(106,478)	31,316	31,348	(32)
G-51	70,213	80,420	(10,207)	1,358	1,359	(1)
G-41	436,281	526,102	(89,821)	4,566	4,571	(5)
G-52	29,220	41,820	(12,600)	236	236	-
G-42	106,888	94,467	12,421	162	162	-
Total Commercial and Industrial	**1,338,661**	**1,553,220**	**(214,559)**	**47,274**	**47,322**	**(48)**
Total Company	2,088,141	2,388,279	(300,138)	159,869	159,036	833

	Normal Average Use			Change in Sales Due to Change in:			
	2009-10 Actual	**2009-10 Forecast**	**Difference**	**Meter Count**	**Load Pattern**	**Total Change Mcf**	**% Difference**
Res Heat	8.42	9.56	(1.14)	236	(94,603)	(94,367)	-11.96%
Res Non Heat	1.83	1.58	0.25	1,561	7,227	8,788	19.01%
Total Res	**6.66**	**7.47**	**(0.81)**	**1,797**	**(87,376)**	**(85,579)**	**-10.25%**
G-50	11.08	11.89	(0.81)	(111)	(7,763)	(7,874)	-6.87%
G-40	18.82	22.19	(3.37)	(602)	(105,876)	(106,478)	-15.30%
G-51	51.70	59.18	(7.48)	(52)	(10,155)	(10,207)	-12.69%
G-41	95.55	115.10	(19.55)	(478)	(89,343)	(89,821)	-17.07%
G-52	123.81	177.20	(53.39)	-	(12,600)	(12,600)	-30.13%
G-42	659.80	583.13	76.67	-	12,421	12,421	13.15%
Total Commercial and Industrial	**28.32**	**32.82**	**(4.50)**	**(1,243)**	**(213,316)**	**(214,559)**	**-13.81%**
Total Company	13.06	15.02	(1.96)	554	(300,692)	(300,138)	-12.57%

Schedule 7

Maine Division
Original and Revised 2010-2011 Peak Period Reconciliation

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010-11 PEAK PERIOD RECONCILIATION
May 2010 - April 2011

Original Reconciliation

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010-11 PEAK PERIOD RECONCILIATION
SCHEDULE 1: PEAK DEMAND SUMMARY
November 2010 - April 2011

		AMOUNT	
Peak Demand Beginning Balance	$	424,922	SCHEDULE 2
Less: Cost of Firm Gas Revenue (Demand)	$	(15,354,902)	SCHEDULE 2
Add: Cost of Firm Gas Allowable (Demand)	$	14,211,538	SCHEDULE 2
Add: Interest	$	53,992	SCHEDULE 2
Peak Demand Ending Balance	$	(664,450)	

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010-11 PEAK PERIOD RECONCILIATION
SCHEDULE 1: PEAK COMMODITY SUMMARY
November 2010 - April 2011

		AMOUNT	
Peak Commodity Beginning Balance	$	(1,584,608)	SCHEDULE 2
Less: Cost of Firm Gas Revenue (Commodity)	$	(10,483,237)	SCHEDULE 2
Add: Cost of Firm Gas Allowable (Commodity)	$	10,305,839	SCHEDULE 2
Add: Interest	$	(36,074)	SCHEDULE 2
Peak Commodity Ending Balance	$	(1,798,080)	
Net Peak Demand and Commodity Ending Balance	$	(2,462,529)	

FORM III
Schedule 2

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010-11 PEAK PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED PEAK PERIOD ACCOUNTS
May 2010 - April 2011

		May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
1	**PEAK DEMAND - ACCOUNT 191.20**													
2	Peak Demand Account Beginning Balance	424,922	1,073,933	1,978,526	2,699,526	3,436,706	4,189,447	4,932,787	4,836,904	3,585,789	1,835,226	579,858	(510,338)	424,922
3	Plus: Cost of Gas Demand Allowable (Schedule 4)	533,014	902,003	717,441	731,304	745,927	734,135	1,210,591	1,734,529	1,970,718	1,803,561	1,969,564	1,158,752	14,211,538
4	Less: Cost of Gas Demand Revenue (Schedule 3)	114,548	(395)	(995)	57	(351)	637	(1,315,640)	(2,993,575)	(3,726,383)	(3,061,204)	(3,059,826)	(1,311,775)	(15,354,902)
5	**Preliminary Ending Balance**	**1,072,483**	**1,975,541**	**2,694,972**	**3,430,887**	**4,182,282**	**4,924,220**	**4,827,737**	**3,577,858**	**1,830,124**	**577,583**	**(510,404)**	**(663,362)**	**(718,442)**
6	Month's Average Balance ((Line 2 + Line 5) / 2)	748,703	1,524,737	2,336,749	3,065,207	3,809,494	4,556,834	4,880,262	4,207,381	2,707,957	1,206,405	34,727	(586,850)	
7	Interest Rate (Short Term Borrowing Rate)	2.323%	2.349%	2.339%	2.278%	2.257%	2.256%	2.254%	2.262%	2.261%	2.263%	2.255%	2.224%	
8	Interest Applied (Line 6 * (Line 7 / 12))	1,449	2,985	4,555	5,819	7,165	8,567	9,167	7,931	5,102	2,275	65	(1,088)	53,992
9	**Peak Demand Account Ending Balance**	**1,073,933**	**1,978,526**	**2,699,526**	**3,436,706**	**4,189,447**	**4,932,787**	**4,836,904**	**3,585,789**	**1,835,226**	**579,858**	**(510,338)**	**(664,450)**	**(664,450)**
10	**PEAK COMMODITY - ACCOUNT 191.19**													
11	Peak Commodity Account Beginning Balance	(1,584,608)	(1,711,160)	(1,584,206)	(1,547,761)	(1,444,604)	(1,448,719)	(1,447,495)	(1,230,021)	(1,581,914)	(1,598,246)	(1,700,703)	(2,047,507)	(1,584,608)
12	Plus: Cost of Gas Commodity Allowable (Schedule 4)	(308,028)	131,190	40,856	105,805	(869)	1,029	1,138,570	1,721,979	2,522,324	2,009,676	1,761,739	1,181,565	10,305,839
13	Less: Cost of Gas Commodity Revenue (Schedule 3)	184,662	(1,014)	(1,362)	190	(528)	2,915	(918,584)	(2,071,225)	(2,535,663)	(2,109,026)	(2,105,025)	(928,578)	(10,483,237)
14	**Preliminary Ending Balance**	**(1,707,974)**	**(1,580,984)**	**(1,544,712)**	**(1,441,766)**	**(1,446,000)**	**(1,444,775)**	**(1,227,509)**	**(1,579,267)**	**(1,595,253)**	**(1,697,595)**	**(2,043,989)**	**(1,794,519)**	**(1,762,006)**
15	Month's Average Balance ((Line 11 + Line 14) / 2)	(1,646,291)	(1,646,072)	(1,564,459)	(1,494,764)	(1,445,302)	(1,446,747)	(1,337,502)	(1,404,644)	(1,588,584)	(1,647,921)	(1,872,346)	(1,921,013)	
16	Interest Rate (Short Term Borrowing Rate)	2.323%	2.349%	2.339%	2.278%	2.257%	2.256%	2.254%	2.262%	2.261%	2.263%	2.255%	2.224%	
17	Interest Applied (Line 16 * (Line 15 / 12))	(3,187)	(3,222)	(3,049)	(2,838)	(2,718)	(2,720)	(2,512)	(2,648)	(2,993)	(3,108)	(3,518)	(3,560)	(36,074)
18	**Peak Commodity Account Ending Balance**	**(1,711,160)**	**(1,584,206)**	**(1,547,761)**	**(1,444,604)**	**(1,448,719)**	**(1,447,495)**	**(1,230,021)**	**(1,581,914)**	**(1,598,246)**	**(1,700,703)**	**(2,047,507)**	**(1,798,080)**	**(1,798,080)**

FORM III
Schedule 3

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010-11 PEAK PERIOD RECONCILIATION
SCHEDULE 3: BILLED REVENUE
May 2010 - April 2011

	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
Demand Revenue:													
Accrued Revenue	$ (424,409)	$ -	$ -	$ -	$ -	$ -	$ 842,443	$ 707,639	$ 473,147	$ (522,008)	$ 277,304	$ (756,697)	$ 597,420
Billed Revenue	$ 309,861	$ 395	$ 995	$ (57)	$ 351	$ (637)	$ 473,197	$ 2,285,936	$ 3,253,235	$ 3,583,212	$ 2,782,522	$ 2,068,472	$ 14,757,482
Calendarized Revenue	**$ (114,548)**	**$ 395**	**$ 995**	**$ (57)**	**$ 351**	**$ (637)**	**$ 1,315,640**	**$ 2,993,575**	**$ 3,726,383**	**$ 3,061,204**	**$ 3,059,826**	**$ 1,311,775**	**$ 15,354,902**
Commodity Revenue:													
Accrued Revenue	$ (721,385)	$ -	$ -	$ -	$ -	$ -	$ 583,812	$ 476,700	$ 314,615	$ (343,095)	$ 193,989	$ (506,446)	$ (1,811)
Billed Revenue	$ 536,724	$ 1,014	$ 1,362	$ (190)	$ 528	$ (2,915)	$ 334,772	$ 1,594,525	$ 2,221,048	$ 2,452,121	$ 1,911,035	$ 1,435,024	$ 10,485,047
Calendarized Revenue	**$ (184,662)**	**$ 1,014**	**$ 1,362**	**$ (190)**	**$ 528**	**$ (2,915)**	**$ 918,584**	**$ 2,071,225**	**$ 2,535,663**	**$ 2,109,026**	**$ 2,105,025**	**$ 928,578**	**$ 10,483,237**
Total Revenue	**$ (299,210)**	**$ 1,409**	**$ 2,357**	**$ (247)**	**$ 878**	**$ (3,552)**	**$ 2,234,224**	**$ 5,064,800**	**$ 6,262,045**	**$ 5,170,230**	**$ 5,164,850**	**$ 2,240,353**	**$ 25,838,139**

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010-11 PEAK PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO PEAK PERIOD
May 2010 - April 2011

FORM III
Schedule 4
Page 1 of 3

Commodity Costs	May-10 (Actual)	Jun-10 (Actual)	Jul-10 (Actual)	Aug-10 (Actual)	Sep-10 (Actual)	Oct-10 (Actual)	Nov-10 (Actual)	Dec-10 (Actual)	Jan-11 (Actual)	Feb-11 (Actual)	Mar-11 (Actual)	Apr-11 (Actual)	Total Peak
BG Energy Merchants, LLC	-	-	-	-	-	-	-	-	602,011	391,145	384,495	380,162	**1,757,812**
Distrigas of Massachusetts, LLC	-	-	-	-	-	-	-	89,132	185,151	198,418	215,780	210,348	**898,829**
Emera Energy Services, Inc.	229,406	3,226	-	-	-	-	-	57,403	312,924	320,505	341,112	144,305	**1,408,882**
FPL Energy	-	-	-	-	-	-	-	-	30,876	178,048	80,110	-	**289,034**
JP Morgan Ventures Energy Corp	287,074	-	-	-	-	-	-	-	-	-	-	-	**287,074**
Louis Dreyfus Electric Power	-	-	-	-	-	-	-	9,711	167,802	-	-	-	**177,513**
Macquarie Cook Energy, LLC	-	-	-	-	-	-	-	33,122	-	-	-	-	**33,122**
National Energy & Trade	143,537	-	-	-	-	-	-	-	45,022	89,995	61,925	18,795	**359,275**
Portland Natural Gas	-	-	-	-	-	-	-	-	-	-	-	563	**563**
Repsol	-	-	-	-	-	-	-	-	-	73,405	184,132	51,476	**309,013**
South Jersey Resources	9,576	-	-	-	-	-	10,798	-	-	-	-	4,768	**25,142**
Spark Energy Gas, LP	-	-	-	-	-	-	-	130,706	-	275,008	-	318,012	**723,726**
Sprague Energy Corp.	74,411	-	-	-	-	-	-	-	-	-	-	-	**74,411**
Tennessee Gas Pipeline Co	1,559	-	-	-	-	-	-	-	4,743	3,187	1,720	2,523	**13,733**
Rust Consulting	-	-	-	-	(1,772)	-	-	-	-	-	-	-	**(1,772)**
Virginia Power	-	-	-	-	-	-	-	-	-	-	158,228	35,239	**193,467**
Subtotal	**745,564**	**3,226**	**-**	**-**	**(1,772)**	**-**	**10,798**	**320,074**	**1,348,528**	**1,529,712**	**1,427,502**	**1,166,192**	**6,549,824**
Commodity Cost Estimates	-	-	-	-	-	-	649,170	1,368,494	1,646,400	1,392,555	1,169,716	1,088,069	**7,314,404**
Commodity Cost Reversals	(1,093,220)	-	-	-	-	-	-	(649,170)	(1,368,494)	(1,646,400)	(1,392,555)	(1,169,716)	**(7,319,555)**
Subtotal	**(1,093,220)**	**-**	**-**	**-**	**-**	**-**	**649,170**	**719,324**	**277,906**	**(253,845)**	**(222,839)**	**(81,647)**	**(5,151)**
Withdrawal Charges	-	-	-	-	-	-	863,167	1,992,463	1,936,158	1,275,774	979,930	733	**7,048,224**
Interruptible Costs	-	-	-	-	-	-	(26,881)	59,113	85,073	69,083	82,632	20,081	**289,101**
Non Traditional Sales	(349,376)	-	-	-	-	-	-	(2,034)	(687,843)	(107,541)	(105,303)	(22,081)	**(1,274,177)**
Net OBA Adj.	-	-	-	-	-	-	9,002	1,410	8,910	25,190	(152)	7,139	**51,500**
Company Managed	-	-	-	-	-	-	-	(164,104)	(992,215)	(1,189,990)	(749,772)	(565,462)	**(3,661,543)**
LNG Boiloff	-	-	-	-	-	-	3,520	5,166	5,553	993	2,647	4,397	**22,276**
Transportation Charges	38,791	127,468	40,166	105,002	-	-	-	3,072	77,252	21,863	74,902	56,154	**544,670**
Hedging Costs	-	-	-	-	-	-	103,579	87,188	49,343	65,123	67,134	82,469	**454,836**
Propane	516	-	-	-	-	-	530	562	867	747	581	770	**4,573**
Inventory Finance Charges	322	496	690	803	903	1,029	961	860	553	288	148	41	**7,093**
Subtotal	**(309,748)**	**127,964**	**40,856**	**105,805**	**903**	**1,029**	**953,880**	**1,983,695**	**483,652**	**161,530**	**352,746**	**(415,760)**	**3,486,552**
Sales for Resale Estimates	**-**	**-**	**-**	**-**	**-**	**-**	**(475,278)**	**(1,776,391)**	**(1,364,152)**	**(791,872)**	**(587,543)**	**(74,762)**	**(5,069,999)**
Sales for Resale Reversals	**349,376**	**-**	**-**	**-**	**-**	**-**	**-**	**475,278**	**1,776,391**	**1,364,152**	**791,872**	**587,543**	**5,344,613**
Subtotal	**349,376**	**-**	**-**	**-**	**-**	**-**	**(475,278)**	**(1,301,114)**	**412,239**	**572,280**	**204,330**	**512,781**	**274,614**
Total Commodity Costs	**(308,028)**	**131,190**	**40,856**	**105,805**	**(869)**	**1,029**	**1,138,570**	**1,721,979**	**2,522,324**	**2,009,676**	**1,761,739**	**1,181,565**	**10,305,839**

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010-11 PEAK PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO PEAK PERIOD
May 2010 - April 2011

Demand Costs	**May-09 (Actual)**	**Jun-09 (Actual)**	**Jul-09 (Actual)**	**Aug-09 (Actual)**	**Sep-09 (Actual)**	**Oct-09 (Actual)**	**Nov-09 (Actual)**	**Dec-09 (Actual)**	**Jan-10 (Actual)**	**Feb-10 (Actual)**	**Mar-10 (Actual)**	**Apr-10 (Actual)**	**Total Peak**
Pipeline Reservation													
Algonquin Gas Transmission	$ 17,455	$ 17,458	$ 17,455	$ 17,455	$ 17,455	$ 17,455	$ 17,455	$ 17,063	$ 17,063	$ 17,063	$ 17,063	$ 17,063	**$ 207,504**
BG Energy Merchants, LLC	$ 367,894	$ 381,747	$ 371,921	$ 372,562	$ 378,800	$ 381,563	$ 383,480	$ 371,614	$ 364,921	$ 377,820	$ 386,810	$ 566,409	**$ 4,705,541**
Emera Energy Services, Inc.	$ -	$ 67,030	$ 33,885	$ 33,261	$ 34,295	$ 34,356	$ -	$ 34,369	$ -	$ -	$ -	$ -	**$ 237,196**
Granite State Gas Transmission, Inc.	$ 86,792	$ 86,792	$ 86,805	$ 86,805	$ 86,829	$ 86,807	$ 84,858	$ 84,750	$ 142,386	$ 142,318	$ 142,272	$ 142,228	**$ 1,259,641**
Iroquois Gas Transmision System	$ 22,769	$ 22,769	$ 22,769	$ 22,769	$ 22,769	$ 22,769	$ 22,769	$ 22,258	$ 22,258	$ 22,258	$ -	$ 44,515	**$ 270,670**
Portland Natural Gas Transmission	$ 15,837	$ 15,837	$ 15,837	$ 15,837	$ 15,837	$ 15,837	$ 15,841	$ 897,890	$ 1,318,754	$ 1,318,872	$ 1,318,754	$ 1,318,754	**$ 6,283,884**
Tennessee Gas Pipeline Co	$ 144,353	$ 144,353	$ 116,956	$ 144,353	$ 144,353	$ 116,956	$ 144,353	$ 141,111	$ 83,863	$ 141,111	$ 141,111	$ 83,863	**$ 1,546,735**
Texas Eastern Transmission	$ -	$ 3,611	$ 10,832	$ 3,611	$ 3,603	$ 3,603	$ 3,603	$ 3,522	$ 3,522	$ 3,522	$ 3,489	$ 3,489	**$ 46,405**
Union Gas Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,235	$ 7,632	$ 7,680	$ 7,767	**$ 38,315**
Vector Pipeline LP	$ 94,914	$ 94,911	$ 94,922	$ 94,912	$ 94,931	$ 94,963	$ 94,972	$ 132,871	$ 132,894	$ 132,897	$ 132,897	$ 132,962	**$ 1,329,045**
Subtotal	**$ 750,014**	**$ 834,507**	**$ 771,382**	**$ 791,564**	**$ 798,870**	**$ 774,308**	**$ 767,330**	**$ 1,705,447**	**$ 2,100,896**	**$ 2,163,493**	**$ 2,150,077**	**$ 2,317,049**	**$ 15,924,937**
Product Demand													
Alberta Northeast Gas Ltd.	$ 1,132	$ 1,135	$ 1,264	$ 1,496	$ 1,313	$ 1,203	$ 1,223	$ 1,199	$ 1,278	$ -	$ 2,360	$ -	**$ 13,603**
Distrigas of Massachusetts	$ 109,751	$ 109,751	$ 109,751	$ 109,751	$ 109,751	$ 109,751	$ 109,751	$ 102,422	$ 113,880	$ 113,880	$ 113,880	$ 113,880	**$ 1,326,200**
FPL/NextEra	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 198,481	$ 198,481	$ 198,481	$ 198,481	$ 198,481	**$ 992,404**
Subtotal	**$ 110,883**	**$ 110,887**	**$ 111,015**	**$ 111,247**	**$ 111,065**	**$ 110,955**	**$ 110,974**	**$ 302,103**	**$ 313,638**	**$ 312,360**	**$ 314,720**	**$ 312,360**	**$ 2,332,207**
Storage Pipeline Transportation and Demand Reservation													
Tennessee Gas Pipeline	$ 5,084	$ 5,084	$ 5,084	$ 5,084	$ 5,084	$ 5,084	$ 5,084	$ 4,970	$ 4,970	$ 4,970	$ 4,970	$ 4,970	**$ 60,442**
Washington 10 (BG Energy)	$ 126,534	$ 126,534	$ 126,534	$ 126,534	$ 126,534	$ 126,534	$ 126,534	$ 123,692	$ 123,692	$ 123,692	$ 123,692	$ 123,692	**$ 1,504,197**
Texas Eastern	$ -	$ 92	$ 276	$ 92	$ 91	$ 92	$ 92	$ 89	$ 89	$ 89	$ 88	$ 89	**$ 1,177**
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (849,929)	$ (853,829)	$ (859,991)	$ (862,535)	$ (860,669)	**$ (4,286,953)**
Subtotal	**$ 131,618**	**$ 131,710**	**$ 131,894**	**$ 131,710**	**$ 131,710**	**$ 131,710**	**$ 131,710**	**$ (721,177)**	**$ (725,078)**	**$ (731,240)**	**$ (733,784)**	**$ (731,918)**	**$ (2,721,136)**
Demand Cost Estimates	$ 828,655	$ 951,320	$ 957,180	$ 949,696	$ 949,695	$ 962,353	$ 1,214,664	$ 1,602,056	$ 1,600,351	$ 1,593,999	$ 1,784,137	$ 1,115,108	**$ 14,509,215**
Demand Cost Reversals	$ (994,565)	$ (828,655)	$ (951,320)	$ (957,180)	$ (949,696)	$ (949,695)	$ (962,353)	$ (1,214,664)	$ (1,602,056)	$ (1,600,351)	$ (1,593,999)	$ (1,784,137)	**$ (14,388,672)**
Subtotal	**$ (165,910)**	**$ 122,665**	**$ 5,860**	**$ (7,484)**	**$ (1)**	**$ 12,658**	**$ 252,311**	**$ 387,391**	**$ (1,705)**	**$ (6,352)**	**$ 190,137**	**$ (669,029)**	**$ 120,543**
Total Fixed Demand	**$ 826,605**	**$ 1,199,769**	**$ 1,020,151**	**$ 1,027,038**	**$ 1,041,643**	**$ 1,029,631**	**$ 1,262,326**	**$ 1,673,764**	**$ 1,687,751**	**$ 1,738,261**	**$ 1,921,150**	**$ 1,228,462**	**$ 15,656,550**

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010-11 PEAK PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO PEAK PERIOD
May 2010 - April 2011

Other Demand Costs	**May-09 (Actual)**	**Jun-09 (Actual)**	**Jul-09 (Actual)**	**Aug-09 (Actual)**	**Sep-09 (Actual)**	**Oct-09 (Actual)**	**Nov-09 (Actual)**	**Dec-09 (Actual)**	**Jan-10 (Actual)**	**Feb-10 (Actual)**	**Mar-10 (Actual)**	**Apr-10 (Actual)**	**Total Peak**
Interruptible Profits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Capacity Release	$ (130,226)	$ (133,317)	$ (138,262)	$ (131,286)	$ (131,269)	$ (131,048)	$ (131,107)	$ (92,095)	$ (163,687)	$ (128,049)	$ (127,394)	$ (128,295)	**$ (1,566,035)**
Other A&G	$ -	$ -	$ -	$ -	$ -	$ -	$ 42,098	$ 107,703	$ 237,602	$ 110,479	$ 100,230	$ 41,464	**$ 639,576**
Local Production & Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 34,219	$ 80,895	$ 173,313	$ 82,870	$ 75,578	$ 33,768	**$ 480,643**
Subtotal	$ (130,226)	$ (133,317)	$ (138,262)	$ (131,286)	$ (131,269)	$ (131,048)	$ (54,790)	$ 96,503	$ 247,228	$ 65,300	$ 48,414	$ (53,063)	**$ (445,816)**
Capacity Release Estimates	$ (130,322)	$ (130,322)	$ (130,322)	$ (130,322)	$ (130,322)	$ (130,322)	$ (127,267)	$ (163,005)	$ (127,267)	$ (127,267)	$ (127,267)	$ (143,914)	**$ (1,597,919)**
Capacity Release Reversals	$ 131,405	$ 130,322	$ 130,322	$ 130,322	$ 130,322	$ 130,322	$ 130,322	$ 127,267	$ 163,005	$ 127,267	$ 127,267	$ 127,267	**$ 1,585,410**
Subtotal	$ 1,083	$ -	$ -	$ (0)	$ 0	$ -	$ 3,055	$ (35,738)	$ 35,738	$ -	$ -	$ (16,647)	**$ (12,509)**
Total Demand Costs	**$ 697,462**	**$ 1,066,451**	**$ 881,889**	**$ 895,752**	**$ 910,375**	**$ 898,583**	**$ 1,210,591**	**$ 1,734,529**	**$ 1,970,718**	**$ 1,803,561**	**$ 1,969,564**	**$ 1,158,752**	**$ 15,198,225**
Demand Costs Transferred to Off Peak Period	$ (164,448)	$ (164,448)	$ (164,448)	$ (164,448)	$ (164,448)	$ (164,448)	$ -	$ -	$ -	$ -	$ -	$ -	**$ (986,687)**
Net Demand Costs For Peak Period	**$ 533,014**	**$ 902,003**	**$ 717,441**	**$ 731,304**	**$ 745,927**	**$ 734,135**	**$ 1,210,591**	**$ 1,734,529**	**$ 1,970,718**	**$ 1,803,561**	**$ 1,969,564**	**$ 1,158,752**	**$ 14,211,538**
Total Gas Costs	**$ 224,986**	**$ 1,033,194**	**$ 758,297**	**$ 837,109**	**$ 745,058**	**$ 735,164**	**$ 2,349,161**	**$ 3,456,508**	**$ 4,493,042**	**$ 3,813,237**	**$ 3,731,303**	**$ 2,340,317**	**$ 24,517,377**

FORM III
Schedule 5

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010-11 PEAK PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
May 2010 - April 2011

	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
Maine													
Throughput IN													
BTU Factor	1.055	1.055	1.051	1.049	1.055	1.057	1.047	1.042	1.048	1.051	1.052	1.054	
GST Meter Throughput (MCF)	309,911	236,953	205,537	220,939	205,810	365,897	547,528	856,907	1,023,260	860,616	693,980	521,809	6,049,147
Kittery Meter (MCF)	55,523	48,024	49,076	50,815	49,104	63,228	100,987	125,432	137,909	126,221	127,453	99,553	1,033,325
LNG/Propane	1,484	1,539	1,851	1,186	1,119	1,181	960	1,425	1,779	494	1,250	1,894	16,162
GST Meter Throughput (DTH)	326,956	249,985	216,019	231,765	217,130	386,753	573,262	892,897	1,072,376	904,507	730,067	549,987	6,351,705
Kittery Meter (DTH)	58,577	50,665	51,579	53,305	51,805	66,832	105,733	130,700	144,529	132,658	134,081	104,929	1,085,392
Cotton Road (Lewiston)(DTH)	43,400	42,073	43,388	43,411	71,996	93,220	141,201	165,880	178,607	163,530	175,604	81,577	1,243,888
LNG/Propane	1,566	1,624	1,945	1,244	1,181	1,248	1,005	1,485	1,864	519	1,315	1,996	16,992
Total Throughput	430,498	344,347	312,932	329,725	342,111	548,053	821,201	1,190,962	1,397,377	1,201,215	1,041,067	738,489	8,697,978
Throughput OUT													
Residential Gas													
Charged	57,876	33,273	26,871	22,348	24,815	34,231	77,409	137,675	202,368	221,679	176,212	133,917	1,148,673
Uncharged Current	13,004	10,063	11,929	12,171	19,162	33,890	56,519	107,793	126,204	93,018	112,680	66,565	662,996
Uncharged Prior	-42,176	-13,004	-10,063	-11,929	-12,171	-19,162	-35,821	-56,519	-107,793	-126,204	-93,018	-112,680	-640,538
Total Residential Gas	**28,704**	**30,331**	**28,737**	**22,590**	**31,806**	**48,959**	**98,107**	**188,949**	**220,779**	**188,493**	**195,874**	**87,802**	**1,171,131**
Interruptible	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Commercial/Industrial Gas													
Charged	93,487	57,323	52,883	46,195	52,033	69,760	128,735	249,051	343,113	382,390	294,687	219,979	1,989,636
Uncharged Current	26,611	22,156	23,845	24,994	34,450	50,263	86,510	187,571	211,883	161,058	189,332	110,534	1,129,206
Uncharged Prior	-71,128	-26,611	-22,156	-23,845	-24,994	-34,450	-53,128	-86,510	-187,571	-211,883	-161,058	-189,332	-1,092,665
Total C/I Gas	**48,970**	**52,868**	**54,572**	**47,344**	**61,488**	**85,573**	**162,117**	**350,112**	**367,425**	**331565**	**322,961**	**141,181**	**2,026,177**
Transportation													
Charged	314,228	256,941	237,347	248,508	252,304	331,752	458,963	632,036	755,229	717,908	654,897	510,872	5,370,985
Uncharged Current	87,175	87,482	81,276	101,644	121,487	168,152	220,033	357,258	356,555	242,253	328,889	208,235	2,360,439
Uncharged Prior	-136,064	-87,175	-87,482	-81,276	-101,644	-121,487	-177,737	-220,033	-357,258	-356,555	-242,253	-328,889	-2,297,853
Total Transportation	**265,339**	**257,248**	**231,141**	**268,876**	**272,147**	**378,417**	**501,259**	**769,261**	**754,526**	**603,606**	**741,533**	**390,218**	**5,433,571**
Company Use	**337**	**162**	**145**	**120**	**121**	**254**	**456**	**732**	**1,162**	**1,488**	**1,166**	**858**	**7,002**
Total Throughput OUT	**343,349**	**340,610**	**314,595**	**338,931**	**365,562**	**513,203**	**761,939**	**1,309,054**	**1,343,892**	**1,125,152**	**1,261,534**	**620,059**	**8,637,881**
Total Throughput IN	**430,498**	**344,347**	**312,932**	**329,725**	**342,111**	**548,053**	**821,201**	**1,190,962**	**1,397,377**	**1,201,215**	**1,041,067**	**738,489**	**8,697,978**
Difference IN/OUT	87,149	3,738	-1,663	-9,206	-23,452	34,850	59,261	-118,092	53,485	76,063	-220,467	118,430	60,097
%													0.69%

Note: November 2010 Uncharged Prior line items reflect corrected conversion factors from prior months.

Attachment A

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010-11 PEAK PERIOD RECONCILIATION
INTERRUPTIBLE PROFIT SCHEDULE
May 2010 - April 2011

NONE

Attachment B

NORTHERN UTILITIES, INC. - MAINE DIVISION
DEFERRED PEAK WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
Period Ending April 30, 2011

PEAK DEMAND - ACCOUNT 182.13

	BEGINNING BALANCE	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	(D)	E = B + (D)	F = A + E	G = (A + F) / 2	H	I = G * (H/12)	J = F + I
MAY 2010	4,394	2,351	0.4410%	646	2,997	7,391	5,893	2.32%	11	7,402
JUNE	7,402	3,978	0.4410%	(1)	3,977	11,379	9,391	2.35%	18	11,398
JULY	11,398	3,164	0.4410%	(4)	3,159	14,557	12,977	2.34%	25	14,582
AUGUST	14,582	3,225	0.4410%	1	3,226	17,808	16,195	2.28%	31	17,839
SEPTEMBER	17,839	3,290	0.4410%	(2)	3,288	21,127	19,483	2.26%	37	21,163
OCTOBER	21,163	3,238	0.4410%	9	3,247	24,410	22,787	2.26%	43	24,453
NOVEMBER	24,453	5,339	0.4410%	(5,999)	(661)	23,792	24,123	2.25%	45	23,838
DECEMBER	23,838	7,649	0.4410%	(13,480)	(5,830)	18,008	20,923	2.26%	39	18,047
JANUARY 2011	18,047	8,691	0.4410%	(16,652)	(7,961)	10,086	14,067	2.26%	27	10,113
FEBRUARY	10,113	7,954	0.4410%	(13,832)	(5,878)	4,235	7,174	2.26%	14	4,248
MARCH	4,248	8,686	0.4410%	(13,803)	(5,117)	(869)	1,690	2.26%	3	(866)
APRIL	(866)	5,110	0.4410%	(6,068)	(957)	(1,823)	(1,344)	2.22%	(2)	(1,825)
Totals		62,673		(69,185)					291	

PEAK COMMODITY - ACCOUNT 182.11

	BEGINNING BALANCE	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	(D)	E = B + (D)	F = A + E	G = (A + F) / 2	H	I = G * (H/12)	J = F + I
MAY 2010	(3,826)	(1,358)	0.4410%	793	(566)	(4,392)	(4,109)	2.32%	(8)	(4,400)
JUNE	(4,400)	579	0.4410%	(5)	574	(3,826)	(4,113)	2.35%	(8)	(3,834)
JULY	(3,834)	180	0.4410%	(6)	174	(3,660)	(3,747)	2.34%	(7)	(3,667)
AUGUST	(3,667)	467	0.4410%	1	467	(3,200)	(3,434)	2.28%	(7)	(3,207)
SEPTEMBER	(3,207)	(4)	0.4410%	(2)	(6)	(3,213)	(3,210)	2.26%	(6)	(3,219)
OCTOBER	(3,219)	5	0.4410%	11	16	(3,203)	(3,211)	2.26%	(6)	(3,209)
NOVEMBER	(3,209)	5,021	0.4410%	(4,288)	733	(2,476)	(2,842)	2.25%	(5)	(2,481)
DECEMBER	(2,481)	7,594	0.4410%	(9,694)	(2,100)	(4,581)	(3,531)	2.26%	(7)	(4,588)
JANUARY 2011	(4,588)	11,123	0.4410%	(11,895)	(771)	(5,359)	(4,974)	2.26%	(9)	(5,369)
FEBRUARY	(5,369)	8,863	0.4410%	(9,877)	(1,014)	(6,383)	(5,876)	2.26%	(11)	(6,394)
MARCH	(6,394)	7,769	0.4410%	(9,860)	(2,091)	(8,485)	(7,439)	2.26%	(14)	(8,499)
APRIL	(8,499)	5,211	0.4410%	(4,334)	877	(7,622)	(8,060)	2.22%	(15)	(7,636)
Totals		45,449		(49,155)					(103)	
Combined Totals		108,122		(118,340)					188	

Attachment C

NORTHERN UTILITIES, INC - MAINE DIVISION
DEFERRED PEAK 2009-10 BAD DEBT CALCULATION OF COLLECTION ALLOWANCE
Period Ending April 30, 2011

ACCOUNT 182.16

	BEG. BAL	MAINE GAS COSTS PER BOOKS ALLOWED FOR BAD DEBT	BAD DEBT % ALLOWED	ACTUAL BAD DEBT ALLOWANCE(1)	ACTUAL BAD DEBT COLLECTION	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	(E)	F = D + (E)	G = A + F	H = (A+G)/2	I = G*(H/12)	J = F + I	
MAY 2010	(3,596)	225,978	1.06%	2,395	3,486	5,881	2,285	(656)	2.32%	(1)	2,284
JUNE	2,284	1,037,750	1.06%	11,000	(14)	10,986	13,269	7,777	2.35%	15	13,285
JULY	13,285	761,641	1.06%	8,073	(26)	8,048	21,332	17,308	2.34%	34	21,366
AUGUST	21,366	840,801	1.06%	8,912	4	8,916	30,282	25,824	2.28%	49	30,331
SEPTEMBER	30,331	748,344	1.06%	7,932	(10)	7,922	38,253	34,292	2.26%	65	38,318
OCTOBER	38,318	738,406	1.06%	7,827	49	7,876	46,194	42,256	2.26%	79	46,274
NOVEMBER	46,274	2,359,521	1.06%	25,011	(24,671)	340	46,614	46,444	2.25%	87	46,701
DECEMBER	46,701	3,471,752	1.06%	36,801	(55,535)	(18,734)	27,967	37,334	2.26%	70	28,037
JANUARY 2011	28,037	4,512,856	1.06%	47,836	(68,399)	(20,563)	7,475	17,756	2.26%	33	7,508
FEBRUARY	7,508	3,830,053	1.06%	40,599	(56,810)	(16,211)	(8,703)	(597)	2.26%	(1)	(8,704)
MARCH	(8,704)	3,747,758	1.06%	39,726	(56,698)	(16,972)	(25,676)	(17,190)	2.26%	(32)	(25,708)
APRIL	(25,708)	2,350,638	1.06%	24,917	(24,921)	(5)	(25,713)	(25,711)	2.22%	(48)	(25,761)
Totals				261,030	(283,546)					351	

(1) Bad Debt Allowance calculated by multiplying Bad Debt % Allowed by Total Gas Cost on Schedule 4, page 3 of 3, and Working Capital Allowances on Attachment B.

NORTHERN UTILITIES - MAINE DIVISION
SALES VARIANCE ANALYSIS
PEAK PERIOD 2010-11

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
Forecast Calendar Month Sales	262,993	442,106	535,451	440,646	427,488	261,358	2,370,042
Actual Calendar Month Sales	249,346	517,989	559,641	493,901	492,960	216,706	2,530,544
Difference	(13,647)	75,883	24,190	53,255	65,472	(44,652)	160,502
Add:							
Volume Variance due to Weather							
Normal Calendar Month Sales	251,569	521,937	575,290	476,970	502,393	214,941	2,543,100
Actual Calendar Month Sales	249,346	517,989	559,641	493,901	492,960	216,706	2,530,544
Weather Variance	2,223	3,948	15,649	(16,931)	9,433	(1,766)	12,556
Total Variance Excluding Weather	(11,424)	79,831	39,839	36,324	74,905	(46,417)	173,058
Variance-change in meter count							9,781
-change in load pattern							66,849
							76,630

NORTHERN UTILITIES - MAINE DIVISION
SALES VARIANCE ANALYSIS
PEAK PERIOD 2010-11

	Normal Mcf			Meters		
	2010-11 Actual	**2010-11 Forecast**	**Difference**	**2010-11 Actual**	**2010-11 Forecast**	**Difference**
Res Heat	838,891	809,251	29,640	85,525	86,134	(609)
Res Non Heat	65,749	55,961	9,788	29,653	29,502	151
Total Res	**904,640**	**865,212**	**39,428**	**115,178**	**115,636**	**(458)**
G-50	127,779	108,010	19,769	8,044	7,964	80
G-40	698,177	666,836	31,341	26,916	26,647	269
G-51	74,080	75,801	(1,721)	660	653	7
G-41	543,032	513,294	29,738	2,204	2,182	22
G-52	51,829	29,964	21,865	37	37	0
G-42	47,135	110,924	(63,789)	31	31	0
Total Commercial and Industrial	**1,542,031**	**1,504,829**	**37,202**	**37,892**	**37,513**	**379**
Total Company	2,446,671	2,370,041	76,630	153,070	153,149	(79)

	Normal Average Use			Change in Sales Due to Change in:			
	2010-11 Actual	**2010-11 Forecast**	**Difference**	**Meter Count**	**Load Pattern**	**Total Change Mcf**	**% Difference**
Res Heat	9.81	9.40	0.41	(5,974)	35,614	29,640	3.66%
Res Non Heat	2.22	1.90	0.32	335	9,453	9,788	17.49%
Total Res	**7.85**	**7.48**	**0.37**	**(5,639)**	**45,067**	**39,428**	**4.56%**
G-50	15.89	13.56	2.33	1,278	18,491	19,769	18.30%
G-40	25.94	25.02	0.92	6,982	24,359	31,341	4.70%
G-51	112.24	116.01	(3.77)	741	(2,462)	(1,721)	-2.27%
G-41	246.38	235.24	11.14	5,430	24,308	29,738	5.79%
G-52	1,400.77	818.02	582.75	518	21,347	21,865	72.97%
G-42	1,520.48	3,614.34	(2,093.86)	471	(64,260)	(63,789)	-57.51%
Total Commercial and Industrial	**40.70**	**40.11**	**0.59**	**15,420**	**21,782**	**37,202**	**2.47%**
Total Company	15.98	15.48	0.50	9,781	66,849	76,630	3.23%

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010-11 PEAK PERIOD RECONCILIATION
May 2010 - April 2011

Recalculated Reconciliation

FORM III
Schedule 1
Page 1 of 2
Updated July 2012

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010-11 PEAK PERIOD RECONCILIATION
SCHEDULE 1: PEAK DEMAND SUMMARY
May 2010 - April 2011

		AMOUNT	
Peak Demand Beginning Balance	$	424,922	SCHEDULE 2
Less: Cost of Firm Gas Revenue (Demand)	$	(15,354,902)	SCHEDULE 2
Add: Cost of Firm Gas Allowable (Demand)	$	14,211,538	SCHEDULE 2
Add: Interest	$	53,992	SCHEDULE 2
Peak Demand Ending Balance	$	(664,450)	

FORM III
Schedule 1
Page 2 of 2
Updated July 2012

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010-11 PEAK PERIOD RECONCILIATION
SCHEDULE 1: PEAK COMMODITY SUMMARY
May 2010 - April 2011

		AMOUNT	
Peak Commodity Beginning Balance	$	499,008	SCHEDULE 2
Less: Cost of Firm Gas Revenue (Commodity)	$	(10,483,237)	SCHEDULE 2
Add: Cost of Firm Gas Allowable (Commodity)	$	12,211,286	SCHEDULE 2
Add: Interest	$	21,488	SCHEDULE 2
Peak Commodity Ending Balance	$	2,248,546	
Net Peak Demand and Commodity Ending Balance	$	1,584,096	

FORM III
Updated July 2012 Schedule 2

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010-11 PEAK PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED PEAK PERIOD ACCOUNTS
May 2010 - April 2011

		May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
1	**PEAK DEMAND - ACCOUNT 191.20**													
2	Peak Demand Account Beginning Balance	$ 424,922	$ 1,073,933	$ 1,978,526	$ 2,699,526	$ 3,436,706	$ 4,189,447	$ 4,932,787	$ 4,836,904	$ 3,585,789	$ 1,835,226	$ 579,858	$ (510,338)	$ 424,922
3	Plus: Cost of Gas Demand Allowable (Schedule 4)	$ 533,014	$ 902,003	$ 717,441	$ 731,304	$ 745,927	$ 734,135	$ 1,210,591	$ 1,734,529	$ 1,970,718	$ 1,803,561	$ 1,969,564	$ 1,158,752	$ 14,211,538
4	Less: Cost of Gas Demand Revenue (Schedule 3)	$ 114,548	$ (395)	$ (995)	$ 57	$ (351)	$ 637	$ (1,315,640)	$ (2,993,575)	$ (3,726,383)	$ (3,061,204)	$ (3,059,826)	$ (1,311,775)	$ (15,354,902)
5	**Preliminary Ending Balance**	**$ 1,072,483**	**$ 1,975,541**	**$ 2,694,972**	**$ 3,430,887**	**$ 4,182,282**	**$ 4,924,220**	**$ 4,827,737**	**$ 3,577,858**	**$ 1,830,124**	**$ 577,583**	**$ (510,404)**	**$ (663,362)**	**$ (718,442)**
6	Month's Average Balance ((Line 2 + Line 5) / 2)	$ 748,703	$ 1,524,737	$ 2,336,749	$ 3,065,207	$ 3,809,494	$ 4,556,834	$ 4,880,262	$ 4,207,381	$ 2,707,957	$ 1,206,405	$ 34,727	$ (586,850)	
7	Interest Rate (Short Term Borrowing Rate)	2.323%	2.349%	2.339%	2.278%	2.257%	2.256%	2.254%	2.262%	2.261%	2.263%	2.255%	2.224%	
8	Interest Applied (Line 6 * (Line 7 / 12))	$ 1,449	$ 2,985	$ 4,555	$ 5,819	$ 7,165	$ 8,567	$ 9,167	$ 7,931	$ 5,102	$ 2,275	$ 65	$ (1,088)	$ 53,992
9	**Peak Demand Account Ending Balance**	**$ 1,073,933**	**$ 1,978,526**	**$ 2,699,526**	**$ 3,436,706**	**$ 4,189,447**	**$ 4,932,787**	**$ 4,836,904**	**$ 3,585,789**	**$ 1,835,226**	**$ 579,858**	**$ (510,338)**	**$ (664,450)**	**$ (664,450)**
10	**PEAK COMMODITY - ACCOUNT 191.19**													
11	Peak Commodity Account Beginning Balance	$ 499,008	$ 376,527	$ 507,508	$ 427,919	$ 534,827	$ 534,494	$ 539,446	$ 846,206	$ 1,019,076	$ 1,536,803	$ 1,868,256	$ 1,842,298	$ 499,008
12	Plus: Cost of Gas Commodity Allowable (Schedule 4	$ (307,989)	$ 131,130	$ (79,137)	$ 105,805	$ (811)	$ 1,029	$ 1,224,044	$ 2,242,338	$ 3,050,985	$ 2,437,271	$ 2,075,583	$ 1,331,038	$ 12,211,286
13	Less: Cost of Gas Commodity Revenue (Schedule 3)	$ 184,662	$ (1,014)	$ (1,362)	$ 190	$ (528)	$ 2,915	$ (918,584)	$ (2,071,225)	$ (2,535,663)	$ (2,109,026)	$ (2,105,025)	$ (928,578)	$ (10,483,237)
14	**Preliminary Ending Balance**	**$ 375,681**	**$ 506,643**	**$ 427,009**	**$ 533,914**	**$ 533,489**	**$ 538,437**	**$ 844,906**	**$ 1,017,319**	**$ 1,534,398**	**$ 1,865,048**	**$ 1,838,814**	**$ 2,244,758**	**$ 2,227,058**
15	Month's Average Balance ((Line 11 + Line 14) / 2)	$ 437,344	$ 441,585	$ 467,258	$ 480,917	$ 534,158	$ 536,465	$ 692,176	$ 931,763	$ 1,276,737	$ 1,700,926	$ 1,853,535	$ 2,043,528	
16	Interest Rate (Short Term Borrowing Rate)	2.323%	2.349%	2.339%	2.278%	2.257%	2.256%	2.254%	2.262%	2.261%	2.263%	2.255%	2.224%	
17	Interest Applied (Line 16 * (Line 15 / 12))	$ 847	$ 864	$ 911	$ 913	$ 1,005	$ 1,009	$ 1,300	$ 1,756	$ 2,406	$ 3,208	$ 3,483	$ 3,787	$ 21,488
18	**Peak Commodity Account Ending Balance**	**$ 376,527**	**$ 507,508**	**$ 427,919**	**$ 534,827**	**$ 534,494**	**$ 539,446**	**$ 846,206**	**$ 1,019,076**	**$ 1,536,803**	**$ 1,868,256**	**$ 1,842,298**	**$ 2,248,546**	**$ 2,248,546**

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010-11 PEAK PERIOD RECONCILIATION
SCHEDULE 3: BILLED REVENUE
May 2010 - April 2011

FORM III
Schedule 3

	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
Demand Revenue:													
Accrued Revenue	$ (424,409)	$ -	$ -	$ -	$ -	$ -	$ 842,443	$ 707,639	$ 473,147	$ (522,008)	$ 277,304	$ (756,697)	$ 597,420
Billed Revenue	$ 309,861	$ 395	$ 995	$ (57)	$ 351	$ (637)	$ 473,197	$ 2,285,936	$ 3,253,235	$ 3,583,212	$ 2,782,522	$ 2,068,472	$ 14,757,482
Calendarized Revenue	**$ (114,548)**	**$ 395**	**$ 995**	**$ (57)**	**$ 351**	**$ (637)**	**$ 1,315,640**	**$ 2,993,575**	**$ 3,726,383**	**$ 3,061,204**	**$ 3,059,826**	**$ 1,311,775**	**$ 15,354,902**
Commodity Revenue:													
Accrued Revenue	$ (721,385)	$ -	$ -	$ -	$ -	$ -	$ 583,812	$ 476,700	$ 314,615	$ (343,095)	$ 193,989	$ (506,446)	$ (1,811)
Billed Revenue	$ 536,724	$ 1,014	$ 1,362	$ (190)	$ 528	$ (2,915)	$ 334,772	$ 1,594,525	$ 2,221,048	$ 2,452,121	$ 1,911,035	$ 1,435,024	$ 10,485,047
Calendarized Revenue	**$ (184,662)**	**$ 1,014**	**$ 1,362**	**$ (190)**	**$ 528**	**$ (2,915)**	**$ 918,584**	**$ 2,071,225**	**$ 2,535,663**	**$ 2,109,026**	**$ 2,105,025**	**$ 928,578**	**$ 10,483,237**
Total Revenue	**$ (299,210)**	**$ 1,409**	**$ 2,357**	**$ (247)**	**$ 878**	**$ (3,552)**	**$ 2,234,224**	**$ 5,064,800**	**$ 6,262,045**	**$ 5,170,230**	**$ 5,164,850**	**$ 2,240,353**	**$ 25,838,139**

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010-11 PEAK PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO PEAK PERIOD
May 2010 - April 2011

Updated July 2012

Commodity Costs	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
BG Energy Merchants, LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 602,011	$ 391,145	$ 384,495	$ 380,162	**$ 1,757,812**
Distrigas of Massachusetts, LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 89,132	$ 185,151	$ 198,418	$ 215,780	$ 210,348	**$ 898,829**
Emera Energy Services, Inc.	$ 229,406	$ 3,226	$ -	$ -	$ -	$ -	$ -	$ 57,403	$ 312,924	$ 320,505	$ 341,112	$ 144,305	**$ 1,408,882**
FPL Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 30,876	$ 178,048	$ 80,110	$ -	**$ 289,034**
JP Morgan Ventures Energy Corp	$ 287,074	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 287,074**
Louis Dreyfus Electric Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,711	$ 167,802	$ -	$ -	$ -	**$ 177,513**
Macquarie Cook Energy, LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 33,122	$ -	$ -	$ -	$ -	**$ 33,122**
National Energy & Trade	$ 143,537	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 45,022	$ 89,995	$ 61,925	$ 18,795	**$ 359,275**
Portland Natural Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 563	**$ 563**
Repsol	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 73,405	$ 184,132	$ 51,476	**$ 309,013**
South Jersey Resources	$ 9,576	$ -	$ -	$ -	$ -	$ -	$ 10,798	$ -	$ -	$ -	$ -	$ 4,768	**$ 25,142**
Spark Energy Gas, LP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 130,706	$ -	$ 275,008	$ -	$ 318,012	**$ 723,726**
Sprague Energy Corp.	$ 74,411	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 74,411**
Tennessee Gas Pipeline Co	$ 1,559	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,743	$ 3,187	$ 1,720	$ 2,523	**$ 13,733**
Rust Consulting	$ -	$ -	$ -	$ -	$ (1,772)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ (1,772)**
Virginia Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 158,228	$ 35,239	**$ 193,467**
Subtotal	**$ 745,564**	**$ 3,226**	**$ -**	**$ -**	**$ (1,772)**	**$ -**	**$ 10,798**	**$ 320,074**	**$ 1,348,528**	**$ 1,529,712**	**$ 1,427,502**	**$ 1,166,192**	**$ 6,549,824**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 649,170	$ 1,368,494	$ 1,646,400	$ 1,392,555	$ 1,169,716	$ 1,088,069	**$ 7,314,404**
Commodity Cost Reversals	$ (1,093,220)	$ -	$ -	$ -	$ -	$ -	$ -	$ (649,170)	$ (1,368,494)	$ (1,646,400)	$ (1,392,555)	$ (1,169,716)	**$ (7,319,555)**
Subtotal	**$ (1,093,220)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 649,170**	**$ 719,324**	**$ 277,906**	**$ (253,845)**	**$ (222,839)**	**$ (81,647)**	**$ (5,151)**
Withdrawal Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 863,167	$ 1,992,463	$ 1,936,158	$ 1,275,774	$ 979,930	$ 733	**$ 7,048,224**
Interruptible Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ (26,881)	$ 59,113	$ 85,073	$ 69,083	$ 82,632	$ 20,081	**$ 289,101**
Non Traditional Sales	$ (349,376)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,034)	$ (687,843)	$ (107,541)	$ (105,303)	$ (22,081)	**$ (1,274,177)**
Net OBA Adj.	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,002	$ 1,410	$ 8,910	$ 25,190	$ (152)	$ 7,139	**$ 51,500**
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (164,104)	$ (992,215)	$ (1,189,990)	$ (749,772)	$ (565,462)	**$ (3,661,543)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,520	$ 5,166	$ 5,553	$ 993	$ 2,647	$ 4,397	**$ 22,276**
Transportation Charges	$ 38,791	$ 127,468	$ 40,166	$ 105,002	$ -	$ -	$ -	$ 3,072	$ 77,252	$ 21,863	$ 74,902	$ 56,154	**$ 544,670**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 103,579	$ 87,188	$ 49,343	$ 65,123	$ 67,134	$ 82,469	**$ 454,836**
Propane	$ 516	$ -	$ -	$ -	$ -	$ -	$ 530	$ 562	$ 867	$ 747	$ 581	$ 770	**$ 4,573**
Inventory Finance Charges	$ 322	$ 496	$ 690	$ 803	$ 903	$ 1,029	$ 961	$ 860	$ 553	$ 288	$ 148	$ 41	**$ 7,093**
Allocation Adjustments	$ 38	$ (61)	$ (119,993)	$ 0	$ 58	$ 0	$ 85,474	$ 520,359	$ 528,660	$ 427,595	$ 313,844	$ 149,473	**$ 1,905,447**
Subtotal	**$ (309,709)**	**$ 127,903**	**$ (79,137)**	**$ 105,805**	**$ 961**	**$ 1,029**	**$ 1,039,354**	**$ 2,504,053**	**$ 1,012,312**	**$ 589,124**	**$ 666,590**	**$ (266,287)**	**$ 5,392,000**
Sales for Resale Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ (475,278)	$ (1,776,391)	$ (1,364,152)	$ (791,872)	$ (587,543)	$ (74,762)	**$ (5,069,999)**
Sales for Resale Reversals	$ 349,376	$ -	$ -	$ -	$ -	$ -	$ -	$ 475,278	$ 1,776,391	$ 1,364,152	$ 791,872	$ 587,543	**$ 5,344,613**
Subtotal	**$ 349,376**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (475,278)**	**$ (1,301,114)**	**$ 412,239**	**$ 572,280**	**$ 204,330**	**$ 512,781**	**$ 274,614**
Total Commodity Costs	**$ (307,989)**	**$ 131,130**	**$ (79,137)**	**$ 105,805**	**$ (811)**	**$ 1,029**	**$ 1,224,044**	**$ 2,242,338**	**$ 3,050,985**	**$ 2,437,271**	**$ 2,075,583**	**$ 1,331,038**	**$ 12,211,286**

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010-11 PEAK PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO PEAK PERIOD
May 2010 - April 2011

Updated July 2012

Demand Costs	**May-09**	**Jun-09**	**Jul-09**	**Aug-09**	**Sep-09**	**Oct-09**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**Total**
Pipeline Reservation													
Algonquin Gas Transmission	$ 17,455	$ 17,458	$ 17,455	$ 17,455	$ 17,455	$ 17,455	$ 17,455	$ 17,063	$ 17,063	$ 17,063	$ 17,063	$ 17,063	**$ 207,504**
BG Energy Merchants, LLC	$ 367,894	$ 381,747	$ 371,921	$ 372,562	$ 378,800	$ 381,563	$ 383,480	$ 371,614	$ 364,921	$ 377,820	$ 386,810	$ 566,409	**$ 4,705,541**
Emera Energy Services, Inc.	$ -	$ 67,030	$ 33,885	$ 33,261	$ 34,295	$ 34,356	$ -	$ 34,369	$ -	$ -	$ -	$ -	**$ 237,196**
Granite State Gas Transmission, Inc.	$ 86,792	$ 86,792	$ 86,805	$ 86,805	$ 86,829	$ 86,807	$ 84,858	$ 84,750	$ 142,386	$ 142,318	$ 142,272	$ 142,228	**$ 1,259,641**
Iroquois Gas Transmision System	$ 22,769	$ 22,769	$ 22,769	$ 22,769	$ 22,769	$ 22,769	$ 22,769	$ 22,258	$ 22,258	$ 22,258	$ -	$ 44,515	**$ 270,670**
Portland Natural Gas Transmission	$ 15,837	$ 15,837	$ 15,837	$ 15,837	$ 15,837	$ 15,837	$ 15,841	$ 897,890	$ 1,318,754	$ 1,318,872	$ 1,318,754	$ 1,318,754	**$ 6,283,884**
Tennessee Gas Pipeline Co	$ 144,353	$ 144,353	$ 116,956	$ 144,353	$ 144,353	$ 116,956	$ 144,353	$ 141,111	$ 83,863	$ 141,111	$ 141,111	$ 83,863	**$ 1,546,735**
Texas Eastern Transmission	$ -	$ 3,611	$ 10,832	$ 3,611	$ 3,603	$ 3,603	$ 3,603	$ 3,522	$ 3,522	$ 3,522	$ 3,489	$ 3,489	**$ 46,405**
Union Gas Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,235	$ 7,632	$ 7,680	$ 7,767	**$ 38,315**
Vector Pipeline LP	$ 94,914	$ 94,911	$ 94,922	$ 94,912	$ 94,931	$ 94,963	$ 94,972	$ 132,871	$ 132,894	$ 132,897	$ 132,897	$ 132,962	**$ 1,329,045**
Subtotal	**$ 750,014**	**$ 834,507**	**$ 771,382**	**$ 791,564**	**$ 798,870**	**$ 774,308**	**$ 767,330**	**$ 1,705,447**	**$ 2,100,896**	**$ 2,163,493**	**$ 2,150,077**	**$ 2,317,049**	**$ 15,924,937**
Product Demand													
Alberta Northeast Gas Ltd.	$ 1,132	$ 1,135	$ 1,264	$ 1,496	$ 1,313	$ 1,203	$ 1,223	$ 1,199	$ 1,278	$ -	$ 2,360	$ -	**$ 13,603**
Distrigas of Massachusetts	$ 109,751	$ 109,751	$ 109,751	$ 109,751	$ 109,751	$ 109,751	$ 109,751	$ 102,422	$ 113,880	$ 113,880	$ 113,880	$ 113,880	**$ 1,326,200**
FPL/NextEra	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 198,481	$ 198,481	$ 198,481	$ 198,481	$ 198,481	**$ 992,404**
Subtotal	**$ 110,883**	**$ 110,887**	**$ 111,015**	**$ 111,247**	**$ 111,065**	**$ 110,955**	**$ 110,974**	**$ 302,103**	**$ 313,638**	**$ 312,360**	**$ 314,720**	**$ 312,360**	**$ 2,332,207**
Storage Pipeline Transportation and Demand Reservation													
Tennessee Gas Pipeline	$ 5,084	$ 5,084	$ 5,084	$ 5,084	$ 5,084	$ 5,084	$ 5,084	$ 4,970	$ 4,970	$ 4,970	$ 4,970	$ 4,970	**$ 60,442**
Washington 10 (BG Energy)	$ 126,534	$ 126,534	$ 126,534	$ 126,534	$ 126,534	$ 126,534	$ 126,534	$ 123,692	$ 123,692	$ 123,692	$ 123,692	$ 123,692	**$ 1,504,197**
Texas Eastern	$ -	$ 92	$ 276	$ 92	$ 91	$ 92	$ 92	$ 89	$ 89	$ 89	$ 88	$ 89	**$ 1,177**
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (849,929)	$ (853,829)	$ (859,991)	$ (862,535)	$ (860,669)	**$ (4,286,953)**
Subtotal	**$ 131,618**	**$ 131,710**	**$ 131,894**	**$ 131,710**	**$ 131,710**	**$ 131,710**	**$ 131,710**	**$ (721,177)**	**$ (725,078)**	**$ (731,240)**	**$ (733,784)**	**$ (731,918)**	**$ (2,721,136)**
Demand Cost Estimates	$ 828,655	$ 951,320	$ 957,180	$ 949,696	$ 949,695	$ 962,353	$ 1,214,664	$ 1,602,056	$ 1,600,351	$ 1,593,999	$ 1,784,137	$ 1,115,108	**$ 14,509,215**
Demand Cost Reversals	$ (994,565)	$ (828,655)	$ (951,320)	$ (957,180)	$ (949,696)	$ (949,695)	$ (962,353)	$ (1,214,664)	$ (1,602,056)	$ (1,600,351)	$ (1,593,999)	$ (1,784,137)	**$ (14,388,672)**
Subtotal	**$ (165,910)**	**$ 122,665**	**$ 5,860**	**$ (7,484)**	**$ (1)**	**$ 12,658**	**$ 252,311**	**$ 387,391**	**$ (1,705)**	**$ (6,352)**	**$ 190,137**	**$ (669,029)**	**$ 120,543**
Total Fixed Demand	**$ 826,605**	**$ 1,199,769**	**$ 1,020,151**	**$ 1,027,038**	**$ 1,041,643**	**$ 1,029,631**	**$ 1,262,326**	**$ 1,673,764**	**$ 1,687,751**	**$ 1,738,261**	**$ 1,921,150**	**$ 1,228,462**	**$ 15,656,550**

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010-11 PEAK PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO PEAK PERIOD
May 2010 - April 2011

	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
Other Demand Costs													
Interruptible Profits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Capacity Release	$ (130,226)	$ (133,317)	$ (138,262)	$ (131,286)	$ (131,269)	$ (131,048)	$ (131,107)	$ (92,095)	$ (163,687)	$ (128,049)	$ (127,394)	$ (128,295)	**$ (1,566,035)**
Other A&G	$ -	$ -	$ -	$ -	$ -	$ -	$ 42,098	$ 107,703	$ 237,602	$ 110,479	$ 100,230	$ 41,464	**$ 639,576**
Local Production & Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 34,219	$ 80,895	$ 173,313	$ 82,870	$ 75,578	$ 33,768	**$ 480,643**
Subtotal	$ (130,226)	$ (133,317)	$ (138,262)	$ (131,286)	$ (131,269)	$ (131,048)	$ (54,790)	$ 96,503	$ 247,228	$ 65,300	$ 48,414	$ (53,063)	**$ (445,816)**
Capacity Release Estimates	$ (130,322)	$ (130,322)	$ (130,322)	$ (130,322)	$ (130,322)	$ (130,322)	$ (127,267)	$ (163,005)	$ (127,267)	$ (127,267)	$ (127,267)	$ (143,914)	**$ (1,597,919)**
Capacity Release Reversals	$ 131,405	$ 130,322	$ 130,322	$ 130,322	$ 130,322	$ 130,322	$ 130,322	$ 127,267	$ 163,005	$ 127,267	$ 127,267	$ 127,267	**$ 1,585,410**
Subtotal	$ 1,083	$ -	$ -	$ (0)	$ 0	$ -	$ 3,055	$ (35,738)	$ 35,738	$ -	$ -	$ (16,647)	**$ (12,509)**
Total Demand Costs	**$ 697,462**	**$ 1,066,451**	**$ 881,889**	**$ 895,752**	**$ 910,375**	**$ 898,583**	**$ 1,210,591**	**$ 1,734,529**	**$ 1,970,718**	**$ 1,803,561**	**$ 1,969,564**	**$ 1,158,752**	**$ 15,198,225**
Demand Costs Transferred to Off Peak Period	$ (164,448)	$ (164,448)	$ (164,448)	$ (164,448)	$ (164,448)	$ (164,448)	$ -	$ -	$ -	$ -	$ -	$ -	**$ (986,687)**
Net Demand Costs For Peak Period	**$ 533,014**	**$ 902,003**	**$ 717,441**	**$ 731,304**	**$ 745,927**	**$ 734,135**	**$ 1,210,591**	**$ 1,734,529**	**$ 1,970,718**	**$ 1,803,561**	**$ 1,969,564**	**$ 1,158,752**	**$ 14,211,538**
Total Gas Costs	**$ 225,025**	**$ 1,033,133**	**$ 638,304**	**$ 837,109**	**$ 745,116**	**$ 735,165**	**$ 2,434,635**	**$ 3,976,867**	**$ 5,021,702**	**$ 4,240,832**	**$ 4,045,147**	**$ 2,489,790**	**$ 26,422,824**

FORM III
Schedule 5

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010-11 PEAK PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
May 2010 - April 2011

	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
Maine													
Throughput IN													
BTU Factor	1.055	1.055	1.051	1.049	1.055	1.057	1.047	1.042	1.048	1.051	1.052	1.054	
GST Meter Throughput (MCF)	309,911	236,953	205,537	220,939	205,810	365,897	547,528	856,907	1,023,260	860,616	693,980	521,809	6,049,147
Kittery Meter (MCF)	55,523	48,024	49,076	50,815	49,104	63,228	100,987	125,432	137,909	126,221	127,453	99,553	1,033,325
LNG/Propane	1,484	1,539	1,851	1,186	1,119	1,181	960	1,425	1,779	494	1,250	1,894	16,162
GST Meter Throughput (DTH)	326,956	249,985	216,019	231,765	217,130	386,753	573,262	892,897	1,072,376	904,507	730,067	549,987	6,351,705
Kittery Meter (DTH)	58,577	50,665	51,579	53,305	51,805	66,832	105,733	130,700	144,529	132,658	134,081	104,929	1,085,392
Cotton Road (Lewiston)(DTH)	43,400	42,073	43,388	43,411	71,996	93,220	141,201	165,880	178,607	163,530	175,604	81,577	1,243,888
LNG/Propane	1,566	1,624	1,945	1,244	1,181	1,248	1,005	1,485	1,864	519	1,315	1,996	16,992
Total Throughput	430,498	344,347	312,932	329,725	342,111	548,053	821,201	1,190,962	1,397,377	1,201,215	1,041,067	738,489	8,697,978
Throughput OUT													
Residential Gas													
Charged	57,876	33,273	26,871	22,348	24,815	34,231	77,409	137,675	202,368	221,679	176,212	133,917	1,148,673
Uncharged Current	13,004	10,063	11,929	12,171	19,162	33,890	56,519	107,793	126,204	93,018	112,680	66,565	662,996
Uncharged Prior	-42,176	-13,004	-10,063	-11,929	-12,171	-19,162	-35,821	-56,519	-107,793	-126,204	-93,018	-112,680	-640,538
Total Residential Gas	**28,704**	**30,331**	**28,737**	**22,590**	**31,806**	**48,959**	**98,107**	**188,949**	**220,779**	**188,493**	**195,874**	**87,802**	**1,171,131**
Interruptible	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Commercial/Industrial Gas													
Charged	93,487	57,323	52,883	46,195	52,033	69,760	128,735	249,051	343,113	382,390	294,687	219,979	1,989,636
Uncharged Current	26,611	22,156	23,845	24,994	34,450	50,263	86,510	187,571	211,883	161,058	189,332	110,534	1,129,206
Uncharged Prior	-71,128	-26,611	-22,156	-23,845	-24,994	-34,450	-53,128	-86,510	-187,571	-211,883	-161,058	-189,332	-1,092,665
Total C/I Gas	**48,970**	**52,868**	**54,572**	**47,344**	**61,488**	**85,573**	**162,117**	**350,112**	**367,425**	**331,565**	**322,961**	**141,181**	**2,026,177**
Transportation													
Charged	314,228	256,941	237,347	248,508	252,304	331,752	458,963	632,036	755,229	717,908	654,897	510,872	5,370,985
Uncharged Current	87,175	87,482	81,276	101,644	121,487	168,152	220,033	357,258	356,555	242,253	328,889	208,235	2,360,439
Uncharged Prior	-136,064	-87,175	-87,482	-81,276	-101,644	-121,487	-177,737	-220,033	-357,258	-356,555	-242,253	-328,889	-2,297,853
Total Transportation	**265,339**	**257,248**	**231,141**	**268,876**	**272,147**	**378,417**	**501,259**	**769,261**	**754,526**	**603,606**	**741,533**	**390,218**	**5,433,571**
Company Use	**337**	**162**	**145**	**120**	**121**	**254**	**456**	**732**	**1,162**	**1,488**	**1,166**	**858**	**7,002**
Total Throughput OUT	**343,349**	**340,610**	**314,595**	**338,931**	**365,562**	**513,203**	**761,939**	**1,309,054**	**1,343,892**	**1,125,152**	**1,261,534**	**620,059**	**8,637,881**
Total Throughput IN	**430,498**	**344,347**	**312,932**	**329,725**	**342,111**	**548,053**	**821,201**	**1,190,962**	**1,397,377**	**1,201,215**	**1,041,067**	**738,489**	**8,697,978**
Difference IN/OUT	87,149	3,738	-1,663	-9,206	-23,452	34,850	59,261	-118,092	53,485	76,063	-220,467	118,430	60,097
%													0.69%

Note: November 2010 Uncharged Prior line items reflect corrected conversion factors from prior months.

Attachment A

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010-11 PEAK PERIOD RECONCILIATION
INTERRUPTIBLE PROFIT SCHEDULE
May 2010 - April 2011

NONE

Updated July 2012 Attachment B

NORTHERN UTILITIES, INC. - MAINE DIVISION
DEFERRED PEAK WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
May 2010 - April 2011

PEAK DEMAND - ACCOUNT 182.13

	BEGINNING BALANCE	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	(D)	E = B + (D)	F = A + E	G = (A + F) / 2	H	I = G * (H/12)	J = F + I
MAY 2010	4,394	2,351	0.4410%	646	2,997	7,391	5,893	2.32%	11	7,403
JUNE	7,403	3,978	0.4410%	(1)	3,977	11,380	9,391	2.35%	18	11,398
JULY	11,398	3,164	0.4410%	(4)	3,159	14,557	12,978	2.34%	25	14,582
AUGUST	14,582	3,225	0.4410%	1	3,226	17,808	16,195	2.28%	31	17,839
SEPTEMBER	17,839	3,290	0.4410%	(2)	3,288	21,127	19,483	2.26%	37	21,164
OCTOBER	21,164	3,238	0.4410%	9	3,247	24,411	22,787	2.26%	43	24,454
NOVEMBER	24,454	5,339	0.4410%	(5,999)	(661)	23,793	24,123	2.25%	45	23,838
DECEMBER	23,838	7,649	0.4410%	(13,480)	(5,830)	18,008	20,923	2.26%	39	18,047
JANUARY 2011	18,047	8,691	0.4410%	(16,652)	(7,961)	10,086	14,067	2.26%	27	10,113
FEBRUARY	10,113	7,954	0.4410%	(13,832)	(5,878)	4,235	7,174	2.26%	14	4,248
MARCH	4,248	8,686	0.4410%	(13,803)	(5,117)	(869)	1,690	2.26%	3	(866)
APRIL	(866)	5,110	0.4410%	(6,068)	(957)	(1,823)	(1,344)	2.22%	(2)	(1,825)
Totals		62,673		(69,185)					291	

PEAK COMMODITY - ACCOUNT 182.11

	BEGINNING BALANCE	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	(D)	E = B + (D)	F = A + E	G = (A + F) / 2	H	I = G * (H/12)	J = F + I
MAY 2010	5,363	(1,358)	0.4410%	793	(565)	4,797	5,080	2.32%	10	4,807
JUNE	4,807	578	0.4410%	(5)	574	5,381	5,094	2.35%	10	5,391
JULY	5,391	(349)	0.4410%	(6)	(355)	5,036	5,213	2.34%	10	5,046
AUGUST	5,046	467	0.4410%	1	467	5,513	5,280	2.28%	10	5,523
SEPTEMBER	5,523	(4)	0.4410%	(2)	(6)	5,517	5,520	2.26%	10	5,528
OCTOBER	5,528	5	0.4410%	11	16	5,544	5,536	2.26%	10	5,554
NOVEMBER	5,554	5,398	0.4410%	(4,288)	1,110	6,664	6,109	2.25%	11	6,676
DECEMBER	6,676	9,889	0.4410%	(9,694)	194	6,870	6,773	2.26%	13	6,883
JANUARY 2011	6,883	13,455	0.4410%	(11,895)	1,560	8,443	7,663	2.26%	14	8,457
FEBRUARY	8,457	10,748	0.4410%	(9,877)	872	9,329	8,893	2.26%	17	9,346
MARCH	9,346	9,153	0.4410%	(9,860)	(707)	8,639	8,992	2.26%	17	8,656
APRIL	8,656	5,870	0.4410%	(4,334)	1,536	10,192	9,424	2.22%	17	10,210
Totals		53,852		(49,155)					151	
Combined Totals		116,525		(118,340)					441	

Updated July 2012 Attachment C

NORTHERN UTILITIES, INC - MAINE DIVISION
DEFERRED PEAK 2009-10 BAD DEBT CALCULATION OF COLLECTION ALLOWANCE
May 2010 - April 2011

ACCOUNT 182.16

	BEG. BAL	MAINE GAS COSTS PER BOOKS ALLOWED FOR BAD DEBT	BAD DEBT % ALLOWED	ACTUAL BAD DEBT ALLOWANCE(1)	ACTUAL BAD DEBT COLLECTION	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	(E)	F = D + (E)	G = A + F	H = (A+G)/2	I = G*(H/12)	J = F + I	
MAY 2010	18,588	226,017	1.06%	2,396	3,486	5,881	24,469	21,529	2.32%	42	24,511
JUNE	24,511	1,037,689	1.06%	11,000	(14)	10,985	35,496	30,003	2.35%	59	35,555
JULY	35,555	641,119	1.06%	6,796	(26)	6,770	42,325	38,940	2.34%	76	42,401
AUGUST	42,401	840,801	1.06%	8,912	4	8,916	51,317	46,859	2.28%	89	51,406
SEPTEMBER	51,406	748,402	1.06%	7,933	(10)	7,923	59,329	55,367	2.26%	104	59,433
OCTOBER	59,433	738,407	1.06%	7,827	49	7,876	67,309	63,371	2.26%	119	67,428
NOVEMBER	67,428	2,445,372	1.06%	25,921	(24,671)	1,250	68,678	68,053	2.25%	128	68,806
DECEMBER	68,806	3,994,405	1.06%	42,341	(55,535)	(13,194)	55,612	62,209	2.26%	117	55,730
JANUARY 2011	55,730	5,043,848	1.06%	53,465	(68,399)	(14,934)	40,795	48,263	2.26%	91	40,886
FEBRUARY	40,886	4,259,534	1.06%	45,151	(56,810)	(11,659)	29,228	35,057	2.26%	66	29,294
MARCH	29,294	4,062,986	1.06%	43,068	(56,698)	(13,631)	15,663	22,479	2.26%	42	15,705
APRIL	15,705	2,500,770	1.06%	26,508	(24,921)	1,587	17,292	16,499	2.22%	31	17,323
TOTALS				281,317	(283,546)					963	

(1) Bad Debt Allowance calculated by multiplying Bad Debt % Allowed by Total Gas Cost on Schedule 4, page 3 of 3, and Working Capital Allowances on Attachment B.

NORTHERN UTILITIES - MAINE DIVISION
SALES VARIANCE ANALYSIS
PEAK PERIOD 2010-11

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
Forecast Calendar Month Sales	262,993	442,106	535,451	440,646	427,488	261,358	2,370,042
Actual Calendar Month Sales	249,346	517,989	559,641	493,901	492,960	216,706	2,530,544
Difference	(13,647)	75,883	24,190	53,255	65,472	(44,652)	160,502
Add:							
Volume Variance due to Weather							
Normal Calendar Month Sales	251,569	521,937	575,290	476,970	502,393	214,941	2,543,100
Actual Calendar Month Sales	249,346	517,989	559,641	493,901	492,960	216,706	2,530,544
Weather Variance	2,223	3,948	15,649	(16,931)	9,433	(1,766)	12,556
Total Variance Excluding Weather	(11,424)	79,831	39,839	36,324	74,905	(46,417)	173,058

Variance-change in meter count	9,781
-change in load pattern	66,849
	76,630

Attachment D
Page 2 of 2

NORTHERN UTILITIES - MAINE DIVISION
SALES VARIANCE ANALYSIS
PEAK PERIOD 2010-11

	Normal Mcf			Meters		
	2010-11 Actual	2010-11 Forecast	Difference	2010-11 Actual	2010-11 Forecast	Difference
Res Heat	838,891	809,251	29,640	85,525	86,134	(609)
Res Non Heat	65,749	55,961	9,788	29,653	29,502	151
Total Res	**904,640**	**865,212**	**39,428**	**115,178**	**115,636**	**(458)**
G-50	127,779	108,010	19,769	8,044	7,964	80
G-40	698,177	666,836	31,341	26,916	26,647	269
G-51	74,080	75,801	(1,721)	660	653	7
G-41	543,032	513,294	29,738	2,204	2,182	22
G-52	51,829	29,964	21,865	37	37	0
G-42	47,135	110,924	(63,789)	31	31	0
Total Commercial and Industrial	**1,542,031**	**1,504,829**	**37,202**	**37,892**	**37,513**	**379**
Total Company	2,446,671	2,370,041	76,630	153,070	153,149	(79)

	Normal Average Use			Change in Sales Due to Change in:			
	2010-11 Actual	2010-11 Forecast	Difference	Meter Count	Load Pattern	Total Change Mcf	% Difference
Res Heat	9.81	9.40	0.41	(5,974)	35,614	29,640	3.66%
Res Non Heat	2.22	1.90	0.32	335	9,453	9,788	17.49%
Total Res	**7.85**	**7.48**	**0.37**	**(5,639)**	**45,067**	**39,428**	**4.56%**
G-50	15.89	13.56	2.33	1,278	18,491	19,769	18.30%
G-40	25.94	25.02	0.92	6,982	24,359	31,341	4.70%
G-51	112.24	116.01	(3.77)	741	(2,462)	(1,721)	-2.27%
G-41	246.38	235.24	11.14	5,430	24,308	29,738	5.79%
G-52	1,400.77	818.02	582.75	518	21,347	21,865	72.97%
G-42	1,520.48	3,614.34	(2,093.86)	471	(64,260)	(63,789)	-57.51%
Total Commercial and Industrial	**40.70**	**40.11**	**0.59**	**15,420**	**21,782**	**37,202**	**2.47%**
Total Company	15.98	15.48	0.50	9,781	66,849	76,630	3.23%

Schedule 8

New Hampshire Division
Original and Revised 2009 Summer Period Reconciliation

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009 SUMMER PERIOD RECONCILIATION
November 2008 - October 2009

Original Reconciliation - Conformed

FORM III
Schedule 1
Conformed to Current Presentation

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009 SUMMER PERIOD RECONCILIATION
SCHEDULE 1: SUMMARY OF SUMMER PERIOD BALANCE
November 2008 - October 2009

	AMOUNT	
Summer Period Beg. Balance	$525,907	SCHEDULE 2
Less: Reported Collections	($5,892,337)	SCHEDULE 2
Less: Billing Adjustment	$0	SCHEDULE 2
Add: Cost of Firm Gas Allowable	$5,445,545	SCHEDULE 4
Add: Interest	$12,420	SCHEDULE 2
Summer Period Ending Balance	$91,535	

FORM III
Schedule 2
Conformed to Current Presentation

NORTHERN UTILTIES, INC. - NEW HAMPSHIRE DIVISION
2009 SUMMER PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED SUMMER PERIOD ACCOUNTS
November 2008 - October 2009
Acct 191.10

	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
SUMMER PERIOD													
Summer Period Account Beginning Balance (1)	$ 525,907	$ 489,758	$ 491,231	$ 492,561	$ 493,895	$ 495,233	$ 496,574	$ 728,829	$ 306,554	$ 266,708	$ 106,002	$ (255,320)	$ 525,907
Plus: Cost of Firm Gas (Schedule 4)	$ 2,027	$ -	$ -	$ -	$ -	$ -	$ 1,400,967	$ 501,695	$ 594,295	$ 592,389	$ 413,590	$ 1,940,581	$ 5,445,545
Less: Reported Collections (Schedule 3)(2)	$ (39,866)	$ -	$ -	$ -	$ -	$ -	$ (1,170,369)	$ (925,371)	$ (634,916)	$ (753,599)	$ (774,711)	$ (1,593,505)	$ (5,892,337)
Less: Billing Adjustment													
Summer Period Account Ending Balance	$ 488,068	$ 489,758	$ 491,231	$ 492,561	$ 493,895	$ 495,233	$ 727,172	$ 305,154	$ 265,933	$ 105,498	$ (255,118)	$ 91,756	$ 79,115
Month's Average Balance	$ 506,987	$ 489,758	$ 491,231	$ 492,561	$ 493,895	$ 495,233	$ 611,873	$ 516,991	$ 286,243	$ 186,103	$ (74,558)	$ (81,782)	
Interest Rate (Prime Rate)	4.00%	3.61%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
Interest Applied	$ 1,690	$ 1,473	$ 1,330	$ 1,334	$ 1,338	$ 1,341	$ 1,657	$ 1,400	$ 775	$ 504	$ (202)	$ (221)	$ 12,420
Summer Period Account Ending Balance w/int(3)	$ 489,758	$ 491,231	$ 492,561	$ 493,895	$ 495,233	$ 496,574	$ 728,829	$ 306,554	$ 266,708	$ 106,002	$ (255,320)	$ 91,535	$ 91,535

(1) Summer period balance as of October 31, 2008, $2,032,076, is adjusted by ($1,506,169) to account for the transition to accrual accounting as required by Commission Order No. 25,038, dated October 30, 2009 in DG 07-033.
(2) Reported collections for November 2008 are the reversal of October 2008 accrued revenues in order to reflect the transition to accrual accounting as required by Commission Order No. 25,038, dated October 30, 2009 in DG 07-033.
(3) Summer period actual ending balance with interest per DG 08-041 Audit Report is $494,007. This is adjusted by ($1,735) for a correction to November 2008 revenues, and ($2,514) to adjust interest due to the transition to accrual accounting.

FORM III
Schedule 3
Conformed to Current Presentation

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS(1)
November 2008 - October 2009

	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
Accrued Revenue	$ (1,506,169)	$ -	$ -	$ -	$ -	$ -	$ 613,494	$ (283,725)	$ (27,943)	$ 107,080	$ 117,255	$ 458,140	$ (521,869)
Billed Revenue	$ 1,546,035	$ -	$ -	$ -	$ -	$ -	$ 556,876	$ 1,209,096	$ 662,859	$ 646,519	$ 657,456	$ 1,135,365	$ 6,414,206
Calendarized Revenue	**$ 39,866**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,170,369**	**$ 925,371**	**$ 634,916**	**$ 753,599**	**$ 774,711**	**$ 1,593,505**	**$ 5,892,337**

(1) Revenue figures reflect the transition to accrual accounting as required by Commission Order No. 25,038, dated October 30, 2009 in DG 07-033.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009 SUMMER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO SUMMER PERIOD
November 2008 - October 2009

FORM III
Schedule 4
Page 1 of 2

Conformed to Current Presentation

Commodity Costs:	**Nov-08**	**Dec-08**	**Jan-09**	**Feb-09**	**Mar-09**	**Apr-09**	**May-09**	**Jun-09**	**Jul-09**	**Aug-09**	**Sep-09**	**Oct-09**	**Total Summer**
Anadarka Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 30,195	$ 49,874	$ 24,397	$ 25,637	$ 79,156	**$ 209,259**
Distrigas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
DTE Energy Trading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,540	$ -	$ -	$ -	**$ 13,540**
Emera Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 67,726	$ 65,494	$ 77,222	$ 63,100	$ 50,930	**$ 324,471**
Hess	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,683	$ -	$ -	$ -	**$ 17,683**
JP Morgan	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 234,064	$ 167,353	$ 237,707	$ 241,820	$ -	**$ 880,945**
South Jersey Resources	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 64,049	**$ 64,049**
Tennessee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,320	$ 2,051	$ 890	$ -	$ 5,236	**$ 9,498**
Subtotal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 333,305	$ 315,995	$ 340,218	$ 330,556	$ 199,370	**$ 1,519,444**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 415,087	$ 314,544	$ 331,235	$ 329,454	$ 210,109	$ 835,648	**$ 2,436,077**
Commodity Cost Reversals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (415,087)	$ (314,544)	$ (331,235)	$ (329,454)	$ (210,109)	**$ (1,600,429)**
Subtotal	$ -	$ -	$ -	$ -	$ -	$ -	$ 415,087	$ 232,762	$ 332,686	$ 338,437	$ 211,211	$ 824,909	**$ 2,355,092**
Withdrawal Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,180	$ 1,416	$ (1,334)	$ 1,346	$ (719)	$ 177	**$ 2,066**
Interruptible Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ (390)	$ -	$ (7,661)	$ (4,412)	$ (11,317)	$ (11,884)	**$ (35,665)**
Non Traditional Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ (6,031)	$ -	$ -	$ -	$ (15,847)	$ -	**$ (21,878)**
Net OBA Adj	$ -	$ -	$ -	$ -	$ -	$ -	$ 43,338	$ 1,077	$ 646	$ 304	$ 470	$ 31,547	**$ 77,382**
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,372)	$ (9,065)	$ -	$ -	$ (18,887)	$ (3,602)	**$ (38,926)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,110	$ -	$ 10,619	$ 7,534	$ 7,111	$ 4,863	**$ 35,237**
Transportation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ (15,084)	$ 25,398	$ 9,519	$ -	$ (8,625)	$ (130,224)	**$ (119,017)**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 785,953	$ 6,412	$ 5,627	$ 5,393	$ 6,412	$ 978,505	**$ 1,788,302**
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ (67,162)	$ -	$ -	$ -	$ -	$ -	**$ (67,162)**
Prior Period Adjustment	$ 2,027	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 2,027**
Subtotal	$ 2,027	$ -	$ -	$ -	$ -	$ -	$ 739,542	$ 25,237	$ 17,415	$ 10,164	$ (41,401)	$ 869,382	**$ 1,622,367**
Total Commodity Costs	**$ 2,027**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,154,629**	**$ 257,998**	**$ 350,102**	**$ 348,601**	**$ 169,810**	**$ 1,694,291**	**$ 3,977,459**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009 SUMMER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO SUMMER PERIOD
November 2008 - October 2009

Conformed to Current Presentation

Demand Costs	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total Summer
Forecasted Summer Demand Costs (DG 09-052)	$ -	$ -	$ -	$ -	$ -	$ -	$ 239,471	$ 239,471	$ 239,471	$ 239,471	$ 239,471	$ 239,471	**$ 1,436,825**
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,867	$ 4,226	$ 4,723	$ 4,317	$ 4,309	$ 6,818	**$ 31,261**
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 246,338**	**$ 243,697**	**$ 244,194**	**$ 243,788**	**$ 243,780**	**$ 246,289**	**$ 1,468,086**
Total Gas Costs	**$ 2,027**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,400,967**	**$ 501,695**	**$ 594,295**	**$ 592,389**	**$ 413,590**	**$ 1,940,581**	**$ 5,445,545**

FORM III
Schedule 5

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009 SUMMER PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
November 2008 - October 2009

New Hampshire	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
Throughput IN													
BTU Factor	1.043	1.046	1.033	1.031	1.037	1.035	1.058	1.043	1.046	1.029	1.050	1.042	
GST Meter Throughput (MCF)	644,728	858,124	1,034,316	809,663	772,880	513,047	318,202	259,715	275,694	259,076	278,578	460,252	6,484,275
Salem Meter (MCF)	36,383	55,135	71,820	50,982	42,498	23,072	13,740	10,711	11,098	10,145	11,353	21,545	358,482
GST Meter Throughpurt (DTH)	672,451	897,598	1,068,448	834,763	801,477	531,004	336,658	270,883	288,376	266,589	292,507	479,583	6,740,335
Salem Meter (DTH)	37,947	57,671	74,190	52,562	44,070	23,880	14,537	11,172	11,609	10,439	11,921	22,450	372,448
LNG/Propane													0
Total Throughput	710,399	955,269	1,142,638	887,325	845,547	554,883	351,195	282,054	299,984	277,028	304,428	502,032	7,112,783
Throughput OUT													
Residential Gas													
Charged	107,101	198,238	314,584	294,937	246,711	176,594	91,409	45,514	54,713	33,949	34,637	53,953	1,652,338
Uncharged Current	107,200	101,913	157,316	125,763	108,917	57,682	40,334	10,780	19,977	21,823	32,708	47,772	832,185
Uncharged Prior	-81,473	-107,200	-101,913	-157,316	-125,763	-108,917	-57,682	-40,334	-10,780	-19,977	-21,823	-32,708	-865,886
Total Residential Gas	**132,828**	**192,950**	**369,987**	**263,384**	**229,865**	**125,359**	**74,060**	**15,960**	**63,910**	**35,795**	**45,522**	**69,016**	1,618,637
Interruptible	**2,929**	**1,558**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	4,487
Commercial/Industrial Gas													
Charged	145,792	274,760	410,979	356,022	292,486	206,342	95,223	92,202	53,650	54,112	54,903	82,024	2,118,495
Uncharged Current	142,000	137,776	205,117	151,061	128,281	65,679	41,496	33,674	21,433	33,488	37,652	56,218	1,053,876
Uncharged Prior	-79,307	-142,000	-137,776	-205,117	-151,061	-128,281	-65,679	-41,496	-33,674	-21,433	-33,488	-37,652	-1,076,965
Total C/I Gas	**208,485**	**270,536**	**478,321**	**301,966**	**269,706**	**143,740**	**71,040**	**84,379**	**41,409**	**66,168**	**59,067**	**100,589**	2,095,406
Transportation													
Charged	304,029	354,798	327,455	357,460	355,546	305,728	205,707	194,417	194,706	180,110	199,077	252,958	3,231,989
Uncharged Current	14,000	42,348	58,061	41,697	39,026	21,875	16,613	42,700	40,205	12,581	70,882	101,472	501,460
Uncharged Prior	-21,399	-14,000	-42,348	-58,061	-41,697	-39,026	-21,875	-16,613	-42,700	-40,205	-12,581	-70,882	-421,388
Total Transportation	**296,630**	**383,146**	**343,168**	**341,096**	**352,875**	**288,577**	**200,445**	**220,504**	**192,210**	**152,485**	**257,379**	**283,547**	**3,312,062**
Company Use	**100**	**203**	**343**	**219**	**328**	**190**	**88**	**47**	**5**	**1**	**7**	**21**	**1,551**
Total Throughput OUT	**640,972**	**848,394**	**1,191,818**	**906,665**	**852,774**	**557,866**	**345,633**	**320,891**	**297,533**	**254,449**	**361,975**	**453,174**	**7,032,143**
Total Throughput IN	**710,399**	**955,269**	**1,142,638**	**887,325**	**845,547**	**554,883**	**351,195**	**282,054**	**299,984**	**277,028**	**304,428**	**502,032**	**7,112,783**
Difference IN/OUT	69,427	106,875	-49,180	-19,340	-7,227	-2,983	5,562	-38,836	2,451	22,579	-57,547	48,859	80,640
%													1.13%

Attachment A
Conformed to Current Presentation

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
DEFERRED OFF-PEAK WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
November 2008 - October 2009

OFF-PEAK PERIOD - Acct 182.21

		BEGINNING BALANCE(1)	WORKING CAP ALLOWANCE(2)	WORKING CAP PERCENTAGE	WORKING CAP COLLECTIONS(3)	WORKING CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
		A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
November 2008	$	5,158	1	0.0694%	216	217	5,375	5,266	4.00%	18	5,393
December 2008	$	5,393	0	0.0626%	0	0	5,393	5,393	3.61%	16	5,409
January 2009	$	5,409	0	0.0564%	0	0	5,409	5,409	3.25%	15	5,423
February	$	5,423	0	0.0564%	0	0	5,423	5,423	3.25%	15	5,438
March	$	5,438	0	0.0564%	0	0	5,438	5,438	3.25%	15	5,453
April	$	5,453	0	0.0564%	0	0	5,453	5,453	3.25%	15	5,468
May	$	5,468	790	0.0564%	(3,263)	(2,474)	2,994	4,231	3.25%	11	3,005
June	$	3,005	283	0.0564%	(2,590)	(2,307)	698	1,852	3.25%	5	703
July	$	703	335	0.0564%	(1,825)	(1,490)	(787)	(42)	3.25%	(0)	(787)
August	$	(787)	334	0.0564%	(2,142)	(1,808)	(2,595)	(1,691)	3.25%	(5)	(2,599)
September	$	(2,599)	233	0.0564%	(2,189)	(1,956)	(4,555)	(3,577)	3.25%	(10)	(4,565)
October	$	(4,565)	1,094	0.0564%	(3,552)	(2,458)	(7,023)	(5,794)	3.25%	(16)	(7,039)
Totals			3,070		(15,345)					79	

(1) Balance for November 2008, $7,918, approved in DG 09-052, is adjusted by ($2,762) for the transition to accrual accounting required by Commission Order No. 25,038, dated October 30, 2009 in DG 07-033.
(2) Working Capital Allowance Calculated by taking Eligible Gas Costs from Sch 4 and multiplying by (6.33/365)*Interest Rate.
(3) Working Capital Collections for November 2008, ($2,547), is adjusted by $2,762 for the transition to accrual accounting required by Commission Order No. 25,038, dated October 30, 2009 in DG 07-033.

Attachment B
Conformed to Current Presentation

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
BAD DEBT EXPENSE - CALCULATION OF COLLECTION ALLOWANCE
November 2008 - October 2009

OFF-PEAK PERIOD - Acct 182.22

	BEGINNING BALANCE(1)	BAD DEBT ALLOWANCE(2)	% ALLOWED BAD DEBT	BAD DEBT COLLECTIONS(3)	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
November 2008	12,464	9	0.45%	499	508	12,972	12,718	4.00%	42	13,014
December 2008	13,014	0	0.45%	0	0	13,014	13,014	3.61%	39	13,054
January 2009	13,054	0	0.45%	0	0	13,054	13,054	3.25%	35	13,089
February	13,089	0	0.45%	0	0	13,089	13,089	3.25%	35	13,124
March	13,124	0	0.45%	0	0	13,124	13,124	3.25%	36	13,160
April	13,160	0	0.45%	0	0	13,160	13,160	3.25%	36	13,196
May	13,196	6,308	0.45%	(8,236)	(1,928)	11,267	12,231	3.25%	33	11,300
June	11,300	2,259	0.45%	(6,537)	(4,278)	7,022	9,161	3.25%	25	7,047
July	7,047	2,676	0.45%	(4,607)	(1,931)	5,116	6,082	3.25%	16	5,132
August	5,132	2,667	0.45%	(5,405)	(2,737)	2,395	3,764	3.25%	10	2,405
September	2,405	1,862	0.45%	(5,524)	(3,662)	(1,257)	574	3.25%	2	(1,256)
October	(1,256)	8,738	0.45%	(8,965)	(228)	(1,483)	(1,369)	3.25%	(4)	(1,487)
Totals		24,519		(38,776)					306	

(1) Balance for November 2008, $18,852, approved in DG 09-052, is adjusted by ($6,388) for the transition to accrual accounting required by Order No. 25,038.
(2) Bad Debt Allowance calculated by multiplying Bad Debt % by Gas Cost on Schedule 4 and Working Capital Allowance on Attachment A.
(3) Bad Debt Collections for November 2008, ($5,889), is adjusted by $6,388 for the transition to accrual accounting required by Order No. 25,038.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
SUMMER 2009

Attachment C
Page 1 of 2

	May	June	July	August	September	October	TOTAL
Forecast Calendar Month Sales	202,050	124,344	138,957	127,031	126,789	200,618	919,789
Actual Sales	186,632	137,716	108,363	88,061	89,540	135,976	746,288
Difference	(15,418)	13,372	(30,594)	(38,970)	(37,249)	(64,642)	(173,501)
Add:							
Volume Variance due to Weather							
Normal Cal. Month Actual Sales	145,100	100,339	105,319	101,963	104,589	169,605	726,916
Actual Sales	186,632	137,716	108,363	88,061	89,540	135,976	746,288
Weather Variance	(41,532)	(37,376)	(3,044)	13,901	15,050	33,629	(19,372)
Total Variance Excluding Weather (excl weather effect)	(56,950)	(24,005)	(33,638)	(25,068)	(22,200)	(31,013)	(192,873)
Variance-difference due to meter count							(41,044)
-difference in load pattern							(69,837)
SALES							(110,881)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
SUMMER 2009

	NORMAL MMBtu			METERS		
	2009 Forecast	2009 Actual	Difference	2009 Forecast	2009 Actual	Difference
Res Heat	311,361	317,880	6,519	118,747	119,842	1,095
Res General	11,438	12,438	1,000	9,883	10,038	155
Total Res	322,799	330,318	7,519	128,630	129,880	1,250
G-40	115,571	101,803	(13,768)	25,158	24,999	(159)
G-50	75,918	80,471	4,553	5,904	5,869	(35)
G-41	63,899	156,701	92,802	2,280	2,235	(45)
G-51	179,984	107,068	(72,916)	1,038	976	(62)
G-42	48,642	12,180	(36,462)	72	82	10
G-52	112,975	20,366	(92,609)	36	24	(12)
Total C & I	596,989	478,589	(118,400)	34,488	34,185	(303)
Total Company	919,789	808,907	(110,881)	163,118	164,065	947

	NORMAL AVERAGE USE			Change in Sales Due to Change In:			
	2009 Forecast	2009 Actual	Difference	Meter Count	Load Pattern	Total Chg MMBtu	% Difference
Res Heat	2.62	2.65	0.03	2,871	3,648	6,519	2.09%
Res General	1.16	1.24	0.08	179	821	1,000	8.74%
Total Res	3.78	3.89	0.11	3,051	4,468	7,519	2.33%
G-40	4.59	4.07	(0.52)	(730)	(13,038)	(13,768)	-11.91%
G-50	12.86	13.71	0.85	(450)	5,003	4,553	6.00%
G-41	28.03	70.11	42.09	(1,261)	94,063	92,802	145.23%
G-51	173.39	109.70	(63.69)	(10,750)	(62,166)	(72,916)	-40.51%
G-42	675.58	148.54	(527.05)	6,756	(43,218)	(36,462)	-74.96%
G-52	3,138.19	848.58	(2,289.61)	(37,658)	(54,951)	(92,609)	-81.97%
Total C & I	17.31	14.00	(3.31)	(44,095)	(74,305)	(118,400)	-19.83%
Total Company	5.64	4.93	(0.71)	(41,044)	(69,837)	(110,881)	-12.06%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009 SUMMER PERIOD RECONCILIATION
November 2008 - October 2009

Recalculated Reconciliation

FORM III
Schedule 1
Updated July 2012

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009 SUMMER PERIOD RECONCILIATION
SCHEDULE 1: SUMMARY OF SUMMER PERIOD BALANCE
November 2008 - October 2009

	AMOUNT	
Summer Period Beg. Balance	$525,907	SCHEDULE 2
Less: Reported Collections	($5,892,337)	SCHEDULE 2
Less: Billing Adjustment	$0	SCHEDULE 2
Add: Cost of Firm Gas Allowable	$5,448,567	SCHEDULE 4
Add: Interest	$12,438	SCHEDULE 2
Summer Period Ending Balance	$94,574	

FORM III
Schedule 2
Updated July 2012

NORTHERN UTILTIES, INC. - NEW HAMPSHIRE DIVISION
2009 SUMMER PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED SUMMER PERIOD ACCOUNTS
November 2008 - November 2009
Acct 191.10

	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
SUMMER PERIOD													
Summer Period Account Beginning Balance (1)	$ 525,907	$ 489,758	$ 491,231	$ 492,561	$ 493,895	$ 495,233	$ 496,574	$ 728,621	$ 307,211	$ 267,121	$ 107,356	$ (252,502)	$ 525,907
Plus: Cost of Firm Gas (Schedule 4)	$ 2,027	$ -	$ -	$ -	$ -	$ -	$ 1,400,760	$ 502,559	$ 594,049	$ 593,328	$ 415,049	$ 1,940,794	$ 5,448,567
Less: Reported Collections (Schedule 3)(2)	$ (39,866)	$ -	$ -	$ -	$ -	$ -	$ (1,170,369)	$ (925,371)	$ (634,916)	$ (753,599)	$ (774,711)	$ (1,593,505)	$ (5,892,337)
Less: Billing Adjustment													
Summer Period Account Ending Balance	$ 488,068	$ 489,758	$ 491,231	$ 492,561	$ 493,895	$ 495,233	$ 726,965	$ 305,810	$ 266,344	$ 106,850	$ (252,306)	$ 94,788	$ 82,137
Month's Average Balance	$ 506,987	$ 489,758	$ 491,231	$ 492,561	$ 493,895	$ 495,233	$ 611,769	$ 517,216	$ 286,777	$ 186,985	$ (72,475)	$ (78,857)	
Interest Rate (Prime Rate)	4.00%	3.61%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
Interest Applied	$ 1,690	$ 1,473	$ 1,330	$ 1,334	$ 1,338	$ 1,341	$ 1,657	$ 1,401	$ 777	$ 506	$ (196)	$ (214)	$ 12,438
Summer Period Account Ending Balance w/int(3)	$ 489,758	$ 491,231	$ 492,561	$ 493,895	$ 495,233	$ 496,574	$ 728,621	$ 307,211	$ 267,121	$ 107,356	$ (252,502)	$ 94,574	$ 94,574

(1) Summer period balance as of October 31, 2008, $2,032,076, is adjusted by ($1,506,169) to account for the transition to accrual accounting as required by Commission Order No. 25,038, dated October 30, 2009 in DG 07-033.
(2) Reported collections for November 2008 are the reversal of October 2008 accrued revenues in order to reflect the transition to accrual accounting as required by Commission Order No. 25,038, dated October 30, 2009 in DG 07-033.
(3) Summer period actual ending balance with interest per DG 08-041 Audit Report is $494,007. This is adjusted by ($1,735) for a correction to November 2008 revenues, and ($2,514) to adjust interest due to the transition to accrual accounting.

FORM III
Schedule 3

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS(1)
November 2008 - November 2009

	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
Accrued Revenue	$ (1,506,169)	$ -	$ -	$ -	$ -	$ -	$ 613,494	$ (283,725)	$ (27,943)	$ 107,080	$ 117,255	$ 458,140	$ (521,869)
Billed Revenue	$ 1,546,035	$ -	$ -	$ -	$ -	$ -	$ 556,876	$ 1,209,096	$ 662,859	$ 646,519	$ 657,456	$ 1,135,365	$ 6,414,206
Calendarized Revenue	**$ 39,866**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,170,369**	**$ 925,371**	**$ 634,916**	**$ 753,599**	**$ 774,711**	**$ 1,593,505**	**$ 5,892,337**

(1) Revenue figures reflect the transition to accrual accounting as required by Commission Order No. 25,038, dated October 30, 2009 in DG 07-033.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009 SUMMER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO SUMMER PERIOD
November 2008 - October 2009

FORM III
Schedule 4
Page 1 of 2

Updated July 2012

Commodity Costs:	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
Anadarka Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 30,195	$ 49,874	$ 24,397	$ 25,637	$ 79,156	**$ 209,259**
Distrigas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
DTE Energy Trading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,540	$ -	$ -	$ -	**$ 13,540**
Emera Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 67,726	$ 65,494	$ 77,222	$ 63,100	$ 50,930	**$ 324,471**
Hess	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,683	$ -	$ -	$ -	**$ 17,683**
JP Morgan	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 234,064	$ 167,353	$ 237,707	$ 241,820	$ -	**$ 880,945**
South Jersey Resources	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 64,049	**$ 64,049**
Tennessee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,320	$ 2,051	$ 890	$ -	$ 5,236	**$ 9,498**
Subtotal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 333,305	$ 315,995	$ 340,218	$ 330,556	$ 199,370	**$ 1,519,444**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 415,087	$ 314,544	$ 331,235	$ 329,454	$ 210,109	$ 835,648	**$ 2,436,077**
Commodity Cost Reversals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (415,087)	$ (314,544)	$ (331,235)	$ (329,454)	$ (210,109)	**$ (1,600,429)**
Subtotal - Supply	$ -	$ -	$ -	$ -	$ -	$ -	$ 415,087	$ 232,762	$ 332,686	$ 338,437	$ 211,211	$ 824,909	**$ 2,355,092**
Withdrawal Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,180	$ 1,416	$ (1,334)	$ 1,346	$ (719)	$ 177	**$ 2,066**
Interruptible Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ (390)	$ -	$ (7,661)	$ (4,412)	$ (11,317)	$ (11,884)	**$ (35,665)**
Non Traditional Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ (6,031)	$ -	$ -	$ -	$ (15,847)	$ -	**$ (21,878)**
Net OBA Adj	$ -	$ -	$ -	$ -	$ -	$ -	$ 43,338	$ 1,077	$ 646	$ 304	$ 470	$ 31,547	**$ 77,382**
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,372)	$ (9,065)	$ -	$ -	$ (18,887)	$ (3,602)	**$ (38,926)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,110	$ -	$ 10,619	$ 7,534	$ 7,111	$ 4,863	**$ 35,237**
Transportation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ (15,084)	$ 25,398	$ 9,519	$ -	$ (8,625)	$ (130,224)	**$ (119,017)**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 785,953	$ 6,412	$ 5,627	$ 5,393	$ 6,412	$ 978,505	**$ 1,788,302**
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ (67,162)	$ -	$ -	$ -	$ -	$ -	**$ (67,162)**
Prior Period Adjustment	$ 2,027	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 2,027**
Allocation Adjustments	$ -	$ -	$ -	$ -	$ -	$ -	$ (207)	$ 864	$ (246)	$ 939	$ 1,459	$ 214	**$ 3,022**
Subtotal	$ 2,027	$ -	$ -	$ -	$ -	$ -	$ 739,334	$ 26,101	$ 17,169	$ 11,103	$ (39,942)	$ 869,596	**$ 1,625,389**
Total Commodity Costs	**$ 2,027**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,154,422**	**$ 258,862**	**$ 349,856**	**$ 349,540**	**$ 171,269**	**$ 1,694,505**	**$ 3,980,481**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009 SUMMER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO SUMMER PERIOD
November 2008 - October 2009

FORM III
Schedule 4
Page 2 of 2

Demand Costs

	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
Forecasted Summer Demand Costs (DG 09-052)	$ -	$ -	$ -	$ -	$ -	$ -	$ 239,471	$ 239,471	$ 239,471	$ 239,471	$ 239,471	$ 239,471	**$ 1,436,825**
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,867	$ 4,226	$ 4,723	$ 4,317	$ 4,309	$ 6,818	**$ 31,261**
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 246,338**	**$ 243,697**	**$ 244,194**	**$ 243,788**	**$ 243,780**	**$ 246,289**	**$ 1,468,086**
Total Gas Costs	**$ 2,027**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,400,760**	**$ 502,559**	**$ 594,049**	**$ 593,328**	**$ 415,049**	**$ 1,940,794**	**$ 5,448,567**

FORM III
Schedule 5

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009 SUMMER PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
November 2008 - October 2009

New Hampshire	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
Throughput IN													
BTU Factor	1.043	1.046	1.033	1.031	1.037	1.035	1.058	1.043	1.046	1.029	1.050	1.042	
GST Meter Throughput (MCF)	644,728	858,124	1,034,316	809,663	772,880	513,047	318,202	259,715	275,694	259,076	278,578	460,252	6,484,275
Salem Meter (MCF)	36,383	55,135	71,820	50,982	42,498	23,072	13,740	10,711	11,098	10,145	11,353	21,545	358,482
GST Meter Throughput (DTH)	672,451	897,598	1,068,448	834,763	801,477	531,004	336,658	270,883	288,376	266,589	292,507	479,583	6,740,335
Salem Meter (DTH)	37,947	57,671	74,190	52,562	44,070	23,880	14,537	11,172	11,609	10,439	11,921	22,450	372,448
LNG/Propane													0
Total Throughput	710,399	955,269	1,142,638	887,325	845,547	554,883	351,195	282,054	299,984	277,028	304,428	502,032	7,112,783
Throughput OUT													
Residential Gas													
Charged	107,101	198,238	314,584	294,937	246,711	176,594	91,409	45,514	54,713	33,949	34,637	53,953	1,652,338
Uncharged Current	107,200	101,913	157,316	125,763	108,917	57,682	40,334	10,780	19,977	21,823	32,708	47,772	832,185
Uncharged Prior	-81,473	-107,200	-101,913	-157,316	-125,763	-108,917	-57,682	-40,334	-10,780	-19,977	-21,823	-32,708	-865,886
Total Residential Gas	**132,828**	**192,950**	**369,987**	**263,384**	**229,865**	**125,359**	**74,060**	**15,960**	**63,910**	**35,795**	**45,522**	**69,016**	1,618,637
Interruptible	**2,929**	**1,558**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	4,487
Commercial/Industrial Gas													
Charged	145,792	274,760	410,979	356,022	292,486	206,342	95,223	92,202	53,650	54,112	54,903	82,024	2,118,495
Uncharged Current	142,000	137,776	205,117	151,061	128,281	65,679	41,496	33,674	21,433	33,488	37,652	56,218	1,053,876
Uncharged Prior	-79,307	-142,000	-137,776	-205,117	-151,061	-128,281	-65,679	-41,496	-33,674	-21,433	-33,488	-37,652	-1,076,965
Total C/I Gas	**208,485**	**270,536**	**478,321**	**301,966**	**269,706**	**143,740**	**71,040**	**84,379**	**41,409**	**66,168**	**59,067**	**100,589**	2,095,406
Transportation													
Charged	304,029	354,798	327,455	357,460	355,546	305,728	205,707	194,417	194,706	180,110	199,077	252,958	3,231,989
Uncharged Current	14,000	42,348	58,061	41,697	39,026	21,875	16,613	42,700	40,205	12,581	70,882	101,472	501,460
Uncharged Prior	-21,399	-14,000	-42,348	-58,061	-41,697	-39,026	-21,875	-16,613	-42,700	-40,205	-12,581	-70,882	-421,388
Total Transportation	**296,630**	**383,146**	**343,168**	**341,096**	**352,875**	**288,577**	**200,445**	**220,504**	**192,210**	**152,485**	**257,379**	**283,547**	**3,312,062**
Company Use	**100**	**203**	**343**	**219**	**328**	**190**	**88**	**47**	**5**	**1**	**7**	**21**	**1,551**
Total Throughput OUT	**640,972**	**848,394**	**1,191,818**	**906,665**	**852,774**	**557,866**	**345,633**	**320,891**	**297,533**	**254,449**	**361,975**	**453,174**	**7,032,143**
Total Throughput IN	**710,399**	**955,269**	**1,142,638**	**887,325**	**845,547**	**554,883**	**351,195**	**282,054**	**299,984**	**277,028**	**304,428**	**502,032**	**7,112,783**
Difference IN/OUT	69,427	106,875	-49,180	-19,340	-7,227	-2,983	5,562	-38,836	2,451	22,579	-57,547	48,859	80,640
%													1.13%

Attachment A
Updated July 2012

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
DEFERRED OFF-PEAK WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
November 2008 - October 2009

OFF-PEAK PERIOD - Acct 182.21

		BEGINNING BALANCE(1)	WORKING CAP ALLOWANCE(2)	WORKING CAP PERCENTAGE	WORKING CAP COLLECTIONS(3)	WORKING CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
		A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
November 2008	$	5,156	1	0.0694%	216	217	5,373	5,264	4.00%	18	5,390
December 2008	$	5,390	0	0.0626%	0	0	5,390	5,390	3.61%	16	5,407
January 2009	$	5,407	0	0.0564%	0	0	5,407	5,407	3.25%	15	5,421
February	$	5,421	0	0.0564%	0	0	5,421	5,421	3.25%	15	5,436
March	$	5,436	0	0.0564%	0	0	5,436	5,436	3.25%	15	5,451
April	$	5,451	0	0.0564%	0	0	5,451	5,451	3.25%	15	5,466
May	$	5,466	790	0.0564%	(3,263)	(2,474)	2,992	4,229	3.25%	11	3,003
June	$	3,003	283	0.0564%	(2,590)	(2,307)	696	1,850	3.25%	5	701
July	$	701	335	0.0564%	(1,825)	(1,490)	(789)	(44)	3.25%	(0)	(789)
August	$	(789)	334	0.0564%	(2,142)	(1,807)	(2,596)	(1,692)	3.25%	(5)	(2,601)
September	$	(2,601)	234	0.0564%	(2,189)	(1,955)	(4,555)	(3,578)	3.25%	(10)	(4,565)
October	$	(4,565)	1,094	0.0564%	(3,552)	(2,458)	(7,024)	(5,794)	3.25%	(16)	(7,039)
Totals			3,071		(15,345)					79	

(1) Balance for November 2008, $7,918, approved in DG 09-052, is adjusted by ($2,762) for the transition to accrual accounting required by Commission Order No. 25,038, dated October 30, 2009 in DG 07-033.
(2) Working Capital Allowance Calculated by taking Eligible Gas Costs from Sch 4 and multiplying by (6.33/365)*Interest Rate.
(3) Working Capital Collections for November 2008, ($2,547), is adjusted by $2,762 for the transition to accrual accounting required by Commission Order No. 25,038, dated October 30, 2009 in DG 07-033.

Attachment B
Updated July 2012

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
BAD DEBT EXPENSE - CALCULATION OF COLLECTION ALLOWANCE
November 2008 - October 2009

OFF-PEAK PERIOD - Acct 182.22

	BEGINNING BALANCE(1)	BAD DEBT ALLOWANCE(2)	% ALLOWED BAD DEBT	BAD DEBT COLLECTIONS(3)	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
November 2008	12,464	9	0.45%	499	508	12,972	12,718	4.00%	42	13,014
December 2008	13,014	0	0.45%	0	0	13,014	13,014	3.61%	39	13,054
January 2009	13,054	0	0.45%	0	0	13,054	13,054	3.25%	35	13,089
February	13,089	0	0.45%	0	0	13,089	13,089	3.25%	35	13,124
March	13,124	0	0.45%	0	0	13,124	13,124	3.25%	36	13,160
April	13,160	0	0.45%	0	0	13,160	13,160	3.25%	36	13,196
May	13,196	6,307	0.45%	(8,236)	(1,929)	11,266	12,231	3.25%	33	11,299
June	11,299	2,263	0.45%	(6,537)	(4,274)	7,025	9,162	3.25%	25	7,050
July	7,050	2,675	0.45%	(4,607)	(1,932)	5,118	6,084	3.25%	16	5,134
August	5,134	2,671	0.45%	(5,405)	(2,733)	2,401	3,768	3.25%	10	2,411
September	2,411	1,869	0.45%	(5,524)	(3,656)	(1,244)	583	3.25%	2	(1,243)
October	(1,243)	8,738	0.45%	(8,965)	(227)	(1,470)	(1,356)	3.25%	(4)	(1,473)
Totals		24,532		(38,776)					306	

(1) Balance for November 2008, $18,852, approved in DG 09-052, is adjusted by ($6,388) for the transition to accrual accounting required by Order No. 25,038.
(2) Bad Debt Allowance calculated by multiplying Bad Debt % by Gas Cost on Schedule 4 and Working Capital Allowance on Attachment A.
(3) Bad Debt Collections for November 2008, ($5,889), is adjusted by $6,388 for the transition to accrual accounting required by Order No. 25,038.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
SUMMER 2009

Attachment C
Page 1 of 2

	May	June	July	August	September	October	TOTAL
Forecast Calendar Month Sales	202,050	124,344	138,957	127,031	126,789	200,618	919,789
Actual Sales	186,632	137,716	108,363	88,061	89,540	135,976	746,288
Difference	(15,418)	13,372	(30,594)	(38,970)	(37,249)	(64,642)	(173,501)
Add:							
Volume Variance due to Weather							
Normal Cal. Month Actual Sales	145,100	100,339	105,319	101,963	104,589	169,605	726,916
Actual Sales	186,632	137,716	108,363	88,061	89,540	135,976	746,288
Weather Variance	(41,532)	(37,376)	(3,044)	13,901	15,050	33,629	(19,372)
Total Variance Excluding Weather (excl weather effect)	(56,950)	(24,005)	(33,638)	(25,068)	(22,200)	(31,013)	(192,873)
Variance-difference due to meter count							(41,044)
-difference in load pattern							(69,837)
SALES							(110,881)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
SUMMER 2009

Attachment C
Page 2 of 2

	NORMAL MMBtu			METERS		
	2009 Forecast	2009 Actual	Difference	2009 Forecast	2009 Actual	Difference
Res Heat	311,361	317,880	6,519	118,747	119,842	1,095
Res General	11,438	12,438	1,000	9,883	10,038	155
Total Res	322,799	330,318	7,519	128,630	129,880	1,250
G-40	115,571	101,803	(13,768)	25,158	24,999	(159)
G-50	75,918	80,471	4,553	5,904	5,869	(35)
G-41	63,899	156,701	92,802	2,280	2,235	(45)
G-51	179,984	107,068	(72,916)	1,038	976	(62)
G-42	48,642	12,180	(36,462)	72	82	10
G-52	112,975	20,366	(92,609)	36	24	(12)
Total C & I	596,989	478,589	(118,400)	34,488	34,185	(303)
Total Company	919,789	808,907	(110,881)	163,118	164,065	947

	NORMAL AVERAGE USE			Change in Sales Due to Change In:			
	2009 Forecast	2009 Actual	Difference	Meter Count	Load Pattern	Total Chg MMBtu	% Difference
Res Heat	2.62	2.65	0.03	2,871	3,648	6,519	2.09%
Res General	1.16	1.24	0.08	179	821	1,000	8.74%
Total Res	3.78	3.89	0.11	3,051	4,468	7,519	2.33%
G-40	4.59	4.07	(0.52)	(730)	(13,038)	(13,768)	-11.91%
G-50	12.86	13.71	0.85	(450)	5,003	4,553	6.00%
G-41	28.03	70.11	42.09	(1,261)	94,063	92,802	145.23%
G-51	173.39	109.70	(63.69)	(10,750)	(62,166)	(72,916)	-40.51%
G-42	675.58	148.54	(527.05)	6,756	(43,218)	(36,462)	-74.96%
G-52	3,138.19	848.58	(2,289.61)	(37,658)	(54,951)	(92,609)	-81.97%
Total C & I	17.31	14.00	(3.31)	(44,095)	(74,305)	(118,400)	-19.83%
Total Company	5.64	4.93	(0.71)	(41,044)	(69,837)	(110,881)	-12.06%

Schedule 9

New Hampshire Division
Original and Revised 2010 Summer Period Reconciliation

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010 SUMMER PERIOD RECONCILIATION
November 2009 - October 2010

Original Reconciliation

FORM III
Schedule 1
Updated March 3, 2011

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010 SUMMER PERIOD RECONCILIATION
SCHEDULE 1: SUMMARY OF SUMMER PERIOD BALANCE
November 2009 - October 2010

	AMOUNT	
Summer Period Beg. Balance (1)	$91,535	SCHEDULE 2
Less: Reported Collections	($4,942,961)	SCHEDULE 2
Less: Billing Adjustment	$0	SCHEDULE 2
Add: Cost of Firm Gas Allowable	$4,981,640	SCHEDULE 4
Add: Interest	($5,937)	SCHEDULE 2
Summer Period Ending Balance	$124,276	

(1) Summer period balance as of October 31, 2009, ($536,749) as approved in Order 25,097 in DG 10-050 was adjusted by $628,284 to remove November 2009 costs and collections that were incorrectly included. The amount of $91,535 was the ending balance as of October 31, 2009.

FORM III
Schedule 2

NORTHERN UTILTIES, INC. - NEW HAMPSHIRE DIVISION
2010 SUMMER PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED SUMMER PERIOD ACCOUNTS
November 2009 - October 2010
Acct 191.10

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
SUMMER PERIOD													
Summer Period Account Beginning Balance	$ 91,535	$ (536,595)	$ (563,865)	$ (578,644)	$ (616,819)	$ (579,200)	$ (66,593)	$ 221,130	$ 212,643	$ 127,080	$ 123,316	$ (45,590)	$ 91,535
Plus: Cost of Firm Gas (Schedule 4)	$ (87,372)	$ -	$ (12,107)	$ (38,480)	$ 39,716	$ 512,862	$ 1,091,441	$ 527,927	$ 533,730	$ 613,501	$ 527,271	$ 1,273,151	$ 4,981,640
Less: Reported Collections (Schedule 3)	$ (540,155)	$ (25,782)	$ (1,127)	$ 1,922	$ (480)	$ 618	$ (803,927)	$ (537,000)	$ (619,752)	$ (617,603)	$ (696,282)	$ (1,103,392)	$ (4,942,961)
Less: Billing Adjustment													
Summer Period Account Ending Balance	$ (535,993)	$ (562,377)	$ (577,098)	$ (615,202)	$ (577,583)	$ (65,720)	$ 220,921	$ 212,057	$ 126,620	$ 122,978	$ (45,695)	$ 124,170	$ 130,213
Month's Average Balance	$ (222,229)	$ (549,486)	$ (570,482)	$ (596,923)	$ (597,201)	$ (322,460)	$ 77,164	$ 216,593	$ 169,632	$ 125,029	$ 38,811	$ 39,290	
Interest Rate (Prime Rate)	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
Interest Applied	$ (602)	$ (1,488)	$ (1,545)	$ (1,617)	$ (1,617)	$ (873)	$ 209	$ 587	$ 459	$ 339	$ 105	$ 106	$ (5,937)
Summer Period Account Ending Balance w/int	$ (536,595)	$ (563,865)	$ (578,644)	$ (616,819)	$ (579,200)	$ (66,593)	$ 221,130	$ 212,643	$ 127,080	$ 123,316	$ (45,590)	$ 124,276	$ 124,276

FORM III
Schedule 3
Updated March 3, 2011

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS(1)
November 2009 - October 2010

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
Accrued Revenue	$ (984,300)	$ -	$ -	$ -	$ -	$ -	$ 374,909	$ (130,936)	$ 60,573	$ 39,813	$ 62,690	$ 311,677	$ (265,574)
Billed Revenue	$ 1,524,456	$ 25,782	$ 1,127	$ (1,922)	$ 480	$ (618)	$ 429,018	$ 667,936	$ 559,179	$ 577,790	$ 633,592	$ 791,716	$ 5,208,535
Calendarized Revenue	**$ 540,155**	**$ 25,782**	**$ 1,127**	**$ (1,922)**	**$ 480**	**$ (618)**	**$ 803,927**	**$ 537,000**	**$ 619,752**	**$ 617,603**	**$ 696,282**	**$ 1,103,392**	**$ 4,942,961**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010 SUMMER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO SUMMER PERIOD
November 2009 - October 2010

Updated March 3, 2011

Commodity Costs:	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
Anadarka Energy	$ 83,446	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 83,446**
Distrigas	$ 5,097	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 5,097**
Emera Energy	$ 117,096	$ -	$ -	$ -	$ 41,634	$ -	$ -	$ 71,921	$ 67,425	$ 72,644	$ 118,540	$ 59,175	**$ 548,435**
Hess	$ (575)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 257,175	$ 41,925	$ -	$ -	**$ 298,525**
JP Morgan	$ 391,059	$ -	$ -	$ -	$ -	$ -	$ -	$ 319,361	$ -	$ -	$ -	$ -	**$ 710,419**
Sempra	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,723	**$ 5,723**
South Jersey Resources	$ 156,014	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 156,014**
Spark Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 54,003	$ 266,029	**$ 320,032**
Sprague Energy	$ (649)	$ -	$ -	$ -	$ -	$ -	$ -	$ 105,043	$ 98,308	$ 120,611	$ 126,617	$ 130,682	**$ 580,613**
Tennessee	$ 3,310	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,996	$ 1,906	$ 2,097	$ 2,156	$ 2,952	**$ 14,417**
Total Gas & Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 152,615	$ -	**$ 152,615**
Misc Small Suppliers	$ (6,522)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ (6,522)**
Subtotal	$ 748,276	$ -	$ -	$ -	$ 41,634	$ -	$ -	$ 498,320	$ 424,813	$ 237,277	$ 453,931	$ 464,561	**$ 2,868,814**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 484,957	$ 424,981	$ 242,533	$ 458,734	$ 457,048	$ 746,407	**$ 2,814,660**
Commodity Cost Reversals	$ (835,648)	$ -	$ -	$ -	$ -	$ -	$ -	$ (484,957)	$ (424,981)	$ (242,533)	$ (458,734)	$ (457,048)	**$ (2,903,901)**
Subtotal	$ (87,372)	$ -	$ -	$ -	$ 41,634	$ -	$ 484,957	$ 438,344	$ 242,365	$ 453,479	$ 452,245	$ 753,920	**$ 2,779,573**
Withdrawal Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ (509)	$ (395)	$ 3,154	$ 185	$ 166	$ (679)	**$ 1,922**
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 289,307	$ 233,654	$ 224,568	$ (11,661)	$ (853)	$ 127,328	**$ 862,344**
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (8,317)	$ (8,046)	$ (8,805)	$ (8,512)	$ (6,921)	**$ (40,600)**
Non Traditional Sales	$ -	$ -	$ -	$ -	$ -	$ (14,135)	$ -	$ (65,099)	$ (330,547)	$ (54,378)	$ -	$ (98,471)	**$ (562,630)**
Net OBA Adj	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,774)	$ 115	$ (2,108)	$ (2,824)	$ (4,551)	$ (560)	**$ (11,701)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,967	$ 6,228	$ 4,643	$ 5,346	$ 5,274	$ 4,944	**$ 32,402**
Transportation Charges	$ -	$ -	$ (12,107)	$ (38,480)	$ (1,918)	$ 526,997	$ -	$ 1,424	$ (57,059)	$ (3,983)	$ (1,504)	$ (25,672)	**$ 387,699**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 205,387	$ 2,144	$ 2,131	$ 1,719	$ 1,957	$ 314,303	**$ 527,641**
Prior Period Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Subtotal	$ -	$ -	$ (12,107)	$ (38,480)	$ (1,918)	$ 512,862	$ 498,378	$ 169,755	$ (163,264)	$ (74,400)	$ (8,022)	$ 314,273	**$ 1,197,077**
Sales for Resale Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ (75,967)	$ (337,983)	$ (63,183)	$ (8,512)	$ (105,392)	$ (81,484)	**$ (672,521)**
Sales for Resale Reversals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 75,967	$ 337,983	$ 63,183	$ 8,512	$ 105,392	**$ 591,036**
Total Commodity Costs	**$ (87,372)**	**$ -**	**$ (12,107)**	**$ (38,480)**	**$ 39,716**	**$ 512,862**	**$ 907,368**	**$ 346,083**	**$ 353,901**	**$ 433,749**	**$ 347,344**	**$ 1,092,101**	**$ 3,895,166**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010 SUMMER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO SUMMER PERIOD
November 2009 - October 2010

Demand Costs	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	0 Total
Forecasted Summer Demand Costs (DG 10-05(	$ -	$ -	$ -	$ -	$ -	$ -	$ 176,337	$ 176,337	$ 176,337	$ 176,337	$ 176,337	$ 176,337	**$ 1,058,022**
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,736	$ 5,506	$ 3,492	$ 3,414	$ 3,590	$ 4,713	**$ 28,452**
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 184,073**	**$ 181,843**	**$ 179,829**	**$ 179,751**	**$ 179,927**	**$ 181,050**	**$ 1,086,474**
Total Gas Costs	**$ (87,372)**	**$ -**	**$ (12,107)**	**$ (38,480)**	**$ 39,716**	**$ 512,862**	**$ 1,091,441**	**$ 527,927**	**$ 533,730**	**$ 613,501**	**$ 527,271**	**$ 1,273,151**	**$ 4,981,640**

FORM III
Schedule 5
Updated March 3, 2011

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010 SUMMER PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
November 2009 - October 2010

New Hampshire	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
Throughput IN													
BTU Factor	1.037	1.04053	1.042	1.044	1.039	1.03975	1.038	1.039	1.033	1.036	1.039	1.041	
GST Meter Throughput (M	528,094	880,611	977,063	812,599	665,946	416,782	312,869	265,598	249,025	269,606	273,645	427,825	6,079,663
Salem Meter (MCF)	27,009	56,707	61,967	49,058	34,966	18,950	12,766	9,904	9,385	9,959	10,496	18,586	319,753
GST Meter Throughput (I	547,633	916,302	1,018,100	848,353	691,918	433,349	324,758	275,956	257,243	279,312	284,317	445,366	6,322,608
Salem Meter (DTH)	28,008	59,005	64,570	51,217	36,330	19,703	13,251	10,290	9,695	10,318	10,905	19,348	332,640
LNG/Propane													-
Total Throughput	575,642	975,307	1,082,669	899,570	728,248	453,052	338,009	286,247	266,938	289,629	295,222	464,714	6,655,247
Throughput OUT													
Residential Gas													
Charged	114,181	153,165	320,901	266,164	208,617	154,085	89,805	48,593	37,542	31,398	35,343	45,287	1,505,081
Uncharged Current	71,699	132,901	139,568	126,626	96,640	71,183	24,753	17,120	17,902	18,960	24,555	50,075	791,981
Uncharged Prior	(47,772)	(71,699)	(132,901)	(139,568)	(126,626)	(96,640)	(71,183)	(24,753)	(17,120)	(17,902)	(18,960)	(24,555)	(789,678)
Total Residential Gas	**138,108**	**214,367**	**327,568**	**253,222**	**178,631**	**128,628**	**43,375**	**40,960**	**38,324**	**32,457**	**40,938**	**70,806**	1,507,384
Interruptible	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	-
Commercial/Industrial Gas													
Charged	134,296	213,173	371,131	308,200	236,761	162,214	100,468	56,259	50,821	48,982	52,749	63,675	1,798,729
Uncharged Current	81,951	157,742	163,939	151,115	114,042	75,149	33,010	24,405	24,409	28,929	31,853	48,382	934,925
Uncharged Prior	(56,218)	(81,951)	(157,742)	(163,939)	(151,115)	(114,042)	(75,149)	(33,010)	(24,405)	(24,409)	(28,929)	(31,853)	(942,761)
Total C/I Gas	**160,029**	**288,963**	**377,329**	**295,376**	**199,688**	**123,321**	**58,329**	**47,654**	**50,825**	**53,502**	**55,673**	**80,204**	1,790,894
Transportation													
Charged	274,355	362,827	418,102	374,369	348,655	274,469	210,279	200,287	183,338	202,932	206,761	246,364	3,302,738
Uncharged Current	110,691	186,138	147,132	139,598	124,303	85,504	55,335	55,311	49,937	65,560	74,219	115,721	1,209,449
Uncharged Prior	(101,472)	(110,691)	(186,138)	(147,132)	(139,598)	(124,303)	(85,504)	(55,335)	(55,311)	(49,937)	(65,560)	(74,219)	(1,195,200)
Total Transportation	**283,574**	**438,274**	**379,095**	**366,836**	**333,359**	**235,670**	**180,110**	**200,263**	**177,964**	**218,555**	**215,420**	**287,866**	**3,316,987**
Company Use	**38**	**81**	**137**	**118**	**76**	**49**	**25**	**7**	**2**	**2**	**6**	**17**	**555**
Total Throughput OUT	**581,750**	**941,685**	**1,084,129**	**915,550**	**711,754**	**487,669**	**281,838**	**288,884**	**267,115**	**304,515**	**312,037**	**438,893**	**6,615,819**
Total Throughput IN	**575,642**	**975,307**	**1,082,669**	**899,570**	**728,248**	**453,052**	**338,009**	**286,247**	**266,938**	**289,629**	**295,222**	**464,714**	**6,655,247**
Difference IN/OUT	(6,108)	33,622	(1,460)	(15,980)	16,494	(34,616)	56,171	(2,637)	(178)	(14,885)	(16,815)	25,821	39,428
%													0.59%

Attachment A
Updated March 3, 2011

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
DEFERRED SUMMER PERIOD WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
November 2009 - October 2010

SUMMER PERIOD - Acct 182.21

		BEGINNING BALANCE	WORKING CAP ALLOWANCE	WORKING CAP PERCENTAGE	WORKING CAP COLLECTIONS	WORKING CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
		A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
November 2009	$	(7,039)	(49)	0.0564%	(1,189)	(1,238)	(8,277)	(7,658)	3.25%	(21)	(8,297)
December	$	(8,297)	0	0.0564%	(57)	(57)	(8,354)	(8,326)	3.25%	(23)	(8,377)
January 2010	$	(8,377)	(7)	0.0564%	(3)	(10)	(8,387)	(8,382)	3.25%	(23)	(8,410)
February	$	(8,410)	(22)	0.0564%	5	(16)	(8,426)	(8,418)	3.25%	(23)	(8,449)
March	$	(8,449)	22	0.0564%	(1)	22	(8,427)	(8,438)	3.25%	(23)	(8,450)
April	$	(8,450)	289	0.0564%	2	291	(8,159)	(8,305)	3.25%	(22)	(8,182)
May	$	(8,182)	616	0.0564%	(348)	267	(7,914)	(8,048)	3.25%	(22)	(7,936)
June	$	(7,936)	298	0.0564%	(226)	72	(7,864)	(7,900)	3.25%	(21)	(7,885)
July	$	(7,885)	301	0.0564%	(220)	82	(7,804)	(7,845)	3.25%	(21)	(7,825)
August	$	(7,825)	346	0.0564%	(244)	102	(7,723)	(7,774)	3.25%	(21)	(7,744)
September	$	(7,744)	297	0.0564%	(276)	21	(7,723)	(7,733)	3.25%	(21)	(7,744)
October	$	(7,744)	718	0.0564%	(448)	270	(7,473)	(7,608)	3.25%	(21)	(7,494)
Totals			2,810		(3,003)					(261)	

Attachment B
Updated March 3, 2011

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
BAD DEBT EXPENSE - CALCULATION OF COLLECTION ALLOWANCE
November 2009 - October 2010

SUMMER PERIOD - Acct 182.22

	BEGINNING BALANCE	BAD DEBT ALLOWANCE(1)	% ALLOWED BAD DEBT	BAD DEBT COLLECTIONS	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
November 2009	(1,487)	(393)	0.45%	(2,998)	(3,391)	(4,878)	(3,183)	3.25%	(9)	(4,887)
December	(4,887)	0	0.45%	(144)	(144)	(5,031)	(4,959)	3.25%	(13)	(5,044)
January 2010	(5,044)	(55)	0.45%	(8)	(63)	(5,107)	(5,075)	3.25%	(14)	(5,121)
February	(5,121)	(173)	0.45%	13	(160)	(5,280)	(5,200)	3.25%	(14)	(5,294)
March	(5,294)	179	0.45%	(2)	177	(5,118)	(5,206)	3.25%	(14)	(5,132)
April	(5,132)	2,309	0.45%	4	2,314	(2,818)	(3,975)	3.25%	(11)	(2,829)
May	(2,829)	4,914	0.45%	(2,828)	2,086	(743)	(1,786)	3.25%	(5)	(747)
June	(747)	2,377	0.45%	(2,045)	332	(416)	(581)	3.25%	(2)	(417)
July	(417)	2,403	0.45%	(2,043)	361	(56)	(237)	3.25%	(1)	(57)
August	(57)	2,762	0.45%	(1,978)	784	727	335	3.25%	1	728
September	728	2,374	0.45%	(2,211)	163	891	810	3.25%	2	893
October	893	5,732	0.45%	(3,472)	2,261	3,154	2,024	3.25%	5	3,159
Totals		22,430		(17,711)					(73)	

(1) Bad Debt Allowance calculated by multiplying Bad Debt % by Gas Cost on Schedule 4 and Working Capital Allowance on Attachment A.

Attachment C
Page 1 of 2
Updated March 3, 2011

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
SUMMER PERIOD 2010

	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	TOTAL
Forecast Calendar Month Sales	227,554	161,959	102,702	100,429	105,605	138,634	836,884
Actual Sales	190,273	104,852	88,363	80,380	88,092	108,961	660,921
Difference	(37,281)	(57,107)	(14,339)	(20,049)	(17,513)	(29,673)	(175,963)
Add:							
Volume Variance due to Weather							
Normal Cal. Month Actual Sales	205,158	124,346	94,820	82,366	92,083	120,558	719,331
Actual Sales	190,273	104,852	88,363	80,380	88,092	108,961	660,921
Weather Variance	14,885	19,494	6,457	1,986	3,991	11,597	58,410
Total Variance Excluding Weather (excl weather effect)	(22,396)	(37,613)	(7,882)	(18,063)	(13,522)	(18,076)	(117,553)
Variance-difference due to meter count							(11,505)
-difference in load pattern							(144,558)
SALES							(156,063)

Attachment C
Updated March 3, 2011 Page 2 of 2

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
SUMMER PERIOD 2010

	NORMAL MMBtu			METERS		
	2010 Forecast	2010 Actual	Difference	2010 Forecast	2010 Actual	Difference
Res Heat	333,305	289,852	(43,453)	124,623	122,064	(2,559)
Res General	11,312	11,795	483	9,544	9,881	337
Total Res	344,617	301,647	(42,970)	134,167	131,945	(2,222)
G-40	123,056	87,056	(36,000)	25,158	24,828	(330)
G-50	81,583	72,423	(9,160)	5,904	5,625	(279)
G-41	143,584	111,885	(31,699)	2,280	2,304	24
G-51	122,918	95,626	(27,292)	1,038	999	(39)
G-42	17,929	18,308	379	72	113	41
G-52	14,174	4,853	(9,321)	36	19	(17)
Total C & I	503,244	390,151	(113,093)	34,488	33,888	(600)
Total Company	847,861	691,798	(156,063)	168,655	165,833	(2,822)

	NORMAL AVERAGE USE			Change in Sales Due to Change In:			
	2010 Forecast	2010 Actual	Difference	Meter Count	Load Pattern	Total Chg MMBtu	% Difference
Res Heat	2.67	2.37	(0.30)	(6,844)	(36,609)	(43,453)	-13.04%
Res General	1.19	1.19	0.01	399	84	483	4.27%
Total Res	3.86	3.57	(0.29)	(6,445)	(36,525)	(42,970)	-12.47%
G-40	4.89	3.51	(1.38)	(1,614)	(34,386)	(36,000)	-29.25%
G-50	13.82	12.88	(0.94)	(3,855)	(5,305)	(9,160)	-11.23%
G-41	62.98	48.56	(14.41)	1,511	(33,210)	(31,699)	-22.08%
G-51	118.42	95.72	(22.70)	(4,618)	(22,674)	(27,292)	-22.20%
G-42	249.01	162.02	(87.00)	10,210	(9,831)	379	2.11%
G-52	393.72	255.42	(138.30)	(6,693)	(2,628)	(9,321)	-65.76%
Total C & I	14.59	11.51	(3.08)	(5,060)	(108,033)	(113,093)	-22.47%
Total Company	5.03	4.17	(0.86)	(11,505)	(144,558)	(156,063)	-18.41%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010 SUMMER PERIOD RECONCILIATION
November 2009 - October 2010

Recalculated Reconciliation

FORM III
Schedule 1
Updated July 2012

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010 SUMMER PERIOD RECONCILIATION
SCHEDULE 1: SUMMARY OF SUMMER PERIOD BALANCE
November 2009 - October 2010

	AMOUNT	
Summer Period Beg. Balance (1)	$94,574	SCHEDULE 2
Less: Reported Collections	($4,942,961)	SCHEDULE 2
Less: Billing Adjustment	$0	SCHEDULE 2
Add: Cost of Firm Gas Allowable	$4,950,214	SCHEDULE 4
Add: Interest	($6,304)	SCHEDULE 2
Summer Period Ending Balance	$95,523	

(1) Summer period balance as of October 31, 2009, ($536,749) as approved in Order 25,097 in DG 10-050 was adjusted by $628,284 to remove November 2009 costs and collections that were incorrectly included. The amount of $91,535 was the ending balance as of October 31, 2009.

FORM III
Updated July 2012 Schedule 2

NORTHERN UTILTIES, INC. - NEW HAMPSHIRE DIVISION
2010 SUMMER PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED SUMMER PERIOD ACCOUNTS
November 2009 - October 2010
Acct 191.10

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
SUMMER PERIOD													
Summer Period Account Beginning Balance	$ 94,574	$ (528,508)	$ (555,757)	$ (569,417)	$ (604,527)	$ (568,036)	$ (95,432)	$ 192,445	$ 184,023	$ 98,502	$ 94,809	$ (74,115)	$ 94,574
Plus: Cost of Firm Gas (Schedule 4)	$ (82,340)	$ -	$ (11,012)	$ (35,444)	$ 38,557	$ 472,883	$ 1,091,673	$ 528,068	$ 533,850	$ 613,648	$ 527,330	$ 1,273,001	$ 4,950,214
Less: Reported Collections (Schedule 3)	$ (540,155)	$ (25,782)	$ (1,127)	$ 1,922	$ (480)	$ 618	$ (803,927)	$ (537,000)	$ (619,752)	$ (617,603)	$ (696,282)	$ (1,103,392)	$ (4,942,961)
Less: Billing Adjustment													
Summer Period Account Ending Balance	$ (527,921)	$ (554,291)	$ (567,896)	$ (602,939)	$ (566,450)	$ (94,535)	$ 192,314	$ 183,514	$ 98,120	$ 94,547	$ (74,143)	$ 95,494	$ 101,828
Month's Average Balance	$ (216,674)	$ (541,399)	$ (561,826)	$ (586,178)	$ (585,489)	$ (331,285)	$ 48,441	$ 187,979	$ 141,071	$ 96,525	$ 10,333	$ 10,690	
Interest Rate (Prime Rate)	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
Interest Applied	$ (587)	$ (1,466)	$ (1,522)	$ (1,588)	$ (1,586)	$ (897)	$ 131	$ 509	$ 382	$ 261	$ 28	$ 29	$ (6,304)
Summer Period Account Ending Balance w/int	$ (528,508)	$ (555,757)	$ (569,417)	$ (604,527)	$ (568,036)	$ (95,432)	$ 192,445	$ 184,023	$ 98,502	$ 94,809	$ (74,115)	$ 95,523	$ 95,523

FORM III
Schedule 3

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS(1)
November 2009 - October 2010

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
Accrued Revenue	$ (984,300)	$ -	$ -	$ -	$ -	$ -	$ 374,909	$ (130,936)	$ 60,573	$ 39,813	$ 62,690	$ 311,677	**$ (265,574)**
Billed Revenue	$ 1,524,456	$ 25,782	$ 1,127	$ (1,922)	$ 480	$ (618)	$ 429,018	$ 667,936	$ 559,179	$ 577,790	$ 633,592	$ 791,716	**$ 5,208,535**
Calendarized Revenue	**$ 540,155**	**$ 25,782**	**$ 1,127**	**$ (1,922)**	**$ 480**	**$ (618)**	**$ 803,927**	**$ 537,000**	**$ 619,752**	**$ 617,603**	**$ 696,282**	**$ 1,103,392**	**$ 4,942,961**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010 SUMMER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO SUMMER PERIOD
November 2009 - October 2010

Commodity Costs:	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
Anadarka Energy	$ 83,446	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 83,446**
Distrigas	$ 5,097	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 5,097**
Emera Energy	$ 117,096	$ -	$ -	$ -	$ 41,634	$ -	$ -	$ 71,921	$ 67,425	$ 72,644	$ 118,540	$ 59,175	**$ 548,435**
Hess	$ (575)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 257,175	$ 41,925	$ -	$ -	**$ 298,525**
JP Morgan	$ 391,059	$ -	$ -	$ -	$ -	$ -	$ -	$ 319,361	$ -	$ -	$ -	$ -	**$ 710,419**
Sempra	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,723	**$ 5,723**
South Jersey Resources	$ 156,014	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 156,014**
Spark Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 54,003	$ 266,029	**$ 320,032**
Sprague Energy	$ (649)	$ -	$ -	$ -	$ -	$ -	$ -	$ 105,043	$ 98,308	$ 120,611	$ 126,617	$ 130,682	**$ 580,613**
Tennessee	$ 3,310	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,996	$ 1,906	$ 2,097	$ 2,156	$ 2,952	**$ 14,417**
Total Gas & Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 152,615	$ -	**$ 152,615**
Misc Small Suppliers	$ (6,522)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ (6,522)**
Subtotal	$ 748,276	$ -	$ -	$ -	$ 41,634	$ -	$ -	$ 498,320	$ 424,813	$ 237,277	$ 453,931	$ 464,561	**$ 2,868,814**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 484,957	$ 424,981	$ 242,533	$ 458,734	$ 457,048	$ 746,407	**$ 2,814,660**
Commodity Cost Reversals	$ (835,648)	$ -	$ -	$ -	$ -	$ -	$ -	$ (484,957)	$ (424,981)	$ (242,533)	$ (458,734)	$ (457,048)	**$ (2,903,901)**
Subtotal - Supply	$ (87,372)	$ -	$ -	$ -	$ 41,634	$ -	$ 484,957	$ 438,344	$ 242,365	$ 453,479	$ 452,245	$ 753,920	**$ 2,779,573**
Withdrawal Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ (509)	$ (395)	$ 3,154	$ 185	$ 166	$ (679)	**$ 1,922**
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 289,307	$ 233,654	$ 224,568	$ (11,661)	$ (853)	$ 127,328	**$ 862,344**
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (8,317)	$ (8,046)	$ (8,805)	$ (8,512)	$ (6,921)	**$ (40,600)**
Non Traditional Sales	$ -	$ -	$ -	$ -	$ -	$ (14,135)	$ -	$ (65,099)	$ (330,547)	$ (54,378)	$ -	$ (98,471)	**$ (562,630)**
Net OBA Adj	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,774)	$ 115	$ (2,108)	$ (2,824)	$ (4,551)	$ (560)	**$ (11,701)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,967	$ 6,228	$ 4,643	$ 5,346	$ 5,274	$ 4,944	**$ 32,402**
Transportation Charges	$ -	$ -	$ (12,107)	$ (38,480)	$ (1,918)	$ 526,997	$ -	$ 1,424	$ (57,059)	$ (3,983)	$ (1,504)	$ (25,672)	**$ 387,699**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 205,387	$ 2,144	$ 2,131	$ 1,719	$ 1,957	$ 314,303	**$ 527,641**
Allocation Adjustments	$ 5,032	$ -	$ 1,094	$ 3,037	$ (1,160)	$ (39,979)	$ 232	$ 141	$ 120	$ 148	$ 59	$ (150)	**$ (31,425)**
Subtotal	$ 5,032	$ -	$ (11,012)	$ (35,444)	$ (3,078)	$ 472,883	$ 498,610	$ 169,896	$ (163,144)	$ (74,252)	$ (7,963)	$ 314,123	**$ 1,165,651**
Sales for Resale Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ (75,967)	$ (337,983)	$ (63,183)	$ (8,512)	$ (105,392)	$ (81,484)	**$ (672,521)**
Sales for Resale Reversals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 75,967	$ 337,983	$ 63,183	$ 8,512	$ 105,392	**$ 591,036**
Total Commodity Costs	**$ (82,340)**	**$ -**	**$ (11,012)**	**$ (35,444)**	**$ 38,557**	**$ 472,883**	**$ 907,600**	**$ 346,225**	**$ 354,021**	**$ 433,897**	**$ 347,403**	**$ 1,091,951**	**$ 3,863,740**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010 SUMMER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO SUMMER PERIOD
November 2009 - October 2010

Demand Costs

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
Forecasted Summer Demand Costs (DG 10-050)	$ -	$ -	$ -	$ -	$ -	$ -	$ 176,337	$ 176,337	$ 176,337	$ 176,337	$ 176,337	$ 176,337	**$ 1,058,022**
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,736	$ 5,506	$ 3,492	$ 3,414	$ 3,590	$ 4,713	**$ 28,452**
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 184,073**	**$ 181,843**	**$ 179,829**	**$ 179,751**	**$ 179,927**	**$ 181,050**	**$ 1,086,474**
Total Gas Costs	**$ (82,340)**	**$ -**	**$ (11,012)**	**$ (35,444)**	**$ 38,557**	**$ 472,883**	**$ 1,091,673**	**$ 528,068**	**$ 533,850**	**$ 613,648**	**$ 527,330**	**$ 1,273,001**	**$ 4,950,214**

FORM III
Updated March 3, 2011 Schedule 5

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2010 SUMMER PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
November 2009 - October 2010

New Hampshire	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
Throughput IN													
BTU Factor	1.037	1.04053	1.042	1.044	1.039	1.03975	1.038	1.039	1.033	1.036	1.039	1.041	
GST Meter Throughput (M	528,094	880,611	977,063	812,599	665,946	416,782	312,869	265,598	249,025	269,606	273,645	427,825	6,079,663
Salem Meter (MCF)	27,009	56,707	61,967	49,058	34,966	18,950	12,766	9,904	9,385	9,959	10,496	18,586	319,753
GST Meter Throughpurt (I	547,633	916,302	1,018,100	848,353	691,918	433,349	324,758	275,956	257,243	279,312	284,317	445,366	6,322,608
Salem Meter (DTH)	28,008	59,005	64,570	51,217	36,330	19,703	13,251	10,290	9,695	10,318	10,905	19,348	332,640
LNG/Propane													-
Total Throughput	575,642	975,307	1,082,669	899,570	728,248	453,052	338,009	286,247	266,938	289,629	295,222	464,714	6,655,247
Throughput OUT													
Residential Gas													
Charged	114,181	153,165	320,901	266,164	208,617	154,085	89,805	48,593	37,542	31,398	35,343	45,287	1,505,081
Uncharged Current	71,699	132,901	139,568	126,626	96,640	71,183	24,753	17,120	17,902	18,960	24,555	50,075	791,981
Uncharged Prior	(47,772)	(71,699)	(132,901)	(139,568)	(126,626)	(96,640)	(71,183)	(24,753)	(17,120)	(17,902)	(18,960)	(24,555)	(789,678)
Total Residential Gas	**138,108**	**214,367**	**327,568**	**253,222**	**178,631**	**128,628**	**43,375**	**40,960**	**38,324**	**32,457**	**40,938**	**70,806**	1,507,384
Interruptible	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	-
Commercial//Industrial Gas													
Charged	134,296	213,173	371,131	308,200	236,761	162,214	100,468	56,259	50,821	48,982	52,749	63,675	1,798,729
Uncharged Current	81,951	157,742	163,939	151,115	114,042	75,149	33,010	24,405	24,409	28,929	31,853	48,382	934,925
Uncharged Prior	(56,218)	(81,951)	(157,742)	(163,939)	(151,115)	(114,042)	(75,149)	(33,010)	(24,405)	(24,409)	(28,929)	(31,853)	(942,761)
Total C/I Gas	**160,029**	**288,963**	**377,329**	**295,376**	**199,688**	**123,321**	**58,329**	**47,654**	**50,825**	**53,502**	**55,673**	**80,204**	1,790,894
Transportation													
Charged	274,355	362,827	418,102	374,369	348,655	274,469	210,279	200,287	183,338	202,932	206,761	246,364	3,302,738
Uncharged Current	110,691	186,138	147,132	139,598	124,303	85,504	55,335	55,311	49,937	65,560	74,219	115,721	1,209,449
Uncharged Prior	(101,472)	(110,691)	(186,138)	(147,132)	(139,598)	(124,303)	(85,504)	(55,335)	(55,311)	(49,937)	(65,560)	(74,219)	(1,195,200)
Total Transportation	**283,574**	**438,274**	**379,095**	**366,836**	**333,359**	**235,670**	**180,110**	**200,263**	**177,964**	**218,555**	**215,420**	**287,866**	**3,316,987**
Company Use	**38**	**81**	**137**	**118**	**76**	**49**	**25**	**7**	**2**	**2**	**6**	**17**	**555**
Total Throughput OUT	**581,750**	**941,685**	**1,084,129**	**915,550**	**711,754**	**487,669**	**281,838**	**288,884**	**267,115**	**304,515**	**312,037**	**438,893**	**6,615,819**
Total Throughput IN	**575,642**	**975,307**	**1,082,669**	**899,570**	**728,248**	**453,052**	**338,009**	**286,247**	**266,938**	**289,629**	**295,222**	**464,714**	**6,655,247**
Difference IN/OUT	(6,108)	33,622	(1,460)	(15,980)	16,494	(34,616)	56,171	(2,637)	(178)	(14,885)	(16,815)	25,821	39,428
%													0.59%

Attachment A
Updated July 2012

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
DEFERRED SUMMER PERIOD WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
November 2009 - October 2010

SUMMER PERIOD - Acct 182.21

		BEGINNING BALANCE	WORKING CAP ALLOWANCE	WORKING CAP PERCENTAGE	WORKING CAP COLLECTIONS	WORKING CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
		A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
November 2009	$	(7,039)	(46)	0.0564%	(1,189)	(1,235)	(8,274)	(7,657)	3.25%	(21)	(8,295)
December	$	(8,295)	0	0.0564%	(57)	(57)	(8,352)	(8,323)	3.25%	(23)	(8,374)
January 2010	$	(8,374)	(6)	0.0564%	(3)	(10)	(8,384)	(8,379)	3.25%	(23)	(8,407)
February	$	(8,407)	(20)	0.0564%	5	(15)	(8,421)	(8,414)	3.25%	(23)	(8,444)
March	$	(8,444)	22	0.0564%	(1)	21	(8,423)	(8,433)	3.25%	(23)	(8,446)
April	$	(8,446)	267	0.0564%	2	268	(8,177)	(8,312)	3.25%	(23)	(8,200)
May	$	(8,200)	616	0.0564%	(348)	267	(7,933)	(8,066)	3.25%	(22)	(7,954)
June	$	(7,954)	298	0.0564%	(226)	72	(7,882)	(7,918)	3.25%	(21)	(7,904)
July	$	(7,904)	301	0.0564%	(220)	82	(7,822)	(7,863)	3.25%	(21)	(7,843)
August	$	(7,843)	346	0.0564%	(244)	102	(7,741)	(7,792)	3.25%	(21)	(7,762)
September	$	(7,762)	297	0.0564%	(276)	22	(7,741)	(7,752)	3.25%	(21)	(7,762)
October	$	(7,762)	718	0.0564%	(448)	270	(7,492)	(7,627)	3.25%	(21)	(7,512)
Totals			2,792		(3,003)					(261)	

Attachment B
Updated July 2012

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
BAD DEBT EXPENSE - CALCULATION OF COLLECTION ALLOWANCE
November 2009 - October 2010

SUMMER PERIOD - Acct 182.22

	BEGINNING BALANCE	BAD DEBT ALLOWANCE(1)	% ALLOWED BAD DEBT	BAD DEBT COLLECTIONS	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
November 2009	(1,473)	(371)	0.45%	(2,998)	(3,369)	(4,842)	(3,158)	3.25%	(9)	(4,851)
December	(4,851)	0	0.45%	(144)	(144)	(4,994)	(4,922)	3.25%	(13)	(5,007)
January 2010	(5,007)	(50)	0.45%	(8)	(58)	(5,065)	(5,036)	3.25%	(14)	(5,079)
February	(5,079)	(160)	0.45%	13	(146)	(5,225)	(5,152)	3.25%	(14)	(5,239)
March	(5,239)	174	0.45%	(2)	172	(5,067)	(5,153)	3.25%	(14)	(5,081)
April	(5,081)	2,129	0.45%	4	2,134	(2,948)	(4,015)	3.25%	(11)	(2,959)
May	(2,959)	4,915	0.45%	(2,828)	2,087	(871)	(1,915)	3.25%	(5)	(877)
June	(877)	2,378	0.45%	(2,045)	332	(544)	(710)	3.25%	(2)	(546)
July	(546)	2,404	0.45%	(2,043)	361	(185)	(365)	3.25%	(1)	(186)
August	(186)	2,763	0.45%	(1,978)	785	599	207	3.25%	1	600
September	600	2,374	0.45%	(2,211)	163	763	681	3.25%	2	765
October	765	5,732	0.45%	(3,472)	2,260	3,025	1,895	3.25%	5	3,030
Totals		22,289		(17,711)					(75)	

(1) Bad Debt Allowance calculated by multiplying Bad Debt % by Gas Cost on Schedule 4 and Working Capital Allowance on Attachment A.

Attachment C
Updated March 3, 2011 Page 1 of 2

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
SUMMER PERIOD 2010

	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	TOTAL
Forecast Calendar Month Sales	227,554	161,959	102,702	100,429	105,605	138,634	836,884
Actual Sales	190,273	104,852	88,363	80,380	88,092	108,961	660,921
Difference	(37,281)	(57,107)	(14,339)	(20,049)	(17,513)	(29,673)	(175,963)
Add:							
Volume Variance due to Weather							
Normal Cal. Month Actual Sales	205,158	124,346	94,820	82,366	92,083	120,558	719,331
Actual Sales	190,273	104,852	88,363	80,380	88,092	108,961	660,921
Weather Variance	14,885	19,494	6,457	1,986	3,991	11,597	58,410
Total Variance Excluding Weather (excl weather effect)	(22,396)	(37,613)	(7,882)	(18,063)	(13,522)	(18,076)	(117,553)
Variance-difference due to meter count							(11,505)
-difference in load pattern							(144,558)
SALES							(156,063)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
SUMMER PERIOD 2010

	NORMAL MMBtu			METERS		
	2010 Forecast	2010 Actual	Difference	2010 Forecast	2010 Actual	Difference
Res Heat	333,305	289,852	(43,453)	124,623	122,064	(2,559)
Res General	11,312	11,795	483	9,544	9,881	337
Total Res	344,617	301,647	(42,970)	134,167	131,945	(2,222)
G-40	123,056	87,056	(36,000)	25,158	24,828	(330)
G-50	81,583	72,423	(9,160)	5,904	5,625	(279)
G-41	143,584	111,885	(31,699)	2,280	2,304	24
G-51	122,918	95,626	(27,292)	1,038	999	(39)
G-42	17,929	18,308	379	72	113	41
G-52	14,174	4,853	(9,321)	36	19	(17)
Total C & I	503,244	390,151	(113,093)	34,488	33,888	(600)
Total Company	847,861	691,798	(156,063)	168,655	165,833	(2,822)

	NORMAL AVERAGE USE			Change in Sales Due to Change In:			
	2010 Forecast	2010 Actual	Difference	Meter Count	Load Pattern	Total Chg MMBtu	% Difference
Res Heat	2.67	2.37	(0.30)	(6,844)	(36,609)	(43,453)	-13.04%
Res General	1.19	1.19	0.01	399	84	483	4.27%
Total Res	3.86	3.57	(0.29)	(6,445)	(36,525)	(42,970)	-12.47%
G-40	4.89	3.51	(1.38)	(1,614)	(34,386)	(36,000)	-29.25%
G-50	13.82	12.88	(0.94)	(3,855)	(5,305)	(9,160)	-11.23%
G-41	62.98	48.56	(14.41)	1,511	(33,210)	(31,699)	-22.08%
G-51	118.42	95.72	(22.70)	(4,618)	(22,674)	(27,292)	-22.20%
G-42	249.01	162.02	(87.00)	10,210	(9,831)	379	2.11%
G-52	393.72	255.42	(138.30)	(6,693)	(2,628)	(9,321)	-65.76%
Total C & I	14.59	11.51	(3.08)	(5,060)	(108,033)	(113,093)	-22.47%
Total Company	5.03	4.17	(0.86)	(11,505)	(144,558)	(156,063)	-18.41%

Schedule 10

New Hampshire Division
Original and Revised 2011 Summer Period Reconciliation

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2011 SUMMER PERIOD RECONCILIATION
November 2010 - October 2011

Original Reconciliation

FORM III
Schedule 1

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2011 SUMMER SEASON COG RECONCILIATION
SCHEDULE 1: SUMMARY OF SUMMER SEASON BALANCE
November 2010 - October 2011

	AMOUNT	
Summer Season Beg. Balance	$124,276	SCHEDULE 2
Less: Reported Collections	($4,448,096)	SCHEDULE 2
Add: Cost of Firm Gas Allowable	$4,217,855	SCHEDULE 4
Add: Interest	($8,994)	SCHEDULE 2
Summer Season Ending Balance	($114,960)	

FORM III
Schedule 2

NORTHERN UTILTIES, INC. - NEW HAMPSHIRE DIVISION
2011 SUMMER SEASON COG RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED SUMMER SEASON ACCOUNTS
November 2010 - October 2011
Acct 191.10

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
SUMMER SEASON													
Summer Season Account Beginning Balance	$ 124,276	$ (293,079)	$ (312,036)	$ (307,614)	$ (310,010)	$ (310,683)	$ (309,133)	$ (542,932)	$ (310,174)	$ (314,629)	$ (191,246)	$ (128,542)	$ 124,276
Plus: Cost of Firm Gas (Schedule 4)	$ (3,408)	$ (20,479)	$ -	$ -	$ -	$ 2,535	$ 952,398	$ 625,177	$ 525,759	$ 647,752	$ 587,666	$ 900,454	$ 4,217,855
Less: Reported Collections (Schedule 3)	$ (413,719)	$ 2,341	$ 5,259	$ (1,560)	$ 167	$ (147)	$ (1,185,045)	$ (391,265)	$ (529,369)	$ (523,685)	$ (524,529)	$ (886,543)	$ (4,448,096)
Summer Season Account Ending Balance	$ (292,851)	$ (311,217)	$ (306,776)	$ (309,175)	$ (309,843)	$ (308,295)	$ (541,780)	$ (309,020)	$ (313,784)	$ (190,562)	$ (128,109)	$ (114,630)	$ (105,965)
Month's Average Balance	$ (84,287)	$ (302,148)	$ (309,406)	$ (308,394)	$ (309,926)	$ (309,489)	$ (425,457)	$ (425,976)	$ (311,979)	$ (252,595)	$ (159,678)	$ (121,586)	
Interest Rate (Prime Rate)	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
Interest Applied	$ (228)	$ (818)	$ (838)	$ (835)	$ (839)	$ (838)	$ (1,152)	$ (1,154)	$ (845)	$ (684)	$ (432)	$ (329)	$ (8,994)
Summer Season Account Ending Balance w/int	$ (293,079)	$ (312,036)	$ (307,614)	$ (310,010)	$ (310,683)	$ (309,133)	$ (542,932)	$ (310,174)	$ (314,629)	$ (191,246)	$ (128,542)	$ (114,960)	$ (114,960)

FORM III
Schedule 3

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2011 SUMMER SEASON COG RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2010 - October 2011

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
Accrued Revenue	$ (718,726)	$ -	$ -	$ -	$ -	$ -	$ 768,209	$ (474,534)	$ (52,089)	$ 49,568	$ (13,923)	$ 320,377	$ (121,116)
Billed Revenue	$ 1,132,445	$ (2,341)	$ (5,259)	$ 1,560	$ (167)	$ 147	$ 416,835	$ 865,798	$ 581,458	$ 474,117	$ 538,452	$ 566,166	$ 4,569,213
Calendarized Revenue	**$ 413,719**	**$ (2,341)**	**$ (5,259)**	**$ 1,560**	**$ (167)**	**$ 147**	**$ 1,185,045**	**$ 391,265**	**$ 529,369**	**$ 523,685**	**$ 524,529**	**$ 886,543**	**$ 4,448,096**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2011 SUMMER SEASON COG RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO SUMMER SEASON
November 2010 - October 2011

FORM III
Schedule 4
Page 1 of 2

Commodity Costs:	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total Off Peak
DTE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 582,422	$ -	$ -	$ -	$ -	**$ 582,422**
Distrigas	$ 180,377	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 16,330	**$ 196,708**
Emera Energy	$ 65,785	$ 3,974	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 69,758**
JP Morgan	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 330,448	$ -	$ -	**$ 330,448**
Portland	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 51	$ 68	$ 66	**$ 184**
Repsol	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 267,049	$ 269,506	$ 608,931	$ 236,891	**$ 1,382,377**
Sempra	$ 4,956	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 4,956**
Sequent	$ 5,108	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 5,108**
South Jersey Resources	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 145,318	$ -	$ -	$ -	**$ 145,318**
Sprague Energy	$ 160,952	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 160,952**
Tennessee	$ 2,952	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,021	$ 2,657	$ 2,666	$ 2,701	$ 2,638	**$ 19,636**
Total Gas & Power	$ 309,204	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 309,204**
Virginia Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 338,212	$ 181,647	$ -	$ -	$ 284,920	**$ 804,780**
Subtotal	$ 729,333	$ 3,974	$ -	$ -	$ -	$ -	$ -	$ 926,656	$ 596,671	$ 602,670	$ 611,700	$ 540,845	**$ 4,011,849**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 960,537	$ 596,763	$ 604,312	$ 611,632	$ 529,963	$ 648,112	**$ 3,951,319**
Commodity Cost Reversals	$ (746,407)	$ -	$ -	$ -	$ -	$ -	$ -	$ (960,537)	$ (596,763)	$ (604,312)	$ (611,632)	$ (529,963)	**$ (4,049,614)**
Subtotal - Supply	$ (17,074)	$ 3,974	$ -	$ -	$ -	$ -	$ 960,537	$ 562,882	$ 604,220	$ 609,990	$ 530,031	$ 658,994	**$ 3,913,554**
Withdrawal Charges	$ (5,102)	$ -	$ -	$ -	$ -	$ -	$ (529)	$ 752	$ (297)	$ 775	$ (2,678)	$ (137)	**$ (7,216)**
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 90,239	$ 18,793	$ 3,583	$ (17,344)	$ 6,329	$ 41,345	**$ 142,946**
Company Managed	$ (7,267)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ (7,267)**
Non Traditional Sales	$ (69,697)	$ -	$ -	$ -	$ -	$ -	$ -	$ (340,132)	$ (164,840)	$ (283,329)	$ (162,598)	$ (170,241)	**$ (1,190,837)**
Net OBA Adj.	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,291	$ (8,977)	$ (8,710)	$ 988	$ 2,973	$ (10,532)	**$ (20,967)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,900	$ 4,436	$ 6,889	$ 5,731	$ 6,764	$ 4,524	**$ 34,244**
Transportation Charges	$ 14,248	$ (24,452)	$ -	$ -	$ -	$ 2,535	$ -	$ 1,394	$ (6,202)	$ -	$ 2,017	$ (5,696)	**$ (16,157)**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,188	$ 1,833	$ 916	$ 1,090	$ 1,206	$ 66,231	**$ 95,463**
													$ -
Subtotal	$ (67,819)	$ (24,452)	$ -	$ -	$ -	$ 2,535	$ 123,089	$ (321,900)	$ (168,661)	$ (292,089)	$ (145,988)	$ (74,507)	**$ (969,791)**
Sales for Resale Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ (340,132)	$ (164,840)	$ (283,544)	$ (162,598)	$ (167,879)	$ (60,816)	**$ (1,179,809)**
Sales for Resale Reversals	$ 81,484	$ -	$ -	$ -	$ -	$ -	$ -	$ 340,132	$ 164,840	$ 283,544	$ 162,598	$ 167,879	**$ 1,200,477**
Total Commodity Costs	**$ (3,408)**	**$ (20,479)**	**$ -**	**$ -**	**$ -**	**$ 2,535**	**$ 743,494**	**$ 416,273**	**$ 316,855**	**$ 438,848**	**$ 378,762**	**$ 691,550**	**$ 2,964,431**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2011 SUMMER SEASON COG RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO SUMMER SEASON
November 2010 - October 2011

Demand Costs	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total Off Peak
Forecasted Summer Demand Costs (DG :	$ -	$ -	$ -	$ -	$ -	$ -	$ 204,577	$ 204,577	$ 204,577	$ 204,577	$ 204,577	$ 204,577	**$ 1,227,460**
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,327	$ 4,327	$ 4,327	$ 4,327	$ 4,327	$ 4,327	**$ 25,964**
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 208,904**	**$ 208,904**	**$ 208,904**	**$ 208,904**	**$ 208,904**	**$ 208,904**	**$ 1,253,424**
Total Gas Costs	**$ (3,408)**	**$ (20,479)**	**$ -**	**$ -**	**$ -**	**$ 2,535**	**$ 952,398**	**$ 625,177**	**$ 525,759**	**$ 647,752**	**$ 587,666**	**$ 900,454**	**$ 4,217,855**

FORM III
Schedule 5

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2011 SUMMER SEASON COG RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
November 2010 - October 2011

New Hampshire	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
Throughput IN													
BTU Factor	1.039	1.039	1.046	1.049	1.048	1.041	1.027	1.043	1.039	1.038	1.041	1.042	
GST Meter Throughput (MCF)	569,708	849,169	1,045,428	914,419	780,093	493,361	356,512	270,436	244,612	266,618	284,943	411,448	6,486,747
Salem Meter (MCF)	31,154	57,324	67,178	57,567	45,512	25,940	16,128	11,573	9,849	10,962	11,554	20,294	365,035
GST Meter Throughpurt (DTH)	591,927	882,287	1,093,518	959,226	817,537	513,589	366,138	282,065	254,152	276,749	296,626	428,729	6,762,541
Salem Meter (DTH)	32,369	59,560	70,268	60,388	47,697	27,004	16,563	12,071	10,233	11,379	12,028	21,146	380,705
LNG/Propane													-
Total Throughput	624,296	941,846	1,163,786	1,019,613	865,234	540,592	382,701	294,135	264,385	288,128	308,653	449,875	7,143,246
Throughput OUT													
Residential Gas													
Charged	107,248	195,796	291,469	327,102	254,646	192,084	99,021	60,207	39,982	32,065	35,704	42,794	1,678,118
Uncharged Current	80,135	148,473	168,349	135,111	164,902	93,513	54,059	36,548	23,711	26,200	30,507	67,389	1,028,898
Uncharged Prior	(50,075)	(80,135)	(148,473)	(168,349)	(135,111)	(164,902)	(93,513)	(54,059)	(36,548)	(23,711)	(26,200)	(30,507)	(1,011,583)
Total Residential Gas	**137,308**	**264,134**	**311,345**	**293,864**	**284,436**	**120,695**	**59,567**	**42,695**	**27,145**	**34,555**	**40,010**	**79,677**	1,695,433
Interruptible	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	-
<u>*Commercial/Industrial Gas*</u>													
Charged	121,973	208,217	342,640	350,674	278,007	203,456	105,557	73,565	51,650	45,133	51,409	58,886	1,891,167
Uncharged Current	82,007	151,318	195,063	145,510	181,239	100,854	60,304	50,260	31,891	37,106	37,702	65,381	1,138,634
Uncharged Prior	(48,382)	(82,007)	(151,318)	(195,063)	(145,510)	(181,239)	(100,854)	(60,304)	(50,260)	(31,891)	(37,106)	(37,702)	(1,121,636)
Total C/I Gas	**155,597**	**277,528**	**386,386**	**301,121**	**313,736**	**123,071**	**65,006**	**63,521**	**33,281**	**50,348**	**52,005**	**86,565**	1,908,166
Transportation													
Charged	292,350	379,482	438,660	419,294	396,434	311,797	245,934	206,899	186,227	199,963	218,544	240,520	3,536,104
Uncharged Current	133,472	208,493	192,682	145,148	206,752	127,983	106,878	102,924	75,397	102,105	102,288	155,863	1,659,984
Uncharged Prior	(115,721)	(133,472)	(208,493)	(192,682)	(145,148)	(206,752)	(127,983)	(106,878)	(102,924)	(75,397)	(102,105)	(102,288)	(1,619,842)
Total Transportation	**310,101**	**454,503**	**422,850**	**371,759**	**458,038**	**233,029**	**224,829**	**202,945**	**158,700**	**226,671**	**218,726**	**294,095**	**3,576,246**
Company Use	**37**	**85**	**145**	**141**	**104**	**76**	**31**	**29**	**22**	**21**	**28**	**102**	**821**
Total Throughput OUT	**603,043**	**996,250**	**1,120,725**	**966,885**	**1,056,314**	**476,871**	**349,433**	**309,190**	**219,149**	**311,595**	**310,769**	**460,439**	**7,180,666**
Total Throughput IN	**624,296**	**941,846**	**1,163,786**	**1,019,613**	**865,234**	**540,592**	**382,701**	**294,135**	**264,385**	**288,128**	**308,653**	**449,875**	**7,143,246**
Difference IN/OUT	21,252	(54,404)	43,060	52,728	(191,080)	63,721	33,268	(15,055)	45,236	(23,467)	(2,116)	(10,563)	(37,420)
%													-0.52%

Attachment A

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
DEFERRED SUMMER SEASON WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
November 2010 - October 2011

SUMMER SEASON - Acct 182.21

		BEGINNING BALANCE	WORKING CAP ALLOWANCE (1)	WORKING CAP PERCENTAGE	WORKING CAP COLLECTIONS	WORKING CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
		A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
November 2010	$	(7,494)	(2)	0.0564%	(163)	(165)	(7,659)	(7,577)	3.25%	(21)	(7,680)
December	$	(7,680)	(12)	0.0564%	1	(11)	(7,690)	(7,685)	3.25%	(21)	(7,711)
January 2011	$	(7,711)	0	0.0564%	6	6	(7,705)	(7,708)	3.25%	(21)	(7,726)
February	$	(7,726)	0	0.0564%	(1)	(1)	(7,727)	(7,727)	3.25%	(21)	(7,748)
March	$	(7,748)	0	0.0564%	0	0	(7,748)	(7,748)	3.25%	(21)	(7,769)
April	$	(7,769)	1	0.0564%	0	1	(7,768)	(7,768)	3.25%	(21)	(7,789)
May	$	(7,789)	537	0.0564%	1,222	1,759	(6,030)	(6,909)	3.25%	(19)	(6,048)
June	$	(6,048)	353	0.0564%	420	773	(5,275)	(5,662)	3.25%	(15)	(5,291)
July	$	(5,291)	297	0.0564%	598	895	(4,396)	(4,843)	3.25%	(13)	(4,409)
August	$	(4,409)	365	0.0564%	540	905	(3,504)	(3,957)	3.25%	(11)	(3,515)
September	$	(3,515)	331	0.0564%	630	962	(2,554)	(3,034)	3.25%	(8)	(2,562)
October	$	(2,562)	508	0.0564%	1,101	1,609	(953)	(1,757)	3.25%	(5)	(958)
Totals			2,379		4,353					(196)	

Attachment B

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SUMMER SEASON BAD DEBT EXPENSE - CALCULATION OF COLLECTION ALLOWANCE
November 2010 - October 2011

SUMMER SEASON- Acct 182.22

	BEGINNING BALANCE	BAD DEBT ALLOWANCE(1)	% ALLOWED BAD DEBT	BAD DEBT COLLECTIONS	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
November 2010	3,159	(15)	0.45%	(1,297)	(1,312)	1,847	2,503	3.25%	7	1,854
December	1,854	(92)	0.45%	7	(85)	1,769	1,811	3.25%	5	1,774
January 2011	1,774	0	0.45%	23	23	1,797	1,785	3.25%	5	1,802
February	1,802	0	0.45%	(5)	(5)	1,796	1,799	3.25%	5	1,801
March	1,801	0	0.45%	1	1	1,802	1,801	3.25%	5	1,807
April	1,807	11	0.45%	(0)	11	1,818	1,812	3.25%	5	1,823
May	1,823	4,288	0.45%	(5,982)	(1,694)	129	976	3.25%	3	131
June	131	2,815	0.45%	(2,036)	779	910	521	3.25%	1	912
July	912	2,367	0.45%	(2,995)	(628)	284	598	3.25%	2	286
August	286	2,917	0.45%	(2,731)	186	472	379	3.25%	1	473
September	473	2,646	0.45%	(3,158)	(512)	(39)	217	3.25%	1	(39)
October	(39)	4,054	0.45%	(5,345)	(1,290)	(1,329)	(684)	3.25%	(2)	(1,331)
Totals		18,991		(23,518)					37	

(1) Bad Debt Allowance calculated by multiplying Bad Debt % by Gas Cost on Schedule 4 and Working Capital Allowance on Attachment A.

Attachment C
Page 1 of 2

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
SUMMER SEASON 2011

	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	TOTAL
Forecast Calendar Month Sales	164,519	104,668	82,572	94,844	113,688	179,773	740,064
Actual Sales	126,835	106,131	61,043	84,833	91,773	164,726	635,341
Difference	(37,684)	1,463	(21,529)	(10,011)	(21,915)	(15,047)	(104,723)
Add:							
Volume Variance due to Weather							
Normal Cal. Month Actual Sales	128,741	106,131	61,043	84,833	91,773	215,607	688,128
Actual Sales	126,835	106,131	61,043	84,833	91,773	164,726	635,341
Weather Variance	1,906	-	-	-	-	50,881	52,787
Total Variance Excluding Weather (excl weather effect)	(35,778)	1,463	(21,529)	(10,011)	(21,915)	35,834	(51,936)
Variance-difference due to meter count							(5,942)
-difference in load pattern							(45,995)
SALES							(51,937)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
SUMMER SEASON 2011

	NORMAL MMBtu			METERS		
	2011 Forecast	**2011 Actual**	**Difference**	**2011 Forecast**	**2011 Actual**	**Difference**
Res Heat	316,150	297,304	(18,846)	124,419	123,170	(1,249)
Res General	11,319	11,945	626	9,702	9,878	176
Total Res	327,469	309,249	(18,220)	134,121	133,048	(1,073)
G-40	87,368	95,090	7,722	25,152	24,971	(181)
G-50	72,599	70,067	(2,532)	5,460	5,421	(39)
G-41	131,026	120,820	(10,206)	2,210	2,194	(16)
G-51	96,646	79,198	(17,448)	907	900	(7)
G-42	10,791	10,444	(347)	70	69	(1)
G-52	14,164	3,258	(10,906)	30	30	(0)
Total C & I	412,594	378,877	(33,717)	33,829	33,585	(244)
Total Company	740,063	688,126	(51,937)	167,950	166,633	(1,317)

	NORMAL AVERAGE USE			Change In:			
	2011 Forecast	**2011 Actual**	**Difference**	**Meter Count**	**Load Pattern**	**Total Chg MMBtu**	**% Difference**
Res Heat	2.54	2.41	(0.13)	(3,174)	(15,672)	(18,846)	-5.96%
Res General	1.17	1.21	0.04	205	421	626	5.53%
Total Res	3.71	3.62	(0.08)	(2,968)	(15,252)	(18,220)	-5.56%
G-40	3.47	3.81	0.33	(630)	8,352	7,722	8.84%
G-50	13.30	12.93	(0.37)	(523)	(2,009)	(2,532)	-3.49%
G-41	59.29	55.07	(4.22)	(944)	(9,262)	(10,206)	-7.79%
G-51	106.61	88.00	(18.61)	(697)	(16,751)	(17,448)	-18.05%
G-42	155.26	151.36	(3.90)	(78)	(269)	(347)	-3.22%
G-52	468.73	108.60	(360.13)	(102)	(10,804)	(10,906)	-77.00%
Total C & I	12.20	11.28	(0.92)	(2,974)	(30,743)	(33,717)	-8.17%
Total Company	4.41	4.13	(0.28)	(5,942)	(45,995)	(51,937)	-7.02%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2011 SUMMER PERIOD RECONCILIATION
November 2010 - October 2011

Recalculated Reconciliation

FORM III
Schedule 1
Updated July 2012

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2011 SUMMER SEASON COG RECONCILIATION
SCHEDULE 1: SUMMARY OF SUMMER PERIOD BALANCE
November 2010 - October 2011

	AMOUNT	
Summer Period Beg. Balance	$95,523	SCHEDULE 2
Less: Reported Collections	($4,448,096)	SCHEDULE 2
Add: Cost of Firm Gas Allowable	$4,228,267	SCHEDULE 4
Add: Interest	($9,832)	SCHEDULE 2
Summer Period Ending Balance	($134,138)	

FORM III
Schedule 2
Updated July 2012

NORTHERN UTILTIES, INC. - NEW HAMPSHIRE DIVISION
2011 SUMMER SEASON COG RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED SUMMER PERIOD ACCOUNTS
November 2010 - October 2011
Acct 191.10

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
SUMMER SEASON													
Summer Season Account Beginning Balance	$ 95,523	$ (321,940)	$ (339,223)	$ (334,875)	$ (337,344)	$ (338,091)	$ (336,872)	$ (570,307)	$ (335,463)	$ (338,402)	$ (213,832)	$ (149,436)	$ 95,523
Plus: Cost of Firm Gas (Schedule 4)	$ (3,438)	$ (18,729)	$ -	$ -	$ -	$ 2,279	$ 952,836	$ 627,334	$ 527,342	$ 649,002	$ 589,416	$ 902,224	$ 4,228,267
Less: Reported Collections (Schedule 3)	$ (413,719)	$ 2,341	$ 5,259	$ (1,560)	$ 167	$ (147)	$ (1,185,045)	$ (391,265)	$ (529,369)	$ (523,685)	$ (524,529)	$ (886,543)	$ (4,448,096)
Summer Season Account Ending Balance	$ (321,634)	$ (338,328)	$ (333,963)	$ (336,435)	$ (337,178)	$ (335,959)	$ (569,080)	$ (334,238)	$ (337,491)	$ (213,085)	$ (148,945)	$ (133,754)	$ (124,306)
Month's Average Balance	$ (113,055)	$ (330,134)	$ (336,593)	$ (335,655)	$ (337,261)	$ (337,025)	$ (452,976)	$ (452,272)	$ (336,477)	$ (275,743)	$ (181,388)	$ (141,595)	
Interest Rate (Prime Rate)	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
Interest Applied	$ (306)	$ (894)	$ (912)	$ (909)	$ (913)	$ (913)	$ (1,227)	$ (1,225)	$ (911)	$ (747)	$ (491)	$ (383)	$ (9,832)
Summer Season Account Ending Balance w/int	$ (321,940)	$ (339,223)	$ (334,875)	$ (337,344)	$ (338,091)	$ (336,872)	$ (570,307)	$ (335,463)	$ (338,402)	$ (213,832)	$ (149,436)	$ (134,138)	$ (134,138)

FORM III
Schedule 3

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2011 SUMMER SEASON COG RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2010 - October 2011

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
Accrued Revenue	$ (718,726)	$ -	$ -	$ -	$ -	$ -	$ 768,209	$ (474,534)	$ (52,089)	$ 49,568	$ (13,923)	$ 320,377	$ (121,116)
Billed Revenue	$ 1,132,445	$ (2,341)	$ (5,259)	$ 1,560	$ (167)	$ 147	$ 416,835	$ 865,798	$ 581,458	$ 474,117	$ 538,452	$ 566,166	$ 4,569,213
Calendarized Revenue	**$ 413,719**	**$ (2,341)**	**$ (5,259)**	**$ 1,560**	**$ (167)**	**$ 147**	**$ 1,185,045**	**$ 391,265**	**$ 529,369**	**$ 523,685**	**$ 524,529**	**$ 886,543**	**$ 4,448,096**

FORM III
Schedule 4
Updated July 2012 **Page 1 of 2**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2011 SUMMER SEASON COG RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO SUMMER SEASON
November 2010 - October 2011

Commodity Costs:	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Total**
DTE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 582,422	$ -	$ -	$ -	$ -	**$ 582,422**
Distrigas	$ 180,377	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 16,330	**$ 196,708**
Emera Energy	$ 65,785	$ 3,974	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 69,758**
JP Morgan	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 330,448	$ -	$ -	**$ 330,448**
Portland	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 51	$ 68	$ 66	**$ 184**
Repsol	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 267,049	$ 269,506	$ 608,931	$ 236,891	**$ 1,382,377**
Sempra	$ 4,956	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 4,956**
Sequent	$ 5,108	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 5,108**
South Jersey Resources	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 145,318	$ -	$ -	$ -	**$ 145,318**
Sprague Energy	$ 160,952	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 160,952**
Tennessee	$ 2,952	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,021	$ 2,657	$ 2,666	$ 2,701	$ 2,638	**$ 19,636**
Total Gas & Power	$ 309,204	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 309,204**
Virginia Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 338,212	$ 181,647	$ -	$ -	$ 284,920	**$ 804,780**
Subtotal	$ 729,333	$ 3,974	$ -	$ -	$ -	$ -	$ -	$ 926,656	$ 596,671	$ 602,670	$ 611,700	$ 540,845	**$ 4,011,849**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 960,537	$ 596,763	$ 604,312	$ 611,632	$ 529,963	$ 648,112	**$ 3,951,319**
Commodity Cost Reversals	$ (746,407)	$ -	$ -	$ -	$ -	$ -	$ -	$ (960,537)	$ (596,763)	$ (604,312)	$ (611,632)	$ (529,963)	**$ (4,049,614)**
Subtotal - Supply	$ (17,074)	$ 3,974	$ -	$ -	$ -	$ -	$ 960,537	$ 562,882	$ 604,220	$ 609,990	$ 530,031	$ 658,994	**$ 3,913,554**
Withdrawal Charges	$ (5,102)	$ -	$ -	$ -	$ -	$ -	$ (529)	$ 752	$ (297)	$ 775	$ (2,678)	$ (137)	**$ (7,216)**
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 90,239	$ 18,793	$ 3,583	$ (17,344)	$ 6,329	$ 41,345	**$ 142,946**
Company Managed	$ (7,267)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ (7,267)**
Non Traditional Sales	$ (69,697)	$ -	$ -	$ -	$ -	$ -	$ -	$ (340,132)	$ (164,840)	$ (283,329)	$ (162,598)	$ (170,241)	**$ (1,190,837)**
Net OBA Adj.	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,291	$ (8,977)	$ (8,710)	$ 988	$ 2,973	$ (10,532)	**$ (20,967)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,900	$ 4,436	$ 6,889	$ 5,731	$ 6,764	$ 4,524	**$ 34,244**
Transportation Charges	$ 14,248	$ (24,452)	$ -	$ -	$ -	$ 2,535	$ -	$ 1,394	$ (6,202)	$ -	$ 2,017	$ (5,696)	**$ (16,157)**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,188	$ 1,833	$ 916	$ 1,090	$ 1,206	$ 66,231	**$ 95,463**
Allocation Adjustments	$ (30)	$ 1,750	$ -	$ -	$ -	$ (256)	$ 439	$ 2,157	$ 1,582	$ 1,250	$ 1,750	$ 1,770	**$ 10,412**
Subtotal	$ (67,848)	$ (22,703)	$ -	$ -	$ -	$ 2,279	$ 123,527	$ (319,743)	$ (167,078)	$ (290,838)	$ (144,238)	$ (72,737)	**$ (959,379)**
Sales for Resale Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ (340,132)	$ (164,840)	$ (283,544)	$ (162,598)	$ (167,879)	$ (60,816)	**$ (1,179,809)**
Sales for Resale Reversals	$ 81,484	$ -	$ -	$ -	$ -	$ -	$ -	$ 340,132	$ 164,840	$ 283,544	$ 162,598	$ 167,879	**$ 1,200,477**
Total Commodity Costs	**$ (3,438)**	**$ (18,729)**	**$ -**	**$ -**	**$ -**	**$ 2,279**	**$ 743,932**	**$ 418,430**	**$ 318,438**	**$ 440,098**	**$ 380,512**	**$ 693,320**	**$ 2,974,843**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2011 SUMMER SEASON COG RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO SUMMER SEASON
November 2010 - October 2011

Demand Costs

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
Forecasted Summer Demand Costs (DG 1	$ -	$ -	$ -	$ -	$ -	$ -	$ 204,577	$ 204,577	$ 204,577	$ 204,577	$ 204,577	$ 204,577	**$ 1,227,460**
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,327	$ 4,327	$ 4,327	$ 4,327	$ 4,327	$ 4,327	**$ 25,964**
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 208,904**	**$ 208,904**	**$ 208,904**	**$ 208,904**	**$ 208,904**	**$ 208,904**	**$ 1,253,424**
Total Gas Costs	**$ (3,438)**	**$ (18,729)**	**$ -**	**$ -**	**$ -**	**$ 2,279**	**$ 952,836**	**$ 627,334**	**$ 527,342**	**$ 649,002**	**$ 589,416**	**$ 902,224**	**$ 4,228,267**

FORM III
Schedule 5

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2011 SUMMER SEASON COG RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
November 2010 - October 2011

New Hampshire	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
Throughput IN													
BTU Factor	1.039	1.039	1.046	1.049	1.048	1.041	1.027	1.043	1.039	1.038	1.041	1.042	
GST Meter Throughput (MCF)	569,708	849,169	1,045,428	914,419	780,093	493,361	356,512	270,436	244,612	266,618	284,943	411,448	6,486,747
Salem Meter (MCF)	31,154	57,324	67,178	57,567	45,512	25,940	16,128	11,573	9,849	10,962	11,554	20,294	365,035
GST Meter Throughpurt (DTH)	591,927	882,287	1,093,518	959,226	817,537	513,589	366,138	282,065	254,152	276,749	296,626	428,729	6,762,541
Salem Meter (DTH)	32,369	59,560	70,268	60,388	47,697	27,004	16,563	12,071	10,233	11,379	12,028	21,146	380,705
LNG/Propane													-
Total Throughput	624,296	941,846	1,163,786	1,019,613	865,234	540,592	382,701	294,135	264,385	288,128	308,653	449,875	7,143,246
Throughput OUT													
Residential Gas													
Charged	107,248	195,796	291,469	327,102	254,646	192,084	99,021	60,207	39,982	32,065	35,704	42,794	1,678,118
Uncharged Current	80,135	148,473	168,349	135,111	164,902	93,513	54,059	36,548	23,711	26,200	30,507	67,389	1,028,898
Uncharged Prior	(50,075)	(80,135)	(148,473)	(168,349)	(135,111)	(164,902)	(93,513)	(54,059)	(36,548)	(23,711)	(26,200)	(30,507)	(1,011,583)
Total Residential Gas	**137,308**	**264,134**	**311,345**	**293,864**	**284,436**	**120,695**	**59,567**	**42,695**	**27,145**	**34,555**	**40,010**	**79,677**	1,695,433
Interruptible	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	-
Commercial/Industrial Gas													
Charged	121,973	208,217	342,640	350,674	278,007	203,456	105,557	73,565	51,650	45,133	51,409	58,886	1,891,167
Uncharged Current	82,007	151,318	195,063	145,510	181,239	100,854	60,304	50,260	31,891	37,106	37,702	65,381	1,138,634
Uncharged Prior	(48,382)	(82,007)	(151,318)	(195,063)	(145,510)	(181,239)	(100,854)	(60,304)	(50,260)	(31,891)	(37,106)	(37,702)	(1,121,636)
Total C/I Gas	**155,597**	**277,528**	**386,386**	**301,121**	**313,736**	**123,071**	**65,006**	**63,521**	**33,281**	**50,348**	**52,005**	**86,565**	1,908,166
Transportation													
Charged	292,350	379,482	438,660	419,294	396,434	311,797	245,934	206,899	186,227	199,963	218,544	240,520	3,536,104
Uncharged Current	133,472	208,493	192,682	145,148	206,752	127,983	106,878	102,924	75,397	102,105	102,288	155,863	1,659,984
Uncharged Prior	(115,721)	(133,472)	(208,493)	(192,682)	(145,148)	(206,752)	(127,983)	(106,878)	(102,924)	(75,397)	(102,105)	(102,288)	(1,619,842)
Total Transportation	**310,101**	**454,503**	**422,850**	**371,759**	**458,038**	**233,029**	**224,829**	**202,945**	**158,700**	**226,671**	**218,726**	**294,095**	**3,576,246**
Company Use	**37**	**85**	**145**	**141**	**104**	**76**	**31**	**29**	**22**	**21**	**28**	**102**	**821**
Total Throughput OUT	**603,043**	**996,250**	**1,120,725**	**966,885**	**1,056,314**	**476,871**	**349,433**	**309,190**	**219,149**	**311,595**	**310,769**	**460,439**	**7,180,666**
Total Throughput IN	**624,296**	**941,846**	**1,163,786**	**1,019,613**	**865,234**	**540,592**	**382,701**	**294,135**	**264,385**	**288,128**	**308,653**	**449,875**	**7,143,246**
Difference IN/OUT	21,252	(54,404)	43,060	52,728	(191,080)	63,721	33,268	(15,055)	45,236	(23,467)	(2,116)	(10,563)	(37,420)
%													-0.52%

Attachment A
Updated July 2012

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
DEFERRED SUMMER SEASON WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
November 2010 - October 2011

SUMMER SEASON - Acct 182.21

	BEGINNING BALANCE	WORKING CAP ALLOWANCE (1)	WORKING CAP PERCENTAGE	WORKING CAP COLLECTIONS	WORKING CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
November 2010	$ (7,512)	(2)	0.0564%	(163)	(165)	(7,678)	(7,595)	3.25%	(21)	(7,698)
December	$ (7,698)	(11)	0.0564%	1	(10)	(7,708)	(7,703)	3.25%	(21)	(7,729)
January 2011	$ (7,729)	0	0.0564%	6	6	(7,723)	(7,726)	3.25%	(21)	(7,744)
February	$ (7,744)	0	0.0564%	(1)	(1)	(7,745)	(7,744)	3.25%	(21)	(7,766)
March	$ (7,766)	0	0.0564%	0	0	(7,766)	(7,766)	3.25%	(21)	(7,787)
April	$ (7,787)	1	0.0564%	0	1	(7,785)	(7,786)	3.25%	(21)	(7,806)
May	$ (7,806)	537	0.0564%	1,222	1,759	(6,047)	(6,927)	3.25%	(19)	(6,066)
June	$ (6,066)	354	0.0564%	420	774	(5,292)	(5,679)	3.25%	(15)	(5,307)
July	$ (5,307)	297	0.0564%	598	896	(4,412)	(4,859)	3.25%	(13)	(4,425)
August	$ (4,425)	366	0.0564%	540	906	(3,519)	(3,972)	3.25%	(11)	(3,530)
September	$ (3,530)	332	0.0564%	630	963	(2,567)	(3,049)	3.25%	(8)	(2,576)
October	$ (2,576)	509	0.0564%	1,101	1,610	(966)	(1,771)	3.25%	(5)	(971)
Totals		2,385		4,353					(197)	

(1) Working Capital Allowance calculated by taking Total Gas Costs on Sch 4, page 2 of 2, and multiplying by (6.33/365) * Interest Rate

Attachment B
Updated July 2012

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SUMMER SEASON BAD DEBT EXPENSE - CALCULATION OF COLLECTION ALLOWANCE
November 2010 - October 2011

SUMMER SEASON- Acct 182.22

	BEGINNING BALANCE	BAD DEBT ALLOWANCE(1)	% ALLOWED BAD DEBT	BAD DEBT COLLECTIONS	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
November 2010	3,030	(15)	0.45%	(1,297)	(1,312)	1,717	2,374	3.25%	6	1,724
December	1,724	(84)	0.45%	7	(77)	1,647	1,685	3.25%	5	1,651
January 2011	1,651	0	0.45%	23	23	1,674	1,663	3.25%	5	1,679
February	1,679	0	0.45%	(5)	(5)	1,674	1,676	3.25%	5	1,678
March	1,678	0	0.45%	1	1	1,679	1,678	3.25%	5	1,683
April	1,683	10	0.45%	(0)	10	1,693	1,688	3.25%	5	1,698
May	1,698	4,290	0.45%	(5,982)	(1,692)	6	852	3.25%	2	8
June	8	2,825	0.45%	(2,036)	789	797	402	3.25%	1	798
July	798	2,374	0.45%	(2,995)	(621)	177	488	3.25%	1	179
August	179	2,922	0.45%	(2,731)	191	370	274	3.25%	1	371
September	371	2,654	0.45%	(3,158)	(504)	(133)	119	3.25%	0	(133)
October	(133)	4,062	0.45%	(5,345)	(1,282)	(1,415)	(774)	3.25%	(2)	(1,417)
Totals		19,038		(23,518)					33	

(1) Bad Debt Allowance calculated by multiplying Bad Debt % by Gas Cost on Schedule 4 and Working Capital Allowance on Attachment A.

Attachment C
Page 1 of 2

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
SUMMER SEASON 2011

	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	TOTAL
Forecast Calendar Month Sales	164,519	104,668	82,572	94,844	113,688	179,773	740,064
Actual Sales	126,835	106,131	61,043	84,833	91,773	164,726	635,341
Difference	(37,684)	1,463	(21,529)	(10,011)	(21,915)	(15,047)	(104,723)
Add:							
Volume Variance due to Weather							
Normal Cal. Month Actual Sales	128,741	106,131	61,043	84,833	91,773	215,607	688,128
Actual Sales	126,835	106,131	61,043	84,833	91,773	164,726	635,341
Weather Variance	1,906	-	-	-	-	50,881	52,787
Total Variance Excluding Weather (excl weather effect)	(35,778)	1,463	(21,529)	(10,011)	(21,915)	35,834	(51,936)
Variance-difference due to meter count							(5,942)
-difference in load pattern							(45,995)
SALES							(51,937)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
SUMMER SEASON 2011

	NORMAL MMBtu			METERS		
	2011 Forecast	2011 Actual	Difference	2011 Forecast	2011 Actual	Difference
Res Heat	316,150	297,304	(18,846)	124,419	123,170	(1,249)
Res General	11,319	11,945	626	9,702	9,878	176
Total Res	327,469	309,249	(18,220)	134,121	133,048	(1,073)
G-40	87,368	95,090	7,722	25,152	24,971	(181)
G-50	72,599	70,067	(2,532)	5,460	5,421	(39)
G-41	131,026	120,820	(10,206)	2,210	2,194	(16)
G-51	96,646	79,198	(17,448)	907	900	(7)
G-42	10,791	10,444	(347)	70	69	(1)
G-52	14,164	3,258	(10,906)	30	30	(0)
Total C & I	412,594	378,877	(33,717)	33,829	33,585	(244)
Total Company	740,063	688,126	(51,937)	167,950	166,633	(1,317)

	NORMAL AVERAGE USE			Change in Sales Due to Change In:			
	2011 Forecast	2011 Actual	Difference	Meter Count	Load Pattern	Total Chg MMBtu	% Difference
Res Heat	2.54	2.41	(0.13)	(3,174)	(15,672)	(18,846)	-5.96%
Res General	1.17	1.21	0.04	205	421	626	5.53%
Total Res	3.71	3.62	(0.08)	(2,968)	(15,252)	(18,220)	-5.56%
G-40	3.47	3.81	0.33	(630)	8,352	7,722	8.84%
G-50	13.30	12.93	(0.37)	(523)	(2,009)	(2,532)	-3.49%
G-41	59.29	55.07	(4.22)	(944)	(9,262)	(10,206)	-7.79%
G-51	106.61	88.00	(18.61)	(697)	(16,751)	(17,448)	-18.05%
G-42	155.26	151.36	(3.90)	(78)	(269)	(347)	-3.22%
G-52	468.73	108.60	(360.13)	(102)	(10,804)	(10,906)	-77.00%
Total C & I	12.20	11.28	(0.92)	(2,974)	(30,743)	(33,717)	-8.17%
Total Company	4.41	4.13	(0.28)	(5,942)	(45,995)	(51,937)	-7.02%

Schedule 11

Maine Division
Original and Revised 2009 Off-Peak Period Reconciliation

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009 OFF-PEAK PERIOD RECONCILIATION
November 2008 - October 2009

Original Reconciliation - Conformed

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 1: OFF PEAK DEMAND SUMMARY
November 2008 - October 2009

		AMOUNT	
Off-Peak Demand Beginning Balance	$	949,042	SCHEDULE 2
Less: Cost of Firm Gas Revenue (Demand)	$	(1,707,415)	SCHEDULE 2
Add: Cost of Firm Gas Allowable (Demand)	$	1,285,602	SCHEDULE 2
Add: Interest	$	22,111	SCHEDULE 2
Off-Peak Demand Ending Balance	$	549,340	

FORM III
Schedule 1
Page 2 of 2
Conformed to Current Presentation

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 1: OFF PEAK COMMODITY SUMMARY
November 2008 - October 2009

		AMOUNT	
Off-Peak Commodity Beginning Balance	$	316,255	SCHEDULE 2
Less: Cost of Firm Gas Revenue (Commodity)	$	(3,521,000)	SCHEDULE 2
Add: Cost of Firm Gas Allowable (Commodity)	$	3,595,126	SCHEDULE 2
Add: Interest	$	(15,761)	SCHEDULE 2
Off-Peak Summer Commodity Ending Balance	$	374,620	
Net Off-Peak Demand and Commodity Ending Balance	$	923,960	

FORM III
Schedule 2
Conformed to Current Presentation

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED OFF PEAK PERIOD ACCOUNTS
November 2008 - October 2009

		Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
1	**OFF PEAK DEMAND - ACCOUNT 191.10**													
2	Off Peak Demand Account Beginning Balance	$ 949,042	$ 731,256	$ 733,007	$ 735,347	$ 737,770	$ 740,250	$ 743,002	$ 720,657	$ 602,100	$ 571,245	$ 614,495	$ 659,498	$ 949,042
3	Plus: Cost of Gas Demand Allowable (Schedule 4)	$ -	$ -	$ -	$ -	$ -	$ -	$ 216,028	$ 213,138	$ 213,791	$ 213,422	$ 213,251	$ 215,972	$ 1,285,602
4	Less: Cost of Gas Demand Revenue (Schedule 3)	$ (220,373)	$ -	$ -	$ -	$ -	$ -	$ (240,876)	$ (332,834)	$ (245,644)	$ (171,170)	$ (169,308)	$ (327,211)	$ (1,707,415)
5	**Preliminary Ending Balance**	**$ 728,669**	**$ 731,256**	**$ 733,007**	**$ 735,347**	**$ 737,770**	**$ 740,250**	**$ 718,153**	**$ 600,961**	**$ 570,247**	**$ 613,497**	**$ 658,438**	**$ 548,259**	**$ 527,229**
6	Month's Average Balance ((Line 2 + Line 5) / 2)	$ 838,856	$ 731,256	$ 733,007	$ 735,347	$ 737,770	$ 740,250	$ 730,577	$ 660,809	$ 586,173	$ 592,371	$ 636,467	$ 603,878	
7	Interest Rate (Short Term Borrowing Rate)	3.700%	2.874%	3.831%	3.954%	4.033%	4.461%	4.112%	2.067%	2.044%	2.022%	1.998%	2.148%	
8	Interest Applied (Line 6 * (Line 7 / 12))	$ 2,586	$ 1,751	$ 2,340	$ 2,423	$ 2,480	$ 2,752	$ 2,503	$ 1,138	$ 998	$ 998	$ 1,060	$ 1,081	$ 22,111
9	**Off Peak Demand Account Ending Balance**(1)	**$ 731,256**	**$ 733,007**	**$ 735,347**	**$ 737,770**	**$ 740,250**	**$ 743,002**	**$ 720,657**	**$ 602,100**	**$ 571,245**	**$ 614,495**	**$ 659,498**	**$ 549,340**	**$ 549,340**

(1) Off Peak Period Ending Balance of $735,895 approved by Commission Order dated April 28, 2009, in Docket No. 2009-63. This figure is reduced by $4,639 to reflect final revenue for Nov-08.

		Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
10	**OFF PEAK COMMODITY - ACCOUNT 191.09**													
11	Off Peak Commodity Account Beginning Balance	$ 316,255	$ (695,396)	$ (697,061)	$ (699,287)	$ (701,591)	$ (703,949)	$ (706,566)	$ 6,639	$ (370,117)	$ (408,533)	$ (456,987)	$ (614,816)	$ 316,255
12	Plus: Cost of Gas Commodity Allowable (Schedule 4)	$ 1,691	$ -	$ -	$ -	$ -	$ -	$ 1,114,074	$ 190,843	$ 377,462	$ 245,837	$ 128,374	$ 1,536,845	$ 3,595,126
13	Less: Cost of Gas Commodity Revenue (Schedule 3)	$ (1,012,758)	$ -	$ -	$ -	$ -	$ -	($399,673)	($567,286)	($415,215)	($293,563)	($285,311)	($547,194)	$ (3,521,000)
14	**Preliminary Ending Balance**	**$ (694,812)**	**$ (695,396)**	**$ (697,061)**	**$ (699,287)**	**$ (701,591)**	**$ (703,949)**	**$ 7,836**	**$ (369,804)**	**$ (407,870)**	**$ (456,259)**	**$ (613,924)**	**$ 374,835**	**$ 390,381**
15	Month's Average Balance ((Line 10 + Line 15) / 2)	$ (189,278)	$ (695,396)	$ (697,061)	$ (699,287)	$ (701,591)	$ (703,949)	$ (349,365)	$ (181,583)	$ (388,993)	$ (432,396)	$ (535,456)	$ (119,991)	
16	Interest Rate (Short Term Borrowing Rate)	3.700%	2.874%	3.831%	3.954%	4.033%	4.461%	4.112%	2.067%	2.044%	2.022%	1.998%	2.148%	
17	Interest Applied (Line 16 * (Line 17 / 12))	$ (584)	$ (1,665)	$ (2,225)	$ (2,304)	$ (2,358)	$ (2,617)	$ (1,197)	$ (313)	$ (663)	$ (729)	$ (892)	$ (215)	$ (15,761)
18	**Off Peak Commodity Account Ending Balance**(1)	**$ (695,396)**	**$ (697,061)**	**$ (699,287)**	**$ (701,591)**	**$ (703,949)**	**$ (706,566)**	**$ 6,639**	**$ (370,117)**	**$ (408,533)**	**$ (456,987)**	**$ (614,816)**	**$ 374,620**	**$ 374,620**

(1) Off Peak Period Ending Balance of ($695,396) approved by Commission Order dated April 28, 2009, in Docket No. 2009-63.

FORM III
Schedule 3
Conformed to Current Presentation

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: BILLED REVENUE
November 2008 - October 2009

	November	December	January	February	March	April	May	June	July	August	September	October	Total
Demand Revenue	$ 220,373	$ -	$ -	$ -	$ -	$ -	$ 240,876	$ 332,834	$ 245,644	$ 171,170	$ 169,308	$ 327,211	$ 1,707,415
Commodity Revenue	$ 1,012,758	$ -	$ -	$ -	$ -	$ -	$ 399,673	$ 567,286	$ 415,215	$ 293,563	$ 285,311	$ 547,194	$ 3,521,000
Total Revenue	**$ 1,233,131**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 640,549**	**$ 900,119**	**$ 660,859**	**$ 464,734**	**$ 454,618**	**$ 874,405**	**$ 5,228,416**

FORM III
Schedule 4
Page 1 of 2
Conformed to Current Presentation

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO OFF PEAK PERIOD
November 2008 - November 2009

Commodity Costs	**November (Actual)**	**December (Actual)**	**January (Actual)**	**February (Actual)**	**March (Actual)**	**April (Actual)**	**May (Actual)**	**June (Actual)**	**July (Actual)**	**August (Actual)**	**September (Actual)**	**October (Actual)**	**Total Summer**
Anadarka Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 27,631	$ 37,675	$ 26,338	$ 17,660	$ 52,662	$ 161,966
Distrigas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DTE Energy Trading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,228	$ -	$ -	$ -	$ 10,228
Emera Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 61,975	$ 49,474	$ 83,366	$ 43,466	$ 33,883	$ 272,163
Hess	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,357	$ -	$ -	$ -	$ 13,357
JP Morgan	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 214,189	$ 126,417	$ 256,617	$ 166,575	$ -	$ 763,799
South Jersey Resources	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 42,611	$ 42,611
Tennessee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,208	$ 1,549	$ 961	$ -	$ 3,509	$ 7,228
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 305,002	$ 238,701	$ 367,283	$ 227,701	$ 132,666	**$ 1,271,352**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 379,840	$ 237,605	$ 357,586	$ 226,942	$ 139,894	$ 753,881	$ 2,095,748
Commodity Cost Reversals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (379,840)	$ (237,605)	$ (357,586)	$ (226,942)	$ (139,894)	$ (1,341,867)
Subtotal	$ -	$ -	$ -	$ -	$ -	$ -	$ 379,840	$ 162,767	$ 358,682	$ 236,639	$ 140,653	$ 746,653	**$ 2,025,233**
Withdrawal Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,079	$ 1,069	$ (1,440)	$ 927	$ (478)	$ 160	$ 1,318
Interruptible Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ (357)	$ -	$ (8,271)	$ (3,039)	$ (7,529)	$ (10,732)	$ (29,929)
Non Traditional Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,469)	$ -	$ -	$ -	$ (10,543)	$ -	$ (16,012)
Net OBA Adj.	$ -	$ -	$ -	$ -	$ -	$ -	$ 39,658	$ 814	$ 697	$ 209	$ 313	$ 28,489	$ 70,180
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ (12,578)	$ -	$ -	$ -	$ -	$ -	$ (12,578)
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,676	$ -	$ 11,464	$ 5,190	$ 4,731	$ 4,392	$ 30,453
Transportation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ (13,803)	$ 19,185	$ 10,276	$ -	$ (5,738)	$ (117,603)	$ (107,683)
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 720,340	$ 6,408	$ 5,628	$ 5,391	$ 6,407	$ 884,270	$ 1,628,444
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ 688	$ 600	$ 427	$ 522	$ 558	$ 1,215	$ 4,010
Prior Period Adjustments	$ 1,691	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,691
Subtotal	$ 1,691	$ -	$ -	$ -	$ -	$ -	$ 734,234	$ 28,076	$ 18,780	$ 9,199	$ (12,279)	$ 790,192	**$ 1,569,893**
Total Commodity Costs	**$ 1,691**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,114,074**	**$ 190,843**	**$ 377,462**	**$ 245,837**	**$ 128,374**	**$ 1,536,845**	**$ 3,595,126**

FORM III
Schedule 4
Page 2 of 2
Conformed to Current Presentation

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO OFF PEAK PERIOD
November 2008 - November 2009

Demand Costs	November (Actual)	December (Actual)	January (Actual)	February (Actual)	March (Actual)	April (Actual)	May (Actual)	June (Actual)	July (Actual)	August (Actual)	September (Actual)	October (Actual)	Total Summer
Summer Demand Costs (Fcst 2009-250)	$ -	$ -	$ -	$ -	$ -	$ -	$ 210,249	$ 210,249	$ 210,249	$ 210,249	$ 210,249	$ 210,249	$ 1,261,492
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,780	$ 2,889	$ 3,543	$ 3,173	$ 3,002	$ 5,723	$ 24,110
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 216,028**	**$ 213,138**	**$ 213,791**	**$ 213,422**	**$ 213,251**	**$ 215,972**	**$ 1,285,602**
Total Gas Costs	**$ 1,691**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,330,102**	**$ 403,981**	**$ 591,253**	**$ 459,259**	**$ 341,624**	**$ 1,752,817**	**$ 4,880,728**

FORM III
Schedule 5

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
November 2008 - October 2009

	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
Maine													
Throughput IN													
BTU Factor	1.05	1.049	1.038	1.038	1.042	1.044	1.068	1.047	1.056	1.022	1.054	1.0498	
GST Meter Throughput (MCF)	573,246	823,030	1,085,298	777,310	724,644	436,305	315,350	262,374	243,827	234,846	229,378	403,099	6,108,707
Kittery Meter (MCF)	93,642	122,039	138,443	122,552	124,353	95,094	58,567	48,524	53,025	49,244	50,689	63,360	1,019,532
GST Meter Throughput (DTH)	601,908	863,358	1,126,539	806,848	755,079	455,502	336,794	274,706	257,481	240,013	241,764	423,173	6,383,166
Kittery Meter (DTH)	98,324	128,019	143,704	127,209	129,576	99,278	62,550	50,805	55,994	50,327	53,426	66,515	1,065,727
Cotton Road (Lewiston)(DTH)	92,617	154,585	186,528	168,014	136,986	81,507	44,584	32,997	32,760	34,060	75,004	93,008	1,132,650
LNG/Propane	800	1,036	794	814	1,268	1,446	952	1,068	1,139	1,495	1,323	1,097	13,232
Total Throughput	793,649	1,146,998	1,457,565	1,102,885	1,022,909	637,734	444,879	359,575	347,375	325,895	371,518	583,794	8,594,776
Throughput OUT													
Residential Gas													
Charged	66,620	135,800	206,476	192,347	166,446	105,256	56,461	22,684	49,411	21,758	24,033	39,237	1,086,531
Uncharged Current	67,000	52,562	99,461	87,869	69,728	29,217	22,514	2,109	17,517	13,812	20,920	34,608	517,317
Uncharged Prior	-40,762	-67,000	-52,562	-99,461	-87,869	-69,728	-29,217	-22,514	-2,109	-17,517	-13,812	-20,920	-523,471
Total Residential Gas	**92,858**	**121,362**	**253,376**	**180,754**	**148,305**	**64,746**	**49,758**	**2,279**	**64,819**	**18,053**	**31,142**	**52,925**	**1,080,376**
Interruptible	**3,452**	**10**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**3,462**
Commercial/Industrial Gas													
Charged	135,788	284,237	382,918	336,601	317,804	169,155	112,209	83,467	66,893	110,730	77,805	87,814	2,165,421
Uncharged Current	139,000	109,818	186,026	150,259	131,280	38,421	44,764	29,462	23,049	26,073	26,344	55,542	960,038
Uncharged Prior	-61,913	-139,000	-109,818	-186,026	-150,259	-131,280	-38,421	-44,764	-29,462	-23,049	-26,073	-26,344	-966,409
Total C/I Gas	**212,875**	**255,055**	**459,127**	**300,833**	**298,825**	**76,297**	**118,552**	**68,164**	**60,481**	**113,754**	**78,075**	**117,012**	**2,159,050**
Transportation													
Charged	365,111	611,165	733,616	615,292	605,788	425,771	318,773	267,430	241,386	289,592	231,949	343,039	5,048,912
Uncharged Current	35,000	54,033	92,913	76,157	67,182	25,609	28,601	77,564	69,107	27,300	125,449	167,050	845,966
Uncharged Prior	-25,717	-35,000	-54,033	-92,913	-76,157	-67,182	-25,609	-28,601	-77,564	-69,107	-27,300	-125,449	-704,632
Total Transportation	**374,394**	**630,198**	**772,496**	**598,535**	**596,814**	**384,198**	**321,766**	**316,393**	**232,928**	**247,784**	**330,098**	**384,640**	**5,190,245**
Company Use	**128**	**770**	**1,035**	**909**	**875**	**427**	**1,278**	**297**	**150**	**153**	**60**	**290**	**6,371**
Total Throughput OUT	**683,707**	**1,007,394**	**1,486,033**	**1,081,032**	**1,044,818**	**525,668**	**491,354**	**387,134**	**358,379**	**379,743**	**439,375**	**554,867**	**8,439,504**
Total Throughput IN	**793,649**	**1,146,998**	**1,457,565**	**1,102,885**	**1,022,909**	**637,734**	**444,879**	**359,575**	**347,375**	**325,895**	**371,518**	**583,794**	**8,594,776**
Difference IN/OUT	109,942	139,605	-28,468	21,853	-21,909	112,066	-46,475	-27,559	-11,005	-53,848	-67,858	28,927	155,272
%													1.81%

Attachment A
Conformed to Current Presentation

NORTHERN UTILITIES, INC. - MAINE DIVISION
DEFERRED OFF-PEAK WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
Period Ending October 31, 2009

OFF PEAK DEMAND - ACCOUNT 182.20

	BEGINNING BALANCE	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	(D)	E = B + (D)	F = A + E	G = (A + F) / 2	H	I = G * (H/12)	J = F + I
NOVEMBER	3,129	0	0.4410%	(1,118)	(1,118)	2,011	2,570	3.70%	8	2,018
DECEMBER	2,018	0	0.4410%	0	0	2,018	2,018	2.87%	5	2,023
JANAUARY 2009	2,023	0	0.4410%	0	0	2,023	2,023	3.83%	6	2,030
FEBRUARY	2,030	0	0.4410%	0	0	2,030	2,030	3.95%	7	2,036
MARCH	2,036	0	0.4410%	0	0	2,036	2,036	4.03%	7	2,043
APRIL	2,043	0	0.4410%	0	0	2,043	2,043	4.46%	8	2,051
MAY	2,051	953	0.4410%	(933)	20	2,071	2,061	4.11%	7	2,078
JUNE	2,078	940	0.4410%	(1,325)	(385)	1,693	1,885	2.07%	3	1,696
JULY	1,696	943	0.4410%	(968)	(25)	1,671	1,684	2.04%	3	1,674
AUGUST	1,674	941	0.4410%	(684)	258	1,932	1,803	2.02%	3	1,935
SEPTEMBER	1,935	940	0.4410%	(665)	275	2,210	2,073	2.00%	3	2,214
OCTOBER	2,214	952	0.4410%	(1,275)	(323)	1,891	2,052	2.15%	4	1,894
Totals		5,670		(6,968)					64	

OFF PEAK COMMODITY - ACCOUNT 182.21

	BEGINNING BALANCE	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	(D)	E = B + (D)	F = A + E	G = (A + F) / 2	H	I = G * (H/12)	J = F + I
NOVEMBER	1,286	7	0.4410%	(4,660)	(4,652)	(3,366)	(1,040)	3.70%	(3)	(3,369)
DECEMBER	(3,369)	0	0.4410%	0	0	(3,369)	(3,369)	2.87%	(8)	(3,378)
JANAUARY 2009	(3,378)	0	0.4410%	0	0	(3,378)	(3,378)	3.83%	(11)	(3,388)
FEBRUARY	(3,388)	0	0.4410%	0	0	(3,388)	(3,388)	3.95%	(11)	(3,399)
MARCH	(3,399)	0	0.4410%	0	0	(3,399)	(3,399)	4.03%	(11)	(3,411)
APRIL	(3,411)	0	0.4410%	0	0	(3,411)	(3,411)	4.46%	(13)	(3,424)
MAY	(3,424)	4,913	0.4410%	(1,696)	3,217	(206)	(1,815)	4.11%	(6)	(213)
JUNE	(213)	842	0.4410%	(2,409)	(1,567)	(1,780)	(996)	2.07%	(2)	(1,782)
JULY	(1,782)	1,665	0.4410%	(1,762)	(97)	(1,879)	(1,830)	2.04%	(3)	(1,882)
AUGUST	(1,882)	1,084	0.4410%	(1,246)	(162)	(2,043)	(1,963)	2.02%	(3)	(2,047)
SEPTEMBER	(2,047)	566	0.4410%	(1,210)	(644)	(2,691)	(2,369)	2.00%	(4)	(2,695)
OCTOBER	(2,695)	6,777	0.4410%	(2,321)	4,457	1,762	(466)	2.15%	(1)	1,761
Totals		15,855		(15,303)					(76)	
Combined Totals		21,524		(22,271)					(13)	

Attachment B
Conformed to Current Presentation

NORTHERN UTILITIES, INC - MAINE DIVISION
DEFERRED OFF PEAK 2009 BAD DEBT CALCULATION OF COLLECTION ALLOWANCE
Period Ending October 31, 2009

ACCOUNT 182.22

DEFERRED ACCT 518216

	BEG. BAL	MAINE GAS COSTS PER BOOKS ALLOWED FOR BAD DEBT	BAD DEBT % ALLOWED	ACTUAL BAD DEBT ALLOWANCE(1)	ACTUAL BAD DEBT COLLECTION	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	(E)	F = D + (E)	G = A + F	H = (A+G)/2	I = G*(H/12)	J = F + I	
NOVEMBER	10,331	1,698	1.06%	18	(13,233)	(13,215)	(2,884)	3,723	3.70%	11	(2,873)
DECEMBER	(2,873)	0	1.06%	0	0	0	(2,873)	(2,873)	2.87%	(7)	(2,880)
JANUARY 2009	(2,880)	0	1.06%	0	0	0	(2,880)	(2,880)	3.83%	(9)	(2,889)
FEBRUARY	(2,889)	0	1.06%	0	0	0	(2,889)	(2,889)	3.95%	(10)	(2,898)
MARCH	(2,898)	0	1.06%	0	0	0	(2,898)	(2,898)	4.03%	(10)	(2,908)
APRIL	(2,908)	0	1.06%	0	0	0	(2,908)	(2,908)	4.46%	(11)	(2,919)
MAY	(2,919)	1,335,968	1.06%	14,161	(6,359)	7,802	4,883	982	4.11%	3	4,886
JUNE	4,886	405,763	1.06%	4,301	(9,033)	(4,732)	154	2,520	2.07%	4	159
JULY	159	593,861	1.06%	6,295	(6,635)	(340)	(182)	(12)	2.04%	(0)	(182)
AUGUST	(182)	461,284	1.06%	4,890	(4,700)	190	8	(87)	2.02%	(0)	8
SEPTEMBER	8	343,131	1.06%	3,637	(4,568)	(930)	(922)	(457)	2.00%	(1)	(923)
OCTOBER	(923)	1,760,547	1.06%	18,662	(8,736)	9,926	9,003	4,040	2.15%	7	9,010
Totals				51,964	(53,264)					(21)	

(1) Bad Debt Allowance calculated by multiplying Bad Debt % Allowed times Gas Cost on Schedule 4 and Working Capital Allowance on Attachment A.

Attachment C
Page 1 of 2

NORTHERN UTILITIES - MAINE DIVISION
SALES VARIANCE ANALYSIS
OFF PEAK PERIOD 2009

	May	June	July	August	September	October	Total
Forecast Calendar Month Sales	207,320	103,103	102,533	90,463	89,903	136,882	730,204
Actual Calendar Month Sales	168,670	106,151	116,305	132,488	101,839	127,051	752,504
Difference	(38,650)	3,048	13,772	42,025	11,936	(9,831)	22,300
Add:							
Volume Variance due to Weather							
Normal Calendar Month Sales	168,310	70,443	125,301	131,806	109,217	169,937	775,014
Actual Calendar Month Sales	168,670	106,151	116,305	132,488	101,839	127,051	752,504
Weather Variance	(360)	(35,708)	8,996	(682)	7,379	42,886	22,511
Total Variance Excluding Weather	(39,010)	(32,660)	22,768	41,343	19,314	33,055	44,810
Variance-change in meter count							(327)
-change in load pattern							(73,391)
							(73,718)

Attachment C
Page 2 of 2

NORTHERN UTILITIES - MAINE DIVISION
SALES VARIANCE ANALYSIS
OFF PEAK PERIOD 2009

	Normal Mcf			Meters		
	2009 Actual	2009 Forecast	Difference	2009 Actual	2009 Forecast	Difference
Res Heat	195,543	187,677	7,866	79,716	76,510	3,206
Res Non Heat	29,676	28,291	1,385	29,467	30,232	(765)
Total Res	**225,219**	**215,968**	**9,251**	**109,183**	**106,742**	**2,441**
G-50	70,878	77,781	(6,903)	9,002	9,756	(754)
G-40	121,589	135,298	(13,709)	27,014	26,678	336
G-51	62,919	88,726	(25,807)	641	752	(111)
G-41	121,259	149,691	(28,432)	2,118	2,199	(81)
G-52	29,576	51,175	(21,599)	47	24	23
G-42	25,045	11,564	13,481	39	42	(3)
Total Commercial and Industrial	**431,266**	**514,235**	**(82,969)**	**38,861**	**39,451**	**(590)**
Total Company	656,485	730,203	(73,718)	148,044	146,193	1,851

	Normal Average Use			Change in Sales Due to Change in:		Total	
	2009 Actual	2009 Forecast	Difference	Meter Count	Load Pattern	Total Change Mcf	% Difference
Res Heat	2.45	2.45	-	7,855	11	7,866	4.19%
Res Non Heat	1.01	0.94	0.07	(773)	2,158	1,385	4.90%
Total Res	**2.06**	**2.02**	**0.04**	**7,082**	**2,169**	**9,251**	**4.28%**
G-50	7.87	7.97	(0.10)	(5,934)	(969)	(6,903)	-8.87%
G-40	4.50	5.07	(0.57)	1,512	(15,221)	(13,709)	-10.13%
G-51	98.16	117.99	(19.83)	(10,896)	(14,911)	(25,807)	-29.09%
G-41	57.25	68.07	(10.82)	(4,637)	(23,795)	(28,432)	-18.99%
G-52	629.28	2,132.29	(1,503.01)	14,473	(36,072)	(21,599)	-42.21%
G-42	642.18	275.33	366.85	(1,927)	15,408	13,481	116.58%
Total Commercial and Industrial	**11.10**	**13.03**	**(1.93)**	**(7,409)**	**(75,560)**	**(82,969)**	**-16.13%**
Total Company	4.43	4.99	(0.56)	(327)	(73,391)	(73,718)	-10.10%

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009 OFF-PEAK PERIOD RECONCILIATION
November 2008 - October 2009

Recalculated Reconciliation

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 1: OFF PEAK DEMAND SUMMARY
November 2008 - October 2009

		AMOUNT	
Off-Peak Demand Beginning Balance	$	949,042	SCHEDULE 2
Less: Cost of Firm Gas Revenue (Demand)	$	(1,707,415)	SCHEDULE 2
Add: Cost of Firm Gas Allowable (Demand)	$	1,285,602	SCHEDULE 2
Add: Interest	$	22,111	SCHEDULE 2
Off-Peak Demand Ending Balance	$	549,340	

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 1: OFF PEAK COMMODITY SUMMARY
November 2008 - October 2009

		AMOUNT	
Off-Peak Commodity Beginning Balance	$	316,255	SCHEDULE 2
Less: Cost of Firm Gas Revenue (Commodity)	$	(3,521,000)	SCHEDULE 2
Add: Cost of Firm Gas Allowable (Commodity)	$	3,592,104	SCHEDULE 2
Add: Interest	$	(15,772)	SCHEDULE 2
Off-Peak Summer Commodity Ending Balance	$	371,587	
Net Off-Peak Demand and Commodity Ending Balance	$	920,927	

FORM III
Updated July 2012 Schedule 2

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED OFF PEAK PERIOD ACCOUNTS
November 2008 - October 2009

	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
OFF PEAK DEMAND - ACCOUNT 191.10													
Off Peak Demand Account Beginning Balance	$ 949,042	$ 731,256	$ 733,007	$ 735,347	$ 737,770	$ 740,250	$ 743,002	$ 720,657	$ 602,100	$ 571,245	$ 614,495	$ 659,498	$ 949,042
Plus: Cost of Gas Demand Allowable (Schedule 4)	$ -	$ -	$ -	$ -	$ -	$ -	$ 216,028	$ 213,138	$ 213,791	$ 213,422	$ 213,251	$ 215,972	$ 1,285,602
Less: Cost of Gas Demand Revenue (Schedule 3)	$ (220,373)	$ -	$ -	$ -	$ -	$ -	$ (240,876)	$ (332,834)	$ (245,644)	$ (171,170)	$ (169,308)	$ (327,211)	$ (1,707,415)
Preliminary Ending Balance	**$ 728,669**	**$ 731,256**	**$ 733,007**	**$ 735,347**	**$ 737,770**	**$ 740,250**	**$ 718,153**	**$ 600,961**	**$ 570,247**	**$ 613,497**	**$ 658,438**	**$ 548,259**	**$ 527,229**
Month's Average Balance ((Line 2 + Line 5) / 2)	$ 838,856	$ 731,256	$ 733,007	$ 735,347	$ 737,770	$ 740,250	$ 730,577	$ 660,809	$ 586,173	$ 592,371	$ 636,467	$ 603,878	
Interest Rate (Short Term Borrowing Rate)	3.700%	2.874%	3.831%	3.954%	4.033%	4.461%	4.112%	2.067%	2.044%	2.022%	1.998%	2.148%	
Interest Applied (Line 6 * (Line 7 / 12))	$ 2,586	$ 1,751	$ 2,340	$ 2,423	$ 2,480	$ 2,752	$ 2,503	$ 1,138	$ 998	$ 998	$ 1,060	$ 1,081	$ 22,111
Off Peak Demand Account Ending Balance (1)	**$ 731,256**	**$ 733,007**	**$ 735,347**	**$ 737,770**	**$ 740,250**	**$ 743,002**	**$ 720,657**	**$ 602,100**	**$ 571,245**	**$ 614,495**	**$ 659,498**	**$ 549,340**	**$ 549,340**

(1) Off Peak Period Ending Balance of $735,895 approved by Commission Order dated April 28, 2009, in Docket No. 2009-63. This figure is reduced by $4,639 to reflect final revenue for Nov-08.

	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
OFF PEAK COMMODITY - ACCOUNT 191.09													
Off Peak Commodity Account Beginning Balance	$ 316,255	$ (695,396)	$ (697,061)	$ (699,287)	$ (701,591)	$ (703,949)	$ (706,566)	$ 6,846	$ (370,774)	$ (408,944)	$ (458,339)	$ (617,630)	$ 316,255
Plus: Cost of Gas Commodity Allowable (Schedule 4)	$ 1,691	$ -	$ -	$ -	$ -	$ -	$ 1,114,281	$ 189,979	$ 377,708	$ 244,899	$ 126,915	$ 1,536,631	$ 3,592,104
Less: Cost of Gas Commodity Revenue (Schedule 3)	$ (1,012,758)	$ -	$ -	$ -	$ -	-	($399,673)	($567,286)	($415,215)	($293,563)	($285,311)	($547,194)	$ (3,521,000)
Preliminary Ending Balance	**$ (694,812)**	**$ (695,396)**	**$ (697,061)**	**$ (699,287)**	**$ (701,591)**	**$ (703,949)**	**$ 8,043**	**$ (370,460)**	**$ (408,281)**	**$ (457,609)**	**$ (616,735)**	**$ 371,807**	**$ 387,359**
Month's Average Balance ((Line 10 + Line 15) / 2)	$ (189,278)	$ (695,396)	$ (697,061)	$ (699,287)	$ (701,591)	$ (703,949)	$ (349,261)	$ (181,807)	$ (389,527)	$ (433,277)	$ (537,537)	$ (122,911)	
Interest Rate (Short Term Borrowing Rate)	3.700%	2.874%	3.831%	3.954%	4.033%	4.461%	4.112%	2.067%	2.044%	2.022%	1.998%	2.148%	
Interest Applied (Line 16 * (Line 17 / 12))	$ (584)	$ (1,665)	$ (2,225)	$ (2,304)	$ (2,358)	$ (2,617)	$ (1,197)	$ (313)	$ (663)	$ (730)	$ (895)	$ (220)	$ (15,772)
Off Peak Commodity Account Ending Balance(1)	**$ (695,396)**	**$ (697,061)**	**$ (699,287)**	**$ (701,591)**	**$ (703,949)**	**$ (706,566)**	**$ 6,846**	**$ (370,774)**	**$ (408,944)**	**$ (458,339)**	**$ (617,630)**	**$ 371,587**	**$ 371,587**

(1) Off Peak Period Ending Balance of ($695,396) approved by Commission Order dated April 28, 2009, in Docket No. 2009-63.

FORM III
Schedule 3

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 3: BILLED REVENUE
November 2008 - October 2009

	November	December	January	February	March	April	May	June	July	August	September	October	Total
Demand Revenue	$ 220,373	$ -	$ -	$ -	$ -	$ -	$ 240,876	$ 332,834	$ 245,644	$ 171,170	$ 169,308	$ 327,211	$ 1,707,415
Commodity Revenue	$ 1,012,758	$ -	$ -	$ -	$ -	$ -	$ 399,673	$ 567,286	$ 415,215	$ 293,563	$ 285,311	$ 547,194	$ 3,521,000
Total Revenue	**$ 1,233,131**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 640,549**	**$ 900,119**	**$ 660,859**	**$ 464,734**	**$ 454,618**	**$ 874,405**	**$ 5,228,416**

FORM III
Schedule 4
Updated July 2012 Page 1 of 2

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO OFF PEAK PERIOD
November 2008 - October 2009

Commodity Costs	**November**	**December**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**Total**
Anadarka Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 27,631	$ 37,675	$ 26,338	$ 17,660	$ 52,662	**$ 161,966**
Distrigas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
DTE Energy Trading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,228	$ -	$ -	$ -	**$ 10,228**
Emera Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 61,975	$ 49,474	$ 83,366	$ 43,466	$ 33,883	**$ 272,163**
Hess	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,357	$ -	$ -	$ -	**$ 13,357**
JP Morgan	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 214,189	$ 126,417	$ 256,617	$ 166,575	$ -	**$ 763,799**
South Jersey Resources	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 42,611	**$ 42,611**
Tennessee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,208	$ 1,549	$ 961	$ -	$ 3,509	**$ 7,228**
													$ -
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 305,002	$ 238,701	$ 367,283	$ 227,701	$ 132,666	**$ 1,271,352**
													$ -
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 379,840	$ 237,605	$ 357,586	$ 226,942	$ 139,894	$ 753,881	**$ 2,095,748**
Commodity Cost Reversals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (379,840)	$ (237,605)	$ (357,586)	$ (226,942)	$ (139,894)	**$ (1,341,867)**
Subtotal	$ -	$ -	$ -	$ -	$ -	$ -	$ 379,840	$ 162,767	$ 358,682	$ 236,639	$ 140,653	$ 746,653	**$ 2,025,233**
													$ -
Withdrawal Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,079	$ 1,069	$ (1,440)	$ 927	$ (478)	$ 160	**$ 1,318**
Interruptible Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ (357)	$ -	$ (8,271)	$ (3,039)	$ (7,529)	$ (10,732)	**$ (29,929)**
Non Traditional Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,469)	$ -	$ -	$ -	$ (10,543)	$ -	**$ (16,012)**
Net OBA Adj.	$ -	$ -	$ -	$ -	$ -	$ -	$ 39,658	$ 814	$ 697	$ 209	$ 313	$ 28,489	**$ 70,180**
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ (12,578)	$ -	$ -	$ -	$ -	$ -	**$ (12,578)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,676	$ -	$ 11,464	$ 5,190	$ 4,731	$ 4,392	**$ 30,453**
Transportation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ (13,803)	$ 19,185	$ 10,276	$ -	$ (5,738)	$ (117,603)	**$ (107,683)**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 720,340	$ 6,408	$ 5,628	$ 5,391	$ 6,407	$ 884,270	**$ 1,628,444**
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ 688	$ 600	$ 427	$ 522	$ 558	$ 1,215	**$ 4,010**
Prior Period Adjustments	$ 1,691	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 1,691**
Allocation Adjustments	$ -	$ -	$ -	$ -	$ -	$ -	$ 207	$ (864)	$ 246	$ (939)	$ (1,459)	$ (214)	**$ (3,022)**
Subtotal	$ 1,691	$ -	$ -	$ -	$ -	$ -	$ 734,441	$ 27,212	$ 19,026	$ 8,260	$ (13,738)	$ 789,978	**$ 1,566,871**
Total Commodity Costs	**$ 1,691**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,114,281**	**$ 189,979**	**$ 377,708**	**$ 244,899**	**$ 126,915**	**$ 1,536,631**	**$ 3,592,104**

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO OFF PEAK PERIOD
November 2008 - October 2009

Demand Costs	November	December	January	February	March	April	May	June	July	August	September	October	Total
Summer Demand Costs (Fcst 2009-250)	$ -	$ -	$ -	$ -	$ -	$ -	$ 210,249	$ 210,249	$ 210,249	$ 210,249	$ 210,249	$ 210,249	**$ 1,261,492**
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,780	$ 2,889	$ 3,543	$ 3,173	$ 3,002	$ 5,723	**$ 24,110**
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 216,028**	**$ 213,138**	**$ 213,791**	**$ 213,422**	**$ 213,251**	**$ 215,972**	**$ 1,285,602**
Total Gas Costs	**$ 1,691**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,330,309**	**$ 403,117**	**$ 591,499**	**$ 458,320**	**$ 340,166**	**$ 1,752,603**	**$ 4,877,706**

FORM III
Schedule 5

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
November 2008 - October 2009

	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
Maine													
Throughput IN													
BTU Factor	1.05	1.049	1.038	1.038	1.042	1.044	1.068	1.047	1.056	1.022	1.054	1.0498	
GST Meter Throughput (MCF)	573,246	823,030	1,085,298	777,310	724,644	436,305	315,350	262,374	243,827	234,846	229,378	403,099	6,108,707
Kittery Meter (MCF)	93,642	122,039	138,443	122,552	124,353	95,094	58,567	48,524	53,025	49,244	50,689	63,360	1,019,532
GST Meter Throughput (DTH)	601,908	863,358	1,126,539	806,848	755,079	455,502	336,794	274,706	257,481	240,013	241,764	423,173	6,383,166
Kittery Meter (DTH)	98,324	128,019	143,704	127,209	129,576	99,278	62,550	50,805	55,994	50,327	53,426	66,515	1,065,727
Cotton Road (Lewiston)(DTH)	92,617	154,585	186,528	168,014	136,986	81,507	44,584	32,997	32,760	34,060	75,004	93,008	1,132,650
LNG/Propane	800	1,036	794	814	1,268	1,446	952	1,068	1,139	1,495	1,323	1,097	13,232
Total Throughput	793,649	1,146,998	1,457,565	1,102,885	1,022,909	637,734	444,879	359,575	347,375	325,895	371,518	583,794	8,594,776
Throughput OUT													
Residential Gas													
Charged	66,620	135,800	206,476	192,347	166,446	105,256	56,461	22,684	49,411	21,758	24,033	39,237	1,086,531
Uncharged Current	67,000	52,562	99,461	87,869	69,728	29,217	22,514	2,109	17,517	13,812	20,920	34,608	517,317
Uncharged Prior	-40,762	-67,000	-52,562	-99,461	-87,869	-69,728	-29,217	-22,514	-2,109	-17,517	-13,812	-20,920	-523,471
Total Residential Gas	**92,858**	**121,362**	**253,376**	**180,754**	**148,305**	**64,746**	**49,758**	**2,279**	**64,819**	**18,053**	**31,142**	**52,925**	**1,080,376**
Interruptible	**3,452**	**10**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**3,462**
Commercial/Industrial Gas													
Charged	135,788	284,237	382,918	336,601	317,804	169,155	112,209	83,467	66,893	110,730	77,805	87,814	2,165,421
Uncharged Current	139,000	109,818	186,026	150,259	131,280	38,421	44,764	29,462	23,049	26,073	26,344	55,542	960,038
Uncharged Prior	-61,913	-139,000	-109,818	-186,026	-150,259	-131,280	-38,421	-44,764	-29,462	-23,049	-26,073	-26,344	-966,409
Total C/I Gas	**212,875**	**255,055**	**459,127**	**300,833**	**298,825**	**76,297**	**118,552**	**68,164**	**60,481**	**113,754**	**78,075**	**117,012**	**2,159,050**
Transportation													
Charged	365,111	611,165	733,616	615,292	605,788	425,771	318,773	267,430	241,386	289,592	231,949	343,039	5,048,912
Uncharged Current	35,000	54,033	92,913	76,157	67,182	25,609	28,601	77,564	69,107	27,300	125,449	167,050	845,966
Uncharged Prior	-25,717	-35,000	-54,033	-92,913	-76,157	-67,182	-25,609	-28,601	-77,564	-69,107	-27,300	-125,449	-704,632
Total Transportation	**374,394**	**630,198**	**772,496**	**598,535**	**596,814**	**384,198**	**321,766**	**316,393**	**232,928**	**247,784**	**330,098**	**384,640**	**5,190,245**
Company Use	**128**	**770**	**1,035**	**909**	**875**	**427**	**1,278**	**297**	**150**	**153**	**60**	**290**	**6,371**
Total Throughput OUT	**683,707**	**1,007,394**	**1,486,033**	**1,081,032**	**1,044,818**	**525,668**	**491,354**	**387,134**	**358,379**	**379,743**	**439,375**	**554,867**	**8,439,504**
Total Throughput IN	**793,649**	**1,146,998**	**1,457,565**	**1,102,885**	**1,022,909**	**637,734**	**444,879**	**359,575**	**347,375**	**325,895**	**371,518**	**583,794**	**8,594,776**
Difference IN/OUT	109,942	139,605	-28,468	21,853	-21,909	112,066	-46,475	-27,559	-11,005	-53,848	-67,858	28,927	155,272
%													1.81%

Updated July 2012 Attachment A

NORTHERN UTILITIES, INC. - MAINE DIVISION
DEFERRED OFF-PEAK WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
November 2008 - October 2009

OFF PEAK DEMAND - ACCOUNT 182.20

	BEGINNING BALANCE	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	(D)	E = B + (D)	F = A + E	G = (A + F) / 2	H	I = G * (H/12)	J = F + I
NOVEMBER	3,129	0	0.4410%	(1,118)	(1,118)	2,011	2,570	3.70%	8	2,018
DECEMBER	2,018	0	0.4410%	0	0	2,018	2,018	2.87%	5	2,023
JANAUARY 2009	2,023	0	0.4410%	0	0	2,023	2,023	3.83%	6	2,030
FEBRUARY	2,030	0	0.4410%	0	0	2,030	2,030	3.95%	7	2,036
MARCH	2,036	0	0.4410%	0	0	2,036	2,036	4.03%	7	2,043
APRIL	2,043	0	0.4410%	0	0	2,043	2,043	4.46%	8	2,051
MAY	2,051	953	0.4410%	(933)	20	2,071	2,061	4.11%	7	2,078
JUNE	2,078	940	0.4410%	(1,325)	(385)	1,693	1,885	2.07%	3	1,696
JULY	1,696	943	0.4410%	(968)	(25)	1,671	1,684	2.04%	3	1,674
AUGUST	1,674	941	0.4410%	(684)	258	1,932	1,803	2.02%	3	1,935
SEPTEMBER	1,935	940	0.4410%	(665)	275	2,210	2,073	2.00%	3	2,214
OCTOBER	2,214	952	0.4410%	(1,275)	(323)	1,891	2,052	2.15%	4	1,894
TOTALS		5,670		(6,968)					64	

OFF PEAK COMMODITY - ACCOUNT 182.21

	BEGINNING BALANCE	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	(D)	E = B + (D)	F = A + E	G = (A + F) / 2	H	I = G * (H/12)	J = F + I
NOVEMBER	1,286	7	0.4410%	(4,660)	(4,652)	(3,366)	(1,040)	3.70%	(3)	(3,369)
DECEMBER	(3,369)	0	0.4410%	0	0	(3,369)	(3,369)	2.87%	(8)	(3,378)
JANAUARY 2009	(3,378)	0	0.4410%	0	0	(3,378)	(3,378)	3.83%	(11)	(3,388)
FEBRUARY	(3,388)	0	0.4410%	0	0	(3,388)	(3,388)	3.95%	(11)	(3,399)
MARCH	(3,399)	0	0.4410%	0	0	(3,399)	(3,399)	4.03%	(11)	(3,411)
APRIL	(3,411)	0	0.4410%	0	0	(3,411)	(3,411)	4.46%	(13)	(3,424)
MAY	(3,424)	4,914	0.4410%	(1,696)	3,218	(205)	(1,815)	4.11%	(6)	(212)
JUNE	(212)	838	0.4410%	(2,409)	(1,571)	(1,783)	(997)	2.07%	(2)	(1,784)
JULY	(1,784)	1,666	0.4410%	(1,762)	(96)	(1,880)	(1,832)	2.04%	(3)	(1,883)
AUGUST	(1,883)	1,080	0.4410%	(1,246)	(166)	(2,049)	(1,966)	2.02%	(3)	(2,053)
SEPTEMBER	(2,053)	560	0.4410%	(1,210)	(651)	(2,703)	(2,378)	2.00%	(4)	(2,707)
OCTOBER	(2,707)	6,777	0.4410%	(2,321)	4,456	1,748	(479)	2.15%	(1)	1,748
TOTALS		15,841		(15,303)					(77)	
COMBINED TOTALS		21,511		(22,271)					(13)	

Updated July 2012 Attachment B

NORTHERN UTILITIES, INC - MAINE DIVISION
DEFERRED OFF PEAK 2009 BAD DEBT CALCULATION OF COLLECTION ALLOWANCE
November 2008 - October 2009

ACCOUNT 182.22

DEFERRED ACCT 518216

	BEG. BAL	MAINE GAS COSTS PER BOOKS ALLOWED FOR BAD DEBT	BAD DEBT % ALLOWED	ACTUAL BAD DEBT ALLOWANCE(1)	ACTUAL BAD DEBT COLLECTION	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	(E)	F = D + (E)	G = A + F	H = (A+G)/2	I = G*(H/12)	J = F + I	
NOVEMBER	10,331	1,698	1.06%	18	(13,233)	(13,215)	(2,884)	3,723	3.70%	11	(2,873)
DECEMBER	(2,873)	0	1.06%	0	0	0	(2,873)	(2,873)	2.87%	(7)	(2,880)
JANUARY 2009	(2,880)	0	1.06%	0	0	0	(2,880)	(2,880)	3.83%	(9)	(2,889)
FEBRUARY	(2,889)	0	1.06%	0	0	0	(2,889)	(2,889)	3.95%	(10)	(2,898)
MARCH	(2,898)	0	1.06%	0	0	0	(2,898)	(2,898)	4.03%	(10)	(2,908)
APRIL	(2,908)	0	1.06%	0	0	0	(2,908)	(2,908)	4.46%	(11)	(2,919)
MAY	(2,919)	1,336,176	1.06%	14,163	(6,359)	7,804	4,885	983	4.11%	3	4,888
JUNE	4,888	404,895	1.06%	4,292	(9,033)	(4,741)	147	2,518	2.07%	4	152
JULY	152	594,108	1.06%	6,298	(6,635)	(338)	(186)	(17)	2.04%	(0)	(186)
AUGUST	(186)	460,341	1.06%	4,880	(4,700)	180	(6)	(96)	2.02%	(0)	(6)
SEPTEMBER	(6)	341,666	1.06%	3,622	(4,568)	(946)	(952)	(479)	2.00%	(1)	(953)
OCTOBER	(953)	1,760,332	1.06%	18,660	(8,736)	9,923	8,970	4,009	2.15%	7	8,978
TOTALS				51,932	(53,264)					(21)	

(1) Bad Debt Allowance calculated by multiplying Bad Debt % Allowed times Gas Cost on Schedule 4 and Working Capital Allowance on Attachment A.

Attachment C
Page 1 of 2

NORTHERN UTILITIES - MAINE DIVISION
SALES VARIANCE ANALYSIS
OFF PEAK PERIOD 2009

	May	June	July	August	September	October	Total
Forecast Calendar Month Sales	207,320	103,103	102,533	90,463	89,903	136,882	730,204
Actual Calendar Month Sales	168,670	106,151	116,305	132,488	101,839	127,051	752,504
Difference	(38,650)	3,048	13,772	42,025	11,936	(9,831)	22,300
Add:							
Volume Variance due to Weather							
Normal Calendar Month Sales	168,310	70,443	125,301	131,806	109,217	169,937	775,014
Actual Calendar Month Sales	168,670	106,151	116,305	132,488	101,839	127,051	752,504
Weather Variance	(360)	(35,708)	8,996	(682)	7,379	42,886	22,511
Total Variance Excluding Weather	(39,010)	(32,660)	22,768	41,343	19,314	33,055	44,810
Variance-change in meter count							(327)
-change in load pattern							(73,391)
							(73,718)

Attachment C
Page 2 of 2

NORTHERN UTILITIES - MAINE DIVISION
SALES VARIANCE ANALYSIS
OFF PEAK PERIOD 2009

	Normal Mcf 2009 Actual	Normal Mcf 2009 Forecast	Normal Mcf Difference	Meters 2009 Actual	Meters 2009 Forecast	Meters Difference
Res Heat	195,543	187,677	7,866	79,716	76,510	3,206
Res Non Heat	29,676	28,291	1,385	29,467	30,232	(765)
Total Res	**225,219**	**215,968**	**9,251**	**109,183**	**106,742**	**2,441**
G-50	70,878	77,781	(6,903)	9,002	9,756	(754)
G-40	121,589	135,298	(13,709)	27,014	26,678	336
G-51	62,919	88,726	(25,807)	641	752	(111)
G-41	121,259	149,691	(28,432)	2,118	2,199	(81)
G-52	29,576	51,175	(21,599)	47	24	23
G-42	25,045	11,564	13,481	39	42	(3)
Total Commercial and Industrial	**431,266**	**514,235**	**(82,969)**	**38,861**	**39,451**	**(590)**
Total Company	656,485	730,203	(73,718)	148,044	146,193	1,851

	Normal Average Use 2009 Actual	Normal Average Use 2009 Forecast	Normal Average Use Difference	Change in Sales Due to Change in: Meter Count	Change in Sales Due to Change in: Load Pattern	Total Change Mcf	% Difference
Res Heat	2.45	2.45	-	7,855	11	7,866	4.19%
Res Non Heat	1.01	0.94	0.07	(773)	2,158	1,385	4.90%
Total Res	**2.06**	**2.02**	**0.04**	**7,082**	**2,169**	**9,251**	**4.28%**
G-50	7.87	7.97	(0.10)	(5,934)	(969)	(6,903)	-8.87%
G-40	4.50	5.07	(0.57)	1,512	(15,221)	(13,709)	-10.13%
G-51	98.16	117.99	(19.83)	(10,896)	(14,911)	(25,807)	-29.09%
G-41	57.25	68.07	(10.82)	(4,637)	(23,795)	(28,432)	-18.99%
G-52	629.28	2,132.29	(1,503.01)	14,473	(36,072)	(21,599)	-42.21%
G-42	642.18	275.33	366.85	(1,927)	15,408	13,481	116.58%
Total Commercial and Industrial	**11.10**	**13.03**	**(1.93)**	**(7,409)**	**(75,560)**	**(82,969)**	**-16.13%**
Total Company	4.43	4.99	(0.56)	(327)	(73,391)	(73,718)	-10.10%

Schedule 12

Maine Division
Original and Revised 2010 Off-Peak Period Reconciliation

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010 OFF-PEAK PERIOD RECONCILIATION
November 2009 - October 2010

Original Reconciliation

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 1: OFF PEAK DEMAND SUMMARY
November 2009 - October 2010

	AMOUNT	
Off-Peak Demand Beginning Balance	$ 292,734	SCHEDULE 2
Less: Cost of Firm Gas Revenue (Demand)	(836,024)	SCHEDULE 2
Add: Cost of Firm Gas Allowable (Demand)	1,020,599	SCHEDULE 2
Add: Interest	6,743	SCHEDULE 2
Off-Peak Demand Ending Balance	$ 484,052	

FORM III
Schedule 1
Page 2 of 2
Updated March 3, 2011

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 1: OFF PEAK COMMODITY SUMMARY
November 2009 - October 2010

	AMOUNT	
Off-Peak Commodity Beginning Balance	$ (50,256)	SCHEDULE 2
Less: Cost of Firm Gas Revenue (Commodity)	(3,597,550)	SCHEDULE 2
Add: Cost of Firm Gas Allowable (Commodity)	3,377,317	SCHEDULE 2
Add: Interest	(3,733)	SCHEDULE 2
Off-Peak Summer Commodity Ending Balance	$ (274,223)	
Net Off-Peak Demand and Commodity Ending Balance	$ 209,829	

FORM III
Updated March 3, 2011 **Schedule 2**

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED OFF PEAK PERIOD ACCOUNTS
November 2009 - October 2010

		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
1	**OFF PEAK DEMAND - ACCOUNT 191.10**													
2	Off Peak Demand Account Beginning Balance	$ 292,734	$ 212,254	$ 217,870	$ 214,251	$ 214,378	$ 215,185	$ 215,567	$ 249,401	$ 311,863	$ 373,457	$ 453,284	$ 499,720	$ 292,734
3	Plus: Cost of Gas Demand Allowable (Schedule 4)	$ -	$ -	$ -	$ -	$ -	$ -	$ 173,612	$ 170,616	$ 168,597	$ 168,513	$ 168,471	$ 170,790	$ 1,020,599
4	Less: Cost of Gas Demand Revenue (Schedule 3)	$ (80,951)	$ 5,217	$ (4,021)	$ (270)	$ 407	$ (22)	$ (140,228)	$ (108,703)	$ (107,669)	$ (89,470)	$ (122,931)	$ (187,382)	$ (836,024)
5	**Preliminary Ending Balance**	**$ 211,783**	**$ 217,471**	**$ 213,849**	**$ 213,980**	**$ 214,785**	**$ 215,163**	**$ 248,952**	**$ 311,314**	**$ 372,790**	**$ 452,500**	**$ 498,824**	**$ 483,128**	**$ 477,309**
6	Month's Average Balance ((Line 2 + Line 5) / 2)	$ 252,259	$ 214,862	$ 215,860	$ 214,115	$ 214,581	$ 215,174	$ 232,259	$ 280,357	$ 342,326	$ 412,979	$ 476,054	$ 491,424	
7	Interest Rate (Short Term Borrowing Rate)	2.240%	2.233%	2.232%	2.229%	2.236%	2.255%	2.323%	2.349%	2.339%	2.278%	2.257%	2.256%	
8	Interest Applied (Line 6 * (Line 7 / 12))	$ 471	$ 400	$ 401	$ 398	$ 400	$ 404	$ 450	$ 549	$ 667	$ 784	$ 895	$ 924	$ 6,743
9	**Off Peak Demand Account Ending Balance**(1)	**$ 212,254**	**$ 217,870**	**$ 214,251**	**$ 214,378**	**$ 215,185**	**$ 215,567**	**$ 249,401**	**$ 311,863**	**$ 373,457**	**$ 453,284**	**$ 499,720**	**$ 484,052**	**$ 484,052**

(1) Off Peak Period Ending Balance of $212,493 approved by Commission Order dated April 28, 2010, in Docket No. 2010-63. This figure is increased by $239 to reflect final revenue for Nov-09.

		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
10	**OFF PEAK COMMODITY - ACCOUNT 191.09**													
11	Off Peak Commodity Account Beginning Balance	$ (50,256)	$ (249,273)	$ (241,545)	$ (259,294)	$ (289,507)	$ (256,030)	$ 115,116	$ 211,134	$ 10,299	$ (169,455)	$ (224,281)	$ (488,883)	$ (50,256)
12	Plus: Cost of Gas Commodity Allowable (Schedule 4)	$ (68,405)	$ -	$ (10,284)	$ (29,260)	$ 33,323	$ 371,313	$ 729,486	$ 303,167	$ 326,270	$ 372,054	$ 306,367	$ 1,043,284	$ 3,377,317
13	Less: Cost of Gas Commodity Revenue (Schedule 3)	$ (130,333)	$ 8,185	$ (7,000)	$ (444)	$ 662	$ (34)	$ (633,784)	$ (504,219)	$ (505,869)	$ (426,506)	$ (570,299)	$ (827,907)	$ (3,597,550)
14	**Preliminary Ending Balance**	**$ (248,994)**	**$ (241,088)**	**$ (258,828)**	**$ (288,998)**	**$ (255,523)**	**$ 115,248**	**$ 210,818**	**$ 10,082**	**$ (169,300)**	**$ (223,907)**	**$ (488,213)**	**$ (273,506)**	**$ (270,490)**
15	Month's Average Balance ((Line 10 + Line 15) / 2)	$ (149,625)	$ (245,181)	$ (250,187)	$ (274,146)	$ (272,515)	$ (70,391)	$ 162,967	$ 110,608	$ (79,501)	$ (196,681)	$ (356,247)	$ (381,194)	
16	Interest Rate (Short Term Borrowing Rate)	2.240%	2.233%	2.232%	2.229%	2.236%	2.255%	2.323%	2.349%	2.339%	2.278%	2.257%	2.256%	
17	Interest Applied (Line 16 * (Line 17 / 12))	$ (279)	$ (456)	$ (465)	$ (509)	$ (508)	$ (132)	$ 315	$ 217	$ (155)	$ (373)	$ (670)	$ (717)	$ (3,733)
18	**Off Peak Commodity Account Ending Balance**(1)	**$ (249,273)**	**$ (241,545)**	**$ (259,294)**	**$ (289,507)**	**$ (256,030)**	**$ 115,116**	**$ 211,134**	**$ 10,299**	**$ (169,455)**	**$ (224,281)**	**$ (488,883)**	**$ (274,223)**	**$ (274,223)**

(1) Off Peak Period Ending Balance of ($248,877) approved by Commission Order dated April 28, 2010, in Docket No. 2010-63. This figure is increased by $396 to reflect final revenue for Nov-09.

FORM III
Schedule 3

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009 OFF-PEAK PERIOD RECONCILIATION
SCHEDULE 3: BILLED REVENUE
November 2009 - October 2010

	November 200(	December	January	February	March	April	May	June	July	August	September	October 201(	Total
Demand Revenue:													
Billed Revenue	$ 337,557	$ (5,217)	$ 4,021	$ 270	$ (407)	$ 22	$ 86,275	$ 120,634	$ 101,433	$ 87,762	$ 98,304	$ 138,615	$ 969,269
Accrued Revenue	$ (256,606)	$ -	$ -	$ -	$ -	$ -	$ 53,953	$ (11,931)	$ 6,237	$ 1,708	$ 24,627	$ 48,767	$ (133,245)
Calendarized Demand Revenue	**$ 80,951**	**$ (5,217)**	**$ 4,021**	**$ 270**	**$ (407)**	**$ 22**	**$ 140,228**	**$ 108,703**	**$ 107,669**	**$ 89,470**	**$ 122,931**	**$ 187,382**	**$ 836,024**
Commodity Revenue:													
Billed Revenue	$ 555,209	$ (8,185)	$ 7,000	$ 444	$ (662)	$ 34	$ 380,560	$ 551,678	$ 483,007	$ 417,633	$ 464,937	$ 631,948	$ 3,483,605
Accrued Revenue	$ (424,877)	$ -	$ -	$ -	$ -	$ -	$ 253,224	$ (47,458)	$ 22,862	$ 8,874	$ 105,362	$ 195,959	$ 113,946
Calendarized Commodity Revenu	**$ 130,333**	**$ (8,185)**	**$ 7,000**	**$ 444**	**$ (662)**	**$ 34**	**$ 633,784**	**$ 504,219**	**$ 505,869**	**$ 426,506**	**$ 570,299**	**$ 827,907**	**$ 3,597,550**

FORM III
Schedule 4
Updated March 3, 2011 Page 1 of 2

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO OFF PEAK PERIOD
November 2009 - October 2010

Commodity Costs	**lovember 200**	**December**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October 2010**	**Total Off Peak**
Anadarka Energy	$ 75,358	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 75,358
Distrigas	$ 4,603	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,603
Emera Energy	$ 106,267	$ -	$ -	$ -	$ 34,741	$ -	$ -	$ 57,261	$ 57,760	$ 64,783	$ 99,565	$ 51,000	$ 471,377
Hess	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 220,313	$ 37,388	$ -	$ -	$ 257,701
JP Morgan	$ 355,365	$ -	$ -	$ -	$ -	$ -	$ -	$ 254,263	$ -	$ -	$ -	$ -	$ 609,629
Sempra	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,807	$ 4,807
South Jersey Resources	$ 140,893	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 140,893
Spark Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 45,359	$ 229,277	$ 274,636
Sprague Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 83,632	$ 84,217	$ 107,560	$ 106,349	$ 112,629	$ 494,386
Tennessee	$ 2,990	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,589	$ 1,633	$ 1,870	$ 1,811	$ 2,544	$ 12,436
Total Gas & Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 128,185	$ -	$ 128,185
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ 685,476	$ -	$ -	$ -	$ 34,741	$ -	$ -	$ 396,745	$ 363,923	$ 211,602	$ 381,269	$ 400,257	**$ 2,474,012**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 386,105	$ 364,066	$ 216,289	$ 385,303	$ 393,907	$ 706,878	$ 2,452,548
Commodity Cost Reversals	$ (753,881)	$ -	$ -	$ -	$ -	$ -	$ -	$ (386,105)	$ (364,066)	$ (216,289)	$ (385,303)	$ (393,907)	$ (2,499,551)
Subtotal	$ (68,405)	$ -	$ -	$ -	$ 34,741	$ -	$ 386,105	$ 374,706	$ 216,146	$ 380,615	$ 389,873	$ 713,228	**$ 2,427,009**
Withdrawal Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ (405)	$ (339)	$ 2,813	$ 155	$ 143	$ (643)	$ 1,725
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 230,336	$ 200,163	$ 200,267	$ (9,794)	$ (735)	$ 120,585	$ 740,822
Non Traditional Sales	$ -	$ -	$ -	$ -	$ -	$ (12,935)	$ -	$ (51,830)	$ (283,168)	$ (48,494)	$ -	$ (84,867)	$ (481,294)
Net OBA Adj.	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,413)	$ 99	$ (1,880)	$ (2,372)	$ (3,922)	$ (530)	$ (10,017)
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,751	$ 5,335	$ 4,141	$ 4,490	$ 4,546	$ 4,683	$ 27,945
Transportation Charges	$ -	$ -	$ (10,284)	$ (29,260)	$ (1,418)	$ 384,247	$ -	$ 1,134	$ (48,880)	$ (3,552)	$ (1,263)	$ (22,125)	$ 268,600
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 163,982	$ 2,139	$ 2,127	$ 1,713	$ 1,952	$ 297,788	$ 469,703
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 536	$ 554	$ 798	$ 640	$ 584	$ 3,111
Prior Period Adjustments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal	$ -	$ -	$ (10,284)	$ (29,260)	$ (1,418)	$ 371,313	$ 397,251	$ 157,237	$ (124,027)	$ (57,055)	$ 1,361	$ 315,475	**$ 1,020,594**
Sales for Resale Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ (53,870)	$ (282,645)	$ (48,494)	$ -	$ (84,867)	$ (70,286)	$ (540,163)
Sales for Resale Reversals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 53,870	$ 282,645	$ 48,494	$ -	$ 84,867	$ 469,876
Total Commodity Costs	**$ (68,405)**	**$ -**	**$ (10,284)**	**$ (29,260)**	**$ 33,323**	**$ 371,313**	**$ 729,486**	**$ 303,167**	**$ 326,270**	**$ 372,054**	**$ 306,367**	**$ 1,043,284**	**$ 3,377,317**

FORM III
Schedule 4
Updated March 3, 2011 **Page 2 of 2**

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO OFF PEAK PERIOD
November 2009 - October 2010

Demand Costs	November	December	January	February	March	April	May	June	July	August	September	October 2010	Total Off Peak
Summer Demand Costs (Fcst 2009-250)	$ -	$ -	$ -	$ -	$ -	$ -	$ 164,448	$ 164,448	$ 164,448	$ 164,448	$ 164,448	$ 164,448	$ 986,687
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,164	$ 6,168	$ 4,149	$ 4,065	$ 4,023	$ 6,342	$ 33,912
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 173,612**	**$ 170,616**	**$ 168,597**	**$ 168,513**	**$ 168,471**	**$ 170,790**	**$ 1,020,599**
Total Gas Costs	**$ (68,405)**	**$ -**	**$ (10,284)**	**$ (29,260)**	**$ 33,323**	**$ 371,313**	**$ 903,098**	**$ 473,783**	**$ 494,867**	**$ 540,567**	**$ 474,838**	**$ 1,214,074**	**$ 4,397,916**

FORM III
Schedule 5
Page 1 of 1
Updated March 3, 2011

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
November 2009 - October 2010

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
Maine													
Throughput IN													
BTU Factor	1.043	1.04354	1.043	1.045	1.04869	1.04978	1.055	1.055	1.051	1.049	1.055	1.057	
GST Meter Throughput (MCF)	507,050	835,228	890,230	703,595	564,701	394,783	309,911	236,953	205,537	220,939	205,810	365,897	5,440,634
Kittery Meter (MCF)	89,080	120,178	128,573	114,728	118,070	86,859	55,523	48,024	49,076	50,815	49,104	63,228	973,258
GST Meter Throughput (DTH)	528,853	871,594	928,510	735,257	592,196	414,435	326,956	249,985	216,019	231,765	217,130	386,753	5,699,454
Kittery Meter (DTH)	92,910	125,411	134,102	119,891	123,819	91,183	58,577	50,665	51,579	53,305	51,805	66,832	1,020,078
Cotton Road (Lewiston)(DTH)	89,983	148,885	187,409	166,726	152,016	61,625	43,400	42,073	43,388	43,411	71,996	93,220	1,144,132
LNG/Propane	900	861	1,062	1,110	1,375	1,539	1,566	1,624	1,945	1,244	1,181	1,248	15,654
Total Throughput	712,647	1,146,750	1,251,082	1,022,983	869,406	568,782	430,498	344,347	312,932	329,725	342,111	548,053	7,879,318
Throughput OUT													
Residential Gas													
Charged	78,764	114,202	206,234	169,145	131,164	97,552	57,876	33,273	26,871	22,348	24,815	34,231	996,474
Uncharged Current	43,747	92,643	89,141	78,142	67,962	42,176	13,004	10,063	11,929	12,171	19,162	33,890	514,028
Uncharged Prior	-34,608	-43,747	-92,643	-89,141	-78,142	-67,962	-42,176	-13,004	-10,063	-11,929	-12,171	-19,162	-514,746
Total Residential Gas	**87,904**	**163,097**	**202,732**	**158,146**	**120,984**	**71,765**	**28,704**	**30,331**	**28,737**	**22,590**	**31,806**	**48,959**	**995,756**
Interruptible	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Commercial/Industrial Gas													
Charged	140,996	228,668	362,528	292,022	232,086	163,484	93,487	57,323	52,883	46,195	52,033	69,760	1,791,464
Uncharged Current	78,012	162,681	157,805	137,669	123,900	71,128	26,611	22,156	23,845	24,994	34,450	50,263	913,512
Uncharged Prior	-55,542	-78,012	-162,681	-157,805	-137,669	-123,900	-71,128	-26,611	-22,156	-23,845	-24,994	-34,450	-918,791
Total C/I Gas	**163,466**	**313,337**	**357,652**	**271,886**	**218,317**	**110,712**	**48,970**	**52,868**	**54,572**	**47,344**	**61,488**	**85,573**	**1,786,186**
Transportation													
Charged	424,558	577,854	685,209	592,960	522,065	411,220	314,228	256,941	237,347	248,508	252,304	331,752	4,854,947
Uncharged Current	71,142	293,812	232,929	214,679	212,900	136,064	87,175	87,482	81,276	101,644	121,487	168,152	1,808,742
Uncharged Prior	-167,050	-71,142	-293,812	-232,929	-214,679	-212,900	-136,064	-87,175	-87,482	-81,276	-101,644	-121,487	-1,807,640
Total Transportation	**328,650**	**800,524**	**624,327**	**574,710**	**520,287**	**334,384**	**265,339**	**257,248**	**231,141**	**268,876**	**272,147**	**378,417**	**4,856,049**
Company Use	**440**	**535**	**1,144**	**870**	**802**	**693**	**337**	**162**	**145**	**120**	**121**	**254**	**5,622**
Total Throughput OUT	**580,460**	**1,277,493**	**1,185,855**	**1,005,612**	**860,390**	**517,554**	**343,349**	**340,610**	**314,595**	**338,931**	**365,562**	**513,203**	**7,643,613**
Total Throughput IN	**712,647**	**1,146,750**	**1,251,082**	**1,022,983**	**869,406**	**568,782**	**430,498**	**344,347**	**312,932**	**329,725**	**342,111**	**548,053**	**7,879,318**
Difference IN/OUT	132,187	-130,742	65,227	17,371	9,016	51,228	87,149	3,738	-1,663	-9,206	-23,452	34,850	235,705
%													2.99%

Attachment A
Page 1 of 1
Updated March 3, 2011

NORTHERN UTILITIES, INC. - MAINE DIVISION
DEFERRED OFF-PEAK WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
November 2009 - October 2010

OFF PEAK DEMAND - ACCOUNT 182.20

	BEGINNING BALANCE	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	(D)	E = B + (D)	F = A + E	G = (A + F) / 2	H	I = G * (H/12)	J = F + I
NOVEMBER	902	-	0.4410%	(301)	(301)	602	752	2.24%	1	603
DECEMBER	603	-	0.4410%	19	19	622	612	2.23%	1	623
JANAUARY 2009	623	-	0.4410%	(16)	(16)	607	615	2.23%	1	608
FEBRUARY	608	-	0.4410%	(1)	(1)	607	607	2.23%	1	608
MARCH	608	-	0.4410%	2	2	609.59	608.83	2.24%	1.13	610.72
APRIL	611	-	0.4410%	0	0	611	611	2.26%	1	612
MAY	612	766	0.4410%	(682)	84	696	654	2.32%	1	697
JUNE	697	752	0.4410%	(547)	206	903	800	2.35%	2	904
JULY	904	744	0.4410%	(545)	198	1,102	1,003	2.34%	2	1,104
AUGUST	1,104	743	0.4410%	(460)	283	1,388	1,246	2.28%	2	1,390
SEPTEMBER	1,390	743	0.4410%	(619)	124	1,514	1,452	2.26%	3	1,517
OCTOBER	1,517	753	0.4410%	(898)	(145)	1,372	1,445	2.26%	3	1,375
Totals		4,501		(4,048)					20	

OFF PEAK COMMODITY - ACCOUNT 182.21

	BEGINNING BALANCE	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	(D)	E = B + (D)	F = A + E	G = (A + F) / 2	H	I = G * (H/12)	J = F + I
NOVEMBER	(42)	(302)	0.4410%	(554)	(856)	(898)	(470)	2.24%	(1)	(899)
DECEMBER	(899)	0	0.4410%	35	35	(864)	(882)	2.23%	(2)	(866)
JANAUARY 2009	(866)	(45)	0.4410%	(30)	(75)	(941)	(904)	2.23%	(2)	(943)
FEBRUARY	(943)	(129)	0.4410%	(2)	(131)	(1,074)	(1,008)	2.23%	(2)	(1,076)
MARCH	(1,076)	147	0.4410%	3	150	(926)	(1,001)	2.24%	(2)	(928)
APRIL	(928)	1,637	0.4410%	(0)	1,637	710	(109)	2.26%	(0)	710
MAY	710	3,217	0.4410%	(2,373)	844	1,553	1,131	2.32%	2	1,555
JUNE	1,555	1,337	0.4410%	(1,888)	(551)	1,004	1,280	2.35%	3	1,007
JULY	1,007	1,439	0.4410%	(1,893)	(454)	553	780	2.34%	2	554
AUGUST	554	1,641	0.4410%	(1,597)	44	598	576	2.28%	1	599
SEPTEMBER	599	1,351	0.4410%	(2,135)	(784)	(184)	207	2.26%	0	(184)
OCTOBER	(184)	4,601	0.4410%	(3,098)	1,503	1,319	567	2.26%	1	1,320
Totals		14,894		(13,533)					1	
Combined Totals		19,395		(17,581)					20	

Attachment B
Page 1 of 1
Updated March 3, 2011

NORTHERN UTILITIES, INC - MAINE DIVISION
DEFERRED OFF PEAK 2009 BAD DEBT CALCULATION OF COLLECTION ALLOWANCE
November 2009 - October 2010

ACCOUNT 182.22

	BEG. BAL	MAINE GAS COSTS PER BOOKS ALLOWED FOR BAD DEBT	BAD DEBT % ALLOWED	ACTUAL BAD DEBT ALLOWANCE(1)	ACTUAL BAD DEBT COLLECTION	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	(E)	F = D + (E)	G = A + F	H = (A+G)/2	I = G*(H/12)	J = F + I	
NOVEMBER	2,249	(68,707)	1.06%	(728)	(2,076)	(2,804)	(555)	847	2.24%	2	(554)
DECEMBER	(554)	0	1.06%	0	130	130	(424)	(489)	2.23%	(1)	(425)
JANUARY 2009	(425)	(10,329)	1.06%	(109)	(112)	(221)	(646)	(535)	2.23%	(1)	(647)
FEBRUARY	(647)	(29,389)	1.06%	(312)	(7)	(319)	(965)	(806)	2.23%	(2)	(967)
MARCH	(967)	33,470	1.06%	355	11	365	(601)	(784)	2.24%	(1)	(603)
APRIL	(603)	372,950	1.06%	3,953	(0)	3,953	3,350	1,374	2.26%	3	3,353
MAY	3,353	907,081	1.06%	9,615	(7,530)	2,085	5,437	4,395	2.32%	9	5,446
JUNE	5,446	475,873	1.06%	5,044	(9,018)	(3,974)	1,472	3,459	2.35%	7	1,479
JULY	1,479	497,050	1.06%	5,269	(6,011)	(742)	736	1,107	2.34%	2	738
AUGUST	738	542,951	1.06%	5,755	(5,077)	678	1,417	1,078	2.28%	2	1,419
SEPTEMBER	1,419	476,933	1.06%	5,055	(6,785)	(1,729)	(311)	554	2.26%	1	(310)
OCTOBER	(310)	1,219,428	1.06%	12,926	(9,831)	3,095	2,785	1,238	2.26%	2	2,787
Totals				46,823	(46,307)					22	

(1) Bad Debt Allowance calculated by multiplying Bad Debt % Allowed times Gas Cost on Schedule 4 and Working Capital Allowance on Attachment A.

Attachment C
Page 1 of 2
Updated March 3, 2011

NORTHERN UTILITIES - MAINE DIVISION
SALES VARIANCE ANALYSIS
OFF PEAK PERIOD 2010

	May	June	July	August	September	October	Total
Forecast Calendar Month Sales (Weather Normalized)	188,238	103,949	81,033	74,683	93,101	120,220	661,224
Actual Calendar Month Sales	77,674	83,199	83,309	69,934	93,294	134,532	541,942
Volume Variance due to Weather	7,463	13,487	6,417	1,758	6,557	16,127	51,808
Weather Normal Actual Calender Sales	85,137	96,686	89,726	71,692	99,851	150,659	593,750
Total Variance in Weather Normalized Sales	(103,101)	(7,263)	8,693	(2,991)	6,750	30,439	67,474
Variance-change in meter count							(9,832)
-change in load pattern							(109,450)
							(119,282)

Attachment C
Page 2 of 2
Updated March 3, 2011

NORTHERN UTILITIES - MAINE DIVISION
SALES VARIANCE ANALYSIS
OFF PEAK PERIOD 2010

	Normal Mcf			Meters		
	2010 Actual	2010 Forecast	Difference	2010 Actual	2010 Forecast	Difference
Res Heat	161,872	200,522	(38,650)	82,024	83,547	(1,523)
Res Non Heat	29,254	27,648	1,606	29,391	28,526	865
Total Res	**191,127**	**228,170**	**(37,043)**	**111,415**	**112,073**	**(658)**
G-50	64,031	54,858	9,173	8,321	8,432	(111)
G-40	89,072	157,227	(68,155)	26,600	26,678	(78)
G-51	49,268	48,703	565	628	703	(75)
G-41	95,491	123,326	(27,835)	2,124	2,198	(74)
G-52	28,508	25,187	3,321	37	32	5
G-42	24,446	23,754	692	40	42	(2)
Total Commercial and Industrial	**350,816**	**433,055**	**(82,239)**	**37,750**	**38,085**	**(335)**
Total Company	541,943	661,225	(119,282)	149,165	150,158	(993)

	Normal Average Use			Change in Sales Due to Change in:		Total	
	2010 Actual	2010 Forecast	Difference	Meter Count	Load Pattern	Change Mcf	% Difference
Res Heat	1.97	2.40	(0.43)	(3,000)	(35,650)	(38,650)	-19.27%
Res Non Heat	1.00	0.97	0.03	865	741	1,606	5.81%
Total Res	**1.72**	**2.04**	**(0.32)**	**(2,135)**	**(34,908)**	**(37,043)**	**-16.23%**
G-50	7.70	6.51	1.19	(855)	10,028	9,173	16.72%
G-40	3.35	5.89	(2.54)	(261)	(67,894)	(68,155)	-43.35%
G-51	78.45	69.28	9.17	(5,884)	6,449	565	1.16%
G-41	44.96	56.11	(11.15)	(3,327)	(24,508)	(27,835)	-22.57%
G-52	770.49	787.09	(16.60)	3,852	(531)	3,321	13.19%
G-42	611.16	565.57	45.59	(1,222)	1,914	692	2.91%
Total Commercial and Industrial	**9.29**	**11.37**	**(2.08)**	**(7,697)**	**(74,542)**	**(82,239)**	**-18.99%**
Total Company	3.63	4.40	(0.77)	(9,832)	(109,450)	(119,282)	-18.04%

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010 OFF-PEAK PERIOD RECONCILIATION
November 2009 - October 2010

Recalculated Reconciliation

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 1: OFF PEAK DEMAND SUMMARY
November 2009 - October 2010

	AMOUNT	
Off-Peak Demand Beginning Balance	$ 292,734	SCHEDULE 2
Less: Cost of Firm Gas Revenue (Demand)	(836,024)	SCHEDULE 2
Add: Cost of Firm Gas Allowable (Demand)	1,020,599	SCHEDULE 2
Add: Interest	6,743	SCHEDULE 2
Off-Peak Demand Ending Balance	$ 484,052	

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 1: OFF PEAK COMMODITY SUMMARY
November 2009 - October 2010

	AMOUNT	
Off-Peak Commodity Beginning Balance	$ (53,289)	SCHEDULE 2
Less: Cost of Firm Gas Revenue (Commodity)	(3,597,550)	SCHEDULE 2
Add: Cost of Firm Gas Allowable (Commodity)	3,408,742	SCHEDULE 2
Add: Interest	(3,471)	SCHEDULE 2
Off-Peak Summer Commodity Ending Balance	$ (245,568)	
Net Off-Peak Demand and Commodity Ending Balance	$ 238,484	

FORM III
Updated July 2012 Schedule 2

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED OFF PEAK PERIOD ACCOUNTS
November 2009 - October 2010

		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
1	**OFF PEAK DEMAND - ACCOUNT 191.10**													
2	Off Peak Demand Account Beginning Balance	$ 292,734	$ 212,254	$ 217,870	$ 214,251	$ 214,378	$ 215,185	$ 215,567	$ 249,401	$ 311,862	$ 373,457	$ 453,284	$ 499,720	$ 292,734
3	Plus: Cost of Gas Demand Allowable (Schedule 4)	$ -	$ -	$ -	$ -	$ -	$ -	$ 173,612	$ 170,616	$ 168,597	$ 168,513	$ 168,471	$ 170,790	$ 1,020,599
4	Less: Cost of Gas Demand Revenue (Schedule 3)	$ (80,951)	$ 5,217	$ (4,021)	$ (270)	$ 407	$ (22)	$ (140,228)	$ (108,703)	$ (107,669)	$ (89,470)	$ (122,931)	$ (187,382)	$ (836,024)
5	**Preliminary Ending Balance**	**$ 211,783**	**$ 217,471**	**$ 213,849**	**$ 213,980**	**$ 214,785**	**$ 215,163**	**$ 248,951**	**$ 311,314**	**$ 372,790**	**$ 452,500**	**$ 498,824**	**$ 483,128**	**$ 477,309**
6	Month's Average Balance ((Line 2 + Line 5) / 2)	$ 252,258	$ 214,862	$ 215,860	$ 214,115	$ 214,581	$ 215,174	$ 232,259	$ 280,357	$ 342,326	$ 412,978	$ 476,054	$ 491,424	
7	Interest Rate (Short Term Borrowing Rate)	2.240%	2.233%	2.232%	2.229%	2.236%	2.255%	2.323%	2.349%	2.339%	2.278%	2.257%	2.256%	
8	Interest Applied (Line 6 * (Line 7 / 12))	$ 471	$ 400	$ 401	$ 398	$ 400	$ 404	$ 450	$ 549	$ 667	$ 784	$ 895	$ 924	$ 6,743
9	**Off Peak Demand Account Ending Balance** (1)	**$ 212,254**	**$ 217,870**	**$ 214,251**	**$ 214,378**	**$ 215,185**	**$ 215,567**	**$ 249,401**	**$ 311,862**	**$ 373,457**	**$ 453,284**	**$ 499,720**	**$ 484,052**	**$ 484,052**

(1) Off Peak Period Ending Balance of $212,493 approved by Commission Order dated April 28, 2010, in Docket No. 2010-63. This figure is increased by $239 to reflect final revenue for Nov-09.

		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
10	**OFF PEAK COMMODITY - ACCOUNT 191.09**													
11	Off Peak Commodity Account Beginning Balance	$ (53,289)	$ (257,348)	$ (249,634)	$ (268,494)	$ (301,764)	$ (267,150)	$ 143,993	$ 239,834	$ 38,913	$ (140,905)	$ (195,824)	$ (460,432)	$ (53,289)
12	Plus: Cost of Gas Commodity Allowable (Schedule 4)	$ (73,437)	$ -	$ (11,378)	$ (32,296)	$ 34,482	$ 411,292	$ 729,254	$ 303,026	$ 326,150	$ 371,907	$ 306,308	$ 1,043,434	$ 3,408,742
13	Less: Cost of Gas Commodity Revenue (Schedule 3)	$ (130,333)	$ 8,185	$ (7,000)	$ (444)	$ 662	$ (34)	$ (633,784)	$ (504,219)	$ (505,869)	$ (426,506)	$ (570,299)	$ (827,907)	$ (3,597,550)
14	**Preliminary Ending Balance**	**$ (257,058)**	**$ (249,163)**	**$ (268,013)**	**$ (301,235)**	**$ (266,620)**	**$ 144,108**	**$ 239,463**	**$ 38,640**	**$ (140,806)**	**$ (195,505)**	**$ (459,815)**	**$ (244,905)**	**$ (242,097)**
15	Month's Average Balance ((Line 10 + Line 15) / 2)	$ (155,173)	$ (253,255)	$ (258,824)	$ (284,864)	$ (284,192)	$ (61,521)	$ 191,728	$ 139,237	$ (50,946)	$ (168,205)	$ (327,820)	$ (352,668)	
16	Interest Rate (Short Term Borrowing Rate)	2.240%	2.233%	2.232%	2.229%	2.236%	2.255%	2.323%	2.349%	2.339%	2.278%	2.257%	2.256%	
17	Interest Applied (Line 16 * (Line 17 / 12))	$ (290)	$ (471)	$ (481)	$ (529)	$ (529)	$ (116)	$ 371	$ 273	$ (99)	$ (319)	$ (617)	$ (663)	$ (3,471)
18	**Off Peak Commodity Account Ending Balance** (1)	**$ (257,348)**	**$ (249,634)**	**$ (268,494)**	**$ (301,764)**	**$ (267,150)**	**$ 143,993**	**$ 239,834**	**$ 38,913**	**$ (140,905)**	**$ (195,824)**	**$ (460,432)**	**$ (245,568)**	**$ (245,568)**

(1) Off Peak Period Ending Balance of ($248,877) approved by Commission Order dated April 28, 2010, in Docket No. 2010-63. This figure is increased by $396 to reflect final revenue for Nov-09.

FORM III
Schedule 3

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010 OFF-PEAK PERIOD RECONCILIATION
SCHEDULE 3: BILLED REVENUE
November 2009 - October 2010

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
Demand Revenue:													
Billed Revenue	$ 337,557	$ (5,217)	$ 4,021	$ 270	$ (407)	$ 22	$ 86,275	$ 120,634	$ 101,433	$ 87,762	$ 98,304	$ 138,615	**$ 969,269**
Accrued Revenue	$ (256,606)	$ -	$ -	$ -	$ -	$ -	$ 53,953	$ (11,931)	$ 6,237	$ 1,708	$ 24,627	$ 48,767	**$ (133,245)**
Calendarized Demand Revenue	**$ 80,951**	**$ (5,217)**	**$ 4,021**	**$ 270**	**$ (407)**	**$ 22**	**$ 140,228**	**$ 108,703**	**$ 107,669**	**$ 89,470**	**$ 122,931**	**$ 187,382**	**$ 836,024**
Commodity Revenue:													
Billed Revenue	$ 555,209	$ (8,185)	$ 7,000	$ 444	$ (662)	$ 34	$ 380,560	$ 551,678	$ 483,007	$ 417,633	$ 464,937	$ 631,948	**$ 3,483,605**
Accrued Revenue	$ (424,877)	$ -	$ -	$ -	$ -	$ -	$ 253,224	$ (47,458)	$ 22,862	$ 8,874	$ 105,362	$ 195,959	**$ 113,946**
Calendarized Commodity Revenu	**$ 130,333**	**$ (8,185)**	**$ 7,000**	**$ 444**	**$ (662)**	**$ 34**	**$ 633,784**	**$ 504,219**	**$ 505,869**	**$ 426,506**	**$ 570,299**	**$ 827,907**	**$ 3,597,550**

FORM III
Schedule 4
Updated July 2012 **Page 1 of 2**

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO OFF PEAK PERIOD
November 2009 - October 2010

Commodity Costs	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Total**
Anadarka Energy	$ 75,358	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 75,358**
Distrigas	$ 4,603	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 4,603**
Emera Energy	$ 106,267	$ -	$ -	$ -	$ 34,741	$ -	$ -	$ 57,261	$ 57,760	$ 64,783	$ 99,565	$ 51,000	**$ 471,377**
Hess	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 220,313	$ 37,388	$ -	$ -	**$ 257,701**
JP Morgan	$ 355,365	$ -	$ -	$ -	$ -	$ -	$ -	$ 254,263	$ -	$ -	$ -	$ -	**$ 609,629**
Sempra	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,807	**$ 4,807**
South Jersey Resources	$ 140,893	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 140,893**
Spark Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 45,359	$ 229,277	**$ 274,636**
Sprague Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 83,632	$ 84,217	$ 107,560	$ 106,349	$ 112,629	**$ 494,386**
Tennessee	$ 2,990	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,589	$ 1,633	$ 1,870	$ 1,811	$ 2,544	**$ 12,436**
Total Gas & Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 128,185	$ -	**$ 128,185**
	$ 685,476	$ -	$ -	$ -	$ 34,741	$ -	$ -	$ 396,745	$ 363,923	$ 211,602	$ 381,269	$ 400,257	**$ 2,474,012**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 386,105	$ 364,066	$ 216,289	$ 385,303	$ 393,907	$ 706,878	**$ 2,452,548**
Commodity Cost Reversals	$ (753,881)	$ -	$ -	$ -	$ -	$ -	$ -	$ (386,105)	$ (364,066)	$ (216,289)	$ (385,303)	$ (393,907)	**$ (2,499,551)**
Subtotal	$ (68,405)	$ -	$ -	$ -	$ 34,741	$ -	$ 386,105	$ 374,706	$ 216,146	$ 380,615	$ 389,873	$ 713,228	**$ 2,427,009**
Withdrawal Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ (405)	$ (339)	$ 2,813	$ 155	$ 143	$ (643)	**$ 1,725**
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 230,336	$ 200,163	$ 200,267	$ (9,794)	$ (735)	$ 120,585	**$ 740,822**
Non Traditional Sales	$ -	$ -	$ -	$ -	$ -	$ (12,935)	$ -	$ (51,830)	$ (283,168)	$ (48,494)	$ -	$ (84,867)	**$ (481,294)**
Net OBA Adj.	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,413)	$ 99	$ (1,880)	$ (2,372)	$ (3,922)	$ (530)	**$ (10,017)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,751	$ 5,335	$ 4,141	$ 4,490	$ 4,546	$ 4,683	**$ 27,945**
Transportation Charges	$ -	$ -	$ (10,284)	$ (29,260)	$ (1,418)	$ 384,247	$ -	$ 1,134	$ (48,880)	$ (3,552)	$ (1,263)	$ (22,125)	**$ 268,600**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 163,982	$ 2,139	$ 2,127	$ 1,713	$ 1,952	$ 297,788	**$ 469,703**
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 536	$ 554	$ 798	$ 640	$ 584	**$ 3,111**
Allocation Adjustments	$ (5,032)	$ -	$ (1,094)	$ (3,037)	$ 1,160	$ 39,979	$ (232)	$ (141)	$ (120)	$ (148)	$ (59)	$ 150	**$ 31,425**
Subtotal	$ (5,032)	$ -	$ (11,378)	$ (32,296)	$ (258)	$ 411,292	$ 397,019	$ 157,096	$ (124,147)	$ (57,203)	$ 1,302	$ 315,625	**$ 1,052,019**
Sales for Resale Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ (53,870)	$ (282,645)	$ (48,494)	$ -	$ (84,867)	$ (70,286)	**$ (540,163)**
Sales for Resale Reversals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 53,870	$ 282,645	$ 48,494	$ -	$ 84,867	**$ 469,876**
Total Commodity Costs	**$ (73,437)**	**$ -**	**$ (11,378)**	**$ (32,296)**	**$ 34,482**	**$ 411,292**	**$ 729,254**	**$ 303,026**	**$ 326,150**	**$ 371,907**	**$ 306,308**	**$ 1,043,434**	**$ 3,408,742**

FORM III
Schedule 4
Page 2 of 2

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO OFF PEAK PERIOD
November 2009 - October 2010

Demand Costs	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
Summer Demand Costs (Fcst 2009-250)	$ -	$ -	$ -	$ -	$ -	$ -	$ 164,448	$ 164,448	$ 164,448	$ 164,448	$ 164,448	$ 164,448	**$ 986,687**
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,164	$ 6,168	$ 4,149	$ 4,065	$ 4,023	$ 6,342	**$ 33,912**
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 173,612**	**$ 170,616**	**$ 168,597**	**$ 168,513**	**$ 168,471**	**$ 170,790**	**$ 1,020,599**
Total Gas Costs	**$ (73,437)**	**$ -**	**$ (11,378)**	**$ (32,296)**	**$ 34,482**	**$ 411,292**	**$ 902,866**	**$ 473,642**	**$ 494,747**	**$ 540,420**	**$ 474,779**	**$ 1,214,224**	**$ 4,429,341**

FORM III
Schedule 5
Page 1 of 1

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
Maine													
Throughput IN													
BTU Factor	1.043	1.04354	1.043	1.045	1.04869	1.04978	1.055	1.055	1.051	1.049	1.055	1.057	
GST Meter Throughput (MCF)	507,050	835,228	890,230	703,595	564,701	394,783	309,911	236,953	205,537	220,939	205,810	365,897	5,440,634
Kittery Meter (MCF)	89,080	120,178	128,573	114,728	118,070	86,859	55,523	48,024	49,076	50,815	49,104	63,228	973,258
GST Meter Throughput (DTH)	528,853	871,594	928,510	735,257	592,196	414,435	326,956	249,985	216,019	231,765	217,130	386,753	5,699,454
Kittery Meter (DTH)	92,910	125,411	134,102	119,891	123,819	91,183	58,577	50,665	51,579	53,305	51,805	66,832	1,020,078
Cotton Road (Lewiston)(DTH)	89,983	148,885	187,409	166,726	152,016	61,625	43,400	42,073	43,388	43,411	71,996	93,220	1,144,132
LNG/Propane	900	861	1,062	1,110	1,375	1,539	1,566	1,624	1,945	1,244	1,181	1,248	15,654
Total Throughput	712,647	1,146,750	1,251,082	1,022,983	869,406	568,782	430,498	344,347	312,932	329,725	342,111	548,053	7,879,318
Throughput OUT													
Residential Gas													
Charged	78,764	114,202	206,234	169,145	131,164	97,552	57,876	33,273	26,871	22,348	24,815	34,231	996,474
Uncharged Current	43,747	92,643	89,141	78,142	67,962	42,176	13,004	10,063	11,929	12,171	19,162	33,890	514,028
Uncharged Prior	-34,608	-43,747	-92,643	-89,141	-78,142	-67,962	-42,176	-13,004	-10,063	-11,929	-12,171	-19,162	-514,746
Total Residential Gas	**87,904**	**163,097**	**202,732**	**158,146**	**120,984**	**71,765**	**28,704**	**30,331**	**28,737**	**22,590**	**31,806**	**48,959**	**995,756**
Interruptible	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Commercial/Industrial Gas													
Charged	140,996	228,668	362,528	292,022	232,086	163,484	93,487	57,323	52,883	46,195	52,033	69,760	1,791,464
Uncharged Current	78,012	162,681	157,805	137,669	123,900	71,128	26,611	22,156	23,845	24,994	34,450	50,263	913,512
Uncharged Prior	-55,542	-78,012	-162,681	-157,805	-137,669	-123,900	-71,128	-26,611	-22,156	-23,845	-24,994	-34,450	-918,791
Total C/I Gas	**163,466**	**313,337**	**357,652**	**271,886**	**218,317**	**110,712**	**48,970**	**52,868**	**54,572**	**47,344**	**61,488**	**85,573**	**1,786,186**
Transportation													
Charged	424,558	577,854	685,209	592,960	522,065	411,220	314,228	256,941	237,347	248,508	252,304	331,752	4,854,947
Uncharged Current	71,142	293,812	232,929	214,679	212,900	136,064	87,175	87,482	81,276	101,644	121,487	168,152	1,808,742
Uncharged Prior	-167,050	-71,142	-293,812	-232,929	-214,679	-212,900	-136,064	-87,175	-87,482	-81,276	-101,644	-121,487	-1,807,640
Total Transportation	**328,650**	**800,524**	**624,327**	**574,710**	**520,287**	**334,384**	**265,339**	**257,248**	**231,141**	**268,876**	**272,147**	**378,417**	**4,856,049**
Company Use	**440**	**535**	**1,144**	**870**	**802**	**693**	**337**	**162**	**145**	**120**	**121**	**254**	**5,622**
Total Throughput OUT	**580,460**	**1,277,493**	**1,185,855**	**1,005,612**	**860,390**	**517,554**	**343,349**	**340,610**	**314,595**	**338,931**	**365,562**	**513,203**	**7,643,613**
Total Throughput IN	**712,647**	**1,146,750**	**1,251,082**	**1,022,983**	**869,406**	**568,782**	**430,498**	**344,347**	**312,932**	**329,725**	**342,111**	**548,053**	**7,879,318**
Difference IN/OUT	132,187	-130,742	65,227	17,371	9,016	51,228	87,149	3,738	-1,663	-9,206	-23,452	34,850	235,705
%													2.99%

Attachment A
Updated July 2012

NORTHERN UTILITIES, INC. - MAINE DIVISION
2010 OFF-PEAK WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
November 2009 - October 2010

OFF PEAK DEMAND - ACCOUNT 182.20

	BEGINNING BALANCE	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	(D)	E = B + (D)	F = A + E	G = (A + F) / 2	H	I = G * (H/12)	J = F + I
NOVEMBER	902	-	0.4410%	(301)	(301)	601	752	2.24%	1	603
DECEMBER	603	-	0.4410%	19	19	622	612	2.23%	1	623
JANAUARY 2009	623	-	0.4410%	(16)	(16)	607	615	2.23%	1	608
FEBRUARY	608	-	0.4410%	(1)	(1)	607	607	2.23%	1	608
MARCH	608	-	0.4410%	2	2	609.49	608.73	2.24%	1.13	610.62
APRIL	611	-	0.4410%	0	0	611	611	2.26%	1	612
MAY	612	766	0.4410%	(682)	84	696	654	2.32%	1	697
JUNE	697	752	0.4410%	(547)	206	903	800	2.35%	2	904
JULY	904	744	0.4410%	(545)	198	1,102	1,003	2.34%	2	1,104
AUGUST	1,104	743	0.4410%	(460)	283	1,387	1,246	2.28%	2	1,390
SEPTEMBER	1,390	743	0.4410%	(619)	124	1,514	1,452	2.26%	3	1,517
OCTOBER	1,517	753	0.4410%	(898)	(145)	1,372	1,445	2.26%	3	1,375
TOTALS		4,501		(4,048)					20	

OFF PEAK COMMODITY - ACCOUNT 182.21

	BEGINNING BALANCE	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	(D)	E = B + (D)	F = A + E	G = (A + F) / 2	H	I = G * (H/12)	J = F + I
NOVEMBER	(55)	(324)	0.4410%	(554)	(878)	(934)	(495)	2.24%	(1)	(935)
DECEMBER	(935)	0	0.4410%	35	35	(900)	(917)	2.23%	(2)	(902)
JANAUARY 2009	(902)	(50)	0.4410%	(30)	(80)	(982)	(942)	2.23%	(2)	(983)
FEBRUARY	(983)	(142)	0.4410%	(2)	(144)	(1,128)	(1,055)	2.23%	(2)	(1,130)
MARCH	(1,130)	152	0.4410%	3	155	(975)	(1,052)	2.24%	(2)	(977)
APRIL	(977)	1,814	0.4410%	(0)	1,814	837	(70)	2.26%	(0)	837
MAY	837	3,216	0.4410%	(2,373)	843	1,679	1,258	2.32%	2	1,682
JUNE	1,682	1,336	0.4410%	(1,888)	(552)	1,130	1,406	2.35%	3	1,133
JULY	1,133	1,438	0.4410%	(1,893)	(455)	678	906	2.34%	2	680
AUGUST	680	1,640	0.4410%	(1,597)	43	723	702	2.28%	1	725
SEPTEMBER	725	1,351	0.4410%	(2,135)	(784)	(59)	333	2.26%	1	(59)
OCTOBER	(59)	4,602	0.4410%	(3,098)	1,503	1,445	693	2.26%	1	1,446
TOTALS		15,033		(13,533)					2	
COMBINED TOTALS		19,533		(17,581)					22	

Attachment B
Updated July 2012

NORTHERN UTILITIES, INC - MAINE DIVISION
2010 OFF PEAK BAD DEBT CALCULATION OF COLLECTION ALLOWANCE
November 2009 - October 2010

ACCOUNT 182.22

	BEG. BAL	MAINE GAS COSTS PER BOOKS ALLOWED FOR BAD DEBT	BAD DEBT % ALLOWED	ACTUAL BAD DEBT ALLOWANCE(1)	ACTUAL BAD DEBT COLLECTION	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	(E)	F = D + (E)	G = A + F	H = (A+G)/2	I = G*(H/12)	J = F + I	
NOVEMBER	2,217	(73,760)	1.06%	(782)	(2,076)	(2,857)	(641)	788	2.24%	1	(639)
DECEMBER	(639)	0	1.06%	0	130	130	(509)	(574)	2.23%	(1)	(511)
JANUARY 2009	(511)	(11,428)	1.06%	(121)	(112)	(233)	(743)	(627)	2.23%	(1)	(744)
FEBRUARY	(744)	(32,439)	1.06%	(344)	(7)	(351)	(1,095)	(920)	2.23%	(2)	(1,097)
MARCH	(1,097)	34,634	1.06%	367	11	378	(719)	(908)	2.24%	(2)	(721)
APRIL	(721)	413,105	1.06%	4,379	(0)	4,379	3,658	1,468	2.26%	3	3,660
MAY	3,660	906,848	1.06%	9,613	(7,530)	2,082	5,743	4,701	2.32%	9	5,752
JUNE	5,752	475,731	1.06%	5,043	(9,018)	(3,976)	1,776	3,764	2.35%	7	1,783
JULY	1,783	496,929	1.06%	5,267	(6,011)	(744)	1,040	1,412	2.34%	3	1,043
AUGUST	1,043	542,803	1.06%	5,754	(5,077)	677	1,719	1,381	2.28%	3	1,722
SEPTEMBER	1,722	476,873	1.06%	5,055	(6,785)	(1,730)	(8)	857	2.26%	2	(7)
OCTOBER	(7)	1,219,579	1.06%	12,928	(9,831)	3,096	3,090	1,542	2.26%	3	3,093
TOTALS				47,158	(46,307)					25	

(1) Bad Debt Allowance calculated by multiplying Bad Debt % Allowed times Gas Cost on Schedule 4 and Working Capital Allowance on Attachment A.

Attachment C
Page 1 of 2

NORTHERN UTILITIES - MAINE DIVISION
SALES VARIANCE ANALYSIS
OFF PEAK PERIOD 2010

	May	June	July	August	September	October	Total
Forecast Calendar Month Sales (Weather Normalized)	188,238	103,949	81,033	74,683	93,101	120,220	661,224
Actual Calendar Month Sales	77,674	83,199	83,309	69,934	93,294	134,532	541,942
Volume Variance due to Weather	7,463	13,487	6,417	1,758	6,557	16,127	51,808
Weather Normal Actual Calender Sales	85,137	96,686	89,726	71,692	99,851	150,659	593,750
Total Variance in Weather Normalized Sales	(103,101)	(7,263)	8,693	(2,991)	6,750	30,439	67,474

Variance-change in meter count	(9,832)
-change in load pattern	(109,450)
	(119,282)

Attachment C
Updated March 3, 2011 **Page 2 of 2**

NORTHERN UTILITIES - MAINE DIVISION
SALES VARIANCE ANALYSIS
OFF PEAK PERIOD 2010

	Normal Mcf			Meters		
	2010 Actual	2010 Forecast	Difference	2010 Actual	2010 Forecast	Difference
Res Heat	161,872	200,522	(38,650)	82,024	83,547	(1,523)
Res Non Heat	29,254	27,648	1,606	29,391	28,526	865
Total Res	**191,127**	**228,170**	**(37,043)**	**111,415**	**112,073**	**(658)**
G-50	64,031	54,858	9,173	8,321	8,432	(111)
G-40	89,072	157,227	(68,155)	26,600	26,678	(78)
G-51	49,268	48,703	565	628	703	(75)
G-41	95,491	123,326	(27,835)	2,124	2,198	(74)
G-52	28,508	25,187	3,321	37	32	5
G-42	24,446	23,754	692	40	42	(2)
Total Commercial and Industrial	**350,816**	**433,055**	**(82,239)**	**37,750**	**38,085**	**(335)**
Total Company	541,943	661,225	(119,282)	149,165	150,158	(993)

	Normal Average Use			Change in Sales Due to Change in:		Total Change Mcf	% Difference
	2010 Actual	2010 Forecast	Difference	Meter Count	Load Pattern		
Res Heat	1.97	2.40	(0.43)	(3,000)	(35,650)	(38,650)	-19.27%
Res Non Heat	1.00	0.97	0.03	865	741	1,606	5.81%
Total Res	**1.72**	**2.04**	**(0.32)**	**(2,135)**	**(34,908)**	**(37,043)**	**-16.23%**
G-50	7.70	6.51	1.19	(855)	10,028	9,173	16.72%
G-40	3.35	5.89	(2.54)	(261)	(67,894)	(68,155)	-43.35%
G-51	78.45	69.28	9.17	(5,884)	6,449	565	1.16%
G-41	44.96	56.11	(11.15)	(3,327)	(24,508)	(27,835)	-22.57%
G-52	770.49	787.09	(16.60)	3,852	(531)	3,321	13.19%
G-42	611.16	565.57	45.59	(1,222)	1,914	692	2.91%
Total Commercial and Industrial	**9.29**	**11.37**	**(2.08)**	**(7,697)**	**(74,542)**	**(82,239)**	**-18.99%**
Total Company	3.63	4.40	(0.77)	(9,832)	(109,450)	(119,282)	-18.04%

Schedule 13

Maine Division
Original and Revised 2011 Off-Peak Period Reconciliation

NORTHERN UTILITIES, INC. - MAINE DIVISION
2011 OFF PEAK PERIOD RECONCILIATION
November 2010 - October 2011

Original Reconciliation

FORM III
Schedule 1
Page 1 of 2

NORTHERN UTILITIES, INC. - MAINE DIVISION
2011 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 1: OFF PEAK DEMAND SUMMARY
November 2010 - October 2011

	AMOUNT	
Off-Peak Demand Beginning Balance	$ 484,052	SCHEDULE 2
Less: Cost of Firm Gas Revenue (Demand)	(1,707,070)	SCHEDULE 2
Add: Cost of Firm Gas Allowable (Demand)	1,267,915	SCHEDULE 2
Add: Interest	7,744	SCHEDULE 2
Off-Peak Demand Ending Balance	$ 52,640	

NORTHERN UTILITIES, INC. - MAINE DIVISION
2011 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 1: OFF PEAK COMMODITY SUMMARY
November 2010 - October 2011

		AMOUNT	
Off-Peak Commodity Beginning Balance	$	(274,223)	SCHEDULE 2
Less: Cost of Firm Gas Revenue (Commodity)		(2,862,348)	SCHEDULE 2
Add: Cost of Firm Gas Allowable (Commodity)		2,664,627	SCHEDULE 2
Add: Interest		(11,507)	SCHEDULE 2
Off-Peak Summer Commodity Ending Balance	$	(483,451)	
Net Off-Peak Demand and Commodity Ending Balance	$	(430,811)	

FORM III
Schedule 2

NORTHERN UTILITIES, INC. - MAINE DIVISION
2011 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED OFF PEAK PERIOD ACCOUNTS
November 2010 - October 2011

		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
1	**OFF PEAK DEMAND - ACCOUNT 191.10**													
2	Off Peak Demand Account Beginning Balance	$ 484,052	$ 432,040	$ 432,088	$ 433,347	$ 434,454	$ 435,411	$ 436,176	$ 169,095	$ 280,108	$ 288,825	$ 323,929	$ 236,461	$ 484,052
3	Plus: Cost of Gas Demand Allowable (Schedule 4)	$ -	$ -	$ -	$ -	$ -	$ -	$ 216,049	$ 207,487	$ 205,368	$ 206,875	$ 210,300	$ 221,837	$ 1,267,915
4	Less: Cost of Gas Demand Revenue (Schedule 3)	$ (52,871)	$ (766)	$ 445	$ 290	$ 141	$ (42)	$ (483,684)	$ (96,883)	$ (197,169)	$ (172,334)	$ (298,288)	$ (405,909)	$ (1,707,070)
5	**Preliminary Ending Balance**	**$ 431,181**	**$ 431,274**	**$ 432,532**	**$ 433,637**	**$ 434,595**	**$ 435,369**	**$ 168,541**	**$ 279,699**	**$ 288,307**	**$ 323,366**	**$ 235,941**	**$ 52,390**	**$ 44,896**
6	Month's Average Balance ((Line 2 + Line 5) / 2)	$ 457,616	$ 431,657	$ 432,310	$ 433,492	$ 434,525	$ 435,390	$ 302,358	$ 224,397	$ 284,207	$ 306,095	$ 279,935	$ 144,425	
7	Interest Rate (Short Term Borrowing Rate)	2.254%	2.262%	2.261%	2.263%	2.255%	2.224%	2.200%	2.188%	2.186%	2.209%	2.229%	2.082%	
8	Interest Applied (Line 6 * (Line 7 / 12))	$ 860	$ 814	$ 815	$ 817	$ 817	$ 807	$ 554	$ 409	$ 518	$ 563	$ 520	$ 251	$ 7,744
9	**Off Peak Demand Account Ending Balance** (1)	**$ 432,040**	**$ 432,088**	**$ 433,347**	**$ 434,454**	**$ 435,411**	**$ 436,176**	**$ 169,095**	**$ 280,108**	**$ 288,825**	**$ 323,929**	**$ 236,461**	**$ 52,640**	**$ 52,640**
10	**OFF PEAK COMMODITY - ACCOUNT 191.09**													
11	Off Peak Commodity Account Beginning Balance	$ (274,223)	$ (505,782)	$ (527,186)	$ (526,784)	$ (527,242)	$ (528,033)	$ (527,088)	$ (647,791)	$ (495,375)	$ (559,424)	$ (481,856)	$ (529,212)	$ (274,223)
12	Plus: Cost of Gas Commodity Allowable (Schedule 4)	$ (7,760)	$ (17,713)	$ -	$ -	$ -	$ 2,046	$ 651,547	$ 352,973	$ 287,658	$ 386,467	$ 332,200	$ 677,208	$ 2,664,627
13	Less: Cost of Gas Commodity Revenue (Schedule 3)	$ (223,068)	$ (2,719)	$ 1,394	$ 535	$ 199	$ (124)	$ (771,174)	$ (199,516)	$ (350,748)	$ (307,941)	$ (378,618)	$ (630,569)	$ (2,862,348)
14	**Preliminary Ending Balance**	**$ (505,050)**	**$ (526,214)**	**$ (525,792)**	**$ (526,249)**	**$ (527,043)**	**$ (526,111)**	**$ (646,715)**	**$ (494,334)**	**$ (558,464)**	**$ (480,898)**	**$ (528,274)**	**$ (482,573)**	**$ (471,944)**
15	Month's Average Balance ((Line 10 + Line 15) / 2)	$ (389,636)	$ (515,998)	$ (526,489)	$ (526,517)	$ (527,142)	$ (527,072)	$ (586,901)	$ (571,062)	$ (526,920)	$ (520,161)	$ (505,065)	$ (505,893)	
16	Interest Rate (Short Term Borrowing Rate)	2.254%	2.262%	2.261%	2.263%	2.255%	2.224%	2.200%	2.188%	2.186%	2.209%	2.229%	2.082%	
17	Interest Applied (Line 16 * (Line 17 / 12))	$ (732)	$ (973)	$ (992)	$ (993)	$ (991)	$ (977)	$ (1,076)	$ (1,041)	$ (960)	$ (958)	$ (938)	$ (878)	$ (11,507)
18	**Off Peak Commodity Account Ending Balance**(1)	**$ (505,782)**	**$ (527,186)**	**$ (526,784)**	**$ (527,242)**	**$ (528,033)**	**$ (527,088)**	**$ (647,791)**	**$ (495,375)**	**$ (559,424)**	**$ (481,856)**	**$ (529,212)**	**$ (483,451)**	**$ (483,451)**

(1) Off Peak Period Ending Balance of ($248,877) approved by Commission Order dated April 28, 2010, in Docket No. 2010-63. This figure is increased by $396 to reflect final revenue for Nov-09.

FORM III
Schedule 3

NORTHERN UTILITIES, INC. - MAINE DIVISION
2011 OFF-PEAK PERIOD RECONCILIATION
SCHEDULE 3: BILLED REVENUE
November 2010 - October 2011

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
Demand Revenue:													
Billed Revenue	$ 176,232	$ 766	$ (445)	$ (290)	$ (141)	$ 42	$ 191,892	$ 288,603	$ 203,261	$ 163,947	$ 270,753	$ 271,624	$ 1,566,245
Accrued Revenue	$ (123,361)	$ -	$ -	$ -	$ -	$ -	$ 291,792	$ (191,721)	$ (6,092)	$ 8,387	$ 27,534	$ 134,285	$ 140,825
Calendarized Demand Revenue	**$ 52,871**	**$ 766**	**$ (445)**	**$ (290)**	**$ (141)**	**$ 42**	**$ 483,684**	**$ 96,883**	**$ 197,169**	**$ 172,334**	**$ 298,288**	**$ 405,909**	**$ 1,707,070**
Commodity Revenue:													
Billed Revenue	$ 761,890	$ 2,719	$ (1,394)	$ (535)	$ (199)	$ 124	$ 317,394	$ 490,144	$ 357,909	$ 293,701	$ 341,331	$ 433,615	$ 2,996,698
Accrued Revenue	$ (538,822)	$ -	$ -	$ -	$ -	$ -	$ 453,779	$ (290,628)	$ (7,161)	$ 14,240	$ 37,287	$ 196,955	$ (134,350)
Calendarized Commodity Revenu	**$ 223,068**	**$ 2,719**	**$ (1,394)**	**$ (535)**	**$ (199)**	**$ 124**	**$ 771,174**	**$ 199,516**	**$ 350,748**	**$ 307,941**	**$ 378,618**	**$ 630,569**	**$ 2,862,348**

FORM III
Schedule 4
Page 1 of 2

NORTHERN UTILITIES, INC. - MAINE DIVISION
2011 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO OFF PEAK PERIOD
November 2010 - October 2011

Commodity Costs	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Total**
DTE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 509,891	$ -	$ -	$ -	$ -	$ 509,891
Distrigas	$ 170,825	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,297	$ 185,121
Emera Energy	$ 62,301	$ 3,763	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 66,064
JP Morgan	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 298,976	$ -	$ -	$ 298,976
Portland	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 46	$ 59	$ 57	$ 163
Repsol	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 226,481	$ 243,839	$ 535,246	$ 207,390	$ 1,212,956
Sempra	$ 4,694	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,694
Sequent	$ 4,837	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,837
South Jersey Resources	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 123,242	$ -	$ -	$ -	$ 123,242
Spark Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sprague Energy	$ 152,428	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 152,428
Tennessee	$ 2,544	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,272	$ 2,253	$ 2,412	$ 2,374	$ 2,310	$ 17,165
Total Gas & Power	$ 292,829	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 292,829
Virginia Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 296,094	$ 154,053	$ -	$ -	$ 249,439	$ 699,586
Total	$ 690,457	$ 3,763	$ -	$ -	$ -	$ -	$ -	$ 811,257	$ 506,029	$ 545,273	$ 537,680	$ 473,493	**$ 3,567,952**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 840,920	$ 506,106	$ 546,758	$ 537,620	$ 463,966	$ 634,515	$ 3,529,885
Commodity Cost Reversals	$ (706,878)	$ -	$ -	$ -	$ -	$ -	$ -	$ (840,920)	$ (506,106)	$ (546,758)	$ (537,620)	$ (463,966)	$ (3,602,248)
Subtotal	$ (16,421)	$ 3,763	$ -	$ -	$ -	$ -	$ 840,920	$ 476,443	$ 546,681	$ 536,135	$ 464,026	$ 644,042	**$ 3,495,589**
Withdrawal Charges	$ (4,832)	$ -	$ -	$ -	$ -	$ -	$ (463)	$ 638	$ (269)	$ 681	$ (2,345)	$ (134)	$ (6,723)
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 79,002	$ 15,938	$ 3,242	$ (15,246)	$ 5,541	$ 40,478	$ 128,955
Non Traditional Sales	$ (70,286)	$ -	$ -	$ -	$ -	$ -	$ -	$ (297,775)	$ (139,799)	$ (256,345)	$ (142,923)	$ (149,041)	$ (1,056,169)
Net OBA Adj.	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,881	$ (7,613)	$ (7,880)	$ 993	$ 2,602	$ (10,312)	$ (19,328)
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,165	$ 3,762	$ 6,233	$ 5,038	$ 5,922	$ 4,429	$ 30,549
Transportation Charges	$ 13,493	$ (21,476)	$ -	$ -	$ -	$ 2,046	$ -	$ 1,221	$ (5,259)	$ -	$ 1,773	$ (4,987)	$ (13,190)
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 21,176	$ 1,554	$ 829	$ 958	$ 1,056	$ 64,841	$ 90,414
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ 641	$ 828	$ 622	$ 635	$ 596	$ 459	$ 3,783
Subtotal	$ (61,625)	$ (21,476)	$ -	$ -	$ -	$ 2,046	$ 108,402	$ (281,446)	$ (142,282)	$ (263,285)	$ (127,777)	$ (54,266)	**$ (841,709)**
Sales for Resale Estimates		$ -	$ -	$ -	$ -	$ -	$ (297,775)	$ (139,799)	$ (256,540)	$ (142,923)	$ (146,972)	$ (59,540)	$ (1,043,549)
Sales for Resale Reversals	$ 70,286	$ -	$ -	$ -	$ -	$ -	$ -	$ 297,775	$ 139,799	$ 256,540	$ 142,923	$ 146,972	$ 1,054,295
Total Commodity Costs	**$ (7,760)**	**$ (17,713)**	**$ -**	**$ -**	**$ -**	**$ 2,046**	**$ 651,547**	**$ 352,973**	**$ 287,658**	**$ 386,467**	**$ 332,200**	**$ 677,208**	**$ 2,664,627**

NORTHERN UTILITIES, INC. - MAINE DIVISION
2011 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO OFF PEAK PERIOD
November 2010 - October 2011

Demand Costs	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
Summer Demand Costs (Fcst 2009-250)	$ -	$ -	$ -	$ -	$ -	$ -	$ 205,321	$ 205,321	$ 205,321	$ 205,321	$ 205,321	$ 205,321	$ 1,231,925
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,728	$ 2,166	$ 47	$ 1,554	$ 4,979	$ 16,516	$ 35,990
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 216,049**	**$ 207,487**	**$ 205,368**	**$ 206,875**	**$ 210,300**	**$ 221,837**	**$ 1,267,915**
Total Gas Costs	**$ (7,760)**	**$ (17,713)**	**$ -**	**$ -**	**$ -**	**$ 2,046**	**$ 867,596**	**$ 560,460**	**$ 493,026**	**$ 593,342**	**$ 542,500**	**$ 899,045**	**$ 3,932,542**

NORTHERN UTILITIES, INC. - MAINE DIVISION
2009 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
November 2010 - October 2011

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
Maine													
Throughput IN													
BTU Factor	1.047	1.042	1.048	1.051	1.052	1.054	1.027	1.057	1.058	1.055	1.052	1.049	
GST Meter Throughput (MCF)	547,528	856,907	1,023,260	860,616	693,980	521,809	425,606	270,255	246,333	251,507	261,158	418,328	6,377,287
Kittery Meter (MCF)	100,987	125,432	137,909	126,221	127,453	99,553	66,076	50,877	48,262	49,047	48,176	61,376	1,041,369
GST Meter Throughput (DTH)	573,262	892,897	1,072,376	904,507	730,067	549,987	437,097	285,660	260,620	265,340	274,738	438,826	6,685,378
Kittery Meter (DTH)	105,733	130,700	144,529	132,658	134,081	104,929	67,860	53,777	51,061	51,745	50,681	64,383	1,092,137
Cotton Road (Lewiston)(DTH)	141,201	165,880	178,607	163,530	175,604	81,577	89	45,159	30,134	43,948	42,242	71,589	1,139,562
LNG/Propane	1,005	1,485	1,864	519	1,315	1,996	2,002	1,684	2,138	1,825	1,820	1,378	19,032
Total Throughput	821,201	1,190,962	1,397,377	1,201,215	1,041,067	738,489	507,048	386,280	343,954	362,858	369,481	576,177	8,936,109
Throughput OUT													
Residential Gas													
Charged	77,409	137,675	202,368	221,679	176,212	133,917	67,234	43,969	29,715	22,771	26,650	33,783	1,173,382
Uncharged Current	56,519	107,793	126,204	93,018	112,680	66,565	36,955	27,549	16,753	18,796	23,716	47,951	734,499
Uncharged Prior	-35,821	-56,519	-107,793	-126,204	-93,018	-112,680	-66,565	-36,955	-27,549	-16,753	-18,796	-23,716	-722,369
Total Residential Gas	**98,107**	**188,949**	**220,779**	**188,493**	**195,874**	**87,802**	**37,624**	**34,563**	**18,919**	**24,814**	**31,570**	**58,018**	**1,185,512**
Interruptible	**0**	**0**	**0**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Commercial/Industrial Gas													
Charged	128,735	249,051	343,113	382,390	294,687	219,979	109,838	68,320	52,222	44,321	51,079	64,675	2,008,410
Uncharged Current	86,510	187,571	211,883	161,058	189,331	110,535	63,837	46,431	30,954	36,789	39,357	67,885	1,232,141
Uncharged Prior	-53,128	-86,510	-187,571	-211,883	-161,058	-189,331	-110,535	-63,837	-46,431	-30,954	-36,789	-39,357	-1,217,384
Total C/I Gas	**162,117**	**350,112**	**367,425**	**331,565**	**322,960**	**141,183**	**63,140**	**50,914**	**36,745**	**50,156**	**53,647**	**93,203**	**2,023,167**
Transportation													
Charged	458,963	632,036	755,229	717,908	654,897	510,872	374,203	303,265	271,297	277,146	280,485	359,260	5,595,561
Uncharged Current	220,034	357,258	356,555	242,253	328,889	208,235	186,603	182,629	128,767	179,950	160,736	269,611	2,821,520
Uncharged Prior	-177,736	-220,034	-357,258	-356,555	-242,253	-328,889	-208,235	-186,603	-182,629	-128,767	-179,950	-160,736	-2,729,645
Total Transportation	**501,261**	**769,260**	**754,526**	**603,606**	**741,533**	**390,218**	**352,571**	**299,291**	**217,435**	**328,329**	**261,271**	**468,135**	**5,687,436**
Company Use	**456**	**732**	**1,162**	**1,488**	**1,166**	**858**	**327**	**75**	**165**	**119**	**166**	**201**	**6,916**
Total Throughput OUT	**761,941**	**1,309,053**	**1,343,892**	**1,125,152**	**1,261,533**	**620,061**	**453,662**	**384,843**	**273,264**	**403,418**	**346,654**	**619,557**	**8,903,031**
Total Throughput IN	**821,201**	**1,190,962**	**1,397,377**	**1,201,215**	**1,041,067**	**738,489**	**507,048**	**386,280**	**343,954**	**362,858**	**369,481**	**576,177**	**8,936,109**
Difference IN/OUT	59,259	-118,091	53,485	76,063	-220,466	118,428	53,387	1,437	70,690	-40,561	22,828	-43,380	33,078
%													0.37%

Attachment A
Page 1 of 1

NORTHERN UTILITIES, INC. - MAINE DIVISION
DEFERRED OFF-PEAK WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
November 2010 - October 2011

OFF PEAK DEMAND - ACCOUNT 182.20

	BEGINNING BALANCE	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	(D)	E = B + (D)	F = A + E	G = (A + F) / 2	H	I = G * (H/12)	J = F + I
NOVEMBER	1,375	-	0.4410%	(240)	(240)	1,135	1,255	2.25%	2	1,138
DECEMBER	1,138	-	0.4410%	(3)	(3)	1,134	1,136	2.26%	2	1,136
JANAUARY 2011	1,136	-	0.4410%	2	2	1,138	1,137	2.26%	2	1,140
FEBRUARY	1,140	-	0.4410%	1	1	1,141	1,141	2.26%	2	1,143
MARCH	1,143	-	0.4410%	1	1	1,143.94	1,143.61	2.26%	2.15	1,146.09
APRIL	1,146	-	0.4410%	(0)	(0)	1,146	1,146	2.22%	2	1,148
MAY	1,148	953	0.4410%	(1,990)	(1,037)	111	630	2.20%	1	112
JUNE	112	915	0.4410%	(512)	403	515	314	2.19%	1	515
JULY	515	906	0.4410%	(906)	(0)	515	515	2.19%	1	516
AUGUST	516	912	0.4410%	(795)	118	634	575	2.21%	1	635
SEPTEMBER	635	927	0.4410%	(979)	(51)	584	609	2.23%	1	585
OCTOBER	585	978	0.4410%	(1,630)	(652)	(67)	259	2.08%	0	(66)
Totals		5,592		(7,052)					18	

OFF PEAK COMMODITY - ACCOUNT 182.21

	BEGINNING BALANCE	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	(D)	E = B + (D)	F = A + E	G = (A + F) / 2	H	I = G * (H/12)	J = F + I
NOVEMBER	1,320	(34)	0.4410%	(835)	(869)	451	885	2.25%	2	452
DECEMBER	452	(78)	0.4410%	(10)	(88)	364	408	2.26%	1	365
JANAUARY 2011	365	0	0.4410%	5	5	370	367	2.26%	1	371
FEBRUARY	371	0	0.4410%	2	2	373	372	2.26%	1	374
MARCH	374	0	0.4410%	1	1	375	374	2.26%	1	375
APRIL	375	9	0.4410%	(1)	9	384	379	2.22%	1	384
MAY	384	2,873	0.4410%	(4,327)	(1,454)	(1,069)	(343)	2.20%	(1)	(1,070)
JUNE	(1,070)	1,557	0.4410%	(1,126)	430	(640)	(855)	2.19%	(2)	(642)
JULY	(642)	1,269	0.4410%	(1,977)	(709)	(1,350)	(996)	2.19%	(2)	(1,352)
AUGUST	(1,352)	1,704	0.4410%	(1,737)	(33)	(1,385)	(1,369)	2.21%	(3)	(1,388)
SEPTEMBER	(1,388)	1,465	0.4410%	(2,133)	(668)	(2,056)	(1,722)	2.23%	(3)	(2,059)
OCTOBER	(2,059)	2,986	0.4410%	(3,549)	(563)	(2,622)	(2,341)	2.08%	(4)	(2,626)
Totals		11,751		(15,688)					(9)	
Combined Totals		17,343		(22,740)					10	

NORTHERN UTILITIES, INC - MAINE DIVISION
DEFERRED OFF PEAK 2009 BAD DEBT CALCULATION OF COLLECTION ALLOWANCE
November 2010 - October 2011

ACCOUNT 182.22

	BEG. BAL	MAINE GAS COSTS PER BOOKS ALLOWED FOR BAD DEBT	BAD DEBT % ALLOWED	ACTUAL BAD DEBT ALLOWANCE(1)	ACTUAL BAD DEBT COLLECTION	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	(E)	F = D + (E)	G = A + F	H = (A+G)/2	I = G*(H/12)	J = F + I	
NOVEMBER	2,787	(7,794)	1.06%	(83)	362	280	3,067	2,927	2.25%	6	3,072
DECEMBER	3,072	(17,791)	1.06%	(189)	(33)	(222)	2,850	2,961	2.26%	6	2,856
JANUARY 201	2,856	0	1.06%	0	17	17	2,873	2,864	2.26%	5	2,878
FEBRUARY	2,878	0	1.06%	0	8	8	2,886	2,882	2.26%	5	2,891
MARCH	2,891	0	1.06%	0	4	4	2,895	2,893	2.26%	5	2,901
APRIL	2,901	2,056	1.06%	22	(2)	20	2,921	2,911	2.22%	5	2,926
MAY	2,926	871,422	1.06%	9,237	(13,660)	(4,423)	(1,497)	715	2.20%	1	(1,496)
JUNE	(1,496)	562,931	1.06%	5,967	(3,543)	2,424	928	(284)	2.19%	(1)	928
JULY	928	495,200	1.06%	5,249	(6,229)	(980)	(52)	438	2.19%	1	(51)
AUGUST	(51)	595,959	1.06%	6,317	(5,468)	850	799	374	2.21%	1	799
SEPTEMBER	799	544,892	1.06%	5,776	(6,719)	(943)	(144)	328	2.23%	1	(143)
OCTOBER	(143)	903,010	1.06%	9,572	(11,183)	(1,611)	(1,755)	(949)	2.08%	(2)	(1,756)
Totals				41,869	(46,446)					34	

(1) Bad Debt Allowance calculated by multiplying Bad Debt % Allowed times Gas Cost on Schedule 4 and Working Capital Allowance on Attachment A.

Attachment C
Page 1 of 2

NORTHERN UTILITIES - MAINE DIVISION
SALES VARIANCE ANALYSIS
OFF PEAK PERIOD 2011

	May	June	July	August	September	October	Total
Forecast Calendar Month Sales (Weather Normalized)	130,795	78,333	53,582	76,791	96,425	159,129	595,055
Actual Calendar Month Sales	102,532	78,079	52,549	71,189	81,154	144,330	529,833
Volume Variance due to Weather	4,217	-	-	-	-	39,851	44,068
Weather Normal Actual Calender Sales	106,749	78,079	52,549	71,189	81,154	184,181	573,901
Total Variance in Weather Normalized Sales	(24,046)	(254)	(1,033)	(5,602)	(15,271)	25,052	21,154

Variance-change in meter count	(7,202)
-change in load pattern	(14,453)
	(21,655)

NORTHERN UTILITIES - MAINE DIVISION
SALES VARIANCE ANALYSIS
OFF PEAK PERIOD 2011

	Normal Mcf			Meters		
	2011 Actual	**2011 Forecast**	**Difference**	**2011 Actual**	**2011 Forecast**	**Difference**
Res Heat	183,404	182,973	431	84,949	86,521	(1,572)
Res Non Heat	28,163	27,882	281	29,202	28,598	604
Total Res	**211,567**	**210,855**	**712**	**114,151**	**115,119**	**(968)**
G-50	60,820	60,082	738	7,862	7,957	(95)
G-40	113,728	111,521	2,207	26,781	27,105	(324)
G-51	45,176	55,421	(10,245)	668	676	(8)
G-41	107,410	113,924	(6,514)	2,251	2,278	(27)
G-52	24,763	18,397	6,366	28	28	(0)
G-42	10,437	25,356	(14,919)	42	43	(1)
Total Commercial and Industrial	**362,334**	**384,701**	**(22,367)**	**37,632**	**38,087**	**(455)**
Total Company	573,901	595,556	(21,655)	151,783	153,206	(1,423)

	Normal Average Use			Change in Sales Due to Change in:			
	2011 Actual	**2011 Forecast**	**Difference**	**Meter Count**	**Load Pattern**	**Total Change Mcf**	**% Difference**
Res Heat	2.16	2.11	0.05	(3,396)	3,827	431	0.24%
Res Non Heat	0.96	0.97	(0.01)	580	(299)	281	1.01%
Total Res	**1.85**	**1.83**	**0.02**	**(2,816)**	**3,528**	**712**	**0.34%**
G-50	7.74	7.55	0.19	(736)	1,474	738	1.23%
G-40	4.25	4.11	0.14	(1,377)	3,584	2,207	1.98%
G-51	67.63	81.97	(14.34)	(547)	(9,698)	(10,245)	-18.49%
G-41	47.72	50.01	(2.29)	(1,300)	(5,214)	(6,514)	-5.72%
G-52	884.39	649.18	235.21	(300)	6,666	6,366	34.60%
G-42	248.50	596.50	(348.00)	(126)	(14,793)	(14,919)	-58.84%
Total Commercial and Industrial	**9.63**	**10.10**	**(0.47)**	**(4,386)**	**(17,981)**	**(22,367)**	**-5.81%**
Total Company	3.78	3.89	(0.11)	(7,202)	(14,453)	(21,655)	-3.64%

NORTHERN UTILITIES, INC. - MAINE DIVISION
2011 OFF PEAK PERIOD RECONCILIATION
November 2010 - October 2011

Recalculated Reconciliation

FORM III
Schedule 1
Page 1 of 2
Updated July 2012

NORTHERN UTILITIES, INC. - MAINE DIVISION
2011 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 1: OFF PEAK DEMAND SUMMARY
November 2010 - October 2011

		AMOUNT	
Off-Peak Demand Beginning Balance	$	484,052	SCHEDULE 2
Less: Cost of Firm Gas Revenue (Demand)		(1,707,070)	SCHEDULE 2
Add: Cost of Firm Gas Allowable (Demand)		1,267,915	SCHEDULE 2
Add: Interest		7,744	SCHEDULE 2
Off-Peak Demand Ending Balance	$	52,640	

NORTHERN UTILITIES, INC. - MAINE DIVISION
2011 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 1: OFF PEAK COMMODITY SUMMARY
November 2010 - October 2011

	AMOUNT	
Off-Peak Commodity Beginning Balance	$ (245,568)	SCHEDULE 2
Less: Cost of Firm Gas Revenue (Commodity)	(2,862,348)	SCHEDULE 2
Add: Cost of Firm Gas Allowable (Commodity)	2,654,215	SCHEDULE 2
Add: Interest	(10,940)	SCHEDULE 2
Off-Peak Summer Commodity Ending Balance	$ (464,641)	
Net Off-Peak Demand and Commodity Ending Balance	$ (412,001)	

FORM III
Updated July 2012 Schedule 2

NORTHERN UTILITIES, INC. - MAINE DIVISION
2011 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED OFF PEAK PERIOD ACCOUNTS
November 2010 - October 2011

		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
1	**OFF PEAK DEMAND - ACCOUNT 191.10**													
2	Off Peak Demand Account Beginning Balance	$ 484,052	$ 432,040	$ 432,088	$ 433,347	$ 434,454	$ 435,411	$ 436,176	$ 169,095	$ 280,108	$ 288,825	$ 323,929	$ 236,461	$ 484,052
3	Plus: Cost of Gas Demand Allowable (Schedule 4)	$ -	$ -	$ -	$ -	$ -	$ -	$ 216,049	$ 207,487	$ 205,368	$ 206,875	$ 210,300	$ 221,837	$ 1,267,915
4	Less: Cost of Gas Demand Revenue (Schedule 3)	$ (52,871)	$ (766)	$ 445	$ 290	$ 141	$ (42)	$ (483,684)	$ (96,883)	$ (197,169)	$ (172,334)	$ (298,288)	$ (405,909)	$ (1,707,070)
5	**Preliminary Ending Balance**	**$ 431,181**	**$ 431,274**	**$ 432,532**	**$ 433,637**	**$ 434,595**	**$ 435,369**	**$ 168,541**	**$ 279,699**	**$ 288,307**	**$ 323,365**	**$ 235,941**	**$ 52,389**	**$ 44,896**
6	Month's Average Balance ((Line 2 + Line 5) / 2)	$ 457,616	$ 431,657	$ 432,310	$ 433,492	$ 434,524	$ 435,390	$ 302,358	$ 224,397	$ 284,207	$ 306,095	$ 279,935	$ 144,425	
7	Interest Rate (Short Term Borrowing Rate)	2.254%	2.262%	2.261%	2.263%	2.255%	2.224%	2.200%	2.188%	2.186%	2.209%	2.229%	2.082%	
8	Interest Applied (Line 6 * (Line 7 / 12))	$ 860	$ 814	$ 815	$ 817	$ 817	$ 807	$ 554	$ 409	$ 518	$ 563	$ 520	$ 251	$ 7,744
9	**Off Peak Demand Account Ending Balance**(1)	**$ 432,040**	**$ 432,088**	**$ 433,347**	**$ 434,454**	**$ 435,411**	**$ 436,176**	**$ 169,095**	**$ 280,108**	**$ 288,825**	**$ 323,929**	**$ 236,461**	**$ 52,640**	**$ 52,640**
10	**OFF PEAK COMMODITY - ACCOUNT 191.09**													
11	Off Peak Commodity Account Beginning Balance	$ (245,568)	$ (477,044)	$ (500,145)	$ (499,692)	$ (500,098)	$ (500,839)	$ (499,587)	$ (620,679)	$ (470,372)	$ (535,960)	$ (459,599)	$ (508,666)	$ (245,568)
12	Plus: Cost of Gas Commodity Allowable (Schedule 4)	$ (7,730)	$ (19,462)	$ -	$ -	$ -	$ 2,302	$ 651,108	$ 350,816	$ 286,076	$ 385,217	$ 330,450	$ 675,438	$ 2,654,215
13	Less: Cost of Gas Commodity Revenue (Schedule 3)	$ (223,068)	$ (2,719)	$ 1,394	$ 535	$ 199	$ (124)	$ (771,174)	$ (199,516)	$ (350,748)	$ (307,941)	$ (378,618)	$ (630,569)	$ (2,862,348)
14	**Preliminary Ending Balance**	**$ (476,366)**	**$ (499,225)**	**$ (498,751)**	**$ (499,157)**	**$ (499,899)**	**$ (498,661)**	**$ (619,653)**	**$ (469,378)**	**$ (535,044)**	**$ (458,684)**	**$ (507,768)**	**$ (463,798)**	**$ (453,701)**
15	Month's Average Balance ((Line 10 + Line 15) / 2)	$ (360,967)	$ (488,134)	$ (499,448)	$ (499,424)	$ (499,999)	$ (499,750)	$ (559,620)	$ (545,028)	$ (502,708)	$ (497,322)	$ (483,683)	$ (486,232)	
16	Interest Rate (Short Term Borrowing Rate)	2.254%	2.262%	2.261%	2.263%	2.255%	2.224%	2.200%	2.188%	2.186%	2.209%	2.229%	2.082%	
17	Interest Applied (Line 16 * (Line 17 / 12))	$ (678)	$ (920)	$ (941)	$ (942)	$ (940)	$ (926)	$ (1,026)	$ (994)	$ (916)	$ (915)	$ (898)	$ (844)	(10,940)
18	**Off Peak Commodity Account Ending Balance**(1)	**$ (477,044)**	**$ (500,145)**	**$ (499,692)**	**$ (500,098)**	**$ (500,839)**	**$ (499,587)**	**$ (620,679)**	**$ (470,372)**	**$ (535,960)**	**$ (459,599)**	**$ (508,666)**	**$ (464,641)**	**$ (464,641)**

(1) Off Peak Period Ending Balance of ($248,877) approved by Commission Order dated April 28, 2010, in Docket No. 2010-63. This figure is increased by $396 to reflect final revenue for Nov-09.

FORM III
Schedule 3

NORTHERN UTILITIES, INC. - MAINE DIVISION
2011 OFF-PEAK PERIOD RECONCILIATION
SCHEDULE 3: BILLED REVENUE
November 2010 - October 2011

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
Demand Revenue:													
Billed Revenue	$ 176,232	$ 766	$ (445)	$ (290)	$ (141)	$ 42	$ 191,892	$ 288,603	$ 203,261	$ 163,947	$ 270,753	$ 271,624	**$ 1,566,245**
Accrued Revenue	$(123,361)	$ -	$ -	$ -	$ -	$ -	$ 291,792	$(191,721)	$ (6,092)	$ 8,387	$ 27,534	$ 134,285	**$ 140,825**
Calendarized Demand Revenue	**$ 52,871**	**$ 766**	**$ (445)**	**$ (290)**	**$ (141)**	**$ 42**	**$ 483,684**	**$ 96,883**	**$ 197,169**	**$ 172,334**	**$ 298,288**	**$ 405,909**	**$ 1,707,070**
Commodity Revenue:													
Billed Revenue	$ 761,890	$ 2,719	$ (1,394)	$ (535)	$ (199)	$ 124	$ 317,394	$ 490,144	$ 357,909	$ 293,701	$ 341,331	$ 433,615	**$ 2,996,698**
Accrued Revenue	$(538,822)	$ -	$ -	$ -	$ -	$ -	$ 453,779	$(290,628)	$ (7,161)	$ 14,240	$ 37,287	$ 196,955	**$ (134,350)**
Calendarized Commodity Revenue	**$ 223,068**	**$ 2,719**	**$ (1,394)**	**$ (535)**	**$ (199)**	**$ 124**	**$ 771,174**	**$ 199,516**	**$ 350,748**	**$ 307,941**	**$ 378,618**	**$ 630,569**	**$ 2,862,348**

FORM III
Schedule 4
Updated July 2012 **Page 1 of 2**

NORTHERN UTILITIES, INC. - MAINE DIVISION
2011 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO OFF PEAK PERIOD
November 2010 - October 2011

Commodity Costs	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
DTE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 509,891	$ -	$ -	$ -	$ -	**$ 509,891**
Distrigas	$ 170,825	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,297	**$ 185,121**
Emera Energy	$ 62,301	$ 3,763	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 66,064**
JP Morgan	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 298,976	$ -	$ -	**$ 298,976**
Portland	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 46	$ 59	$ 57	**$ 163**
Repsol	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 226,481	$ 243,839	$ 535,246	$ 207,390	**$ 1,212,956**
Sempra	$ 4,694	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 4,694**
Sequent	$ 4,837	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 4,837**
South Jersey Resources	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 123,242	$ -	$ -	$ -	**$ 123,242**
Spark Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Sprague Energy	$ 152,428	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 152,428**
Tennessee	$ 2,544	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,272	$ 2,253	$ 2,412	$ 2,374	$ 2,310	**$ 17,165**
Total Gas & Power	$ 292,829	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 292,829**
Virginia Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 296,094	$ 154,053	$ -	$ -	$ 249,439	**$ 699,586**
Total	$ 690,457	$ 3,763	$ -	$ -	$ -	$ -	$ -	$ 811,257	$ 506,029	$ 545,273	$ 537,680	$ 473,493	**$ 3,567,952**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 840,920	$ 506,106	$ 546,758	$ 537,620	$ 463,966	$ 634,515	**$ 3,529,885**
Commodity Cost Reversals	$ (706,878)	$ -	$ -	$ -	$ -	$ -	$ -	$ (840,920)	$ (506,106)	$ (546,758)	$ (537,620)	$ (463,966)	**$ (3,602,248)**
Subtotal	$ (16,421)	$ 3,763	$ -	$ -	$ -	$ -	$ 840,920	$ 476,443	$ 546,681	$ 536,135	$ 464,026	$ 644,042	**$ 3,495,589**
Withdrawal Charges	$ (4,832)	$ -	$ -	$ -	$ -	$ -	$ (463)	$ 638	$ (269)	$ 681	$ (2,345)	$ (134)	**$ (6,723)**
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 79,002	$ 15,938	$ 3,242	$ (15,246)	$ 5,541	$ 40,478	**$ 128,955**
Non Traditional Sales	$ (70,286)	$ -	$ -	$ -	$ -	$ -	$ -	$ (297,775)	$ (139,799)	$ (256,345)	$ (142,923)	$ (149,041)	**$ (1,056,169)**
Net OBA Adj.	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,881	$ (7,613)	$ (7,880)	$ 993	$ 2,602	$ (10,312)	**$ (19,328)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,165	$ 3,762	$ 6,233	$ 5,038	$ 5,922	$ 4,429	**$ 30,549**
Transportation Charges	$ 13,493	$ (21,476)	$ -	$ -	$ -	$ 2,046	$ -	$ 1,221	$ (5,259)	$ -	$ 1,773	$ (4,987)	**$ (13,190)**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 21,176	$ 1,554	$ 829	$ 958	$ 1,056	$ 64,841	**$ 90,414**
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ 641	$ 828	$ 622	$ 635	$ 596	$ 459	**$ 3,783**
Allocation Adjustments	$ 30	$ (1,750)	$ -	$ -	$ -	$ 256	$ (439)	$ (2,157)	$ (1,582)	$ (1,250)	$ (1,750)	$ (1,770)	**$ (10,412)**
Subtotal	$ (61,595)	$ (23,226)	$ -	$ -	$ -	$ 2,302	$ 107,963	$ (283,603)	$ (143,864)	$ (264,535)	$ (129,527)	$ (56,036)	**$ (852,121)**
Sales for Resale Estimates		$ -	$ -	$ -	$ -	$ -	$ (297,775)	$ (139,799)	$ (256,540)	$ (142,923)	$ (146,972)	$ (59,540)	**$ (1,043,549)**
Sales for Resale Reversals	$ 70,286	$ -	$ -	$ -	$ -	$ -	$ -	$ 297,775	$ 139,799	$ 256,540	$ 142,923	$ 146,972	**$ 1,054,295**
Total Commodity Costs	**$ (7,730)**	**$ (19,462)**	**$ -**	**$ -**	**$ -**	**$ 2,302**	**$ 651,108**	**$ 350,816**	**$ 286,076**	**$ 385,217**	**$ 330,450**	**$ 675,438**	**$ 2,654,215**

NORTHERN UTILITIES, INC. - MAINE DIVISION
2011 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO OFF PEAK PERIOD
November 2010 - October 2011

Demand Costs	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
Summer Demand Costs (Fcst 2009-250)	$ -	$ -	$ -	$ -	$ -	$ -	$ 205,321	$ 205,321	$ 205,321	$ 205,321	$ 205,321	$ 205,321	**$ 1,231,925**
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,728	$ 2,166	$ 47	$ 1,554	$ 4,979	$ 16,516	**$ 35,990**
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 216,049**	**$ 207,487**	**$ 205,368**	**$ 206,875**	**$ 210,300**	**$ 221,837**	**$ 1,267,915**
Total Gas Costs	**$ (7,730)**	**$ (19,462)**	**$ -**	**$ -**	**$ -**	**$ 2,302**	**$ 867,157**	**$ 558,303**	**$ 491,444**	**$ 592,092**	**$ 540,749**	**$ 897,275**	**$ 3,922,130**

FORM III
Schedule 5
Page 1 of 1

NORTHERN UTILITIES, INC. - MAINE DIVISION
2011 OFF PEAK PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
November 2010 - October 2011

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
Maine													
Throughput IN													
BTU Factor	1.047	1.042	1.048	1.051	1.052	1.054	1.027	1.057	1.058	1.055	1.052	1.049	
GST Meter Throughput (MCF)	547,528	856,907	1,023,260	860,616	693,980	521,809	425,606	270,255	246,333	251,507	261,158	418,328	6,377,287
Kittery Meter (MCF)	100,987	125,432	137,909	126,221	127,453	99,553	66,076	50,877	48,262	49,047	48,176	61,376	1,041,369
GST Meter Throughput (DTH)	573,262	892,897	1,072,376	904,507	730,067	549,987	437,097	285,660	260,620	265,340	274,738	438,826	6,685,378
Kittery Meter (DTH)	105,733	130,700	144,529	132,658	134,081	104,929	67,860	53,777	51,061	51,745	50,681	64,383	1,092,137
Cotton Road (Lewiston)(DTH)	141,201	165,880	178,607	163,530	175,604	81,577	89	45,159	30,134	43,948	42,242	71,589	1,139,562
LNG/Propane	1,005	1,485	1,864	519	1,315	1,996	2,002	1,684	2,138	1,825	1,820	1,378	19,032
Total Throughput	821,201	1,190,962	1,397,377	1,201,215	1,041,067	738,489	507,048	386,280	343,954	362,858	369,481	576,177	8,936,109
Throughput OUT													
Residential Gas													
Charged	77,409	137,675	202,368	221,679	176,212	133,917	67,234	43,969	29,715	22,771	26,650	33,783	1,173,382
Uncharged Current	56,519	107,793	126,204	93,018	112,680	66,565	36,955	27,549	16,753	18,796	23,716	47,951	734,499
Uncharged Prior	-35,821	-56,519	-107,793	-126,204	-93,018	-112,680	-66,565	-36,955	-27,549	-16,753	-18,796	-23,716	-722,369
Total Residential Gas	**98,107**	**188,949**	**220,779**	**188,493**	**195,874**	**87,802**	**37,624**	**34,563**	**18,919**	**24,814**	**31,570**	**58,018**	**1,185,512**
Interruptible	**0**	**0**	**0**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Commercial//Industrial Gas													
Charged	128,735	249,051	343,113	382,390	294,687	219,979	109,838	68,320	52,222	44,321	51,079	64,675	2,008,410
Uncharged Current	86,510	187,571	211,883	161,058	189,331	110,535	63,837	46,431	30,954	36,789	39,357	67,885	1,232,141
Uncharged Prior	-53,128	-86,510	-187,571	-211,883	-161,058	-189,331	-110,535	-63,837	-46,431	-30,954	-36,789	-39,357	-1,217,384
Total C/I Gas	**162,117**	**350,112**	**367,425**	**331,565**	**322,960**	**141,183**	**63,140**	**50,914**	**36,745**	**50,156**	**53,647**	**93,203**	**2,023,167**
Transportation													
Charged	458,963	632,036	755,229	717,908	654,897	510,872	374,203	303,265	271,297	277,146	280,485	359,260	5,595,561
Uncharged Current	220,034	357,258	356,555	242,253	328,889	208,235	186,603	182,629	128,767	179,950	160,736	269,611	2,821,520
Uncharged Prior	-177,736	-220,034	-357,258	-356,555	-242,253	-328,889	-208,235	-186,603	-182,629	-128,767	-179,950	-160,736	-2,729,645
Total Transportation	**501,261**	**769,260**	**754,526**	**603,606**	**741,533**	**390,218**	**352,571**	**299,291**	**217,435**	**328,329**	**261,271**	**468,135**	**5,687,436**
Company Use	**456**	**732**	**1,162**	**1,488**	**1,166**	**858**	**327**	**75**	**165**	**119**	**166**	**201**	**6,916**
Total Throughput OUT	**761,941**	**1,309,053**	**1,343,892**	**1,125,152**	**1,261,533**	**620,061**	**453,662**	**384,843**	**273,264**	**403,418**	**346,654**	**619,557**	**8,903,031**
Total Throughput IN	**821,201**	**1,190,962**	**1,397,377**	**1,201,215**	**1,041,067**	**738,489**	**507,048**	**386,280**	**343,954**	**362,858**	**369,481**	**576,177**	**8,936,109**
Difference IN/OUT	59,259	-118,091	53,485	76,063	-220,466	118,428	53,387	1,437	70,690	-40,561	22,828	-43,380	33,078
%													0.37%

Attachment A
Updated July 2012

NORTHERN UTILITIES, INC. - MAINE DIVISION
2011 OFF-PEAK WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
November 2010 - October 2011

OFF PEAK DEMAND - ACCOUNT 182.20

	BEGINNING BALANCE	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	WKG CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	(D)	E = B + (D)	F = A + E	G = (A + F) / 2	H	I = G * (H/12)	J = F + I
NOVEMBER	1,375	-	0.4410%	(240)	(240)	1,135	1,255	2.25%	2	1,137
DECEMBER	1,137	-	0.4410%	(3)	(3)	1,134	1,136	2.26%	2	1,136
JANAUARY 2011	1,136	-	0.4410%	2	2	1,138	1,137	2.26%	2	1,140
FEBRUARY	1,140	-	0.4410%	1	1	1,141	1,141	2.26%	2	1,143
MARCH	1,143	-	0.4410%	1	1	1,143.84	1,143.51	2.26%	2.15	1,145.99
APRIL	1,146	-	0.4410%	(0)	(0)	1,146	1,146	2.22%	2	1,148
MAY	1,148	953	0.4410%	(1,990)	(1,037)	111	629	2.20%	1	112
JUNE	112	915	0.4410%	(512)	403	515	313	2.19%	1	515
JULY	515	906	0.4410%	(906)	(0)	515	515	2.19%	1	516
AUGUST	516	912	0.4410%	(795)	118	634	575	2.21%	1	635
SEPTEMBER	635	927	0.4410%	(979)	(51)	584	609	2.23%	1	585
OCTOBER	585	978	0.4410%	(1,630)	(652)	(67)	259	2.08%	0	(67)
TOTALS		5,592		(7,052)					18	

OFF PEAK COMMODITY - ACCOUNT 182.21

	BEGINNING BALANCE	WKG CAP ALLOWANCE	WORKING CAP PERCENTAGE	WKG CAP COLLECTIONS	DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	(D)	E = B + (D)	F = A + E	G = (A + F) / 2	H	I = G * (H/12)	J = F + I
NOVEMBER	1,446	(34)	0.4410%	(835)	(869)	577	1,012	2.25%	2	579
DECEMBER	579	(86)	0.4410%	(10)	(96)	483	531	2.26%	1	484
JANAUARY 2011	484	0	0.4410%	5	5	489	487	2.26%	1	490
FEBRUARY	490	0	0.4410%	2	2	492	491	2.26%	1	493
MARCH	493	0	0.4410%	1	1	494	494	2.26%	1	495
APRIL	495	10	0.4410%	(1)	10	505	500	2.22%	1	506
MAY	506	2,871	0.4410%	(4,327)	(1,456)	(950)	(222)	2.20%	(0)	(951)
JUNE	(951)	1,547	0.4410%	(1,126)	421	(530)	(740)	2.19%	(1)	(531)
JULY	(531)	1,262	0.4410%	(1,977)	(716)	(1,247)	(889)	2.19%	(2)	(1,249)
AUGUST	(1,249)	1,699	0.4410%	(1,737)	(39)	(1,287)	(1,268)	2.21%	(2)	(1,290)
SEPTEMBER	(1,290)	1,457	0.4410%	(2,133)	(676)	(1,966)	(1,628)	2.23%	(3)	(1,969)
OCTOBER	(1,969)	2,979	0.4410%	(3,549)	(571)	(2,539)	(2,254)	2.08%	(4)	(2,543)
TOTALS		11,705		(15,688)					(6)	
COMBINED TOTALS		17,297		(22,740)					12	

Attachment B
Updated July 2012

NORTHERN UTILITIES, INC - MAINE DIVISION
2011 OFF PEAK BAD DEBT CALCULATION OF COLLECTION ALLOWANCE
November 2010 - October 2011

ACCOUNT 182.22

	BEG. BAL	MAINE GAS COSTS PER BOOKS ALLOWED FOR BAD DEBT	BAD DEBT % ALLOWED	ACTUAL BAD DEBT ALLOWANCE(1)	ACTUAL BAD DEBT COLLECTION	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	(E)	F = D + (E)	G = A + F	H = (A+G)/2	I = G*(H/12)	J = F + I	
NOVEMBER	3,093	(7,764)	1.06%	(82)	362	280	3,372	3,232	2.25%	6	3,378
DECEMBER	3,378	(19,548)	1.06%	(207)	(33)	(240)	3,138	3,258	2.26%	6	3,144
JANUARY 201	3,144	0	1.06%	0	17	17	3,161	3,152	2.26%	6	3,167
FEBRUARY	3,167	0	1.06%	0	8	8	3,175	3,171	2.26%	6	3,181
MARCH	3,181	0	1.06%	0	4	4	3,184	3,183	2.26%	6	3,190
APRIL	3,190	2,312	1.06%	25	(2)	23	3,213	3,202	2.22%	6	3,219
MAY	3,219	870,981	1.06%	9,232	(13,660)	(4,428)	(1,209)	1,005	2.20%	2	(1,207)
JUNE	(1,207)	560,765	1.06%	5,944	(3,543)	2,401	1,194	(6)	2.19%	(0)	1,194
JULY	1,194	493,611	1.06%	5,232	(6,229)	(997)	198	696	2.19%	1	199
AUGUST	199	594,703	1.06%	6,304	(5,468)	836	1,035	617	2.21%	1	1,036
SEPTEMBER	1,036	543,134	1.06%	5,757	(6,719)	(962)	75	556	2.23%	1	76
OCTOBER	76	901,232	1.06%	9,553	(11,183)	(1,630)	(1,555)	(739)	2.08%	(1)	(1,556)
TOTALS				41,758	(46,446)					40	

(1) Bad Debt Allowance calculated by multiplying Bad Debt % Allowed times Gas Cost on Schedule 4 and Working Capital Allowance on Attachment A.

Attachment C
Page 1 of 2

NORTHERN UTILITIES - MAINE DIVISION
SALES VARIANCE ANALYSIS
OFF PEAK PERIOD 2011

	May	June	July	August	September	October	Total
Forecast Calendar Month Sales (Weather Normalized)	130,795	78,333	53,582	76,791	96,425	159,129	595,055
Actual Calendar Month Sales	102,532	78,079	52,549	71,189	81,154	144,330	529,833
Volume Variance due to Weather	4,217	-	-	-	-	39,851	44,068
Weather Normal Actual Calender Sales	106,749	78,079	52,549	71,189	81,154	184,181	573,901
Total Variance in Weather Normalized Sales	(24,046)	(254)	(1,033)	(5,602)	(15,271)	25,052	21,154

Variance-change in meter count	(7,202)
-change in load pattern	(14,453)
	(21,655)

Attachment C
Page 2 of 2

NORTHERN UTILITIES - MAINE DIVISION
SALES VARIANCE ANALYSIS
OFF PEAK PERIOD 2011

	Normal Mcf			Meters		
	2011 Actual	2011 Forecast	Difference	2011 Actual	2011 Forecast	Difference
Res Heat	183,404	182,973	431	84,949	86,521	(1,572)
Res Non Heat	28,163	27,882	281	29,202	28,598	604
Total Res	**211,567**	**210,855**	**712**	**114,151**	**115,119**	**(968)**
G-50	60,820	60,082	738	7,862	7,957	(95)
G-40	113,728	111,521	2,207	26,781	27,105	(324)
G-51	45,176	55,421	(10,245)	668	676	(8)
G-41	107,410	113,924	(6,514)	2,251	2,278	(27)
G-52	24,763	18,397	6,366	28	28	(0)
G-42	10,437	25,356	(14,919)	42	43	(1)
Total Commercial and Industrial	**362,334**	**384,701**	**(22,367)**	**37,632**	**38,087**	**(455)**
Total Company	573,901	595,556	(21,655)	151,783	153,206	(1,423)

	Normal Average Use			Change in Sales Due to Change in:		Total	
	2011 Actual	2011 Forecast	Difference	Meter Count	Load Pattern	Total Change Mcf	% Difference
Res Heat	2.16	2.11	0.05	(3,396)	3,827	431	0.24%
Res Non Heat	0.96	0.97	(0.01)	580	(299)	281	1.01%
Total Res	**1.85**	**1.83**	**0.02**	**(2,816)**	**3,528**	**712**	**0.34%**
G-50	7.74	7.55	0.19	(736)	1,474	738	1.23%
G-40	4.25	4.11	0.14	(1,377)	3,584	2,207	1.98%
G-51	67.63	81.97	(14.34)	(547)	(9,698)	(10,245)	-18.49%
G-41	47.72	50.01	(2.29)	(1,300)	(5,214)	(6,514)	-5.72%
G-52	884.39	649.18	235.21	(300)	6,666	6,366	34.60%
G-42	248.50	596.50	(348.00)	(126)	(14,793)	(14,919)	-58.84%
Total Commercial and Industrial	**9.63**	**10.10**	**(0.47)**	**(4,386)**	**(17,981)**	**(22,367)**	**-5.81%**
Total Company	3.78	3.89	(0.11)	(7,202)	(14,453)	(21,655)	-3.64%

Schedule 14

Recalculation of Commodity Allocation Ratios
(Original and Recast)

Northern Utilities
Variable Gas Commodity Allocators
Period: Dec 2008 through Oct 2011 (recast ratios) - Version 4

RATIOS RECAST TO REFLECT THE REMOVAL OF COMPANY MANAGED FROM THE LAUF ADJUSTMENT (EFF. DEC 2008) WITH LAUF RATE ADJ ANNUALLY IN NOVEMBER (EFF. NOV 2010), THE CORRECTION OF NEW HAMPSHIRE COMPANY MANAGED (DEC 2008-MAR 2009) AND THE ADDITION OF MAINE COMPANY MANAGED (EFF. DEC 2008)

Line #	Description	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
1	***New Hampshire:***																
2	Billed Sales - Therms	4,745,563	7,255,630	6,509,587	5,391,971	3,829,357	1,866,319	1,377,155	1,083,629	880,612	895,399	1,359,765	2,484,761	3,663,381	6,920,318	5,743,633	4,453,776
3	Less: Interruptible Sales	(15,584)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Plus: Company Managed Therms	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Plus: Company Use - Therms	2,031	3,430	2,188	3,275	1,903	880	468	47	10	65	206	377	827	1,366	1,175	762
6		4,732,010	7,259,060	6,511,775	5,395,246	3,831,260	1,867,199	1,377,623	1,083,676	880,623	895,464	1,359,970	2,485,138	3,664,208	6,921,684	5,744,808	4,454,538
7	Conversion Factor for Dth	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
8	Tariff Sales Volumes Dth (Billed & Unbilled)	473,201	725,906	651,178	539,525	383,126	186,720	137,762	108,368	88,062	89,546	135,997	248,514	366,421	692,168	574,481	445,454
9	Adj Factor - Lost and Unaccounted For (LAUF)	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100
10	Subtotal	477,933	733,165	657,689	544,920	386,957	188,587	139,140	109,451	88,943	90,442	137,357	250,999	370,085	699,090	580,226	449,908
11	Plus: Co-Managed (Dth)	15,449	47,636	10,964	9,096	2,494	2,578	2,495	2,578	2,578	2,495	2,547	2,969	41,993	64,706	56,633	58,744
12	Less: Newington Free Gas (Dth)	(64,319)	(23,392)	(21,128)	(23,392)	(55,807)	(23,392)	(22,637)	(23,392)	(23,392)	(22,637)	(23,392)	(22,637)	(5,881)	-	-	-
14	**Adj Volumes (Dth) - New Hampshire Division**	429,063	757,409	647,525	530,624	333,645	167,773	118,998	88,638	68,129	70,300	116,512	231,331	406,197	763,796	636,859	508,652
15	***Maine:***																
16	Billed Sales - Ccf	4,004,257	5,678,163	5,095,832	4,647,309	2,628,453	1,579,303	1,013,866	1,067,790	635,453	966,207	1,161,638	2,107,002	3,285,642	5,453,140	4,413,081	3,463,830
17	Less: Interruptible Sales	(91)	-	-	-	(4,660)	(3,176)	1,442	-	-	(356,500)	-	-	-	-	-	-
18	Plus: Company Managed - Ccf	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Plus: Company Use - Ccf	7,700	9,971	8,757	8,397	4,090	11,966	2,837	1,420	1,497	569	2,762	4,220	5,117	10,969	8,325	7,648
20	Subtotal	4,011,866	5,688,134	5,104,589	4,655,706	2,627,883	1,588,093	1,018,145	1,069,211	636,950	610,276	1,164,400	2,111,222	3,290,759	5,464,109	4,421,407	3,471,478
21	Conversion Factor to Mcf	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
22	Subtotal	401,187	568,813	510,459	465,571	262,788	158,809	101,814	106,921	63,695	61,028	116,440	211,122	329,076	546,411	442,141	347,148
23	ME Pipeline Conversion BTU Factor:	1.0490	1.0380	1.0380	1.0420	1.0440	1.0680	1.0470	1.0560	1.0220	1.0540	1.0499	1.0426	1.0435	1.0429	1.0450	1.0486
24	Tariff Sales Volumes Dth (Billed & Unbilled)	420,845	590,428	529,856	485,125	274,351	169,608	106,600	112,909	65,096	64,323	122,248	220,108	343,404	569,868	462,037	364,019
25	Adj Factor - Lost and Unaccounted For (LAUF)	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200
26	Subtotal	429,262	602,237	540,453	494,827	279,838	173,001	108,732	115,167	66,398	65,610	124,693	224,510	350,272	581,266	471,278	371,300
27	Plus: Co-Managed (Dth)	45,678	116,982	26,381	18,193	-	-	-	-	-	-	-	10,803	74,302	114,713	98,281	71,102
28	Less: Newington Free Gas (Dth)	(53,481)	(19,450)	(17,568)	(19,450)	(46,403)	(19,450)	(18,823)	(19,450)	(19,450)	(18,823)	(19,450)	(18,823)	(4,890)	-	-	-
29	**Adj Volumes (Dth) - Maine Division**	421,458	699,769	549,267	493,570	233,435	153,550	89,909	95,717	46,948	46,787	105,243	216,490	419,684	695,979	569,559	442,402
30	**Adj Volumes (Dth) - Both Divisions**	850,522	1,457,178	1,196,792	1,024,194	567,079	321,324	208,907	184,354	115,077	117,086	221,755	447,821	825,881	1,459,775	1,206,417	951,054
31	**Variable Commodity Allocation - New Hampshire**	50.4471%	51.9778%	54.1051%	51.8089%	58.8356%	52.2132%	56.9622%	48.0800%	59.2030%	60.0408%	52.5410%	51.6571%	49.1835%	52.3229%	52.7892%	53.4830%
32	**Variable Commodity Allocation - Maine**	49.5529%	48.0222%	45.8949%	48.1911%	41.1644%	47.7868%	43.0378%	51.9200%	40.7970%	39.9592%	47.4590%	48.3429%	50.8165%	47.6771%	47.2108%	46.5170%
33	**Total *(rounding check - s/b 100%):***	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%
	Variance to Original - NH	-2.1224%	-2.9777%	-0.9228%	-0.6305%	-0.0018%	-0.0038%	-0.0051%	-0.0073%	-0.0092%	-0.0085%	-0.0054%	-1.2801%	-4.8880%	-4.48%	-4.70%	-4.35%
	Variance to Original - ME	2.1224%	2.9777%	0.9228%	0.6305%	0.0018%	0.0038%	0.0051%	0.0073%	0.0092%	0.0085%	0.0054%	1.2801%	4.8880%	4.48%	4.70%	4.35%

Northern Utilities
Variable Gas Commodity Allocators
Period: Dec 2008 through Oct 2011 (recast ratios) - Version 3

RATIOS RECAST TO REFLECT THE REMOVAL OF COMPANY MANAGED FROM THE LAUF ADJUSTMENT (EFF. DEC 2008) WITH LAUF RATE ADJ ANNUALLY IN NOVEMBER (EFF. NOV 2010) AND THE CORRECTION OF NEW HAMPSHIRE COMPANY MANAGED (DEC 2008-MAR 2009)

		Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
1	***New Hampshire:***																
2	Billed Sales - Therms	4,745,563	7,255,630	6,509,587	5,391,971	3,829,357	1,866,319	1,377,155	1,083,629	880,612	895,399	1,359,765	2,484,761	3,663,381	6,920,318	5,743,633	4,453,776
3	Less: Interruptible Sales	(15,584)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Plus: Company Managed Therms	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Plus: Company Use - Therms	2,031	3,430	2,188	3,275	1,903	880	468	47	10	65	206	377	827	1,366	1,175	762
6		4,732,010	7,259,060	6,511,775	5,395,246	3,831,260	1,867,199	1,377,623	1,083,676	880,623	895,464	1,359,970	2,485,138	3,664,208	6,921,684	5,744,808	4,454,538
7	Conversion Factor for Dth	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
8	Tariff Sales Volumes Dth (Billed & Unbilled)	473,201	725,906	651,178	539,525	383,126	186,720	137,762	108,368	88,062	89,546	135,997	248,514	366,421	692,168	574,481	445,454
9	Adj Factor - Lost and Unaccounted For (LAUF)	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100
10	Subtotal	477,933	733,165	657,689	544,920	386,957	188,587	139,140	109,451	88,943	90,442	137,357	250,999	370,085	699,090	580,226	449,908
11	**Plus: Co-Managed (Dth)**	15,449	47,636	10,964	9,096	2,494	2,578	2,495	2,578	2,578	2,495	2,547	2,969	41,993	64,706	56,633	58,744
12	Less: Newington Free Gas (Dth)	(64,319)	(23,392)	(21,128)	(23,392)	(55,807)	(23,392)	(22,637)	(23,392)	(23,392)	(22,637)	(23,392)	(22,637)	(5,881)	-	-	-
14	**Adj Volumes (Dth) - New Hampshire Division**	429,063	757,409	647,525	530,624	333,645	167,773	118,998	88,638	68,129	70,300	116,512	231,331	406,197	763,796	636,859	508,652
15	***Maine:***																
16	Billed Sales - Ccf	4,004,257	5,678,163	5,095,832	4,647,309	2,628,453	1,579,303	1,013,866	1,067,790	635,453	966,207	1,161,638	2,107,002	3,285,642	5,453,140	4,413,081	3,463,830
17	Less: Interruptible Sales	(91)	-	-	-	(4,660)	(3,176)	1,442	-	-	(356,500)	-	-	-	-	-	-
18	Plus: Company Managed - Ccf	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Plus: Company Use - Ccf	7,700	9,971	8,757	8,397	4,090	11,966	2,837	1,420	1,497	569	2,762	4,220	5,117	10,969	8,325	7,648
20	Subtotal	4,011,866	5,688,134	5,104,589	4,655,706	2,627,883	1,588,093	1,018,145	1,069,211	636,950	610,276	1,164,400	2,111,222	3,290,759	5,464,109	4,421,407	3,471,478
21	Conversion Factor to Mcf	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
22	Subtotal	401,187	568,813	510,459	465,571	262,788	158,809	101,814	106,921	63,695	61,028	116,440	211,122	329,076	546,411	442,141	347,148
23	ME Pipeline Conversion BTU Factor:	1.0490	1.0380	1.0380	1.0420	1.0440	1.0680	1.0470	1.0560	1.0220	1.0540	1.0499	1.0426	1.0435	1.0429	1.0450	1.0486
24	Tariff Sales Volumes Dth (Billed & Unbilled)	420,845	590,428	529,856	485,125	274,351	169,608	106,600	112,909	65,096	64,323	122,248	220,108	343,404	569,868	462,037	364,019
25	Adj Factor - Lost and Unaccounted For (LAUF)	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200
26	Subtotal	429,262	602,237	540,453	494,827	279,838	173,001	108,732	115,167	66,398	65,610	124,693	224,510	350,272	581,266	471,278	371,300
27	**Plus: Co-Managed (Dth)**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Less: Newington Free Gas (Dth)	(53,481)	(19,450)	(17,568)	(19,450)	(46,403)	(19,450)	(18,823)	(19,450)	(19,450)	(18,823)	(19,450)	(18,823)	(4,890)	-	-	-
29	**Adj Volumes (Dth) - Maine Division**	375,780	582,787	522,886	475,377	233,435	153,550	89,909	95,717	46,948	46,787	105,243	205,687	345,382	581,266	471,278	371,300
30	**Adj Volumes (Dth) - Both Divisions**	804,844	1,340,196	1,170,411	1,006,001	567,079	321,324	208,907	184,354	115,077	117,086	221,755	437,018	751,579	1,345,062	1,108,136	879,952
31	**Variable Commodity Allocation - New Hampshire**	53.3101%	56.5148%	55.3246%	52.7459%	58.8356%	52.2132%	56.9622%	48.0800%	59.2030%	60.0408%	52.5410%	52.9340%	54.0458%	56.7852%	57.4711%	57.8046%
32	**Variable Commodity Allocation - Maine**	46.6899%	43.4852%	44.6754%	47.2541%	41.1644%	47.7868%	43.0378%	51.9200%	40.7970%	39.9592%	47.4590%	47.0660%	45.9542%	43.2148%	42.5289%	42.1954%
33	**Total *(rounding check - s/b 100%)*:**	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%
	Variance to Original - NH	0.7406%	1.5593%	0.2967%	0.3065%	-0.0018%	-0.0038%	-0.0051%	-0.0073%	-0.0092%	-0.0085%	-0.0054%	-0.0032%	-0.0257%	-0.0208%	-0.0218%	-0.0281%
	Variance to Original - ME	-0.7406%	-1.5593%	-0.2967%	-0.3065%	0.0018%	0.0038%	0.0051%	0.0073%	0.0092%	0.0085%	0.0054%	0.0032%	0.0257%	0.0208%	0.0218%	0.0281%

Northern Utilities
Gas Cost Allocators
Period: Dec 2008 through Oct 2011 (recast ratios) - Version 2

RATIOS RECAST TO REFLECT THE REMOVAL OF COMPANY MANAGED FROM THE LAUF ADJUSTMENT (EFF. DEC 2008) WITH LAUF RATE ADJ ANNUALLY IN NOVEMBER (EFF. NOV 2010)

		Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
1	***New Hampshire:***																
2	Billed Sales - Therms	4,745,563	7,255,630	6,509,587	5,391,971	3,829,357	1,866,319	1,377,155	1,083,629	880,612	895,399	1,359,765	2,484,761	3,663,381	6,920,318	5,743,633	4,453,776
3	Less: Interruptible Sales	(15,584)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Plus: Company Managed Therms	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Plus: Company Use - Therms	2,031	3,430	2,188	3,275	1,903	880	468	47	10	65	206	377	827	1,366	1,175	762
6		4,732,010	7,259,060	6,511,775	5,395,246	3,831,260	1,867,199	1,377,623	1,083,676	880,623	895,464	1,359,970	2,485,138	3,664,208	6,921,684	5,744,808	4,454,538
7	Conversion Factor for Dth	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
8	Tariff Sales Volumes Dth (Billed & Unbilled)	473,201	725,906	651,178	539,525	383,126	186,720	137,762	108,368	88,062	89,546	135,997	248,514	366,421	692,168	574,481	445,454
9	Adj Factor - Lost and Unaccounted For (LAUF)	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100
10	Subtotal	477,933	733,165	657,689	544,920	386,957	188,587	139,140	109,451	88,943	90,442	137,357	250,999	370,085	699,090	580,226	449,908
11	**Plus: Co-Managed (Dth)**	2,852	1,230	3,209	2,588	2,494	2,578	2,495	2,578	2,578	2,495	2,547	2,969	41,993	64,706	56,633	58,744
12	Less: Newington Free Gas (Dth)	(64,319)	(23,392)	(21,128)	(23,392)	(55,807)	(23,392)	(22,637)	(23,392)	(23,392)	(22,637)	(23,392)	(22,637)	(5,881)	-	-	-
14	**Adj Volumes (Dth) - New Hampshire Division**	416,466	711,003	639,770	524,116	333,645	167,773	118,998	88,638	68,129	70,300	116,512	231,331	406,197	763,796	636,859	508,652
15	***Maine:***																
16	Billed Sales - Ccf	4,004,257	5,678,163	5,095,832	4,647,309	2,628,453	1,579,303	1,013,866	1,067,790	635,453	966,207	1,161,638	2,107,002	3,285,642	5,453,140	4,413,081	3,463,830
17	Less: Interruptible Sales	(91)	-	-	-	(4,660)	(3,176)	1,442	-	-	(356,500)	-	-	-	-	-	-
18	Plus: Company Managed - Ccf	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Plus: Company Use - Ccf	7,700	9,971	8,757	8,397	4,090	11,966	2,837	1,420	1,497	569	2,762	4,220	5,117	10,969	8,325	7,648
20	Subtotal	4,011,866	5,688,134	5,104,589	4,655,706	2,627,883	1,588,093	1,018,145	1,069,211	636,950	610,276	1,164,400	2,111,222	3,290,759	5,464,109	4,421,407	3,471,478
21	Conversion Factor to Mcf	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
22	Subtotal	401,187	568,813	510,459	465,571	262,788	158,809	101,814	106,921	63,695	61,028	116,440	211,122	329,076	546,411	442,141	347,148
23	ME Pipeline Conversion BTU Factor:	1.0490	1.0380	1.0380	1.0420	1.0440	1.0680	1.0470	1.0560	1.0220	1.0540	1.0499	1.0426	1.0435	1.0429	1.0450	1.0486
24	Tariff Sales Volumes Dth (Billed & Unbilled)	420,845	590,428	529,856	485,125	274,351	169,608	106,600	112,909	65,096	64,323	122,248	220,108	343,404	569,868	462,037	364,019
25	Adj Factor - Lost and Unaccounted For (LAUF)	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200
26	Subtotal	429,262	602,237	540,453	494,827	279,838	173,001	108,732	115,167	66,398	65,610	124,693	224,510	350,272	581,266	471,278	371,300
27	**Plus: Co-Managed (Dth)**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Less: Newington Free Gas (Dth)	(53,481)	(19,450)	(17,568)	(19,450)	(46,403)	(19,450)	(18,823)	(19,450)	(19,450)	(18,823)	(19,450)	(18,823)	(4,890)	-	-	-
29	**Adj Volumes (Dth) - Maine Division**	375,780	582,787	522,886	475,377	233,435	153,550	89,909	95,717	46,948	46,787	105,243	205,687	345,382	581,266	471,278	371,300
30	**Adj Volumes (Dth) - Both Divisions**	792,247	1,293,790	1,162,656	999,493	567,079	321,324	208,907	184,354	115,077	117,086	221,755	437,018	751,579	1,345,062	1,108,136	879,952
31	**Variable Commodity Allocation - New Hampshire**	52.5677%	54.9551%	55.0266%	52.4382%	58.8356%	52.2132%	56.9622%	48.0800%	59.2030%	60.0408%	52.5410%	52.9340%	54.0458%	56.7852%	57.4711%	57.8046%
32	**Variable Commodity Allocation - Maine**	47.4323%	45.0449%	44.9734%	47.5618%	41.1644%	47.7868%	43.0378%	51.9200%	40.7970%	39.9592%	47.4590%	47.0660%	45.9542%	43.2148%	42.5289%	42.1954%
33	**Total *(rounding check - s/b 100%)*:**	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%
	Variance to Original - NH	-0.0018%	-0.0004%	-0.0013%	-0.0012%	-0.0018%	-0.0038%	-0.0051%	-0.0073%	-0.0092%	-0.0085%	-0.0054%	-0.0032%	-0.0257%	-0.0208%	-0.0218%	-0.0281%
	Variance to Original - ME	0.0018%	0.0004%	0.0013%	0.0012%	0.0018%	0.0038%	0.0051%	0.0073%	0.0092%	0.0085%	0.0054%	0.0032%	0.0257%	0.0208%	0.0218%	0.0281%

Northern Utilities
Gas Cost Allocators
Period: Dec 2008 through Oct 2011 (original ratios) - Version 1

ORIGINAL CALCULATIONS THROUGH OCTOBER. METHODOLOGY CORRECTED FOR NOVEMBER 2011 AND FORWARD

		Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
1	***New Hampshire:***																
2	Billed Sales - Therms	4,745,563	7,255,630	6,509,587	5,391,971	3,829,357	1,866,319	1,377,155	1,083,629	880,612	895,399	1,359,765	2,484,761	3,663,381	6,920,318	5,743,633	4,453,776
3	Less: Interruptible Sales	(15,584)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Plus: Company Managed Therms	28,520	12,300	32,090	25,880	24,940	25,780	24,950	25,780	25,780	24,950	25,470	29,690	419,930	647,060	566,330	587,440
5	Plus: Company Use - Therms	2,031	3,430	2,188	3,275	1,903	880	468	47	10	65	206	377	827	1,366	1,175	762
6		4,760,530	7,271,360	6,543,865	5,421,126	3,856,200	1,892,979	1,402,573	1,109,456	906,403	920,414	1,385,440	2,514,828	4,084,138	7,568,744	6,311,138	5,041,978
7	Conversion Factor for Dth	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
8	Tariff Sales Volumes Dth (Billed & Unbilled)	476,053	727,136	654,387	542,113	385,620	189,298	140,257	110,946	90,640	92,041	138,544	251,483	408,414	756,874	631,114	504,198
9	Adj Factor - Lost and Unaccounted For (LAUF)	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100
10	Subtotal	480,814	734,407	660,930	547,534	389,476	191,191	141,660	112,055	91,547	92,962	139,929	253,998	412,498	764,443	637,425	509,240
11	Plus: Co-Managed (Dth)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Less: Newington Free Gas (Dth)	(64,319)	(23,392)	(21,128)	(23,392)	(55,807)	(23,392)	(22,637)	(23,392)	(23,392)	(22,637)	(23,392)	(22,637)	(5,881)	-	-	-
14	**Adj Volumes (Dth) - New Hampshire Division**	416,495	711,016	639,802	524,142	333,670	167,799	119,023	88,663	68,155	70,325	116,538	231,361	406,617	764,443	637,425	509,240
15	***Maine:***																
16	Billed Sales - Ccf	4,004,257	5,678,163	5,095,832	4,647,309	2,628,453	1,579,303	1,013,866	1,067,790	635,453	966,207	1,161,638	2,107,002	3,285,642	5,453,140	4,413,081	3,463,830
17	Less: Interruptible Sales	(91)	-	-	-	(4,660)	(3,176)	1,442	-	-	(356,500)	-	-	-	-	-	-
18	Plus: Company Managed - Ccf	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Plus: Company Use - Ccf	7,700	9,971	8,757	8,397	4,090	11,966	2,837	1,420	1,497	569	2,762	4,220	5,117	10,969	8,325	7,648
20	Subtotal	4,011,866	5,688,134	5,104,589	4,655,706	2,627,883	1,588,093	1,018,145	1,069,211	636,950	610,276	1,164,400	2,111,222	3,290,759	5,464,109	4,421,407	3,471,478
21	Conversion Factor to Mcf	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
22	Subtotal	401,187	568,813	510,459	465,571	262,788	158,809	101,814	106,921	63,695	61,028	116,440	211,122	329,076	546,411	442,141	347,148
23	ME Pipeline Conversion BTU Factor:	1.0490	1.0380	1.0380	1.0420	1.0440	1.0680	1.0470	1.0560	1.0220	1.0540	1.0499	1.0426	1.0435	1.0429	1.0450	1.0486
24	Tariff Sales Volumes Dth (Billed & Unbilled)	420,845	590,428	529,856	485,125	274,351	169,608	106,600	112,909	65,096	64,323	122,248	220,108	343,404	569,868	462,037	364,019
25	Adj Factor - Lost and Unaccounted For (LAUF)	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200
26	Subtotal	429,262	602,237	540,453	494,827	279,838	173,001	108,732	115,167	66,398	65,610	124,693	224,510	350,272	581,266	471,278	371,300
27	Plus: Co-Managed (Dth)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Less: Newington Free Gas (Dth)	(53,481)	(19,450)	(17,568)	(19,450)	(46,403)	(19,450)	(18,823)	(19,450)	(19,450)	(18,823)	(19,450)	(18,823)	(4,890)	-	-	-
29	**Adj Volumes (Dth) - Maine Division**	375,780	582,787	522,886	475,377	233,435	153,550	89,909	95,717	46,948	46,787	105,243	205,687	345,382	581,266	471,278	371,300
30	**Adj Volumes (Dth) - Both Divisions**	792,275	1,293,802	1,162,688	999,519	567,104	321,349	208,932	184,380	115,103	117,111	221,780	437,047	751,999	1,345,709	1,108,703	880,539
31	**Variable Commodity Allocation - New Hampshire**	52.5695%	54.9555%	55.0279%	52.4394%	58.8374%	52.2170%	56.9673%	48.0873%	59.2122%	60.0493%	52.5464%	52.9372%	54.0715%	56.8060%	57.4929%	57.8327%
32	**Variable Commodity Allocation - Maine**	47.4305%	45.0445%	44.9721%	47.5606%	41.1626%	47.7830%	43.0327%	51.9127%	40.7878%	39.9507%	47.4536%	47.0628%	45.9285%	43.1940%	42.5071%	42.1673%
33	**Total *(rounding check - s/b 100%)*:**	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%

Northern Utilities
Variable Gas Commodity Allocators
Period: Dec 2008 through Oct 2011 (recast ratios)

RATIOS RECAST TO REFLECT THE REMOVAL OF COMPANY MANAGED FROM THE LAUF ADJUSTMENT (EFF. DEC 2008) WITH LAUF RATE ADJ ANNUALLY IN NOVEMBER (EFF. NOV 2010), THE CORRECTION OF NEW HAMPSHIRE COMPANY MANAGED (DEC 2008-MAR 2009) AND THE ADDITION OF MAINE COMPANY MANAGED (EFF. DEC 2008)

Line #	Description	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	
	(A)	(R)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)	(AJ)	(AI)
1	***New Hampshire:***																				
2	Billed Sales - Therms	3,162,991	1,902,734	1,048,526	883,627	803,799	880,919	1,089,612	2,292,202	4,040,136	6,341,088	6,777,765	5,326,532	3,955,400	2,045,773	1,337,725	916,318	771,977	871,128	1,016,794	
3	Less: Interruptible Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
4	Plus: Company Managed Therms	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
5	Plus: Company Use - Therms	490	247	67	20	20	60	170	372	853	1,451	1,411	1,037	760	311	294	223	207	27,398	1,016	
6		3,163,481	1,902,981	1,048,593	883,647	803,819	880,979	1,089,782	2,292,574	4,040,989	6,342,539	6,779,176	5,327,569	3,956,160	2,046,084	1,338,019	916,541	772,184	898,526	1,017,810	
7	Conversion Factor for Dth	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
8	Tariff Sales Volumes Dth (Billed & Unbilled)	316,348	190,298	104,859	88,365	80,382	88,098	108,978	229,257	404,099	634,254	677,918	532,757	395,616	204,608	133,802	91,654	77,218	89,853	101,781	
9	Adj Factor - Lost and Unaccounted For (LAUF)	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0096	1.0096	1.0096	1.0096	1.0096	1.0096	1.0096	1.0096	1.0096	1.0096	1.0096	1.0096	
10	Subtotal	319,512	192,201	105,908	89,248	81,186	88,979	110,068	231,458	407,978	640,343	684,426	537,871	399,414	206,573	135,086	92,534	77,960	90,715	102,758	
11	**Plus: Co-Managed (Dth)**	5,197	2,161	2,108	2,167	2,121	2,076	2,180	8,269	78,355	91,811	76,612	57,793	2,786	-	-	-	-	-	-	
12	Less: Newington Free Gas (Dth)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
14	**Adj Volumes (Dth) - New Hampshire Division**	324,709	194,362	108,016	91,415	83,307	91,055	112,248	239,727	486,333	732,154	761,038	595,664	402,200	206,573	135,086	92,534	77,960	90,715	102,758	
15	***Maine:***																				
16	Billed Sales - Ccf	2,486,577	1,434,714	858,729	758,839	653,412	728,403	983,828	1,968,903	3,711,389	5,204,975	5,747,567	4,476,233	3,357,642	1,724,159	1,062,322	774,456	635,947	738,866	938,589	
17	Less: Interruptible Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
18	Plus: Company Managed - Ccf	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
19	Plus: Company Use - Ccf	6,601	3,194	1,536	1,450	1,200	1,210	2,540	4,360	7,029	11,088	14,159	11,080	8,143	3,181	710	1,561	1,132	1,576	1,917	
20	Subtotal	2,493,178	1,437,907	860,265	760,289	654,612	729,613	986,368	1,973,263	3,718,418	5,216,063	5,761,726	4,487,313	3,365,785	1,727,340	1,063,032	776,017	637,079	740,442	940,506	
21	Conversion Factor to Mcf	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
22	Subtotal	249,318	143,791	86,026	76,029	65,461	72,961	98,637	197,326	371,842	521,606	576,173	448,731	336,579	172,734	106,303	77,602	63,708	74,044	94,051	
23	ME Pipeline Conversion BTU Factor:	1.0498	1.0552	1.0547	1.0514	1.0485	1.0550	1.0570	1.0470	1.0420	1.048	1.051	1.052	1.054	1.027	1.057	1.058	1.055	1.052	1.049	
24	Tariff Sales Volumes Dth (Billed & Unbilled)	261,729	151,727	90,732	79,937	68,636	76,974	104,259	206,601	387,459	546,643	605,557	472,065	354,754	177,398	112,362	82,103	67,212	77,894	98,659	
25	Adj Factor - Lost and Unaccounted For (LAUF)	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0115	1.0115	1.0115	1.0115	1.0115	1.0115	1.0115	1.0115	1.0115	1.0115	1.0115	1.0115	
26	Subtotal	266,963	154,761	92,547	81,535	70,009	78,514	106,344	208,977	391,915	552,930	612,521	477,494	358,833	179,438	113,655	83,047	67,985	78,790	99,794	
27	**Plus: Co-Managed (Dth)**	-	-	-	-	-	-	-	40,172	204,028	209,466	145,645	124,173	-	-	-	-	-	-	-	
28	Less: Newington Free Gas (Dth)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
29	**Adj Volumes (Dth) - Maine Division**	266,963	154,761	92,547	81,535	70,009	78,514	106,344	249,149	595,943	762,396	758,166	601,667	358,833	179,438	113,655	83,047	67,985	78,790	99,794	
30	**Adj Volumes (Dth) - Both Divisions**	591,672	349,123	200,563	172,951	153,316	169,569	218,592	488,876	1,082,276	1,494,550	1,519,204	1,197,331	761,033	386,011	248,741	175,581	145,944	169,505	202,552	
31	**Variable Commodity Allocation - New Hampshire**	54.8798%	55.6715%	53.86%	52.86%	54.34%	53.70%	51.35%	49.04%	44.94%	48.99%	50.09%	49.75%	52.85%	53.51%	54.31%	52.70%	53.42%	53.52%	50.73%	
32	**Variable Commodity Allocation - Maine**	45.1202%	44.3285%	46.14%	47.14%	45.66%	46.30%	48.65%	50.96%	55.06%	51.01%	49.91%	50.25%	47.15%	46.49%	45.69%	47.30%	46.58%	46.48%	49.27%	
33	**Total *(rounding check - s/b 100%)*:**	100.0000%	100.0000%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
	Variance to Original - NH	0.00%	0.00%	0.00%	0.00%	-0.01%	-0.01%	-0.01%	-4.20%	-10.28%	-7.82%	-5.14%	-5.58%	0.20%	0.19%	0.20%	0.20%	0.20%	0.20%	0.20%	
	Variance to Original - ME	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%	4.20%	10.28%	7.82%	5.14%	5.58%	-0.20%	-0.19%	-0.20%	-0.20%	-0.20%	-0.20%	-0.20%	

Northern Utilities
Variable Gas Commodity Allocators
Period: Dec 2008 through Oct 2011 **(recast ratios)**

RATIOS RECAST TO REFLECT THE REMOVAL OF COMPANY MANAGED FROM THE LAUF ADJUSTMENT (EFF. DEC 2008) WITH LAUF RATE ADJ ANNUALLY IN NOVEMBER (EFF. NOV 2010) AND THE CORRECTION OF NEW HAMPSHIRE COMPANY MANAGED (DEC 2008-MAR 2009)

		Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11
	(A)	(R)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
1	***New Hampshire:***										
2	Billed Sales - Therms	3,162,991	1,902,734	1,048,526	883,627	803,799	880,919	1,089,612	2,292,202	4,040,136	6,341,088
3	Less: Interruptible Sales	-	-	-	-	-	-	-	-	-	-
4	Plus: Company Managed Therms	-	-	-	-	-	-	-	-	-	-
5	Plus: Company Use - Therms	490	247	67	20	20	60	170	372	853	1,451
6		3,163,481	1,902,981	1,048,593	883,647	803,819	880,979	1,089,782	2,292,574	4,040,989	6,342,539
7	Conversion Factor for Dth	10	10	10	10	10	10	10	10	10	10
8	Tariff Sales Volumes Dth (Billed & Unbilled)	316,348	190,298	104,859	88,365	80,382	88,098	108,978	229,257	404,099	634,254
9	Adj Factor - Lost and Unaccounted For (LAUF)	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0096	1.0096	1.0096
10	Subtotal	319,512	192,201	105,908	89,248	81,186	88,979	110,068	231,458	407,978	640,343
11	**Plus: Co-Managed (Dth)**	5,197	2,161	2,108	2,167	2,121	2,076	2,180	8,269	78,355	91,811
12	Less: Newington Free Gas (Dth)	-	-	-	-	-	-	-	-	-	-
14	**Adj Volumes (Dth) - New Hampshire Division**	324,709	194,362	108,016	91,415	83,307	91,055	112,248	239,727	486,333	732,154
15	***Maine:***										
16	Billed Sales - Ccf	2,486,577	1,434,714	858,729	758,839	653,412	728,403	983,828	1,968,903	3,711,389	5,204,975
17	Less: Interruptible Sales	-	-	-	-	-	-	-	-	-	-
18	Plus: Company Managed - Ccf	-	-	-	-	-	-	-	-	-	-
19	Plus: Company Use - Ccf	6,601	3,194	1,536	1,450	1,200	1,210	2,540	4,360	7,029	11,088
20	Subtotal	2,493,178	1,437,907	860,265	760,289	654,612	729,613	986,368	1,973,263	3,718,418	5,216,063
21	Conversion Factor to Mcf	10	10	10	10	10	10	10	10	10	10
22	Subtotal	249,318	143,791	86,026	76,029	65,461	72,961	98,637	197,326	371,842	521,606
23	ME Pipeline Conversion BTU Factor:	1.0498	1.0552	1.0547	1.0514	1.0485	1.0550	1.0570	1.0470	1.0420	1.048
24	Tariff Sales Volumes Dth (Billed & Unbilled)	261,729	151,727	90,732	79,937	68,636	76,974	104,259	206,601	387,459	546,643
25	Adj Factor - Lost and Unaccounted For (LAUF)	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0115	1.0115	1.0115
26	Subtotal	266,963	154,761	92,547	81,535	70,009	78,514	106,344	208,977	391,915	552,930
27	**Plus: Co-Managed (Dth)**	-	-	-	-	-	-	-	-	-	-
28	Less: Newington Free Gas (Dth)	-	-	-	-	-	-	-	-	-	-
29	**Adj Volumes (Dth) - Maine Division**	266,963	154,761	92,547	81,535	70,009	78,514	106,344	208,977	391,915	552,930
30	**Adj Volumes (Dth) - Both Divisions**	591,672	349,123	200,563	172,951	153,316	169,569	218,592	448,704	878,248	1,285,084
31	**Variable Commodity Allocation - New Hampshire**	54.8798%	55.6715%	53.86%	52.86%	54.34%	53.70%	51.35%	53.43%	55.38%	56.97%
32	**Variable Commodity Allocation - Maine**	45.1202%	44.3285%	46.14%	47.14%	45.66%	46.30%	48.65%	46.57%	44.62%	43.03%
33	**Total *(rounding check - s/b 100%):***	100.0000%	100.0000%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	Variance to Original - NH	-0.0040%	-0.0027%	0.0000%	0.0000%	-0.0100%	-0.0100%	-0.0100%	0.1900%	0.1600%	0.1600%
	Variance to Original - ME	0.0040%	0.0027%	0.0000%	0.0000%	0.0100%	0.0100%	0.0100%	-0.1900%	-0.1600%	-0.1600%

		Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	
	(A)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)	(AJ)	(AI)
1	***New Hampshire:***										
2	Billed Sales - Therms	6,777,765	5,326,532	3,955,400	2,045,773	1,337,725	916,318	771,977	871,128	1,016,794	
3	Less: Interruptible Sales	-	-	-	-	-	-	-	-	-	
4	Plus: Company Managed Therms	-	-	-	-	-	-	-	-	-	
5	Plus: Company Use - Therms	1,411	1,037	760	311	294	223	207	27,398	1,016	
6		6,779,176	5,327,569	3,956,160	2,046,084	1,338,019	916,541	772,184	898,526	1,017,810	
7	Conversion Factor for Dth	10	10	10	10	10	10	10	10	10	
8	Tariff Sales Volumes Dth (Billed & Unbilled)	677,918	532,757	395,616	204,608	133,802	91,654	77,218	89,853	101,781	
9	Adj Factor - Lost and Unaccounted For (LAUF)	1.0096	1.0096	1.0096	1.0096	1.0096	1.0096	1.0096	1.0096	1.0096	
10	Subtotal	684,426	537,871	399,414	206,573	135,086	92,534	77,960	90,715	102,758	
11	**Plus: Co-Managed (Dth)**	76,612	57,793	2,786	-	-	-	-	-	-	
12	Less: Newington Free Gas (Dth)	-	-	-	-	-	-	-	-	-	
14	**Adj Volumes (Dth) - New Hampshire Division**	761,038	595,664	402,200	206,573	135,086	92,534	77,960	90,715	102,758	
15	***Maine:***										
16	Billed Sales - Ccf	5,747,567	4,476,233	3,357,642	1,724,159	1,062,322	774,456	635,947	738,866	938,589	
17	Less: Interruptible Sales	-	-	-	-	-	-	-	-	-	
18	Plus: Company Managed - Ccf	-	-	-	-	-	-	-	-	-	
19	Plus: Company Use - Ccf	14,159	11,080	8,143	3,181	710	1,561	1,132	1,576	1,917	
20	Subtotal	5,761,726	4,487,313	3,365,785	1,727,340	1,063,032	776,017	637,079	740,442	940,506	
21	Conversion Factor to Mcf	10	10	10	10	10	10	10	10	10	
22	Subtotal	576,173	448,731	336,579	172,734	106,303	77,602	63,708	74,044	94,051	
23	ME Pipeline Conversion BTU Factor:	1.051	1.052	1.054	1.027	1.057	1.058	1.055	1.052	1.049	
24	Tariff Sales Volumes Dth (Billed & Unbilled)	605,557	472,065	354,754	177,398	112,362	82,103	67,212	77,894	98,659	
25	Adj Factor - Lost and Unaccounted For (LAUF)	1.0115	1.0115	1.0115	1.0115	1.0115	1.0115	1.0115	1.0115	1.0115	
26	Subtotal	612,521	477,494	358,833	179,438	113,655	83,047	67,985	78,790	99,794	
27	**Plus: Co-Managed (Dth)**	-	-	-	-	-	-	-	-	-	
28	Less: Newington Free Gas (Dth)	-	-	-	-	-	-	-	-	-	
29	**Adj Volumes (Dth) - Maine Division**	612,521	477,494	358,833	179,438	113,655	83,047	67,985	78,790	99,794	
30	**Adj Volumes (Dth) - Both Divisions**	1,373,559	1,073,158	761,033	386,011	248,741	175,581	145,944	169,505	202,552	
31	**Variable Commodity Allocation - New Hampshire**	55.41%	55.51%	52.85%	53.51%	54.31%	52.70%	53.42%	53.52%	50.73%	
32	**Variable Commodity Allocation - Maine**	44.59%	44.49%	47.15%	46.49%	45.69%	47.30%	46.58%	46.48%	49.27%	
33	**Total *(rounding check - s/b 100%):***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
	Variance to Original - NH	0.1800%	0.1800%	0.2000%	0.1900%	0.2000%	0.2000%	0.2000%	0.2000%	0.2000%	
	Variance to Original - ME	-0.1800%	-0.1800%	-0.2000%	-0.1900%	-0.2000%	-0.2000%	-0.2000%	-0.2000%	-0.2000%	

Northern Utilities
Gas Cost Allocators
Period: Dec 2008 through Oct 2011 (recast ratios)

RATIOS RECAST TO REFLECT THE REMOVAL OF COMPANY MANAGED FROM THE LAUF ADJUSTMENT (EFF. DEC 2008) WITH LAUF RATE ADJ ANNUALLY IN NOVEMBER (EFF. NOV 2010)

		Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	
	(A)	(R)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)	(AJ)	(AI)
1	***New Hampshire:***																				
2	Billed Sales - Therms	3,162,991	1,902,734	1,048,526	883,627	803,799	880,919	1,089,612	2,292,202	4,040,136	6,341,088	6,777,765	5,326,532	3,955,400	2,045,773	1,337,725	916,318	771,977	871,128	1,016,794	
3	Less: Interruptible Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
4	Plus: Company Managed Therms	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
5	Plus: Company Use - Therms	490	247	67	20	20	60	170	372	853	1,451	1,411	1,037	760	311	294	223	207	27,398	1,016	
6		3,163,481	1,902,981	1,048,593	883,647	803,819	880,979	1,089,782	2,292,574	4,040,989	6,342,539	6,779,176	5,327,569	3,956,160	2,046,084	1,338,019	916,541	772,184	898,526	1,017,810	
7	Conversion Factor for Dth	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
8	Tariff Sales Volumes Dth (Billed & Unbilled)	316,348	190,298	104,859	88,365	80,382	88,098	108,978	229,257	404,099	634,254	677,918	532,757	395,616	204,608	133,802	91,654	77,218	89,853	101,781	
9	Adj Factor - Lost and Unaccounted For (LAUF)	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0096	1.0096	1.0096	1.0096	1.0096	1.0096	1.0096	1.0096	1.0096	1.0096	1.0096	1.0096	
10	Subtotal	319,512	192,201	105,908	89,248	81,186	88,979	110,068	231,458	407,978	640,343	684,426	537,871	399,414	206,573	135,086	92,534	77,960	90,715	102,758	
11	**Plus: Co-Managed (Dth)**	5,197	2,161	2,108	2,167	2,121	2,076	2,180	8,269	78,355	91,811	76,612	57,793	2,786	-	-	-	-	-	-	
12	Less: Newington Free Gas (Dth)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
14	**Adj Volumes (Dth) - New Hampshire Division**	324,709	194,362	108,016	91,415	83,307	91,055	112,248	239,727	486,333	732,154	761,038	595,664	402,200	206,573	135,086	92,534	77,960	90,715	102,758	
15	***Maine:***																				
16	Billed Sales - Ccf	2,486,577	1,434,714	858,729	758,839	653,412	728,403	983,828	1,968,903	3,711,389	5,204,975	5,747,567	4,476,233	3,357,642	1,724,159	1,062,322	774,456	635,947	738,866	938,589	
17	Less: Interruptible Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
18	Plus: Company Managed - Ccf	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
19	Plus: Company Use - Ccf	6,601	3,194	1,536	1,450	1,200	1,210	2,540	4,360	7,029	11,088	14,159	11,080	8,143	3,181	710	1,561	1,132	1,576	1,917	
20	Subtotal	2,493,178	1,437,907	860,265	760,289	654,612	729,613	986,368	1,973,263	3,718,418	5,216,063	5,761,726	4,487,313	3,365,785	1,727,340	1,063,032	776,017	637,079	740,442	940,506	
21	Conversion Factor to Mcf	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
22	Subtotal	249,318	143,791	86,026	76,029	65,461	72,961	98,637	197,326	371,842	521,606	576,173	448,731	336,579	172,734	106,303	77,602	63,708	74,044	94,051	
23	ME Pipeline Conversion BTU Factor:	1.0498	1.0552	1.0547	1.0514	1.0485	1.0550	1.0570	1.0470	1.0420	1.048	1.051	1.052	1.054	1.027	1.057	1.058	1.055	1.052	1.049	
24	Tariff Sales Volumes Dth (Billed & Unbilled)	261,729	151,727	90,732	79,937	68,636	76,974	104,259	206,601	387,459	546,643	605,557	472,065	354,754	177,398	112,362	82,103	67,212	77,894	98,659	
25	Adj Factor - Lost and Unaccounted For (LAUF)	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0115	1.0115	1.0115	1.0115	1.0115	1.0115	1.0115	1.0115	1.0115	1.0115	1.0115	1.0115	
26	Subtotal	266,963	154,761	92,547	81,535	70,009	78,514	106,344	208,977	391,915	552,930	612,521	477,494	358,833	179,438	113,655	83,047	67,985	78,790	99,794	
27	**Plus: Co-Managed (Dth)**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
28	Less: Newington Free Gas (Dth)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
29	**Adj Volumes (Dth) - Maine Division**	266,963	154,761	92,547	81,535	70,009	78,514	106,344	208,977	391,915	552,930	612,521	477,494	358,833	179,438	113,655	83,047	67,985	78,790	99,794	
30	**Adj Volumes (Dth) - Both Divisions**	591,672	349,123	200,563	172,951	153,316	169,569	218,592	448,704	878,248	1,285,084	1,373,559	1,073,158	761,033	386,011	248,741	175,581	145,944	169,505	202,552	
31	**Variable Commodity Allocation - New Hampshire**	54.8798%	55.6715%	53.86%	52.86%	54.34%	53.70%	51.35%	53.43%	55.38%	56.97%	55.41%	55.51%	52.85%	53.51%	54.31%	52.70%	53.42%	53.52%	50.73%	
32	**Variable Commodity Allocation - Maine**	45.1202%	44.3285%	46.14%	47.14%	45.66%	46.30%	48.65%	46.57%	44.62%	43.03%	44.59%	44.49%	47.15%	46.49%	45.69%	47.30%	46.58%	46.48%	49.27%	
33	**Total *(rounding check - s/b 100%):***	100.0000%	100.0000%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
	Variance to Original - NH	-0.0040%	-0.0027%	0.0000%	0.0000%	-0.0100%	-0.0100%	-0.0100%	0.1900%	0.1600%	0.16%	0.18%	0.18%	0.20%	0.19%	0.20%	0.20%	0.20%	0.20%	0.20%	
	Variance to Original - ME	0.0040%	0.0027%	0.0000%	0.0000%	0.0100%	0.0100%	0.0100%	-0.1900%	-0.1600%	-0.16%	-0.18%	-0.18%	-0.20%	-0.19%	-0.20%	-0.20%	-0.20%	-0.20%	-0.20%	

Northern Utilities
Gas Cost Allocators
Period: Dec 2008 through Oct 2011 **(original ratio**

ORIGINAL CALCULATIONS THROUGH OCTOBER. METHODOLOGY CORRECTED FOR NOVEMBER 2011 AND FORWARD

		Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	
	(A)	(R)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)	(AJ)	(AI)
1	***New Hampshire:***																				
2	Billed Sales - Therms	3,162,991	1,902,734	1,048,526	883,627	803,799	880,919	1,089,612	2,292,202	4,040,136	6,341,088	6,777,765	5,326,532	3,955,400	2,045,773	1,337,725	916,318	771,977	871,128	1,016,794	
3	Less: Interruptible Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
4	Plus: Company Managed Therms	51,970	21,610	21,080	21,670	21,210	20,760	21,800	82,690	783,550	918,110	766,120	577,930	27,860	-	-	-	-	-	-	
5	Plus: Company Use - Therms	490	247	67	20	18	55	165	372	853	1,451	1,411	1,037	760	311	294	223	207	27,398	1,016	
6		3,215,451	1,924,591	1,069,673	905,317	825,027	901,734	1,111,577	2,375,264	4,824,539	7,260,649	7,545,296	5,905,499	3,984,020	2,046,084	1,338,019	916,541	772,184	898,526	1,017,810	
7	Conversion Factor for Dth	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
8	Tariff Sales Volumes Dth (Billed & Unbilled)	321,545	192,459	106,967	90,532	82,503	90,173	111,158	237,526	482,454	726,065	754,530	590,550	398,402	204,608	133,802	91,654	77,218	89,853	101,781	
9	Adj Factor - Lost and Unaccounted For (LAUF)	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	1.0100	
10	Subtotal	324,761	194,384	108,037	91,437	83,328	91,075	112,269	239,902	487,278	733,326	762,075	596,455	402,386	206,654	135,140	92,571	77,991	90,751	102,799	
11	Plus: Co-Managed (Dth)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
12	Less: Newington Free Gas (Dth)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
14	**Adj Volumes (Dth) - New Hampshire Division**	324,761	194,384	108,037	91,437	83,328	91,075	112,269	239,902	487,278	733,326	762,075	596,455	402,386	206,654	135,140	92,571	77,991	90,751	102,799	
15	***Maine:***																				
16	Billed Sales - Ccf	2,486,577	1,434,714	858,729	758,839	653,412	728,403	983,828	1,968,903	3,711,389	5,204,975	5,747,567	4,476,233	3,357,642	1,724,159	1,062,322	774,456	635,947	738,866	938,589	
17	Less: Interruptible Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
18	Plus: Company Managed - Ccf	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
19	Plus: Company Use - Ccf	6,601	3,194	1,536	1,450	1,148	1,147	2,403	4,360	7,029	11,088	14,159	11,080	8,143	3,181	710	1,561	1,132	1,576	1,917	
20	Subtotal	2,493,178	1,437,907	860,265	760,289	654,560	729,550	986,231	1,973,263	3,718,418	5,216,063	5,761,726	4,487,313	3,365,785	1,727,340	1,063,032	776,017	637,079	740,442	940,506	
21	Conversion Factor to Mcf	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
22	Subtotal	249,318	143,791	86,026	76,029	65,456	72,955	98,623	197,326	371,842	521,606	576,173	448,731	336,579	172,734	106,303	77,602	63,708	74,044	94,051	
23	ME Pipeline Conversion BTU Factor:	1.0498	1.0552	1.0547	1.0514	1.0485	1.0550	1.0570	1.0470	1.0420	1.048	1.051	1.052	1.054	1.027	1.057	1.058	1.055	1.052	1.049	
24	Tariff Sales Volumes Dth (Billed & Unbilled)	261,729	151,727	90,732	79,937	68,631	76,968	104,245	206,601	387,459	546,643	605,557	472,065	354,754	177,398	112,362	82,103	67,212	77,894	98,659	
25	Adj Factor - Lost and Unaccounted For (LAUF)	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	1.0200	
26	Subtotal	266,963	154,761	92,547	81,535	70,003	78,507	106,329	210,733	395,208	557,576	617,669	481,507	361,849	180,946	114,610	83,745	68,556	79,452	100,632	
27	Plus: Co-Managed (Dth)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
28	Less: Newington Free Gas (Dth)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
29	**Adj Volumes (Dth) - Maine Division**	266,963	154,761	92,547	81,535	70,003	78,507	106,329	210,733	395,208	557,576	617,669	481,507	361,849	180,946	114,610	83,745	68,556	79,452	100,632	
30	**Adj Volumes (Dth) - Both Divisions**	591,724	349,145	200,584	172,972	153,331	169,582	218,599	450,634	882,487	1,290,902	1,379,743	1,077,962	764,235	387,600	249,750	176,315	146,547	170,204	203,431	
31	**Variable Commodity Allocation - New Hampshire**	54.8838%	55.6742%	53.86%	52.86%	54.35%	53.71%	51.36%	53.24%	55.22%	56.81%	55.23%	55.33%	52.65%	53.32%	54.11%	52.50%	53.22%	53.32%	50.53%	
32	**Variable Commodity Allocation - Maine**	45.1162%	44.3258%	46.14%	47.14%	45.65%	46.29%	48.64%	46.76%	44.78%	43.19%	44.77%	44.67%	47.35%	46.68%	45.89%	47.50%	46.78%	46.68%	49.47%	
33	**Total *(rounding check - s/b 100%):***	100.0000%	100.0000%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

Schedule 15

Summary of Allocation Adjustment Calculation
Peak Period - May 2008 through April 2011
(By Month)

Northern Utilities, Inc.
Summary of Allocation Adjustment calculation - Peak Period - May 2008 through April 2011

Line No.	Description	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10
	(A)							(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
1	**Costs allocated on Current Month Ratios:**																							
2	**Withdrawal Charges**																							
3	NH Division	-	-	-	-	-	-	2,270,234	4,034,698	4,849,388	3,538,004	2,543,943	962,204	108	2,801	2,273	3,064	-	4,088	5,007	100,799	1,171,362	1,644,641	1,125,338
4	ME Division	-	-	-	-	-	-	2,116,298	3,645,421	3,974,834	2,891,376	2,307,252	673,368	76	2,791	2,265	3,053	-	4,074	4,452	85,619	890,666	1,215,884	820,519
5	**ATV Reconciliation Charges (reclass from Transportation)**																							
6	NH Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	101,847	593,753	833,586	687,955	447,709
7	ME Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90,545	504,335	633,840	508,637	326,436
8	**Net OBA Adjustment**																							
9	NH Division	-	-	-	-	-	-	(352,941)	122,165	(4,092)	(11,822)	(44,346)	(870)	-	-	-	-	-	-	9,022	13,478	7,907	(4,850)	(3,845)
10	ME Division	-	-	-	-	-	-	(329,188)	110,222	(3,354)	(9,662)	(40,220)	(609)	-	-	-	-	-	-	8,021	11,449	6,012	(3,586)	(2,803)
11	**Transportation Charges**																							
12	NH Division	-	-	-	-	-	-	42,521	64,809	34,173	81,200	(19,738)	(29,546)	-	-	-	-	-	-	-	-	-	-	-
13	ME Division	-	-	-	-	-	-	39,660	58,474	28,010	66,367	(17,902)	(20,390)	-	-	-	-	-	-	-	-	-	-	-
14	**LNG Boiloff**																							
15	NH Division	-	-	-	-	-	-	3,910	-	2,023	18	6,905	8,786	-	-	-	-	-	-	3,706	-	-	-	-
16	ME Division	-	-	-	-	-	-	5,786	-	1,658	15	6,263	6,147	-	-	-	-	-	-	3,295	-	-	-	-
17	**Interruptible**																							
18	NH Division	-	-	-	-	-	-	(31,164)	(7,818)	-	-	-	(2,328)	-	-	-	-	-	-	-	-	7,649	-	-
19	ME Division	-	-	-	-	-	-	(29,066)	(9,231)	-	-	-	(1,629)	-	-	-	-	-	-	-	-	5,816	-	-
20	**Hedging Costs**																							
21	NH Division	-	-	-	-	-	-	244,516	357,301	474,693	580,332	525,569	778,238	-	-	-	-	-	-	391,680	497,797	359,604	415,832	551,773
22	ME Division	-	-	-	-	-	-	228,727	322,373	389,084	474,282	476,672	544,455	-	-	-	-	-	-	348,653	423,423	274,513	308,062	402,950
23	**Inventory Finance Charges**																							
24	NH Division	11,905	22,418	30,593	30,166	41,998	59,351	53,246	2,901	3,157	2,254	1,490	624	512	431	514	815	898	938	1,088	1,130	920	556	302
25	ME Division	11,871	22,355	23,401	30,421	41,881	59,185	53,055	2,618	2,588	1,842	1,351	437	468	325	555	562	597	847	967	959	700	411	220
26	Subtotal - Costs allocated on Current Month Ratios																							
27	NH Division - Lines 3+6+9+12+15+18+21+24	11,905	22,418	30,593	30,166	41,998	59,351	2,230,324	4,574,056	5,359,342	4,189,986	3,013,824	1,717,109	620	3,231	2,787	3,879	898	5,027	512,351	1,206,957	2,381,027	2,744,134	2,121,277
28	ME Division - Lines 4+7+10+13+16+19+22+25	11,871	22,355	23,401	30,421	41,881	59,185	2,085,271	4,129,877	4,392,820	3,424,221	2,733,417	1,201,779	544	3,116	2,820	3,614	597	4,921	455,932	1,025,785	1,811,546	2,029,408	1,547,321
29																								
30	**Costs allocated on Prior Month Ratios:**																							
31	**Vendor Payments**																							
32	NH Division	-	-	-	-	-	-	1,273,080	1,261,680	1,474,565	2,646,032	1,156,277	1,028,495	564,769	-	-	-	-	-	-	1,092,000	3,078,330	2,975,947	2,161,725
33	ME Division	-	-	-	-	-	-	1,189,619	1,180,321	1,337,779	2,172,008	947,669	938,232	395,112	-	-	-	-	-	-	970,821	2,614,743	2,262,851	1,600,050
34	**Non-Traditional Sales**																							
35	NH Division (1)	(33,079)	(15,195)	-	-	-	-	(13,514)	-	-	-	-	-	(58,807)	-	-	-	-	-	-	-	(71,930)	(958,751)	(1,694,948)
36	ME Division (1)	(28,643)	(11,203)	-	-	-	-	-	-	-	-	-	-	(41,142)	-	-	-	-	-	-	-	(61,098)	(729,013)	(1,253,152)
37	**Transportation Charges**																							
38	NH Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	101,847	593,753	834,653	703,532	500,280
39	ME Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90,545	504,335	634,746	520,481	365,304
40	**ATV Reconciliation Charges (reclass from Transportation)**																							
41	NH Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(101,847)	(593,753)	(833,586)	(687,955)	(447,709)
42	ME Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(90,545)	(504,335)	(633,840)	(508,637)	(326,436)
43	Subtotal - Costs allocated on Prior Month Ratios																							
44	NH Division - Lines 32+35+38+41	(33,079)	(15,195)	-	-	-	-	1,259,567	1,261,680	1,474,565	2,646,032	1,156,277	1,028,495	505,961	-	-	-	-	-	-	1,092,000	3,007,467	2,032,774	519,348
45	ME Division - Lines 33+36+39+42	(28,643)	(11,203)	-	-	-	-	1,189,619	1,180,321	1,337,779	2,172,008	947,669	938,232	353,970	-	-	-	-	-	-	970,821	2,554,552	1,545,684	385,767
46																								

Northern Utilities, Inc.
Summary of Allocation Adjustment calculation - Peak Period - May 2008 through April 2011

Line No.	Description	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10
	(A)							(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
47	**Costs not requiring reallocation:**																							
48	**Company Managed**																							
49	NH Division	-	-	-	-	-	-	(8,837)	(10,001)	(17,760)	(18,059)	(16,400)	(16,782)	-	-	(8,779)	-	-	-	-	(13,437)	(283,247)	(273,692)	(235,583)
50	ME Division	-	-	-	-	-	-	(12,118)	-	9,215	(42,012)	3,492	13,103	-	-	-	-	-	-	-	(44,486)	(417,106)	(577,070)	(457,556)
51	**Propane**																							
52	NH Division	-	-	-	-	-	-	548	(67,152)	(121,986)	(263,123)	(109,513)	(104,739)	-	-	-	-	-	-	-	-	-	-	-
53	ME Division	-	-	-	-	-	-	511	(510,687)	(716,202)	(1,133,178)	(596,120)	(548,551)	-	154	822	-	-	-	(749)	1,913	1,399	729	548
54	**Estimates**																							
55	NH Division	-	-	-	-	-	-	-	158,184	1,302,891	(1,246,645)	(468,018)	(504,939)	(517,082)	-	-	-	-	-	1,080,518	1,889,560	(1,214,067)	(1,478,250)	(48,993)
56	ME Division	-	-	-	-	-	-	-	103,846	949,529	(1,275,385)	(40,814)	(565,186)	(361,751)	-	-	-	-	-	960,614	1,649,023	(465,159)	(1,462,496)	(331,213)
57	**Transportation Commodity**																							
58	NH Division	-	-	-	-	-	-	4,136	3,808	8,821	3,876	3,292	5,982	-	-	-	-	-	-	-	-	-	-	-
59	ME Division	-	-	-	-	-	-	-	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-
60	**Other**																							
61	NH Division	226	228	232	207	(29)	(31)	146	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
62	ME Division	196	168	178	173	(28)	(26)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
63	**Prior Period Adjustments**																							
64	NH Division	-	-	-	273,086	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65	ME Division	-	-	-	213,551	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66	Subtotal - Costs not requiring reallocation																							
67	NH Division - Lines 49+52+55+58+61+64	226	228	232	273,293	(29)	(31)	(4,007)	84,839	1,171,967	(1,523,952)	(590,639)	(620,479)	(517,082)	-	(8,779)	-	-	-	1,080,518	1,876,124	(1,497,313)	(1,751,941)	(284,576)
68	NH Division - Lines 50+53+56+59+62+65	196	168	178	213,724	(28)	(26)	(11,607)	(406,840)	243,139	(2,450,575)	(633,442)	(1,100,634)	(361,751)	154	822	-	-	-	959,865	1,606,450	(880,866)	(2,038,837)	(788,221)
69																								
70	**Total Commodity Costs as Originally Filed:**																							
71	**NH Division - Lines 27+44+67**	**(20,948)**	**7,451**	**30,825**	**303,459**	**41,969**	**59,320**	**3,485,883**	**5,920,575**	**8,005,874**	**5,312,066**	**3,579,461**	**2,125,124**	**(10,501)**	**3,231**	**(5,991)**	**3,879**	**898**	**5,027**	**1,592,869**	**4,175,080**	**3,891,181**	**3,024,966**	**2,356,050**
72	**ME Division - Lines 28+45+68**	**(16,576)**	**11,320**	**23,579**	**244,145**	**41,853**	**59,159**	**3,263,283**	**4,903,357**	**5,973,738**	**3,145,653**	**3,047,644**	**1,039,377**	**(7,236)**	**3,270**	**3,642**	**3,614**	**597**	**4,921**	**1,415,797**	**3,603,056**	**3,485,232**	**1,536,254**	**1,144,867**
73																								
74																								
75	**Updated Ratios:**	**Note: Changes to the Variable Commodity Allocation Ratios were to move the Company Managed units outside the LAUF adjustment and begin adjusting this factor annually, effective November 2010.**																						
76	NH Ratio 50.96%			Amounts not reallocated prior to Dec-2008					52.57%	54.96%	55.03%	52.44%	58.84%	52.21%	56.96%	48.08%	59.20%	60.04%	52.54%	52.93%	54.05%	56.79%	57.47%	57.80%
77	ME Ratio 49.04%								47.43%	45.04%	44.97%	47.56%	41.16%	47.79%	43.04%	51.92%	40.80%	39.96%	47.46%	47.07%	45.95%	43.21%	42.53%	42.20%
78																								
79	**Costs based on Current Month ratios:**																							
80	NH Division - Lines (27+28) x 76 (current month allocator)	11,905	22,418	30,593	30,166	41,998	59,351	2,230,324	4,575,458	5,359,311	4,189,839	3,013,749	1,717,345	608	3,615	2,696	4,436	898	5,227	512,551	1,206,703	2,380,761	2,743,407	2,120,619
81	ME Division - Lines (27+28) x 77 (current month allocator)	11,871	22,355	23,401	30,421	41,881	59,185	2,085,271	4,128,476	4,392,852	3,424,368	2,733,491	1,201,543	556	2,732	2,911	3,057	597	4,721	455,732	1,026,039	1,811,812	2,030,135	1,547,980
82	**Costs based on Prior Month Ratios:**																							
83	NH Division - Lines (44+45) x 76 (prior month allocator)	(33,079)	(15,195)	-	-	-	-	1,259,567	1,244,534	1,478,384	2,647,759	1,157,730	1,031,316	505,946	-	-	-	-	-	-	1,091,934	3,006,037	2,032,034	520,180
84	ME Division - Lines (44+45) x 77 (prior month allocator)	(28,643)	(11,203)	-	-	-	-	1,189,619	1,197,467	1,333,959	2,170,281	946,216	935,410	353,986	-	-	-	-	-	-	970,887	2,555,981	1,546,423	384,935
85	**Costs not requiring reallocation:**																							
86	NH Division - Line 67	226	228	232	273,293	(29)	(31)	(4,007)	84,839	1,171,967	(1,523,952)	(590,639)	(620,479)	(517,082)	-	(8,779)	-	-	-	1,080,518	1,876,124	(1,497,313)	(1,751,941)	(284,576)
87	ME Division - Line 68	196	168	178	213,724	(28)	(26)	(11,607)	(406,840)	243,139	(2,450,575)	(633,442)	(1,100,634)	(361,751)	154	822	-	-	-	959,865	1,606,450	(880,866)	(2,038,837)	(788,221)
88																								
89	**Adjusted Commodity Costs:**																							
90	**NH Division - Lines 126+129+132**	**(20,948)**	**7,451**	**30,825**	**303,459**	**41,969**	**59,320**	**3,485,883**	**5,904,830**	**8,009,662**	**5,313,646**	**3,580,840**	**2,128,182**	**(10,529)**	**3,615**	**(6,083)**	**4,436**	**898**	**5,227**	**1,593,069**	**4,174,760**	**3,889,485**	**3,023,500**	**2,356,222**
91	**ME Division - Lines 127+130+133**	**(16,576)**	**11,320**	**23,579**	**244,145**	**41,853**	**59,159**	**3,263,283**	**4,919,102**	**5,969,950**	**3,144,074**	**3,046,265**	**1,036,319**	**(7,209)**	**2,886**	**3,734**	**3,057**	**597**	**4,721**	**1,415,597**	**3,603,376**	**3,486,927**	**1,537,721**	**1,144,695**
92																								
93	**Allocation Adjustment - LAUF adjustment:**																							
94	**NH Division - Lines 90-71**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**(15,745)**	**3,788**	**1,580**	**1,379**	**3,058**	**(28)**	**384**	**(91)**	**557**	**(0)**	**200**	**200**	**(320)**	**(1,696)**	**(1,467)**	**173**
95	**ME Division - Lines 91-72**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**15,745**	**(3,788)**	**(1,580)**	**(1,379)**	**(3,058)**	**28**	**(384)**	**91**	**(557)**	**0**	**(200)**	**(200)**	**320**	**1,696**	**1,467**	**(173)**

Northern Utilities, Inc.
Summary of Allocation Adjustment calculation - Peak Period - May 2008 through April 2011

Line No.	Description		May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10
	(A)								(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
96																									
97	**Updated Ratios:**	Note: Changes to the Variable Commodity Allocation Ratios were to move the Company Managed units outside the LAUF adjustment and the correction of New Hampshire Company Managed units (Dec 2008 - Mar 2009).																							
98	NH Ratio	50.96%	Amounts not reallocated prior to Dec-2008							53.31%	56.51%	55.32%	52.75%	58.84%	52.21%	56.96%	48.08%	59.20%	60.04%	52.54%	52.93%	54.05%	56.79%	57.47%	57.80%
99	ME Ratio	49.04%								46.69%	43.49%	44.68%	47.25%	41.16%	47.79%	43.04%	51.92%	40.80%	39.96%	47.46%	47.07%	45.95%	43.21%	42.53%	42.20%
100																									
101	<u>Costs based on Current Month ratios:</u>																								
102	NH Division - Lines (27+28) x 98 (current month allocator)		11,905	22,418	30,593	30,166	41,998	59,351	2,230,324	4,640,076	5,511,415	4,212,529	3,031,434	1,717,345	608	3,615	2,696	4,436	898	5,227	512,551	1,206,703	2,380,761	2,743,407	2,120,619
103	ME Division - Lines (27+28) x 99 (current month allocator)		11,871	22,355	23,401	30,421	41,881	59,185	2,085,271	4,063,858	4,240,748	3,401,677	2,715,807	1,201,543	556	2,732	2,911	3,057	597	4,721	455,732	1,026,039	1,811,812	2,030,135	1,547,980
104	<u>Costs based on Prior Month Ratios:</u>																								
105	NH Division - Lines (44+45) x 98 (prior month allocator)		(33,079)	(15,195)	-	-	-	-	1,259,567	1,244,534	1,499,263	2,722,906	1,164,000	1,037,367	505,946	-	-	-	-	-	-	1,091,934	3,006,037	2,032,034	520,180
106	ME Division - Lines (44+45) x 99 (prior month allocator)		(28,643)	(11,203)	-	-	-	-	1,189,619	1,197,467	1,313,080	2,095,134	939,946	929,359	353,986	-	-	-	-	-	-	970,887	2,555,981	1,546,423	384,935
107	<u>Costs not requiring reallocation:</u>																								
108	NH Division - Line 67		226	228	232	273,293	(29)	(31)	(4,007)	84,839	1,171,967	(1,523,952)	(590,639)	(620,479)	(517,082)	-	(8,779)	-	-	-	1,080,518	1,876,124	(1,497,313)	(1,751,941)	(284,576)
109	ME Division - Line 68		196	168	178	213,724	(28)	(26)	(11,607)	(406,840)	243,139	(2,450,575)	(633,442)	(1,100,634)	(361,751)	154	822	-	-	-	959,865	1,606,450	(880,866)	(2,038,837)	(788,221)
110																									
111	**Adjusted Commodity Costs:**																								
112	**NH Division - Lines 102+105+108**		**(20,948)**	**7,451**	**30,825**	**303,459**	**41,969**	**59,320**	**3,485,883**	**5,969,448**	**8,182,645**	**5,411,483**	**3,604,794**	**2,134,234**	**(10,529)**	**3,615**	**(6,083)**	**4,436**	**898**	**5,227**	**1,593,069**	**4,174,760**	**3,889,485**	**3,023,500**	**2,356,222**
113	**ME Division - Lines 103+106+109**		**(16,576)**	**11,320**	**23,579**	**244,145**	**41,853**	**59,159**	**3,263,283**	**4,854,484**	**5,796,967**	**3,046,236**	**3,022,311**	**1,030,268**	**(7,209)**	**2,886**	**3,734**	**3,057**	**597**	**4,721**	**1,415,597**	**3,603,376**	**3,486,927**	**1,537,721**	**1,144,695**
114																									
115	**Allocation Adjustment - Company Managed Units:**																								
116	**NH Division - Lines 112-90**		-	-	-	-	-	-	-	**64,618**	**172,983**	**97,837**	**23,954**	**6,052**	-	-	-	-	-	-	-	-	-	-	-
117	**ME Division - Lines 113-91**		-	-	-	-	-	-	-	**(64,618)**	**(172,983)**	**(97,837)**	**(23,954)**	**(6,052)**	-	-	-	-	-	-	-	-	-	-	-
118																									
119																									
120	**Updated Ratios:**	Changes to the Variable Commodity Allocation Ratios were to move the Company Managed units outside the LAUF adjustment, correction of New Hampshire Company Managed Units (Dec08 - Mar09) AND to include Maine Company Managed units in the calculation.																							
121	NH Ratio	50.96%	Amounts not reallocated prior to Dec-2008							50.45%	51.98%	54.11%	51.81%	58.84%	52.21%	56.96%	48.08%	59.20%	60.04%	52.54%	51.66%	49.18%	52.32%	52.79%	53.48%
122	ME Ratio	49.04%								49.55%	48.02%	45.89%	48.19%	41.16%	47.79%	43.04%	51.92%	40.80%	39.96%	47.46%	48.34%	50.82%	47.68%	47.21%	46.52%
123																									
124	<u>Costs based on Current Month ratios:</u>																								
125	NH Division - Lines (27+28) x 121 (current month allocator)		11,905	22,418	30,593	30,166	41,998	59,351	2,230,324	4,390,882	5,068,960	4,119,674	2,977,582	1,717,345	608	3,615	2,696	4,436	898	5,227	500,187	1,098,141	2,193,676	2,519,914	1,962,077
126	ME Division - Lines (27+28) x 122 (current month allocator)		11,871	22,355	23,401	30,421	41,881	59,185	2,085,271	4,313,051	4,683,203	3,494,532	2,769,658	1,201,543	556	2,732	2,911	3,057	597	4,721	468,096	1,134,601	1,998,897	2,253,627	1,706,522
127	<u>Costs based on Prior Month Ratios:</u>																								
128	NH Division - Lines (44+45) x 121 (prior month allocator)		(33,079)	(15,195)	-	-	-	-	1,259,567	1,244,534	1,418,746	2,504,311	1,138,342	1,018,939	505,946	-	-	-	-	-	-	1,065,593	2,735,595	1,872,353	477,803
129	ME Division - Lines (44+45) x 122 (prior month allocator)		(28,643)	(11,203)	-	-	-	-	1,189,619	1,197,467	1,393,598	2,313,729	965,604	947,787	353,986	-	-	-	-	-	-	997,227	2,826,423	1,706,105	427,312
130	<u>Costs not requiring reallocation:</u>																								
131	NH Division - Line 67		226	228	232	273,293	(29)	(31)	(4,007)	84,839	1,171,967	(1,523,952)	(590,639)	(620,479)	(517,082)	-	(8,779)	-	-	-	1,080,518	1,876,124	(1,497,313)	(1,751,941)	(284,576)
132	ME Division - Line 68		196	168	178	213,724	(28)	(26)	(11,607)	(406,840)	243,139	(2,450,575)	(633,442)	(1,100,634)	(361,751)	154	822	-	-	-	959,865	1,606,450	(880,866)	(2,038,837)	(788,221)
133																									
134	**Total Commodity Costs - adjusted:**																								
135	**NH Division - Lines 125+128+131**		**(20,948)**	**7,451**	**30,825**	**303,459**	**41,969**	**59,320**	**3,485,883**	**5,720,254**	**7,659,672**	**5,100,033**	**3,525,285**	**2,115,805**	**(10,529)**	**3,615**	**(6,083)**	**4,436**	**898**	**5,227**	**1,580,705**	**4,039,858**	**3,431,958**	**2,640,326**	**2,155,304**
136	**ME Division - Lines 126+129+132**		**(16,576)**	**11,320**	**23,579**	**244,145**	**41,853**	**59,159**	**3,263,283**	**5,103,678**	**6,319,940**	**3,357,686**	**3,101,820**	**1,048,696**	**(7,209)**	**2,886**	**3,734**	**3,057**	**597**	**4,721**	**1,427,961**	**3,738,279**	**3,944,454**	**1,920,895**	**1,345,613**
137																									
138	**Allocation Adjustment - ME Company Managed:**																								
139	**NH Division - Lines 135-112**		-	-	-	-	-	-	-	**(249,194)**	**(522,973)**	**(311,450)**	**(79,509)**	**(18,428)**	-	-	-	-	-	-	**(12,364)**	**(134,903)**	**(457,527)**	**(383,174)**	**(200,919)**
140	**ME Division - Lines 136-113**		-	-	-	-	-	-	-	**249,194**	**522,973**	**311,450**	**79,509**	**18,428**	-	-	-	-	-	-	**12,364**	**134,903**	**457,527**	**383,174**	**200,919**
141																									
142	**Allocation Adjustment - Total:**																								
143	**NH Division - Lines 135-112**		-	-	-	-	-	-	-	**(200,320)**	**(346,202)**	**(212,033)**	**(54,176)**	**(9,319)**	**(28)**	**384**	**(91)**	**557**	**(0)**	**200**	**(12,164)**	**(135,223)**	**(459,223)**	**(384,641)**	**(200,746)**
144	**ME Division - Lines 136-113**		-	-	-	-	-	-	-	**200,320**	**346,202**	**212,033**	**54,176**	**9,319**	**28**	**(384)**	**91**	**(557)**	**0**	**(200)**	**12,164**	**135,223**	**459,223**	**384,641**	**200,746**

Northern Utilities, Inc.

Summary of Allocation Adjustment calculation - Peak Period - May 2008 througl

Line No.	Description	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	**Total**
	(A)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	**(AL)**
1	**Costs allocated on Current Month Ratios:**														
2	**Withdrawal Charges**														
3	NH Division	10,539	-	-	-	-	-	-	982,785	2,454,160	2,544,470	1,576,288	1,213,681	870	**31,040,746**
4	ME Division	8,233	-	-	-	-	-	-	863,167	1,992,463	1,936,158	1,275,774	979,930	733	**25,694,402**
5	**ATV Reconciliation Charges (reclass from Transportation)**														
6	NH Division	290,951	-	-	-	-	-	-	(30,606)	72,894	111,901	85,224	102,352	22,329	**3,319,893**
7	ME Division	239,171	-	-	-	-	-	-	(26,881)	59,113	85,073	69,083	82,632	20,081	**2,592,065**
8	**Net OBA Adjustment**														
9	NH Division	(81)	-	-	-	-	-	-	10,250	1,739	11,720	31,076	(188)	7,938	**(207,739)**
10	ME Division	(66)	-	-	-	-	-	-	9,002	1,410	8,910	25,190	(152)	7,139	**(202,284)**
11	**Transportation Charges**														
12	NH Division	-	-	-	-	-	-	-	-	-	-	-	-	-	**173,421**
13	ME Division	-	-	-	-	-	-	-	-	-	-	-	-	-	**154,219**
14	**LNG Boiloff**														
15	NH Division	-	-	-	-	-	-	-	4,008	6,370	7,304	1,225	3,279	4,889	**52,424**
16	ME Division	-	-	-	-	-	-	-	3,520	5,166	5,553	993	2,647	4,397	**45,439**
17	**Interruptible**														
18	NH Division	-	-	-	-	-	-	-	-	-	-	-	-	-	**(33,661)**
19	ME Division	-	-	-	-	-	-	-	-	-	-	-	-	-	**(34,110)**
20	**Hedging Costs**														
21	NH Division	668,016	-	-	-	-	-	-	117,625	106,961	64,904	80,338	83,155	91,699	**6,390,034**
22	ME Division	549,474	-	-	-	-	-	-	103,579	87,188	49,343	65,123	67,134	82,469	**5,197,503**
23	**Inventory Finance Charges**														
24	NH Division	209	404	579	774	957	1,048	1,087	1,095	1,060	727	355	183	46	**276,728**
25	ME Division	172	322	496	690	803	903	1,029	961	860	553	288	148	41	**264,882**
26	Subtotal - Costs allocated on Current Month Ratios														
27	NH Division - Lines 3+6+9+12+15+18+21+24	969,635	404	579	774	957	1,048	1,087	1,085,156	2,643,184	2,741,026	1,774,504	1,402,462	127,770	**41,011,845**
28	ME Division - Lines 4+7+10+13+16+19+22+25	796,984	322	496	690	803	903	1,029	953,350	2,146,199	2,085,590	1,436,450	1,132,339	114,859	**33,712,117**
29															
30	**Costs allocated on Prior Month Ratios:**														
31	**Vendor Payments**														
32	NH Division	478,042	906,977	3,925	-	-	(1,983)	-	11,402	365,766	1,631,662	2,012,108	1,785,157	1,444,491	**27,350,446**
33	ME Division	348,553	745,564	3,226	-	-	(1,772)	-	10,798	320,074	1,348,528	1,529,712	1,427,502	1,166,192	**22,507,581**
34	**Non-Traditional Sales**														
35	NH Division (1)	-	(425,015)	-	-	-	-	-	(4,520)	(2,316)	(848,206)	(141,454)	(129,906)	(27,350)	**(4,424,990)**
36	ME Division (1)	-	(349,376)	-	-	-	-	-	(4,280)	(2,034)	(687,843)	(107,541)	(105,303)	(22,081)	**(3,402,706)**
37	**Transportation Charges**														
38	NH Division	278,881	47,189	160,076	(213,177)	117,743	-	-	-	3,498	95,263	28,758	92,402	69,554	**3,414,250**
39	ME Division	230,371	38,791	127,468	40,166	105,002	-	-	-	3,072	77,252	21,863	74,902	56,154	**2,890,453**
40	**ATV Reconciliation Charges (reclass from Transportation)**														
41	NH Division	(290,951)	-	-	-	-	-	-	-	-	-	-	-	-	**(2,955,800)**
42	ME Division	(239,171)	-	-	-	-	-	-	-	-	-	-	-	-	**(2,302,964)**
43	Subtotal - Costs allocated on Prior Month Ratios														
44	NH Division - Lines 32+35+38+41	465,973	529,151	164,000	(213,177)	117,743	(1,983)	-	6,882	366,948	878,718	1,899,411	1,747,652	1,486,695	**23,383,905**
45	ME Division - Lines 33+36+39+42	339,753	434,979	130,694	40,166	105,002	(1,772)	-	6,518	321,112	737,937	1,444,034	1,397,101	1,200,265	**19,692,363**
46															

Northern Utilities, Inc.

Summary of Allocation Adjustment calculation - Peak Period - May 2008 througl

Line No.	Description		Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	**Total**
	(A)		(S)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	**(AL)**
47	**Costs not requiring reallocation:**															
48	**Company Managed**															
49	NH Division		(243,681)	(20,480)	-	-	-	-	-	-	(34,309)	(341,851)	(402,896)	(336,167)	(246,181)	**(2,528,142)**
50	ME Division		(318,705)	-	-	-	-	-	-	-	(164,104)	(992,215)	(1,189,990)	(749,772)	(565,462)	**(5,504,788)**
51	**Propane**															
52	NH Division		-	-	-	-	-	-	-	-	-	-	-	-	-	**(665,965)**
53	ME Division		619	516	-	-	-	-	-	530	562	867	747	581	770	**(3,494,219)**
54	**Estimates**															
55	NH Division		278,936	(507,705)	-	-	-	-	-	350,527	125,859	1,057,228	(203,808)	(154,481)	(59,407)	**(159,693)**
56	ME Division		393,074	(743,844)	-	-	-	-	-	173,892	(581,789)	690,145	318,435	(18,509)	431,134	**(176,452)**
57	**Transportation Commodity**															
58	NH Division		-	-	-	-	-	-	-	-	-	-	-	-	-	**29,915**
59	ME Division		-	-	-	-	-	-	-	-	-	-	-	-	-	**597**
60	**Other**															
61	NH Division		-	-	-	-	-	-	-	-	297,080	83,020	86,800	115,600	120,480	**703,959**
62	ME Division		-	-	-	-	-	-	-	4,280	-	-	-	-	-	**4,942**
63	**Prior Period Adjustments**															
64	NH Division		-	-	-	-	-	-	-	-	-	-	-	-	-	**273,086**
65	ME Division		-	-	-	-	-	-	-	-	-	-	-	-	-	**213,551**
66	Subtotal - Costs not requiring reallocation															
67	NH Division - Lines 49+52+55+58+61+64		35,255	(528,185)	-	-	-	-	-	350,527	388,629	798,397	(519,904)	(375,049)	(185,107)	**(2,346,841)**
68	NH Division - Lines 50+53+56+59+62+65		74,988	(743,328)	-	-	-	-	-	178,703	(745,332)	(301,203)	(870,808)	(767,701)	(133,558)	**(8,956,370)**
69																
70	**Total Commodity Costs as Originally Filed:**															
71	**NH Division - Lines 27+44+67**		**1,470,863**	**1,370**	**164,579**	**(212,403)**	**118,699**	**(935)**	**1,087**	**1,442,565**	**3,398,761**	**4,418,142**	**3,154,012**	**2,775,065**	**1,429,358**	**62,048,909**
72	**ME Division - Lines 28+45+68**		**1,211,724**	**(308,028)**	**131,190**	**40,856**	**105,805**	**(869)**	**1,029**	**1,138,570**	**1,721,979**	**2,522,324**	**2,009,676**	**1,761,739**	**1,181,565**	**44,448,111**
73																
74																
75	**Updated Ratios:**	**Note: C**														
76	NH Ratio	50.96%	54.88%	55.67%	53.86%	52.86%	54.34%	53.70%	51.35%	53.43%	55.38%	56.97%	55.41%	55.51%	52.85%	
77	ME Ratio	49.04%	45.12%	44.33%	46.14%	47.14%	45.66%	46.30%	48.65%	46.57%	44.62%	43.03%	44.59%	44.49%	47.15%	
78																
79	**Costs based on Current Month ratios:**															
80	NH Division - Lines (27+28) x 76 (current month allocator)		969,517	404	579	774	956	1,048	1,086	1,089,174	2,652,360	2,749,723	1,779,190	1,407,068	128,229	**41,044,085**
81	ME Division - Lines (27+28) x 77 (current month allocator)		797,102	322	496	690	804	904	1,029	949,332	2,137,023	2,076,893	1,431,765	1,127,733	114,400	**33,679,877**
82	**Costs based on Prior Month Ratios:**															
83	NH Division - Lines (44+45) x 76 (prior month allocator)		465,746	529,112	164,061	(93,183)	117,743	(2,040)	-	6,881	367,631	895,304	1,904,761	1,742,508	1,491,531	**23,517,200**
84	ME Division - Lines (44+45) x 77 (prior month allocator)		339,979	435,017	130,634	(79,827)	105,002	(1,715)	-	6,519	320,430	721,352	1,438,685	1,402,245	1,195,428	**19,559,069**
85	**Costs not requiring reallocation:**															
86	NH Division - Line 67		35,255	(528,185)	-	-	-	-	-	350,527	388,629	798,397	(519,904)	(375,049)	(185,107)	**(2,346,841)**
87	ME Division - Line 68		74,988	(743,328)	-	-	-	-	-	178,703	(745,332)	(301,203)	(870,808)	(767,701)	(133,558)	**(8,956,370)**
88																
89	**Adjusted Commodity Costs:**															
90	**NH Division - Lines 126+129+132**		**1,470,518**	**1,331**	**164,640**	**(92,410)**	**118,699**	**(993)**	**1,086**	**1,446,581**	**3,408,620**	**4,443,424**	**3,164,047**	**2,774,527**	**1,434,653**	**62,214,444**
91	**ME Division - Lines 127+130+133**		**1,212,069**	**(307,989)**	**131,130**	**(79,137)**	**105,805**	**(811)**	**1,029**	**1,134,554**	**1,712,121**	**2,497,042**	**1,999,641**	**1,762,278**	**1,176,270**	**44,282,576**
92																
93	**Allocation Adjustment - LAUF adjustment:**															
94	**NH Division - Lines 90-71**		**(345)**	**(38)**	**61**	**119,993**	**(0)**	**(58)**	**(0)**	**4,016**	**9,859**	**25,282**	**10,035**	**(538)**	**5,296**	**165,535**
95	**ME Division - Lines 91-72**		**345**	**38**	**(61)**	**(119,993)**	**0**	**58**	**0**	**(4,016)**	**(9,859)**	**(25,282)**	**(10,035)**	**538**	**(5,296)**	**(165,535)**

Northern Utilities, Inc.

Summary of Allocation Adjustment calculation - Peak Period - May 2008 throug

Line No.	Description		Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	**Total**
	(A)		(S)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	**(AL)**
96																
97	**Updated Ratios:**	Note: C														
98	NH Ratio	50.96%	54.88%	55.67%	53.86%	52.86%	54.34%	53.70%	51.35%	53.43%	55.38%	56.97%	55.41%	55.51%	52.85%	
99	ME Ratio	49.04%	45.12%	44.33%	46.14%	47.14%	45.66%	46.30%	48.65%	46.57%	44.62%	43.03%	44.59%	44.49%	47.15%	
100																
101	**Costs based on Current Month ratios:**															
102	NH Division - Lines (27+28) x 98 (current month allocator)		969,517	404	579	774	956	1,048	1,086	1,089,174	2,652,360	2,749,723	1,779,190	1,407,068	128,229	**41,301,182**
103	ME Division - Lines (27+28) x 99 (current month allocator)		797,102	322	496	690	804	904	1,029	949,332	2,137,023	2,076,893	1,431,765	1,127,733	114,400	**33,422,780**
104	**Costs based on Prior Month Ratios:**															
105	NH Division - Lines (44+45) x 98 (prior month allocator)		465,746	529,112	164,061	(93,183)	117,743	(2,040)	-	6,881	367,631	895,304	1,904,761	1,742,508	1,491,531	**23,625,547**
106	ME Division - Lines (44+45) x 99 (prior month allocator)		339,979	435,017	130,634	(79,827)	105,002	(1,715)	-	6,519	320,430	721,352	1,438,685	1,402,245	1,195,428	**19,450,722**
107	**Costs not requiring reallocation:**															
108	NH Division - Line 67		35,255	(528,185)	-	-	-	-	-	350,527	388,629	798,397	(519,904)	(375,049)	(185,107)	**(2,346,841)**
109	ME Division - Line 68		74,988	(743,328)	-	-	-	-	-	178,703	(745,332)	(301,203)	(870,808)	(767,701)	(133,558)	**(8,956,370)**
110																
111	**Adjusted Commodity Costs:**															
112	**NH Division - Lines 102+105+108**		**1,470,518**	**1,331**	**164,640**	**(92,410)**	**118,699**	**(993)**	**1,086**	**1,446,581**	**3,408,620**	**4,443,424**	**3,164,047**	**2,774,527**	**1,434,653**	**62,579,889**
113	**ME Division - Lines 103+106+109**		**1,212,069**	**(307,989)**	**131,130**	**(79,137)**	**105,805**	**(811)**	**1,029**	**1,134,554**	**1,712,121**	**2,497,042**	**1,999,641**	**1,762,278**	**1,176,270**	**43,917,132**
114																
115	**Allocation Adjustment - Company Managed Units:**															
116	**NH Division - Lines 112-90**		-	-	-	-	-	-	-	-	-	-	-	-	-	**365,444**
117	**ME Division - Lines 113-91**		-	-	-	-	-	-	-	-	-	-	-	-	-	**(365,444)**
118																
119																
120	**Updated Ratios:**	Changes														
121	NH Ratio	50.96%	54.88%	55.67%	53.86%	52.86%	54.34%	53.70%	51.35%	49.04%	44.94%	48.99%	50.09%	49.75%	52.85%	
122	ME Ratio	49.04%	45.12%	44.33%	46.14%	47.14%	45.66%	46.30%	48.65%	50.96%	55.06%	51.01%	49.91%	50.25%	47.15%	
123																
124	**Costs based on Current Month ratios:**															
125	NH Division - Lines (27+28) x 121 (current month allocator)		969,517	404	579	774	956	1,048	1,086	999,683	2,152,349	2,364,559	1,608,367	1,261,063	128,229	**38,481,286**
126	ME Division - Lines (27+28) x 122 (current month allocator)		797,102	322	496	690	804	904	1,029	1,038,822	2,637,034	2,462,057	1,602,588	1,273,737	114,400	**36,242,676**
127	**Costs based on Prior Month Ratios:**															
128	NH Division - Lines (44+45) x 121 (prior month allocator)		430,926	529,112	164,061	(93,183)	117,743	(2,040)	-	6,881	337,425	726,525	1,637,954	1,575,207	1,336,763	**21,960,828**
129	ME Division - Lines (44+45) x 122 (prior month allocator)		374,799	435,017	130,634	(79,827)	105,002	(1,715)	-	6,519	350,636	890,130	1,705,491	1,569,546	1,350,197	**21,115,441**
130	**Costs not requiring reallocation:**															
131	NH Division - Line 67		35,255	(528,185)	-	-	-	-	-	350,527	388,629	798,397	(519,904)	(375,049)	(185,107)	**(2,346,841)**
132	ME Division - Line 68		74,988	(743,328)	-	-	-	-	-	178,703	(745,332)	(301,203)	(870,808)	(767,701)	(133,558)	**(8,956,370)**
133																
134	**Total Commodity Costs - adjusted:**															
135	**NH Division - Lines 125+128+131**		**1,435,698**	**1,331**	**164,640**	**(92,410)**	**118,699**	**(993)**	**1,086**	**1,357,091**	**2,878,403**	**3,889,481**	**2,726,417**	**2,461,221**	**1,279,884**	**58,095,273**
136	**ME Division - Lines 126+129+132**		**1,246,889**	**(307,989)**	**131,130**	**(79,137)**	**105,805**	**(811)**	**1,029**	**1,224,044**	**2,242,338**	**3,050,985**	**2,437,271**	**2,075,583**	**1,331,038**	**48,401,747**
137																
138	**Allocation Adjustment - ME Company Managed:**															
139	**NH Division - Lines 135-112**		**(34,820)**	-	-	-	-	-	-	**(89,490)**	**(530,217)**	**(553,943)**	**(437,630)**	**(313,305)**	**(154,769)**	**(4,484,615)**
140	**ME Division - Lines 136-113**		**34,820**	-	-	-	-	-	-	**89,490**	**530,217**	**553,943**	**437,630**	**313,305**	**154,769**	**4,484,615**
141																
142	**Allocation Adjustment - Total:**															
143	**NH Division - Lines 135-112**		**(35,165)**	**(38)**	**61**	**119,993**	**(0)**	**(58)**	**(0)**	**(85,474)**	**(520,359)**	**(528,660)**	**(427,595)**	**(313,844)**	**(149,473)**	**(3,953,636)**
144	**ME Division - Lines 136-113**		**35,165**	**38**	**(61)**	**(119,993)**	**0**	**58**	**0**	**85,474**	**520,359**	**528,660**	**427,595**	**313,844**	**149,473**	**3,953,636**

Schedule 16

Summary of Allocation Adjustment Calculation
Off-Peak Period - November 2008 through October 2011 (By Month)

Northern Utilities, Inc.

Summary of Allocation Adjustment calculation - Off-Peak Period - November 2008 through October 2011

Line No.	Description	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)
1	**Costs allocated on Current Month Ratios:**																						
2	**Withdrawal Charges**																						
3	NH Division	-	-	-	-	-	-	1,180	1,416	(1,334)	1,346	(719)	177	-	-	-	-	-	-	(509)	(395)	3,154	185
4	ME Division	-	-	-	-	-	-	1,079	1,069	(1,440)	927	(478)	160	-	-	-	-	-	-	(405)	(339)	2,813	155
5	**ATV Reconciliation Charges (moved from Transportation charges)**																						
6	NH Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	289,307	233,654	224,568	(11,661)
7	ME Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	230,336	200,163	200,267	(9,794)
8	**Net OBA Adjustment**																						
9	NH Division	-	-	-	-	-	-	43,338	1,077	646	304	470	31,547	-	-	-	-	-	-	(1,774)	115	(2,108)	(2,824)
10	ME Division	-	-	-	-	-	-	39,658	814	697	209	313	28,489	-	-	-	-	-	-	(1,413)	99	(1,880)	(2,372)
11	**Transportation Charges**																						
12	NH Division	-	-	-	-	-	-	(15,084)	25,398	9,519	-	(8,625)	(130,224)	-	-	-	-	-	-	-	-	-	-
13	ME Division	-	-	-	-	-	-	(13,803)	19,185	10,276	-	(5,738)	(117,603)	-	-	-	-	-	-	-	-	-	-
14	**LNG Boiloff**																						
15	NH Division	-	-	-	-	-	-	5,110	-	10,619	7,534	7,111	4,863	-	-	-	-	-	-	5,967	6,228	4,643	5,346
16	ME Division	-	-	-	-	-	-	4,676	-	11,464	5,190	4,731	4,392	-	-	-	-	-	-	4,751	5,335	4,141	4,490
17	**Interruptible**																						
18	NH Division	-	-	-	-	-	-	(390)	-	(7,661)	(4,412)	(11,317)	(11,884)	-	-	-	-	-	-	-	-	-	-
19	ME Division	-	-	-	-	-	-	(357)	-	(8,271)	(3,039)	(7,529)	(10,732)	-	-	-	-	-	-	-	-	-	-
20	**Hedging Costs**																						
21	NH Division	-	-	-	-	-	-	785,953	6,412	5,627	5,393	6,412	978,505	-	-	-	-	-	-	205,387	2,144	2,131	1,719
22	ME Division	-	-	-	-	-	-	720,340	6,408	5,628	5,391	6,407	884,270	-	-	-	-	-	-	163,982	2,139	2,127	1,713
23	**Inventory Finance Charges**																						
24	NH Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	ME Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Subtotal - Costs allocated on Current Month Ratios																						
27	NH Division - Lines 3+6+9+12+15+18+21+24	-	-	-	-	-	-	820,106	34,302	17,415	10,164	(6,667)	872,985	-	-	-	-	-	-	498,378	241,746	232,387	(7,234)
28	ME Division - Lines 4+7+10+13+16+19+22+25	-	-	-	-	-	-	751,593	27,477	18,354	8,677	(2,294)	788,977	-	-	-	-	-	-	397,251	207,397	207,468	(5,807)
29																							
30	**Costs allocated on Prior Month Ratios:**																						
31	**Vendor Payments**																						
32	NH Division	-	-	-	-	-	-	-	333,305	315,995	340,218	330,556	199,370	748,276	-	-	-	41,634	-	-	498,320	424,813	237,277
33	ME Division	-	-	-	-	-	-	-	305,002	238,701	367,283	227,701	132,666	685,476	-	-	-	34,741	-	-	396,745	363,923	211,602
34	**Non-Traditional Sales**																						
35	NH Division (1)	-	-	-	-	-	-	(6,031)	-	-	-	(15,847)	-	-	-	-	-	-	(14,135)	-	(65,099)	(330,547)	(54,378)
36	ME Division (1)	-	-	-	-	-	-	(5,469)	-	-	-	(10,543)	-	-	-	-	-	-	(12,935)	-	(51,830)	(283,168)	(48,494)
37	**Transportation Charges**																						
38	NH Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(12,107)	(38,480)	(1,918)	526,997	-	1,424	(57,059)	(3,983)
39	ME Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(10,284)	(29,260)	(1,418)	384,247	-	1,134	(48,880)	(3,552)
40	**Remove ATV Recon Amts from Transportation (moved above)**																						
41	NH Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	ME Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	Subtotal - Costs allocated on Prior Month Ratios																						
44	NH Division - Lines 32+35+38+41	-	-	-	-	-	-	(6,031)	333,305	315,995	340,218	314,709	199,370	748,276	-	(12,107)	(38,480)	39,716	512,862	-	434,646	37,208	178,917
45	ME Division - Lines 33+36+39+42	-	-	-	-	-	-	(5,469)	305,002	238,701	367,283	217,158	132,666	685,476	-	(10,284)	(29,260)	33,323	371,313	-	346,049	31,875	159,556
46																							

Northern Utilities, Inc.
Summary of Allocation Adjustment calculation - Off-Peak Period - November 2008 through October 2011

Line No.	Description	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)
47	**Costs not requiring reallocation:**																						
48	**Company Managed**																						
49	NH Division	-	-	-	-	-	-	(7,372)	(9,065)	-	-	(18,887)	(3,602)	-	-	-	-	-	-	-	(8,317)	(8,046)	(8,805)
50	ME Division	-	-	-	-	-	-	(12,578)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	**Propane**																						
52	NH Division	-	-	-	-	-	-	(67,162)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	ME Division	-	-	-	-	-	-	688	600	427	522	558	1,215	-	-	-	-	-	-	-	536	554	798
54	**Estimates**																						
55	NH Division	-	-	-	-	-	-	415,087	(100,543)	16,691	(1,781)	(119,345)	625,539	(835,648)	-	-	-	-	-	408,990	(321,991)	92,352	270,872
56	ME Division	-	-	-	-	-	-	379,840	(142,235)	119,981	(130,644)	(87,048)	613,987	(753,881)	-	-	-	-	-	332,235	(250,814)	86,374	217,508
57	**Transportation Commodity**																						
58	NH Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59	ME Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
60	**Other**																						
61	NH Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
62	ME Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
63	**Prior Period Adjustments**																						
64	NH Division	2,027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65	ME Division	1,691	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66	Subtotal - Costs not requiring reallocation																						
67	NH Division - Lines 49+52+55+58+61+64	2,027	-	-	-	-	-	340,553	(109,609)	16,691	(1,781)	(138,232)	621,937	(835,648)	-	-	-	-	-	408,990	(330,308)	84,306	262,067
68	NH Division - Lines 50+53+56+59+62+65	1,691	-	-	-	-	-	367,950	(141,635)	120,408	(130,122)	(86,490)	615,202	(753,881)	-	-	-	-	-	332,235	(250,279)	86,928	218,305
69																							
70	**Total Commodity Costs as Originally Filed:**																						
71	**NH Division - Lines 27+44+67**	**2,027**	**-**	**-**	**-**	**-**	**-**	**1,154,629**	**257,998**	**350,102**	**348,601**	**169,810**	**1,694,291**	**(87,372)**	**-**	**(12,107)**	**(38,480)**	**39,716**	**512,862**	**907,368**	**346,083**	**353,901**	**433,749**
72	**ME Division - Lines 28+45+68**	**1,691**	**-**	**-**	**-**	**-**	**-**	**1,114,074**	**190,843**	**377,462**	**245,837**	**128,374**	**1,536,845**	**(68,405)**	**-**	**(10,284)**	**(29,260)**	**33,323**	**371,313**	**729,486**	**303,167**	**326,270**	**372,054**
73																							
74																							
75	**Updated Ratios:**	**Changes to the Variable Commodity Allocation Ratios were to move the Company Managed units outside the LAUF adjustment and begin adjusting this factor annually, effective November 2010.**																					
76	NH Ratio		52.57%	54.96%	55.03%	52.44%	58.84%	52.21%	56.96%	48.08%	59.20%	60.04%	52.54%	52.93%	54.05%	56.79%	57.47%	57.80%	54.88%	55.67%	53.86%	52.86%	54.34%
77	ME Ratio		47.43%	45.04%	44.97%	47.56%	41.16%	47.79%	43.04%	51.92%	40.80%	39.96%	47.46%	47.07%	45.95%	43.21%	42.53%	42.20%	45.12%	44.33%	46.14%	47.14%	45.66%
78																							
79	**Costs based on Current Month ratios:**																						
80	NH Division - Lines (27+28) x 76 (current month allocator)	-	-	-	-	-	-	820,634	35,191	17,198	11,155	(5,380)	873,211	-	-	-	-	-	-	498,610	241,908	232,507	(7,087)
81	ME Division - Lines (27+28) x 77 (current month allocator)	-	-	-	-	-	-	751,065	26,588	18,571	7,687	(3,581)	788,750	-	-	-	-	-	-	397,019	207,235	207,348	(5,955)
82	**Costs based on Prior Month Ratios:**																						
83	NH Division - Lines (44+45) x 76 (prior month allocator)	-	-	-	-	-	-	(6,766)	333,280	315,967	340,166	314,881	199,357	753,308	-	(12,101)	(38,466)	41,976	511,094	-	434,624	37,208	178,917
84	ME Division - Lines (44+45) x 77 (prior month allocator)	-	-	-	-	-	-	(4,734)	305,026	238,729	367,334	216,986	132,679	680,444	-	(10,289)	(29,274)	31,063	373,081	-	346,070	31,875	159,556
85	**Costs not requiring reallocation:**																						
86	NH Division - Line 67	2,027	-	-	-	-	-	340,553	(109,609)	16,691	(1,781)	(138,232)	621,937	(835,648)	-	-	-	-	-	408,990	(330,308)	84,306	262,067
87	ME Division - Line 68	1,691	-	-	-	-	-	367,950	(141,635)	120,408	(130,122)	(86,490)	615,202	(753,881)	-	-	-	-	-	332,235	(250,279)	86,928	218,305
88																							
89	**Adjusted Commodity Costs:**																						
90	**NH Division - Lines 126+129+132**	**2,027**	**-**	**-**	**-**	**-**	**-**	**1,154,422**	**258,862**	**349,856**	**349,540**	**171,269**	**1,694,505**	**(82,340)**	**-**	**(12,101)**	**(38,466)**	**41,976**	**511,094**	**907,600**	**346,225**	**354,021**	**433,897**
91	**ME Division - Lines 127+130+133**	**1,691**	**-**	**-**	**-**	**-**	**-**	**1,114,281**	**189,979**	**377,708**	**244,899**	**126,915**	**1,536,631**	**(73,437)**	**-**	**(10,289)**	**(29,274)**	**31,063**	**373,081**	**729,254**	**303,026**	**326,150**	**371,907**
92																							
93	**Allocation Adjustment:**																						
94	**NH Division - Lines 90-71**	**-**	**-**	**-**	**-**	**-**	**-**	**(207)**	**864**	**(246)**	**939**	**1,459**	**214**	**5,032**	**-**	**6**	**14**	**2,260**	**(1,769)**	**232**	**141**	**120**	**148**
95	**ME Division - Lines 91-72**	**-**	**-**	**-**	**-**	**-**	**-**	**207**	**(864)**	**246**	**(939)**	**(1,459)**	**(214)**	**(5,032)**	**-**	**(6)**	**(14)**	**(2,260)**	**1,769**	**(232)**	**(141)**	**(120)**	**(148)**

Northern Utilities, Inc.
Summary of Allocation Adjustment calculation - Off-Peak Period - November 2008 through October 2011

Line No.	Description	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)
96																							
97	**Updated Ratios:**	**Changes to the Variable Commodity Allocation Ratios were to move the Company Managed units outside the LAUF adjustment and the correction of New Hampshire Company Managed units (Dec 2008 - Mar 2009).**																					
98	NH Ratio		53.31%	56.51%	55.32%	52.75%	58.84%	52.21%	56.96%	48.08%	59.20%	60.04%	52.54%	52.93%	54.05%	56.79%	57.47%	57.80%	54.88%	55.67%	53.86%	52.86%	54.34%
99	ME Ratio		46.69%	43.49%	44.68%	47.25%	41.16%	47.79%	43.04%	51.92%	40.80%	39.96%	47.46%	47.07%	45.95%	43.21%	42.53%	42.20%	45.12%	44.33%	46.14%	47.14%	45.66%
100																							
101	**Costs based on Current Month ratios:**																						
102	NH Division - Lines (27+28) x 98 (current month allocator)	-	-	-	-	-	-	820,634	35,191	17,198	11,155	(5,380)	873,211	-	-	-	-	-	-	498,610	241,908	232,507	(7,087)
103	ME Division - Lines (27+28) x 99 (current month allocator)	-	-	-	-	-	-	751,065	26,588	18,571	7,687	(3,581)	788,750	-	-	-	-	-	-	397,019	207,235	207,348	(5,955)
104	**Costs based on Prior Month Ratios:**																						
105	NH Division - Lines (44+45) x 98 (prior month allocator)		-	-	-	-	-	(6,766)	333,280	315,967	340,166	314,881	199,357	753,308	-	(12,101)	(38,466)	41,976	511,094	-	434,624	37,208	178,917
106	ME Division - Lines (44+45) x 99 (prior month allocator)	-	-	-	-	-	-	(4,734)	305,026	238,729	367,334	216,986	132,679	680,444	-	(10,289)	(29,274)	31,063	373,081	-	346,070	31,875	159,556
107	**Costs not requiring reallocation:**																						
108	NH Division - Line 67	2,027	-	-	-	-	-	340,553	(109,609)	16,691	(1,781)	(138,232)	621,937	(835,648)	-	-	-	-	-	408,990	(330,308)	84,306	262,067
109	ME Division - Line 68	1,691	-	-	-	-	-	367,950	(141,635)	120,408	(130,122)	(86,490)	615,202	(753,881)	-	-	-	-	-	332,235	(250,279)	86,928	218,305
110																							
111	**Adjusted Commodity Costs:**																						
112	**NH Division - Lines 102+105+108**	**2,027**	**-**	**-**	**-**	**-**	**-**	**1,154,422**	**258,862**	**349,856**	**349,540**	**171,269**	**1,694,505**	**(82,340)**	**-**	**(12,101)**	**(38,466)**	**41,976**	**511,094**	**907,600**	**346,225**	**354,021**	**433,897**
113	**ME Division - Lines 103+106+109**	**1,691**	**-**	**-**	**-**	**-**	**-**	**1,114,281**	**189,979**	**377,708**	**244,899**	**126,915**	**1,536,631**	**(73,437)**	**-**	**(10,289)**	**(29,274)**	**31,063**	**373,081**	**729,254**	**303,026**	**326,150**	**371,907**
114																							
115	**Allocation Adjustment:**																						
116	**NH Division - Lines 112-90**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
117	**ME Division - Lines 113-91**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
118																							
119																							
120	**Updated Ratios:**	**Changes to the Variable Commodity Allocation Ratios were to move the Company Managed units outside the LAUF adjustment, correction of New Hampshire Company Managed Units (Dec08 - Mar09) AND to include Maine Company Managed units in the calculation.**																					
121	NH Ratio		50.45%	51.98%	54.11%	51.81%	58.84%	52.21%	56.96%	48.08%	59.20%	60.04%	52.54%	51.66%	49.18%	52.32%	52.79%	53.48%	54.88%	55.67%	53.86%	52.86%	54.34%
122	ME Ratio		49.55%	48.02%	45.89%	48.19%	41.16%	47.79%	43.04%	51.92%	40.80%	39.96%	47.46%	48.34%	50.82%	47.68%	47.21%	46.52%	45.12%	44.33%	46.14%	47.14%	45.66%
123																							
124	**Costs based on Current Month ratios:**																						
125	NH Division - Lines (27+28) x 121 (current month allocator)	-	-	-	-	-	-	820,634	35,191	17,198	11,155	(5,380)	873,211	-	-	-	-	-	-	498,610	241,908	232,507	(7,087)
126	ME Division - Lines (27+28) x 122 (current month allocator)	-	-	-	-	-	-	751,065	26,588	18,571	7,687	(3,581)	788,750	-	-	-	-	-	-	397,019	207,235	207,348	(5,955)
127	**Costs based on Prior Month Ratios:**																						
128	NH Division - Lines (44+45) x 121 (prior month allocator)		-	-	-	-	-	(6,766)	333,280	315,967	340,166	314,881	199,357	753,308	-	(11,012)	(35,444)	38,557	472,883	-	434,624	37,208	178,917
129	ME Division - Lines (44+45) x 122 (prior month allocator)		-	-	-	-	-	(4,734)	305,026	238,729	367,334	216,986	132,679	680,444	-	(11,378)	(32,296)	34,482	411,292	-	346,070	31,875	159,556
130	**Costs not requiring reallocation:**																						
131	NH Division - Line 67	2,027	-	-	-	-	-	340,553	(109,609)	16,691	(1,781)	(138,232)	621,937	(835,648)	-	-	-	-	-	408,990	(330,308)	84,306	262,067
132	ME Division - Line 68	1,691	-	-	-	-	-	367,950	(141,635)	120,408	(130,122)	(86,490)	615,202	(753,881)	-	-	-	-	-	332,235	(250,279)	86,928	218,305
133																							
134	**Total Commodity Costs - adjusted:**																						
135	**NH Division - Lines 125+128+131**	**2,027**	**-**	**-**	**-**	**-**	**-**	**1,154,422**	**258,862**	**349,856**	**349,540**	**171,269**	**1,694,505**	**(82,340)**	**-**	**(11,012)**	**(35,444)**	**38,557**	**472,883**	**907,600**	**346,225**	**354,021**	**433,897**
136	**ME Division - Lines 126+129+132**	**1,691**	**-**	**-**	**-**	**-**	**-**	**1,114,281**	**189,979**	**377,708**	**244,899**	**126,915**	**1,536,631**	**(73,437)**	**-**	**(11,378)**	**(32,296)**	**34,482**	**411,292**	**729,254**	**303,026**	**326,150**	**371,907**
137																							
138	**Allocation Adjustment:**																						
139	**NH Division - Lines 135-112**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**1,089**	**3,023**	**(3,420)**	**(38,211)**	**-**	**-**	**-**	**-**
140	**ME Division - Lines 136-113**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**(1,089)**	**(3,023)**	**3,420**	**38,211**	**-**	**-**	**-**	**-**
141																							
142	**Allocation Adjustment:**																						
143	**NH Division - Lines 135-112**	**-**	**-**	**-**	**-**	**-**	**-**	**(207)**	**864**	**(246)**	**939**	**1,459**	**214**	**5,032**	**-**	**1,094**	**3,037**	**(1,160)**	**(39,979)**	**232**	**141**	**120**	**148**
144	**ME Division - Lines 136-113**	**-**	**-**	**-**	**-**	**-**	**-**	**207**	**(864)**	**246**	**(939)**	**(1,459)**	**(214)**	**(5,032)**	**-**	**(1,094)**	**(3,037)**	**1,160**	**39,979**	**(232)**	**(141)**	**(120)**	**(148)**

Northern Utilities, Inc.
Summary of Allocation Adjustment calculation - Off-Peak Period - November 2008 tl

Line No.	Description	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	**Total**
	(A)	(X)	(Y)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	**(AF)**	(AG)	(AH)	(AI)	(AJ)	(AK)	**(AL)**
1	**Costs allocated on Current Month Ratios:**															
2	**Withdrawal Charges**															
3	NH Division	166	(679)	(5,102)	-	-	-	-	-	(529)	752	(297)	775	(2,678)	(137)	**(3,228)**
4	ME Division	143	(643)	(4,832)	-	-	-	-	-	(463)	638	(269)	681	(2,345)	(134)	**(3,680)**
5	**ATV Reconciliation Charges (moved from Transportation charges)**															
6	NH Division	(853)	127,328	-	-	-	-	-	-	90,239	18,793	3,583	(17,344)	6,329	41,345	**1,005,289**
7	ME Division	(735)	120,585	-	-	-	-	-	-	79,002	15,938	3,242	(15,246)	5,541	40,478	**869,777**
8	**Net OBA Adjustment**															
9	NH Division	(4,551)	(560)	-	-	-	-	-	-	3,291	(8,977)	(8,710)	988	2,973	(10,532)	**44,714**
10	ME Division	(3,922)	(530)	-	-	-	-	-	-	2,881	(7,613)	(7,880)	993	2,602	(10,312)	**40,835**
11	**Transportation Charges**															
12	NH Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**(119,017)**
13	ME Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**(107,683)**
14	**LNG Boiloff**															
15	NH Division	5,274	4,944	-	-	-	-	-	-	5,900	4,436	6,889	5,731	6,764	4,524	**101,884**
16	ME Division	4,546	4,683	-	-	-	-	-	-	5,165	3,762	6,233	5,038	5,922	4,429	**88,946**
17	**Interruptible**															
18	NH Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**(35,665)**
19	ME Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**(29,929)**
20	**Hedging Costs**															
21	NH Division	1,957	314,303	-	-	-	-	-	-	24,188	1,833	916	1,090	1,206	66,231	**2,411,406**
22	ME Division	1,952	297,788	-	-	-	-	-	-	21,176	1,554	829	958	1,056	64,841	**2,188,561**
23	**Inventory Finance Charges**															
24	NH Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
25	ME Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
26	Subtotal - Costs allocated on Current Month Ratios															
27	NH Division - Lines 3+6+9+12+15+18+21+24	1,994	445,337	(5,102)	-	-	-	-	-	123,089	16,838	2,381	(8,759)	14,594	101,430	**3,405,384**
28	ME Division - Lines 4+7+10+13+16+19+22+25	1,985	421,883	(4,832)	-	-	-	-	-	107,760	14,280	2,154	(7,575)	12,776	99,302	**3,046,827**
29																
30	**Costs allocated on Prior Month Ratios:**															
31	**Vendor Payments**															
32	NH Division	453,931	464,561	729,333	3,974	-	-	-	-	-	926,656	596,671	602,670	611,700	540,845	**8,400,107**
33	ME Division	381,269	400,257	690,457	3,763	-	-	-	-	-	811,257	506,029	545,273	537,680	473,493	**7,313,317**
34	**Non-Traditional Sales**															
35	NH Division (1)	-	(98,471)	(69,697)	-	-	-	-	-	-	(340,132)	(164,840)	(283,329)	(162,598)	(170,241)	**(1,775,345)**
36	ME Division (1)	-	(84,867)	(66,006)	-	-	-	-	-	-	(297,775)	(139,799)	(256,345)	(142,923)	(149,041)	**(1,549,195)**
37	**Transportation Charges**															
38	NH Division	(1,504)	(25,672)	14,248	(24,452)	-	-	-	2,535	-	1,394	(6,202)	-	2,017	(5,696)	**371,543**
39	ME Division	(1,263)	(22,125)	13,493	(21,476)	-	-	-	2,046	-	1,221	(5,259)	-	1,773	(4,987)	**255,410**
40	**Remove ATV Recon Amts from Transportation (moved above)**															
41	NH Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
42	ME Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
43	Subtotal - Costs allocated on Prior Month Ratios															
44	NH Division - Lines 32+35+38+41	452,427	340,419	673,884	(20,479)	-	-	-	2,535	-	587,918	425,629	319,341	451,119	364,908	**6,996,305**
45	ME Division - Lines 33+36+39+42	380,006	293,265	637,944	(17,713)	-	-	-	2,046	-	514,703	360,971	288,928	396,530	319,466	**6,019,532**
46																

Northern Utilities, Inc.
Summary of Allocation Adjustment calculation - Off-Peak Period - November 2008 tl

Line No.	Description	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
	(A)	(X)	(Y)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	**(AF)**	(AG)	(AH)	(AI)	(AJ)	(AK)	**(AL)**
47	**Costs not requiring reallocation:**															
48	**Company Managed**															
49	NH Division	(8,512)	(6,921)	(7,267)	-	-	-	-	-	-	-	-	-	-	-	**(86,794)**
50	ME Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**(12,578)**
51	**Propane**															
52	NH Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**(67,162)**
53	ME Division	640	584	-	-	-	-	-	-	641	828	622	635	596	459	**10,904**
54	**Estimates**															
55	NH Division	(98,565)	313,266	(664,923)	-	-	-	-	-	620,405	(188,482)	(111,155)	128,266	(86,950)	225,212	**587,296**
56	ME Division	(76,263)	327,552	(636,592)	-	-	-	-	-	543,145	(176,838)	(76,089)	104,479	(77,703)	257,981	**574,975**
57	**Transportation Commodity**															
58	NH Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
59	ME Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
60	**Other**															
61	NH Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
62	ME Division	-	-	(4,280)	-	-	-	-	-	-	-	-	-	-	-	**(4,280)**
63	**Prior Period Adjustments**															
64	NH Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**2,027**
65	ME Division	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**1,691**
66	Subtotal - Costs not requiring reallocation															
67	NH Division - Lines 49+52+55+58+61+64	(107,078)	306,346	(672,190)	-	-	-	-	-	620,405	(188,482)	(111,155)	128,266	(86,950)	225,212	**435,367**
68	NH Division - Lines 50+53+56+59+62+65	(75,623)	328,136	(640,872)	-	-	-	-	-	543,786	(176,010)	(75,467)	105,114	(77,107)	258,440	**570,711**
69																
70	**Total Commodity Costs as Originally Filed:**															
71	**NH Division - Lines 27+44+67**	**347,344**	**1,092,101**	**(3,408)**	**(20,479)**	**-**	**-**	**-**	**2,535**	**743,494**	**416,273**	**316,855**	**438,848**	**378,762**	**691,550**	**10,837,056**
72	**ME Division - Lines 28+45+68**	**306,367**	**1,043,284**	**(7,760)**	**(17,713)**	**-**	**-**	**-**	**2,046**	**651,547**	**352,973**	**287,658**	**386,467**	**332,200**	**677,208**	**9,637,070**
73																
74																
75	**Updated Ratios:** **Change**															
76	NH Ratio	53.70%	51.35%	53.43%	55.38%	56.97%	55.41%	55.51%	52.85%	53.51%	54.31%	52.70%	53.42%	53.52%	50.73%	
77	ME Ratio	46.30%	48.65%	46.57%	44.62%	43.03%	44.59%	44.49%	47.15%	46.49%	45.69%	47.30%	46.58%	46.48%	49.27%	
78																
79	**Costs based on Current Month ratios:**															
80	NH Division - Lines (27+28) x 76 (current month allocator)	2,137	445,317	(5,307)	-	-	-	-	-	123,527	16,900	2,390	(8,726)	14,648	101,832	**3,410,666**
81	ME Division - Lines (27+28) x 77 (current month allocator)	1,842	421,902	(4,626)	-	-	-	-	-	107,322	14,218	2,145	(7,608)	12,722	98,901	**3,041,545**
82	**Costs based on Prior Month Ratios:**															
83	NH Division - Lines (44+45) x 76 (prior month allocator)	452,344	340,288	673,624	(20,406)	-	-	-	2,543	-	590,012	427,203	320,558	452,814	366,277	**7,008,701**
84	ME Division - Lines (44+45) x 77 (prior month allocator)	380,089	293,395	638,204	(17,786)	-	-	-	2,038	-	512,608	359,398	287,711	394,835	318,097	**6,007,136**
85	**Costs not requiring reallocation:**															
86	NH Division - Line 67	(107,078)	306,346	(672,190)	-	-	-	-	-	620,405	(188,482)	(111,155)	128,266	(86,950)	225,212	**435,367**
87	ME Division - Line 68	(75,623)	328,136	(640,872)	-	-	-	-	-	543,786	(176,010)	(75,467)	105,114	(77,107)	258,440	**570,711**
88																
89	**Adjusted Commodity Costs:**															
90	**NH Division - Lines 126+129+132**	**347,403**	**1,091,951**	**(3,874)**	**(20,406)**	**-**	**-**	**-**	**2,543**	**743,932**	**418,430**	**318,438**	**440,098**	**380,512**	**693,320**	**10,854,734**
91	**ME Division - Lines 127+130+133**	**306,308**	**1,043,434**	**(7,294)**	**(17,786)**	**-**	**-**	**-**	**2,038**	**651,108**	**350,816**	**286,076**	**385,217**	**330,450**	**675,438**	**9,619,391**
92																
93	**Allocation Adjustment:**															
94	**NH Division - Lines 90-71**	**59**	**(150)**	**(466)**	**73**	**-**	**-**	**-**	**8**	**439**	**2,157**	**1,582**	**1,250**	**1,750**	**1,770**	**17,679**
95	**ME Division - Lines 91-72**	**(59)**	**150**	**466**	**(73)**	**-**	**-**	**-**	**(8)**	**(439)**	**(2,157)**	**(1,582)**	**(1,250)**	**(1,750)**	**(1,770)**	**(17,679)**

Northern Utilities, Inc.
Summary of Allocation Adjustment calculation - Off-Peak Period - November 2008 tl

Line No.	Description	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	**Total**
	(A)	(X)	(Y)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	**(AF)**	(AG)	(AH)	(AI)	(AJ)	(AK)	**(AL)**
96																
97	**Updated Ratios:** **Change**															
98	NH Ratio	53.70%	51.35%	53.43%	55.38%	56.97%	55.41%	55.51%	52.85%	53.51%	54.31%	52.70%	53.42%	53.52%	50.73%	
99	ME Ratio	46.30%	48.65%	46.57%	44.62%	43.03%	44.59%	44.49%	47.15%	46.49%	45.69%	47.30%	46.58%	46.48%	49.27%	
100																
101	**Costs based on Current Month ratios:**															
102	NH Division - Lines (27+28) x 98 (current month allocator)	2,137	445,317	(5,307)	-	-	-	-	-	123,527	16,900	2,390	(8,726)	14,648	101,832	**3,410,666**
103	ME Division - Lines (27+28) x 99 (current month allocator)	1,842	421,902	(4,626)	-	-	-	-	-	107,322	14,218	2,145	(7,608)	12,722	98,901	**3,041,545**
104	**Costs based on Prior Month Ratios:**															
105	NH Division - Lines (44+45) x 98 (prior month allocator)	452,344	340,288	673,624	(20,406)	-	-	-	2,543	-	590,012	427,203	320,558	452,814	366,277	**7,008,701**
106	ME Division - Lines (44+45) x 99 (prior month allocator)	380,089	293,395	638,204	(17,786)	-	-	-	2,038	-	512,608	359,398	287,711	394,835	318,097	**6,007,136**
107	**Costs not requiring reallocation:**															
108	NH Division - Line 67	(107,078)	306,346	(672,190)	-	-	-	-	-	620,405	(188,482)	(111,155)	128,266	(86,950)	225,212	**435,367**
109	ME Division - Line 68	(75,623)	328,136	(640,872)	-	-	-	-	-	543,786	(176,010)	(75,467)	105,114	(77,107)	258,440	**570,711**
110																
111	**Adjusted Commodity Costs:**															
112	**NH Division - Lines 102+105+108**	**347,403**	**1,091,951**	**(3,874)**	**(20,406)**	**-**	**-**	**-**	**2,543**	**743,932**	**418,430**	**318,438**	**440,098**	**380,512**	**693,320**	**10,854,734**
113	**ME Division - Lines 103+106+109**	**306,308**	**1,043,434**	**(7,294)**	**(17,786)**	**-**	**-**	**-**	**2,038**	**651,108**	**350,816**	**286,076**	**385,217**	**330,450**	**675,438**	**9,619,391**
114																
115	**Allocation Adjustment:**															
116	**NH Division - Lines 112-90**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
117	**ME Division - Lines 113-91**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
118																
119																
120	**Updated Ratios:** **Change:**															
121	NH Ratio	53.70%	51.35%	49.04%	44.94%	48.99%	50.09%	49.75%	52.85%	53.51%	54.31%	52.70%	53.42%	53.52%	50.73%	
122	ME Ratio	46.30%	48.65%	50.96%	55.06%	51.01%	49.91%	50.25%	47.15%	46.49%	45.69%	47.30%	46.58%	46.48%	49.27%	
123																
124	**Costs based on Current Month ratios:**															
125	NH Division - Lines (27+28) x 121 (current month allocator)	2,137	445,317	(4,871)	-	-	-	-	-	123,527	16,900	2,390	(8,726)	14,648	101,832	**3,411,102**
126	ME Division - Lines (27+28) x 122 (current month allocator)	1,842	421,902	(5,062)	-	-	-	-	-	107,322	14,218	2,145	(7,608)	12,722	98,901	**3,041,108**
127	**Costs based on Prior Month Ratios:**															
128	NH Division - Lines (44+45) x 121 (prior month allocator)	452,344	340,288	673,624	(18,729)	-	-	-	2,279	-	590,012	427,203	320,558	452,814	366,277	**6,972,595**
129	ME Division - Lines (44+45) x 122 (prior month allocator)	380,089	293,395	638,204	(19,462)	-	-	-	2,302	-	512,608	359,398	287,711	394,835	318,097	**6,043,242**
130	**Costs not requiring reallocation:**															
131	NH Division - Line 67	(107,078)	306,346	(672,190)	-	-	-	-	-	620,405	(188,482)	(111,155)	128,266	(86,950)	225,212	**435,367**
132	ME Division - Line 68	(75,623)	328,136	(640,872)	-	-	-	-	-	543,786	(176,010)	(75,467)	105,114	(77,107)	258,440	**570,711**
133																
134	**Total Commodity Costs - adjusted:**															
135	**NH Division - Lines 125+128+131**	**347,403**	**1,091,951**	**(3,438)**	**(18,729)**	**-**	**-**	**-**	**2,279**	**743,932**	**418,430**	**318,438**	**440,098**	**380,512**	**693,320**	**10,819,064**
136	**ME Division - Lines 126+129+132**	**306,308**	**1,043,434**	**(7,730)**	**(19,462)**	**-**	**-**	**-**	**2,302**	**651,108**	**350,816**	**286,076**	**385,217**	**330,450**	**675,438**	**9,655,061**
137																
138	**Allocation Adjustment:**															
139	**NH Division - Lines 135-112**	**-**	**-**	**436**	**1,677**	**-**	**-**	**-**	**(264)**	**-**	**-**	**-**	**-**	**-**	**-**	**(35,670)**
140	**ME Division - Lines 136-113**	**-**	**-**	**(436)**	**(1,677)**	**-**	**-**	**-**	**264**	**-**	**-**	**-**	**-**	**-**	**-**	**35,670**
141																
142	**Allocation Adjustment:**															
143	**NH Division - Lines 135-112**	**59**	**(150)**	**(30)**	**1,750**	**-**	**-**	**-**	**(256)**	**439**	**2,157**	**1,582**	**1,250**	**1,750**	**1,770**	**(17,991)**
144	**ME Division - Lines 136-113**	**(59)**	**150**	**30**	**(1,750)**	**-**	**-**	**-**	**256**	**(439)**	**(2,157)**	**(1,582)**	**(1,250)**	**(1,750)**	**(1,770)**	**17,991**

Schedule 17

Total Impacts by Division, by Period, & by Type of Revision

Northern Utilities, Inc.
Reconciliation of New Hampshire and Maine Cost of Gas ("COG") for December 2008 to October 2011

		Peak Period		Off-Peak Period		Both Periods		
Line No.	Period	NH	ME	NH	ME	NH	ME	References
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	LAUF update:							
2	As Originally Filed	$62,048,909	$44,448,111	$10,837,056	$ 9,637,070	$ 72,885,965	$ 54,085,181	Sch 1, L.60 and L.69, Col.B and Col.E
3	As Revised for LAUF	$62,214,444	$44,282,576	$10,854,734	$ 9,619,391	$ 73,069,178	$ 53,901,968	Sch 15/Sch 16, P.5, L.90/L.91, Col. AL
4	Change due to LAUF	$ 165,535	$ (165,535)	$ 17,679	$ (17,679)	$ 183,213	$ (183,213)	L.3 - L.2
5	NH Company Managed update:							
6	As Revised for LAUF	$62,214,444	$44,282,576	$10,854,734	$ 9,619,391	$ 73,069,178	$ 53,901,968	L.3
7	Revised to adj NH Co Mgd	$62,579,889	$43,917,132	$10,854,734	$ 9,619,391	$ 73,434,623	$ 53,536,523	Sch 15/Sch 16, P.6, L.112/L.113, Col.
8	Change due to NH Co Mgd	$ 365,444	$ (365,444)	$ -	$ -	$ 365,444	$ (365,444)	L.7 - L.6
9	ME Company Managed update:							
10	As Revised for NH Company Mgd	$62,579,889	$43,917,132	$10,854,734	$ 9,619,391	$ 73,434,623	$ 53,536,523	L.7
11	Revised to add ME Co Mgd)	$58,095,273	$48,401,747	$10,819,065	$ 9,655,061	$ 68,914,338	$ 58,056,808	Sch 1, L.60 and L.69, Col.C and Col.F
12	Change due to ME Co Mgd	$ (4,484,616)	$ 4,484,615	$ (35,670)	$ 35,670	$ (4,520,285)	$ 4,520,285	L.11 - L.10
13	Sum of Updates	$ (3,953,636)	$ 3,953,636	$ (17,991)	$ 17,991	$ (3,971,627)	$ 3,971,627	L.4 + L.8 + L.12
14	Working Capital update:							
15	As Originally Filed	$ 60,016	$ 355,451	$ 8,259	$ 58,262	$ 68,275	$ 413,713	Sch 1, L.63 and L.72, Col.B and Col.E
16	Revised Working Capital	$ 57,773	$ 372,887	$ 8,248	$ 58,341	$ 66,021	$ 431,228	Sch 1, L.63 and L.72, Col.C and Col.F
17	Change in Working Capital	$ (2,243)	$ 17,436	$ (11)	$ 79	$ (2,254)	$ 17,515	L.16 - L.15
18	Bad Debt update:							
19	As Originally Filed	$ 442,226	$ 858,140	$ 65,940	$ 140,656	$ 508,166	$ 998,796	Sch 1, L.65 and L.74, Col.B and Col.E
20	Revised Bad Debt	$ 424,425	$ 900,233	$ 65,859	$ 140,848	$ 490,284	$ 1,041,081	Sch 1, L.65 and L.74, Col.C and Col.F
21	Change in Bad Debt	$ (17,801)	$ 42,093	$ (81)	$ 192	$ (17,882)	$ 42,285	L.20 - L.19
22	Carrying Charges update:							
23	As Originally Filed	$ 308,155	$ 67,232	$ (2,619)	$ 5,649	$ 305,536	$ 72,881	Sch 1, L.88 and L.89, Col.B and Col.E
24	Revised Carrying Charges	$ 180,056	$ 161,619	$ (3,813)	$ 6,472	$ 176,243	$ 168,091	Sch 1, L.88 and L.89, Col.C and Col.F
25	Change in Carrying Charges	$ (128,099)	$ 94,387	$ (1,194)	$ 823	$ (129,293)	$ 95,210	L.24 - L.23
26	**Total Updates to Commodity Costs**	**$ (4,101,779)**	**$ 4,107,552**	**$ (19,277)**	**$ 19,085**	**$ (4,121,057)**	**$ 4,126,637**	L.13 + L.17 + L.21 + L.25

27 Note 1 - LAUF update: Provides the changes to commodity costs due to updating the calculation of commodity allocation ratios, specifically to isolate and remove company managed units from the Lost and Unaccounted For (LAUF) adjustment. This change in costs is also related to the annual adjustment to the LAUF factor beginning in November 2010.

28 Note 2 - NH Company Managed update: Provides the changes to commodity costs due updating the variable commodity allocation ratios related to a change in the New Hampshire company managed units for Dec 2008 to Mar 2009.

29 Note 3 - ME Company Managed update: Provides the changes to commodity costs due to updating the variable commodity allocation ratios related to the inclusion of Maine company managed units.