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Senior Attorney

April 30, 2007

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VIA OVERNIGHT & ELECTRONIC MAIL

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

Re: Docket No. DE 07- ; 2007 Integrated Least Cost Resource Plan

Dear Ms. Howland:

Pursuant to RSA 378:38, I am submitting seven (7) copies of the 2007 least cost integrated resource plan of Granite State Electric Company, New England Power Company, New England Electric Transmission Corporation, New England Hydro-Transmission Corporation and New England Hydro-Transmission Electric Company, Inc.

Please feel free to contact me at (508) 389-3243 with any questions.

Very truly yours,

Alexandra E. Blackmore

Alexandra E. Blackmore

Enclosures
cc: Donald Pfundstein, Esq.
Meredith A. Hatfield, Esq.

NHPUC MAY01'07 AM10:45

GRANITE STATE ELECTRIC COMPANY

REPORT ON

LEAST COST

INTEGRATED RESOURCE PLANNING

May 2007

nationalgrid

Granite State Electric Company
New England Power Company
New England Electric Transmission Corporation
New England Hydro-Transmission Corporation
New England Hydro-Transmission Electric Company, Inc.

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1.0 EXECUTIVE SUMMARY

Pursuant to RSA 378:38, Granite State Electric Company ("GSEC" or "Granite State"), as well as New England Power Company ("NEP"), New England Electric Transmission Corporation ("NEET"), New England Hydro-Transmission Corporation ("NHH"), and New England Hydro-Transmission Electric Company, Inc. ("NEH") (collectively, "National Grid") are required to submit a least cost integrated resource plan with the New Hampshire Public Utilities Commission ("Commission" or "NHPUC").

Restructuring at both the federal level and within the State of New Hampshire has changed the manner in which utilities perform planning. Comprehensive planning now involves generating assets that are developed by the competitive marketplace and resources are coordinated through a regional transmission organization. While planning now involves significant factors outside of the control of the utility, utilities retain an obligation to meet the needs of their customers by providing for reliable and adequate electric services. Granite State addresses this obligation through a cooperative planning structure that satisfies both the short- and long-term needs of its customers in New Hampshire and supports the overall robustness of the regional bulk power system.

1.1 Effects of Industry Changes

New Hampshire policy is for utilities like Granite State to exit the power generation and supply business and to become a transmission and distribution utility. As required by RSA 374-F and Granite State's Electric Restructuring Settlement Agreement, Granite State has divested all of its generation facilities. Since the divestiture of Granite State's generation facilities, Granite State's obligation to meet the power supply needs of our customers who do not directly contract with competitive suppliers was transferred to unaffiliated third-party suppliers of Default

Service. For Granite State, therefore, availability of supply is left to the competitive marketplace – directly for customers who take service from the wholesale market and indirectly for our customers for whom we secure market-priced, power supply agreements. Granite State no longer maintains control over generating assets and participates in the coordination of transmission planning through National Grid in the Independent System Operator – New England ("ISO-NE") Regional System Planning Process. Consequently, Granite State no longer performs "least cost integrated resource planning" in a traditional sense. Given these marketplace developments, Granite State has emphasized a cooperative approach to distribution/transmission planning and investment and effective demand response programs.

1.2 Filing Overview

Despite industry restructuring, Granite State is required to provide the public and the Commission with an outline of its strategy for ensuring customers receive adequate, reliable electric supply. As a distribution utility, Granite State provides Default Service to customers who may be affected by the uncertainties of the competitive supply market. Granite State does so through the procurement of Default Service, implementation of effective energy efficiency and demand response programs, and a robust distribution planning process, as well as National Grid's transmission planning process. These practices are consistent with the restructuring policy principles in RSA 374-F:3 and numerous Commission Orders approving GSEC's procurement of Default Service in this new marketplace.[1]

This report is organized in five sections and three appendices. Section 1 consists of a general introduction. Section 2 provides an overview of the supply procurement strategy used to

[1] See, Order Nos. 24,412 (12/22/2004), 24318 (4/30/2004), 24,163 (4/25/2003), 23,558 (9/25/2000), 23,523 (7/5/2000), 23,393 (1/27/2000).

ensure that Granite State's customers receive the lowest energy cost possible. Section 3 describes Granite State's participation in the New Hampshire Core Energy Efficiency programs and in ISO-New England's Real-Time Demand Response Programs, including an overview of the results and effectiveness of these programs. Sections 4 and 5 contain a discussion of Granite State's distribution and National Grid's transmission planning processes and identify current projects under review/implementation to address the reliability needs of New Hampshire and facilitate the competitive markets of the region. Appendix A contains Granite State's annual peak load forecast. Appendix B contains the filing previously submitted to the Commission with regard to the New Hampshire Core Energy Efficiency programs. Appendix C is the National Grid Transmission Planning Guide used to define the criteria and standards to assess the reliability of the existing and future National Grid transmission system.

2.0 PROCUREMENT STRATEGY

Granite State's Amended Restructuring Settlement Agreement ("Restructuring Settlement") provided retail access for all retail delivery service customers of Granite State beginning July 1, 1998. The Restructuring Settlement and New Hampshire[2] law require Granite State to provide electricity supply to its customers who are not served by the competitive market. This "provider-of- last-resort service" obligation currently is provided by Energy Service and was previously provided by Transition Service and Default Service.

Transition Service ended on April 30, 2006 and all customers who did not choose a competitive supplier by April 30, 2006 were seamlessly transferred and began receiving Energy Service on May 1, 2006. A settlement agreement approved by the New Hampshire Public Utilities Commission ("Commission") on January 13, 2006 in Order No. 24,577 ("Settlement Agreement") provides for the procurement of Default Service commencing May 1, 2006. On April 13, 2006 (see Order No. 24,614), the Commission allowed electric utilities providing Default Service to use the term Energy Service in customer communications. As a result, Default Service was renamed Energy Service by Granite State.

Energy Service is available to all Granite State customers who are not serviced by a competitive supplier. In accordance with Order Nos. 23,393 (January 27, 2000), 24,577 (January 13, 2006), 24,609 (March 28, 2006), 24,639 (June 22, 2006), 24,675 (September 29, 2006), 24,715 (December 15, 2006), 24,736 (March 26, 2007) and RSA 374-F:3, V(C), Granite State procures its Energy Service requirements via competitive solicitations which are issued every three months and which cover terms ranging from three to six months. The requirements are

[2]Granite State Electric Company's Amended Restructuring Settlement Agreement ("Restructuring Settlement") and RSA 374-F ("New Hampshire Act").

purchased at market prices which are fixed throughout the term. Granite State currently has 100% of its Residential and Small Commercial Customer Group Energy Service requirements under contract through October 31, 2007, and 100% of its Medium and Large Commercial and Industrial Customer Group Energy Service requirements under contract through July 31, 2007. Granite State anticipates issuing a solicitation in May 2007 to obtain 100% of its Medium and Large Commercial and Industrial Customer Group Energy Service requirements for the August 2007 - October 2007 period. In August 2007, Granite State plans to issue a solicitation for 100% of the service requirements for its Medium and Large Commercial and Industrial Customer Group for the three month period November 2007 – January 2008 and for 100% of the service requirements for its Residential and Small Commercial Customer Group for the six month period November 2007 through April 2008.

As required in the Settlement Agreement, for each procurement, Granite State will file with the Commission the results of the procurement, the accompanying retail rates and executed power purchase agreements. The Commission will have five days to review the merits of the filing and approve the proposed retail rates.

3.0 DEMAND SIDE RESOURCES

Granite State currently offers two sets of demand side resource programs: the New Hampshire Core Energy Efficiency Programs ("Core programs") and the Independent System Operator – New England ("ISO-NE") Load Response Program. This section provides an overview of these programs, including their results, impacts, and cost-effectiveness.

3.1 New Hampshire Core Energy Efficiency Programs

Due to National Grid's long history of delivering cost-effective Demand Side Management ("DSM") programs in New England since 1987, Granite State was instrumental in creating the New Hampshire Core Energy Efficiency Programs. Delivery of the Core programs started in June 2002. The same programs are delivered by the four New Hampshire investor-owned electric utilities: Granite State, Public Service Company of New Hampshire, New Hampshire Electric Cooperative, Inc., and Unitil Energy Systems, Inc. These Core programs are:

- **ENERGY STAR Homes**: For residential new construction, the program offers technical assistance and rebates for high efficiency homes as determined by their Home Energy Rating.
- **Home Energy Solutions**: A residential electric retrofit program that offers up to $4,000 in program services to install insulation, weatherization, and cost-effective appliance and lighting upgrades.
- **Home Energy Assistance**: A residential electric and heating fuel low-income retrofit program, delivered by the Community Action Program agencies.
- **ENERGY STAR Lighting**: The program offers rebates for ENERGY STAR residential compact fluorescent light bulbs and fixtures and also offers general marketing and retailer support for all ENERGY STAR lighting products.

- **ENERGY STAR appliances**: The program offers rebates for ENERGY STAR clothes washers and room air conditioners as well as general marketing and retailer support for all ENERGY STAR appliances.

- **Small Business Energy Solutions**: A commercial and industrial retrofit program for smaller customers, offering free business inspections and incentives to replace inefficient lighting and some other measures.

- **Large Business Energy Solutions**: A comprehensive commercial and industrial retrofit program for customers typically over 100 kW that targets operating aging, inefficient equipment and systems.

- **New Equipment and Construction**: A comprehensive commercial and industrial program for customers typically over 100 kW that targets new construction, major renovation, or failed equipment replacement projects.

The program designs are based on the Energy Efficiency Working Group recommendations (Docket No. DR 96-150) that were developed between May 1998 and June 1999 and largely approved by the Commission in November 2000. The New Hampshire electric utilities received final approval from the Commission in May 2002 to launch the Core Programs. The implementation of the Core programs represented the first time that a coordinated effort had been made by the electric utilities to offer the same programs statewide.

Some of the programs, such as the ENERGY STAR programs, are administered jointly by the utilities, while other programs are administered by the individual utilities, using the same program design and rebate levels. From the customer's perspective, the same programs are made available by all investor-owned electric utilities in New Hampshire. Information about the Core programs is available at http://www.nhsaves.com.

3.1 Core Programs' Results and Impacts

The results for the most recent program period, January – December 2005 were excellent (see Table 1), with the utilities together exceeding the statewide goals, reaching 133% of the lifetime energy savings goal and 153% of the customer goal, while spending 100% of the budget.

ıble 1: NH Core Program Highlights – All Electric Utilities (January 1 – December 31, 2005)

NH CORE ENERGY EFFICIENCY PROGRAMS	EXPENSES ($)		SAVINGS (Lifetime kWh)		NUMBER OF CUSTOMERS	
	Actual + In Process + Prospective	Percent of Budget	Actual + In Process + Prospective	Percent of Budget	Actual + In Process + Prospective	Percent of Budget
RESIDENTIAL						
ENERGY STAR Homes	$1,144,982	83%	6,986,237	260%	630	94%
Home Energy Solutions	$2,096,629	110%	48,081,642	111%	1,657	164%
Home Energy Assistance	$2,220,773	100%	34,322,837	114%	1,226	125%
ENERGY STAR Lighting	$1,136,069	87%	93,264,171	125%	63,379	160%
ENERGY STAR Appliances	$894,538	121%	43,227,494	191%	13,248	130%
TOTAL RESIDENTIAL	**$6,875,229**	**99%**	**225,882,381**	**130%**	**80,140**	**153%**
COMMERCIAL & INDUSTRIAL						
Small Business Energy Solutions	$2,313,857	98%	151,033,986	188%	851	206%
Large Business Energy Solutions	$3,783,219	98%	362,070,647	149%	257	86%
New Construction	$2,825,825	104%	233,048,316	99%	259	133%
TOTAL COMMERICAL & INDUSTRIAL	**$8,922,901**	**100%**	**746,152,949**	**134%**	**1,367**	**151%**
TOTAL	**$16,415,891**	**100%**	**972,035,330**	**133%**	**81,507**	**153%**

Granite State's stand-alone results for 2005 were reasonable (see Table 2), with savings made up by the other Core Utilities. The programs achieved 78% of the lifetime savings goal and 161% of the customer goal, while spending 94% of the budget. These results were submitted to the Commission on April 25, 2006, as the "Granite State Electric Company d/b/a National Grid Energy Efficiency 2005 Year-End Report," attached hereto as Appendix B. Granite State's Energy Efficiency 2006 Year-End Report has not yet been completed. However, we anticipate filing the report for 2006 with the Commission during the first week of May 2007.

Table 2: NH Core Program Highlights – ONLY GRANITE STATE (January 1 – December 31, 2005)

NH CORE ENERGY EFFICIENCY PROGRAMS	EXPENSES ($)		SAVINGS (Lifetime kWh)		NUMBER OF CUSTOMERS	
	Actual + In Process + Prospective	Percent of Budget	Actual + In Process + Prospective	Percent of Budget	Actual + In Process + Prospective	Percent of Budget
RESIDENTIAL						
ENERGY STAR Homes	$142,000	73%	1,551,000	146%	96	87%
Home Energy Solutions	$185,000	432%	2,259,000	893%	266	605%
Home Energy Assistance	$63,000	80%	731,000	125%	39	126%
ENERGY STAR Lighting	$65,000	113%	4,561,000	177%	3,260	163%
ENERGY STAR Appliances	$58,000	90%	2,959,000	155%	841	153%
TOTAL RESIDENTIAL	**$513,000**	**117%**	**12,062,000**	**189%**	**4,502**	**165%**
COMMERCIAL & INDUSTRIAL						
Small Business Energy Solutions	$191,000	90%	5,731,000	94%	28	62%
Large Business Energy Solutions	$197,000	66%	9,261,000	42%	9	32%
New Construction	$387,000	91%	26,767,000	77%	45	113%
TOTAL COMMERICAL & INDUSTRIAL	**$776,000**	**83%**	**41,759,000**	**67%**	**82**	**73%**
TOTAL	**$1,288,000**	**94%**	**53,821,000**	**78%**	**4,584**	**161%**

Overall, since the Core programs' inception in 2002, the programs have saved significant amounts of energy and created significant environmental benefits.

Table 3: NH Core Program Impact (June 2002 – December 2005)

Impact Area	Outcome	Equivalent Results
Lifetime kWh saved	3.3 billion kWh	Power Concord for 8.7 years
Customer Served	192,500	43% of NH households
Economic Impact – Dollars Saved	$376 million	6-fold return on investment
Total Emissions Reduction	2.2 million tons	Taking 457,000 cars off the road

Table 4: Granite State Core Program Impact (June 2002 – December 2005)

Impact Area	Outcome	Equivalent Results
Lifetime kWh saved	249 million kWh	Power Concord for eight months
Customer Served	14,226	35% of GSEC customers
Economic Impact – Dollars Saved	$45 million	6-fold return on investment
Total Emissions Reduction	0.3 million tons	Taking 55,400 cars off the road

3.2 Core Programs' Demand Reduction

The Core programs are the only energy efficiency programs Granite State offered in 2006. While the New Hampshire utilities report regularly on kWh savings from the Core programs, these programs generate demand savings as well. Granite State estimates that its 2005 programs achieved an annual 648 kW reduction. The 2006 programs are projected to save 1,265 kW.

Table 5: Granite State Summary of 2005 Year-End and 2006 Planned Annual kW Results

Annual kW Reduction	2005 Year-End	2006 Target
Commercial and Industrial		
New Construction	230	279
Large Business Energy Solutions	207	500
Small Business Energy Solutions	97	134
SUBTOTAL	**534**	**913**
Residential Programs		
ENERGY STAR® Homes	28	74
Home Energy Solutions	12	5
ENERGY STAR® Appliances	53	39
Home Energy Assistance	5	6
ENERGY STAR® Lighting	16	228
SUBTOTAL	**114**	**352**

TOTAL	**648**	**1,265**

The projected demand savings, in table 5 above, for 2006 are based on the proposed measure mix and updated evaluation results for the 2005 energy efficiency programs.

<u>3.3 ISO-New England Load Response Program</u>

In addition to energy efficiency, Granite State encourages its customers to participate in the Load Response Programs offered by the ISO-NE.

Through ISO-NE, Granite State offered two types of programs in 2006: the Demand Response Program (called "Real-Time Demand Response Program") and the Price Response Program (called "Real-Time Price Response Program"). Eligible customers are those who are capable of reducing their load by a minimum of 100 kW of demand. A customer can fulfill this eligibility through participation of a single account or through participation of a group of accounts (for the same customer). Each program option is summarized in the May 21, 2004 filing letter to the Commission found in Appendix B. Four accounts (0.4 MW total) were enrolled by Granite State in the ISO-NE Load Response Program in 2006.

As of March 30, 2007, for the entire state of New Hampshire, 4.5 MW were enrolled in the Real Time Price Response Program and 4.1 MW were registered in the Real Time Demand Response Program. Due to the developing Forward Capacity Market that ISO-NE administers, additional curtailment services providers and competitive suppliers are also enrolling customers in the Real Time Demand Response Program.

3.4 Cost-Effectiveness of Granite State's Participation

Granite State's participation in the Core programs is cost-effective. As noted in "Granite State Electric Company d/b/a National Grid Energy Efficiency 2005 Year-End Report" in Appendix B, the Total Resource Benefit/Cost ratio for the programs was 2.08. In other words, these programs created over $4 million in value while costing about $2 million. For 2006, Granite State projects that the Benefit/Cost ratio of the programs will be 2.56. Program cost-effectiveness can vary from year to year based on actual services provided.

If customers participate in ISO-NE's demand response programs, the incentive payments to customers under the demand response programs would be made from ISO-NE markets. Real-time price response events are called when the projected hourly wholesale cost of electricity exceeds the trigger price of $100/MWh in the New Hampshire Load Zone. Customers are paid the higher of the trigger price or the hourly zonal clearing price for electricity. Therefore, price response is designed to be no more expensive than the electricity it displaces and is implicitly cost-effective. Real-time demand response is called when reliability criteria are threatened and the New Hampshire Load Zone is part of a Capacity Deficiency declaration. In such cases, cost-effectiveness may be viewed as secondary in importance to providing secure and reliable power to all of New England's customers.

3.5 Least Cost Alternatives to Transmission Upgrades and/or New Generation

Energy efficiency, or demand side management, programs in New Hampshire help offset the steady growth in the demand for electricity. The amount of DSM is factored into Granite State's and ISO-NE's load forecasts and, therefore, helps defer the need for new transmission and/or generation. However, because Granite State is a small electric utility, with about 41,000 customers, DSM impacts in this service territory are generally insufficient to be a viable alternative to transmission or generation capacity measured on the order of hundreds of megawatts.

4.0 DISTRIBUTION PLANNING

National Grid's New England Distribution System Planning group is responsible for planning the development of Granite State's delivery network assets. Distribution System Planning conducts regular system performance reviews to ensure the operating efficiency, reliability, and safety of Granite State's distribution assets. This section outlines the criteria used to assess the delivery capability of distribution assets in Granite State and projects planned to ensure that future electricity demands are met.

4.1 Normal Load Planning

Engineering/Design guidelines specify that normal equipment capabilities must not be exceeded:

- For normal operating conditions
- For the loss of a transformer where a mobile unit cannot be utilized
- For the loss of generation on which area supply and distribution is dependent

Due to the lead times needed to make additional capacity available, screening tools may be set to identify equipment loaded to less than 100% capability.

4.2 Contingency Planning

Engineering/Design guidelines address service reliability under contingency conditions:

- The supply and distribution systems are designed to limit the interruption of energy (MWh) delivery for a loss of any single element. In planning the development of the system, it is recognized that some highly improbable events involving losses of more than one element, such as multiple and common mode outages, may occur resulting in a much larger interruption of energy delivered.

- The indices of service reliability are the annual frequency of customer interruption (SAIFI) and the average duration of interruption (CAIDI). The product of these two indices is the average annual duration of interruption per customer served (SAIDI). Since the total system is involved in supplying the customer, ensuring an acceptable reliability of service to all customers requires designing the supply and the distribution systems in an integrated manner to limit the interruption of energy delivery.

The design criteria are as follows:

Supply Design Criterion (SDC):
The supply system should be designed to limit the interruption caused by an outage of a single supply line or substation element to 480 MWh, based upon peak load.

Feeder Design Criterion (FDC):
The distribution system should be designed to limit the interruption caused by an outage of a single distribution feeder to 20 MWh, based upon peak load.

Duration Design Criterion (DDC):
The supply and the distribution systems should be designed so that the five-year average annual duration of interruption per customer served (Ds) on a feeder basis, excluding severe weather related events, does not exceed 200 minutes per year.

Special Considerations:

Multiple Outages

Simultaneous outage of both circuits on overhead double-circuit structures may result in the loss of an entire area load. Since these outages are nearly always due to faults caused by lightning, it is reasonable to assume that both circuits will not be permanently faulted, and that at least one circuit can be restored to service quickly by a successful reclosure. The effect on the rest of the interconnected system must be evaluated, however, even for temporary simultaneous outages.

Planning for supply to secondary underground networks considers the consequences of overlapping outages on the supply cables.

The loss of two transformers is considered at locations where a mobile or spare transformer is not available or does not have sufficient capability to carry the entire load, and then only with the concept that the second transformer may fail while the first unit is being repaired. The interruption should be limited to 480 MWh, after allowing for load transfers.

The outage of a local generating unit or supply facility while one generator is already out due to failure or maintenance should not result in loss of load. It is reasonable to interrupt 480 MWh or less if a third generating unit is forced out of service.

The probability of independent, overlapping outages of two underground cables or two overhead supply circuits is extremely low. For this reason, facilities are not planned to protect against this condition. In some cases, the size and criticalness of a load may dictate a higher degree of planning to ensure that a double contingency does not affect service. However, the probability of a double contingency occurring is extremely low.

<u>Common Mode Events</u>

Some single events on the system may result in the outage of more than one element. Examples include loss of the common oil supply to parallel pipe-type cables, a dig-in to closely spaced cables in a common duct bank or trench, or loss of a common cooling system to multiple substation transformers.

These occurrences are sufficiently rare so that firm capability need not be provided to protect against them. However, we plan so that no load will be interrupted for more than 24 hours by such an event. Shorter outages may be indicated by the nature of the load interrupted.

<u>Maintenance of Facilities</u>

Although maintenance is usually performed at off-peak periods, an outage of an element (other than a generator) while another element is out for maintenance, may result in some loss of load. The system is designed, however, such that loss of an entire major urban load center or other large block of load for greater than a few hours does not occur following such an event.

4.3 Annual Asset Utilization Reviews

A goal of distribution planning is to provide adequate capacity for each element of the electrical system and to ensure reliable and economic service to the customer. System enhancements are planned to optimize capital expenditures while maintaining acceptable standards of service. In order to meet these goals, planning engineers utilize tools and processes to evaluate the capability and performance of the system with respect to anticipated loading. Efficiency is met by utilizing existing capability on circuits that are under-utilized before building new circuits to offset circuits loaded beyond capability, thus making the system more reliable. As such, system performance is measured as a percentage of asset utilization.

The distribution systems in New England are, in general, summer peaking and summer limited. Therefore capacity reviews are performed following the summer season. Capacity reviews consist of reviewing the ratings of the limiting elements on each substation and circuit in comparison to its actual loading to screen for immediate concerns. In addition, load growth forecasts are updated annually and applied to each circuit to predict future loading constraints. Those facilities expected to exceed their capabilities during the next peak period will have action plans developed for immediate implementation. For those facilities in which loading constraints are forecasted further in the future, long range area planning studies are defined and prioritized.

In addition to reviewing each circuit's performance under peak load conditions, a contingency response screening is performed considering the loading and emergency capability of various interconnections.

Following these reviews and resulting studies, projects are defined, funded and scheduled in the work plan to meet the forecasted capacity needs.

4.4 Long Range Area Planning Studies

An area study may be undertaken if annual reviews indicate significant loading issues in an area, if there is exceptional growth (spot load) projected in the area, or on a periodic basis.

A long range area study is an in-depth investigation into a section of the power system that is usually defined by some electrical or geographic feature. The study typically covers a 10-year planning horizon and addresses:

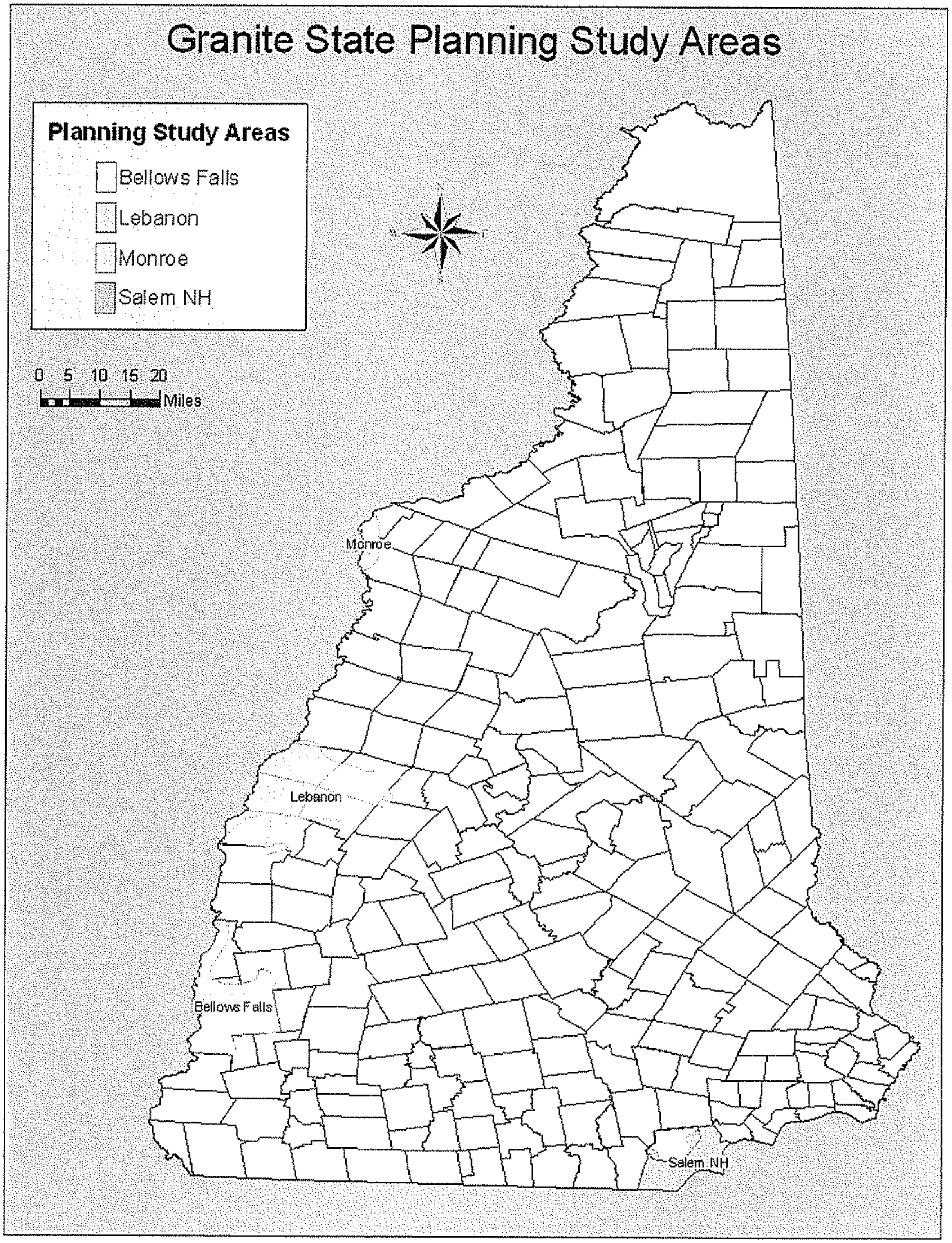
- Thermal capabilities of equipment
- Voltage regulation
- Service reliability
- Contingency operation
- Operation and maintenance
- Protection
- Short circuit duty
- Transmission and sub-transmission supply
- Alternative plan development (with permitting and licensing considerations)
- Economics

Long range area studies include consideration of transmission and sub-transmission supplies as well as distribution issues.

At times, shorter duration studies of a more targeted area may be performed on an as-needed basis. This may be the result of an unanticipated spot load or system condition.

'Study Areas' have been defined and are presented in the figure shown on the next page.[3] A Study Area is a region within a geographic area which typically shares some electrical characteristic such as a common supply path or other logical feature. Defined study areas promote a comprehensive analysis of supply, loading, and reliability issues within a manageable scope.

[3] Previous studies submitted to the New Hampshire PUC include: Granite State West (Lebanon and Hanover) Supply and Distribution Study. September 2002; and Granite State East (Salem, MA / Pelham, NH) Supply and Distribution Study. April 2004.


Granite State Planning Study Areas
Planning Study Areas
Bellows Falls
Lebanon
Monroe
Salem NH
0 5 10 15 20
Miles
Monroe
Lebanon
Bellows Falls
Salem NH

4.5 Significant Capital Projects

The following capital projects are being implemented in New Hampshire by National Grid in fiscal 2008 and/or 2009 (April 2007 – April 2009). The expected year in service indicated below for each project is a calendar year.

Replace Spicket River 13L1 Transformer

Facilities Involved: Spicket River #13

Voltages: 13.2 kV

Geographic Area Impacted: Salem

Narrative Description of Project: Replace the existing 13L1 23/13 kV transformer at the Spicket River #13 substation.

Problem Being Solved: The unit is being replaced due its age and condition.

Expected Year In Service: 2007

New Feeder Position and Distribution Line – 39L1

Facilities Involved: Slayton Hill #39 substation

Voltages: 13.2 kV

Geographic Area Impacted: Lebanon

Narrative Description of Project: A new feeder position (39L1) and associated distribution line work is being constructed for a 13kV feeder supplied from the Slayton Hill #39 substation. Load transfers will provide relief to the Craft Hill 11L1 and Slayton Hill 39L2 feeders. Construction includes adding one circuit breaker, relays and 3-333 kVA regulators at Slayton Hill #39 along with 4,000 circuit feet of 477 Al spacer cable.

Problem Being Solved: The Craft Hill 11L1 and Slayton Hill 39L2 feeders are forecasted to reach their summer normal ratings during peak loading periods. The new Slayton Hill 39L1 will provide capacity to enable load transfers from these two feeders, and keep loading within ratings.

Expected Year In Service: 2007

Feeder Tie Pelham #14-N. Dracut #78

Facilities Involved: Pelham 14L1 and N. Dracut 78L3 Feeders

Voltages: 13.2 kV

Geographic Area Impacted: Salem

Narrative Description of Project: A distribution feeder tie will be constructed between the Pelham 14L1 in New Hampshire and the N. Dracut 78L3 feeder in Massachusetts. Construction includes the addition of 16 new poles, 2,300 circuit feet of 477 Al spacer cable and one loadbreak switch on Mammoth Rd. in Pelham, N.H.

Problem Being Solved: The single Pelham T1 transformer supplies three distribution feeders. An outage of this transformer will interrupt service to customers on all three feeders. This new feeder tie will improve reliability by enabling more customers to be picked up from alternative sources.

Expected Year In Service: 2007

Feeder Tie between Two Pelham #14 feeders

Facilities Involved: Pelham 14L2 and 14L3 Feeders

Voltages: 13.2 kV

Geographic Area Impacted: Salem

Narrative Description of Project: A distribution feeder tie will be constructed between the Pelham 14L2 and 14L3 feeders. Construction includes installing 7,500 circuit feet of 477 Al spacer cable, 35 new poles and two loadbreak switches along Windham, Hayden and Tallant Rds. in Pelham, N.H. There will also be 7,500 feet of single phase construction.

Problem Being Solved: This new tie will provide additional load pickup capability for an outage to the Pelham 14L2 feeder. Reliability performance will be improved as service restoration time will be reduced.

Expected Year In Service: 2007

5.0 TRANSMISSION PLANNING

There is general consensus that transmission planning and expansion must be coordinated and performed on a regional basis. In pursuit of this effort, the Federal Energy Regulatory Commission ("FERC") granted ISO-NE authority to lead the planning effort in New England, while incorporating the planning processes of the transmission owners within the region. As such, ISO-NE provides an independent assessment of the bulk power needs for the New England region with stakeholder input. ISO-NE produces the transmission plan yearly as the Regional System Plan ("RSP") (formerly the Regional Transmission Expansion Plan ("RTEP")). National Grid participates in development of the RSP. In general, transmission planning must identify a plan that creates a flexible, robust transmission system that reliably facilitates markets and serves all loads in a cost-effective manner. As such, ISO-NE, as the regional transmission organization or RTO, is responsible for developing the regional resource plan through assessment of the long range ability of the system and taking into account the needs of the transmission system for both reliability and economic purposes.

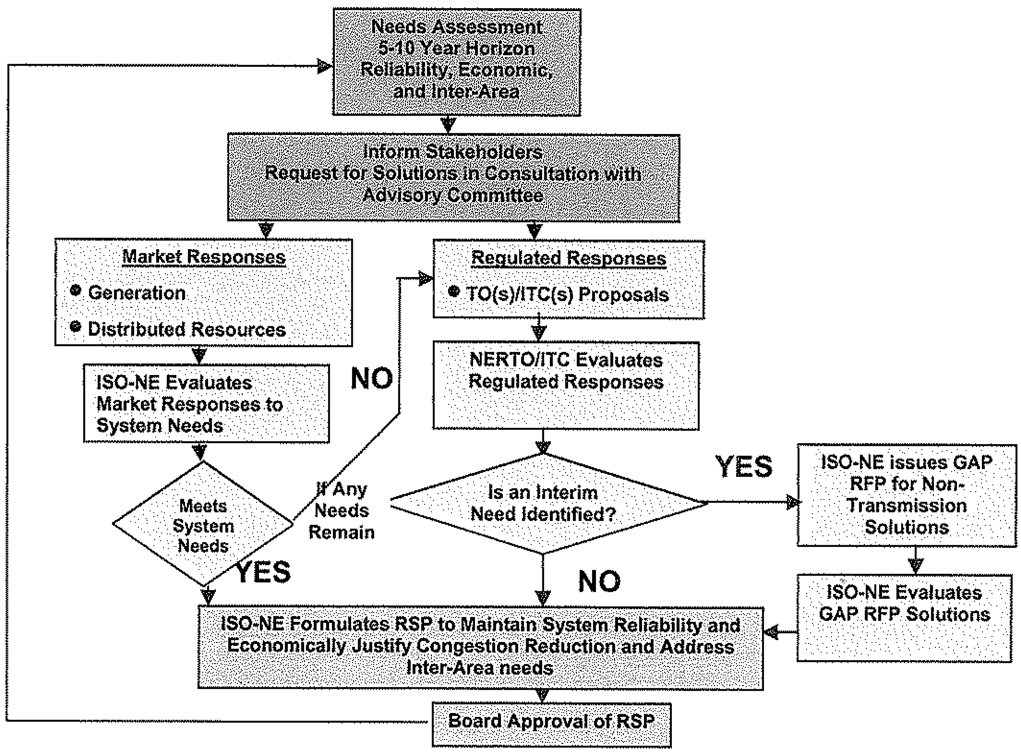
Furthermore, on February 16, 2007, FERC issued its final rule on Open Access Transmission Tariff (OATT) reform – Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890. In its rule, FERC outlined nine planning principles. The stakeholders' group in New England is in regular discussions to ensure compliance with the final rule by the deadline of October 11, 2007.

5.1 Regional Planning Process

The objective of the RSP is to identify regional system needs, to describe the status of studies aimed at identifying proposed plans to address these needs, and to provide the marketplace information to attract installation of generating plants, merchant transmission, distributed generation, and/or demand-response solutions. The RSP process allows for solicitation of market responses on an ongoing basis. When the market is unable to respond in a timely manner, the RSP process requires transmission owners to provide a "backstop solution" to fix problems identified in the RSP. The RSP process provides for coordination with existing transmission systems and takes into account the expansion plans of interconnected systems.

National Grid is an active participant in the ISO-NE Regional System Planning Process, and is a participant in ISO-NE's Planning Advisory Committee ("PAC") formerly the Transmission Expansion Advisory Committee ("TEAC"). As a transmission owner, National Grid provides periodic reliability studies to the ISO, and is responsible for developing the regulated backstop response to a reliability need within the National Grid footprint.

Figure 1: ISO-NE PLANNING PROCESS FLOW DIAGRAM



The ISO-NE planning process acknowledges that many entities exist in the restructured electricity market – independent generators, power marketers, merchant transmission developers, end-users, and traditional regulated transmission and distribution utilities. The ISO-NE planning process takes into account all of the different entities through an open process that provides for stakeholder input, and allows for market proposals to go forward at any time. Through the PAC (comprising transmission owners, generator owners, marketers, load serving entities, and state agencies), ISO-NE is provided input on the development of the RSP that includes conducting planning studies, study objectives, study scopes, and alternative solutions for ISO-NE consideration. As such, ISO-NE is in continual collaboration with the transmission owners to assess the system and develop the regional plan to address market efficiency as well as reliability needs. Additionally, the RSP process is ongoing and addresses the potential impacts that any solution may have on the system.

5.2 Planning Standards

National Grid has adopted transmission reliability standards consistent with the North American Electric Reliability Corporation ("NERC") Reliability Standards, Northeast Power Coordinating Council Inc. ("NPCC") Basic Criteria for Design and Operations of Interconnected Power Systems, and ISO-NE Reliability Standards for the New England Area Bulk Power Supply System. National Grid's Transmission Planning Guide is provided in Appendix C.

The objective of the Transmission Planning Guide is to define the criteria and standards used to assess the reliability of the existing and future National Grid transmission system for reasonably anticipated operating conditions and to provide guidance, with consideration of public safety and safety of operations and personnel, in the design of future modifications or upgrades to the transmission system.

The guide assesses deterministic reliability by defining the topology, load, and generation conditions that the transmission system must be capable of withstanding while retaining conformance with applicable criteria, guides, and standards. This deterministic approach is consistent with ISO-NE and NPCC practice. The transmission system is designed to meet these deterministic criteria to promote the reliability and efficiency of electric service on the bulk power system, and also with the intent of providing an acceptable level of reliability to the customers.

In March of 2007 the FERC promulgated the first set of mandatory reliability standards (FERC Order No. 693, March 19, 2007). These standards take effect as enforceable rules under the Federal Power Act section 215 on June 4, 2007. In addition to the NERC Reliability Standards mentioned above, National Grid will design and operate its system to comply with these mandatory standards as they may change or be amended from time to time by NERC and FERC.

5.3 New Hampshire Enhancement and Expansion Opportunities/Needs

ISO-NE has identified a number of system needs within New Hampshire. RSP06 includes discussion of needs to address both regional transfer capability as well as local reliability. Regional needs have been identified to improve resource adequacy by increasing transmission transfer capability across Northern New England to improve market access to resources in Maine and the Maritime Provinces of Canada.[4] Potential solutions identified by ISO-NE include projects involving Central Maine Power ("CMP") and Public Service Company

[4] ISO-NE Region System Plan 2006, Section 8.2.1"

of New Hampshire ("PSNH"), including addition of shunt capacitors, closing 115 kV line Y-138 between Saco Valley and White Lake, looping 345 kV line 391 into the Deerfield 345 kV substation, addition of 345-115 kV transformers most likely at Scobie, Deerfield, and near Newington substations, and addition of a Static VAr Compensator ("SVC") at Deerfield substation. ISO-NE also identified that "a major north-south reinforcement (such as a Scobie-Tewksbury 345 kV line)" is under study to sustain existing north-south transfer levels which capability has been diminished due to load growth and higher simultaneous levels of Boston import.

Other identified needs are associated with sub-regional load service, system operability, and regional capacity and energy adequacy. RSP06 identifies need for system improvements in the New Hampshire Seacoast, Manchester-Nashua, and Western (Keene, Hillsborough, and Peterborough) areas served by PSNH. In addition, RSP06 discussed regional needs in southeast Vermont, southwest New Hampshire, and north-central Massachusetts, referred to as the Monadnock area, which is the subject of a joint study effort by ISO-NE, VELCO, PSNH, and National Grid.

5.4 New England Power (NEP) Projects Proposed to Solve Needs

A number of upgrades have been proposed to address reliability in the Monadnock area, consisting of Southeastern Vermont, Southwestern New Hampshire, and north-central Massachusetts. The preferred plan identified in the RSP is to construct a new 345-115 kV substation in Fitzwilliam, NH. The substation will be supplied by 345 kV line 379 (Vermont Yankee-Amherst) and 115 kV line I-135N (Bellows Falls-Flagg Pond). Lines 379 and I-135N will both be bifurcated at the new Fitzwilliam substation, resulting in two 345 kV lines and two 115 kV lines terminating at the substation. The new substation will be constructed and owned by PSNH. Additional transmission system reinforcements will be required to accommodate the 115 kV power transfers that will occur with the new substation. National Grid has proposed two projects in conjunction with the Monadnock Reliability Upgrades: reconductoring 115 kV line I-135 (Bellow Falls-Monadnock Tap-Flagg Pond), and re-tensioning 115 kV line W-149 (Bellows Falls-Ascutney tap). In order to implement these projects, no additional rights-of-way are needed and cost is included as part of the overall Monadnock Area Reliability project. The Fitzwilliam 345-115 kV substation is currently proposed with an in-service date of December 2009. The National Grid line work would need to be completed prior to energization of the new substation.

6.0 Conclusion

As previously explained in greater detail, National Grid has submitted this least-cost integrated resource plan pursuant to RSA 378:38. This submission has provided the Commission with a forecast of future electrical demand for GSEC's service area; an assessment of demand-side energy management programs in place within our New Hampshire service territory; and an assessment of Granite State's distribution plans and National Grid's transmission plans. In particular, the filing has: provided an overview of the resource procurement strategy used to ensure that Granite State's customers receive the lowest energy cost possible; described Granite State's participation in the New Hampshire Core Energy Efficiency programs and in ISO-New England's Real-Time Demand Response Programs, including an overview of the results and effectiveness of these programs; discussed National Grid's distribution and transmission planning processes; and identified current projects under review/implementation to address the reliability needs of New Hampshire and facilitate the competitive market of the region.

As competitive markets emerge, Granite State believes that utilities retain an obligation to meet the needs of their customers by providing electric services reliably and adequately. As outlined in this plan, Granite State meets this obligation through a number of diligent, comprehensive mechanisms to ensure sufficient supply of resources and a cooperative planning structure that satisfies both the short- and long-term needs of our customers in New Hampshire and the overall robustness of the regional bulk power system.

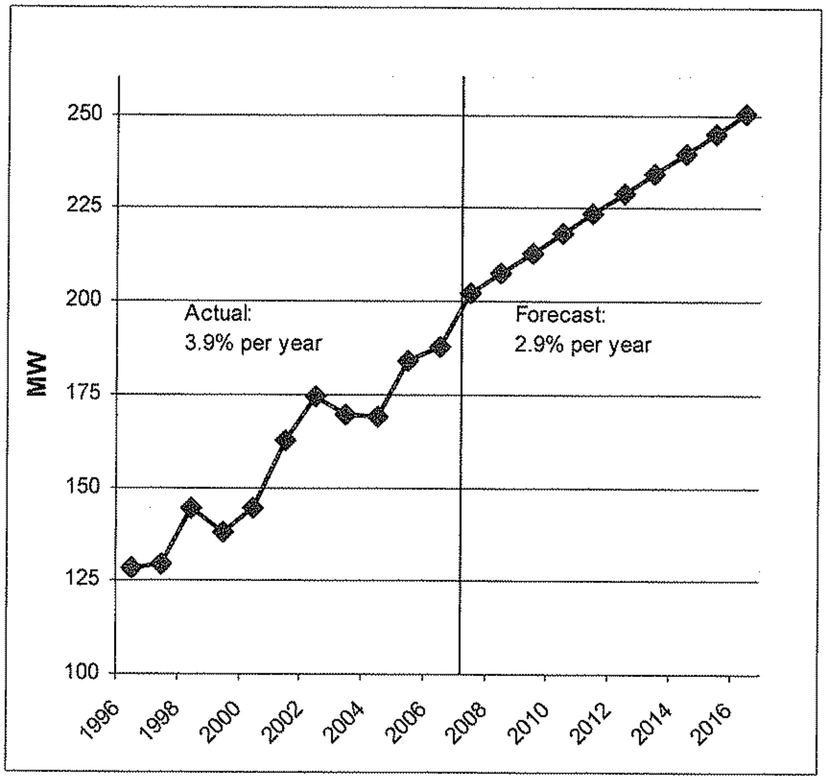
APPENDIX A

A.1 Granite State Annual Peak Load Forecast

Granite State is a summer peaking electric distribution system serving approximately 41,000 customers in 21 New Hampshire communities. Table A.1 shows that Granite State's current peak demand is 188 MW, reached in August 2006. The summer peak is 26% higher than Granite State's current winter peak of 149 MW, achieved in January 2005 (Table A.2). Granite State remains solidly summer peaking despite its northern location. One reason is that residential air conditioning saturation has increased sharply while electric heat saturation has declined. As a result, Granite State's summer peak has grown nearly twice as fast as its winter peak in recent years.

Granite State's historical and forecast summer peak demands are summarized in Figure A.1. The Granite State peak grew rapidly over the historical period, increasing at an average annual rate of 3.9% from 1996-2006. This solid growth was due to an expanding economy during most of that period, the 2001-2005 housing boom and large increases in residential air conditioning saturation. There was also a steady decline in Granite State's load factor during this period as shown in Figure A.2. Load factor, which is defined as average hourly load divided by peak load, declines when peak demand grows more rapidly than energy use. One factor behind the long-term decline in load factor is the shift in the composition of load from industrial to residential and commercial. This occurs as the economy becomes more service oriented. Over the last ten years, residential and commercial energy sales increased 2.6% per year while industrial energy sales increased only 1.1%. As a result, the share of industrial in total load fell

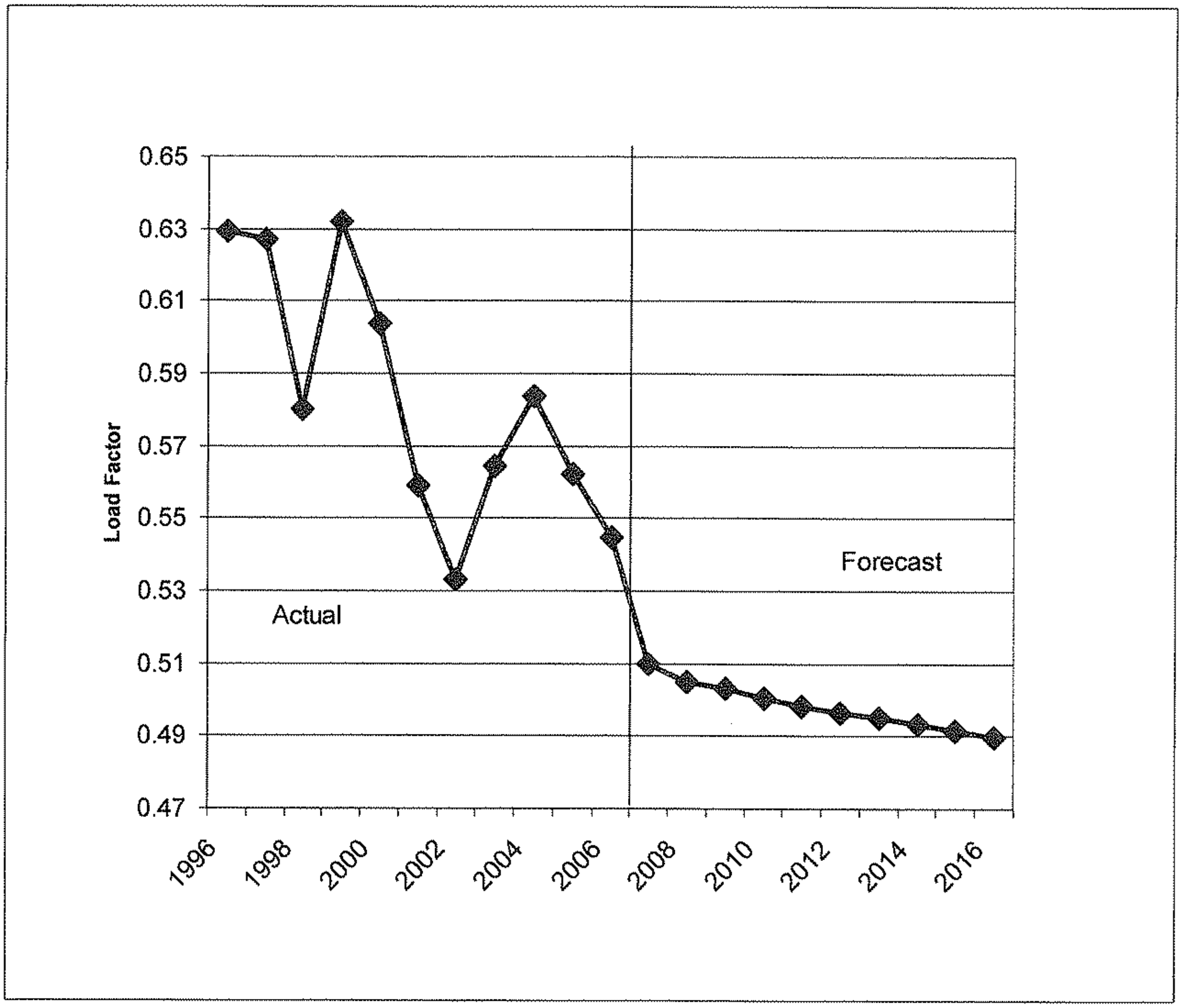
Figure A.1: Granite State Peak Demand Forecast



from 15% to 13%. Residential and commercial customers tend to have lower load factors than industrial customers because air conditioning use during hot summer weather drives their peak well above their average energy use. Industrial customers on the other hand, particularly those that run three shifts, tend to have higher load factors because their average use is much closer to their peak use, which tends not to be driven by air conditioning. Not only has the shift in the composition of load away from industrial reduced load factor, it has also caused the peak to become more weather sensitive.

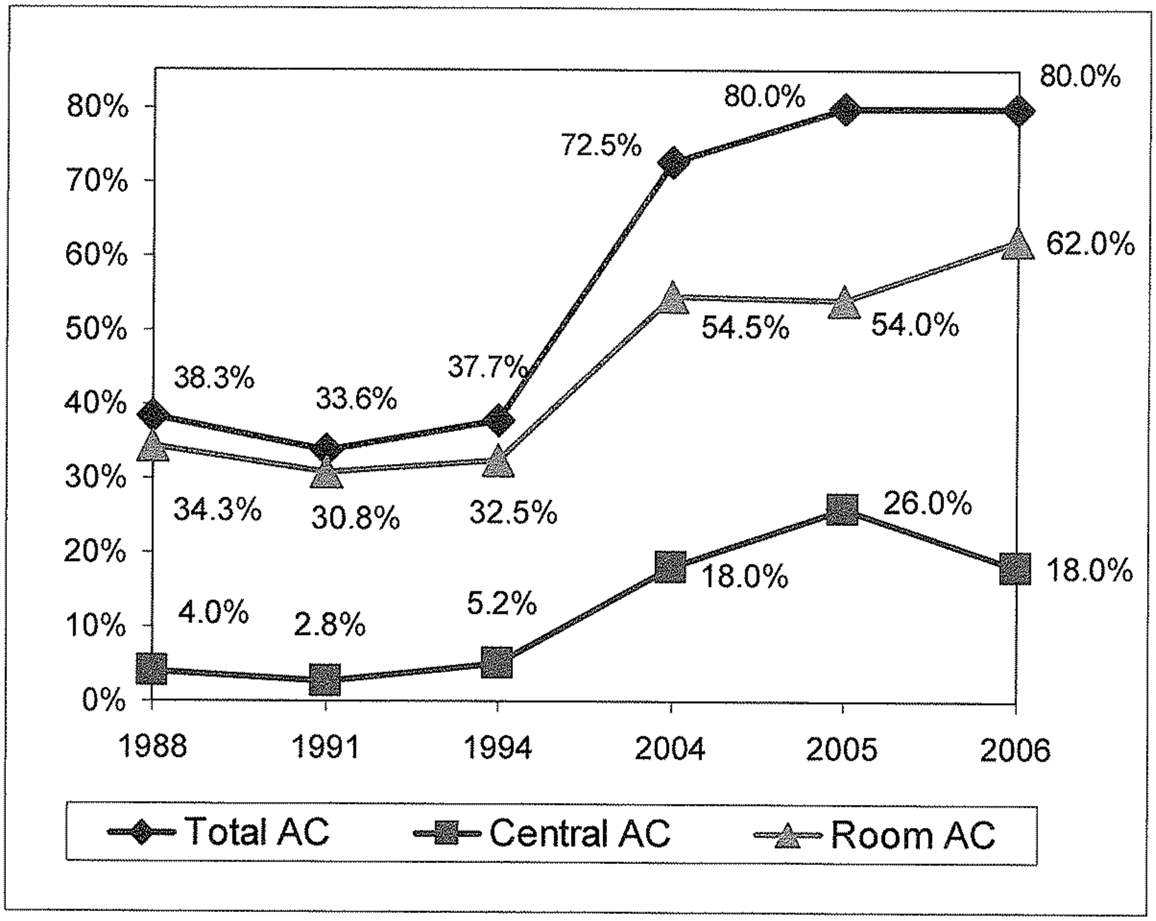
Another factor contributing to the decline in load factor was the housing boom of 2002-2005. This occurred even as the rest of the regional economy was in recession. Thus the housing boom boosted residential load growth as industrial load growth was flagging. Residential customers tend to have even lower load factors than commercial. The housing boom accelerated the shift in load away from industrial to residential and helped drive the large jumps in summer peak demand experienced in 2001, 2002, 2005 and 2006.

Figure A.2: Granite State Load Factor



A third reason for the decline in load factor and large increases in peak is increased residential air conditioning saturation. This is shown in Figure A.3. Since 1994, residential air conditioning saturation more than doubled, increasing from 38% to 80%. Central air conditioning saturation rose from 5% to 18%. The housing boom likely supported this rise as much of the new construction that occurred during the boom included larger single family homes with central air conditioning. Room air conditioning saturation rates increased from 33% to 62% as these units have become more affordable and energy efficient. Room air conditioning saturation rates can also be affected by hot weather. That is, their portability and relatively low cost allows customers to purchase and install them during a heat wave, pushing peak demand higher than it would be otherwise.

Figure A.3: GSEC Percent of Residential Customers with Air Conditioning (1982 -2006)



With extreme summer weather conditions, similar to those experienced in 2002, the 2007 peak is expected to increase 7.5% over the actual 2006 peak but only 4.8% on a weather adjusted basis, as seen in Table A3. Weather-adjusted growth in system peak gradually slows over the forecast period as the decline in load factor moderates and regional economic growth slows, as forecast by Economy.com, the economic consulting firm which provided the economic inputs for the load forecast.

A.2 Overview of Forecast Process and Results

Granite State's peak demand forecasting process entails developing summer and winter peak demand forecasts for two distribution planning areas known as Power Supply Areas (PSAs) serving 21 towns within Granite State Electric's service area. These two PSAs are close in size. Their historical and forecasted summer and winter peak demands are shown on Tables A1 and A2, respectively. The Eastern PSA accounts for 53% of Granite State's summer peak and serves the towns of Salem, Pelham and parts of Derry and Windham. The Western PSA accounts for the remaining 47% of Granite State's peak and serves all or portions of 17 towns, including Lebanon, Hanover, Enfield, Canaan, Charleston, Walpole, Langdon, Alstead and Monroe.

The PSA peak forecasts are allocated to towns based on historical trends in energy growth among the towns in each PSA. Table A4 summarizes the town-level forecast.

The PSA forecasts are developed at the time of the Granite State company peak. Forecasts of a PSA's own peak – that is, the highest demand reached within a given PSA – are calculated by multiplying forecasted PSA peak at the time of the company peak by coincidence factors. These coincidence factors are calculated as the historical ratio of a PSA's maximum peak demand to its peak at time of the company peak.

To capture the uncertainty associated with peak-day weather conditions, peak demands are forecasted under both normal weather conditions (weather that has a 50% chance of occurring) and extreme weather conditions (weather that has only a 5% chance of occurring).

The extreme weather peak forecast scenario represents an upper bound that can be expected for a given set of economic conditions.

A.3 Forecast Methodology

Regression models are used to develop a baseline trend forecast for each PSA. Historical demand at the time of the Granite State peak is related to observed peak-day weather conditions and regional economic conditions. The regression models are based on monthly historical data. The estimation interval is 1995:m1 to 2006:m11. Projected summer and winter demands are taken from the monthly results as the highest monthly demand predicted within these seasons.

A.4 Regional Economic Drivers

Economy.com, a leading economic forecasting firm based in West Chester, PA, provides historical and forecasted economic conditions at the county level. Each PSA is assigned to a county based on the PSA's location. Economy.com calibrates its county level economic forecasts to its state level economic projections. The county-level forecasts are used to drive the PSA peak forecasts. While not a perfect correlation with defined PSAs, this process allows for a better correlation of PSA peak demand growth and underlying area economic activity than does the use of state or national economic forecasts alone. The county-level economic projections used or considered in the PSA forecast models are total employment, income, population and number of households. These economic variables are combined to generate a monthly economic index variable for use as the economic driver variable.

A.5 PSA Load Data

PSA load data were provided by National Grid's distribution planning engineers. Data include monthly peaks at time of the company peak and the PSA coincident peaks (each PSA's highest peak demand). These data are collected from remote access pulse recorders ("RAPRs") located at the tie-line and substation metering points that define a PSA.

A.6 Peak Day Weather Data

Peak day weather data are collected from the National Weather Service's Concord, NH weather station. The following peak-day temperature concepts are collected:

- Maximum temperature on the day of the peak
- Minimum temperature on the day of the peak
- Maximum temperature for the day prior to the peak
- Minimum temperature for the day prior to the peak
- Maximum temperature two-days prior to the peak
- Minimum temperature two-days prior to the peak

The regression models are estimated using the actual historical values of these weather variables. The estimated regression models are then used to simulate historical and forecasted PSA demand under two weather scenarios, normal weather and extreme weather.

A.7 Normal Weather Scenario Forecast

The normal weather scenario PSA demand forecast assumes the same normal peak-producing weather for each year of the forecast. This is the most likely weather scenario as there is a 50% probability that actual weather will be more extreme than normal and a 50% probability that the weather will be less extreme than normal. Normal peak-day weather conditions are calculated from historical peak-day weather covering the period from 1990-2002. A rank and average method is used to derive the peak-day temperature variables. For each year, monthly peak-day temperatures are ranked from the highest to lowest temperature regardless of the month the temperature occurred. The ranked, monthly temperature variables are then averaged across the years to generate twelve monthly normal values for each of the peak-day weather concepts. The normal temperature values are then assigned to a specific month based on the month where that temperature is most likely to occur. For example, the highest maximum temperature value is assigned to July, the next highest to August, and so on until all maximum temperature values are assigned to a month. A similar method is used to assign the normal minimum temperature to specific months. The coldest normal temperature is assigned to January, the next coldest to December, and so on until all months are assigned a minimum temperature.

A.8 Extreme Weather Scenario Forecast

An extreme weather scenario PSA demand forecast is generated to capture the peak demand upper bound for a given set of economic conditions. Based on the historical experience, there is only a 5% probability that actual peak-producing weather will be more extreme than in the extreme weather scenario. The extreme weather peak demand forecast scenario is designed to constrain the uncertainty due to extreme peak weather conditions. Actual 2002 summer weather was very close to the extreme weather scenario.

Extreme weather conditions are defined as peak-day temperatures that have a 5% probability or less of occurring. The same rank and average method used to calculate normal weather conditions is used to calculate extreme weather conditions. However, instead of taking the average temperatures from the historical period, 95th percentile temperatures are selected instead.

A.9 Allocation of PSA Forecasts to Towns

The PSA peak forecasts are allocated to towns based on trends in town-level MWh deliveries over the period from 1996-2006. Separate regression equations are estimated for each of the 21 towns that make up Granite State's service territory. The regressions relate annual town-level MWh deliveries, obtained from Granite State's Customer Information System ("CIS"), to a linear time trend and predict town MWh load for each forecast year. For the historical period, a town's MW peak is estimated by multiplying that town's share of total PSA MWh by the actual PSA peak. For the forecast period, each town is allocated a portion of overall forecasted PSA MW growth. The portion of PSA MW growth allocated to a town is determined by that town's share in total PSA MWh growth, as predicted by the sum of the individual town-level regression equations. This is done for the first five years of the PSA forecast. After five years, all town-level peak demand growth rates converge to the overall PSA demand growth rate. The convergence period is three years.

The process yields town-level peak demand forecasts that add up to the overall PSA peak demand forecast yet grow at different rates, reflecting different trends in recent, historical town-level MWh growth. Although the process yields estimated town-level MW demands for each forecast year, the planner uses the forecasted peak growth rates in area planning studies and facility thermal adequacy analyses. That is, the planner applies the appropriate forecasted town growth rates to the actual area loads that he or she collects for the study or analysis. These growth rates are shown on Table A4. Table A5 shows estimated town-level demands while actual town MWh levels used to develop load growth trends are shown in Table A6.

Table A1: Summer Peak Demands Coincident with GSEC Peak Actual History and Forecast with Extreme Weather (MW)

Year	Mo	Granite State Electric Company	Growth Rate	Eastern PSA*	Growth Rate	Western PSA*	Growth Rate
1996	8	128.300	(0.5%)	66.700	(5.4%)	61.600	5.5%
1997	7	129.300	0.8%	71.600	7.3%	57.700	(6.3%)
1998	7	144.600	11.8%	77.700	8.5%	66.900	15.9%
1999	9	138.019	(4.6%)	73.792	(5.0%)	64.227	(4.0%)
2000	9	144.518	4.7%	74.983	1.6%	69.535	8.3%
2001	8	162.852	12.7%	86.343	15.2%	76.509	10.0%
2002	8	174.215	7.0%	93.073	7.8%	81.142	6.1%
2003	6	169.611	(2.6%)	91.763	(1.4%)	77.848	(4.1%)
2004	8	169.044	(0.3%)	87.320	(4.8%)	81.724	5.0%
2005	7	184.156	8.9%	98.773	13.1%	85.383	4.5%
2006	8	187.936	2.1%	98.589	(0.2%)	89.347	4.6%
Forecast							
2007	8	202.122	7.5%	104.398	5.9%	97.724	9.4%
2008	8	207.406	2.6%	107.510	3.0%	99.896	2.2%
2009	8	212.645	2.5%	110.645	2.9%	102.000	2.1%
2010	8	218.042	2.5%	113.787	2.8%	104.255	2.2%
2011	8	223.469	2.5%	116.937	2.8%	106.531	2.2%
2012	8	229.020	2.5%	120.103	2.7%	108.917	2.2%
2013	8	234.495	2.4%	123.254	2.6%	111.241	2.1%
2014	8	239.893	2.3%	126.405	2.6%	113.488	2.0%
2015	8	245.261	2.2%	129.556	2.5%	115.705	2.0%
2016	8	250.589	2.2%	132.703	2.4%	117.886	1.9%
2017	8	255.931	2.1%	135.863	2.4%	120.068	1.9%
2018	8	261.291	2.1%	139.031	2.3%	122.259	1.8%
2019	8	266.618	2.0%	142.207	2.3%	124.411	1.8%
2020	8	271.950	2.0%	145.392	2.2%	126.558	1.7%
2021	8	277.258	2.0%	148.574	2.2%	128.683	1.7%
Compound Annual Growth							
2001-2006 Five Year			2.9%		2.7%		3.2%
2006-2011 Five Year			3.5%		3.5%		3.6%
2006-2016 Ten Year			2.9%		3.0%		2.8%
2006-2021 Fifteen Year			2.6%		2.8%		2.5%

* Granite State's service area is divided into two power supply areas (PSAs) for power supply planning purposes.

Table A2: Winter Peak Demand Coincident with GSEC Peak Actual History and Forecast with Extreme Weather (MW)

Year	Mo	Granite State Electric Company	Growth Rate	Eastern PSA*	Growth Rate	Western PSA*	Growth Rate
2000	12	126.284	(8.3%)	65.963	(4.7%)	60.321	(12.0%)
2001	12	132.303	4.8%	66.485	0.8%	65.818	9.1%
2003	1	139.795	5.7%	69.693	4.8%	70.102	6.5%
2004	1	146.262	4.6%	71.012	1.9%	75.250	7.3%
2005	1	148.709	1.7%	74.871	5.4%	73.838	(1.9%)
2005	12	147.388	(0.9%)	73.062	(2.4%)	74.326	0.7%
Forecast							
2007	1	165.025	12.0%	79.971	9.5%	85.053	14.4%
2008	1	172.463	4.5%	81.403	1.8%	91.060	7.1%
2009	1	175.607	1.8%	82.803	1.7%	92.803	1.9%
2010	1	178.776	1.8%	84.228	1.7%	94.549	1.9%
2011	1	182.049	1.8%	85.656	1.7%	96.393	2.0%
2012	1	185.403	1.8%	87.100	1.7%	98.303	2.0%
2013	1	188.806	1.8%	88.544	1.7%	100.262	2.0%
2014	1	192.108	1.7%	89.978	1.6%	102.130	1.9%
2015	1	195.360	1.7%	91.415	1.6%	103.946	1.8%
2016	1	198.574	1.6%	92.846	1.6%	105.727	1.7%
2017	1	201.769	1.6%	94.283	1.5%	107.486	1.7%
2018	1	204.991	1.6%	95.731	1.5%	109.260	1.7%
2019	1	208.203	1.6%	97.186	1.5%	111.017	1.6%
2020	1	211.398	1.5%	98.651	1.5%	112.747	1.6%
2021	1	214.590	1.5%	100.120	1.5%	114.470	1.5%

Compound Annual Growth	Granite State Electric Company	Eastern PSA*	Western PSA*
2001-2006 Five Year	3.1%	2.1%	4.3%
2006-2011 Five Year	3.1%	2.1%	4.3%
2006-2016 Ten Year	4.3%	3.2%	5.3%
2006-2021 Fifteen Year	3.0%	2.4%	3.6%

*Granite State's service area is divided into two power supply areas (PSAs) for power supply planning purposes.

Table A3: GSEC Summer Peak Demands (MW)

Year	Mo	With Actual History: Extreme Weather Scenario	Growth Rate	Normal Weather Scenario	Growth Rate	With Weather Adjusted History: Extreme Weather Scenario	Growth Rate	Normal Weather Scenario	Growth Rate	Spot Loads	% of Load
2001	8	162.852	.	162.852	.	172.248	.	158.005	.	0.000	0.0%
2002	8	174.215	7.0%	174.215	7.0%	188.039	9.2%	172.576	9.2%	0.000	0.0%
2003	6	169.611	(2.6%)	169.611	(2.6%)	182.718	(2.8%)	173.122	0.3%	0.000	0.0%
2004	8	169.044	(0.3%)	169.044	(0.3%)	196.229	7.4%	178.324	3.0%	0.000	0.0%
2005	7	184.156	8.9%	184.156	8.9%	195.876	(0.2%)	180.853	1.4%	0.000	0.0%
2006	8	187.936	2.1%	187.936	2.1%	192.635	(1.7%)	172.289	(4.7%)	0.000	0.0%
Forecast											
2007	8	202.122	7.5%	180.554	(3.9%)	202.122	4.9%	180.554	4.8%	4.500	2.2%
2008	8	207.406	2.6%	184.618	2.3%	207.406	2.6%	184.618	2.3%	4.500	2.2%
2009	8	212.645	2.5%	188.636	2.2%	212.645	2.5%	188.636	2.2%	4.500	2.1%
2010	8	218.042	2.5%	192.812	2.2%	218.042	2.5%	192.812	2.2%	4.500	2.1%
2011	8	223.469	2.5%	197.018	2.2%	223.469	2.5%	197.018	2.2%	4.500	2.0%
2012	8	229.020	2.5%	201.349	2.2%	229.020	2.5%	201.349	2.2%	4.500	2.0%
2013	8	234.495	2.4%	205.603	2.1%	234.495	2.4%	205.603	2.1%	4.500	1.9%
2014	8	239.893	2.3%	209.780	2.0%	239.893	2.3%	209.780	2.0%	4.500	1.9%
2015	8	245.261	2.2%	213.928	2.0%	245.261	2.2%	213.928	2.0%	4.500	1.8%
2016	8	250.589	2.2%	218.034	1.9%	250.589	2.2%	218.034	1.9%	4.500	1.8%
2017	8	255.931	2.1%	222.156	1.9%	255.931	2.1%	222.156	1.9%	4.500	1.8%
2018	8	261.291	2.1%	226.295	1.9%	261.291	2.1%	226.295	1.9%	4.500	1.7%
2019	8	266.618	2.0%	230.402	1.8%	266.618	2.0%	230.402	1.8%	4.500	1.7%
2020	8	271.950	2.0%	234.513	1.8%	271.950	2.0%	234.513	1.8%	4.500	1.7%
2021	8	277.258	2.0%	238.599	1.7%	277.258	2.0%	238.599	1.7%	4.500	1.6%
Compound Annual Growth											
2001-2006 Five Year			2.9%		2.9%		2.3%		1.7%		
2006-2011 Five Year			3.5%		0.9%		3.0%		2.7%		
2006-2016 Ten Year			2.9%		1.5%		2.7%		2.4%		
2006-2021 Fifteen Year			2.6%		1.6%		2.5%		2.2%		

Table A4: Allocation of PSA Peak Demand Forecast to Towns Growth in Peak Demand

Granite State Electric	**2.6%**	**2.5%**	**2.5%**	**2.5%**	**2.5%**	**2.4%**	**2.3%**	**2.2%**	**2.2%**	**2.1%**	**2.4%**
Western Granite State Power Supply Area	**2.2%**	**2.1%**	**2.2%**	**2.2%**	**2.2%**	**2.1%**	**2.0%**	**2.0%**	**1.9%**	**1.9%**	**2.1%**
Bath	4.5%	4.4%	4.7%	4.7%	4.3%	3.5%	2.7%	2.0%	1.9%	1.9%	3.4%
Surry	4.0%	3.8%	4.0%	3.9%	3.6%	3.0%	2.4%	2.0%	1.9%	1.9%	3.0%
Grafton	3.2%	3.0%	3.1%	3.1%	2.9%	2.5%	2.2%	2.0%	1.9%	1.9%	2.6%
Lebanon	2.8%	2.7%	2.8%	2.8%	2.7%	2.4%	2.2%	2.0%	1.9%	1.9%	2.4%
Marlow	1.9%	1.8%	1.9%	1.8%	2.0%	2.0%	1.9%	2.0%	1.9%	1.9%	1.9%
Cornish	1.8%	1.7%	1.8%	1.7%	1.9%	1.9%	1.9%	2.0%	1.9%	1.9%	1.8%
Hanover	1.7%	1.6%	1.7%	1.7%	1.8%	1.9%	1.9%	2.0%	1.9%	1.9%	1.8%
Charlestown	1.6%	1.5%	1.6%	1.5%	1.7%	1.8%	1.9%	2.0%	1.9%	1.9%	1.7%
Enfield	1.5%	1.4%	1.5%	1.5%	1.7%	1.8%	1.8%	2.0%	1.9%	1.9%	1.7%
Plainfield	1.5%	1.4%	1.4%	1.4%	1.6%	1.7%	1.8%	2.0%	1.9%	1.9%	1.7%
Canaan	1.4%	1.3%	1.4%	1.3%	1.6%	1.7%	1.8%	2.0%	1.9%	1.9%	1.6%
Alstead	1.1%	1.0%	1.1%	1.0%	1.4%	1.6%	1.7%	2.0%	1.9%	1.9%	1.5%
Walpole	0.9%	0.9%	0.9%	0.9%	1.2%	1.5%	1.7%	2.0%	1.9%	1.9%	1.4%
Acworth	0.8%	0.7%	0.7%	0.7%	1.1%	1.4%	1.7%	2.0%	1.9%	1.9%	1.3%
Monroe	0.2%	0.2%	0.2%	0.2%	0.7%	1.2%	1.6%	2.0%	1.9%	1.9%	1.0%
Orange	-0.1%	-0.1%	-0.1%	-0.1%	0.5%	1.0%	1.5%	2.0%	1.9%	1.9%	0.8%
Langdon	-0.4%	-0.4%	-0.4%	-0.4%	0.2%	0.9%	1.4%	2.0%	1.9%	1.9%	0.6%
Eastern Granite State Power Supply Area	**3.0%**	**2.9%**	**2.8%**	**2.8%**	**2.7%**	**2.6%**	**2.6%**	**2.5%**	**2.4%**	**2.4%**	**2.7%**
Derry	13.5%	13.3%	13.0%	12.7%	10.1%	7.6%	5.1%	2.5%	2.4%	2.4%	8.2%
Pelham	6.3%	6.0%	5.8%	5.5%	4.6%	3.8%	3.1%	2.5%	2.4%	2.4%	4.2%
Windham	4.1%	3.9%	3.8%	3.6%	3.3%	3.0%	2.7%	2.5%	2.4%	2.4%	3.2%
Salem	1.8%	1.7%	1.7%	1.6%	1.8%	2.0%	2.3%	2.5%	2.4%	2.4%	2.0%

Table A5: Allocation of Coincident Peak Demand Forecast to Towns (MW)

Granite State Electric	**209.522**	**214.984**	**220.398**	**225.978**	**231.589**	**237.332**	**242.994**	**248.576**	**254.125**	**259.632**	**265.154**
Western Granite State Power Supply Area	**103.329**	**105.626**	**107.851**	**110.235**	**112.642**	**115.164**	**117.622**	**119.998**	**122.342**	**124.647**	**126.955**
Bath	0.017	0.018	0.019	0.019	0.020	0.021	0.022	0.023	0.023	0.023	0.024
Surry	0.066	0.069	0.071	0.074	0.077	0.080	0.082	0.084	0.086	0.087	0.089
Grafton	0.014	0.015	0.015	0.016	0.016	0.016	0.017	0.017	0.018	0.018	0.018
Lebanon	55.331	56.903	58.435	60.085	61.760	63.429	64.971	66.375	67.672	68.947	70.223
Marlow	0.009	0.009	0.009	0.010	0.010	0.010	0.010	0.010	0.011	0.011	0.011
Cornish	0.216	0.220	0.223	0.227	0.231	0.236	0.240	0.245	0.249	0.254	0.259
Hanover	25.723	26.165	26.588	27.036	27.483	27.985	28.507	29.045	29.613	30.171	30.729
Charlestown	5.118	5.200	5.278	5.361	5.444	5.538	5.639	5.744	5.856	5.966	6.077
Enfield	4.238	4.302	4.364	4.429	4.494	4.570	4.651	4.737	4.829	4.920	5.011
Plainfield	1.408	1.429	1.449	1.470	1.491	1.515	1.542	1.570	1.601	1.631	1.661
Canaan	2.830	2.869	2.906	2.946	2.985	3.032	3.084	3.139	3.201	3.261	3.321
Alstead	1.619	1.637	1.654	1.671	1.689	1.712	1.739	1.769	1.803	1.837	1.871
Walpole	5.491	5.543	5.592	5.643	5.694	5.765	5.851	5.951	6.068	6.182	6.296
Acworth	0.261	0.263	0.264	0.266	0.268	0.271	0.275	0.280	0.285	0.291	0.296
Monroe	0.360	0.361	0.362	0.363	0.363	0.366	0.370	0.376	0.383	0.391	0.398
Orange	0.050	0.050	0.050	0.049	0.049	0.050	0.050	0.051	0.052	0.053	0.054
Langdon	0.577	0.575	0.572	0.570	0.568	0.569	0.574	0.582	0.594	0.605	0.616
Eastern Granite State Power Supply Area	**106.193**	**109.359**	**112.547**	**115.743**	**118.948**	**122.168**	**125.373**	**128.578**	**131.783**	**134.985**	**138.199**
Derry	1.346	1.527	1.730	1.954	2.203	2.425	2.609	2.742	2.811	2.879	2.947
Pelham	22.307	23.708	25.135	26.581	28.046	29.350	30.479	31.439	32.222	33.005	33.791
Windham	4.289	4.465	4.641	4.816	4.990	5.153	5.306	5.450	5.585	5.721	5.857
Salem	78.251	79.659	81.042	82.392	83.709	85.239	86.979	88.948	91.165	93.379	95.603

Table A6: Annual MWh Energy by Town (1996-2006)

Western Granite State PSA

Town	Trend Growth Rate	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Bath	8.0%	38	27	30	30	29	33	37	39	49	62	72
Surry	5.5%	194	186	182	180	215	229	231	258	286	300	286
Lebanon	4.0%	171,555	173,163	183,241	188,863	194,037	204,139	207,788	217,624	232,078	248,211	251,109
Charlestown	2.2%	19,300	19,578	20,007	20,563	21,395	21,817	21,124	22,009	22,708	23,799	24,401
Marlow	2.7%	24	34	37	41	41	34	34	32	37	42	43
Cornish	2.3%	805	909	913	939	924	978	999	1,065	1,059	1,058	1,020
Hanover	2.3%	97153	97350	100894	105175	107722	111339	114245	114258	114794	119797	122074
Grafton	3.6%	48	51	61	67	69	72	88	75	75	74	63
Enfield	2.1%	16,841	16,760	16,704	17,568	18,174	18,423	18,492	19,189	19,392	20,096	20,265
Plainfield	2.0%	5690	5842	5737	6058	6222	6292	6241	6498	6808	6898	6747
Canaan	1.9%	11233	11333	11563	11774	12166	12126	12138	12601	12882	13463	13606
Orange	-0.1%	248	245	249	255	249	343	231	232	243	250	253
Alstead	1.5%	7,092	7,070	7,073	7,367	7,379	7,421	7,264	7,993	8,068	8,081	7,874
Walpole	1.3%	23,979	23,740	24,782	24,818	24,736	25,185	25,172	25,926	26,257	27,251	26,867
Acworth	1.0%	1,189	1,193	1,197	1,202	1,249	1,239	1,159	1,365	1,306	1,278	1,284
Langdon	-0.6%	3,132	3,145	3,111	3,208	3,160	3,101	2,984	3,274	2,936	2,990	2,981
Monroe	0.3%	1,812	1,693	1,712	1,814	1,789	1,682	1,693	1,754	1,792	1,832	1,813
Western Geco PSA	3.0%	360,335	362,320	377,492	389,924	399,555	414,454	419,921	434,193	450,770	475,481	480,758

Eastern Granite State PSA

Town	Trend Growth Rate	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Derry	14.2%	1,115	1,103	1,060	1,099	1,169	1,260	1,672	2,103	2,418	3,656	4,249
Pelham	5.2%	50,167	49,283	53,699	58,824	61,792	64,742	67,480	71,904	74,178	78,029	80,718
Windham	3.3%	11,755	13,124	12,788	13,599	13,666	14,021	14,241	14,954	16,206	17,092	16,207
Salem	1.4%	280,634	281,048	285,774	297,021	283,993	298,295	305,086	310,444	315,581	327,052	309,436
Eastern Geco PSA	2.2%	343,672	344,558	353,321	370,544	360,620	378,318	388,479	399,404	408,382	425,829	410,610

APPENDIX B

B. 1 Granite State Electric Company Energy Efficiency Year-End Report 2005

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

GRANITE STATE ELECTRIC COMPANY

d/b/a

NATIONAL GRID

ENERGY EFFICIENCY

2005 YEAR-END REPORT

April 25, 2006

nationalgrid

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NATIONAL GRID

SUMMARY OF 2005 PROGRAM ACTIVITY

This report presents the results of Granite State Electric Company's ("Company" or "National Grid") residential and commercial and industrial (C&I) energy efficiency programs for calendar year 2005.

Table 1 shows the 2005 year-end performance for the C&I and residential programs compared to annual goals and spending targets. Overall, the Company achieved 85% and 80% of its goals for annual demand savings and annual energy savings respectively. The Company successfully exceeded the participation goal by 61% while under spending its approved implementation budget by approximately 6% in 2005.

Table 2 documents the value created by the 2005 energy efficiency programs. This table shows that efforts in 2005 created over $4 million of value through achieved energy, demand and other resource savings.

Table 3 provides the actual Total Resource Cost (TRC) benefit/cost ratio for each program, by sector (C&I and residential), and for the entire portfolio of energy efficiency programs implemented in 2005. The overall benefit/cost ratio for energy efficiency efforts in 2005 was 2.08.

Table 4 documents the Company's earned 2005 year-end incentive of $120,076. As specified by the Commission, the incentive for 2005 has been documented using assumptions that are consistent with assumptions used to develop program-year goals. The incentive is calculated in accordance with the mechanism described by the New Hampshire Energy Efficiency Working Group and approved by the Commission in Order No. 23,574 (2000). Table 4 is presented on four pages. Page one summarizes the incentive calculation by component (C&I and residential). Page two provides explanatory notes for the information provided on page one. Page three provides additional supporting information used in the incentive calculation. Page four provides explanatory notes for the information provided on page three. As specified by the Commission, results for all programs have been included in the incentive calculation.

Tables 5 through 9 provide the 2005 year-end energy efficiency fund balances. These tables reflect revenues collected in support of energy efficiency efforts, 2005 spending levels, and the 2005 incentive. Table 5 summarizes the 2005 year-end energy efficiency fund balances for both the residential and C&I sectors. Residential and C&I fund balances are shown in Tables 6 and 7, respectively. Tables 8 and 9 provide the residential and C&I fund variance analyses, respectively.

NATIONAL GRID
Table 1 - Summary of 2005 Planned and Year-End Results

	Annual kW			Annual MWh			Participation			Implementation Expense ($ 000's)		
Commercial and Industrial	Filed Target	Year-End	% Achieved	Filed Target	Year-End	% Achieved	Filed Target	Year-End	% Achieved	Filed Target	Year-End	% Achieved
New Construction (1)	305	230	75%	2,106	1,637	78%	40	45	113%	$424	$387	91%
Large Business Energy Solutions (2)	247	207	84%	1,260	551	44%	28	9	32%	$299	$197	66%
Small Business Energy Solutions (3)	156	97	62%	511	408	80%	45	28	62%	$212	$191	90%
SUBTOTAL	**708**	**534**	**75%**	**3,876**	**2,596**	**67%**	**113**	**82**	**73%**	**$935**	**$776**	**83%**
Residential Programs												
ENERGY STAR® Homes	4	28	763%	77	117	153%	110	96	87%	$194	$142	73%
Home Energy Solutions	3	12	459%	28	164	585%	44	266	605%	$43	$185	432%
ENERGY STAR® Appliances	35	53	152%	137	213	155%	550	841	153%	$65	$58	90%
Home Energy Assistance	4	5	126%	45	56	125%	31	39	126%	$78	$63	80%
ENERGY STAR® Lighting	11	16	153%	270	412	153%	1,998	3,260	163%	$57	$65	113%
Home Energy Management	0	0	N/A	0	0	N/A	0	0	N/A	$9	$9	100%
SUBTOTAL	**56**	**114**	**205%**	**557**	**963**	**173%**	**2,733**	**4,502**	**165%**	**$447**	**$522**	**117%**
TOTAL	**764**	**648**	**85%**	**4,433**	**3,559**	**80%**	**2,846**	**4,584**	**161%**	**$1,381**	**$1,298**	**94%**

NOTE:

(1) The spending reported for New Construction is net of actual customer copays in 2005 of $1,938.

(2) The spending reported for Large Business Energy Solutions is net of actual customer copays in 2005 of $1,937.

(3) The spending reported for Small Business Energy Solutions is net of actual customer copays in 2005 of $38,075.

NATIONAL GRID
Table 2 - Summary of Year-End Value, kW, and MWh Savings by Program
2005 Program Year

	Value (000's)										Load Reduction in kW				MWh Saved	
		Capacity				Energy				Non-Electric						
		Generation				Winter		Summer		Resource	Maximum				Maximum	
Commercial and Industrial	Total	Summer	Winter	Trans	MDC	Peak	Off Peak	Peak	Off Peak	Benefits	Annual	Summer	Winter	Lifetime	Annual	Lifetime
New Construction	$1,622	$177	$49	$58	$266	$397	$308	$220	$148	N/A	230	230	223	3,643	1,637	26,767
Large Business Energy Solutions	$775	$164	$17	$42	$169	$169	$82	$93	$40	N/A	207	207	78	3,349	551	9,261
Small Business Energy Solutions	$429	$68	$9	$18	$77	$139	$28	$76	$13	N/A	97	97	51	1,387	408	5,731
SUBTOTAL	$2,826	$409	$76	$118	$512	$704	$418	$389	$201	$0	534	534	352	8,379	2,596	41,759
Residential Programs																
ENERGY STAR Homes	$479	$30	$5	$8	$38	$18	$22	$11	$10	$338	28	28	29	633	117	1,551
Home Energy Solutions	139	6	8	5	30	27	32	16	15	1	12	12	42	119	164	2,259
ENERGY STAR Appliances	509	34	6	10	45	35	42	21	20	297	53	53	31	697	213	2,959
Home Energy Assistance	115	3	1	1	7	9	10	5	5	74	5	5	8	64	56	731
ENERGY STAR Lighting	274	9	16	9	57	55	66	33	31	N/A	16	16	113	180	412	4,561
Home Energy Management	0	0	0	0	0	0	0	0	0	N/A	0	0	0	0	0	0
SUBTOTAL	$1,517	$81	$36	$33	$176	$144	$171	$85	$80	$709	114	114	223	1,692	963	12,062
TOTAL	$4,343	$490	$112	$150	$688	$848	$589	$475	$282	$709	648	648	575	10,071	3,559	53,821

NATIONAL GRID
Table 3 - Summary of Achieved Cost-Effectiveness
2005 Program Year

Commercial and Industrial	TRC Benefit/Cost (4)	Total Value TRC Benefits ($000)	Implementation Expenses ($000)	Evaluation Costs ($000)	Customer Costs ($000)	Customer Costs from Spillover ($000)	Company Incentive ($000)	Total TRC Costs ($000)
New Construction (1)	3.00	$1,622	$387	$16	108	$30	*N/A*	$541
Large Business Energy Solutions (2)	1.66	775	197	32	203	35	*N/A*	468
Small Business Energy Solutions (3)	1.82	429	191	3	38	4	*N/A*	236
Non-Program Specific Planning and Evaluation - C/I	N/A	N/A	N/A	0	N/A	N/A	*N/A*	0
SUBTOTAL (including Company Incentive)	**2.16**	**$2,826**	**$776**	**$51**	**$349**	**$70**	***$64***	**$1,309**
SUBTOTAL (excluding Company Incentive)	**2.27**	**$2,826**	**$776**	**$51**	**$349**	**$70**	***N/A***	**$1,245**
Residential Programs								
ENERGY STAR Homes	3.34	$479	$142	$2	N/A	N/A	N/A	$143
Home Energy Solutions	0.72	139	185	2	7	N/A	N/A	193
ENERGY STAR Appliances	2.37	509	58	0	156	N/A	N/A	215
Home Energy Assistance	1.58	115	63	11	N/A	N/A	N/A	73
ENERGY STAR Lighting	3.16	274	65	0	20	$2	N/A	87
Home Energy Management	0.00	0	9	0	N/A	N/A	N/A	9
Non-Program Specific Planning and Evaluation - Residential	N/A	N/A	N/A	$0	N/A	N/A	N/A	0
SUBTOTAL (including Company Incentive)	**1.95**	**$1,517**	**$522**	**$14**	**$183**	**$2**	***$56***	**$777**
SUBTOTAL (excluding Company Incentive)	**2.10**	**$1,517**	**$522**	**$14**	**$183**	**$2**	**N/A**	**$721**
GRAND TOTAL	**2.08**	**$4,343**	**$1,298**	**$65**	**$531**	**$72**	**$120**	**$2,086**

NOTES:

(1) The customer costs for New Construction is net of actual customer copays in 2005 of $1,938.

(2) The customer costs for Large Business Energy Solutions is net of actual customer copays in 2005 of $1,937.

(3) The customer costs for Small Business Energy Solutions is net of actual customer copays in 2005 of $38,075.

(4) TRC Benefit/Cost = (Total Value)/(Total Costs*), where

Total Costs = (Implementation Expenses + Evaluation Costs + Customer Costs + Customer Costs from Spillover + Company Incentive).

Table 4

Page 1 of 4
National Grid
Year-End 2005 Incentive Calculation

Commercial/Industrial Incentive	
1. Target Benefit/Cost Ratio	2.37
2. Actual Benefit/Cost Ratio	2.27
3. Threshold Benefit/Cost Ratio	1.00
4. Target lifetime MWh	62,659
5. Actual lifetime MWh	41,759
6. Threshold MWh	40,729
7. Budget	$980,444
8. CE Percentage	4.0%
9. Lifetime kWh Percentage	4.0%
10. Target C/I Incentive	**$78,436**
11. Actual C/I Incentive	**$63,662**
12. Cap	**$117,653**
Residential Incentive	
13. Target Benefit/Cost Ratio	1.46
14. Actual Benefit/Cost Ratio	2.10
15. Threshold Benefit/Cost Ratio	1.00
16. Target lifetime MWh	6,394
17. Actual lifetime MWh	12,062
18. Threshold MWh	4,156
19. Budget	$470,119
20. CE Percentage	4.0%
21. Lifetime kWh Percentage	4.0%
22. Target Residential Incentive	**$37,610**
23. Actual Residential Incentive	**$56,414**
24. Cap	**$56,414**
25. TOTAL INCENTIVE EARNED	**$120,076**

Table 4 (continued)

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National Grid

Notes to Year-End 2005 Incentive Calculation

Line No. Notes:

1. See Table 4, page 3 of 4, line 6.
2. See Table 4, page 3 of 4, line 6.
3. Report to the New Hampshire Public Utilities Commission on Ratepayer-Funded Energy Efficiency Issues in New Hampshire, Docket No. DR 96-150 (July 6, 1999), page 21.
4. Target lifetime energy savings for commercial & industrial programs from 2005 Core New Hampshire Energy Efficiency Programs filing, NHPUC Docket No. DE 04-182, filing date: 10/5/04.
5. Source: Program tracking systems
6. 65% of line 4.
7. See Table 4, page 3 of 4, line 7.
8. Report to the New Hampshire Public Utilities Commission on Ratepayer-Funded Energy Efficiency Issues in New Hampshire, Docket No. DR 96-150, page 21.
9. Report to the New Hampshire Public Utilities Commission on Ratepayer-Funded Energy Efficiency Issues in New Hampshire, Docket No. DR 96-150, page 21.
10. 8% of line 7.
11. There are two elements of this calculation. Line 11 is the sum of Element 1 and Element 2, described below. This sum cannot exceed Line 12.
    Element 1 - Incentive related to cost-effectiveness:
    a. Line 2 must be greater than or equal to Line 3.
    b. (Line 2/Line 1) x .04 x Line 7
    Element 2 - Incentive related to Lifetime kWh:
    a. Line 5 must be greater than or equal to Line 6.
    b. (Line 5/Line 4) x .04 x Line 7
12. 12% of Line 7.
13. See Table 4, page 3 of 4, line 13.
14. See Table 4, page 3 of 4, line 13.
15. Report to the New Hampshire Public Utilities Commission on Ratepayer-Funded Energy Efficiency Issues in New Hampshire, Docket No. DR 96-150, page 21.
16. Target lifetime savings for eligible residential programs from 2005 Core New Hampshire Energy Efficiency Programs filing, NHPUC Docket No. DE 04-182, filing date: 10/5/04.
17. Source: Program tracking systems.
18. 65% of line 16.
19. See Table 4, page 3 of 4, line 14.
20. Report to the New Hampshire Public Utilities Commission on Ratepayer-Funded Energy Efficiency Issues in New Hampshire, Docket No. DR 96-150, page 21.
21. Report to the New Hampshire Public Utilities Commission on Ratepayer-Funded Energy Efficiency Issues in New Hampshire, Docket No. DR 96-150, page 21.
22. 8% of line 19.
23. There are two elements of this calculation. Line 23 is the sum of Element 1 and Element 2, described below. This sum cannot exceed Line 24.
    Element 1 - Incentive related to cost-effectiveness:
    a. Line 14 must be greater than or equal to Line 15.
    b. (Line 14/Line 13) x .04 x Line 19
    Element 2 - Incentive related to Lifetime kWh:
    a. Line 17 must be greater than or equal to Line 18.
    b. (Line 17/Line 16) x .04 x Line 19
24. 12% of Line 19.
25. Line 11 + Line 23

Table 4 (continued)
Page 3 of 4
Planned Versus Actual Benefit-Cost Ratio by Sector
National Grid - 2005

	Planned	Actual
Commercial & Industrial:		
1. Benefits (Value) From Eligible Programs	$3,957,335	$2,826,479
2. Implementation Expenses	$934,766	$775,808
3. Customer Contribution	$687,899	$418,315
4. Evaluation Expense	$45,678	$51,212
5. Total Costs Excluding Shareholder Incentive	$1,668,343	$1,245,335
6. Benefit/Cost Ratio - C&I Sector	2.37	2.27
7. Implementation Plus Evaluation Expense - C&I Sector	$980,444	$827,020
Residential:		
8. Benefits (Value) From Eligible Programs	$1,090,195	$1,516,550
9. Implementation Expenses	$446,719	$521,867
10. Customer Contribution	$274,611	$184,845
11. Evaluation Expense	$23,400	$13,853
12. Total Costs Excluding Shareholder Incentive	$744,730	$720,565
13. Benefit/Cost Ratio - Residential Sector	1.46	2.10
14. Implementation Plus Evaluation Expense - Residential Sector	$470,119	$535,720

Table 4 (continued)
Page 4 of 4
Planned Versus Actual Benefit-Cost Ratio by Sector
National Grid - 2005

Line No. Notes:

1. Planned Commercial & Industrial benefits (value) from eligible programs from 2005 Core New Hampshire Energy Efficiency Programs, NHPUC Docket No. DE 04-182, filing date: October 5, 2004, Attachment D, page 4 of 5.
   Actual benefits (value) from eligible programs: Program tracking systems.
2. Planned implementation expenses for C&I programs from eligible programs from 2005 Core New Hampshire Energy Efficiency Programs, NHPUC Docket No. DE 04-182, filing date: October 5, 2004, Attachment D, page 4 of 5.
   Actual implementation expenses: Company accounting system net of customer co-pays.
3. Planned C&I customer contribution from 2005 Core New Hampshire Energy Efficiency Programs, filing date: 10/5/04, Attachment D, page 4 of 5. Actual customer contribution: Program tracking systems plus estimated customer costs related to spillover plus customer co-pays that were netted out of reported implementation expenses.
4. Planned C&I evaluation expenses from 2005 Core New Hampshire Energy Efficiency Programs, filing date: 10/5/04, Attachment D, page 4 of 5. Actual evaluation expenses: Company accounting system.
5. Sum of lines 2-4.
6. Line 1 divided by line 5. The shareholder incentive mechanism described by the New Hampshire Energy Efficiency Working Group and approved by the Commission in Order No. 23,574 (reaffirmed in Order No. 23,982 (2002)) includes a circular calculation. A portion of the earned shareholder incentive is related to the benefit/cost ratio. However, the shareholder incentive is supposed to be included as an energy efficiency cost in determining the benefit/cost ratio. For the purpose of calculating the shareholder incentive, the Company has recalculated the planned benefit/cost ratio excluding the shareholder incentive and is comparing the actual benefit/cost ratio excluding the shareholder incentive to the planned benefit/cost ratio excluding shareholder incentives.
7. Sum of lines 2 and 4. The dollars in the planned column are the C&I sector funds on which the Company may calculate its earned shareholder incentive.
8. Planned Residential benefits (value) from 2005 Core New Hampshire Energy Efficiency Programs, filing date: October 5, 2004, Attachment D, page 4 of 5.
   Actual benefits (value) from eligible programs: Program tracking systems.
9. Planned implementation expenses for residential programs from 2005 Core New Hampshire Energy Efficiency Programs, filing date: 10/5/04. Attachment D, page 4 of 5. Actual implementation expenses: Company accounting system.
10. Planned Residential customer contribution from 2005 Core New Hampshire Energy Efficiency Programs, filing date: 10/5/04, Attachment D, page 4 of 5. Actual customer contribution: Program vendors plus estimated customer costs associated with spillover.
11. Planned residential evaluation expenses from 2005 Core New Hampshire Energy Efficiency Programs, filing date: 10/5/04, Attachment D, page 4 of 5. Actual evaluation expense: Company accounting system.
12. Sum of lines 9-11.
13. Line 8 divided by line 12. The shareholder incentive mechanism described by the New Hampshire Energy Efficiency Working Group and approved by the Commission in Order No. 23,574 (reaffirmed in Order No. 23,982 (2002)) includes a circular calculation. A portion of the earned shareholder incentive is related to the benefit/cost ratio. However, the shareholder incentive is supposed to be included as an energy efficiency cost in determining the benefit/cost ratio. For the purpose of calculating the shareholder incentive, the Company has recalculated the planned benefit/cost ratio excluding the shareholder incentive and is comparing the actual benefit/cost ratio excluding the shareholder incentive to the planned benefit/cost ratio excluding shareholder incentives.
14. Sum of lines 9 and 11. The dollars in the planned column are the Residential sector funds on which the Company may calculate its earned shareholder incentive.

TABLE 5

Date: 12-Apr-06

NATIONAL GRID
ENERGY EFFICIENCY REVENUE/EXPENSE BALANCE

12 Months Actual 2005

Total Energy Efficiency Revenue/Expense for Jan-Dec 2005

		Actual JAN	Actual FEB	Actual MAR	Actual APRIL	Actual MAY	Actual JUNE	6MTHS Y.T.D
	Residential Revenue	$54,747	$49,789	$48,359	$42,964	$36,211	$39,897	$271,967
	C&I. Revenue	$85,045	$75,921	$92,455	$80,103	$80,629	$89,617	$503,769
1.	TOTAL REVENUE (A)	$139,792	$125,709	$140,814	$123,067	$116,840	$129,513	$775,736
	Residential Expense	$8,533	$15,293	$40,583	$12,256	$9,667	$57,638	$143,969
	C&I. Expense	$16,596	$50,428	$18,355	$43,464	$28,790	$129,662	$287,296
2.	TOTAL EXPENSE (B)	$25,129	$65,721	$58,938	$55,720	$38,457	$187,300	$431,265
3.	Cash Flow Over/(Under)	$114,663	$59,988	$81,876	$67,346	$78,383	($57,787)	$344,471
4.	Start of Period Balance (C)	$25,217	$139,880	$199,869	$281,745	$349,091	$427,474	$25,217
5.	End of Period Balance Before Interest	$139,880	$199,869	$281,745	$349,091	$427,474	$369,688	$369,688
6.	Residential Interest	($577)	($996)	($1,323)	($1,568)	($1,680)	($1,771)	($1,771)
	C&I Interest	$938	$2,134	$3,581	$5,338	$7,385	$9,472	$9,472
	TOTAL INTEREST (D)	$361	$1,138	$2,258	$3,769	$5,704	$7,701	$7,701
7.	End of Period Balance After Interest	$140,241	$201,007	$284,003	$352,860	$433,179	$377,388	$377,388

		Actual JULY	Actual AUG	Actual SEPT	Actual OCT	Actual NOV	Actual DEC	ANNUAL TOTAL
	Residential Revenue	$47,211	$53,067	$46,660	$38,604	$39,900	$50,647	$548,056
	C&I. Revenue	$100,014	$103,242	$99,575	$90,973	$81,474	$95,255	$1,074,302
8.	TOTAL REVENUE (A)	$147,225	$156,309	$146,235	$129,577	$121,374	$145,903	$1,622,358
	Residential Expense	$7,796	$25,447	$4,544	$22,171	$36,642	$356,398	$596,967
	C&I. Expense	$89,008	$30,219	$210,431	$33,633	$89,044	$167,932	$907,563
9.	TOTAL EXPENSE (B)	$96,804	$55,666	$214,975	$55,804	$125,686	$524,330	$1,504,530
10.	Cash Flow Over/(Under)	$50,421	$100,643	($68,740)	$73,773	($4,312)	($378,427)	$117,828
11.	Start of Period Balance (C)	$369,688	$420,108	$520,751	$452,012	$525,785	$521,472	$25,217
12.	End of Period Balance Before Interest	$420,108	$520,751	$452,012	$525,785	$521,472	$143,045	$143,045
13.	Residential Interest	($1,809)	($1,668)	($1,333)	($825)	($240)	($544)	($544)
	C&I Interest	$11,567	$13,950	$16,286	$18,528	$20,998	$23,281	$23,281
	TOTAL INTEREST (D)	$9,757	$12,282	$14,953	$17,703	$20,758	$22,737	$22,737
14.	End of Period Balance After Interest	$429,866	$533,033	$466,965	$543,488	$542,230	$165,782	$165,782
15.	End Balance as % of Revenue							10.22%

(A) See Tables 2 & 3
(B) See Tables 2 & 3
(C) "End of Period Balance Before Interest" from prior month.
(D) See Tables 2 & 3

Interest Rates:								
	JAN =	5.25%	FEB =	5.49%	MAR =	5.58%	APR =	5.75%
	MAY =	5.98%	JUN =	6.01%	JUL =	6.25%	AUG =	6.44%
	SEP =	6.59%	OCT =	6.75%	NOV =	7.00%	DEC =	7.15%

TABLE 6

Date: 12-Apr-06

NATIONAL GRID
ENERGY EFFICIENCY REVENUE/EXPENSE BALANCE
RESIDENTIAL FUND
12 Months Actual 2005

Energy Efficiency Residential Revenue/Expense for Jan-Dec 2005

		Actual JAN	Actual FEB	Actual MAR	Actual APRIL	Actual MAY	Actual JUNE
1.	Residential Revenue (A)	$54,747	$49,789	$48,359	$42,964	$36,211	$39,897
2.	Residential Energy Efficiency Expense (B)	$8,533	$15,293	$40,583	$12,256	$9,667	$57,638
3.	Cash Flow Over/(Under)	$46,215	$34,496	$7,776	$30,708	$26,545	($17,741)
4.	Start of Period Balance (C)	($154,993)	($108,778)	($74,282)	($66,506)	($35,798)	($9,254)
5.	End of Period Balance Before Interest	($108,778)	($74,282)	($66,506)	($35,798)	($9,254)	($26,995)
6.	Estimated Cumulative Interest	($577)	($996)	($1,323)	($1,568)	($1,680)	($1,771)
7.	End of Period Balance After Interest	($109,355)	($75,278)	($67,829)	($37,366)	($10,934)	($28,766)

		Actual JULY	Actual AUG	Actual SEPT	Actual OCT	Actual NOV	Actual DEC	ANNUAL TOTAL
8.	Residential Revenue (A)	$47,211	$53,067	$46,660	$38,604	$39,900	$50,647	$548,056
9.	Residential Energy Efficiency Expense (B)	$7,796	$25,447	$4,544	$22,171	$36,642	$356,398	$596,967
10.	Cash Flow Over/(Under)	$39,415	$27,619	$42,116	$16,432	$3,258	($305,750)	($48,912)
11.	Start of Period Balance (C)	($26,995)	$12,420	$40,039	$82,155	$98,587	$101,845	($154,993)
12.	End of Period Balance Before Interest	$12,420	$40,039	$82,155	$98,587	$101,845	($203,905)	($203,905)
13.	Estimated Cumulative Interest	($1,809)	($1,668)	($1,333)	($825)	($240)	($544)	($544)
14.	End of Period Balance After Interest	$10,611	$38,371	$80,822	$97,763	$101,606	($204,449)	($204,449)
15.	End Balance as % of Revenue							-37.30%

FOOTNOTES:
(A) Revenue Report
(B) Source: PeopleSoft query
(C) "End of Period Balance Before Interest" from prior month.
Estimated DSM incentive is included in Dec expense estimate.

Interest Rates:								
	JAN =	5.25%	FEB =	5.49%	MAR =	5.58%	APR =	5.75%
	MAY =	5.98%	JUN =	6.01%	JUL =	6.25%	AUG =	6.44%
	SEP =	6.59%	OCT =	6.75%	NOV =	7.00%	DEC =	7.15%

Note: The Residential Factor is applied to the D-0, D-10, & T-0 rates.

TABLE7

Date: 12-Apr-06

NATIONAL GRID
ENERGY EFFICIENCY REVENUE/EXPENSE BALANCE
COMMERCIAL & INDUSTRIAL FUND
12 Months Actual 2005

Energy Efficiency C&I Revenue/Expense for Jan-Dec 2005

		Actual JAN	Actual FEB	Actual MAR	Actual APRIL	Actual MAY	Actual JUNE
1.	C&I Revenue (A)	$85,045	$75,921	$92,455	$80,103	$80,629	$89,617
2.	C&I Energy Efficiency Expense (B)	$16,596	$50,428	$18,355	$43,464	$28,790	$129,662
3.	Cash Flow Over/(Under)	$68,449	$25,492	$74,100	$36,639	$51,839	($40,045)
4.	Start of Period Balance (C)	$180,210	$248,659	$274,151	$348,250	$384,889	$436,728
5.	End of Period Balance Before Interest	$248,659	$274,151	$348,250	$384,889	$436,728	$396,683
6.	Estimated Cumulative Interest	$938	$2,134	$3,581	$5,338	$7,385	$9,472
7.	End of Period Balance After Interest	$249,597	$276,285	$351,831	$390,227	$444,113	$406,155

		Actual JULY	Actual AUG	Actual SEPT	Actual OCT	Actual NOV	Actual DEC	ANNUAL TOTAL
8.	C&I Revenue (A)	$100,014	$103,242	$99,575	$90,973	$81,474	$95,255	$1,074,302
9.	C&I Energy Efficiency Expense (B)	$89,008	$30,219	$210,431	$33,633	$89,044	$167,932	$907,563
10.	Cash Flow Over/(Under)	$11,005	$73,024	($110,855)	$57,341	($7,571)	($72,677)	$166,740
11.	Start of Period Balance (C)	$396,683	$407,688	$480,712	$369,856	$427,197	$419,627	$180,210
12.	End of Period Balance Before Interest	$407,688	$480,712	$369,856	$427,197	$419,627	$346,950	$346,950
13.	Estimated Cumulative Interest	$11,567	$13,950	$16,286	$18,528	$20,998	$23,281	$23,281
14.	End of Period Balance After Interest	$419,255	$494,662	$386,142	$445,725	$440,624	$370,231	$370,231
15.	End Balance as % of Revenue							34.46%

FOOTNOTES:
(A) Revenue Report
(B) Source: PeopleSoft query
(C) "End of Period Balance Before Interest" from prior month.
Estimated DSM incentive is included in Dec expense estimate.

Interest Rates:								
	JAN =	5.25%	FEB =	5.49%	MAR =	5.58%	APR =	5.75%
	MAY =	5.98%	JUN =	6.01%	JUL =	6.25%	AUG =	6.44%
	SEP =	6.59%	OCT =	6.75%	NOV =	7.00%	DEC =	7.15%

Note: The C&I Factor is applied to the G-1, G-2, G-3, M,& V rates.

TABLE 8

Date: 12-Apr-06

NATIONAL GRID
ENERGY EFFICIENCY VARIANCE ANALYSIS
RESIDENTIAL FUND
12 Months Actual 2005

Energy Efficiency Residential Revenue/Expense for Jan-Dec 2005

		JAN	FEB	MARCH	APRIL	MAY	JUNE
1.	Residential Energy Efficiency Revenue (A)	$54,747	$49,789	$48,359	$42,964	$36,211	$39,897
2.	Estimated Residential Energy Efficiency Revenue (B)	$54,929	$49,565	$46,499	$40,615	$36,302	$38,670
3.	Difference (1)-(2)	($182)	$224	$1,860	$2,349	($91)	$1,227
4.	Residential Energy Efficiency Expense (A)	$8,533	$15,293	$40,583	$12,256	$9,667	$57,638
5.	Estimated Residential Energy Efficiency Expense (C)	$0	$0	$0	$39,126	$34,750	$44,469
6.	Difference Residential Energy Efficiency Expense (4) - (5)	$8,533	$15,293	$40,583	($26,870)	($25,083)	$13,169

		JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
7.	Residential Energy Efficiency Revenue (A)	$47,211	$53,067	$46,660	$38,604	$39,900	$50,647	$548,056
8.	Estimated Residential Energy Efficiency Revenue (B)	$43,405	$44,923	$43,165	$40,958	$41,202	$51,059	$531,292
9.	Difference (7)-(8)	$3,806	$8,144	$3,495	($2,354)	($1,302)	($412)	$16,763
10.	Residential Energy Efficiency Expense (A)	$7,796	$25,447	$4,544	$22,171	$36,642	$356,398	$596,967
11.	Estimated Residential Energy Efficiency Expense (C)	$43,608	$43,070	$62,736	$25,614	$75,614	$289,976	$658,964
12.	Difference Residential Energy Efficiency Expense (10) - (11)	($35,812)	($17,622)	($58,191)	($3,443)	($38,973)	$66,421	($61,996)

FOOTNOTES:

(A) See Table 2
(B) Calculation based on estimated monthly Residential kWh from Company's Winter 2004 forecast multiplied by a factor of $0.00180
(C) Source: Retail Support & Services Dept. No estimates for 1st Q.
Incentives are included in Dec exp est.
Note: The Residential Factor is applied to the D-0, D-10, & T-0 rates.

TABLE 9

NATIONAL GRID
ENERGY EFFICIENCY VARIANCE ANALYSIS
COMMERCIAL & INDUSTRIAL FUND
12 Months Actual 2005

Energy Efficiency C&I Revenue/Expense for Jan-Dec 2005

		JAN	FEB	MARCH	APRIL	MAY	JUNE	
1.	C&I Energy Efficiency Revenue (A)	$85,045	$75,921	$92,455	$80,103	$80,629	$89,617	
2.	Estimated C&I Energy Efficiency Revenue (B)	$85,155	$82,474	$77,459	$77,670	$77,780	$84,342	
3.	Difference (1)-(2)	($110)	($6,553)	$14,996	$2,433	$2,849	$5,275	
4.	C&I Energy Efficiency Expense (A)	$16,596	$50,428	$18,355	$43,464	$28,790	$129,662	
5.	Estimated C&I Energy Efficiency Expense (C)	$0	$0	$0	$78,075	$77,925	$91,517	
6.	Difference C&I Energy Efficiency Expense (4) - (5)	$16,596	$50,428	$18,355	($34,611)	($49,135)	$38,145	
		JULY	**AUG**	**SEPT**	**OCT**	**NOV**	**DEC**	**TOTAL**
7.	C&I Energy Efficiency Revenue (A)	$100,014	$103,242	$99,575	$90,973	$81,474	$95,255	$1,074,302
8.	Estimated C&I Energy Efficiency Revenue (B)	$90,845	$92,409	$88,608	$84,851	$82,001	$87,641	$1,011,235
9.	Difference (7)-(8)	$9,169	$10,834	$10,967	$6,123	($528)	$7,615	$63,069
10.	C&I Energy Efficiency Expense (A)	$89,008	$30,219	$210,431	$33,633	$89,044	$167,932	$907,563
11.	Estimated C&I Energy Efficiency Expense (C)	$99,045	$87,453	$117,386	$126,490	$127,540	$286,332	$1,091,764
12.	Difference C&I Energy Efficiency Expense (10) - (11)	($10,037)	($57,235)	$93,044	($92,858)	($38,496)	($118,399)	($184,201)

FOOTNOTES:

(A) See Table 3
(B) Calculation based on estimated monthly Residential kWh from Company's Winter 2004 forecast multiplied by a factor of $0.00180.
(C) Source: Retail Support & Services. No estimates for 1st Q.

Note: The C&I Factor is applied to the G-1, G-2, G-3, M,& V rates.

C.1 Transmission Planning Guide

TRANSMISSION PLANNING GUIDE

Revision 3.0
05/29/2006

Revision History:
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Revision 1.1: 03/20/2001
Revision 2.0: 01/19/2004
Revision 2.1: 06/29/2004

nationalgrid

TRANSMISSION PLANNING GUIDE

1.0 OBJECTIVE OF THE TRANSMISSION PLANNING GUIDE

The objective of the Transmission Planning Guide is to define the criteria and standards used to assess the reliability of the existing and future National Grid USA (NGUSA) transmission system for reasonably anticipated operating conditions and to provide guidance, with consideration of public safety and safety of operations and personnel, in the design of future modifications or upgrades to the transmission system. The guide is a design tool and is not intended to address unusual or unanticipated operating conditions. This Planning Guide is applicable to all National Grid facilities operated at 69 kV and above.

2.0 PLANNING AND DESIGN CRITERIA

All NGUSA facilities that are part of the bulk power system and part of the interconnected NGUSA system shall be designed in accordance with the latest versions of the ISO-New England Reliability Standards, New York State Reliability Council (NYSRC) Reliability Rules, the Northeast Power Coordinating Council (NPCC) criteria, and the NGUSA criteria. The fundamental guiding documents are the "Reliability Standards for the New England Area Bulk Power Supply System" (ISO-NE Planning Procedure No. 3), the "New York State Reliability Council Reliability Rules for Planning and Operation of the New York State Power System," the "Basic Criteria for Design and Operation of Interconnected Power Systems" (NPCC Document A2), the "Bulk Power System Protection Criteria" (NPCC Document A5), and this document.

Interconnections of new generators to the National Grid transmission system in New England shall be configured and designed in compliance with the ISO-New England document, "General Transmission System Design Requirements for the Interconnection of New Generators (Resources) to the Administered Transmission System." If corresponding New York ISO requirements are established, interconnections to the National Grid transmission system in New York will be configured and designed in compliance with those requirements.

All NGUSA facilities that are not part of the bulk power system, but are part of the interconnected NGUSA system shall be designed in accordance with the latest version of this document.

All NGUSA or NGUSA transmission customers' facilities which are served by transmission providers other than NGUSA shall be designed in accordance with the planning and design criteria of the transmission supplier and the applicable ISO-NE, NYSRC, and NPCC documents.

Detailed design of facilities may require additional guidance from industry or other technical standards which are not addressed by any of the documents referenced in this guide.

3.0 OPERATIONAL CONSIDERATIONS IN PLANNING AND DESIGN

The system should be planned and designed with consideration for ease of operation. Such considerations include, but are not limited to:

- utilization of standard components to facilitate availability of spare parts
- optimization of post contingency switching operations
- reduction of operational risks
- judicious use of Special Protection Systems (SPSs)

1.0 BASIC TYPES OF STUDIES

The basic types of studies conducted to assess conformance with the criteria and standards stated in this guide include but are not limited to Loadflow, Stability, Short Circuit, and Protection.

2.0 STUDY HORIZON

The lead time required to plan, permit, license, and construct transmission system upgrades is typically between one and ten years depending on the complexity of the project. As a result, investments in the transmission system should be evaluated for different planning horizons in the one to ten-year range. The typical horizons are referred to as near term (one to three years), mid-term (three to six years), and long term (six to ten years). The long term time frame may be extended for development of long term transmission infrastructure planning, to aid in development of long term expansion plans, and to assess the adequacy of proposed facilities beyond the ten year horizon. Projects taking less than a year to implement tend to consist of non-construction alternatives that are addressed by operating studies.

3.0 FUTURE FACILITIES

Planned facilities should not automatically be assumed to be in-service during study periods after the planned in-service date. Sensitivity analysis should be performed to identify interdependencies of the planned facilities. These interdependencies should be clearly identified in the results and recommendations.

4.0 EQUIPMENT THERMAL RATINGS

Thermal ratings of each load carrying element in the system are determined such that maximum use can be made of the equipment without damage or undue loss of equipment life. The thermal ratings of each transmission circuit reflect the most limiting series elements within the circuit. The existing rating procedures are based on guidance provided by the NEPOOL System Design Task Force (SDTF), the NYPP Task Force on Tie Line Ratings, and industry standards. A common rating procedure has been developed for rating NGUSA facilities in New England and New York which will be applied to all new and modified facilities. The principal variables used to derive the ratings include specific equipment design, season, ambient conditions, maximum allowable equipment operating temperatures as a function of time, and physical parameters of the equipment. Procedures for calculating the thermal ratings are subject to change.

Equipment ratings are summarized in the following table by durations of allowable loadings for three types of facilities. Where applicable, actions that must be taken to relieve equipment loadings within the specified time period also are included.

Equipment	RATINGS			
	Normal	Long Time Emergency (LTE)	Short Time Emergency (STE)	Drastic Action Limit (DAL)
Overhead Transmission	Continuous	Loading must be reduced below the Normal rating within 4 hours[2]	Loading must be reduced below the LTE rating within 15 minutes	requires immediate action to reduce loading below the STE rating
Underground Cables[1]	Continuous	Loading must be reduced below the 100 hr or 300 hr rating within 4 hours[2]	Loading must be reduced below the 100 hr or 300 hr rating within 15 minutes	requires immediate action to reduce loading below the STE rating
Transmission Transformers	Continuous	Loading must be reduced below the Normal rating within 4 hours[2]	Loading must be reduced below the LTE rating within 15 minutes[3]	requires immediate action to reduce loading below the STE rating

[1] Ratings for other durations may be calculated and utilized for specific conditions on a case-by-case basis. Following expiration of the 100 hr or 300 hr period, loading of the cable must be reduced below the Normal rating. Either the 100 hr or the 300 hr rating may be utilized after the transient period, but not both. If the 100 hr rating is utilized, the loading must be reduced below the Normal rating within 100 hr, and the 300 hr rating may not be used.

[2] The summer LTE rating duration is 12 hours in New England. The winter LTE rating duration in New England, and the summer and winter LTE rating duration in New York is 4 hours.

[3] The transformer STE rating is based on a 30 minute duration to provide additional conservatism, but is applied in operations as a 15 minute rating.

4.1 OTHER EQUIPMENT

Industry standards and input from task forces in New England and New York should continue to be used as sources of guidance for developing procedures for rating new types of equipment or for improving the procedures for rating the existing equipment.

4.2 HIGH VOLTAGE DC

High Voltage dc (HVdc) equipment is rated using the manufacturer's claimed capability.

5.0 MODELING FOR LOADFLOW STUDIES

The representation for loadflow studies should include models of transmission lines, transformers, generators, reactive sources, and any other equipment which can affect power flow or voltage. The representation for fixed-tap, load-tap-changing, and phase shifting transformers should include voltage or angle taps, tap ranges, and voltage or power flow control points. The representation for generators should include reactive capability ranges and voltage control points. Equipment ratings should be modeled for each of these facilities including related station equipment such as buses, circuit breakers and switches. Study specific issues that need to be addressed are discussed below.

5.1 FORECASTED LOAD

The forecasted summer and winter peak active and reactive loads should be obtained annually from the Transmission Customers for a period of ten or more years starting with the highest actual seasonal peak loads within the last three years. The forecast should have sufficient detail to distribute the active and reactive coincident loads (coincident with the Customers' total peak load) across the Customers' Points of Delivery. Customer owned generation should be modeled explicitly when the size is significant compared to the load at the same delivery point, or when the size is large enough to impact system dynamic performance.

The Point of Delivery for loadflow modeling purposes may be different than the point of delivery for billing purposes. Consequently, these points need to be coordinated between NGUSA and the Transmission Customer.

To address forecast uncertainty, the peak load forecast should include forecasts based on normal and extreme weather. Due to the lead time required to construct new facilities, planning should be based conservatively on the extreme weather forecast.

5.2 LOAD LEVELS

To evaluate the sensitivity to daily and seasonal load cycles, many studies require modeling several load levels. The most common load levels studied are peak (100% of the extreme weather peak load forecast), intermediate (70 to 80% of the peak), and light (45 to 55% of the peak). The basis can be either the summer or winter peak forecast. In some areas, both seasons may have to be studied.

Sensitivity to the magnitude of the load assumptions must be evaluated with the assumed generation dispatch to assess the impact of different interactions on transmission circuit loadings and system voltage responses.

5.3 LOAD BALANCE AND HARMONICS

Balanced three-phase 60 Hz ac loads are assumed at each Point of Delivery unless a customer specifies otherwise, or if there is information available to confirm the load is not balanced. Balanced loads are assumed to have the following characteristics:

- The active and reactive load of any phase is within 90% to 110% of the load on both of the other phases
- The voltage unbalance between the phases measured phase-to-phase is 3% or less
- The negative phase sequence current (RMS) in any generator is less than the limits defined by the current version of ANSI C50.13

Harmonic voltage and current distortion is required to be within limits recommended by the current version of IEEE Std. 519.

If a customer load is unbalanced or exceeds harmonic limits, then special conditions not addressed in this guide may apply.

5.4 LOAD POWER FACTOR

Load Power Factor for each delivery point is established by the active and reactive load forecast supplied by the customer in accordance with section 5.1 The Load Power Factor in each area in New England should be consistent with the limits set forth in Operating Procedure 17 (OP17).

5.5 REACTIVE COMPENSATION

Reactive compensation should be modeled as it is designed to operate on the transmission system and, when provided, on the low voltage side of the supply transformers. Reactive compensation on the feeder circuits is assumed to be netted with the load. NGUSA should have the data on file, as provided by the generator owners, to model the generator reactive capability as a function of generator active power output for each generator connected to the transmission system.

5.6 GENERATION DISPATCH

Analysis of generation sensitivity is necessary to model the variations in dispatch that routinely occur at each load level. The intent is to bias the generation dispatch such that the transfers over select portions of the transmission system are stressed pre-contingency as much as reasonably possible. An exception is hydro generation that should account for seasonal variation in the availability of water.

A merit based generation dispatch should be used as a starting point from which to stress transfers. A merit based dispatch can be approximated based on available information such as fuel type and historical information regarding unit commitment. Interface limits can be used as a reference for stressing the transmission system. Dispatching to the interface limits may stress the transmission system in excess of transfer levels that are considered normal.

5.7 FACILITY STATUS

The initial conditions assume all existing facilities normally connected to the transmission system are in service and operating as designed or expected. Future facilities should be treated as discussed in Section B, paragraph 3.0.

6.0 MODELING FOR STABILITY STUDIES

6.1 DYNAMIC MODELS

Dynamic models are required for generators and associated equipment, HVdc terminals, SVCs, other Flexible AC Transmission Systems (FACTS), and protective relays to calculate the fast acting electrical and mechanical dynamics of the power system. Dynamic model data is maintained as required by NEPOOL, NYSRC, and NPCC.

6.2 LOAD LEVEL AND LOAD MODELS

Stability studies within New England typically exhibit the most severe system response under light load conditions. Consequently, transient stability studies are typically performed for several unit dispatches at a system load level of 45% of peak system load. At least one unit dispatch at 100% of system peak load is also analyzed. Other system load levels may be studied when required to stress a system interface, or to capture the response to a particular generation dispatch.

Stability studies within New York typically exhibit the most severe system response under summer peak load conditions. Consequently, transient stability studies are typically performed with a system load level of 100% of summer peak system load. Other system load levels may be studied when required to stress a system interface, or to capture the response to a particular generation dispatch.

System loads within New England and New York are usually modeled as constant admittances for both active and reactive power. These models have been found to be appropriate for studies of rotor angle stability and are considered to provide conservative results. Other load models are utilized where appropriate such as when analyzing the underfrequency performance of an islanded portion of the system, or when analyzing voltage performance of a local portion of a system.

Loads outside NEPOOL are modeled consistent with the practices of the individual Areas and regions. Appropriate load models for other Areas and regions are available through NPCC.

6.3 GENERATION DISPATCH

Generation dispatch for stability studies typically differs from the dispatch used in thermal and voltage analysis. Generation within the area of interest (generation behind a transmission interface or generation at an individual plant) is dispatched at full output within known system constraints. Remaining generation is dispatched to approximate a merit based dispatch. To minimize system inertia, generators are dispatched fully loaded to the extent possible while respecting system reserve requirements.

7.0 MODELING FOR SHORT CIRCUIT STUDIES

Short Circuit studies are performed to determine the maximum fault duty on circuit breakers and other equipment and to determine appropriate fault impedances for modeling unbalanced faults in transient stability studies.

Short Circuit studies for calculating maximum fault duty assume all generators are on line, and all transmission system facilities are in service and operating as designed.

Short Circuit studies for determining impedances for modeling unbalanced faults in stability studies typically assume all generators are on line. Switching sequences associated with the contingency may be accounted for in the calculation.

8.0 MODELING FOR PROTECTION STUDIES

Conceptual protection system design should be performed to ensure adequate fault detection and clearing can be coordinated for the proposed transmission system configuration in accordance with the National Grid protection philosophy and where applicable, with the NPCC "Bulk Power System Protection Criteria". Preliminary relay settings should be calculated based on information obtained from loadflow, stability, and short circuit studies to ensure feasibility of the conceptual design.

When an increase in the thermal rating of main circuit equipment is required, a review of associated protection equipment is necessary to ensure that the desired rating is achieved. The thermal rating of CT secondary equipment must be verified to be greater than the required rating. Also, it is necessary to verify that existing or proposed protective relay trip settings do not restrict loading of the protected element and other series connected elements to a level below the required circuit rating.

9.0 DEVELOPMENT AND EVALUATION OF ALTERNATIVES

If the projected performance or reliability of the system does not conform to the applicable planning criteria, then alternative solutions based on safety, performance, reliability, environmental impacts, and economics need to be developed and evaluated. The evaluation of alternatives leads to a recommendation that is summarized concisely in a report.

9.1 SAFETY

All alternatives shall be designed with consideration to public safety and the safety of operations and maintenance personnel. Characteristics of safe designs include:

- adequate equipment ratings for the conditions studied and margin for unanticipated conditions
- use of standard designs for ease of operation and maintenance
- ability to properly isolate facilities for maintenance
- adequate facilities to allow for staged construction of new facilities

Consideration shall be given to address any other safety issues that are identified that are unique to a specific project or site.

9.2 PERFORMANCE

The system performance with the proposed alternatives should meet or exceed all applicable design criteria.

9.3 RELIABILITY

This guide assesses deterministic reliability by defining the topology, load, and generation conditions that the transmission system must be capable of withstanding safely. This deterministic approach is consistent with NEPOOL, NYSRC, and NPCC practice. Defined outage conditions that the system must be designed to withstand are listed in Section C. The transmission system is designed to meet these deterministic criteria to promote the reliability and efficiency of electric service on the bulk power system, and also with the intent of providing an acceptable level of reliability to the customers.

Application of this guide ensures that all customers receive an acceptable level of reliability, although the level of reliability provided through this approach will vary. All customers or groups of customers will not necessarily receive uniform reliability due to inherent factors such as differences in customer load level, load shape, proximity to generation, interconnection voltage, accessibility of transmission resources, customer service requirements, and class and vintage of equipment.

9.4 ENVIRONMENTAL

An assessment should be made for each alternative of the human and natural environmental impacts. Assessment of the impacts is of particular importance whenever expansion of substation fence lines or transmission rights-of-way are proposed. However, environmental impacts also should be evaluated for work within existing substations and on existing transmission structures. Impacts during construction should be evaluated in addition to the impact of the constructed facilities. Evaluation of environmental impacts will be performed consistent with all applicable National Grid USA policies.

9.5 ECONOMICS

Initial and future investment cost estimates should be prepared for each alternative. The initial capital investment can often be used as a simple form of economic evaluation. This level of analysis is frequently adequate when comparing the costs of alternatives for which all expenditures are made at or near the same time. Additional economic analysis is required to compare the total cost of each alternative when evaluating more complex capital requirements, or for projects that are justified based on economics such as congestion relief. These analyses should include the annual charges on investments, losses, and all other expenses related to each alternative.

A cash flow model is used to assess the impact of each alternative on the National Grid USA business plan. A cumulative present worth of revenue requirements model is used to assess the impact of each alternative on the customer. Evaluation based on one or both models may be required depending on the project.

If the justification of a proposed investment is to reduce or eliminate annual expenses, the economic analysis should include evaluation of the length of time required to recover the investment. Recovery of the investment within 5 years is typically used as a benchmark, although recovery within a shorter or longer period may be appropriate.

9.6 TECHNICAL PREFERENCE

Technical preference should be considered when evaluating alternatives. Technical preference refers to concerns such as standard versus non-standard design or to an effort to develop a future standard. It may also refer to concerns such as age and condition of facilities, availability of spare parts, ease of operations and maintenance, ability to accommodate future expansion, ability to implement, or reduction of risk.

9.7 SIZING OF EQUIPMENT

All equipment should be sized based on economics, operating requirements, standard sizes used by the company, and engineering judgment. Economic analysis should account for indirect costs in addition to the cost to purchase and install the equipment. Engineering judgment should include recognition of realistic future constraints that may be avoided with minor incremental expense. As a guide, unless the equipment is part of a staged expansion, the capability of any new equipment or facilities should be sufficient to operate without constraining the system and without major modifications for at least 10 years. As a rough guide, if load growth is assumed to be 1% to 2%, then the minimum reserve margin should be at least 20% above the maximum expected demand on the equipment at the time of installation. However, margins can be less for a staged expansion.

10.0 RECOMMENDATION

A recommended action should result from every study. The recommendation includes resolution of any potential violation of the design criteria. The recommended action should be based on composite consideration of factors such as safety, the forecasted performance and reliability, environmental impacts, economics, technical preference, schedule, availability of land and materials, acceptable facility designs, and complexity and lead time to license and permit.

11.0 REPORTING STUDY RESULTS

A transmission system planning study should culminate in a concise report describing the assumptions, procedures, problems, alternatives, economic comparison, conclusions, and recommendations resulting from the study.

1.0 OBJECTIVE OF THE DESIGN CRITERIA

The objective of the Design Criteria is to define the design contingencies and measures used to assess the adequacy of the transmission system performance.

2.0 DESIGN CONTINGENCIES

The Design Contingencies used to assess the performance of the transmission system are defined in Table 1. In association with the design contingencies, this table also includes information on allowable facility loading. Control actions may be available to mitigate some contingencies listed in Section C, Table 1.

The reliability of local areas of the transmission system may not be critical to the operation of the interconnected NEPOOL system and the New York State Power System. Where this is the case, the system performance requirements for the local area under NGUSA design contingencies may be less stringent than what is required by NPCC criteria, NEPOOL reliability standards, or NYSRC Reliability Rules.

2.1 FAULT TYPE

As specified in Section C, Table 1, some contingencies are modeled without a fault; others are modeled with a three phase or a single phase to ground fault. All faults are considered permanent with due regard for reclosing facilities and before making any manual system adjustments.

2.2 FAULT CLEARING

Design criteria contingencies involving ac system faults on bulk power system facilities are simulated to ensure that stability is maintained when either of the two independent protection groups that performs the specified protective function operates to initiate fault clearing. In practice, design criteria contingencies are simulated based on the assumption that a single protection system failure has rendered the faster of the two independent protection groups inoperable.

Design criteria contingencies involving ac system faults on facilities that are not part of the bulk power system are simulated based on correct operation of the protection system on the faulted element. Facilities that are not part of the bulk power system must be reviewed periodically to determine whether changes to the power system have caused facilities to become part of the bulk power system. National Grid utilizes for this purpose a methodology based on applying a three-phase fault, uncleared locally, and modeling delayed clearing of remote terminals of any elements that must open to interrupt the fault.

2.3 ALLOWABLE FACILITY LOADING

The normal rating of a facility defines the maximum allowable pre- or post-contingency loading to which the equipment can operate during a normal load cycle. The LTE and STE ratings of equipment may allow an elevation in operating temperatures over a specific period provided the emergency loading is reduced back to, or below, a specific loading in a specific period of time (for specific times, see Section B, System Studies, paragraph 4.0 "Equipment Thermal Ratings").

For normal pre-contingent and emergency transfers, no facility shall be loaded above its normal rating. For emergency transfers however, a facility may be loaded up to the LTE rating pre-contingency, if the loading duration is less than the seasonal time allowance for loading up to the LTE rating, and if the STE rating is reduced to reflect the higher pre-contingent loading.

As a planning practice, the system should be designed to avoid loading equipment above the LTE rating following a design contingency (see Section C, Table 1 contingencies a through i). Under limited circumstances, however, it is acceptable to design the system such that equipment may be loaded above the LTE rating, but lower than the STE rating. Loading above the LTE rating up to the STE rating is permissible for contingencies b, c, e, f, g, h, and i, for momentary conditions provided automatic actions are in place to reduce the loading of the equipment below the LTE rating within 15 minutes, and does not cause any other facility to be loaded above its LTE rating. Such exceptions to the criteria will be well documented and require acceptance by National Grid USA Transmission Network Operations.

The Drastic Action Limit (DAL) is an absolute operating limit, based on the maximum loading to which a piece of equipment can be subjected over a five-minute period without sustaining damage. The DAL is not used in planning studies. In some cases when the DAL may be exceeded, it may be necessary to provide redundant controls to minimize the risk associated with failure of the automated actions to operate as intended.

2.4 RELIABILITY OF SERVICE TO LOAD

The transmission system is designed to allow the loss of any single element without a resulting loss of load, except in cases where a customer is served by a single supply. Where an alternate supply exists interruption of load is acceptable for the time required to transfer the load to the alternate supply.

Loss of load is acceptable for contingencies that involve loss of multiple elements such as simultaneous outage of multiple circuits on a common structure, or a circuit breaker failure resulting in loss of multiple elements. For these contingencies, measures should be evaluated to mitigate the frequency and/or the impact of such contingencies when the amount of load interrupted exceeds 100 MW. Such measures may include differential insulation of transmission circuits on a common structure, or automatic switching to restore unfaulted elements. Where such measures are already implemented, they should be assumed to operate as intended, unless a failure to operate as intended would result in a significant adverse impact outside the local area.

A higher probability of loss of customer load is acceptable during an extended generator or transformer outage, maintenance, or construction of new facilities. Widespread outages resulting from contingencies more severe than those defined by the Design Contingencies may result in loss of customer load in excess of 100 MW and/or service interruptions of more than 3 days.

2.5 LOAD SHEDDING

NPCC requires that each member have underfrequency load shedding capability to prevent widespread system collapse. As a result, load shedding for regional needs is acceptable in whatever quantities are required by the region. In some cases higher quantities of load shedding may be required by the Area or the local System Operator.

Manual or automatic shedding of any load connected to the NGUSA transmission system in response to a design contingency listed in Section C, Table 1 may be employed to maintain system security when adequate facilities are not available to supply load. However, shedding of load is not acceptable as a long term solution to design criteria violations, and recommendations will be made to construct adequate facilities to maintain system security without shedding load.

2.6 EXPECTED RESTORATION TIME

The transmission restoration time for the design contingencies encountered most frequently is typically expected to be within 24 hours. Restoration times are typically not more than 24 hours for equipment including overhead transmission lines, air insulated bus sections, capacitor banks, circuit breakers not installed in a gas insulated substation, and transformers that are spared by a mobile substation. For some contingencies however, restoration time may be significantly longer. Restoration times are typically longer than 24 hours for generators, gas insulated substations, underground cables, and large power transformers. When the expected restoration for a particular contingency is expected to be greater than 24 hours, analysis should be performed to determine the potential impacts if a second design contingency were to occur prior to restoration of the failed equipment.

2.7 GENERATION REJECTION OR RAMP DOWN

Generation rejection or ramp down refers to tripping or running back the output of a generating unit in response to a disturbance on the transmission system. As a general practice, generation rejection or ramp down should not be included in the design of the transmission system. However, generation rejection or ramp down may be considered if the following conditions apply:

- acceptable system performance (voltage, current, and frequency) is maintained following such action
- the interconnection agreement with the generator permits such action
- the expected occurrence is infrequent (the failure of a single element is not typically considered infrequent)
- the exposure to the conditions is unlikely or temporary (temporary implies that system modifications are planned in the near future to eliminate the exposure or the system is operating in an abnormal configuration).

Generation rejection or ramp down may be initiated manually or through automatic actions depending on the anticipated level and duration of the affected facility loading. Plans involving generation rejection or ramp down require review and approval by National Grid USA Transmission Network Operations, and may require approval of the System Operator.

2.8 EXCEPTIONS

These Design Criteria do not apply if a customer receives service from NGUSA and also has a connection to any other transmission provider regardless of whether the connection is open or closed. In this case, NGUSA has the flexibility to evaluate the situation and provide interconnection facilities as deemed appropriate and economic for the service requested.

NGUSA is not required to provide service with greater deterministic reliability than the customers provide for themselves. As an example, if a customer has a single transformer, NGUSA does not have to provide redundant transmission supplies.

3.0 VOLTAGE RESPONSE

Acceptable voltage response is defined in terms of maximum and minimum voltage in per unit (p.u.) for each transmission voltage class (Section C, Table 2), and in terms of percent voltage change from pre-contingency to post-contingency (Section C, Table 3). The values in these tables allow for automatic actions that take less than one minute to operate and which are designed to provide post-contingency voltage support. The voltage response also must be evaluated on the basis of voltage transients.

4.0 STABILITY

4.1 SYSTEM STABILITY

Stability of the transmission system shall be maintained during and following the most severe of the Design Contingencies in Section C, Table 1, with due regard to reclosing. Stability shall also be maintained if the outaged element as described in Section C, Table 1, is re-energized by autoreclosing before any manual system adjustment.

In evaluating the system response it is insufficient to merely determine whether a stable or unstable response is exhibited. There are a number of system responses which may be considered unacceptable even though the bulk power system remains stable. Each of the following responses is considered an unacceptable response to a design contingency:

- Transiently unstable response resulting in wide spread system collapse.
- Transiently stable response with undamped power system oscillations.
- Entry of the line 396 apparent impedance at Keswick into the Keswick GCX SPS relay characteristic.

4.2 GENERATOR UNIT STABILITY

With all transmission facilities in service, generator unit stability shall be maintained on those facilities that remain connected to the system following fault clearing, for

a. A permanent single-line-to-ground fault on any generator, transmission circuit, transformer, or bus section, cleared in normal time with due regard to reclosing.

b. A permanent three-phase fault on any generator, transmission circuit, transformer, or bus section, cleared in normal time with due regard to reclosing.

Isolated generator instability may be acceptable. However, generator instability will not be acceptable if it results in adverse system impact or if it unacceptably impacts any other entity in the system.

Table 1: Design Contingencies

Ref.	CONTINGENCY (Loss or failure of:)	Allowable Facility Loading
a	A permanent three-phase fault on any generator, transmission circuit, transformer, or bus section	LTE
b	Simultaneous permanent single-line-to-ground faults on different phases of two adjacent transmission circuits on a multiple circuit tower (> 1 mile)	LTE[1]
c	A permanent single-line-to-ground fault on any transmission circuit, transformer, or bus section, with a breaker failure	LTE[1]
d	Loss of any element without a fault (including inadvertent opening of a switching device_	LTE
e	A permanent single-phase-to-ground fault on a circuit breaker with normal clearing	LTE[1]
f	Simultaneous permanent loss of both poles of a bipolar HVdc facility without an ac system fault	LTE[1]
g	Failure of a circuit beaker to operate when initiated by an SPS following: loss of any element without a fault, or a permanent single-line-to-ground fault on a transmission circuit, transformer, or bus section	LTE[1]
h	Loss of a system common to multiple transmission elements (e.g., cable cooling)	LTE[1]
i	Permanent single-line-to-ground faults on two cables in a common duct or trench	LTE[1]

Notes:

[1] Loading above LTE, but below STE, is acceptable for momentary conditions provided automatic actions are in place to reduce the loading of equipment below the LTE rating within 15 minutes.

Table 2: Voltage Range

CONDITION	345 & 230 kV		115 kV[1] & Below	
	Low Limit (p.u.)	**High Limit (p.u.)**	**Low Limit (p.u.)**	**High Limit (p.u.)**
Normal Operating	0.98	1.05	0.95	1.05
Post Contingency & Automatic Actions	0.95	1.05	0.90	1.05

[1] Buses that are part of the bulk power system, and other buses deemed critical by Transmission Network Operations shall meet requirements for 345 kV and 230 kV buses.

Table 3: Maximum Percent Voltage Variation at Delivery Points

CONDITION	345 & 230 kV (%)	115 kV[1] & Below (%)
Post Contingency & Automatic Actions	5.0	10.0
Switching of Reactive Sources or Motor Starts (All elements in service)	2.0 *	2.5 *
Switching of Reactive Sources or Motor Starts (One element out of service)	4.0 *	5.0 *

[1] Buses that are part of the bulk power system, and other buses deemed critical by Transmission Network Operations shall meet requirements for 345 kV and 230 kV buses.

* These limits are maximums which do not include frequency of operation. Actual limits will be considered on a case-by-case basis and will include consideration of frequency of operation and impact on customer service in the area.

Notes to Tables 2 and 3:

a. Voltages apply to facilities which are still in service post contingency.
b. Site specific operating restrictions may override these ranges.
c. These limits do not apply to automatic voltage regulation settings which may be more stringent.
d. These limits only apply to NGUSA facilities.

1.0 OBJECTIVE OF THE INTERCONNECTION DESIGN REQUIREMENTS

The objective of the interconnection design requirements is to provide guidance on the minimum acceptable configurations to be applied when a new generator or transmission line is to be interconnected with the National Grid transmission system. The goal is to assure that reliability and operability are not degraded as a consequence of the new interconnection. National Grid will determine the configuration that appropriately addresses safety, reliability, operability, maintainability, and expandability objectives, consistent with this Transmission Planning Guide for each new or revised interconnection.

2.0 DESIGN CRITERIA

2.1 SAFETY

Substation arrangements shall be designed with safety as a primary consideration. Standard designs shall be utilized for ease of operation and maintenance and to promote standardization of switching procedures. Substation arrangements shall also provide means to properly isolate equipment for maintenance and allow appropriate working clearances for installed equipment as well as for staged construction of future facilities. Consideration shall be given to address any other safety issues that are identified that are unique to a specific project or site.

2.2 PLANNING AND OPERATING CRITERIA

Substation arrangements shall be designed such that all applicable Planning and Operating Criteria are met. These requirements may require ensuring that certain system elements do not share common circuit breakers or bus sections so as to avoid loss of both elements following a breaker fault or failure; either by relocating one or both elements to different switch positions or bus sections or by providing two circuit breakers in series. These requirements may also require that existing substation arrangements be reconfigured, e.g. from a straight bus or ring bus to a breaker-and-a-half configuration.

2.3 SYSTEM PROTECTION

Substation arrangements shall provide for design of dependable and secure protection systems. Designs that create multi-terminal lines shall not be allowed except in cases where Protection Engineering verifies that adequate coordination and relay sensitivity can be maintained when infeed or outfeed fault current is present.

To ensure reliable fault clearing, it generally is desirable that no more than two circuit breakers be required to be tripped at each terminal to clear a fault on a line or cable circuit. For transformers located within the substation perimeter, the incidence of faults is sufficiently rare that this requirement may be loosened to permit transformers to be connected directly to the buses in breaker-and-a-half or breaker-and-a-third arrangements.

2.4 OPERABILITY

Substation switching shall be configured to prevent the loss of generation for normal line operations following fault clearing. Generators shall not be connected directly to a transmission line through a single circuit breaker position except when connecting to a radial transmission line. In such cases a switching station consisting of one or more circuit breakers may be required at the point of interconnection depending on the length of the radial line, the length of existing and new taps, the presence of other generation or load connected to the line, and any other relevant factors.

2.5 MAINTAINABILITY

Substations shall be configured to permit circuit breaker maintenance to be performed without taking lines or generators out of service, recognizing that a subsequent fault on an element connected to the substation might result in the isolation of more than the faulted element. At existing substations with straight bus configurations, consideration will be given to modifying terminations in cases where an outage impacts the ability to operate the system reliably.

2.6 FUTURE EXPANSION

Substation designs shall be based on the expected ultimate layout based on future existing system needs and physical constraints associated with the substation plot.

3.0 STANDARD BUS CONFIGURATIONS

Given the development of the transmission system over time and through mergers and acquisitions of numerous companies, several different substation arrangements exist within the National Grid system. Future substation designs are standardized on breaker-and-a-half, breaker-and-a-third, and ring bus configurations, depending on the number of elements to be terminated at the station. Other substation configurations may be retained at existing substations, but are evaluated in periodic transmission assessments to consider whether continued use of such configurations is consistent with the reliable operation of the transmission system.

3.1 BREAKER-AND-A-HALF

A breaker-and-a-half configuration is the preferred substation arrangement for new substations with an ultimate layout expected to terminate greater than four major transmission elements or greater than six total elements. If the entire ultimate layout is not constructed initially, the substation may be configured initially in a ring bus configuration. Cases will exist where a breaker-and-a-half configuration is required with fewer elements terminated in order to meet the criteria stated above.

Major transmission elements include networked transmission lines 115 kV and above and power transformers with at least one terminal connected at 230 kV or 345 kV. Major transmission elements are terminated in a bay position between two circuit breakers in a breaker-and-a-half configuration. Other elements such as capacitor banks, shunt reactors, and radial 115 kV transmission lines may be terminated on the bus through a single circuit breaker. Transformers with no terminal voltage greater than 115 kV may be terminated directly on a bus. It may be permissible to terminate 345-115 kV or 230-115 kV transformers directly on a 115 kV bus if there is no reasonable expectation that more than two such transformers will be installed. Such a decision requires careful consideration however, given the difficulty of re-terminating transformers to avoid tripping two transformers for a breaker fault or failure in the event that a third transformer is installed at a later time.

3.2 <u>BREAKER-AND-A-THIRD</u>

A breaker-and-a-third configuration is an acceptable alternate to a breaker-and-a-half configuration in cases where a breaker-and-a-half arrangement is not feasible due to physical or environmental constraints. Considerations for terminating elements on a bus are the same as for breaker-and-a-half, except that 345-115 kV or 230-115 kV transformers may be terminated directly on a 115 kV bus since additional transformers may be terminated in a bay without a common breaker between two transformers.

3.3 <u>RING BUS</u>

A ring bus may be utilized for new substations where four or fewer major elements will be terminated or six or fewer total elements will be terminated. A ring bus also may be utilized as an interim configuration during staged construction of a substation.

3.4 <u>STRAIGHT BUS</u>

Many older substations on the system have a straight bus configuration, with each element terminating on the bus through a single breaker. Variations exist in which the bus is segmented by one or more bus-tie breakers, provisions are provided for a transfer bus, or the ability exists to transfer some or all elements from the main bus to an emergency bus. New substations shall not utilize a straight bus design. Periodic transmission assessments shall consider whether continued use of a straight bus configuration is consistent with maintaining reliable operation of the transmission system.

Bulk Power System

The interconnected electrical system comprising generation and transmission facilities on which faults or disturbances can have a significant impact outside the local area.

Contingency

An event, usually involving the loss of one or more elements, which affects the power system at least momentarily.

Element

Any electric device with terminals which may be connected to other electric devices, such as a generator, transformer, transmission circuit, circuit breaker, an HVdc pole, braking resistor, a series or shunt compensating device or bus section. A live-tank circuit breaker is understood to include its associated current transformers and the bus section between the breaker bushing and its free standing current transformer(s).

Fault Clearing - Delayed

Fault Clearance consistent with correct operation of a breaker failure protection group and its associated breakers or of a backup protection group with an intentional time delay.

Fault Clearing - Normal

Fault Clearance consistent with correct operation of the protection system and with correct operation of all circuit breakers or other automatic switching devices intended to operate in conjunction with that protection system.
Note: Zone 2 clearing of line-end faults on lines without pilot protection is normal clearing, not delayed clearing, even though a time delay is required for coordination purposes.

High Voltage dc (HVdc) System, Bipolar

An HVdc system with two poles of opposite polarity and negligible ground current.

Interface

A group of transmission lines connecting two areas of the transmission system.

Load Cycle

The normal pattern of demand over a specified time period (typically 24 hours) associated with a device or circuit.

Load Level

A scale factor signifying the total load relative to peak load or the absolute magnitude of load for the year referenced.

Loss of Customer Load (or Loss of Load)

Loss of service to one or more customers for longer than the time required for automatic switching.

Point(s) of Delivery

The point(s) at which the Company delivers energy to the Transmission Customer.

Special Protection Systems

A protection system designed to detect abnormal system conditions and take corrective action other than the isolation of faulted elements. Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages, or power flows. Automatic underfrequency load shedding and conventionally switched locally controlled shunt devices are not considered to be SPSs.

Supply Transformer

Transformers that only supply distribution load to a single customer.

Transfer

The amount of electrical power that flows across a transmission circuit or interface.

Transmission Customer

Any entity that has an agreement to receive wholesale service from the NGUSA transmission system.

Transmission Transformer

Any transformer with two or more transmission voltage level windings or a transformer serving two or more different customers.