THE STATE OF NEW HAMPSHIRE

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October 24, 2008

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

RE: DE 08-066 Public Service Company of New Hampshire, Inc.
2007 Energy Service and Stranded Cost Recovery Charge Reconciliation

Dear Ms. Howland,

Attached please find the Original and six (6) copies of the Direct Testimony of Michael D. Cannata, Jr., P.E. on behalf of the Staff of the Public Utilities Commission.

If you have any questions please feel free to contact me.

Sincerely,

Suzanne G. Amidon
Staff Attorney

Attachments

CC: Service List via Email

STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

DOCKET NO. DE 08-066

IN THE MATTER OF:
PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE, INC.
2007 ENERGY SERVICE AND STRANDED COST RECOVERY CHARGE RECONCILIATION

DIRECT TESTIMONY

OF

MICHAEL D. CANNATA, JR., P. E.
SENIOR CONSULTANT
THE LIBERTY CONSULTING GROUP

OCTOBER 24,2008

Q. Mr. Cannata, please state your full name.

A. My name is Michael D. Cannata, Jr.

Q. Please state your employer and your business address?

A. I am employed by The Liberty Consulting Group (Liberty). My business address is 65A Ridge Road, Deerfield, New Hampshire 03037.

Q. In what capacity are you employed?

A. I am a Senior Consultant. In that role I am generally responsible for the review of energy utility engineering and operations management, practices, and procedures.

Q. Please describe your educational background, work experience, and major accomplishments of your professional career?

A. My educational background, work experience, and major career accomplishments are contained in Exhibit MDC-I.

Q. To what professional organizations or industry groups do you belong or have you belonged?

A. I am a member of the Institute of Electrical and Electronic Engineers and its Power Engineering Society, and am a Registered Professional Engineer in the State of New Hampshire (#5618). I served as a member of virtually all of the former New England Power Pool (NEPOOL) Task Forces and Committees except for their Executive Committee where my role was supportive to an Executive Committee member. I also

served as a member of the New England/Hydro Quebec DC Interconnection Task Force and the Hydro Quebec Phase Two Advisory Committee. These two groups designed the Hydro Quebec Phase One and Phase Two 450kV DC interconnections with New England. The various committees and groups that I have served on existed to address the functions now being performed by the Independent System Operator – New England (ISO-NE).

On national issues, I represented Public Service Company of New Hampshire (PSNH) at the Northeast Power Coordinating Council as its Joint Coordinating Committee member, at the Edison Electric Institute as its System Planning Committee member, and at the Electric Power Research Institute as a member of the Power Systems Planning and Operations Task Force.

While in the employ of the State of New Hampshire, I sat as a full member of the New Hampshire Site Evaluation Committee responsible for siting major energy facilities. At the request of the New Hampshire Public Utilities Commission's (NHPUC or Commission) Chairman, I sat on the State Emergency Response Commission. I was also a member of the former Staff Subcommittee on Engineering of the National Association of Regulatory Utility Commissioners.

Q. Have you testified before regulatory bodies before?

A. I have testified before the NHPUC in rate case, condemnation, least cost planning, fuel adjustment, electric industry restructuring, unit outage reviews, and other

proceedings, the Kentucky Public Service Commission in transmission siting proceedings, and have submitted testimony in proceedings before the Federal Energy Regulatory Commission (FERC). I have also testified at the request of the Commission before Committees of the New Hampshire Legislature on a variety of matters concerning regulated utilities.

Q. Please describe the areas that your testimony addresses today.

A. My testimony addresses four areas. Liberty was requested to review (1) the market-based capacity/energy planning performed by PSNH during 2007 that augmented its own generation to supply energy service (ES) to PSNH customers, (2) the outages that occurred at all PSNH generating units during 2007, (3) the 2006 outages that remained to be reviewed from Docket No. DE 07-057, the review of PSNH's 2006 ES and SCRC costs, and (4) the analysis performed by PSNH to evaluate the economics of proceeding with a biennial maintenance schedule at Merrimack-1. I also express my views regarding the availability and capacity factors of PSNH generating units for 2007, unit efficiency, and the adequacy of future capital and O&M expenditures for sound plant operations.

This testimony addresses the four review areas either through the questions and answers presented below or through a series of individual reports, which are attached to my testimony and are organized as follows.

Capacity/Energy Planning:

Exhibit MDC-2,2007 Capacity/Energy Planning

Generating Unit Outages:

Exhibit MDC-3, Merrimack Outages For 2007

Exhibit MDC-4, Newington Outages For 2007

Exhibit MDC-5, Schiller Unit Outages For 2007

Exhibit MDC-6, Hydroelectric Unit Outages For 2007

Exhibit MDC-7, Combustion Turbine Outages For 2007

Exhibit MDC-8, W. F. Wyman Outages for 2007

Exhibit MDC-9, T & D Caused Outages For 2006

Q. **Please summarize your capacity and energy planning testimony.**

A. Liberty reviewed the capacity and energy testimony filed by PSNH, conducted an on-site interview with knowledgeable personnel responsible for the capacity and energy planning function at PSNH, requested follow-up information, and reviewed detailed, backup information of the summary results supplied by PSNH. Liberty concluded that the capacity factor projections used for 2007 market purchases were reasonable and included ongoing discussions with generating plant personnel.With regard to capacity and energy planning, Liberty also concluded that the PSNH filing is an accurate representation of the capacity and energy purchasing process that took place in 2007, and that PSNH made sound management decisions with regard to its capacity and energy purchases in a market environment. . Liberty also observed that recent customer migration introduced additional volatility into future PSNH customer energy service needs because of the inability to plan purchases for unknown customer

decisions. PSNH has agreed to model changes in unit maintenance scheduling reflecting short, planned reliability outages beginning in 2008

Q. Do you have recommendations regarding capacity and energy planning issues?

A. Liberty's issues with PSNH's capacity and energy planning were brought to the attention of the Commission in Docket DE 06-068 and are being addressed in PSNH's energy service dockets. Most have been resolved; however Liberty remains concerned about the use of 50150 load forecasts based on 30 years of weather history. Because 50150 load forecasts produced from shorter weather-based time frames may produce higher loads in the summer and lower loads in the winter, an argument can be made that PSNH is over-buying in the winter and under-buying in the summer, a result of the 50150 load forecast. To the extent that spot purchases are required in the summer or sales into the market are required in the winter, some of that activity can be traced to the load forecast and its wisdom challenged. This issue needs further discussion and analysis.

Q. Please state the results of your review of the PSNH unit outages that occurred during 2007.

A. With regard to planned and forced unit outages, Liberty found that the base load units on the PSNH system ran well in 2007. In fact, PSNH units generally performed as or better than forecasted and again set new energy production records. Such output records are of note because, over time, unit operation has been complicated, or unit output has been reduced, by increased safety requirements dealing with confined

spaces, the addition of spray modules in the outlet canal at Merrimack, the reduction of the operating level of Unit 2 at Merrimack to reduce the likelihood of full load trips, the installation of supplemental electrostatic precipitators and selective catalytic reduction on both units at Merrimack, and the use of low-sulfur coal to comply with state and federal environmental regulations.

Liberty reviewed outage information, conducted on-site interviews, and submitted follow-up requests for information as necessary. In each instance except those noted below, Liberty found the outages to be reasonable and not unexpected for the particular unit and its vintage, or the outage was necessary for proper operation of the unit. Liberty also concluded that PSNH conducted proper planning and management oversight regarding these planned and forced unit outages. Based on Liberty's review of unit outages, it also has recommendations that it believes supports and elevates PSNH efforts in achieving additional improvement in unit operation.

Q. Which outages did you find unreasonable?

A. The first outage that Liberty believes to be unreasonable is associated with Ayers Island Outage I-E on 10/7/07 as identified in Exhibit MDC–6. This outage occurred because the operator added oil in the lower guide bearing without checking the oil reservoir in the sump as required by procedure. The unit tripped off line due to that high oil level. Oil was drained from the lower guide bearing and the unit returned to service.

Liberty recommends a disallowance for replacement power costs related to this outage as PSNH operators should have been aware of and followed established routine maintenance procedures. Operator inattention in this regard rises to a level above operator error.

The next outage is associated with the Schiller combustion turbine Outage A on 2/7/07 as identified in Exhibit MDC-7. The unit tripped on loss of gas supply. Investigation found that the main gas valve had been left in the closed position during the wood boiler gas supply job and not returned to its open position when the job was completed.

Liberty recommends disallowance for replacement power costs related to this outage. Good utility practice would review the lock out and tag out procedures performed at the beginning of a job and generally follow those procedures in reverse order at the end of a job to pick up switch, valving, or other system conditions that were placed out of configuration. Liberty believes that if such a practice was followed, the incorrect valve position would not have taken place.

The next outage is associated with the Schiller combustion turbine Outage H on 12/13/07 as identified in Exhibit MDC-7. The Schiller combustion turbine starts by its own primary air feed and has a back-up air feed from Schiller Station. The primary air feed compressor was out of service with parts on order. When called to start, the unit failed to do so. The Schiller Station air pressure used to be set to 500# but in

order to increase efficiencies and reduce losses, that pressure had been reduced to 250# which, while adequate for Schiller Station, is too low to start the combustion turbine unit from Schiller. PSNH has changed its procedures to increase air pressure at Schiller if that system is to be used to start the combustion turbine.

Liberty recommends that the replacement power costs relative to this outage be disallowed. The decision to reduce air pressure at Schiller Station either had no review or a review at such a level that the combustion turbine was not considered. Even a cursory review should have raised the question of adequate air pressure for starting the combustion turbine.

The next outage is associated with the Wyrnan-4 Outage I on 12/18/07 as identified in Exhibit MDC-8. The feed water heater became vapor locked during start-up and operations moved forward with loading the unit resulting in the trip of the feed water pumps on low suction pressure. Investigation found that the water level in the feed water heater was high prior to start up and that the operator was inattentive to the condition of the feed water heaters. To prevent this condition from happening in the future, an additional drain path was added to the heater that will allow normal level conditions to be established prior to unit startup.

Liberty recommends. that replacement power costs related to this outage be disallowed. While an additional drain was added to assure proper feed pump water level, this unit has under gone start-ups for 30 years. While normal procedure would

allow for the drains to maintain proper water level, the operator should have known that the feed pumps would trip with a high water level and monitored the water level as he proceeded during start up. The operator would have seen that the water level was not correcting itself, investigated the cause, and found the pluggage.

The last outage Liberty considers unreasonable is the Eastman Falls Outage 1L on 8/22/06 as identified in Exhibit MDC-9. The unit tripped due to low voltage at the Webster substation. Testing was performed on the transformer LTC at Webster and when the controls were tested, the test switch was left in the test position. The switch was moved into the operate position and the unit was returned to service.

Liberty recommends that this outage should be deemed imprudent. Liberty found that procedures were either not understood or followed by PSNH personnel. Liberty understands that there was no generation lost as a result of this incident and no economic impact to the generation dispatch. Liberty makes this recommendation for future guidance to PSNH personnel.

Q. In addition to your recommendations regarding the recovery of outage costs, you stated that Liberty had recommendations that it believes would aid PSNH in improving unit operations. Would you please present those recommendations now?

A. The first recommendation relates to Merrimack-2, Outage D on 5/23/07 as identified in Exhibit MDC-3. The unit was returning to service from its annual overhaul and the

outage was extended to remove debris from an internal system where the foreign matter exclusion procedure was in place during the outage.

Liberty recommends that PSNH review the foreign matter exclusion procedure and modify it to include a check for foreign materials at the end of each shift as well as the current end of job inspection because personnel are much more likely to remember materials they deal with during a shift. Liberty further recommends that when the unit is opened for maintenance, the senior crew person be required to sign off that all foreign materials have been removed prior to closing the unit. This would include a check for foreign material as far into the unit as reasonably possible. The modification should be implemented at all plants. Note: PSNH has informed Liberty that changes to the Merrimack foreign materials exclusion procedure have already been made.

Liberty also recommends that PSNH evaluate the use of a roving practices and procedure person during the outage to ensure that practices, procedures, and safety requirements are being followed per PSNH instructions. This may be accomplished by taking photographs during the outage for later evaluation and review. Liberty does not consider this a full-time position but rather an additional duty to senior PSNH plant personnel. Liberty believes that such an effort would reinforce and enhance PSNH's already strong safety culture. This practice should be implemented at all plants and is applicable for all outages.

The next recommendation relates to Merrimack-2, Outage ***G*** on 5/23/07 as identified in Exhibit MDC-3. When returning the unit to service from a long summer run, feed water flows were observed that were not consistent with other plant parameters. Investigation revealed that the feed water flow nozzle had become detached after 39 years of operation.

PSNH's major plants range from 34 to 60 years old and Liberty believes that PSNH should change inspection procedures accordingly. Liberty recommends that PSNH evaluate original equipment that does not have an inspection schedule and determine if and when such a schedule should be established. Liberty further recommends that PSNH evaluate equipment that does have an established inspection schedule and determine if that schedule should change with the aging of components. These recommendations apply to all major units.

The next set of comments relates to Canaan, Outage H on 8/6/07 as identified in Exhibit MDC-6. The unit tripped due to a line fault that was caused by insulators that broke off of a cross arm. PSNH stated that they performed a pole inspection in 2004, and an infrared inspection in 2008 revealed no other items requiring repair.

Liberty believes that these inspections are not comprehensive enough to identify problems of this nature. Based on this instance and other rot related problems that were identified in the outage reviews conducted by Liberty. Liberty recommends that PSNH not rely on aerial patrols alone for inspections of lines in a right of way and

that all lines in a right of way be inspected from the ground consistent with PSNH's revised NESC inspection program just getting underway as part of the Reliability Enhancement Program approved in PSNH's recent distribution rate case, DE 06-028.

The next recommendation relates to Eastman Falls Outage 1-C on 2/7/07 as identified in Exhibit MDC-6. The unit tripped due to a false operation of the lower guide bearing cooling water flow switch in the wheel pit area. The lower guide bearing cooling water flow switch activated because an operator was trying to unstick the wheel pit sump pump check valve causing flooding in the wheel pit. While trying to strike the submerged sump pump check valve, the pipe to which the lower guide bearing water flow switch is attached was struck as it is both directly adjacent to and above the check valve. The unit was immediately returned to service.

Liberty classified this outage as an operator error. Operators should be aware that sensitive electronics are playing a larger role in hydro unit operation and that if impact force is to be used, care should be exercised not to damage or disturb other components. If a particular check valve has a sticking problem, PSNH should consider moving it so that it may be unstuck without disturbing other systems and also exercise care in the placement of check valves. Liberty further recommends that PSNH conduct an informal survey to identify other areas that exhibit such potential.

The next recommendation relates to Schiller combustion turbine Outage E on 8/3/07 as identified in Exhibit MDC-7. The outage occurred due to configuration differences

between the location of the unit control switch and the voltage regulator control switch on the control panel at Schiller Station and the location of those same switches on the local control panel located at the combustion turbine. Although clearly marked, the unit control switch at the Schiller panel is located in the area where the voltage control switch is located at the rarely used local panel at the unit. The operator operated the wrong switch. Liberty considered the incident an operator error.

The switches are clearly marked but at the local control panel, the voltage regulator control switch is located where the unit control switch is located in the panel at Schiller Station. Liberty recommends that PSNH identify system 1 and system 2 locational problems at its stations to prevent operator errors in the future.

The next recommendation relates to Canaan Outage I on 8/12/06 as identified in Exhibit MDC-9. The unit tripped due to a suspected lightning strike in the area but no line operations were recorded. PSNH stated that they protect their equipment at 34.5kV by installing arrestors at the line terminals and at equipment locations.

Liberty accepts PSNH's statements regarding the lightning protection practices of northeastern utilities for 34.5kV in ROW. If these statements are accepted and no opening of the 355 34.5kV line took place, a lightning strike that occurred off the main line or one that occurred close to the main line induced its effects into the system and caused the unit to trip. Liberty recommends that PSNH check the

lightning protection in the area of the Canaan unit to assure that its practices will not result in lightning damage to the unit.

The last recommendation relates to Garvins Falls Outage **1-A** (Representative of many other similar outages) on 6/1/06 as identified in Exhibit MDC-9. The unit tripped off due to a lightning strike to the system even though all protective devices operated properly and within specified times. PSNH indicates that the unit could have tripped due to instability and Liberty is inclined to agree. PSNH also stated that distribution line relay over current settings at substations must be set with enough time delay to coordinate with multiple downstream devices and that they do not generally review the hydroelectric under-voltage relay settings when line protection settings are revised to provide coordination.

Liberty understands that there is a need to coordinate with new downstream devices and that when a downstream device is added, the upstream devices must have their timing settings increased in order to coordinate with the new device . Liberty further understands that failing to consider the impact of distribution system setting changes on hydroelectric units is a system-wide problem. Liberty recommends that PSNH set system protective settings in the future such that local generation is not impacted. In addition, Liberty recommends that PSNH review existing settings and do whatever is possible to minimize impacts to local generation.

Q. What was the result of your review of the unit availabilities and capacity factors of the PSNH units?

A. As stated above, the base load units have run well especially considering that many factors have tended to reduce unit output and lower performance metrics. Recently, PSNH has been extending the period between which long maintenance outages are performed on some of its units. Major overhauls are now conducted on different cycles, depending on the unit and its maintenance requirements.

Liberty made the following observations regarding capacity and availability factors with planned outages removed from the calculations so that the different maintenance schedules do not skew the data.

Schiller 4 and Schiller 6 availabilities generally run above 90 percent with capacity factors of approximately 80 percent and slightly increasing.

Unit 5 at Schiller had its boiler replaced in late 2006 with a wood-fired fluidized bed boiler. This unit has different characteristics than the old coal-fired boiler so Liberty makes no comparisons with historic operation. Liberty does note that the first full year of commercial operation had numerous startup and warranty issues which negatively impacted the availability and capacity factors for the unit. In spite of new unit difficulties, Schiller 5 had an approximate 85 percent availability and an 80 to 85 percent capacity factor for 2007. The closeness of the availability and capacity factors indicates that there were few forced outages of this unit.

Newington maintains an almost 100 percent availability. Its capacity factor has fallen from 60 percent in 2003 to 40 percent in 2005 and to 10 percent in 2006 and 2007. Its operating cost in relation to the market is the reason for the decline.

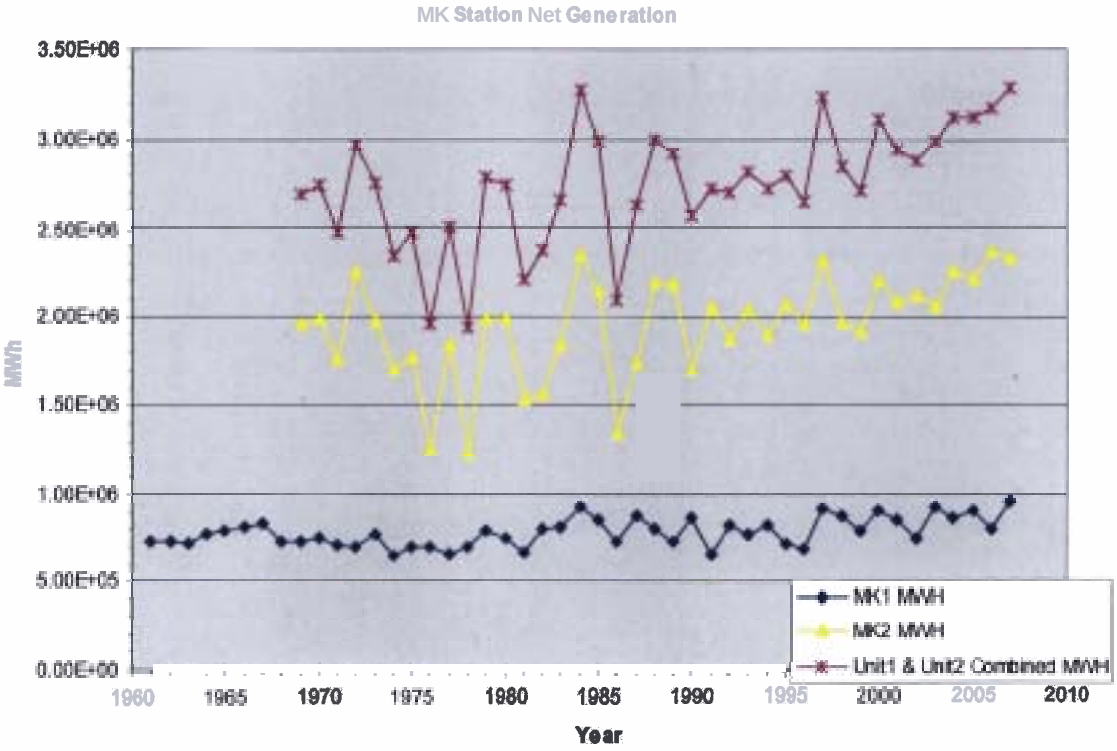
Capacity and availability factors for Merrimack-1 have historically run at approximately 90 percent. Since it went to its two-year maintenance schedule in 2002-2004, these factors have dropped closer to 90 percent or below in the non-outage years. Liberty understands that lengthening the maintenance cycle can bring savings because a major overhaul is eliminated in the two-year period. Those savings are eroded to the degree that the unit runs poorer without the over haul. 2007 was a non-outage year for Merrimack-1. The unit had only three short maintenance outages to clean air heaters which is necessary approximately every 3 to 4 months. Its availability and capacity factors for 2007 were above 95 percent.

The availability factor for Merrinack-2 has historically been approximately 90 percent. The historical capacity factor is about 85 percent. In the last few years including 2007, its availability factor has been 95 percent and its capacity factor has improved to over 90 percent.

Q. Are there other aspects of PSNH unit operation that you wish to comment upon?

A. Yes. I wish to comment on the efficiency improvements that have occurred over the recent past and what Liberty believes are the reasons for improvement.

PSNH's Merrimack units are operating at higher than historic capacity factors . The chart below shows that the total generation at Merrimack is on an increasing trend that began in the mid- to late 1990s. It also shows that there is less volatility to the annual output at the station. There has been an approximate 800,000 MWH increase in plant output sine the mid- to late 1990s, or about a one-third increase. That energy with a price differential to market of approximately $30/MWH brings an additional $25 million of customer benefit per year compared to historical values.



For various reasons, Liberty did not do a similar review of Newington Station or Schiller Station. Newington has been relegated to a peaking function in recent years and, as mentioned, the coal-fired boiler at Schiller Unit 5 was recently replaced with a

wood-fired boiler. Similarly, a review of the hydro stations could not be performed because of significant yearly variation in rainfall which has a direct impact on hydro production.

Given that the units are setting energy production records, Liberty believes that if similar reviews of Newington Station, Schiller Station, or the hydros could be performed on an equal footing, it is likely that similar results would be seen. PSNH now formally shares lessons learned with its generating plant personnel at all plants. That is, if a problem or a solution is found at a station, they are discussed at the regularly scheduled station manager meetings. It is up to the station managers to apply those concepts or lessons learned in a manner that improves their own areas of operation.

Q. In DE 07-057, the 2007 review of 2006 unit outages, Liberty recommended that PSNH analyze the costs and benefits of the reduction in the availability and capacity factors with the new two-year maintenance cycle in the market environment for Merrimack-1 and that it be reviewed in the next similar proceeding. What was the result of your review?

A. Liberty reviewed the 4/14/08 analysis performed by PSNH which it stated justified the current biennial maintenance schedule at Merrimack-1 versus the former annual maintenance schedule. PSNH developed assumptions for its analysis with data back to 1992. The study results showed the biennial maintenance schedule to be more economic. Liberty questioned the study results' validity because the data reflected

historical maintenance schedules, budgets, and operational practices that are different than those currently in use. In addition, PSNH tried to calculate additional savings using information from past time periods along with historic costs. Liberty asked that these deficiencies be rectified.

PSNH performed an additional analysis dated 10/16/08 which used data from 2001 through 2008. PSNH again tried to calculate past cost savings. This study also showed that the biennial maintenance schedule was more economic. Although PSNH made allowances for peak and off-peak conditions in its analysis, trying to recalculate the past still raised questions regarding the assumptions used which a) could cause one to question the validity of the results and b) missed the main point of Liberty's original request. The original request that PSNH perform an analysis resulted from a drop in unit capacity factor in the second year after a biennial outage that was observed when Liberty reviewed the 2006 PSNH outages in Docket DE 07-057. The request was that PSNH demonstrate how a biennial maintenance schedule versus an annual maintenance schedule was the economic choice, and not to calculate actual savings over some past period. Liberty requested that an additional simplified forward-looking analysis be performed.

PSNH performed the requested simplified analysis on 10/21/08 and used recent data for forced outages and costs to develop assumptions on a forward looking basis for the two maintenance schedules. The PSNH study found that the biennial maintenance schedule is more economic and would save customers $6.0 million net present value

(NPV) in 2008 dollars in replacement power costs and $19.7 million NPV in 2008 dollars in reduced maintenance outage costs over a ten-year period. PSNH projected that the second year forced outage rate would increase (with an accompanying decrease in capacity factor) by approximately 0.6 percent due to the lack of the annual outage in the second year. Liberty estimates from the PSNH analysis that the capacity factor of the unit would have to deteriorate by an additional approximately 17 percent in the second year following the biennial outage to be equivalent to the annual outage scenario from a customer cost perspective.

Liberty concluded that the decision to go to a biennial outage schedule for Merrimack-1 was an economic one and is in the best interest of customers.

Q. What did you form as a conclusion when you reviewed the projected spending for capital projects and O&M at PSNH generating stations?

A. Liberty reviewed the capital and O&M budgets for Merrimack Station, Newington Station, Schiller station, and the Hydro group and concluded that PSNH is spending and plans to spend sufficient funds for capital replacement projects and sufficient money for adequate maintenance to assure continued operation of its units with good utility practice and with recognition of their age.

Q. Are there any other items you wish to discuss?

A. I only wish to list the data responses relied upon by Liberty in preparation of its testimony in addition to the materials filed by PSNH and the interviews conducted so they may be officially admitted into the record. Those data responses are:

Liberty Set One

1-1, 1-2, 1-3, 1-8, 1-9, 1-11, 1-14, and 1-15

Copies of those responses have been included in Exhibit MDC-10 attached to my testimony.

Q. Does that conclude your testimony?

A. Yes, it does.

RESUME OF MICHAEL D. CANNATA, JR., P. E.

Michael D. Cannata, Jr., P. E.

Areas of Specialization

Investigations of safety, reliability, and implementation of public policy in the electric and gas industries; electric utility operations and planning; bulk power system planning; transmission system design.

Relevant Experience

The Liberty Consulting Group

- Lead consultant for Liberty's review of the transmission system of Nova Scotia Power for The Nova Scotia Utility and Review Board. Liberty's review examined (1) system maintenance, inspection, structural design, materials, staffing, and related matters, (2) system planning, operations, system design, lessons learned, and other matters, and (3) utility communications, call center operations, staffing, outage management system, lessons learned, and related matters after the collapse of multiple transmission lines in November 2004.
- Lead investigator reviewing the operation and outage of the fossil power plants of Arizona Public Service Company for the Arizona Public Service Commission.
- Lead investigator reviewing the operation and outage of fossil power plants of Duke Energy-Ohio for the Ohio Public Utilities Commission.
- Technical advisor in multiple proceedings to the Maine Public Utilities Commission, Vermont Public Service Board, Kentucky Public Service Commission, and the District of Columbia Public Service Commission regarding the public necessity and convenience for 345 kV, 230 kV, 161 kV, 138 kV, 115 kV, and 69 kV facilities.
- Advisor for the New Hampshire Public Utilities Commission in the merger of National Grid and Key Span and the sale of Verizon assets to Fair Point Communications.
- A lead investigator monitoring Commonwealth Edison's implementation of T&D system reliability improvement recommendations resulting from major system outages for the Illinois Commerce Commission.
- A lead investigator in the investigation of transmission grid security in Illinois after the August 2003 blackout for the governor's blue ribbon committee.
- A lead investigator in the in-depth root cause analysis of a fire at a major Commonwealth Edison substation for the Illinois Commerce Commission.

- Lead investigator of the reliability of the T&D systems of four electric utilities in Maine.
- Served as a lead investigator in the review of distribution and transmission practices at Alabama Power and Georgia Power Company.
- Served as a lead investigator in the review of distribution and transmission practices at Ameren Corporation's three Illinois utilities for the Illinois Commerce Commission.
- Served as lead investigator in prudence reviews of major fossil and coal plant outages of Duke Power-Ohio for the Ohio Public Utilities Commission.
- Served as lead investigator in prudence reviews of major fossil and nuclear plant outages for the New Hampshire Public Utilities Commission.
- Served as the principal technical and analytical member in the Seabrook nuclear unit sale team acting for the New Hampshire Public Utilities Commission.
- Investigated the causes of overlapping unit outages at a major Reliant generation facility.

New Hampshire Public Utilities Commission - Chief Engineer

- Managed a professional staff of engineers and analysts engaged in investigations regarding safety, reliability, emergency planning, and the implementation of public policy in the electric, gas, telecommunications and water industries.
- Prime architect of the settlement between the State of New Hampshire and Public Service Company of New Hampshire (PSNH) that ended years of litigation and allowed state-wide competition in the electric industry to proceed.
- Advisor to the Commission on utility system and operational issues.
- Decision-maker on the Site Evaluation Committee responsible for siting major electric and gas production and transmission facilities.
- Sat as decision maker at the New Hampshire Office of Emergency Management's Emergency Operations Center.
- Re-drafted the state's Bulk Power Siting Statute and facilitated resolution of widespread legislative tensions.
- Instrumental in achieving quality of service levels among the highest in Verizon's service territory.

Public Service Company of New Hampshire (PSNH)

- As Director - Power Pool Operations and Planning, PSNH
    - Responsible for the operation and dispatch of PSNH transmission and generation facilities through the New Hampshire Electric System Control Center.
    - Core participant in the merger/acquisition team activities culminating in the corporate reorganization of PSNH. Recognized and developed a successful employee retention program used during the acquisition.
    - Core Task Force Member for the DC electrical interconnection between Hydro Quebec and the New England Power Pool.
    - Developed real time integrated transmission system loading capabilities for the New Hampshire Electric System Control Center.

- Represented PSNH at all major relevant national and regional reliability organizations including:

  New England Power Pool
  - System planning Committee
  - System Operations Committee
  - All technical planning and operations task forces conducting regional and inter-regional studies and analyses

  Northeast Power Coordinating Council

  Joint Coordinating Council

  Edison Electric Institute
  - System Planning Committee

- As Director - System Planning/Energy Management, PSNH
  - Coordinated the company's capital planning requirements for generation and transmission. Integrated its load forecasting and energy management activities.
  - A lead participant in the development and implementation of response strategies addressing the negative financial impacts associated with the proliferation of non-utility generation.
  - Re-designed the corporate budgeting system to allocate available resources by economic and need prioritization.
  - Driving force in re-directing corporate economic evaluations towards competitive business techniques.

- As Manager - Computer Department and System Planning, PSNH
  - Responsible for the Engineering Division's computer applications support and transmission system planning functions.
  - Principal in the development, design and implementation of the first-in-the-nation application of 345134.5 kV distribution. Resolved daytime corporate-wide computer throughput logjam.
  - Integrated the Engineering Department's computer applications into the corporate computer organization.

Education

M.B.A., Northeastern University - 1975
M.S.E.E., Power System Major, Northeastern University - 1970
B.S.E.E., Power System Major, Northeastern University - 1969

Registration

Registered Professional Engineer - New Hampshire #5618

2007 Capacity/Energy Planning

Background

In 2007 and at summer ratings, PSNH owned approximately 528 MW of coal units at two stations, 409 MW of oil plants in two units, 67 MW of hydro plants from nine stations, 42 MW of wood-fired generation in a single unit, and 83 MW of combustion turbine plants in five units. PSNH also purchases 21 MW of nuclear capability from a single unit, 99 MW from various PURPA-mandated purchases, and 10 MW from IPP buyout replacement contracts. The PSNH portfolio totals approximately 1,258 MW of summer capability (1,315 MW winter). In addition, PSNH receives monthly capacity credits from the Hydro-Quebec interconnection. PSNH must meet its share of the ISO-New England monthly capacity requirement which ranged from 1,947 MW to 2,238 MW. The difference between PSNH resources and the Independent System Operator – New England (ISO-NE) monthly requirement must be made up by supplemental purchases. The market represented approximately 32 percent to 43 percent of PSNH monthly capacity requirements in 2007 and varied from 632 MW to 967 MW.

Due to customer migration, load requirements remained unpredictable to some extent in 2007. On 111, approximately 45 MW of PSNH large customers' load was taking market supply or performing self-supply. This load equivalent value rose in the months of February through March to 125 MW where it hovered until 611. From 611 through the end of July, large customers taking market supply or performing self-supply dropped to approximately 65 MW. From August through October, self-supply customers rose to over 140 MW. Starting in November, the quantity dropped to approximately 50 MW for the remainder of the year,

During 2007, the NU system employed 14 FTEs (full-time equivalents) in the Wholesale Marketing Department with 4.75 FTEs allocated to PSNH. The remaining 9.25 FTEs are allocated to the other two NU subsidiaries that do not have load-serving responsibilities. By function, 1.75 of the 2.00 Bidding and Scheduling FTEs, 2.00 of the 4.00 Resources Planning/Analysis FTEs, 0.50 of the 1.00 Energy and Capacity Purchasing FTE, none of the 2.00 Standard Offer and Default Service Procurement FTEs, none of the 3.00 Contract Administration FTEs, 0.25 of the 1.00 Administrative Support FTE, and 0.25 of the 1.00 Management FTE are allocated to PSNH. Since June 2003, PSNH has had on-site full time capacity/energy planning personnel.

PSNH retains load serving responsibility for customers who have not selected a competitive supplier. PSNH's monthly peak load in 2007 ranged from 1,074 MW to 1,599 MW, on-peak monthly energy ranged from 307 to 432 GWH, and off-peak monthly energy ranged from 262 to 380 GWH. The market supplied 10 percent to 57 percent of PSNH's monthly on-peak energy requirements and 13 percent to 37 percent of PSNH's monthly off-peak energy requirements in 2007. For the year, the market supplied 34 percent of PSNH's on-peak energy requirements and 20 percent of its off-peak energy requirements.

To meet its load responsibility, PSNH requires supplemental on-peak and off-peak (defined by ISO-NE as weekends, holidays, and weekday hours 1-7 and hour 24) purchases that change hourly and vary from 0 MW to 400 MW on-peak to 0 MW to 600 MW off-peak (plus reserves for capacity purchases) depending on the day of the week and month. Newington is not economic off-peak. Liberty considers these requirements to be "fixed" as they are based on no contingencies occurring but do include planned unit maintenance. These requirements are increased if any of the above generation is unavailable when needed to serve load or if loads are higher than planned due to variation in the weather or customer migration. Likewise, these requirements are reduced when loads are less than planned due to variation in the weather or customer migration. Liberty considers this portion of the energy supply to be "variable."

In general, PSNH supplemented its own generation with monthly, weekly, and daily bilateral purchases to meet the "fixed" portion of its supplemental on-peak requirements and used the ISO spot market combined with daily bilateral purchases to meet the "variable" portion of its supplemental requirements. The table below shows how PSNH's on-peak and off-peak energy requirements have been met by its own resources and the bilateral and ISO-NE spot markets. Of note is the increasing reliance on market energy generally due to load growth through time. Major unit outages that do not occur every year and actual weather can also alter these percentages.

Percent Supply of PSNH Energy Requirements from PSNH and Market Sources

	PSNH Owned Generation (Percent)		**Bilateral and Spot Energy (Percent)**	
	On-Peak	**Off-Peak**	**On-Peak**	**Off-Peak**
2004	83	90	17	10
2005	74	85	26	15
2006	67	80	33	20
2007	66	80	34	20

The following table shows how PSNH units and market purchases met PSNH's energy requirements for 2007.

Percent of PSNH 2007 On-Peak and Off-Peak Energy Requirements Supplied by PSNH and Market Purchases

	On-Peak (Percent)	**Off-Peak (Percent)**
Merrimack and Schiller	46	60
Hydro	4	5
Vermont Yankee	2	2
IPP's	8	10
Buyout Contracts	1	1
Newington and Wyman	6	2
Combustion Turbines	0	0
Bilateral Purchases	29	14
ISO-NU Spot Purchases	5	6

The following table depicts PSNH's historical market purchases and their source by percent.

Historical PSNH Supplemental Purchases and Source

	Sup. Purchases (GWH)	LT Bilateral (%)	ST Bilateral (%)	ISO-NE Spot (%)
On-Peak				
2004	900	52	22	26
2005	1,424	83	4	13
2006	1,815	85	10	5
2007	1,642	78	9	13
Off-Peak				
2004	431	0	33	67
2005	847	79	3	18
2006	1,106	79	***6***	15
2007	945	73	5	22

2007 Energy Market

In the first quarter of 2007, price volatility returned to the marketplace. Natural gas varied in price from $7 to $17 per MMBTU, and #6 oil remained stable at approximately $6.50 per MMBTU. These prices produced an on-peak bilateral energy market in New England that varied from $60 to $140 per MWH during the same time period.

Volatility fell in the second quarter of 2007. During that period, natural gas held fairly constant at $8 per MMBTU, and #6 oil rose from $7 to $8 per MMBTU. These prices produced an on-peak bilateral energy market in New England that generally varied from $60 to $100 per MWH during the same time period.

In the third quarter of 2007, the market remained relatively stable. Natural gas dropped to and held at approximately $7 per MMBTU, and #6 oil varied from $8 to $9 per MMBTU. These prices produced an on-peak bilateral energy market in New England that generally varied from $60 to $110 per MWH during the same time period.

In the fourth quarter of 2007, natural gas varied in price from $7 to $9 per MMBTU in October and November and spiked to $21 per MMBTU in December, and #6 oil rose from $9 to $12 per MMBTU. These prices produced an on-peak bilateral energy market in New England that generally varied from $60 to $80 per MWH during the months of October and November and spiked at $160 per MWH in December.

In 2007, PSNH relied on the market for approximately the same portion of its energy requirements coupled with its own sources as in 2006 because loads generally were lower than forecast and up to 125 MW of large customers met their energy needs from the market or self-supply. PSNH can therefore be susceptible to market volatility to a larger degree as its market requirements increase due to increased loads or customers returning to PSNH for energy service.

That market volatility would be expected to increase as ISO-New England loads and sources come more into balance in 2008 and beyond.

PSNH Supply Approach

PSNH has refined its approach to supply procurement each year as it has gained market experience. In the summer of 2005, PSNH continued to cover its position and purchased blocks of bilateral power for 2006 to bring stability to pricing and to limit potential under-recoveries in every month rather than just the peak months and months of unit outages as was done for 2004. PSNH also supplemented its bilateral purchases for July and August in June 2006. In addition, PSNH did more hedging in 2006 for both on- and off-peak load periods to better reflect the forced outage rates of the coal units. In 2007, as in other years, PSNH intended to establish a fixed annual energy service rate that is subject to minimal under- or over-recovery. PSNH established its monthly purchase targets in the first quarter of the year and made a series of purchases of bilateral energy through November to cover those targets. In addition, PSNH purchased short term bilateral energy to cover forced outages and the high load periods. All other energy was either procured from its own units or from the spot market.

In 2005, PSNH purchased 500 MW of its 2006 capacity requirement via an annual contract. The capacity market was scheduled to switch over to the new Forward Capacity Market (FCM) in October 2006, however, the switch over did not take place until December 2006. Uncertainty regarding the start date of the new FCM rules virtually precluded further capacity contracts after June 1, 2006. When the FCM transition period rules took effect in December 2006, each load serving entity was responsible for meeting its percentage of the total NEPOOL qualified capacity resources. NEPOOL qualified capacity resources are reduced by their individual forced outage rates (unforced capacity). The seasonal capability of PSNH units is also discounted for their forced outage rate to meet its percentage of the NEPOOL supply obligation.

The FCM took effect in December 2006 and was in full effect for 2007. Under those rules, PSNH is billed at the transition capacity rate of $3.05 per kW-month for its 5.79 to 6.22 percent share of the 33,196 to 37,417 MW of qualified unforced monthly capacity in ISO-NE or 1,947 to 2,238 MW per month less the value of its own resources. The ISO-NE transition rate produced a bill for $76.6 million for capacity and PSNH unit capacity produced a $48.8 million credit leaving PSNH with a $27.8 million capacity cost for 2007.

PSNH conducts biweekly phone calls with generating station, fuels, operations, and bidding/scheduling personnel. Plant personnel keep capacity/energy planning informed of impending developments at the plants. PSNH views Newington as the key unit on its system as all other owned units are hydro, coal, wood, or long-term resources that are almost always economic or must-take contracts. The net monthly on-peak energy requirements of PSNH were 38 to 176 GWH and their monthly off-peak energy requirements were 28 to 108 GWH. The incremental energy needs from the market are determined by the actual weather that occurred and actual unit operation, not forecasted weather in the energy forecast and forecasted unit operation.

PSNH covered major outages and known shortfalls by executing a series of monthly bilateral forward purchases from April 2006 through November 2006 for the January 2007 through December 2007 period. Monthly blocks of power were procured that closely matched the forecasted energy requirement. Additional monthly purchases were made throughout 2007 to address exposure and the reduced utilization of Newington.

Purchases were based on monthly analysis where PSNH modeled hourly forecasts by month including a hydro schedule, hourly load forecast, IPP forecast, and its own resources. PSNH modeled its own resources as follows: Combustion turbines and Wyman #4 were not modeled as they have extremely low capacity factors and the market price tends to mimic their cost when they do run. Coal units have planned outages specifically modeled and are derated to their annual forced outage rate for the periods in which they run. In 2008, PSNH began discretely modeling the short planned reliability outages. Newington costs were modeled as the projected market cost of oil corrected for SO_2 and NO_X calculations and at a full load dispatch rate. If the cost of Newington was lower than the blocks of power to be purchased, Newington was run as loaded for that block. The remainder of the energy requirements was supplied by the spot market.

The load forecast used by PSNH in determining purchase requirements is a 30-year average weather based forecast that uses weather statistics from the years 1972 through 2001. That is, the temperature would be expected to be exceeded every other year and the temperature would be expected to be lower every other year. The resultant forecast is called a 50150 forecast. PSNH has recently updated its weather data for its load forecast to be consistent with 1977 through 2006 experience. Because 50150 load forecasts produced from shorter weather-based time frames may produce higher loads in the summer and lower loads in the winter, an argument can be made that PSNH is over-buying in the winter and under-buying in the summer, a result of the 50150 load forecast. To the extent that spot purchases are required in the summer or sales into the market are required in the winter, some of that activity can be traced to the load forecast and its wisdom challenged. This issue needs further discussion and analysis.

Financial Transmission Rights (FTRs) are needed on-peak to protect against congestion pricing in the pool. In essence, one trades a known price for a potentially high variable congestion price. These rights are limited by actual system capability, function much like a hedge, and bring certainty to the price of generation with regard to congestion. FTRs are purchased between the major PSNH stations (Seabrook, Vt. Yankee, Mass. Hub, Merrimack, Newington, and Schiller known as the source locations) and the New Hampshire load zone (sink location). The table below shows PSNH's historical FTR purchases, their value regarding avoided congestion costs, and their cost to PSNH customers.

PSNH Historical FTR Costs and Savings

Year	Auction Cost (Thousands)	Avoided Congestion Costs (Thousands)	Net Savings/(Cost) (Thousands)
2003	414	488	74
2004	1,341	1,417	76
2005	777	896	119
2006	301	133	(168)
2007	973	1,133	160

During 2007, PSNH bilaterally purchased 1,435 **GWH** of on-peak energy and 733 **GWH** of off-peak energy. PSNH also spot purchased 207 **GWH** of on-peak energy and 211 **GWH** of off-peak energy. PSNH made two types of sales into the New England market. It sold 1.6 **GWH** of on-peak energy and 54 **GWH** of off peak energy from surplus generation from owned units that netted $0.4 million below cost. PSNH also sold unneeded bilateral energy on the spot market because loads failed to materialize as or when expected. PSNH resold 177 **GWH** of on-peak bilateral energy at a price of $71 per MWH and 195 **GWH** of off-peak bilateral energy at a price of $53 per MWH. These sales resulted in an $18.33 per MWH loss on the sale of on-peak energy ($3.2 million) and a $21.92 per MWH loss on the sale of off-peak energy ($4.3 million) for a total net loss of $7.5 million.

To provide certainty of cost and to limit potential under-recoveries, PSNH purchased most of its bilateral energy via fixed price contracts. PSNH purchased its 2007 energy in the months prior to the recent run up in the price of oil. In addition to market fluctuations, some of PSNH's largest customers, representing approximately 55 to 125 MW of load, signed contracts with retail suppliers (At a 70 percent load factor, the load loss translates to approximately 650 **GWH** annually or 23 to 65 **GWH** per month). Customer migration can swing annual supplemental purchases by 30 percent and by as much as 100 percent in the lower load months. Lower than forecasted sales and better than forecast generation of the PSNH base load units contributed to the excess of energy on the PSNH system in 2007.

Projected Unit Capacity Factors

The table below shows the historical capacity factors and the projected capacity factors used for the 200612007 period.

Actual and Projected Annual Capacity Factors for PSNH Major Units
(Annual Generation/Winter Rating/8760)

	Actual Capacity Factor - Percent							Forecasted Percent
	2001	**2002 (1)**	**2003 (2)**	**2004**	**2005**	**2006**	**2007**	**2007**
Merrimack-1	81.6	74.7	93.3 (3)	86.8	90.6 (3)	80.6	95.7	89.0
Merrimack-2	72.7	75.7	73.9	80.3	79.1	84.1	82.9	75.6
Schiller-4	66.5	65.4	73.9	73.7	76.5	71.1	84.2	75.0
Schiller-5	59.3	68.2	73.5	74.0 (4)	72.4 (4)	42.0(5)	76.7	77.6
Schiller-6	62.8	71.6	75.1	76.6	81.4	77.6	74.6	73.6
Newington	12.6	19.0	55.9	50.3	33.5	8.0	9.3	22.2

(1) - Seabrook not in PSNH mix for November and December.
(2) - First full year Seabrook not in PSNH mix.
(3) - No unit overhaul in this year.
(4) - Very minor outage this year due to wood conversion.
(5) - Coal to wood boiler conversion project.

PSNH based the 2007 projected capacity factors by explicitly modeling planned annual maintenance and consultation with plant personnel. Short-term planned reliability outages are not specifically modeled and are included in the overall annualized forced outage factor (PSNH began incorporating this change to its modeling in 2008). The table clearly shows that PSNH base load units performed better than forecasted.

Evaluation

Liberty reviewed the capacity/energy planning testimony filed by PSNH, conducted an on-site interview with knowledgeable personnel responsible for the capacity/energy planning function at PSNH, submitted follow-up data requests, and reviewed detailed backup information of the summary results supplied by PSNH. Liberty concluded that the PSNH filing is an accurate representation of the process that took place in 2007 and that PSNH made sound management decisions with regard to capacity and energy purchases in its market environment, but still questions the use of long term weather data in its load forecast. Liberty also concluded that the capacity factor projections were reasonable.

Merrimack Outages For 2007

The annual overhaul of MK-2 was the major work conducted at the station in 2007. That outage included tube replacement in both the hot and cold ends of the air heater. In addition to regularly scheduled outage activities, the outage was also used for the removal of shields and the installation of Oxystop on the vertical reheat super heater (VRSH) to increase temperature for improved turbine performance.

Merrimack-1

The following outages occurred at Merrimack-1 during 2007

A - (Outage Report #4)
3/22 – 3.5 days
The unit was scheduled out of service to perform maintenance items that had accumulated during its 107-day run and to increase confidence that the unit would be running during the scheduled annual outage of MK-2 scheduled in April. Work performed included the water washing of the air heaters and replacement of many of the circumferential seals which governed the critical path of the outage.

B - (Outage Report #8)
6/22 – 2.4 days
The unit was scheduled out of service to perform maintenance items that had accumulated during its 89-day run and to increase confidence that the unit would be running during the summer load period. Work performed included the water washing of the air heaters and inspection of all of the circumferential seals which governed the critical path of the outage.

C - (Outage Report #11)
9/20 – **3.4** days
The unit was scheduled out of service to perform maintenance items that had accumulated during its 81-day run. Work performed included a complete boiler inspection and the water washing of the air heaters and replacement of many of the circumferential seals which governed the critical path of the outage.

Merrimack-2

The following outages occurred at Merrimack-2 during 2007.

A - (Outage Report #2)
2/9 – 3.7 days

The unit was removed from service because of excessive water usage. A tube leak was found in the secondary superheater inlet pendant. PSNH repaired the tube leak and adjacent damaged tubes. Water tube leaks were also repaired in the cyclones.

Ultrasonic testing was conducted on the secondary superheater section of the boiler during the 2006 annual inspection and indicated thinning tubes due to ash corrosion. To address the entire tube issue in this section of the boiler, PSNH scheduled its replacement during the extensive turbine work and extended outage planned during in 2008. During the 2007 annual outage, PSNH scheduled enhanced inspections in the secondary superheater to maximize performance until the 2008 overhaul.

B
4/17 – 34.4 days
This planned outage was taken to perform the annual overhaul of the unit and was scheduled to last 32 days. The outage remained within approximately plus/minus 1 day of schedule and was slightly ahead of schedule until May 14, 2007 (day 27). Alignment problems with the new barrel in the Main boiler feed pump and hydraulic coupling placed it on critical path at this time. PSNH changed its start up logic to allow pre-start up testing of the turbine before the turbine was placed on turning gear gained almost a day and removed this activity from critical path. On day 28, the critical path turned to the vertical reheat superheater (VRSH) due the discovery of arc strikes the day before. The repair of the VRSH remained on critical path until startup when start up activities controlled the outage.

One of the major efforts during this outage was to install 5,280 hot air heater tubes and the remaining 6,280 cold air heater tubes. This project dictated critical path through day 22. Other projects included the removal of the temporary carbon re-injection silo and the installation of Oxy Stop in the VRSH section of the boiler. The Oxy Stop is a coating that has been recently developed (2005 to 2006) that when placed on boiler tubes, prevents ash buildup, corrosion, and erosion. PSNH has had these problems in these areas of the boiler and installed tube shields and cocoons at the comers of the tubes. These cocoons are like three dimensional "Us" and the shields in this area are 360-degree shields that were installed in the factory to protect the tubes. The cocoons are not welded in place as the geometry of the installation holds them in place. The tube shields had to be removed and boiler tube welding repairs made prior to the application of the Oxy Stop coating so that better heat transfer from the tubes would be possible. The heat transfer requirement is part of the unit turbine output increase project. There are 5 groups of tubes with 14 tubes in each group in the VRSH. The third group was completed on day 17, the fourth group on day 22, and the fifth group on day 23. Sandblasting on day 27 in preparation of the installation of the Oxy Stop revealed that there was arc strike damage to the tubes that occurred during the tube shield removal.

Arc strike damage occurs when the metals being welded are not properly grounded. In the case of the boiler, repair welds are made without using a ground wire as the boiler is solidly grounded. The arc strikes occurred between the shields that were press fit around the tubes and mechanically held in place and the boiler tubes. Removal of the shields first

or recognition of the poor ground at the cocoon would have resulted in no arc strike damage.

The arc strike damage had to be weld repaired and stress relieved because of the metallurgical properties of the steel used in this section of the boiler. The contractor's weld inspector originally called for a black light test of the weld repairs to assure weld quality but it is a very time consuming process that was adding time loss to critical path. The contractor weld inspector opted for a visual inspection and an additional vacuum test in its place on day 30. This decision was intended to speed up repairs. The comprehensive visual inspection conducted on day 31 revealed yet more arc strike damage. Those repairs were not competed until day **33.**

C
5/22 – 0.4 days
When returning from the annual outage (Outage B above), a generator voltage swing was observed indicating a phase imbalance. Investigation found one finger (or contact) in the potential transformer not making contact as it should. A proper signal was not provided to the voltage regulator. PSNH installed a spacer to readjust the reach of the contact finger and returned the unit to service. In addition, inspection of the contacts has been added to the annual planned outage work.

D
5/23 – 1.7 days
The unit returned to service from Outage C above. During startup, the flow through the main boiler feed pump (MBFP) was lower than expected and there was a leak at the end seals of the MBFP. PSNH removed the unit from service. Investigation found the remains of a rag in the MBFP recirculation valve which would account for the flow problem observed. The debris was removed and the unit was returned to service.

During the annual overhaul, the MBFP had a new barrel installed. The barrel is the internal rotating portion of the pump. The in-line MBFP discharge gate valve and the MBFP recirculation valve (Used to bypass flow during startup) were also refurbished during the outage. These are the only 3 points of the MBFP flow loop that were open during the outage. The discharge gate and recirculation valve work is accomplished by opening the valve in place and making necessary repairs. A rag left inside the valve would be easily noticed unless purposely left in place. The installation of the MBFP barrel required the removal of the pump and therefore resulted in a very large breach of the MBFP system. PSNH believes that the rag entered the MBFP system at this point rather than at either of the discharge gate or recirculation valves.

PSNH has a foreign matter exclusion procedure when openings are made to the internals of the unit. That procedure requires that all openings are to be covered when not working on it. PSNH stated that they interviewed the personnel that worked at these locations who stated that the exclusion procedure was in place and followed at these locations.

E – (Outage Report #7)
5/29 – 3.1 days
The unit was removed from service due to a tube leak in the economizer. PSNH found **3** tubes in the 21st and 3 tubes in the 22nd element with leaks. Prior to the repair, PSNH inspected the tubes in the area and performed ultrasonic testing to check wall thickness. The testing revealed that the initial tube failure resulted from the erosion of an original weld in one of the tubes in the 21st element. PSNH stated that this area of the economizer had been inspected and had non-destructive examination performed during the 2007 annual overhaul (also 2006) and all required repairs were made. PSNH also notes that 100 percent of the area cannot be inspected and that the coal ash encrusted on the tubes renders non-destructive examination less than 100 percent reliable. The necessary repairs were made and the unit returned to service.

F
6/2 – 1.0 days
ISO-NE required that MK-2 be taken off-line in load because of NE transmission constraints. It was Memorial Day weekend which is traditionally a time of very light loads requiring off-normal dispatch patterns and ISO-NE had taken this opportunity to do maintenance on transmission lines. In addition, the unit was not scheduled with the ISO for Friday or Saturday because of uncertainty with the timing of completion of repairs. Had the unit been scheduled and repairs were not completed to meet the schedule, penalties would have resulted.

G – (Outage Report #12)
9/24 – 10.2 days
The unit was removed from service to perform built up maintenance activities that accumulated during a 113-day run through the summer. PSNH took the unit down after MK-1 had completed maintenance repairs in Outage 1-C above. In addition to maintenance items, 16 water tube leaks were identified and repaired.

While operating on the start-up boiler feed pump for the boiler inspection during the outage, feed water flows were observed that were not consistent with other plant parameters. Boroscope inspection revealed that the feedwater flow nozzle that measures the feedwater flow had become detached. The nozzle is a nozzle shaped pipe welded to the inside of the pipe and is an original piece of equipment. The nozzle was calibrated, repairs were made, and the unit returned to service.

As a result of this incident, a program to inspect and replace other flow nozzles throughout the system was instituted. In addition, PSNH ordered a spare flow nozzle.

Evaluation (Except for MK-2B, MK-2D, and *2G)*

Liberty reviewed the outages above and found them either to be reasonable and not unexpected for these units and their vintage, or necessary for proper operation of the unit. Liberty concluded that PSNH conducted proper management oversight.

Evaluation of Outage MK-2B

The annual overhaul was in general a well run outage with one exception. That exception is the work performed on the VRSH which is reviewed in more detail below. Arc strikes to the boiler tubes occurred at a location away from work being performed because of a poor bond between the cocoons loosely fit over the boiler tubes to the boiler tubes. Liberty understands that boiler makers, unlike welders in a weld shop work year after year without the use of grounds because the boiler is solidly grounded and that is their normal work environment. In addition, Liberty's investigation found that instructions were given to boilermakers to note arc strikes that occurred during repairs. The procedure was followed at the area of repair, but the arc strikes that were unnoticed were remote from that location and not readily visible. Liberty concludes that procedures as then crafted across the industry would not capture the potential for damage at the locations where damage occurred. Therefore Liberty considered the incident itself an unfortunate error.

A second evaluation needs to be performed to determine if once known, if effective and correct action was taken to correct the deficiency. A comprehensive inspection of all VSRH tubes was not completed until Day 31, 4 days after arc strike damage was found. The inspection was executed in the same fashion as the shield removal process, in five sections. Each section had to have area staged, tubes spread, inspected, repaired, and stress relieved prior to proceeding to the next section. Liberty found that the inspection approach was a proper procedure.

Liberty further found that the remainder of the outage was conducted with proper management oversight and effectively managed.

Evaluation of Outage MK-2D

Liberty does not believe that debris would be purposefully left in either the discharge gate or the recirculation valve. In addition, it would be difficult to do from a physical standpoint because of clearances. Liberty accepts PSNH's assertion that its foreign materials procedure was in place. However, Liberty believes that there is a weakness in the foreign material exclusion procedure in that it appears to only cover the time period when work is not actively being performed.

Liberty recommends that PSNH review the procedure and modify it to include a check for foreign materials at the end of each shift as well as the current end of job inspection because personnel are much more likely to remember materials they deal with during a shift. Liberty further recommends that when openings to the unit are made, that prior to closing the opening that the senior crew person sign off that all foreign materials have been removed. This would include a check for foreign material as far into the unit as reasonably possible. The modification should be implemented at all plants. Note: PSNH has informed Liberty that changes to the Merrimack foreign materials exclusion procedure have been made.

Liberty also recommends that PSNH evaluate the use of a roving practices and procedure person during the outage to ensure that practices, procedures, and safety requirements are being followed per PSNH instructions. Liberty does not consider this a full-time position but rather an additional duty to senior PSNH plant personnel. Liberty believes that such an effort would

reinforce and enhance PSNH's strong safety culture that is already in place. This practice should be implemented at all plants and is applicable for all outages.

Evaluation of Outage MK-2G

Liberty agrees with PSNH remedial actions related to this outage but believes that PSNH needs further action to maximize potential benefit from this incident. Liberty believes that the subject incident results from normal plant aging. PSNH major plants range from 34 to 60 years old and Liberty believes that PSNH should change inspection procedures accordingly. Liberty recommends that PSNH evaluate original equipment that does not have an inspection schedule and determine if and when one should be established. Liberty further recommends that PSNH evaluate equipment that does have an established inspection schedule and determine if that schedule should change with the aging of components. These recommendations apply for all major units.

Newington Outages For 2007

Newington-1

No major capital projects for this unit were planned for 2007 except for the 2 week scheduled maintenance outage. For 2007, Newington's capacity factor was again in the 10 percent range as it was in 2006. For the years of 2003 through 2005, the unit's capacity factor has hovered from just below 40 percent to above 50 percent.

The following outages took place at Newington during 2007:

A
3/7 – 0.1 days
Newington had shut down at the end of February not expecting to run. In early March, a cold spell occurred which presented an opportunity where it was cheaper to run Newington than to buy power. On the cold start up, there was a problem with the operation of the solenoid on the low pressure fuel oil trip valve delaying the on line time of the unit. The problem was traced to a relay that was not operating properly which prevented the low pressure trip valve from opening. The relay was exercised a few times which corrected the problem and the unit was returned to service. PSNH scheduled the relay for replacement at a later time.

B
3/31 – 14.3 days
This outage was taken to perform the annual maintenance of the unit. There were no major issues like a turbine overhaul to address and the management of the outage was handled by local personnel. The internal schedule called for a 14 day outage and the outage lasted 14 days. The ISO window was 15 days. The critical path was the inspection and repair of the 6 largest electric motors. During this outage, both forced draft fans, both induced draft fans, and both circulating pump motors were sent out for a complete inspection and repair on an expedited basis. Dissimilar metal welds at the secondary super heater outlet had been a previous problem as they were original equipment and made on site. Such welds are now predominately factory made allowing for similar metal welds on site. 344 welds were inspected and 44 repaired.

C
8/1 – 0.2 days
During a full cold start up, the unit tripped due to low boiler drum level. Gas was used for start up fuel instead of oil because of price. Normally oil is used as gas is generally more expensive. An erratic drum level was observed. PSNH believes that boiling in the economizer may have been the reason and that steam bubbles percolated in the drum. The economizer was just cleaned making it more thermally efficient and gas bums further back in the boiler and therefore hotter. There are currently more cold start ups made with

the unit because of its low capacity factor. For the short term, PSNH requires the use of oil on cold start up regardless of price and is working with Alstom to resolve the issue.

D
1013 – 0.7 days
While performing the regularly scheduled bi-weekly testing of the unit, the fuel oil trip valve would not open preventing firing of the boiler (This is the same valve involved in Outage A above). Investigation by the manufacturer's representative found that there was a coordination problem between the Burner Management System (BMS) and a field device's position. Although all inputs and outputs were tested following a software upgrade that was performed two weeks earlier, the software had a coding error that allowed the simulation to work only once and it worked properly during testing. The error prevented operation once the unit returned to service resulting in the current outage. The logic was corrected and the unit returned to service.

E
12/10 – 0.1 days
The unit was down due to operation of the BMS air damper relay. In October, the BMS software had an upgrade installed. All inputs/outputs were tested and found okay at that time. On December 9, 2007, a second software upgrade was made to the BMS system and all inputsloutputs were again tested after that upgrade. PSNH found that a coordination problem existed during start up on the following day which was traced to a relay being in the wrong position. The incorrect position of the relay prevented the BMS system recognizing that the boiler was in the off position and that a purge was needed. PSNH performed a relay reset, and the problem was corrected.

The software upgrades were purposefully made in increments to limit any exposure to problems and to make troubleshooting more manageable if a problem occurred. The December upgrade could not proceed until plant personnel was convinced that the October upgrade was working properly. The relay wound up in the wrong position because non-standard mode tests were conducted. If the relay was in the standard mode, it would have defaulted to the correct mode. In the non-standard mode, the relay position was missed when manually restoring devices to their default position. PSNH stated that there had been a number of lessons learned from this software upgrade and that those lesson have been brought to the other stations including the 2008 upgrade at Merrimack.

Liberty attributes this outage to operator error. Liberty recommends that some form of an "off-normal position" check be instituted in these types of upgrade testing situations where and as applicable.

Evaluation for Outages A through E

Liberty reviewed these outages and found them either to be reasonable and not unexpected for this unit and it's vintage or necessary for proper operation of the unit. Liberty concluded that PSNH conducted proper management oversight.

Schiller Unit Outages For 2007

Unit-4 did not have a scheduled maintenance outage in 2007.

The major work at Unit-5 included the fall warranty/inspection outage. The major component and critical path was the replacement of 48 secondary super heater inlet tubes under warranty. Other targeted warranty work included the inspection and repair of the forced draft fan outlet silencer and the forced draft fan inlet ductwork.

Fly ash re-injection was stopped at Unit-6 in 2005 or 2006. Outages related to flow problems such as tube leaks have not developed since that time. Unit flow diagrams were studied by Advanced Combustion Technology and Reliant Engineering but nothing out of the ordinary was found.

Schiller-4

The following outages occurred at Schiller-4 during 2007.

A
1/20 – 0.5 days
The unit tripped when an induced fan motor lead failed. The motor representative found that the lead failed due to a failed crimp. The crimp was repaired and starts were minimized until the scheduled 2008 annual inspection. PSNH has purchased an automatic crimping tool to replace the older manual tool.

B
3/17 – 0.1 days
The unit tripped due to a master fuel trip. PSNH was clearing coal pluggages in both coal pulverizers. Pulverizer 4B was cleared and was in the process of securing the oil guns when the trip occurred. PSNH found that a valve had a faulty internal limit switch and did not send the burner management system a signal that it had closed. PSNH replaced the valve and the unit returned to service.

C – (Outage Report #5)
3/26 – 4.4 days
The unit was taken off line due to excessive water usage indicating a tube leak. A leak was found in the super heater. The leak was repaired and a hydro test was performed. Another small leak was found in the superheater and repaired. When a hydro test was performed, another small leak was found in the furnace area. That leak was repaired and the unit returned to service. Regarding the number of hydro tests conducted, Liberty notes that hydro tests are only valuable in finding leaks to a certain point, depending on

the nature of the leaks. When a leak or leaks is releasing significant amounts of water, it is difficult to look for moisture when everything is wet. This process sometimes becomes iterative in nature.

D
4/25 – 0.3 days
PSNH boosts city water pressure to 120# for its cooling water make up systems. The water line goes by the station service auxiliary power area. **A** 3 inch water pipe valve split and sprayed water into TB2 cables bus work area, the 115/13.8kV station service for Unit-5 and tripped the unit. Unit-4 and Unit-6 were on running station service at the time, but the electrostatic precipitators and the air compressors for these units were lost with the fault as they are fed off the same bus. Lack of particulate control equipment required PSNH to trip both those units also. PSNH used the 34.5kV system to restore station service. Unit-4 and Unit-6 were returned to service the same day and Unit-5 returned to service the next day.

PSNH states that the pressure in this system can vary from the normal city water pressure of 50# to as high as 150# when the booster pump starts. It was during a start of the booster pump that the valve failed. The vendor/supplier confirmed that the valve was rated for this application and pressure range; however, no conclusive results were obtained by inspection. The valve and piping in this area of the plant has subsequently been replaced with stainless steel piping.

E
5/7 – 0.2 days
The unit tripped due to high furnace draft pressure. PSNH found a blown fuse at the draft pressure switch. Further investigation found that there was a short at a crimp (butt splice) that is suspected to have blown the fuse. This was most likely a workmanship issue. The fuse was replaced and the wire was removed back to a "T" fitting where a non butt slice was made and the unit was returned to service. Instrument and control mechanics were instructed to avoid the use of butt splices unless necessary. PSNH has implemented this instruction at all of its plants.

F
7/10 – 0.0 days
The unit tripped due to pluggage of the coal pulverizer. The unit was operating on one coal mill and at minimum load per request of the ISO when the trip occurred. PSNH found a piece of tarp in the plugged coal mill that was the same color as the tarp that is used to cover the coal pile. This incident has been discussed with the coal pile operator.

G
8/31 – 0.1 days
The unit tripped due to the trip of the lube oil pump on the boiler feed pump (BFP) because of high DC voltage according to the variable frequency drive. PSNH's investigation could not identify a reason for the trip. PSNH is modifying all BFPs with similar systems to only use the variable frequency drive lube oil pumps during start ups

and shut downs with the BFP. During normal operation, a shaft driven lube oil pump will be used.

H
10/2 – 3.6 days
The unit tripped due to a severe rupture of a generator tube that damaged other tubes in the area. The tubes were repaired and the unit returned to service.

Schiller-5

Unit-5 became commercial on 12/1/06. Many of the outages that occurred in 2007 were related to warranty issues. Because the unit was commercial, all outages are discussed here. The warranty issues identified are noise in the ductwork, vibration in the ductwork, inlet air damper rebuild, ash handling hoppers in the bag house, erosion of superheater tubes, the main steam valve, and air heater separation of the tubes.

The wood boiler unit is considered a hybrid unit that uses a circulating fluidized bed. The circulating fluidized bed is made up of approximately 150 tons of material with enough forced air to give the bed the consistency of quicksand. The bed is required to be at a temperature of 1,350 °F to 1,550 °F. The bed material is sensitive to temperature. If bed temperature exceeds the higher limit, it can turn to silica and if it is lower than the lower limit, agglomeration (solidification and crusting of the bed or bed ash accumulation) takes place. Air flow, fuel quality change, and fuel volume flow are critical to bed status and temperature.

There are also approximately 1,400 air nozzles and silica material was causing pluggage.

The unit was expected to have a maturing process with expected capacity factors of 80 percent, 85 percent, and 90 percent for years 1, 2, and 3 respectively. The unit achieved a 78 percent capacity factor on 2007.

The following outages took place at Schiller-5 during 2007:

A – (Outage Report #1)
1/2 – 11.2 days
A wood feeder failure had occurred on 12/30. It is suspected that the bed started to crust at that time while the chain was repaired. PSNH lit the start up burner to maintain bed temperature. In addition, the bed ash drain plugged preventing ash from flowing out of the furnace ultimately causing the bed temperature to lower, loss of fluidization (slumping) and a master fuel trip. PSNH found vortex finders broken on 2 of the 6 cyclones and others were cracked. Poor weld workmanship by Alstom was the cause of the Vortex finder problem. The vortex finders were re-welded and strengthened at Alstom's cost.

B
1/18 – 1.2 days

The unit was taken off line due to a throttle valve flange gasket leak. The gasket was replaced and the unit returned to service.

C
1/31 – 0.2 days
The unit tripped due to loss of wood flow to the silos in the wood yard that feed wood to the boiler house. An ice/wood mixture plugged the emergency wood feed when it was activated. A contractor was responsible for management of the wood yard. As a result of this incident and to ensure fuel quality, PSNH now uses its own personnel.

D
2/4 – 0.1 days
The unit was taken off line when one fuel chute plugged. PSNH stabilized the fuel flow and restarted the unit. Alstom advised that the gas start up burner was not required to be put on for additional heat during this operation. PSNH believes that crusting of the bed began during this outage.

E – (Outage Report #3)
2/9 – 6.8 days
The unit bed temperature reacted erratically after returning to service from Outage D above. Load reductions were required and the boiler finally tripped due to a loss of furnace temperature operation. PSNH used residual heat to keep the unit on line but a plugged cyclone required that the unit be taken off line. While cleaning the cyclones, a broken vortex finder was found in cyclone #3. The bed was replaced and during start up, cyclone #5 again became plugged requiring removal of the bed and cleaning. No other cyclones were plugged. PSNH's investigation found that a piece of refractory from the lined cover had dislodged during the cover installation. PSNH now inspects cover refractory prior to cover installation and exercises additional care. In addition, a thorough inspection is conducted prior to closing the cyclones to ensure no debris remains. The new bed material was installed and the unit was returned to service.

F
2/18 – 0.1 days
The unit tripped due to pluggage of both feeders. The plugging of both feeders emerged when switching from inside wood supply to outside wood supply. Snow can be introduced into the wood supply causing a tendency to plug the feeders. PSNH has changed its procedures so that the wood yard operator is contacted prior to the change to the outside wood supply so that preparations can be made so that pluggage does not occur.

G
2/18 – 0.1 days
During start up from Outage F above, the unit tripped due to low steam pressure in the boiler. PSNH had shut off the gas start up burner per procedure and boiler pressure dropped as load was picked up. PSNH changed its start up procedures to run gas until the bed is stabilized during start up to avoid reoccurrence. In addition, the switch to outside

wood supply (Outage F above) provided a wetter wood supply. Alstom procedures did not recognize that wetter wood would impact bed temperatures and allowed the gas burner to be secured once wood flow was established.

H
3/11 – 0.3 days
Pluggage of the wood feeder caused a master fuel trip. PSNH tried to start the gas burner for additional heat but did not do so in time. The bed was protected from crusting in this event.

I
3/12 – 0.2 days
The unit tripped due to high cyclone temperature. A PC based system is used by operators for the unit. The operator intended to set the set point for 4 percent O_2 but inadvertently set the controller output to 4 percent. The controller was in manual mode at the time and when the air output was set at 4 percent, cyclone trip temperatures were reached when the forced draft fan backed down limiting air flow to the cyclones. PSNH says that the incident was an isolated one, related to the change in control systems from knob adjustment to mouse adjustment, and occurred during the initial start up of the unit. PSNH has reviewed the incident with all control operators.

J
3/18 – 0.2 days
A chain on the wood feed failed causing a master fuel trip. PSNH started the gas burner to stabilize the unit. Investigation found that the chain had insufficient lubrication as the chain guard did not allow for checking the chain or adding lubrication as designed. In addition, complete operating/maintenance instructions had not been received from Alstom. No procedure existed for inspecting and lubing the chain during operation as this was designed to be an off line task. PSNH redesigned the chain guard to facilitate lubing and has defined a weekly routine for mechanics to follow.

K
4/11 – 0.1 days
The unit tripped due to a master fuel trip that was caused by vibration of the forced draft fan. The fan vibration was caused by vibration of the inlet duct causing a piece to break off that went through the fan. This is a warranty issue that was taken care of by the contractor. PSNH verified the integrity of the ductwork and returned the unit to service. Thorough inspection and repairs were scheduled for the scheduled outage four days later.

L
4/15 – 7.8 days
The outage was planned to do scheduled maintenance. An outage list was developed jointly between PSNH and Alstom. Additional tears in the forced draft inlet duct were found requiring repair. Other work included the inspection and repair of the forced draft fan outlet silencer and the forced draft fan inlet ductwork, wood yard systems, and refractory inspections.

M
4/24 – 0.0 days
The unit tripped due to a master fuel trip caused by low boiler furnace pressure. There was a lot of work being performed and the trip could have been from a fuel change or from many of the work projects that were going on. PSNH never was able to determine the cause.

N
4/25 – 1.0 days
This outage was for the same reasons as described in Outage 4D above.

O
4/26 – 0.3 days
The unit tripped due to the failure of a 480V breaker. PSNH tried to rack the breaker and it tripped again. PSNH used a spare 480V breaker for the air compressor and returned the unit to service. The breaker was repaired by replacing the solid state trip device.

P
5/22 – 1.1 days
The unit was taken off line because of an air flow restriction. A cracked weld on a plate in the forced draft fan silencer. Repairs were made by welding and this problem is part of the overall vibration problem being encountered.

Q – (Outage Report #9)
6/22 – 6.7 days
This planned outage was taken to address to address many of the issues that had developed and to make ready for the summer load period. Activities included cleaning the tuyeres (Conical air flow devices on the bed floor) to address air flow limitation. Debris was building up on the inlet side of the tuyeres restricting air flow which in turn caused crusting of the bed. The slits in the tuyeres are extremely small and some of the debris was insulation from the failure of a section of duct silencer. The forced draft fan silencer and inlet ductwork was also inspected and repaired. In addition, PSNH has put into place a procedure to inspect and clean the tuyeres and ducts upstream to remove any debris that could cause pluggage.

R
7/23 – 3.7 days
The plant had a loss of fuel event on 7/22 and high cyclone temperatures were starting to be observed. PSNH was unable to start the gas start up burner and the unit was taken off line. By the time the unit was removed from service, the bed had crusted. Veins were found broken in the air damper which supervise the gas burner start with a full open indication. The permissive was not met. Weld repairs were made and the unit returned to service. PSNH has purchased a spare heavy duty damper and will install it at the next opportunity.

S – (Outage Report #10)
9/3 – 4.9 days
The unit was removed from service due to crusting of the bed material. A water box cleaning was in process to improve water discharge temperature. This is a standard process at Schiller station where load is reduced and one half of the condenser is cleaned. This is the first attempt to do so with the wood fired unit. With the wood fired unit the process is more complicated as the operator must reduce load, reduce fuel input, and remove sand from the boiler trying to maintain differential pressure across the bed. During this process the bed material temperature fluctuated outside of its temperature range causing the bed material problem. The bed material was replaced and the unit was returned to service.

PSNH has revised and enhanced the start up process to include the start up of the gas burner to assist with maintaining temperatures while the unit load and bed material is being adjusted.

T
10/20 – 16.7 days
This scheduled maintenance outage to repair the superheater inlet tubes, install a new forced draft fan silencer, perform inlet ductwork repair, and to rebuild the dilution air damper.

Schiller-6

The following outages took place at Schiller-6 during 2007:

A
1/12 – 3.6 days
The unit tripped off line due to a generator tube leak. Investigation found that an additional 7 tubes were damaged. The tubes were repaired and the unit returned to service.

B
2/19 – 2.1 days
The unit was taken off line due to excessive water usage. One leaking generator tube was found, repaired, and the unit returned to service.

C
6/6 – 36.6 days
This planned maintenance outage and overhaul ran just over 3 days longer than scheduled. Low NOx burners were installed and overhauls were performed on the low pressure turbine and the generator. Both the low pressure to generator coupling and the high pressure coupling were taken out and alignment problems were experienced when installing the low pressure coupling.

D
4/25 – 0.7 days
This outage was for the same reasons as described in Outage 4D above.

E – (Outage Report #6)
4/29 – 7.5 days
The unit was taken off line due to excessive water usage indicating a tube leak. Investigation found leaks at the generator tube to boiler drum rolls. 24 tubes in the drum were re-rolled. When a hydro test was performed, a small generation tube leak was discovered and repaired. A representative from EASCo Tool, the manufacturer of the tube rolling equipment was brought on site to ensure that the tube rolling equipment was functioning properly, that the rolling dies were correct, and that the tube rolling process was correct. The dies and processes were found to be correct. PSNH rolled all 240 generating tubes twice. Upon the next hydro, multiple leaks were found in the screen tubes. Four rolls of screen tubes were rolled. The unit passed a successful hydro, and was returned to service.

The unit runs at 1,350 # drum pressure. PSNH now only brings pressure up to 1,000# for non safety related leaks instead of 1,200#. Metallurgical specialists indicated that the 50 plus year old material is slightly less flexible than newer materials, and as a result is more difficult to obtain good roll results.

Drum roll leaks are usually not observed until pressure reaches 750# or higher. Once observed, even pin hole leaks spray a considerable amount of water suspending the hydro test and the making of repairs on known leaks.

F
5/8 – 0.0 days
While running at minimum load and on one coal mill and three of six burners in service, the unit tripped due to loss of flame. Vendor burner and emission testing was being performed at the time. Soot blowing was performed to facilitate the testing and having clean furnace walls. When soot blowing took place, the steam upset the flame pattern of one of the burners in service and tripped the bank of burners in service at the time. The unit was immediately returned to service.

PSNH states that it is normal practice to perform soot blowing at output levels of 50 percent to 75 percent and that there is no procedure to prevent soot blowing at lower loads other than to monitor steam conditions so that the unit is not starved for steam. PSNH has included in its procedure the monitoring of burner/flame operations. PSNH also shared the lessons learned with all operating crews.

G
6.6 – 3.9 days
The unit was taken off line because of excessive water usage. Investigation found 1 superheater tube leak plus 10 generation tube rolls into the steam drum leaks that were

repaired. Two additional hydros found 11 more generation tube rolls that had to be repaired. Repairs were made and the unit was returned to service.

H
6/18 – 2.3 days
The unit was taken off line because of excessive water usage. Investigation found 1 superheater tube leak plus 1 other tube leak and both were repaired. After repairs were complete, the unit was returned to service.

I
9/3 – 3.9 days
The unit was taken off line because of excessive water usage. Investigation found 2 generator tube leaks. Other tube work was performed in the economizer that showed wear. Repairs were made and the unit was returned to service.

Evaluation

Liberty reviewed the outages at Schiller and found them either to be reasonable and not unexpected for these units and their vintage or necessary for proper operation of the units. Liberty concluded that PSNH conducted proper management oversight.

Hydroelectric Unit Outages For 2007

The following describes the outages at PSNH's hydroelectric (hydro) units during 2007. The outage durations listed have been stated as the actual duration of the total outage regardless whether there was water to run the unit. Liberty indicates water availability by a "Y" or " Nnext to the outage designation.

Amoskeag Station

Major planned projects at this station included relicensing activities which included the mandated change of the operation of this peaking hydro station to a run of river operation. Amoskeag, Hooksett, and Garvins are all licensed by the Federal Energy Regulatory Commission (FERC) under a single license which was issued in May 2007. Construction of the minimum flow bypass gates to accommodate the newly required bypass flows and the portion of the dam that was to be resurfaced in 2007 was deferred to 2008 to accommodate agency consultation. **A** new pond control system for run of river operation was installed.

Amoskeag -1

A
1/29 – 0.23 days – N
This scheduled outage was taken to perform the annual inspection. The annual inspection was moved to G-2 when head gate leakage or debris in the 6 inch drain line for the water wheel scroll case would not facilitate draining. Attempts were made to blow out the drain line with compressed air and add more pumps in the scroll case, to no avail. G-1 was returned to service, and G-2 was taken off line for its annual inspection instead. The G-1 drain line was left open with compressed air going in continuously until the line cleared. This did allow the annual inspection to occur in July. (See Outage 1-E below)

B
2/23 – 0.16 days – N
This scheduled shut down was taken to replace contaminated oil in the lower guide bearing. The results of the yearly oil samples came back showing water in the oil. Seal leakage during the course of the year is suspected as the source of the oil contamination.

C
4/9 – 0.05 days – Y
This scheduled shut down was taken to install an uninterrupted power supply (UPS) for the voltage regulator and to change out the voltage regulator relay

D
4/11 – 0.02 days – Y

All three units tripped due to a cutout failure on the 312 line caused by animal contact. The switch (a privately owned switch at Nielsen Molding) opened automatically. The 312 breaker properly opened and reclosed twice.

E
7/23 – 4.25 days – N
The drain line had cleared allowing for the unit to undergo its scheduled annual inspection. A visual inspection, general cleaning, and equipment tests were performed and one wicket gate arm was replaced. Both the turbine and generator were inspected.

F
8120 – 0.09 days – N
The unit tripped line while operating on the new pond control system and was the only unit operating at that time. G-2 was started immediately by the ESCC. An inspection found a burnt coil in the device that indicates flow for the pond control system. The new pond control system selects units to run with various inflows and dam spillage in order to facilitate run of river conditions. A spare coil was installed the next day.

G
9/29 – 1.68 days – N
All three units were off due to scheduled substation maintenance, which included brown glass replacement in Eddy Substation. Hydro personnel performed maintenance items during this time.

Amoskeag - 2

A
1/30 – 2.99 days – N
The unit was taken off line for its annual inspection when the G-1 drain line was found plugged (See Outage I-A above). A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected.

B
4/9 – 0.04 days – Y
This scheduled shut down was taken to install an UPS for the voltage regulator and to change out the voltage regulator relay. Note – G-3 has a solid state exciter and does not need a UPS.

C
4/11 – 0.02 days – Y
All three units tripped due to a system problem. See Outage I-D above.

D
6/11 – 0.01 days – Y

While adjusting and testing the pond control system, the pond control system took G-2 and G-3 off line. The ESCC started G-1 and restarted G-2.

E
7/10 – 0.03 days – N
The unit tripped off line shortly after start-up due to low oil in the lower guide bearing. Another unit was put on line. PSNH inspection found that all oil levels were at the normal operating levels. All the units had been off due to low flows for several days and PSNH suspected that the low level alarm detected an intermittent condition as the lube oil system stabilized.

F
7/15 – 0.02 days – N
The unit tripped again due to low oil in the lower guide bearing. Another unit was put on line and the PSNH inspection again indicated that all oil levels were at the normal operating levels. The ESCC restarted G-2 and the unit ran fine. Because this event was similar to the event on 7/10, PSNH checked the switches and controls for the lower guide bearing and found that the mercury bulb had slid just enough so the contact would open intermittently inside the mercoid switch. PSNH made adjustments to the switch.

G
9/29 – 1.68 days – N
All three units were off due to scheduled substation maintenance. See Outage 1-G above.

Amoskeag – 3

A
2/5 – 3.17 days – N

The unit was scheduled off line for its annual inspection. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected.

B
3/18 – 0.15 – Y
The unit tripped due to a resistor failure in an over current relay. The resistor was replaced with a resistor with an acceptable value and the unit was returned to service.

C
4/11 – 0.02 days – Y
All three units tripped due to a system problem. See Outage 1-D above.

D
6/11 – 0.01 days – Y
The pond control system took the unit off line. See Outage 2-G above.

E
6/21 – 0.01 days – Y
The unit was taken off line by the pond control system. A sag in the river caused during the draw down of the Hooksett pond in order to install flash boards caused the units at Amoskeag to back off and shutdown via the pond control system. The pond control system correctly took G-2 off line, but the logic could not respond quickly enough to compensate for the increasing sag and then took G-3 off as well. PSNH is in the process of fine tuning and adjusting the pond control parameters and software for the various hydro conditions that exist throughout the year.

F
7/10 – 0.04 days – N
The unit tripped due to a high armature temperature alarm. The Resistive Temperature Device (RTD) for the armature temperature relay failed. The unit was allowed to be dispatched if necessary if an operator was present. PSNH changed over to a different RTD the next day as RTDs are imbedded in the windings and cannot be changed without a generator rewind.

G
9/29 – 1.68 days – Y
All three units were off due to scheduled Substation maintenance. See Outage 1-G above.

Ayers Island

Major projects at Ayers Island for 2007 included the installation of an inclined elevator for personnel access to the station and repairs to the trash racks. Inspection indicated that the trash racks should be replaced in 2008.

Ayers - 1

A
3/31 – 0.03 days – Y
All three units tripped on over speed as a result of the opening of the 3114 breaker at Pemigewasset substation. It was reported that a tree fell across the lines on the 3114X circuit that broke a cross arm and the current limiting fuse off the pole preventing its operation. The fault then required the 3114 breaker to operate. PSNH investigation found correct operation of equipment.

B
5/22 – 0.05 days – Y
The unit did not start upon ESCC command. PSNH inspection found that the governor lockout coil termination point was grounding out on its support point. PSNH adjusted the replacement coils and used a heavier Raychem insulation on the support post. PSNH

checked the two other units and the heavier insulation was installed on those posts. No other installations of this type exist at other hydro stations.

6/25 – 2.31 days – N
The unit was taken out of service for its annual inspection. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected.

D
10/1 – 4.58 days – N
The unit was scheduled out of service for maintenance on the TB-8 and TB-19 breakers and the TB-19 transformer in the Ayers Island substation. Lnsulating oil was tested, porcelains inspected and cleaned, and, TB-19 was disassembled, cleaned and filled with new oil. Some brown glass in the substation was also changed at this time.

E
1017 – 0.06 days – N
The unit tripped on a high oil level alarm/trip. The ESCC started another unit. PSNH inspection found a high oil level in the lower guide bearing. The normal sequence for filling and/or adding oil to the lower guide bearing is to check the oil level in the sump before adding oil to the tank. The oil system is gravity fed with the mechanical pump returning the oil to the upper oil reservoir tank. In this case, the operator did not check the oil level in the sump before adding oil to the tank as required by procedure. Two gallons of oil were drained from the bearing and the unit was returned to service. The operator was counseled and other operators were reminded about checking the oil level in the sump before adding oil to the tank.

Liberty is recommending that replacement power costs related to this outage be disallowed. Existing procedures identify a routine task that must be followed and was not. Operator inattention in this regard rises to a level above operator error.

Ayers - 2

A
3/31 – 0.01 days – Y
All three units tripped due to a system problem. See Outage 1-A above.

B
5/23 – 0.05 days – Y
The unit tripped due to high bearing temperature. PSNH found targets indicating high bearing temperature and low brake air pressure. PSNH checked and found that everything appeared to be normal; the bearing temperatures were 50 degrees on the lower guide, 46 degrees on the middle guide and 58 degrees on the thrust bearing and the brake pressure was 110 pounds. The unit was reset and returned to service.

The next day, using a newly acquired temperature calibration bath device, the capillary type temperature probes were found to be out of calibration and so adjustments were made to correct the temperatures. Similar probes on the other two units were checked and calibrated.

C
6/18 – 3.25 days – N
The unit was scheduled out of service for its annual inspection. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected.

D
1011 – 4.58 days – N
The unit was scheduled out for maintenance in the Ayers Island substation. See Outage 1-D above.

Ayers - 3

A
3131 – 0.02 days – Y
All three units tripped due to a system problem. See Outage 1-A above.

B
5/8 – 0.40 days – Y
The unit tripped on over speed. PSNH removed the electronic speed sensor probe and found loose wires internally on the plug which caused bad readings. The wires were repaired and the unit was returned to service. A new speed sensor probe was ordered and installed during the annual inspection.

C
5/14 – 4.53 days – Y
The scheduled annual inspection was to begin at 0700; however the unit tripped at 0345 due to a mechanical over speed sensor problem. The decision was made not to call in someone to fix the problem as the unit was scheduled for annual inspection later that morning. A new mechanical over speed sensor was installed. All three Ayers Island units now have new mechanical over speed sensors installed. The annual inspection included a visual inspection, general cleaning, and equipment tests of the unit. Both the turbine and generator were inspected.

D
5/29 – 0.01 days – N
The ESCC attempted to start the unit and the unit timed out on start chain sequence. PSNH found that the gate lock solenoid was bouncing causing the position switch to give an intermittent signal. PSNH adjusted the linkage arm on the position trip switch

mechanism and the solenoid and returned the unit to service. The other two units were checked and found to be okay.

E
10/1 – 4.58 days – N
The unit was scheduled out for maintenance in the Ayers Island substation. See Outage 1-D above.

F
10127 – 0.05 days – N
The unit failed to phase upon startup. A differential lockout device had operated and there was an incomplete sequence annunciator target. PSNH inspected the unit and found no problems. The protective devices were reset and the unit returned to service. Similar outages have not occurred and the cause of this outage remains unknown.

Canaan

Major activities at this station included relicensing studies, retaining wall repairs, de-leading the head works, and repairs to the penstock.

Canaan – 1

A
1/6 – 0.10 days – Y
The unit tripped off line due to a line fault on the 355 line in the area of Jordan Hill Road. A tree fell on the line and the fuse properly cleared at the same time as the unit tripped. There were no breaker operations on the distribution system.

B
3123 – 0.16 days – Y
The unit tripped off line due to the loss of the 355 line caused by a pole fire in Groveton. In order to extinguish the fire, the ESCC dispatcher de-energized the 355 line which caused the unit to trip

C
4/16 - 0.08 days - Y
Line faults on the 355 line caused by high winds caused the unit to trip off line twice during the stormy day on over speed. Liberty suspects vegetation contact was the outage cause. PSNH states that this right of way was scheduled to be maintained in August 2007 on its regular 5 year vegetation maintenance cycle. The right of way was maintained at the end of 2007 and the right of way was opened up to its full 100 foot width. In addition, PSNH states that the maintenance cycle trimming cycle has been reduced to 4 years.

D
4/16 - 0.81 days - Y

Same cause as Outage C above. After this second trip it was decided to keep the unit off line until the high winds subsided the next morning. Liberty suspects vegetation contact was the cause. Please see further explanation in Outage 1-C above.

E
4/21 – 0.12 days – Y
The unit tripped off line due to a line fault on the 355 line caused by high winds. OCR 355 tripped and reclosed causing momentary loss of voltage to the unit. Liberty suspects vegetation contact was the cause. Please see further explanation in Outage 1-C above.

F
5/10 – 0.08 days – Y
The unit tripped due to a line fault on the 355 line OCR 355 tripped and reclosed causing momentary loss of voltage to the unit. Liberty suspects vegetation contact was the cause. Please see further explanation in Outage I-C above.

G
6/18 – 25.22 days – Y
The unit was scheduled out for its annual inspection. A visual inspection, general cleaning, and equipment tests were performed. Emergent work included repair of the lower guide bearing and internal steel band repairs to the penstock. Both the turbine and generator were inspected.

H
8/6 – 0.01 days – Y
The unit tripped as a result of a line fault on the 355 line, near the Lost Nation Substation. During a thunderstorm, insulators broke off a cross arm causing the 0355 breaker to trip and reclose twice. PSNH states that the 10 year pole inspection was performed in 2004, and an infrared inspection conducted in May 2008 revealed no other items requiring repair.

PSNH states that ground line pole inspections are planned for lines in right of way beginning in 2009 and those annual inspections were performed from the air prior to the incident and that those inspections are in conformance to the NESC inspection requirement. In addition, PSNH states that rot problems are more visible from the air and that the personnel who perform these patrols are very skilled at identifying problems from the air.

Liberty believes that these inspections are not comprehensive enough to identify problems of this nature. Liberty offers proof in that this instance occurred, and that other rot related problems were identified in the outage reviews conducted by Liberty. Liberty recommends that PSNH does not rely on aerial patrols alone for inspections of lines in a right of way and that all lines in a right of way be inspected G-om the ground consistent with PSNH's revised NESC inspection program just getting underway as part of the Reliability Enhancement Program approved in PSNH's recent distribution rate case, DE 06-028.

I
8/25 – 0.16 days – Y
The unit tripped off line due to a line fault on the 355 line. There were thunder storms in the area. Liberty suspects vegetation contact was the cause. Please see further explanation in Outage 1-C above.

J
8/25 – 1.93 days – Y
Unknown to the ESCC, the unit tripped off line on Saturday evening due to a line fault on the 355 line. There were thunder storms in the area. Upon operator arrival for a routine inspection on Monday, 8/27, he discovered that the unit was off line. This was a second trip of the unit during the storm on 8/25, but loss of station service disrupted the paging system resulting in neither hydro personnel nor the ESCC having been notified that the unit was off line.

K
9/27 – 0.05 days – Y
The unit tripped offline due to a line fault on the 355 line. There were thunder storms in the area. The 0355 breaker at Lost Nation tripped and reclosed.

Eastman Falls

The major projects at this station for 2007 included partial resurfacing of the dam and paving of the lower parking lot.

Eastman Falls - 1

A
1/6 – 0.18 days – Y
The unit tripped upon phasing due to a failure to build up reactive power (MX). There was not enough time for the dispatcher to raise the MX before the unit tripped. There was a minimum differential current target. Due to the high river flows the unit was put on line locally and manually adjusted the MX. When the river flows subsided, PSNH adjusted the automation computer to allow a longer pulse when raising the MX. This action corrected the problem.

B
1/17 – 0.06 days – Y
The unit failed to phase when initiated by the ESCC due to a failure to build up reactive power. There was again a minimum differential current target. PSNH inspected the unit and associated equipment with nothing found. The unit was phased locally and again ran fine. Note - This problem was ultimately corrected as a result of Outage E below.

C
2/7 – 0.00 days – Y

The unit tripped due to a false operation of the lower guide bearing cooling water flow switch in the wheel pit area. The lower guide bearing cooling water flow switch activated because an operator was trying to unstick the wheel pit sump pump check valve causing flooding in the wheel pit. While trying to strike the submerged sump pump check valve, the pipe to which the lower guide bearing water flow switch is attached was struck as it is both directly adjacent to and above the check valve. The unit was immediately returned to service.

Liberty classified this outage as an operator error but cautions that operators should be aware that sensitive electronics are playing a larger role in hydro unit operation and that if impact force is to used, care should be exercised not to damage or disturb other components. If a particular check valve has a sticking problem, PSNH should consider moving it so that it may be unstuck without disturbing other systems and also exercise care in the placement of check valves. Liberty further recommends that PSNH conduct an informal survey to identify other areas that exhibit such potential.

D
2/21 – 0.04 days – N
PSNH responded to a high sump alarm in the lower guide bearing area, started the other unit and took G-1 off line to troubleshoot the problem. PSNH found a problem with the float switch (a cracked housing) on the auxiliary pump which was installed on 2/7 to help keep the pit drained of excess water in the pit due to broken bearing housing bolts. PSNH used a spare float switch of the same style to return the unit to service that day. The float switch was replaced with an updated style on 2/23.

E
5/14 – 0.21 days – Y
The unit failed to phase upon a start initiated by the ESCC due to a bad contact on the generator field rheostat. The contacts were cleaned and the unit was returned to service. PSNH has added the cleaning of the contacts on the rheostat to the shut down checklist for completion during the annual inspection.

F
5/25 – 0.08 days – N
The unit tripped on over speed when the ESCC took the unit off line. PSNH investigated the problem and included restarting and stopping the unit. Nothing was found and the unit was returned to service. No further similar incidents have occurred.

G
7/23 – 21.10 days – N
The unit was scheduled off line for its annual inspection. A visual inspection, general cleaning, and equipment tests were performed. In addition the lower guide bearing was replaced and new bearing housing bolts were installed to permanently address leakage and assure proper bearing clearance. Both the turbine and generator were inspected.

9/16 – 0.04 days – N
The unit failed to phase upon a start initiated by the ESCC due to low pond level. The pond level was being kept at one foot below dam crest for the dam resurfacing project, and due to low river flows both units were off line. As the flows increased, it became necessary to start G-1. With the headwater so low there was insufficient head pressure to start the unit on automatic startup. The responding operator was not familiar with starting this unit under low head conditions and called his supervisor who talked the operator through starting the unit manually under low lead conditions. PSNH developed and held training classes with all Central hydro operators to teach them the appropriate measures to be taken when starting this unit under low head conditions.

Eastman Falls – 2

A
2/7 – 0.29 days – N
The unit was scheduled to shut down to change the oil seal in the hydraulic pump. The unit was already offline due to low flows. The pump was removed and the oil seal was replaced.

B
2/19 – 0.50 days – N
The unit was taken off line due to a high oil level alarm in the hydraulic unit. G-1 was placed in service so no generation was lost. River water had leaked from the blade control mechanism into the hydraulic oil reservoir and mixed with the oil. The oil/water mix was removed and new oil added. The cause of the leak was not found and it is a reoccurring problem.

C
2/28 – 1.19 days – N
This was a scheduled shut down to further troubleshoot the runner control valve problem described in 2006 as Outage 2-J, 11/30/06. On that outage, Liberty said:

The unit tripped due to improper gate/blade correlation indication. The runner blades were not opening all the way while the wicket gates were. The hydraulic pumps, filters and transducers were all checked and nothing was found that would have caused this condition. The unit was restricted to 3.8 MWs. As soon as the river flow lowered, the unit was taken offline for inspection. GC&M completed troubleshooting the problem and found that an electrical control valve in the control scheme was defective. The valve was made in Germany and is obsolete, so PSNH had difficulty finding a replacement valve with the correct voltage. A custom replacement valve is on order. In the mean time, the gate/blade correlation indication has been removed from the tripping scheme and the unit output restriction lifted. The alarm function was maintained. Indication has been removed from the tripping scheme and the unit restriction lifted.

PSNH removed the valve and attempted repair, but it was still not working properly. Vendors were brought in to pursue replacing the valve. Airline Hydraulics found a new valve and manufactured the mounting plate for the new valve which will be installed during the 2008 annual inspection. Subsequently a representative from Rexroth Valve was on site on 3/20 to inspect the runner control valve. The representative felt confident that they could get a replacement valve and they will be working with PSNH to do so.

D
3/15 – 0.06 days – Y
The unit failed to phase after a start was initiated by the ESCC due to an incomplete sequence. PSNH investigation found that the set point for the phasing time was out of adjustment as well as the set point for minimum generation on phasing. PSNH adjusted the set points in the computer program for the start chain logic. E-Pro Engineering was contacted about the automation computer logic problem and they completed the automation computer software changes on 4/10 during Outage J below.

E
3116 – 0.07 days – Y
The unit tripped. Relay targets were gate-failure to respond, over speed, emergency governor trip, and various lock out operations. Upon inspection, nothing was found. PSNH believed the suspected cause was a bad sending unit from the gate latch or a bad wire causing the emergency governor trip that would require a several day outage to correct. PSNH found that the unit could operate and decided to operate it at a reduced output level to take advantage of the available water. The unit was restarted manually and set at 3 MW's. See also Outages F and G below.

F
3/17 – 0.06 days – Y
The unit tripped again at 1607 hours. Relay targets were the same as Outage E above. Upon inspection, nothing was found. PSNH still believed the suspected cause was a bad sending unit from the gate latch or a bad wire. The unit was again restarted manually and set at 3 MWs. See discussion in Outage E above and Outage G below.

G
3/17 – 0.03 days – Y
The unit tripped at 2050 hours with the same relay targets. Further troubleshooting found that the problem appeared to be a computer programming issue. The trip relay for the emergency governor trip was disabled until the problem could be fixed. Disabling the trip relay did not compromise the safety of the unit since other trip schemes were still active. E-Pro Engineering came to re-program the automation computer on 4/10 (Outage J below). The unit was returned to service.

H
4/3 – 0.10 days – Y
The unit was scheduled out of service to change water-contaminated oil and change the oil filters due to water infiltration into the lube oil/control oil. This is a reoccurring

situation that happens randomly (See Outage B above). During the October 2006 annual inspection (Outage H, 10/2/06), the nose cone was taken off to inspect internal linkages and equipment and check for any problems that could have lead to the water problem in the hydraulic tank. None were found. PSNH disassembled and inspected the Bestobell area and guide bearing and found nothing wrong. The drain pipe was checked with a borescope and it was not plugged. A pressure test of the Bestobell seal vent line was completed and the vent line tested OK. In addition, PSNH took special care when installing the new o-rings on the Bestobell seal during assembly, but water infiltration remains a problem. PSNH will address this issue during the 2008 annual inspection.

I
4/5 – 0.14 days – Y
The unit tripped due to low governor oil pressure. There were numerous voltage swings on the power lines due to the wet/heavy snow, which apparently caused the station service voltage to sag. The hydraulic oil pump current increased and caused the circuit breaker to trip due to overload. The unit tripped when the oil pressure got too low. The hydraulic oil pump circuit breaker was reset, checked, and the unit started and ran okay.

J
4/10 – .05 days – N
The unit tripped when the E-Pro contractor computer programmer reset the automation computer after completing the program changes needed to address concerns noted in Outage G above. The contractor had assured PSNH that the changes would not trip the unit and could be performed with the unit running. However, there was a software conflict between the automation computer program settings and E-Pro's "Administrator Status" identity (i.e., those authorized to make changes), which caused the new program to shut down and then caused the unit to trip when the new program was installed. G-1 was started and remained on-line while the computer work was being completed.

K
5131 – 0.07 days – N
The unit tripped due to a line fault on the 337 34.5kV line to Webster substation caused by a lightning strike. Please ***see*** discussion in Outage M below.

L
615 – 0.16 – Y
The unit tripped due to a line fault on the 337 34.5kV line to Webster substation caused by a lightning strike. Please see the discussion in Outage M below.

M
7/15 – 0.06 days – N
The unit tripped due to a line fault on the 337 line to Webster substation caused by a lightning strike. Eastman Falls generation is on a radial connection to the system through the 377 34.5kV line and is lost for interruptions to that circuit.

8/7 – 0.09 days – N
The unit failed to phase after a start was initiated by the ESCC due to a no turbine seal water indication. The unit had been off line for about a week due to low flows which allowed sediment to plug the seal water pipe from the river. The seal water source was switched over to city water and the unit was phased manually. The water pipe was flushed out on 818 and the seal water source swapped back to river water. Subsequent PSNH investigation found the solenoid stop valve was leaking by allowing silt to accumulate and cause a blockage. PSNH replace the defective valve and the problem has not reoccurred. Further, PSNH states that this design is unique to this unit.

O
9117 – 8.19 days – N
The unit was scheduled off line for its annual inspection. Besides the customary inspections, tests and repairs, the Bestobell seal was carefully inspected, a new seal was installed and the push plate was refinished. The nose cone was removed to check linkages to try to address the correlation issues between the wicket gate and turbine blades that the unit has been experiencing. A bent control link was found, which pointed to other items requiring additional future maintenance in the heavy control rod internal to the main shaft used to move the blades and wickets. Due to these findings, an extensive overhaul is planned for 2008. Both the turbine and generator were inspected.

P
11126 – 0.13 days – Y
The unit was taken off line due to a high oil level alarm in the hydraulic unit. River water had leaked from the blade control mechanism into the hydraulic oil reservoir and mixed with the oil. The oil/water mix was removed and new oil added. PSNH has not found the problem causing this water leakage but believes that the control rod problem noted during the annual inspection (Outage O above) may be causing this intermittent leakage.

Garvins Falls

Activities for 2007 included the replacement of TB-36 and associated civil construction work and the replacement of the station battery. In addition, a new pond control system was installed to adapt generation to run of river operation as required by the new FERC license.

Garvins Falls - 1

A
111 – 15.59 days – Y
This is the remainder of the shut down period reported last year as Outage 1-D and 1-E from 2006, which began on August 7,2006. As noted last year, this 2006 shut down was extended to replace the control rod and all 4 blades. As we have agreed to, the outage is included in the year in which the majority of outage time takes place. This outage was included in the discussion of 2006 outages.

B
1/16 – 0.12 days – Y
Shortly after starting up after the major overhaul activities completed in Outage **1-A** above, the unit was taken off line when an operator discovered a leak on the speed increaser gear case. **An** oil line tubing fitting leaked and was replaced and the unit was restarted.

1/19 – 0.01 days – Y
The unit tripped due to failure of the overload fuses on the lube oil pump. PSNH tested the pump and system and the overload fuses were replaced. The unit was returned to service without further incident.

D
4/16 – 0.02 – Y
The unit tripped off line due to a line fault on the 374 line in the Unitil system very close to Garvins Falls. Extremely heavy flooding caused power outages and multiple downed lines throughout the southern portion of the state. PSNH indicates that there were 3 instances of contact, but that only one caused a generator trip. Investigation found that voltage dipped sufficiently to trip the unit. Contact with vegetation is suspected.

PSNH reviewed the incident with Unitil and Unitil stated that their sub-transmission facilities are on a 5 year vegetation management cycle. The area in question was either cleared in 2005 or due to be cleared in 2007. All trimming in the area had been completed prior to the outage. Unitil stated that the tree causing the outage came from outside of the right of way.

E
5/21 – 0.07 days – Y
The unit tripped due to generator low oil pressure or flow. PSNH inspected oil levels and oil filter indicators and found all systems to be normal. The unit was restarted without incident.

F
5/22 – 0.03 days – Y
The unit again tripped due to generator low oil pressure or flow. PSNH again inspected oil levels and oil filter indicators and found all systems to be normal. PSNH replaced the oil filters as an effort to address the repeated relay operation. No further trips have occurred.

G
10/13 – 0.07 days – N
The unit tripped right after remote start up. The unit had not run in a long time due to the low flows. Targets and relay operations included lockout and loss of excitation. PSNH reset the targets and exercised the start chain by initiating three starts quickly in

succession while the unit was on local control. The start chain functioned correctly and the unit was retumed to service. No further incidents have occurred.

H
10120 – 1.44 days – Y
This was a scheduled shut down to facilitate brown glass replacement in the adjacent 34.5kV substation. During the outage, the site's black start emergency generator was operated to supply power to the station batteries and to run the portable sump pumps to keep the wheel pits from flooding.

Garvins Falls – 2

A
116 – 0.07 days – Y
This was a scheduled shut down to facilitate the safe lowering of the G-1 turbine into the station following the shop work which began on August 7,2006. Lowering the G-1 shaft assembly overhead into the facility required the roof to be removed and a quiet operating environment and care for overhead hazards, which could only be provided if G-2 was taken off line during the assembly evolution.

B
1/16 – 0.07 days – Y
This was a scheduled shut down to facilitate the safe startup of G-1 after the overhaul reported in 2006. With G-2 operating, the noise of the unit and the associated equipment made it impossible to hear if G-1 was operating correctly after start up.

C
3113 – 0.27 days – N
This was a scheduled shut down to inspect the inner shaft, the control rod and the seals in the servo head due to a banging noise that was heard on this start up. After removal of the servo and the inner shaft cover plate, the subsequent PSNH inspection found that the shaft was tight but that there was a minor oil leak from the servo. Two seals were replaced on the servo and the unit was reassembled and retumed to service. The banging noise was not heard.

D
10120 – 1.43 days – Y
This was a scheduled shut down for brown glass replacement at the 34.5kV substation. See Outage I-H above.

E
12/24 – 0.03 days – N
The unit failed to phase after a start was initiated by the ESCC due to a hydraulic control valve initially sticking on this start up. The unit was started manually and ran fine. PSNH suspected that weather may have been a contributing cause and states that the problem has not reoccurred.

Garvins Falls – 3

A
6/11 – 4.53 days – N
The unit was taken off line for its scheduled annual inspection. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected.

B
6117 – 0.07 days – N
The unit tripped due to high bearing temperature on a very hot day. PSNH found that all fans were operating and windows were open, but that the roof louvers were not all operating properly. Some louvers opened only half way and some did not open at all due to loosened clamp bolts on some louver control arms. The louvers were adjusted and loctite was used so the bolts would not come loose again.

C
6/27 – 0.07 days – N
The unit tripped due to high bearing temperature, and another unit was started. The temperature outside the station was 97 degrees and approximately 110 degrees inside the station. The louvers were operating properly and PSNH opened an overhead door to increase air circulation. An operator remained on site until cooler temperatures prevailed.

D
7/13 – 0.38 days – N
The ESCC received a No/Go alarm after the unit had been taken offline by the dispatcher due to decreasing flows. The lockout and reverse power relay operated due to reverse power just before shutdown. Since it was eleven o'clock in the evening and flows were decreasing, PSNH decided to wait until the morning to reset the alarms. PSNH inspection the next day found nothing wrong, the alarms were reset, and the unit was returned to service.

E
10120 – 1.42 days – Y
This was a scheduled shut down for brown glass replacement at the 34.5kV substation. See Outage I-H above.

Garvins Falls – 4

A
2/22 – 0.08 days – N
This was a scheduled shut down to replace water contaminated oil in the lower guide bearing which was found as a result of the yearly oil sampling. Slight leakage in the shaft seal area during periods of high flow accumulates in the lower guide bearing oil and the oil periodically needs to be changed.

B
2/28 – 0.10 days – Y
The unit tripped off line due to 3320 breaker failure in the distribution 34.5 kV substation. A brown glass insulator failure on the 03203 bus side disconnect switch caused all 6 bushings to fail on the breaker. The failed breaker operation properly opened all the breakers in the 34.5 kV substation as well as all the breakers in the 115 kV substation. G-4 was the only unit on-line at the time of the fault.

C
3/5 – 0.44 days – Y
This was a scheduled shut down by the distribution department to repair the failed 3320 breaker which caused Outage 4B above. The unit was taken off line and the black start emergency generator was run to supply station service to keep the station batteries charged.

D
7/16 – 4.15 days – N
The unit was taken off line for its scheduled annual inspection. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected.

E
10/20 – 1.42 days – Y
This was a scheduled shut down for brown glass replacement at the 34.5kV substation. See Outage 1-H above.

Gorham

2007 activities included replacement of large windows in the inlet building and license requirements in the recreational areas.

Gorham – 1

A
1/27 – 1.12 days – N
The ESCC took the unit off line initially as a result of a sag in the river caused by flow problems at the Brookfield Power stations upstream. Severe ice problems were developing which caused the upstream problems and ultimately kept the Gorham station off until 1/28 when the flow conditions returned to normal.

B
10/15 – 4.23 days – N
The unit was taken off line for its scheduled annual inspection. Routine maintenance and testing were completed. Both the turbine and generator were inspected.

C
10122 – 4.39 days – Y
This was a scheduled station shut down so that brown glass replacement in the 34.5kV Gorham substation could be accomplished. See also Outage 2-B, Outage 3-C, and Outage 4B below.

D
11/20 – 0.17 days – Y
This was a scheduled station shut down for safe removal of the 351 breaker in the 34.5kV Gorham substation. Due to the close proximity of all the 34.5kV bus and equipment at Gorharn substation, it was determined that the safest way to remove the old 351 breaker was to take a short station shut down. See also Outage 2-C, Outage 3-D, and Outage 4-C below.

Gorham – 2

A
10/15 – 4.23 days – Y
The unit was taken off line for its scheduled annual inspection. Routine maintenance and testing were completed. Both the turbine and generator were inspected. In addition, minor cavitation of the runner was weld-repaired.

B
10122–4.39 days– Y
This was a scheduled shut down for brown glass replacement at the 34.5kV substation. See Outage 1-C above.

11/20 – 0.17 days– Y
This was a scheduled station shut down for safe removal of the 351 breaker. See Outage 1-D above.

Gorham – 3

A
1/8 – 0.11 days – Y
The unit tripped off line due to a false over speed indication. PSNH inspection found no immediate problems and the unit was restarted. Subsequent to this event, a disturbance analyzer was put on the unit to monitor the controls and it recorded electrical spikes in the DC control circuit. Investigation found that the wicket gate DC solenoid actuator was inducing currents into the over speed device. Surge suppressing diodes were installed on the raise and lower coils in the governor actuator cabinet as soon as flows permitted.

B
7/23 – 17.21 days – N

The unit was taken off line for its scheduled annual inspection. Routine maintenance and testing were completed. Both the turbine and generator were inspected. In addition, the turbine bearing was replaced and the shaft was turned to accommodate the new bearing.

C
10122 – 4.39 days – Y
This was a scheduled shut down for brown glass replacement at the 34.5kV substation. See Outage 1-C above.

D
11120–0.18 days – Y
This was a scheduled station shut down for safe removal of the 351 breaker. See Outage 1-D above.

Gorham – 4

A
8/27 – 2.27 days - N
The unit was taken off line for its scheduled annual inspection. Routine maintenance and testing were completed. Both the turbine and generator were inspected.

B
10122 – 4.39 days – Y
This was a scheduled shut down for brown glass replacement at the 34.5kV substation. See Outage 1-C above.

C
11120–0.18 days – Y
This was a scheduled station shut down for safe removal of the 351 breaker. See Outage 1-D above.

Hooksett

Activities in 2007 included a major overhaul of the unit including replacement of all the wicket gates, a generator rewind, and cleaning and inspection of the rotor. In addition, a new pond control system was installed to adapt generation to run of river operation as required by the new FERC license.

Hooksett – 1

A
2/28 – 0.03 days – Y
The events surrounding this outage are the same as those described in Garvins Falls Outage 4B above.

B
415 – 0.04 days – Y
Cutout 335FX2 flashed over during a heavy snow and ice storm and did not open. This misoperation caused the operation of the 332 breaker at Garvins and the 335 breaker at Rimmon and reclosed. The Hooksett unit was not able to be restarted until the fault was cleared and switching was completed.

C
7/15 – 0.06 days – Y
The unit tripped off line due to a line fault on the 3321335 line due to lightning in the area. The 3320 breaker at Garvins and the 335 breaker at Rimmon tripped and reclosed properly. The momentary loss of voltage caused the unit to trip.

D
816– 123.33 days – Y
The unit was taken out of service for its scheduled annual inspection and overhaul. All wicket gates were replaced with new ones with greaseless bushings, the generator was fully rewound, the stator was cleaned and the power leads from the generator to the GSU were replaced. Extensive repairs to the inlet racks and routine maintenance, cleaning and testing were also completed.

E
12/13 – 0.02 days – Y
The unit was scheduled out of service to troubleshoot a harmonic noise noticed during the start up from overhaul described in Outage D above. PSNH and the rewind contractor investigated by monitoring the noise during roll-up, full speed at no load, and phased on line. It was determined that the noise was a low harmonic, most noticeable far below synchronous speed, and was of no operational concern. PSNH plans no follow up action.

Jackman

Major projects for this station in 2007 included the replacement of 1,100 feet of wood stave penstock with fiberglass, electronically operated flood gates, and re-insulation of the generator.

Jackman-1

A, B, C, D, E, F & G
4/5 – 0.12 days total – Y
Numerous line faults and breaker operations caused by an extremely heavy snow storm caused the unit to trip off line repeatedly during the course of 8 hours. Not all disturbances could be specifically identified. Those that could be identified indicated that the 3140 breaker tripped and reclosed twice and the 314053 voltage sensing switch opened to isolate the fault resulting in a unit trip. PSNH found that all operations were correct.

H

6/2 – 0.06 days – Y
The unit tripped off line on over speed due to a line fault on the 313 line caused by lightning in the area.

I
6/11 – 0.06 days – Y
The unit tripped due off line to a line fault on the 3140 line caused by a tree which damaged a pole top insulator. This failure caused the 3140 breaker to trip and reclose twice and the 3140J3 voltage sensing switch to open and isolate the fault resulting in a unit trip. PSNH found that protective equipment operated properly.

J
8/20 – 72.38 days – Y
The unit was scheduled out of service to replace 1,100 feet of wooden penstock with new fiberglass pipe. In addition, five pieces of warranty pipe from the work performed in 2005 were replaced and the generator windings and stator were cleaned and reinsulated. The annual inspection was also performed during this period. Both the turbine and generator were inspected. The thrust bearing babbit was found to be partially de-laminated. While purchasing a new replacement Kingsbury-style bearing was discussed, it was decided to refurbish the original GE-style bearing since it had a good service life and the cost and scheduling difficulties of manufacturing a new Kingsbury bearing (14 weeks from order date) would have extended the outage.

K
11/2 – 0.00 days – Y
The unit tripped off line due to high thrust bearing temperature. As noted in Outage J above, the original refurbished thrust bearing had been installed. It was noticed that the refurbished bearing was running hot. After inspecting the oil systems and finding no problem, it was decided to run the unit at a reduced load (2.4 MW) until the hot running issue could be resolved. The pondage available at Jackman assured no generation would be lost.

L
11/8 – 11.25 days – Y
The unit tripped off line at reduced load, again due to high thrust bearing temperature. PSNH inspection found that the newly refurbished thrust bearing that was installed during Outage J was damaged due to the overheating. An inspection was performed of the original and spare bearing thrust blocks, and it was decided to resurface the better of the two thrust blocks and re-install it in the unit while a new Kingsbury-style replacement could be ordered. In addition, the unit was further reduced to 2.2 MW. No generation was lost due to pondage. The refurbished thrust block was installed and unit released a reduced load until the early summer of 2008 when the new bearing could be installed without loss of generation. PSNH stated that the new Kingsbury style bearing was ordered on 11/14/07, received on 5/29/08 (See Outage H above, 12 weeks late), and installed during the failure of the generator step up transformer in May 2008.

M
11/29 – 0.06 days – Y
This was a scheduled shut down for the transmission department to install and test transfer trips from the mobile transformer installed during line upgrade work.

N
11/30 – 0.09 days – Y
The unit tripped while switching the mobile substation into service when the breaker on TB33 was opened. The investigation revealed that the hard wired transfer trip function between TB33 and the unit was not inhibited prior to switching to the mobile substation. This is an old practice performed in single transformer substations that has not been used by PSNH for a long time. Its existence was overlooked when planning the installation of the mobile transformer.

O
12/20 – 8.77 days – N
The unit tripped due to high thrust bearing temperature. PSNH inspection found that the new thrust bearing that was installed had again become damaged due to overheating. It was removed and sent out to have the bearing plate re-machined, and a new babbit surface poured and machined. Also several new oil grooves were installed to supply more oil to the surface of the bearing. A new Kingsbury bearing that has been on order would not be delivered for 6 - 8 weeks. NOTE: The actual receipt date of the new Kingsbury bearing was 3 months late.

Smith

Activities in 2007 included the installation of a new roof on the power house and the replacement of the generator air cooler.

Smith-1

A
1/8 – 0.48 – Y
The unit was scheduled off line so that equipment required for operation warranty tests immediately following the installation of the new runner in December of 2006 could be installed. The testing was needed in order to determine the warranty performance parameters of the new runner compared to the old one.

B
1/9 – 0.04 - Y
The unit was scheduled off line to perform efficiency testing at all levels of wicket gate openings, including unit shut down. The testing was needed in order to determine the initial warranty performance parameters of the new runner compared to the old one.

C
1/10 – 0.15 – Y
The unit was scheduled off line to perform vibration tests on the penstock. The new runner induced a vibration of the penstock when the unit was operated at about 11 MW, and initial solutions involving increasing ventilation air into the runner nose cone space were attempted.

D
1/12 – 0.18 - Y
The unit was scheduled off line again to perform additional vibration tests on the penstock and implement other possible resolutions. The chosen solution involved adding open piping to the vent system to reduce frictional losses and to preclude any active valving in the system to protect against vibration.

E
4/11 – 0.01 days – Y
The unit was scheduled off line to perform a professional vibration analysis of the slight remaining penstock vibration. Strain gauges were installed along the penstock and connected to computer vibration analysis software. The study was performed by Kleinschrnidt Associates Consulting Engineers and was designed to determine if the minor vibration still observed at 11 MW represented any long term danger of metal fatigue or penstock failure. The analysis determined that the vibrations are below allowable fatigue thresholds and should not impact the service life of the penstock.

F
9/22 – 7.17 days – Y
The unit was scheduled off line for transmission work at the Eastside Substation. The unit annual inspection was completed at the same time. Maintenance, cleaning and testing of the unit were completed during this time. The runner was inspected and found to be in excellent condition.

G
10/17 – 1.37 days – Y
The unit was scheduled off line so that the transmission department could install new cut-ins at the Eastside Sub-station.

Evaluation (Except for Ayers Island 1-E, Canaan 1-H, and Eastman Falls 1-C)
Liberty reviewed the outages above and found them to be reasonable for the system as designed or not unexpected for these units and their vintage, or necessary for proper operation of the unit.

Evaluation of Outage Ayers Island 1-E
Liberty is recommending that replacement power costs related to this outage be disallowed. Existing procedures identify a routine task that must be followed and was not. Operator inattention in this regard rises to a level above operator error.

Evaluation of Outage Canaan H

Liberty would agree with the PSNH position that PSNH inspections conform to NESC requirements and thus NHPUC rules regarding same. Liberty believes that these inspections are not comprehensive enough to identify problems of this nature. Liberty offers proof in that this instance occurred, and that other rot related problems were identified in the outage reviews conducted by Liberty. Liberty recommends that PSNH does not rely on aerial patrols alone for inspections of lines in a right of way and that all lines in a right of way be inspected from the ground consistent with PSNH's revised NESC inspection program just getting underway as part of the Reliability Enhancement Program approved in PSNH's recent distribution rate case, DE 06-028.

Evaluation of Outage Eastman Falls 1-C

Liberty classifies this outage as an operator error but cautions that operators should be aware that sensitive electronics are playing a larger role in hydro unit operation and that if impact force is to used, care should be exercised not to damage or disturb other components. If a particular check valve has a sticking problem, PSNH should consider moving it so that it may be unstuck without disturbing other systems and also exercise care in the placement of check valves. Liberty further recommends that PSNH conduct an informal survey to identify other areas that exhibit such potential.

General Recommendations

Liberty also found that the distribution system as designed and maintained can increase the numbers of outages occumng to theses units. Liberty recommends that PSNH review clearing times on equipment near generating stations to try to minimize sympathy trips of the units. Liberty also recommends that PSNH review right of way and on road vegetation management practices on facilities in proximity to generating stations.

Combustion Turbine Outages For 2007

The following outages took place at PSNH's combustion turbine units during 2007:

Lost Nation CT-1

Completed work in 2007 included the 5 year inspection of fuel oil tanks and secondary containment, installation of a new fuel pump, and establishment of a storage facility for on site storage of oil clean up material.

Lost Nation – 1

A
1/18 – 0.1 days
The unit failed to start when requested to do so by the ESCC due to a loss of flame problem. PSNH cleaned the flame detector lenses and the unit was started to ensure start and returned to service.

B
1/20 – 8.8 days
The unit again failed to start when requested to be the ESCC due to a loss of flame problem. Further investigation by PSNH found low fuel delivery pressure of the main fuel pump. PSNH called in GE, the manufacturer. A spare rebuilt fuel divider was installed, but the unit would still not go to flame leading to the diagnosis that the main fuel pump was faulty. A replacement main fuel pump was procured by GE and installed. The unit started successfully. The faulty main fuel pump was completely overhauled and put into spare stock.

C
3/6 – 0.1 days
The ESCC started the unit but initiated a stop signal because the start was abnormal. The unit showed as started with no output and not ready to phase. Inspection revealed that the clutch between the engine and turbine had not engaged because the clutch limit switch had not returned to its normally open position allowing engagement. Lubrication corrected the problem. PSNH installed a new switch during the annual inspection in May. See Outage D below.

D
5/7 – 4.7 days
This outage was taken to perform the annual inspection and maintenance. Routine maintenance was performed. Both the turbine and generator were inspected and the clutch limit switch was replaced.

E
5/12 – 9.5 days
This outage is an extension of the annual outage because PSNH found the automatic clutch faces worn allowing over travel and binding of the clutch. PSNH states that this is the real root cause of the clutch problem in Outage C above. The clutch, which is located inside a cover, had been damaged by incomplete engagement due to the faulty clutch noted in Outage C above. The clutch was refurbished and reinstalled. The unit has operated successfully since that time.

White Lake CT-1

Major work in 2007 included removal of the loaned rebuilt uncoupled (Free) turbine and the installation of the rebuilt PSNH unit. The fuel control system and liquid fuel modulating valve were also replaced.

White Lake – 1

A
1/25 – 0.4 days
The unit failed to start remotely. Investigation found that fuel was going directly to the fuel dump valve rather than to the engine. The three way fuel valve, the fuel sensor for the dump valve, as well as a leaking fuel bypass hose were replaced. The unit was returned to service.

B
2/20 – 2.3 days
This scheduled outage was taken to remove the loaned uncoupled turbine and install the PSNH refurbished unit.

C
6/2 – 0.4 days
The unit was not running at the time. A lightning strike close to the unit caused multiple drops to occur which gave a No-Go indication at the ESCC. The drops were reset and the No-Go indication cleared.

D
8/7 – 0.3 days
The unit was scheduled out of service to investigate why the unit was not automatically going to its base setting on start up. Investigation found a burnt bulb in the light sensing device control relay. The bulb was replaced and the unit returned to service. PSNH states that this older type of device was replaced with digital controls in Outage E below.

E
8/25 – 0.0 days
The unit was not in service at the time. A nearby lightning strike tripped the B-112 115kV transmission line and caused a vibration alarm. The vibration alarm caused a No-Go indication at the ESCC. The drops on the alarm were reset and the No-Go indication cleared. PSNH believes that the lightning strike was so close to the unit that the accompanying thunderclap shook the engine enclosure sufficiently to be sensed by the vibration probes. In 2008, PSNH changed the logic so that vibration is monitored only when the unit is rotating.

F
10/8 – 40.8 days
This outage was taken to perform the scheduled annual inspection. In addition to normal maintenance and inspection, the turbine and generator were inspected and the fuel control system was replaced. During the inspection of the unit, a crack was found in the exhaust plenum and repaired.

G
1211 – 0.1 days
The unit failed to start when requested to do so by the ESCC. Investigation found a software error in the liquid fuel modulating valve installed with the new fuel control system during the annual inspection. The error occurred due to the change of the fuel viscosity between control system installation in August and December. The manufacturer made changes in the sequencer logic software to correct the problem. PSNH states that the liquid fuel modulating valve was changed out under warranty in Outage H.

H
12113 – 0.1 days
The unit would not phase when requested to do so because the liquid fuel modulating valve. The manufacturer's representative was contacted. The valve was bad and replaced under warranty.

Schiller CT-1

A
316 – 0.1 days
The unit tripped on loss of gas supply. Investigation found that the main gas valve at the manifold was in the closed position. Once the valve was opened, the alarms cleared and the unit was able to be started. PSNH determined that the valve had been closed during the wood boiler gas supply job and not reopened when completed.

Liberty recommends disallowance for replacement power costs related to this outage. Good utility practice would review the lock out and tag out procedures performed at the beginning of a job and generally follow them in reverse order at the end of a job to pick up switch, valving, or other system conditions that were placed out of configuration.

Liberty believes that if such a procedure was followed, the incorrect valve position would not have taken place.

B
412 – 0.3 days
The unit tripped due to vibration. PSNH investigation found that a wire was broken on the vibration probe. The probe was repaired and the unit was placed back on standby. PSNH was not able to determine the cause of the broken wire.

C
4/9 – 3.6 days
This outage was taken to perform the annual inspection and maintenance. Routine maintenance was performed. Both the turbine and generator were inspected and the clutch limit switch was replaced.

D
6114 – 0.3 days
This outage was taken to replace the liquid fuel delivery meter. Problems occurred the previous winter where the meter could not be calibrated.

E
813 – 0.0
The unit phased and could not go beyond 17.3 MW loading from the control panel at Schiller station. The shift supervisor went to the unit local control panel was taking the engine control switch off automatic mode and place it into manual mode, but inadvertently operated the voltage regulator control switch. The operator tried to place the voltage regulator in automatic mode but the switch was stuck. The unit tripped on under voltage. The switch was repaired and the unit was returned to service.

PSNH believes that the switch was inoperative due to minimal use, cleaned the switch, and returned the unit to service. The switches are clearly marked but in the local control panel, the voltage regulator control switch is located where the unit control switch is located in the panel at Schiller station. Liberty recommends that PSNH try to identify system 1 and system 2 locational problems at its stations to prevent operator errors in the future.

F
9/7 – 0.0 days
The unit would not start when requested to do so because of a low lube oil level. PSNH added oil and released the unit for service. PSNH states that the oil level had been checked per procedure and recorded as such. Investigation found no evidence of lost oil in the vicinity and concluded that the operator had not completed a thorough check of the oil level. PSNH counseled the operator and reviewed the incident with all other operations personnel.

G
1211 – 1.7 days
Several attempts were made to start the unit without success. The speed controller was suspected and PSNH contacted its jet consultant. The consultant was not available until the following Monday, so following the consultant's instructions, PSNH prepared to take data during a start up. The unit started successfully. The speed controller is an old mechanical device that controls the unit ramp up speed and the consultant believed that a hang up was likely. The decision was made to monitor the problem for future occurrence.

H
12/13 – 0.7 days
The unit would not start when requested to do so. Several unsuccessful attempts were made. Eventually the unit was started and the outage status cleared. On Saturday with the jet consultant present the unit still would not start. Investigation found that the air pressure to the starter had maxed out the pressure speed timer due to the low pressure. The air feed was taken from Schiller as the normal air feed; the compressor on the unit was out of service and on order from Germany. The jet consultant recommended that the air pressure be increased from 80# to 100# and that maximum roll up time for the generator be increased. The adjustment to air pressure allowed the unit to start.

PSNH stated that the air system at Schiller has been used many times to start the unit. In addition, the Schiller station air pressure used to be set to 500# but in order to increase efficiencies and reduce losses, that pressure has been reduced to 250# which is too low to start the unit from Schiller. PSNH has changed its procedures to increase air pressure at Schiller if that system is to be used to start the combustion turbine.

Liberty recommends that the replacement power relative to this outage be disallowed. The decision to reduce air pressure at Schiller station either had no review or a review at such a level that the combustion turbine was not considered. Even a cursory review should have raised the question of adequate air pressure for starting the combustion turbine.

Merrimack CT-1

A
1/3 – 0.2 days
The unit was scheduled out of service to replace fuel filters.

B
1/9 – 1.0 day
The unit was scheduled out of service because of low CO_2 pressure in the fire protection system. PSNH recharged the system and returned the unit to service.

C
2/10 - 0.0 days
The unit was requested to run and started but tripped while running. The unit was restarted. PSNH investigated the cause of the trip but nothing was found.

D
3/6 – 0.0 days
The unit failed to start when requested to do so. PSNH inspected the unit with no apparent cause found. The unit was restarted and returned to service.

E
4/1 – 10.5 days
This outage was taken to perform the annual inspection and maintenance. Routine maintenance was performed. Both the turbine and generator were inspected and the clutch limit switch was replaced. In addition, under-designed piping was replaced with double wall piping for the leak detection system.

F
5/11 – 0.5 days
The 75 KVA 13.8kV/480V transformer that feeds the units from the plant previously failed. Power for the units had been taken from MT3, the generator step up transformer. The failed transformer was replaced during this outage.

G
6/7 – 0.1 days
This scheduled outage was taken to perform relay testing.

H
7/29 – 0.1 days
PSNH received a stator temperature alarm with the unit off line. PSNH found that it was an instrument problem, made an adjustment, and performed tests. The unit was returned to service.

I
10120 – 0.4 days
PSNH took this planned outage to replace the fuel heater and to repair a fuel leak. PSNH found that the fuel leak could not be repaired at this time as it was coming from the gear box.

J
11/10 – 0.3 days
This planned outage was taken to repair the gearbox leak found in Outage I above. The carbon seals were leaking and PSNH decided to put off the repair until the 2008 annual inspection.

Merrimack CT-2

A
1/3 – 0.2 days
This outage was for the same times and reasons as Outage CT-1A above.

B
1/20 – 0.1 days
The unit would not phase when requested to do so. PSNH exercised the breaker and the unit successfully phased. PSNH inspection found nothing unusual.

C
411 – 10.5 days
This outage was for the same times and reasons as Outage CT-1E above.

D
4/11 – 3.0 days
Coming back from its annual inspection in Outage C above, the unit would not phase. PSNH found a problem with a mechanical trip release at the breaker that prevents the breaker from closing if it is not fully racked (in place). Investigation determined that the breaker was fully racked and that the problem was with the mechanical trip release and most likely due to age. PSNH made the necessary repairs, and returned the unit to service.

E
5/11 – 0.5 days
This outage was for the same times and reasons as Outage CT-1F above.

F
617 – 0.1 days
This outage was for the same times and reasons as Outage CT-1G above.

Evaluation (Except for Outages Schiller CT-A, Schiller CT-E, and Schiller CT-H)

Liberty reviewed the outages above and found them either to be reasonable and not unexpected for these units and their vintage, or necessary for proper operation of the unit. Liberty concluded that PSNH conducted proper management oversight.

Evaluation for Schiller CT-A
Liberty recommends disallowance for replacement power costs related to this outage. Good utility practice would review the lock out and tag out procedures performed at the beginning of a job and generally follow them in reverse order at the end of a job to pick up switch, valving, or other system conditions that were placed out of configuration. Liberty believes that if such a procedure was followed, the incorrect valve position would not have taken place.

Evaluation for Schiller CT-E

PSNH believes that the switch was inoperative due to minimal use, cleaned the switch, and returned the unit to service. The switches are clearly marked but in the local control panel, the voltage regulator control switch is located where the unit control switch is located in the panel at Schiller Station. Liberty recommends that PSNH try to identify system 1 and system 2 locational problems at its stations to prevent operator errors in the future.

Evaluation for Schiller CT-H

Liberty recommends that the replacement power costs relative to this outage be disallowed. The decision to reduce air pressure at Schiller Station either had no review or a review at such a level that the combustion turbine was not considered. Even a cursory review should have raised the question of adequate air pressure for starting the combustion turbine.

W. F. Wyman Outages For 2007

W. F. Wyman Station

The W. F. Wyman Station has been sold to a competitive power supplier and competes in the competitive market to sell its power. Florida Power & Light (FP&L) owns the majority of the unit and is responsible for day-to-day operations. PSNH is a minority owner of Unit #4 at the station, and as such, is aware of how the plant conducts business. However, PSNH has little influence over day-to-day operations of the plant provided those operations are within wide operating bounds. This unit is an extremely high cost oil unit that has tight environmental operating restrictions placed on it. The unit operates at an annual capacity factor of approximately 5 percent. Liberty makes this distinction because it believes that the measurement of prudence is different than the measurement used for PSNH's wholly-owned units providing transition service energy at cost.

W. F. Wyman #4 replaced the burner management system in 2007

W. F. Wyman-4

A
1/17 – 0.0 days
Operators had been having problems with the tripping of one of the boiler feed pumps during the day with the control system placing the other boiler feed pump in manual mode rather than picking up and maintaining drum level. The **4A** boiler feed pump tripped and **4B** pump picked up load and maintained drum level. About 25 minutes later, the **4A** pump again tripped (was in standby mode) and **4B** was in manual mode. When the low drum level sounded, the operator attempted to maintain drum level with the **4B** pump in manual mode but was unsuccessful. The unit tripped.

Investigation found that the **4B** pump had an intermittent connection on the frequency to voltage converter board. The connection caused pump **4B** to swing on flow with the slightest of vibration. New terminals were installed and a break in the wire was found. The terminals were repaired and the unit returned to service. FPL suspects that the operator may have recognized the trip of the **4A** pump when it tripped and alarmed, but not recognized its impact on the operation of the **4B** pump because it was in standby mode. NOTE: Further discussion of this problem appears in Outage **B** below.

B
1/22 – 0.1 days
Operators were having problems controlling the two boiler feed pumps in the automatic mode. Initially, Wyrnan personnel brought in a local contractor that had previous

knowledge of the feed pump control system. In addition to the broken wire identified in Outage A above, a failed control card was identified and replaced that compares the operation of the two feed pumps. FPL brought in the turbine/controller manufacturer who spent a considerable amount of time on site during unit operation in February to perform diagnostics and repairs on the feed pump control system. Given that the feed pump control system was to be replaced as part of the overall control system upgrade to the Ovation system, the performance of the feed pump control system was monitored and adjusted as necessary to ensure operation until the outage began.

C
1/28 – 0.0 days
The turbine failed to reset when requested to do so. Investigation revealed that "O" rings were leaking in the turbine reset solenoid. The "O" rings were replaced and the unit returned to service. The solenoid was identified for replacement in the upcoming unit outage.

D
2/13 – 0.1 days
The unit was late for dispatch because the fuel oil trip valve would not open. The oil recirc valve must open in order for the fuel oil valve to open and must receive an open signal from the oil recirc valve. Investigation found that the oil recirc open signal was not transferred through the burner management system. Several logic cards were checked and found okay. The open signal is generated by a "mercury wetted" relay, but no signal was being generated. The relay was replaced and the unit returned to service. NOTE: All relays of this type were replaced in the upgrade to the Ovation system.

E
9/20 – 0.1 days
The unit tripped on low furnace pressure while inserting a pair of main oil guns. Furnace pressure swing had been observed since the control upgrade was made. Analysis of furnace pressure trends before and after the controls upgrade revealed that the low pressure trip point had been changed from +/- 5 inches of water to +/- 4 inches of water by the control system supplier during the upgrade. The low pressure trip point was reset to +/- 5 inches of water but that was not fully successful. Further tuning was required in the forced draft and induction draft control systems to restore stability.

F
11/5 – 0.1 days
The unit tripped due to a trip of the main furnace. The furnace tripped due to less than the 6 burners required to be in service for operation. Investigation found that the 3A main oil burner gang valve did not fully close. It was determined that the lack of valve travel was due either to a stuck limit switch or the limit switch being defective in the closed indication. Investigation found that the limit switch failed to operate because of oil and dirt accumulation. The limit switch was cleaned and the unit returned to service. In addition, FPL initiated a maintenance procedure to perform periodic cleaning and adjustment of the burner limit switches.

G
11/5 – 0.0 days
The unit tripped due to a trip of the forced draft fan. First indication was that the forced draft master control went from automatic to manual. A second indication was that air flow was less than 30 percent followed by a master fan trip. Both the induced draft A fan and forced draft A fan had also tripped due to the loss of control power. Investigation found that the loss of control power was due to a loose connection to the fuse box supplying control power to this portion of the system. The connection was repaired and all similar connections checked.

H
1212 – 0.1 days
The unit came on line early in the morning and many bad points were noticed on the combustion control graphic. The unit was eventually manually tripped due to high opacity. Investigation found that the fuel oil flow point was off scan which then propagated through the combustion control logic causing other points to go bad and resulting in poor control. The point was put to scan and unit operation was back to normal. Investigation revealed that there was no manual reject logic present on the fuel oil flow point for bad quality and the operator was unaware of the potential problems that would occur with this point off scan. Emerson, the new control system vendor, provided two days of additional on-site operation training.

I
12118 – 0.0 days
During start up, the 2LP heater had a high high-level indication which tripped the main boiler feed pump on low suction pressure. The heater became vapor locked and was not able to drain through either the normal or emergency drains. Operations moved forward with loading the unit which resulted in the tripping of the feed water pumps on low suction pressure. Investigation found that the high water level existed in the heater before startup and that high water level prevented the opening of the extraction steam valve to supply heat to the heater.

The operator was inattentive to the condition of the feed water heaters. It is not clear if the operator realized that the heater was not draining properly and believed that the level would reach normal conditions so that the heater could be placed in service or that procedure required proper level prior to start up. To prevent this condition from happening in the future, an additional drain path was added to the heater that will allow normal level conditions to be established prior to unit startup.

Liberty recommends that replacement power costs related to this outage be disallowed. While an additional drain was added to assure proper feed pump water level, this unit has under gone start ups for 30 years. While normal procedure would allow for the drains to maintain proper water level, the operator should have known that the feed pumps would

trip with a high water level and monitored the water level as he proceeded during start up. The operator would have seen that the water level was not correcting itself, investigated the cause, and found the pluggage.

Evaluation (Except for Outage I)

Liberty reviewed the outages above and found them either to be reasonable and not unexpected for this unit, its vintage, or necessary for proper operation of the unit. Installation of new control systems presents many challenges to plant personal when the unit returns to service. Liberty concluded that PSNH conducted proper management oversight.

Evaluation of Outage I

Liberty recommends that replacement power costs related to this outage be disallowed. While an additional drain was added to assure proper feed pump water level, this unit has under gone start ups for 30 years. While normal procedure would allow for the drains to maintain proper water level, the operator should have known that the feed pumps would trip with a high water level and monitored the water level as he proceeded during start up. The operator would have seen that the water level was not correcting itself, investigated the cause, and found the pluggage.

T & D Related Unit Outages For 2006

The following describes the outages at PSNH's units during 2006 that were related to T & D causes. In its Order No. 24,805 (at 13), the Commission required that the outages that were not completely reviewed be part of the May 2008 filing, the current docket. This exhibit presents Liberty's review of those outages. For the hydroelectric units, the outage durations listed have been stated as the actual duration of the total outage regardless whether there was water to run the unit. Liberty indicates water availability by a "Y" or "N" next to the outage designation.

2006 Outages

Amoskeag - 2

B
4/25 – 0.01 days – Y
An operation of the 388 breaker at the Brook Street substation was caused by a squirrel on the line at Malvern Street, also resulting in the momentary interruption of service to customers on the 372 34.5kV line between the Brook Street and Eddy substations. The 388 breaker automatically reclosed but the momentary loss of AC power at Amoskeag tripped G2 off line. All three units were on line but only G2 tripped since its Loss of AC relay for its static voltage regulator operated quicker than the similar relay on G1. This relay is prone to operate quicker than those on the other units because its factory setting is lower, but still within tolerances. An uninterrupted power supply has since been installed to maintain power to the voltage regulator so the voltage regulator will not be affected by such momentary sags or interruptions. PSNH's investigation revealed that the fault at Malvern Street depressed the voltage at Amoskeag and properly cleared.

Canaan – 1

A
1/16 – 0.04 days – Y
The unit tripped due to recloser OCR355 operation. OCR355 is located in Colebrook on the 355 34.5kV line. For any fault on the 355 line, the unit is intentionally tripped to de-energize the line and isolate the fault.

C
3/9 – 0.08 – Y
The unit tripped off line due to loss of a tap off of the 355 34.5kV line caused by a pole accident on Route 3. The fault caused by the accident operated the fuse on the 355X10 tap. The fault was 9 poles beyond the recloser, very close to the transmission line, and depressed voltage as if the fault occurred on the transmission line from the Canaan unit's viewpoint. The unit more than likely tripped due to over speed conditions.

D
4/23 – 0.08 – Y
The unit tripped due to an apparent fault on the 355 34.5kV line. The relay targets found at the station were the phase 3 over current on the 355 line, the 86 lockout, and unit over speed relay. The 355 line tripped and reclosed properly. The fault location was never determined.

E
5/25 – 0.00 – Y
The unit tripped off line as a result of an operation of the 0355 breaker on the 355 34.5kV line, at Lost Nation Substation. The area work center reported that a logging operation dropped a tree on the line. A PSNH operator was on site and immediately restarted the unit. PSNH identified the logger and billed them accordingly.

I
8/12 – 0.08 – Y
There were thunderstorms in the area and the unit tripped off line due to a suspected lightning strike. The 355 34.5kV line never operated. PSNH states that it protects its equipment at 34.5kV in ROW by installing arrestors at the equipment and line terminals. PSNH further states that the Electric Power Research Institute stated that this practice is consistent with the practice of other northeastern utilities for 34.5kV sub-transmission lines.

Eastman Falls - 1

L
8/22 – 0.05 days – N
The unit tripped due to low voltage at Webster substation. PSNH had incorrect tap changer control occur on transformer TB37 at Webster on 4/25/06, 5/20/06, and on this date. On 4/25 and 4/26, PSNH tested the controls, achieved successful operation, and were returned to service. As a result of the current misoperation, PSNH found the LTC test switch on the TB37 tap changer control in the "test" position. The switch was moved to the correct position of "operate" and the system operated successfully.

Garvins Falls - 1

A
6/1 – 0.03 days – Y
The unit tripped off line due to a line fault on the 332/335 34.5kV line between the Rimmon and Garvins substations caused by severe lightning. PSNH found that the equipment properly operated within specified times. PSNH noted that the tripping of the unit could have been due to stability, reduced excitation, or the drop out of auxiliary equipment. PSNH also stated that distribution line over current settings at substations

must be set with enough time delay to coordinate with multiple downstream devices and that they do not generally review the hydroelectric under voltage relay settings when line protection settings are revised to provide coordination.

Jackman-1

B
5/24 – 0.07 days – Y
The unit tripped due to line fault on the 313 34.5kV line when tree took down a cross arm. This station is connected to a radial 34.5kV feed and will trip for operations of that feed. The unit was restarted when cross arm was replaced.

White Lake – 1

E
7/18 – 0.08 days
The unit tripped due to loss of excitation caused by a line fault on the 337 34.5kV line. The fault occurred due to a lightning strike. PSNH investigation found that the line reclosed into load which would drop the voltage at the White Lake bus. If the voltage drop was lower than the setting of the loss of excitation relay, the unit would trip with a loss of excitation indication.

Evaluation (Except for Canaan 1-I, Eastman Falls 1-L, and Garvins Falls 1-A)

Liberty reviewed these outages and found them either to be reasonable and not unexpected for these units and their vintage or necessary for proper operation of the units. Liberty concluded that PSNH conducted proper management oversight.

Canaan 1-I
Liberty accepts PSNH's statements regarding the lightning protection practices of northeastern utilities for 34.5kV in ROW. If accepted and no opening of the 355 line took place, a lightning strike that occurred off the main line or one that occurred close to the main line induced its effects into the system caused the unit to trip. Liberty recommends that PSNH check the lightning protection in the area of the Canaan unit to assure that its practices will not result in lightning damage to the unit.

Eastman Falls 1-L
Liberty found that procedures were not either understood or followed by PSNH personnel. Liberty recommends that this outage be classified as imprudent. Liberty understands that there was no generation lost as a result of this incident and no economic impact to the generation dispatch. Liberty makes this recommendation for guidance to PSNH personnel.

Garvins Falls 1-A

Liberty understands the need to coordinate with downstream devices. Liberty also understands that the addition of another downsteam device requires that all upstream devices must have their tripping times increased to provide for that coordination. Liberty further understands that not considering the impact of distribution system setting changes on hydroelectric units is a system-wide problem. Liberty will address this issue after reviewing 2007 events for any similar occurrences.

DOCKET DE 08-066

EXHIBIT – MDC-10

PSNH RESPONSES TO DATA REQUESTS

Witness: Richard C. Labrecque
Request from: Liberty Consulting Group

Question:
Please supply traditional information and graphs.

Response:
The attached file provides the following information:

Q1-a bilateral and spot market purchase and sale details.
Q1-b compares actual 2007 bilateral and spot market purchase quantities with the forecasted quantities in the Nov 2006 rate request filing. Includes data and two charts.
Q1-c breaks total supplemental purchase quantities into "monthly bilateral", "short-term bilateral" (i.e. less than one month), and "spot market".
Q1-d breaks total surplus sale quantities into surplus generation vs surplus bilateral purchases.
Q1-e summarizes FTR and ARR activity.

[Q-la] Summary of 2007 PSNH Bilateral Purchases and ISO-NE Spot Purchases & Sales

Peak

	Total Bilateral Purchases MWh	Total Bilateral Purchases $000	Ava Price $/MWh	Sales of Surplus Purchases MWh	Percent (%) Sold as Sumlus	Profit (Loss) on Sales $000	Total ISO-NE Soot Purchases MWh	Total ISO-NE Soot Purchases $000	Ava Price $/MWh
Jan	57.407	5,258	91.60	6.420	11%	(211)	16.503	1,066	64.60
Feb	42.545	4,399	103.39	14,485	34%	(304)	8.097	748	92.33
Mar	105.407	8,911	84.54	12,764	12%	(28)	10,070	788	78.27
Apr	140,710	11.678	82.99	29,962	21%	(29)	16.559	1.307	78.91
May	157.682	13.541	85.87	2.298	1%	(52)	37.144	2,988	80.43
Jun	136.289	12.231	89.74	26,754	20%	(790)	11.957	1,216	101.74
Jul	165.181	14.621	88.51	25.565	15%	(654)	16.103	1,322	82.10
Aug	175,281	15,361	87.63	18.096	10%	(528)	18,117	1,706	94.18
Sep	136,732	11,721	85.72	13.639	10%	(369)	15.710	1,389	88.39
Oct	111,322	10,244	92.02	6.575	6%	(227)	21.854	1.665	76.20
Nov	89.103	8.416	94.45	4,706	5%	(163)	18.657	1.467	78.61
Dec	116,965	10,640	90.96	15,678	13%	111	16.340	1,945	119.03
Totals	1,434,622	127,020	88.54	176,944	12%	(3,244)	207,111	17,606	85.01

Off-Peak

	Total Bilateral Purchases MWh	Total Bilateral Purchases $000	Ava Price $/MWh	Sales of Surplus Purchases MWh	Percent (%) Sold as Surplus	Profit (Loss) on Sales $000	Total ISO-NE Soot Purchases MWh	Total ISO-NE Soot Purchases $000	Avg Price $/MWh
Jan	67.965	5,550	81.66	24,831	37%	(910)	7.673	566	73.71
Feb	64.323	5,257	81.73	24.316	38%	(199)	6,217	483	77.63
Mar	47,169	3,575	75.80	12.008	25%	(260)	11,146	812	72.83
Apr	49,052	3,708	75.60	14.988	31%	(164)	29.163	1,728	59.24
May	85,660	5.899	68.86	12.378	14%	(170)	26,687	1.658	62.11
Jun	53.046	3,933	74.15	13.065	25%	(414)	19,811	1.419	71.60
Jul	70.758	5.286	74.70	19.094	27%	(560)	18.323	1.342	73.23
Aug	75.286	5.647	75.01	16.136	21%	(405)	17.320	1.229	70.97
Sep	75,892	5.456	71.89	14,217	19%	(353)	28.096	1.547	55.05
Oct	43,216	3,285	76.02	18.340	42%	(543)	14,068	776	55.16
Nov	46.764	3.545	75.80	16.544	35%	(406)	7.815	569	72.75
Dec	54,190	4,106	75.77	8,954	17%	112	25.131	2,445	97.28
Totals	733,322	55,248	75.34	194,870	27%	(4,271)	211,452	14.571	68.91

Total

	Total Bilateral Purchases MWh	Total Bilateral Purchases $000	Ava Price $/MWh	Sales of Sumlus Purchases MWh	Percent (%) Sold as Surplus	Profit (Loss) on Sales $000	Total ISO-NE Soot Purchases MWh	Total ISO-NE Soot Purchases $000	Avg Price $/MWh
Jan	125.372	10.808	86.21	31.252	25%	(1,121)	24.177	1,632	67.49
Feb	106.868	9,656	90.35	38,801	36%	(503)	14,314	1.230	85.94
Mar	152.577	12,486	81.84	24,772	16%	(288)	21.216	1.600	75.42
Apr	189.762	15,386	81.08	44,950	24%	(193)	45.722	3,034	66.36
May	243.342	19,440	79.89	14,676	6%	(222)	63.831	4.645	72.77
Jun	189,335	16,164	85.37	39,819	21%	(1,204)	31,768	2,635	82.95
Jul	235,939	19.906	84.37	44,659	19%	(1,214)	34.427	2,664	77.38
Aug	250.567	21.008	83.84	34,232	14%	(933)	35,437	2,936	82.84
Sep	212,623	17.177	80.79	27.856	13%	(722)	43,806	2,935	67.01
Oct	154,537	13.530	87.55	24.914	16%	(770)	35,922	2,441	67.96
Nov	135,867	11.961	88.03	21.250	16%	(569)	26,472	2.035	76.88
Dec	171,155	14.745	86.15	24,632	14%	222	41.471	4.390	105.85
Totals	2,167,944	182,267	84.07	371,814	17%	(7.516)	418,563	32.177	76.88

[Tab Q-1b]

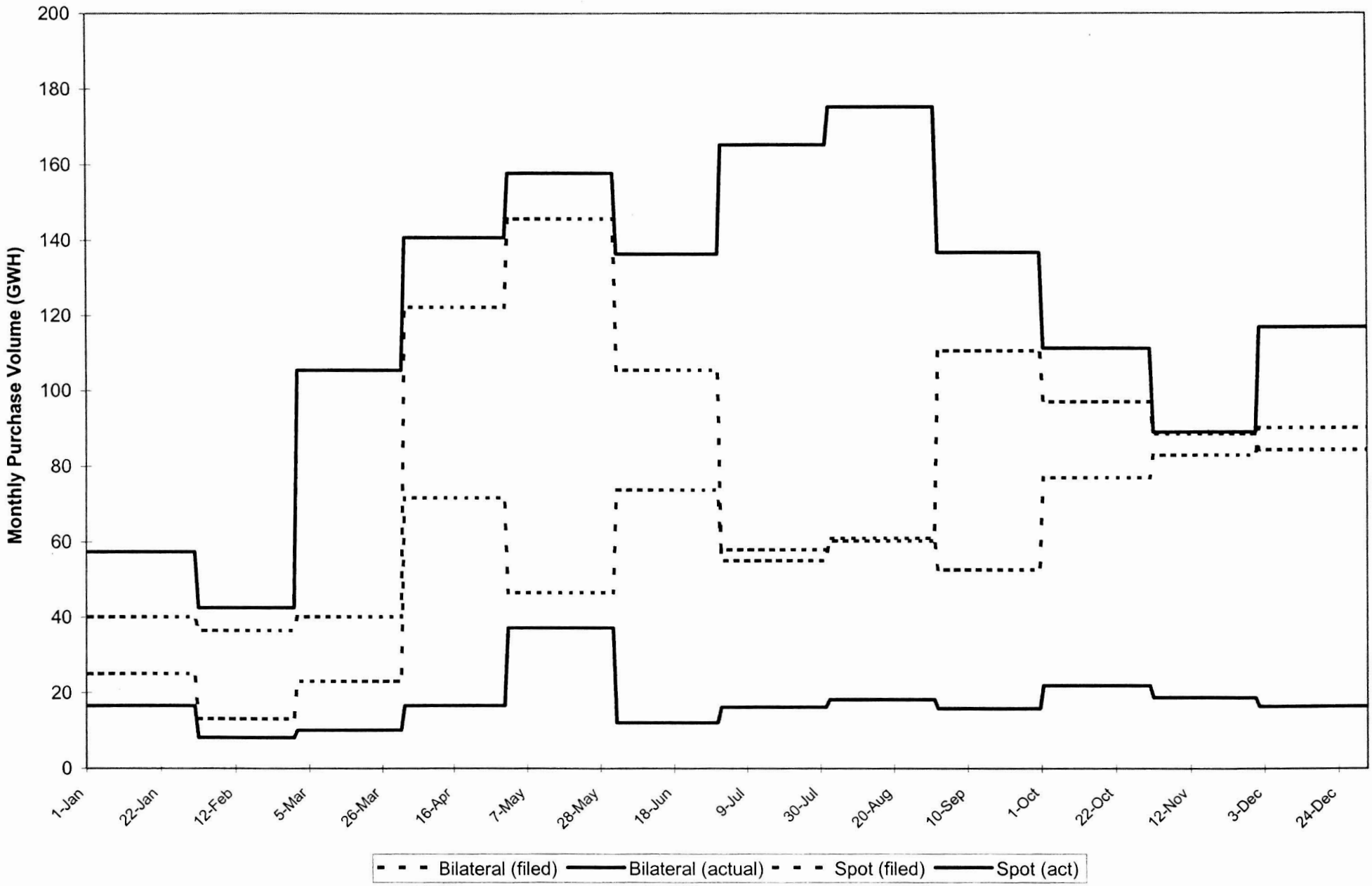
Peak

	Actual 2007 Purchase Quantities		Purchase Quantities Filed with Rate Request	
	Total Bilateral Purchases MWh	Total ISO-NE Spot Purchases MWh	Total Bilateral Purchases MWh	Total ISO-NE Spot Purchases MWh
1	57,407	16,503	40,058	24,963
2	42,545	8,097	36,416	13,073
3	105,407	10,070	40,058	22,991
4	140,710	16,559	122,237	71,616
5	157,682	37,144	145,658	46,591
6	136,289	11,957	105,437	73,689
7	165,181	16,103	55,037	57,948
8	175,281	18,117	60,278	61,000
9	136,732	15,710	110,595	52,616
10	111,322	21,854	97,078	77,018
11	89,103	18,657	88,637	82,976
12	116,965	16,340	84,416	90,259
Totals	1,434,622	207,111	985,904	674,742

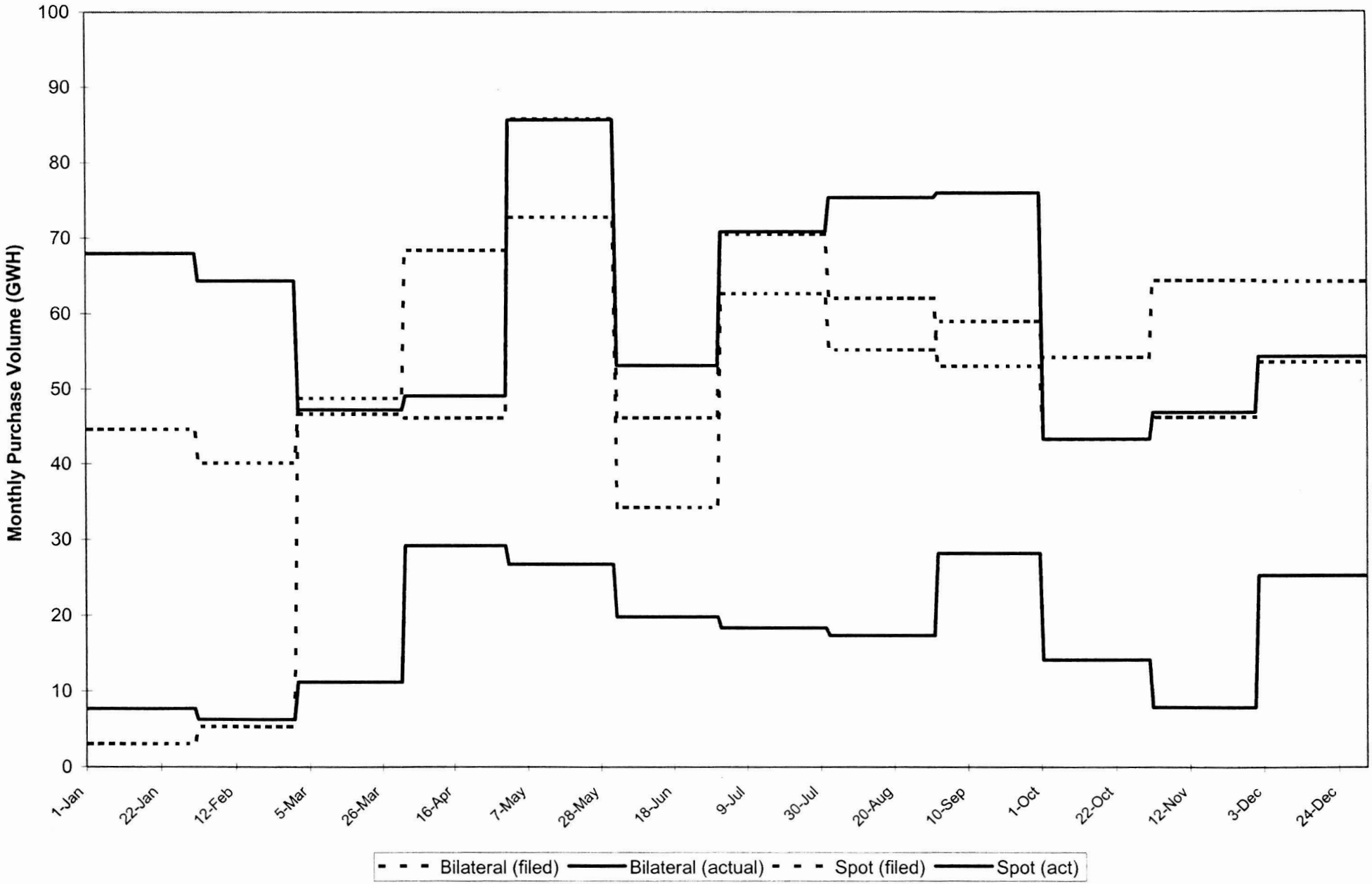
Off-Peak

	Total Bilateral Purchases MWh	Total ISO-NE Spot Purchases MWh	Total Bilateral Purchases MWh	Total ISO-NE Spot Purchases MWh
1	67,965	7,673	44,610	3,061
2	64,323	6,217	40,058	5,302
3	47,169	11,146	46,610	48,712
4	49,052	29,163	46,099	68,371
5	85,660	26,687	85,810	72,705
6	53,046	19,811	46,099	34,164
7	70,758	18,323	70,430	62,620
8	75,286	17,320	61,989	55,133
9	75,892	28,096	52,941	58,911
10	43,216	14,068	43,189	54,099
11	46,764	7,815	46,099	64,283
12	54,190	25,131	53,451	64,177
Totals	733,322	211,452	637,384	591,539

2007 On-Peak Bilateral and Spot Purchase Activity (Actual vs Originally Filed)



2007 Off-Peak Bilateral and Spot Purchase Activity (Actual vs Originally Filed)



Q-1c

Month	On-Peak Power: Total Supplemental Purchases MWh	% Monthly Bilateral Purchases	% Short-Term Bilateral Purchases	% ISO-NE Spot Market Purchases	Off-Peak Power: Total Supplemental Purchases MWh	% Monthly Bilateral Purchases	% Short-Term Bilateral Purchases	% ISO-NE Spot Market Purchases
Jan-04	54,506	92%	0%	8%	13,455	0%	0%	100%
Feb-04	66,872	72%	11%	17%	23,539	0%	0%	100%
Mar-04	141,420	78%	8%	14%	63,115	0%	28%	72%
Apr-04	107,401	98%	0%	2%	49,482	0%	3%	97%
May-04	56,608	0%	42%	58%	23,996	0%	13%	87%
Jun-04	53,239	0%	8%	92%	25,283	0%	19%	81%
Jul-04	89,903	75%	12%	14%	27,426	0%	0%	100%
Aug-04	96,156	73%	12%	15%	39,364	0%	24%	76%
Sep-04	44,180	38%	13%	49%	32,448	0%	79%	21%
Oct-04	139,256	0%	78%	22%	78,562	0%	57%	43%
Nov-04	13,097	0%	18%	82%	40,255	0%	83%	17%
Dec-04	37,819	0%	36%	64%	13,814	0%	12%	88%
Jan-05	77,635	65%	24%	11%	20,082	0%	14%	86%
Feb-05	58,386	44%	32%	25%	25,207	0%	44%	56%
Mar-05	150,227	93%	6%	1%	67,053	85%	0%	15%
Apr-05	100,550	92%	0%	8%	58,987	94%	0%	7%
May-05	191,362	98%	0%	2%	141,334	91%	0%	9%
Jun-05	168,685	89%	2%	9%	105,184	81%	3%	16%
Jul-05	93,220	69%	2%	30%	54,264	68%	6%	26%
Aug-05	109,491	67%	1%	32%	47,339	48%	0%	52%
Sep-05	146,184	83%	2%	16%	71,578	90%	0%	10%
Oct-05	148,895	81%	4%	15%	112,187	78%	1%	21%
Nov-05	111,916	90%	0%	10%	65,306	94%	0%	6%
Dec-05	67,592	87%	0%	13%	78,757	92%	0%	8%
Jan-06	57,045	94%	0%	6%	57,578	81%	0%	19%
Feb-06	130,771	37%	58%	5%	79,510	0%	58%	42%
Mar-06	147,864	100%	0%	0.4%	47,472	81%	0%	19%
Apr-06	176,562	100%	0%	0.3%	126,109	95%	0%	5%
May-06	221,370	95%	1%	4%	129,261	68%	3%	29%
Jun-06	156,009	90%	5%	5%	75,531	91%	0%	9%
Jul-06	121,246	53%	30%	17%	121,614	88%	7%	5%
Aug-06	149,314	49%	28%	23%	92,702	95%	0%	5%
Sep-06	187,516	94%	4%	2%	104,375	57%	8%	35%
Oct-06	158,657	100%	0%	0.2%	70,868	96%	0%	4%
Nov-06	151,615	100%	0%	0.3%	87,183	99%	0%	1%
Dec-06	157,354	92%	4%	5%	114,077	87%	0%	13%
Jan-07	73,910	55%	23%	22.3%	75,638	90%	0%	10%
Feb-07	50,642	73%	11%	16.0%	70,540	87%	5%	9%
Mar-07	115,478	66%	26%	8.7%	58,315	81%	0%	19%
Apr-07	157,269	88%	1%	10.5%	78,215	59%	4%	37%
May-07	194,826	75%	6%	19.1%	112,347	76%	0%	24%
Jun-07	148,246	83%	9%	8.1%	72,858	64%	9%	27%
Jul-07	181,284	77%	14%	8.9%	89,081	79%	0%	21%
Aug-07	193,398	89%	2%	9.4%	92,606	67%	14%	19%
Sep-07	152,442	73%	17%	10.3%	103,988	51%	22%	27%
Oct-07	133,175	73%	10%	16.4%	57,284	75%	0%	25%
Nov-07	107,760	83%	0%	17.3%	54,579	86%	0%	14%
Dec-07	133,305	88%	0%	12.3%	79,321	68%	0%	32%
2004	900,457	52%	22%	26%	430,738	0%	33%	67%
2005	1,424,144	83%	4%	13%	847,280	79%	3%	18%
2006	1,815,322	85%	10%	5%	1,106,280	79%	6%	15%
2007	1,641,733	78%	9%	13%	944,774	73%	5%	22%

[Q-1d]

On-Peak

	Total ISO-NE Spot Sales MWh	Surplus Sales from Generation MWh	Surplus Sales from Bilateral MWh	Total ISO-NE Spot Sales $000	Avg Sale $/MWh
Jan	6,540	120	6,420	437	66.81
Feb	15,448	963	14,485	1,271	82.24
Mar	12,825	61	12,764	1,043	81.36
Apr	30,212	250	29,962	2,482	82.15
May	2,298	0	2,298	146	63.61
Jun	26,834	80	26,754	1,619	60.32
Jul	25,605	40	25,565	1,602	62.56
Aug	18,166	70	18,096	1,062	58.48
Sep	13,651	12	13,639	812	59.47
Oct	6,575	0	6,575	392	59.56
Nov	4,734	28	4,706	284	59.91
Dec	15,690	12	15,678	1,538	98.02
Totals	178,578	1,635	176,944	12,687	71.04

Off-Peak

	Total ISO-NE Spot Sales MWh	Surplus Sales from Generation MWh	Surplus Sales from Bilateral MWh	Total ISO-NE Spot Sales $000	Avg Sale $/MWh
Jan	27,993	3,162	24,831	1,339	47.83
Feb	25,723	1,406	24,316	1,921	74.68
Mar	15,070	3,062	12,008	800	53.11
Apr	24,923	9,935	14,988	1,541	61.83
May	15,022	2,644	12,378	810	53.93
Jun	19,678	6,614	13,065	822	41.79
Jul	21,938	2,844	19,094	975	44.46
Aug	17,826	1,690	16,136	866	48.61
Sep	17,753	3,536	14,217	816	45.99
Oct	28,328	9,989	18,340	1,240	43.77
Nov	22,826	6,282	16,544	1,157	50.69
Dec	11,756	2,802	8,954	974	82.83
Totals	248,834	53,964	194,870	13,263	53.30

[Q-1e]

2007

Month	FTR Auction $	FTR Value $	Net FTR $	ARR $
Jan	(152,858)	230,243	77,385	200,993
Feb	(147,966)	151,268	3,302	176,701
Mar	(116,734)	75,319	(41,414)	173,880
Apr	4,282	(28,034)	(23,752)	162,116
May	85,403	(91,077)	(5,674)	176,255
Jun	26,738	277,686	304,424	222,737
Jul	(337,645)	113,093	(224,552)	386,951
Aug	(133,208)	251,646	118,437	275,389
Sep	(89,401)	150,384	60,983	195,949
Oct	(120,795)	33,897	(86,898)	210,849
Nov	35,792	(40,652)	(4,861)	177,037
Dec	(27,104)	9,724	(17,381)	152,534
	(973,496)	1,133,496	160,000	2,511,389

2006

Month	FTR Auction $	FTR Value $	Net FTR $	ARR $
Jan	(44,282)	58,653	14,372	283,937
Feb	(205,854)	73,277	(132,577)	250,925
Mar	(110,859)	87,091	(23,768)	247,050
Apr	222,166	(8,215)	213,951	222,841
May	113,092	(10,775)	102,316	186,693
Jun	(76,045)	63,738	(12,306)	304,322
Jul	(91,754)	20,664	(71,090)	346,444
Aug	3,587	69,723	73,310	337,714
Sep	(158,853)	42,416	(116,438)	300,679
Oct	(4,380)	(132,606)	(136,985)	196,037
Nov	32,810	(141,823)	(109,013)	192,186
Dec	19,513	11,301	30,814	186,898
	(300,860)	133,446	(167,414)	3,055,729

2005

Month	FTR Auction $	FTR Value $	Net FTR $	ARR $
Jan	(125,331)	45,610	(79,721)	162,399
Feb	(100,506)	45,119	(55,387)	138,018
Mar	22,006	(8,190)	13,816	123,944
Apr	(16,022)	(52,550)	(68,571)	155,291
May	(21,202)	(187,680)	(208,883)	157,833
Jun	(80,132)	173,314	93,182	142,647
Jul	(154,718)	365,756	211,038	215,853
Aug	(207,260)	530,672	323,413	247,272
Sep	123,549	16,936	140,486	401,206
Oct	(149,518)	72,300	(77,218)	277,237
Nov	16,953	(119,912)	(102,959)	307,429
Dec	(84,804)	14,762	(70,041)	226,203
	(776,984)	896,138	119,154	2,555,333

2004

Month	FTR Auction $	FTR Value $	Net FTR $	ARR $
Jan	(61,337)	214,090	152,753	199,279
Feb	(80,663)	117,483	36,820	189,240
Mar	5,016	57,185	62,201	187,899
Apr	(75,787)	130,976	55,189	156,916
May	(78,300)	285,146	206,845	225,429
Jun	(209,578)	135,881	(73,697)	215,446
Jul	(148,478)	28,950	(119,528)	369,110
Aug	(152,839)	78,354	(74,484)	418,012
Sep	(163,036)	94,841	(68,196)	254,044
Oct	(139,034)	928	(138,106)	243,152
Nov	(112,303)	53,921	(58,382)	201,311
Dec	(124,292)	219,187	94,895	191,798
	(1,340,632)	1,416,943	76,311	2,851,636

2003

Month	FTR Auction $	FTR Value $	Net FTR $	ARR $
Jan	-	-	-	-
Feb	-	-	-	-
Mar	7,294	3,045	10,338	92,335
Apr	-	-	-	8,360
May	738	11,033	11,771	10,941
Jun	-	-	-	63,044
Jul	(63,876)	239,863	175,987	79,859
Aug	(132,036)	95,452	(36,583)	137,887
Sep	(138,073)	50,818	(87,255)	189,972
Oct	(29,381)	32,686	3,305	85,666
Nov	(29,979)	19,965	(10,014)	87,378
Dec	(29,047)	35,072	6,025	124,591
	(414,360)	487,934	73,574	880,032

Witness: Richard C. Labrecque
Request from: Liberty Consulting Group

Question:
Page 1 (17-21). Please describe the PSNH strategy to procure energy to supplement PSNH resources, capacity to supplement PSNH resources, and the acquisition of FTRs to manage congestion.

Response:
PSNH's supplemental energy purchase strategy is described in Section V.B.6 of the 2007 Least Cost Integrated Resource Plan, filed Sep 28, 2007 in Docket DE 07-108. Details of the supplemental energy procured for 2007 are provided in response to Q-LCG-007.

During 2007, supplemental capacity was procured via the ISO-NE administered transition period capacity market. Exhibit RCL-5 summarizes the purchase activity.

PSNH procures FTRs to hedge the potential for congestion between significant supply resources (Merrimack, Schiller, Newington, and the delivery location for bilateral purchases, e.g. the Mass. HUB) and the New Hampshire load zone. See response to Q-LCG-010 for details of the FTRs purchased during 2007.

Witness: Richard C. Labrecque
Request from: Liberty Consulting Group

Question:
RCL-2. Please condense this table as structured to its annual figures and compare the results to similar values for the last 5 years or as available data allows.

Response:
See the attached table.

PSNH Supply Resources Used to Serve Energy Requirement

		Energy Requirement MWhr	PSNH Resource Subtotal	IPP	Buyout Contracts	Vermont Yankee	Hydro	Merrimack and Schiller	Newington and Wyman	Bilateral Purchase	ISO-NE Spot Purchases	Combustion Turbines
2007	On-Peak	4,284,254	66%	8%	1%	2%	4%	46%	6%	29%	5%	0.02%
2006	On-Peak	4,224,439	67%	11%	1%	2%	4%	43%	6%	31%	2%	0.02%
2005	On-Peak	4,599,458	74%	10%	2%	2%	4%	42%	15%	22%	4%	0.06%
2004	On-Peak	4,532,956	83%	10%	2%	2%	3%	42%	24%	12%	5%	0.05%
2003	On-Peak	4,387,657	88%	10%	3%	2%	4%	42%	27%	7%	5%	0.07%

		Energy Requirement MWhr	PSNH Resource Subtotal	IPP	Buyout Contracts	Vermont Yankee	Hydro	Merrimack and Schiller	Newington and Wyman	Bilateral Purchase	ISO-NE Spot Purchases	Combustion Turbines
2007	Off-Peak	3,716,781	80%	10%	1%	2%	5%	60%	2%	14%	6%	0.02%
2006	Off-Peak	3,681,609	80%	14%	2%	3%	5%	56%	1%	15%	5%	0.01%
2005	Off-Peak	3,975,561	85%	13%	3%	2%	5%	53%	8%	11%	4%	0.02%
2004	Off-Peak	3,872,775	90%	13%	3%	2%	5%	55%	12%	3%	7%	0.01%
2003	Off-Peak	3,788,473	89%	13%	4%	3%	5%	53%	12%	2%	9%	0.01%

		Energy Requirement MWhr	PSNH Resource Subtotal	IPP	Buyout Contracts	Vermont Yankee	Hydro	Merrimack and Schiller	Newington and Wyman	Bilateral Purchase	ISO-NE Spot Purchases	Combustion Turbines
2007	Total	8,001,035	72%	9%	1%	2%	4%	52%	4%	22%	5%	0.02%
2006	Total	7,906,048	73%	12%	1%	2%	4%	49%	3%	24%	3%	0.01%
2005	Total	8,575,019	79%	11%	2%	2%	4%	47%	12%	17%	4%	0.04%
2004	Total	8,405,731	86%	11%	2%	2%	4%	48%	19%	8%	6%	0.03%
2003	Total	8,176,130	88%	12%	3%	2%	4%	47%	20%	5%	7%	0.05%

Witness: Richard C. Labrecque
Request from: Liberty Consulting Group

Question:
Page 5 (18-19). Please show how the 179 GWH of sold energy was sold on peak by month and the average price received.

Response:
See the attached table, which answers both Q-LCG-008 and Q-LCG-009.

On-Peak

	Total ISO-NE Spot Sales MWh	Surplus Sales from Generation MWh	Surplus Sales from Bilateral MWh	Total ISO-NE Spot Sales $000	Avg Sale $/MWh
Jan	6,540	120	6,420	437	66.81
Feb	15,448	963	14,485	1,271	82.24
Mar	12,825	61	12,764	1,043	81.36
Apr	30,212	250	29,962	2,482	82.15
May	2,298	0	2,298	146	63.61
Jun	26,834	80	26,754	1,619	60.32
Jul	25,605	40	25,565	1,602	62.56
Aug	18,166	70	18,096	1,062	58.48
Sep	13,651	12	13,639	812	59.47
Oct	6,575	0	6,575	392	59.56
Nov	4,734	28	4,706	284	59.91
Dec	15,690	12	15,678	1,538	98.02
Totals	178,578	1,635	176,944	12,687	71.04

Off-Peak

	Total ISO-NE Spot Sales MWh	Surplus Sales from Generation MWh	Surplus Sales from Bilateral MWh	Total ISO-NE Spot Sales $000	Avg Sale $/MWh
Jan	27,993	3,162	24,831	1,339	47.83
Feb	25,723	1,406	24,316	1,921	74.68
Mar	15,070	3,062	12,008	800	53.11
Apr	24,923	9,935	14,988	1,541	61.83
May	15,022	2,644	12,378	810	53.93
Jun	19,678	6,614	13,065	822	41.79
Jul	21,938	2,844	19,094	975	44.46
Aug	17,826	1,690	16,136	866	48.61
Sep	17,753	3,536	14,217	816	45.99
Oct	28,328	9,989	18,340	1,240	43.77
Nov	22,826	6,282	16,544	1,157	50.69
Dec	11,756	2,802	8,954	974	82.83
Totals	248,834	53,964	194,870	13,263	53.30

Totals

	Total ISO-NE Spot Sales MWh	Surplus Sales from Generation MWh	Surplus Sales from Bilateral MWh	Total ISO-NE Spot Sales $000	Avg Sale $/MWh
Jan	34,533	3,282	31,252	1,776	51.43
Feb	41,171	2,369	38,801	3,191	77.52
Mar	27,895	3,123	24,772	1,844	66.10
Apr	55,136	10,185	44,950	4,023	72.96
May	17,320	2,644	14,676	956	55.22
Jun	46,512	6,693	39,819	2,441	52.48
Jul	47,543	2,884	44,659	2,577	54.21
Aug	35,992	1,760	34,232	1,929	53.59
Sep	31,403	3,547	27,856	1,628	51.85
Oct	34,903	9,989	24,914	1,631	46.74
Nov	27,560	6,310	21,250	1,441	52.27
Dec	27,446	2,814	24,632	2,512	91.51
Totals	427,413	55,599	371,814	25,949	60.71

Witness: Richard C. Labrecque
Request from: Liberty Consulting Group

Question:
Please repeat the above request for off peak sold energy and combine the two to show that combined revenue was $26 million.

Response:
See the table provided in response to Q-LCG-008.

Witness: Richard C. Labrecque
Request from: Liberty Consulting Group

Question:
RCL-1. Please show the total cost of ownership of each of the five combustion turbines and its FCM value. As part of your response, please quantify any other value they have.

Response:
The following are the 2007 revenue requirements based on direct costs charged to the combustion turbines, with and without fuel costs:

	Rev. Req. with fuel	Rev. Req. without fuel
Lost Nation	$514K	$428K
MK #10	$398K	$294K
MK #11	$407K	$309K
Schiller #10	$325K	$176K
White Lake	$383K	$211K.

During 2007, the combined capacity value of these assets was approximately $3.3 million. The assets also participated in the ISO-NE forward reserve market and received combined revenues of approximately $4.2 million.

Witness: Richard C. Labrecque
Request from: Liberty Consulting Group

Question:
Provide details on the number of full-time equivalent staff in the Wholesale Marketing department. Include the total number of staff by function (e.g. Bidding and Scheduling) and the approximate allocation of staff expenses to PSNh, CL&P and WMECO.

Response:

	Total FTEs	PSNH	CL&P & WMECo
Bidding & Scheduling	2.00	1.75	0.25
Resource Planning / Analysis	4.00	2.00	2.00
Energy & Capacity Purchasing	1.00	0.50	0.50
Standard Offer & Default Service Procurement	2.00	0.00	2.00
Contract Administration	3.00	0.00	3.00
Administrative Support	1.00	0.25	0.75
Management	1.00	0.25	0.75
Total	14.00	4.75	9.25

Witness: Richard C. Labrecque
Request from: Liberty Consulting Group

Question:
Please provide the 2007 non-fuel revenue requirements of PSNH's share of Wyman-4 and the unit's capacity market value.

Response:
The Wyman-4 total revenue requirements for 2007 were $1,542 K. The non-fuel revenue requirements for Wyman-4 were $817K. The 2007 forward market capacity value of Wyman-4 was $679K.