THE STATE OF NEW HAMPSHIRE

BEFORE THE PUBLIC UTILITIES COMMISSION

PREPARED TESTIMONY OF

RICHARD C. LABRECQUE

Docket No. DE 07-___

PROPOSED DEFAULT ENERGY SERVICE RATE FOR 2008

Q. **Please state your name, business address and position.**

A. My name is Richard C. Labrecque. My business address is PSNH Energy Park, 780 N. Commercial Street, Manchester, New Hampshire. I am a Principal Engineer in the Regulated Wholesale Power Contracts department of Northeast Utilities Service Company (NUSCO).

Q. **Have you previously testified before the Commission?**

A. Yes.

Q. **What is the purpose of your testimony?**

A. The purpose of my testimony is to detail to the Commission the status of three improvement activities that PSNH agreed to as part of the Stipulation and Settlement Agreement reached in Docket DE 06-068 (2005 Stranded Cost Recovery Charge Reconciliation). In that docket, the Commission's consultant, Michael D. Cannata, made three recommendations regarding supplemental power and capacity planning. The settlement agreement required the Company to implement these recommendations and incorporate any resulting process changes into the Company's preliminary 2008 Energy Service rate filing.

Q. Please describe the three recommendations and the current compliance status.

A. 1. Monthly Forced Outage Rates

Mr. Cannata recommended that PSNH model monthly forced outages for its base load units rather than utilizing an annual rate based upon historical data.

Status: PSNH reviewed 2002 – 2006 monthly historical availability for Merrimack Unit 1 and Unit 2 and Schiller Unit 4 and Unit 6. A similar review for Schiller Unit 5 was considered unwarranted due to the significant modifications recently completed during the wood conversion. The results of the review are provided in Attachments RCL-1 through RCL-5. These attachments show monthly forced outage rates for each unit as well as months when planned major maintenance occurred. PSNH has concluded that there is no observable pattern that would suggest a particular monthly or seasonal estimate of forced outages would provide more accurate estimates of unit outages than using an average annual outage rate. Moreover, it does not appear from the data in those attachments that unplanned outages follow any particular pattern in the months following planned maintenance. In addition to the data review, the topic was discussed with PSNH Generation staff. Those discussions did not identify any qualitative factors that would suggest a particular monthly or seasonal pattern to unplanned outages.

While average monthly availability can vary widely from month-to-month resulting in relatively large swings in the amount of energy PSNH must replace from its base load units, PSNH does not procure firm bilateral energy contracts to hedge an assumed level of forced outages at the base load units. Differences between monthly forced outage rates are usually caused by unplanned outages lasting a few days. Those outages could occur at any time during the month. It would not make sense to purchase a strip of power for the month if the power was only going to be needed a few days of the month.

Moreover, even assuming that PSNH had a high degree of confidence that there was going to be an unplanned outage in an upcoming month, there is no way of determining which days an outage will occur, thus making it impractical to purchase power in advance in anticipation of an unplanned outage. When actual forced outages occur, PSNH evaluates the need for firm replacement contracts at that time based on an estimate of the length of time the unit will be out of service. When planning the power supply for the subsequent calendar year, the bilateral energy purchase targets are determined assuming the units are operating at full capability between planned maintenance evolutions. For rate forecasting, forced outage replacement power costs are included in the energy expense model as spot market purchases.

2. Planned Reliability Outages

Mr. Cannata recommended that PSNH specifically model the short, planned reliability outages of its base load units.

Status: PSNH has identified three routine maintenance evolutions that can be expected to occur in a specific month with sufficient certainty to warrant discrete modeling in power supply planning. These outage evolutions (listed below) have been factored into the Energy Service rate expense forecast.

i. Three (3) day outage for Merrimack Unit 1 in March of 2008 just prior to the Merrimack Unit 2 planned maintenance outage. The purpose of this outage would be to perform maintenance work to decrease the probability of a Merrimack Unit 1 forced outage during the Merrimack Unit 2 planned outage and to ensure that the Unit is in the best possible condition for the summer months.

ii. Three (3) day outage for Merrimack Unit 2 in late August of 2008 just prior to the Merrimack Unit 1 planned maintenance outage. The purpose of this outage would be to perform maintenance work to decrease the probability of a Merrimack Unit 2 forced outage during the Merrimack Unit 1 planned outage.

iii. Three (3) day outage for either Schiller 4 or 6 in December just prior to the winter period. The purpose of this outage would be to perform maintenance work to decrease the probability of one of the units experiencing a forced outage during the high demand months of January and February.

The specific work to be accomplished during these outages would be based upon assessed or known equipment or unit vulnerabilities at the time of the outage

3. Load Forecasting

Mr. Cannata's investigation recommended that PSNH develop alternative energy and capacity purchase plans based on 90/10 load forecasts using 10-year, 20-year, and 30-year historical weather data in addition to its 30-year average weather 50/50 load forecast. He also proposed that PSNH be required to analyze the differences between the purchase plans on a month-by-month basis and report to Commission Staff whether a 90/10 load forecast and/or a shorter than 30-year duration weather average forecast should be used. PSNH agreed to analyze the impact of a 90/10 load forecast on the Company's planning for supplemental energy purchases and to provide the results of the analysis to Staff and OCA.

Status: PSNH's base sales forecast for 2008 incorporates 30-year average weather data from 1977 – 2006. To assess the impact of more recent weather history, PSNH performed a sales forecast scenario using 10-year average weather input data (1997 - 2006). The base forecast results and the variances resulting from this weather scenario are provided in Attachment RCL-6. The attachment also notes the change in heating degree days (HDD) and cooling degree days (CDD) resulting from the switch from 30-year to 10-year average weather data. The final column of the attachment converts the monthly sales variance into an average hourly impact. This column can be viewed as the impact of the revised weather scenario on PSNH's supplemental power purchase requirement. At the bottom of the attachment, the monthly information has been grouped into four (4) seasonal averages. As shown, the impact on supplemental purchase planning is not significant. As additional information, Attachment RCL-7 is a graph of HDD and CDD data for Concord, NH since 1949. PSNH proposes to continue to use the base, 30-year sales forecast as the starting point for Energy Service rate forecasting and supplemental power planning. PSNH uses this base forecast for annual and longer-term purchase planning purposes. As the year progresses, PSNH regularly reviews the power supply strategy using more recent information (e.g. customer migration, generation unit performance and maintenance schedules). In addition, PSNH continuously monitors the near-term power supply plan (i.e. for the upcoming week) and makes adjustments to address abnormal weather and load expectations. PSNH will also continue to perform a comparison of weather trends using a more recent, shorter time frame than 30 years as compared to the 30 year trend. If, in the future, the data shows a significant variation, PSNH will assess whether it should modify its supplemental power purchase targets to address the weather-related exposure.

Note: PSNH did not perform any analyses of the impact of a 90/10 methodology (versus a 50/50 methodology) on supplemental power purchase planning. The "90/10" nomenclature typically refers to a peak hour demand forecast, e.g. ISO-NE performs both a 50/50 and a 90/10 review of the anticipated peak demand level for the upcoming year. The 90/10 result is considered to be an upper-bound with only a 10% likelihood of being exceeded. This concept does not easily translate into a monthly or annual GWH sales forecast. However, it would be possible to examine more extreme weather scenarios. For example, instead of using the average July and August cooling degree days over the prior 30 years, one could explore the sales variance resulting from using the single highest cooling degree period over the proceeding 30 years. The resulting sales variance would likely suggest a significant increase in the supplemental power purchase forecast. However, PSNH feels it is not appropriate to utilize such an approach in annual and longer-term planning. As noted above, PSNH believes short-duration weather abnormalities should be managed with short-term power supply purchases.

Attachment RCL-1: Monthly Forced Outage Rate Review

Annual Availability [excludes Planned Maintenance months]

	MK1	MK2	SR4	SR6
2002	94.02	88.91	91.31	95.55
2003	94.16	89.93	95.63	94.06
2004	96.37	89.28	94.11	95.20
2005	92.38	88.98	94.21	96.69
2006	89.35	94.79	95.90	92.27
5yr Avg.	93.26	90.38	94.23	94.75

Monthly Availability
[average from 2002 - 2006, excludes Planned Maintenance months]

	MK1	MK2	SR4	SR6
Jan	94.76	91.82	92.44	97.12
Feb	93.02	83.48	96.04	99.98
Mar	92.14	97.57	93.88	98.63
Apr	90.58	99.00	86.05	85.70
May	92.12	46.80	97.65	97.67
Jun	94.32	95.90	98.76	95.90
Jul	94.74	88.40	97.24	95.10
Aug	91.74	95.80	90.86	93.64
Sep	98.20	88.70	90.88	93.22
Oct	91.07	88.16	99.13	93.56
Nov	91.40	95.92	90.83	89.88
Dec	95.78	89.10	93.34	93.60

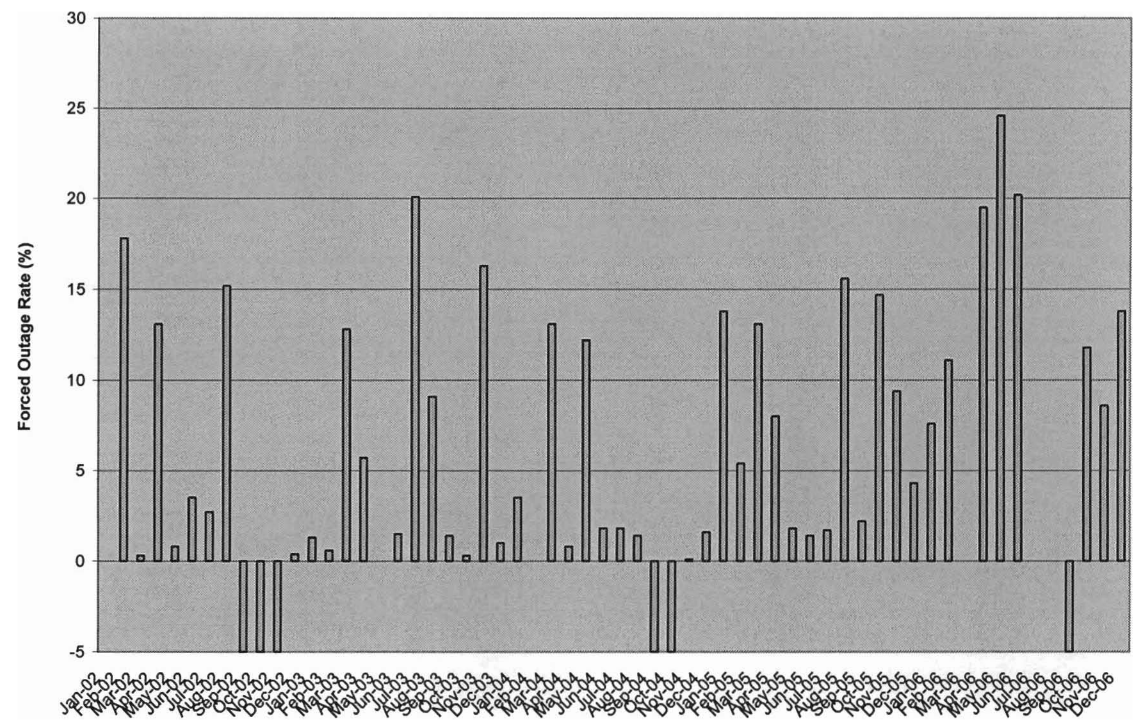
Monthly Availability (as percent of 5 yr avg. annual value)

	MK1	MK2	SR4	SR6
Jan	1.02	1.02	0.98	1.02
Feb	1.00	0.92	1.02	1.06
Mar	0.99	1.08	1.00	1.04
Apr	0.97	1.10	0.91	0.90
May	0.99	0.52	1.04	1.03
Jun	1.01	1.06	1.05	1.01
Jul	1.02	0.98	1.03	1.00
Aug	0.98	1.06	0.96	0.99
Sep	1.05	0.98	0.96	0.98
Oct	0.98	0.98	1.05	0.99
Nov	0.98	1.06	0.96	0.95
Dec	1.03	0.99	0.99	0.99

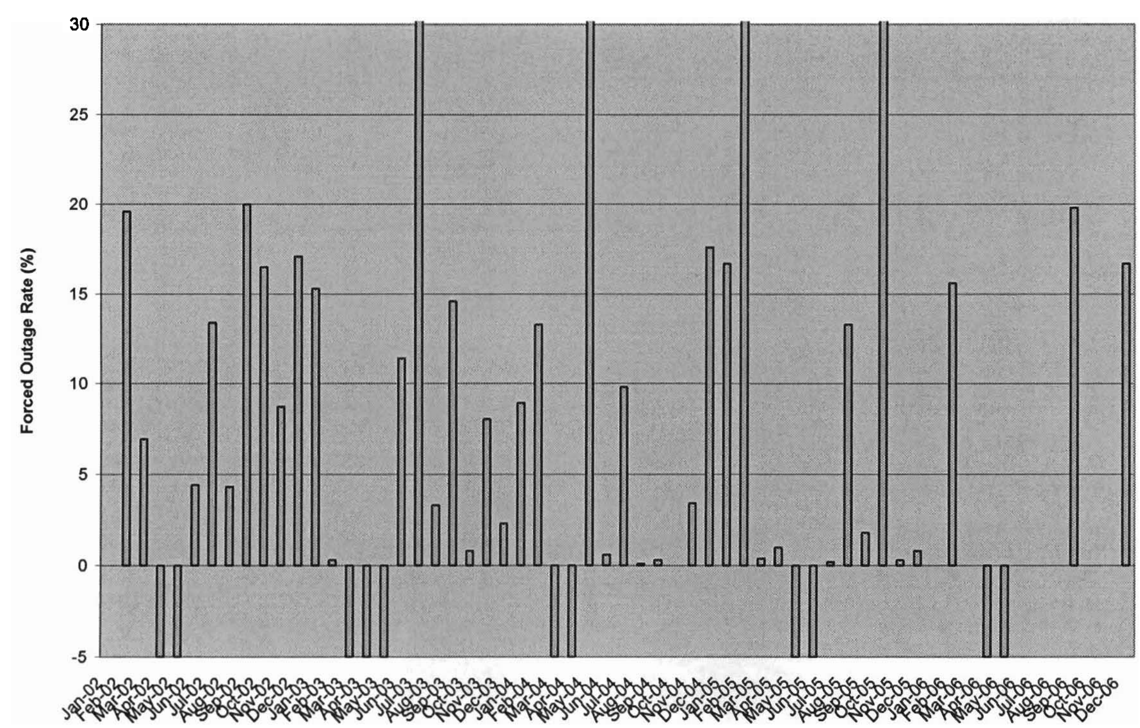
Note: the May value for MK2 is from a single data record (May 2004).
In all other years, MK2 was on planned maintenance during May.

Note: Attachments RCL-2 through RCL-5 provide the monthly forced outage rates during 2002 – 2006. Where the bar chart indicates an outage rate of negative 5%, that is meant to represent the months during which the unit was involved in a major maintenance evolution.

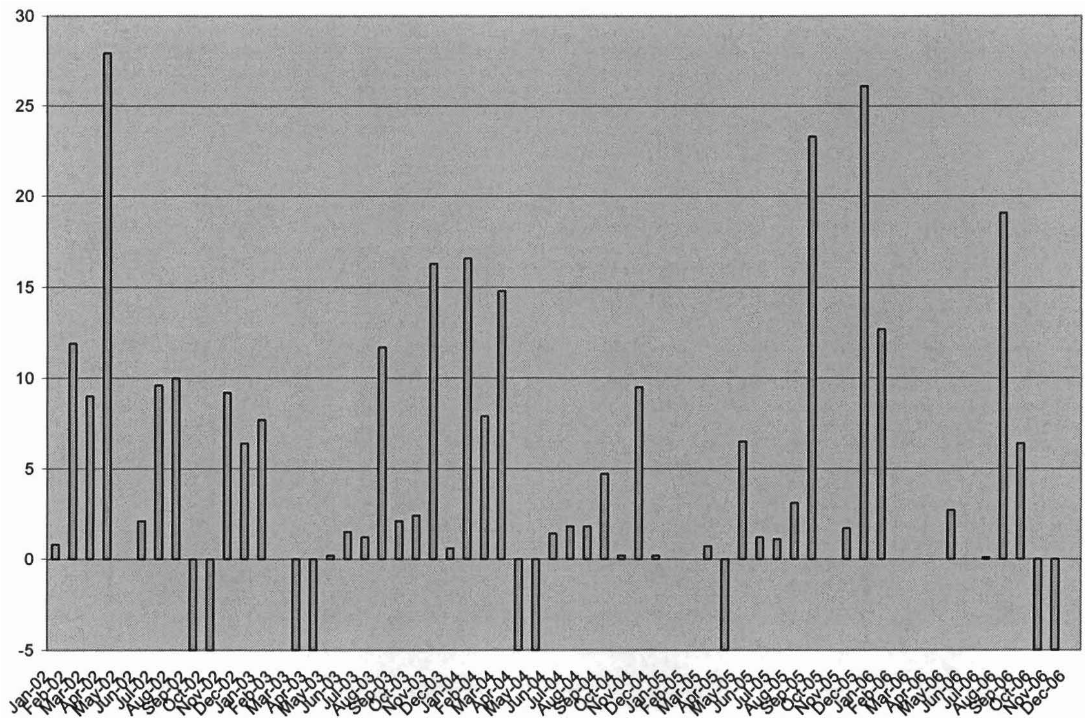
RCL-2 MK1 Monthly Forced Outage Rate 2002 - 2006



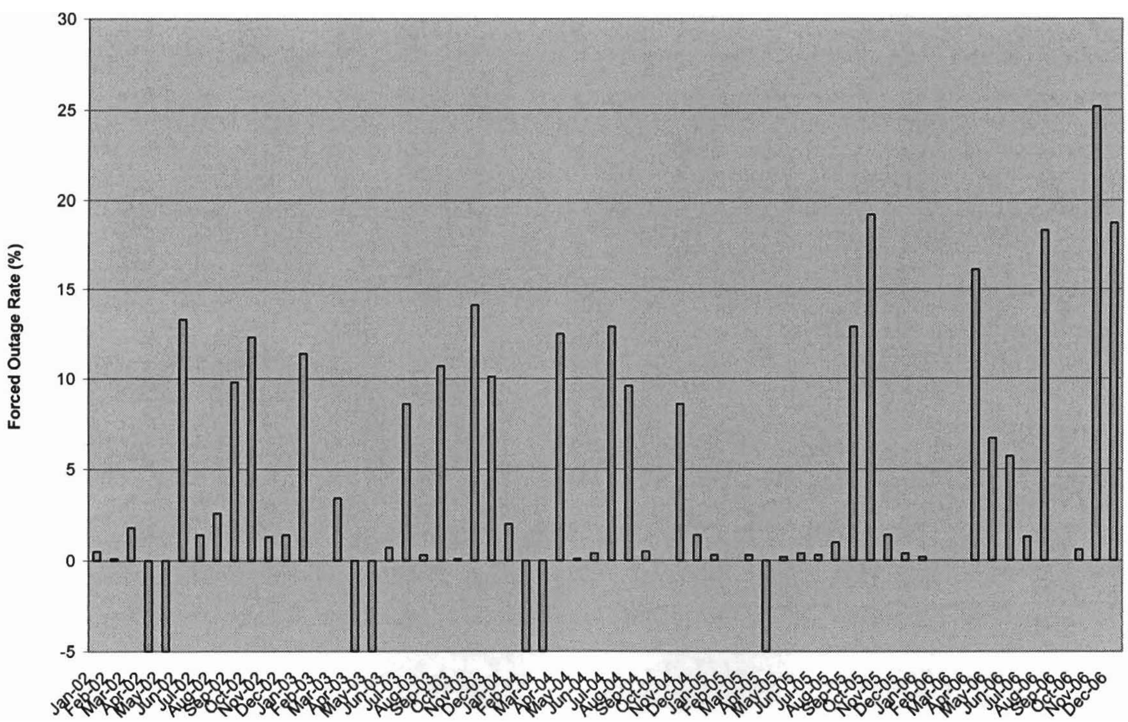
RCL-3 MK2 Monthly Forced Outage Rate 2002 - 2006



RCL-4 SR4 Monthly Forced Outage Rate 2002 - 2006



RCL-5 SR6 Monthly Forced Outage Rate 2002 - 2006



Attachment RCL-6: Load Forecasting

Sales Impact of 10-Year Average Weather (variance from 30-Year)

	HDD	CDD		Total Retail Sales Impact (GWH)	Avg Impact (MWH per hr)
January	-36	0		-4	-5
February	-69	0		-5	-8
March	-6	1		0	-1
April	-19	3		-1	-2
May	16	-8		-3	-4
June	1	21		18	25
July	-6	-3		-3	-3
August	-15	21		18	24
September	-62	5		1	1
October	-27	2		-1	-1
November	-52	0		-3	-4
December	-77	0		-6	-8
Total	**-352**	**42**		**11**	1
Jan, Feb, Dec	-182	0		-15	-7
Mar, Apr, May	-9	-4		-4	-2
Jun, Jul, Aug	-20	39		33	15
Sep, Oct, Nov	-141	7		-3	-1

Attachment RCL-7: Heat and Cooling Degree Day History