Understanding New England Generating Unit Availability

Final Report

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Executive Summary

In August 2000, ISO New England, Inc. (ISO-NE), the operator of New England's bulk power system, commissioned a study of the availability (reliability) of the region's power plants. ISO-NE was interested in generating unit availability after a new wholesale electricity market opened on May 1, 1999. ISO-NE recognized that the new market represented a relatively small sampling period. Nevertheless, ISO-NE felt that it would be beneficial to review available generating unit data from January 1, 1995 through December 31, 2000.

This study is a descriptive statistical analysis of the historical availability of the New England generating units that includes the benefits of several site visits. It is not a market power study. This study was designed to accomplish three things:

1. To create a database for analyzing power plant availability;
2. To determine if plant availability changed between 1995 and 2000; and
3. If so, to determine the probable root causes.

At the onset of the unit availability study, no adequate availability database existed for New England. Plant outage and curtailment (derating) data was extracted, with considerable effort, from two business systems maintained by ISO-NE. Significant effort was devoted to ensuring that the data from these and other sources was consistent and as comparable as possible. It is recommended that the database created for this study be kept current by ISO-NE for use in future studies.

This study concludes that average generating unit availability[1] in New England declined from 1995 to 1997 and then rose again, with availability in 2000 slightly higher than in 1995. See Table ES.1.

- These changes are due mainly to long outages of the Millstone Point nuclear units.
- Average availability of all New England generating units, *excluding nuclear units*, dropped about 6 percentage points from 1995-1998 to 1999-2000.
    - i. Most significantly, the new combined-cycle units that entered service in 1999 and 2000 had poor availability – at least in part due to new design and technology.
    - ii. Fossil steam units were also an important part of the overall decline. Some were stressed in making up for lost Millstone production. Others may be reacting to incentives to keep availability high during peak load seasons, but not necessarily year round.

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[1] In this report average availability statistics are "weighted equivalent availability factors" unless we specifically note otherwise. "Weighted" means that averaging is proportional to unit size, so that a 100 MW unit counts ten times more than a 10 MW unit. "Equivalent" means that both deratings (partial outages) and full unit outages are counted, proportional to the megawatts that are unavailable. See Appendix A for the precise definition of WEAF.

iii. Other classes of units contributed little to the decline in availability. Their declines reflected ten-year planned pumped storage maintenance cycles. Inaccuracies are also possible – in fact, likely - in event reporting for small units.

- Though annual availability of non-nuclear units declined, the seasonal availability matched the demand better in 1999-2000 than it did before. This improved tracking likely was due to changes in ISO-NE maintenance scheduling and to market incentives to keep plants running during high-demand periods.

Table ES.1
Weighted Equivalent Availability Factors (%) by Unit Type, all New England Units

	1995	1996	1997	1998	1999*	2000
System Average	***79***	***78***	***75***	***78***	***80***	***81***
Fossil Steam	81	81	84	81	79	78
Nuclear Total**	63	53	32	53	82	89
Millstone Point	*65*	*15*	*0*	*16*	*80*	*92*
Nuclear w/o Millstone	*62*	*80*	*59*	*85*	*84*	*87*
Jet (aero derivative) Engine	88	92	94	93	70	88
Combustion Turbine	94	92	96	92	90	83
Combined Cycle Total**	90	92	92	89	77	78
Pre-1999 combined cycle	*90*	*92*	*92*	*89*	*91*	*89*
New (installed 1999-2000) combined cycle	*n/a*	*n/a*	*n/a*	*n/a*	*32*	*63*
Hydro	83	88	86	86	81	81
Pumped Storage	97	94	97	91	90	86
Diesel	90	94	90	89	76	88
Other	83	93	90	68	79	91

*1999: May-December only

**Nuclear and combined cycle totals are weighted averages of two subsets as shown

Section 1: Introduction, Conclusions, and Recommendations

> This study of the availability of New England's power plants was sponsored by ISO New England, the operator of the region's bulk power system. A plant availability database was created and analyzed. The study concluded that plant availability has changed and identified the probable causes.

Background

In August 2000, ISO New England Inc. (ISO-NE) engaged a team organized by Merrill Energy LLC to analyze the availability (reliability) of New England's power plants. ISO-NE was interested in unit availability after a new wholesale electricity market opened on May 1, 1999. ISO-NE recognizes that the new market represents a relatively small sampling period. Nevertheless, ISO-NE felt that it would be beneficial to review available generating unit data from January 1, 1995 through December 31, 2000.

ISO-NE is the Independent System Operator responsible for operating the bulk electrical system in New England. Dr. Hyde M. Merrill, principal investigator for this study, is an operations researcher and strategic planner with 30 years' experience in advanced power system analysis. Diamond Ridge, Inc., is a firm of software and database experts. The study team also included:

- Babcock & Wilcox, one of the world's premier boiler companies;
- Clyde V. Maughan, a recognized generator expert; and
- John C. Westcott, a well-known turbine expert.

The Study Objectives

This study is a descriptive statistical analysis of the historical availability of the New England generating units that includes the benefits of several site visits. It is not a market power study. This study was designed to do three things:

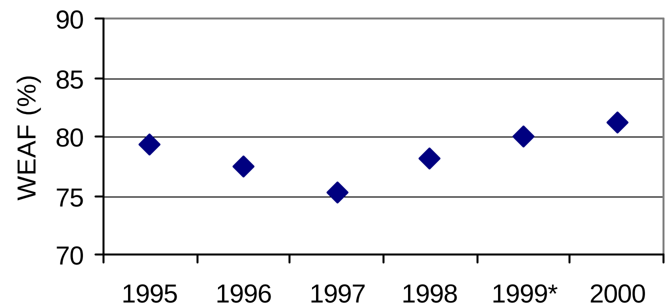
1. To create a database for analyzing power plant availability;
2. To determine if plant availability changed between 1995 and 2000; and
3. If so, to determine the probable root causes.

At the onset of the study, there was no adequate availability database available for New England. Although the North American Electric Reliability Council (NERC) maintains an engineering database with excellent and detailed reliability data, it does not include many New England power plants. Plant outage and curtailment (derating) data was extracted from two business systems maintained by ISO-NE. One covers the period before[2] the new market opened, the other after. Other data was purchased commercially and obtained from other ISO-NE sources. Significant effort was devoted to ensuring that the data from these various sources was as consistent and comparable as possible. A database was developed and used in this study.

Conclusions

This study concludes that average generating unit availability[3] in New England declined from 1995 to 1997 and then rose again, with availability in 2000 slightly higher than in 1995. See Fig. 1.1.

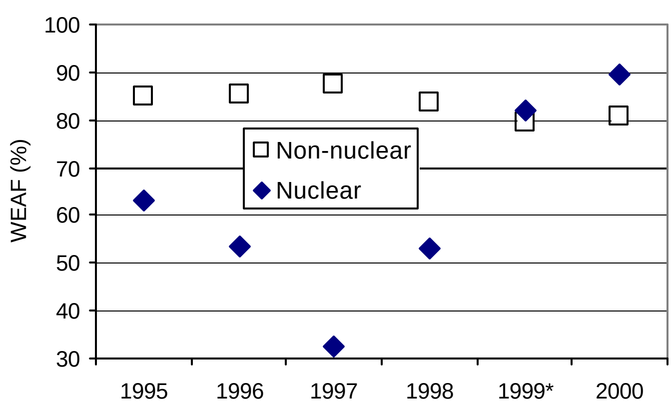
Figure 1.1
Weighted Equivalent Availability Factor (WEAF)
for all New England Generating Units



*1999: May – December only

1. This overall decline and increase are due to effects of nuclear outages, notably long outages of the three Millstone Point nuclear units. They are so large, and their outages were so long, that they dominate the availability statistics.

Figure 1.2
Weighted Equivalent Availability Factor (WEAF)



*1999: May-December only

2. Average availability of all New England generating units, *excluding nuclear units*, was about 6 percentage points lower in 1999-2000 than in 1995-1998. See Fig. 1.2.

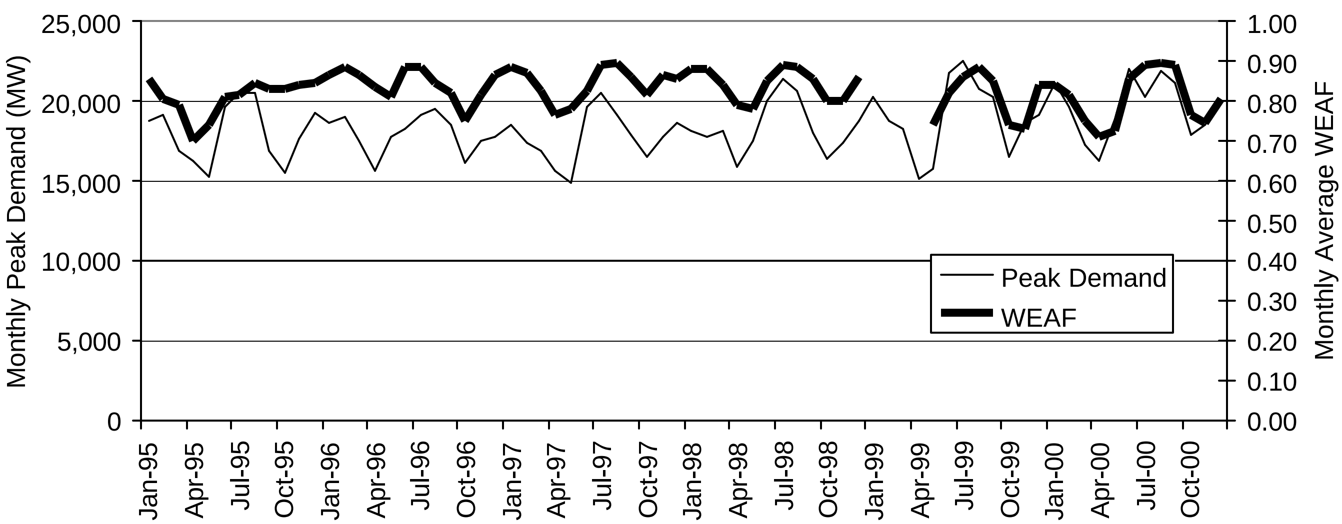
3. A decrease in availability from 1995-1998 to 1999-2000 was common to all classes of New England's generating units except for nuclear units.

4. The most significant contributors to the decline in non-nuclear availability were seven new combined-cycle units that entered service in 1999 and 2000, most of which had very poor availability.

[2] Availability data for January–April 1999 was not developed because of changes in data collecting. We do not believe that data for these four months, were it available, would affect our conclusions materially.
[3] Availability and related terms are defined in Section 2 and Appendix A.

5. Fossil steam units were also an important part of the overall decline.
   - Some fossil units were run harder (higher capacity factor, temperature, and pressure) and with less maintenance to make up for the Millstone outages, stressing the units. Their availability declined thereafter (see Section 3).
   - The market incentive to keep units running during high-demand/high-price seasons is accompanied by a relative disincentive to keep outages short during low-demand seasons. The combined effect may be a reduction in annual availability (see Section 7).
6. Declines in availability of other classes of units contributed little to the decline in average non-nuclear availability. They reflect coincidental planned outages on ten-year maintenance cycles for pumped storage units. Inaccuracies are also possible – in fact, likely - in event reporting for small units.
7. Though annual availability of non-nuclear units declined, the seasonal availability matched the demand better in 1999-2000 than it did before. See Fig. 1.3. This improved matching was likely due to:
   - *Changes in ISO-NE maintenance scheduling*, independent of the new competitive market but coincident with it, that reduced planned maintenance in the summer, and
   - *Economic incentives* to keep plants running during high demand periods when market prices for electricity are presumably higher.

Figure 1.3
Monthly Peak Demand and Monthly Average Availability (WEAF)
(Excluding Millstone Point Units)



Recommendations

As a part of this study, a comprehensive database was developed to support analysis of total system and specific unit availability and performance. This required great effort. With this data-base in place:

- ISO-NE should continue to monitor and analyze the availability of New England's generating units, including seasonal patterns.
- ISO-NE should pay particular attention to tracking the performance of new combined cycle units, because several of them have very poor availability and because they amount to a significant part of New England's generation.
- All generating units above a certain size (perhaps 30 MW) in New England should provide complete and accurate event data to the reliability database developed in this project.

Acknowledgements

This study benefited greatly from the support of ISO-NE senior management and members of several departments, including System Planning, Market Monitoring and Mitigation, Information Technology, and System Operations. Power plant managers also were gracious and cooperative in hosting fact-finding visits. This work would have been impossible without this help.

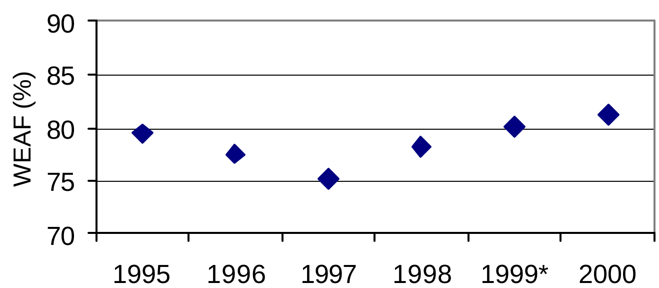
We acknowledge also the contributions of our co-workers on the consultant team.

Section 2: Availability from 1995 to 2000

A thorough analysis showed that the overall availability of generating units in New England declined from 1995 to 1997 and increased thereafter. Not all classes of units follow this pattern, however: the pattern is dominated by nuclear outages, particularly by long outages of the three Millstone Point nuclear units. Availability of non-nuclear units generally decreased from 1995-1998 to 1999-2000. The most significant contributors to the decrease were new combined cycle units and fossil steam units.

A thorough analysis showed that the reliability (weighted equivalent availability factor) of New England generating units changed significantly between 1995 and 2000. See Fig. 2.1.

Figure 2.1
Weighted Equivalent Availability Factor (WEAF)
for all New England Generating Units



*1999: May – December only

"Weighted" means that averaging is proportional to unit size, so a 100 MW unit counts ten times more than a 10 MW unit. "Equivalent" means that both deratings (partial outages) and full unit outages are counted, proportional to the megawatts that are unavailable. See Appendix A for more details on WEAF. In this report when we use the term "availability" we mean WEAF, unless we specifically note otherwise.

For most figures and tables in this report, 1999 data is for May-December only. Changes in record keeping on January 1, 1999, prevented the extraction of availability data for January-April 1999. The consultant does not believe that data for these four months, were it available, would affect the conclusions materially. It would extend the range of the 1995-1998 pre-market data by 8% and would not affect the post-market data at all.

The data available did not permit consistent segregation of planned and forced events, so the availability statistics reflect both event types.

In this and succeeding sections we explain the reasons for the changes in availability shown in Fig. 2.1 – and the reasons for changes that are not evident in this figure.

Availability of Different Classes of Units

Table 2.1 contains the annual WEAF data for New England units on which Fig. 2.1 is based. Table 2.1 also contains a breakdown of availability data by unit type.

Table 2.1
Weighted Equivalent Availability Factors (%) by Unit Type, all New England Units

	1995	1996	1997	1998	1999*	2000
System Average	***79***	***78***	***75***	***78***	***80***	***81***
Fossil Steam	81	81	84	81	79	78
Nuclear Total**	63	53	32	53	82	89
Millstone Point	*65*	*15*	*0*	*16*	*80*	*92*
Nuclear w/o Millstone	*62*	*80*	*59*	*85*	*84*	*87*
Jet (aero derivative) Engine	88	92	94	93	70	88
Combustion Turbine	94	92	96	92	90	83
Combined Cycle Total**	90	92	92	89	77	78
Pre-1999 combined cycle	*90*	*92*	*92*	*89*	*91*	*89*
New (installed 1999-2000) combined cycle	*n/a*	*n/a*	*n/a*	*n/a*	*32*	*63*
Hydro	83	88	86	86	81	81
Pumped Storage	97	94	97	91	90	86
Diesel	90	94	90	89	76	88
Other	83	93	90	68	79	91

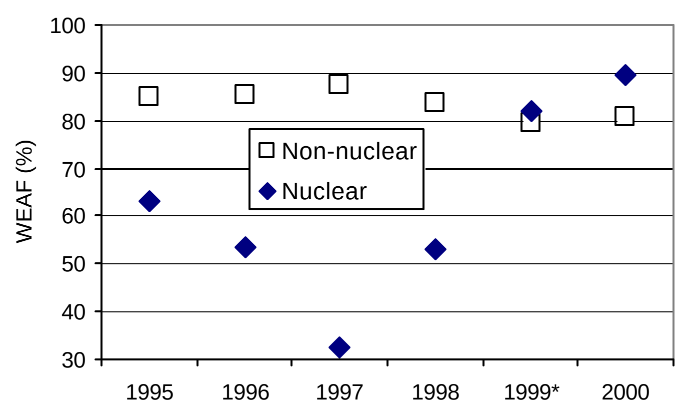
*1999: May-December only

**Nuclear and combined cycle totals are weighted averages of the two subsets shown

For most classes of units the 1999 and 2000 WEAF is down from previous years. The nuclear class is an exception, in part because of the extensive outages of the Millstone units from 1995 to 1998. The improvement in availability of the nuclear units is beneficial. After several long outages, their availability is now very good. This improvement coincided with the implementation of the new market but was not caused by it.

The WEAF of all New England generating units, *excluding nuclear units*, dropped about 6 percentage points in 1999-2000 from the 1995-1998 average. See Fig. 2.2.

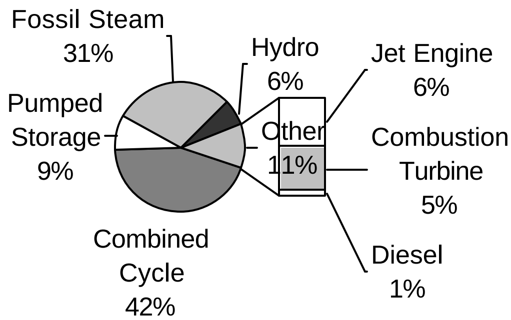
Figure 2.2
Weighted Equivalent Availability Factor (WEAF)



*1999: May-December only

Fig. 2.3 shows how much the various classes of non-nuclear units contributed to this 6 percentage point decline. Note that two classes of units accounted for nearly three-quarters of the decline: combined cycle (particularly new units) and fossil steam. These classes will be discussed further in Sections 3, 4, and 6.

Figure 2.3
Contributors to 6 Percentage Point Decline in Availability
from 1995-1998 to 1999*-2000



*1999: May-December only
Numbers in Fig. 2.3 and Table 2.2 may not sum to totals because of rounding

In computing Fig. 2.3, as well as in computing the "system average" row of Table 2.1, the WEAF of each class of units was weighted by the percent of system megawatts represented by the class. See Table 2.2 for these percentages as of May 1999.[4]

Table 2.2
New England Generation Technologies (5/1/1999)

Generator Type	Total MW	% of Total	Median Size (MW)
Fossil Steam	11,783	48.0%	48
Nuclear	4,366	17.8%	873
Jet Engine	637	2.6%	20
Combustion Turbine	967	3.9%	19
Combined Cycle	3,359	13.7%	154
Hydro	1,608	6.6%	12
Pumped Storage	1,709	7.0%	270
Diesel	121	0.5%	6
Total	24,549	100%	

Note from Tables 2.2 and 2.3 the different sizes that characterize each technology. There are many very small units in the database. Special issues associated with small units are discussed in Section 5.

Table 2.3
Most New England Generators are Small (5/1/1999)

Unit Size (MW)	Number of Units	% of System MW
0-30	160	9%
31-50	36	6%
51-100	26	7%
101-500	45	44%
Over 500	11	34%
Totals	278	100%

New England has few very large units. Long outages of some of these can also confound an analysis unless due care is taken. We have already noted the effects of long outages of large nuclear units. Because they were pervasive across a well-defined class of units, we give them special attention. Large non-

[4] The median column in Table 2.2 is the typical size of generators of each type – half are larger than the median, and half smaller.

nuclear units also have experienced long outages that affect the system statistics. For example, one large fossil unit was out of service for more than nine months in 2000-2001 due to a single unexpected event. This one event reduced the total non-nuclear WEAF by perhaps one-half percentage point in 2000, depending on what one assumes this unit's availability would otherwise have been. But except for the new combined cycle units, long outages of large non-nuclear units were not identified as part of a pattern affecting a class of units and are not treated separately.

Units Sold

Several large blocks of units changed ownership between 1995 and 2000. The availability of some of these blocks improved; others became worse. The data does not indicate that the units sold, as a whole, either improved or deteriorated in availability.

Section 3: Effects of Nuclear Outages

Major nuclear generating unit outages beginning in 1995 and peaking in 1997 stressed fossil units and reduced their availability in 1998, compared to units that were not stressed. While the stressed units continued to have lower availability in 1999 and 2000, so did the units that were not stressed in 1997. A market-related factor that may explain some reduction in availability is discussed in Section 6.

General Effects on New England Generating Units

Outage	Began	Ended
Millstone 1	11/95	retired 11/97
Millstone 2	2/96	5/99
Millstone 3	3/96	6/98

There were extensive nuclear outages in New England from 1995 to 1999, particularly at Millstone Point. In 1997 production from most fossil plants was higher than in any other year in the study period. This record production in 1997 led to lower availability in subsequent years. In fact, Fig. 2.2 shows that availability of non-nuclear units during the study period complemented the availability of the nuclear units. When nuclear unit availability declined, availability of other units improved, and vice versa.

Specifically, of 305 units active in 1996-1998, 194 (64%) produced more power in 1997 than in 1996. Since these units represented 69% of the non-Millstone capacity, it tended to be the larger fossil-steam units that compensated for the absence of the Millstone units.

More strikingly, 37% of New England's units, representing 47% of its non-Millstone capacity, had both higher production in 1997 and lower availability in 1998.

Searching for Root Causes

The figures in the previous paragraph imply but do not prove that more production in 1997 caused less availability in 1998. To prove cause and effect requires the identification of failure mechanisms and verification in the field. Nonetheless, a statistical study is valuable if it draws attention to a possible relationship that otherwise might be unnoticed, and if it shows that both the effect and the possible cause are widespread or significant.

This study provides an example of both of these contributions in a single fossil-steam plant. Managers at one plant told the study team that their plant had done nothing heroic to increase its output in 1997, and that deteriorating reliability thereafter was therefore not caused by 1997 production increases. Yet their largest unit, which was coal-fired, had 84% capacity factor in 1997, up 6 percentage points from 1996. This is a very high number for a coal unit. In order to achieve this, the unit did not get much down time, and had to be run very close to its maximum output when it ran.

For a particular unit it may not be possible to prove that *a particular* 1998 outage was caused or made worse by the increased production in 1997. Yet this same large unit demonstrated possible causal failure mechanisms. It is known that:

- Outage time must be taken eventually to make any repairs that are postponed. In 1997 the plant had very little down time. Its EAF[5] in 1995-1996 averaged 77%. It increased to 88% in 1997. Clearly there was less maintenance work done in 1997 than the average in the preceding years. This had to be made up later.
- The extreme operating conditions associated with maximum output – e.g., increased velocity of abrasive gases in the boiler and increased thermal stress – cause more damage. With an 88% EAF in 1997 and an 84% capacity factor, this unit operated at an average of 95% of its capacity all of the time, except when it was constrained down or off by deratings or outages. Since it likely was backed down occasionally for economic reasons during light load periods, there probably were many hours when it ran at or even above its rated capacity.

The change in production and availability in a given plant are relatively modest – even at this plant, where more than one unit increased its output to high levels from 1996 to 1997 and saw its availability deteriorate from 1997 to 1998. It would be hard for management of a particular plant to prove a cause and effect relationship.

As a group, the units whose output did not increase in 1997 also did not show the dramatic loss of availability in 1998. But this group did experience an equal decline a year later, in 1999. The availability of generating units in 1999 and 2000 is not correlated to whether their output in 1997 was higher or lower. If the effect of the stress persisted beyond 1998, it is not evident from the statistics.

A market-related factor may account for some of the decline in non-nuclear availability beginning in 1999. This mechanism is discussed in Section 6. Our analysis draws no conclusion as to how much of the continued lower availability of the units that were stressed in 1997 is due to the stress, how much to the market factor, and how much to some other unknown cause.

[5] See Appendix A for a definition of equivalent availability factor (EAF).

Section 4: New Combined Cycle Units

Seven new combined cycle units entered service in 1999 and 2000, almost doubling New England's resources of this type. The new combined cycle units were generally larger and much less reliable than the twenty units that were built earlier. It is normal to experience reliability problems when a unit is new, as all seven are – or when a technology is evolving rapidly, which seems to be happening.

Combined Cycle Technology

In a combined cycle unit the exhaust gas from a combustion turbine, which still contains considerable heat, is fed into a heat recovery steam generator (boiler) that powers a steam turbine. There are many variations on this theme. Supplemental firing to raise steam temperature and pressure can be done in different ways. Several combustion turbines may feed a single boiler. The steam may enter a common-header system that feeds more than one steam turbine as well as industrial processes. Development may be staged, with a combustion turbine installed for peaking duty, and later retrofitted with the boiler when growth in demand justifies the tradeoff between higher capital costs and lower operating costs.

Combined cycle units are popular today for several reasons:

1. Their capital cost ($/kW) is low compared to a conventional steam unit.
2. They are more efficient than either straight-through combustion turbines or conventional steam units.
3. They are clean, particularly if they burn natural gas.
4. They are relatively easy to permit.
5. They can be built fast (though recently the gas turbine manufacturers have had backlogs).

Combined Cycle Units in New England

New England has nineteen "old" combined cycle units that have been in service since at least 1995. A twentieth entered service in 1996. Fifteen (75%) of the old units are smaller than 200 MW. In addition seven new combined cycle units were built in 1999-2000, almost doubling New England's combined cycle capacity in two years. See Table 4.1. Five of the seven new units are larger than 200 MW. Fifteen additional combined cycle plants are under development at this writing.

The technologies of the old and new units differ. The difference in technology undoubtedly accounts in part for the differences in availability shown in Table 4.1. In

2000 only one of the new units had an EAF[6] greater than 81%, and only one of the old units had an EAF less than 81%.

Table 4.1
Weighted Equivalent Availability Factors for Old and New Combined-cycle Units

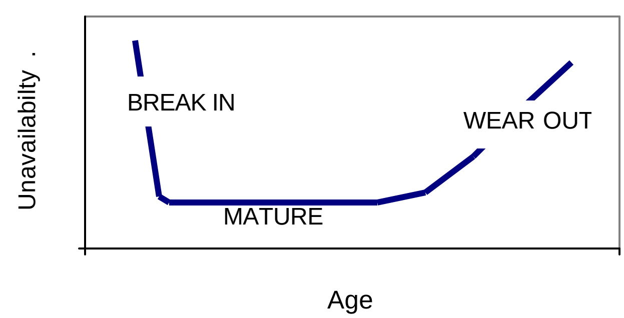
	1995	1996	1997	1998	1999*	2000
In service before 1/1/99: WEAF	90%	92%	92%	89%	91%	89%
Entered service after 1/1/99: WEAF					32%	63%
All combined-cycle units: WEAF	90%	92%	92%	89%	77%	78%
Capacity (MW)	2712	2706	2728	2760	3675	4957

Notes:
Capacity is average maximum monthly claimed capacity for each year.
*1999 data: May - December
WEAF is first computed by unit (some entered service in mid-year), then by year.

Field Observations

The project team visited one of the older combined cycle plants and one of the new ones. The contrast was striking.

Figure 4.2
Classic Bathtub Curve of Plant Unavailability



The reliability of complex mechanical equipment often follows a classic pattern called the bathtub curve. See Fig. 4.2. When the equipment is new the operators and maintenance staff learn to work with it and to deal with its idiosyncrasies. Any commissioning problems and design flaws are worked out. This break in period may be characterized by high forced outages or deratings. The unavailability then drops and remains low for many years after the problems are fixed and the operators learn how to run and maintain the equipment. As it wears out, unavailability increases again. The two plants visited are at two different positions on the bathtub curve.

[6] See Appendix A for a definition of equivalent availability factor (EAF).

An Older Combined Cycle Plant

One older combined cycle plant on the mature portion of the bathtub curve is among New England's most reliable plants.

Plant personnel reported that they experienced equipment problems during the plant's startup years, before the period of this study. These were resolved with the manufacturer, and the plant has performed well since then.

The plant maintains a high inventory of spare parts. However, gas turbine blades embody exotic metallurgy and are expensive. Rather than keep a private inventory of these parts, the plant has a lease/maintenance agreement with the manufacturer to cover spares.

Plant personnel attribute their consistently high availability in part to this inventory policy, in part to continued training in various settings, and in part to keeping a close working relationship with the gas turbine manufacturer.

A New Combined Cycle Plant

One new plant is a classic example of the break in phase of the bathtub curve. It has had an EAF of approximately 50% through the end of 2000. In addition, the plant was rated and operated at less than its design capacity. The plant reported spending or budgeting $8 million in capital improvements and system redesign since entering service.

Most of the problems at this plant were gas turbine related. The turbine design was new. Clearly, problems associated with this plant are due at least in part to an immature design. While these problems are more severe than those of many other new plants, they are representative of what can occur during the first years of operation, particularly as a newer technology is pushed to expand its limits.

Incidentally, though the new combined cycle units as a group had poor availability, one manager whose plant entered service in 2001 (after the period for which statistical analysis was done for this project) reported exceptionally good availability since startup. Not every new plant or new technology has a difficult break in period.

Initial Market Effects

There is no causal relationship between the poor availability of new combined cycle units and the competitive wholesale market.

It might be argued that the new market called the new combined cycle units forth, and that therefore their poor availability is due to the market. This seems to be the technology of choice for independent power producers. But we do not know how much combined cycle capacity would have been built under the traditional structure.

Section 5: Other Unit Types and Effects

The availability of the pumped storage units dropped in 1998 and 2000. This was due to lengthy outages on three large units. These are done on a ten-year cycle.

Data for conventional hydro, combustion turbine, jet (aero derivative) engine, and diesel units is inherently less accurate and less meaningful than data for larger units. Event reporting rules were tightened in the new market, likely increasing the reported outage statistics. Some outages and curtailments that were recorded in 1999- 2000 were undoubtedly omitted earlier.

Section 2 showed that new combined cycle and conventional fossil steam units were the most important contributors to the decline in availability of non-nuclear generating units since 1998. Sections 3 and 4 discussed possible causes for the decline in these two categories. This section discusses the decline in availability of pumped storage, conventional hydro, jet (aero derivative) engines, combustion turbines, and diesel units. See Table 5.1, excerpted from Table 2.1. The "other" category in Table 2.1 includes wind, wood-fired, and other technologies that are too few to analyze statistically and that amount to too little capacity to be of concern in this context.

Table 5.1
Weighted Equivalent Availability Factors (%) for Selected Unit Types

	1995	1996	1997	1998	1999*	2000	*Approx. % of Non-nuclear Capacity*
Pumped Storage	97	94	97	91	90	86	*8%*
Hydro	83	88	86	86	81	81	*8%*
Combustion Turbine	94	92	96	92	90	83	*4%*
Jet (aeroderivative) Engine	88	92	94	93	70	88	*3%*
Diesel	90	94	90	89	76	88	*1%*

*1999: May-December only

Pumped Storage Hydro

New England has two large pumped storage plants, Bear Swamp (two units @ 294.5 MW = 589 MW) and Northfield Mountain (four units @ 270 MW = 1,120 MW), totaling 1,709 MW.

Each unit is scheduled for a major outage of up to 18 weeks approximately once every ten years, according to ISO-NE. Records show that during 1995-1998 there was only one such outage (in 1998) while in 2000 there were two.

These major ten-year-cycle outages account for the large drop in pumped storage availability in 2000 and for the smaller drop in 1998.

Other Hydro, Jet Engine, Combustion Turbine, and Diesels

The conventional hydro, jet (aero derivative) engine, combustion turbine, and diesel units share two important characteristics: they are small (see Table 2.2) and they (particularly the thermal units) have low capacity factors.

In addition, the source data for these types includes many composite units representing several smaller units. The aggregation is not always stable. For example, the current ISO-NE Market Information System (MIS) aggregates the four Northfield Mountain units into a single composite unit; in the older system, each was recorded separately. These large units were easily identified in the analysis. The aggregation is more common with smaller units that are harder to spot. There were many changes in aggregation when the MIS became operational in May 1999. But there were also changes before and after that date.

This all means that data for smaller units is inherently *less accurate* and *less meaningful*.

- Since the units included in the aggregations can change, it is not practical to compare the availability of such units from one year to another. It is not always obvious when a unit in the source data represents a single physical unit and when it represents an aggregation. It also is not clear what the statistics for such aggregated units mean.
- Before 1999 people were less likely to bother to fill out outage or curtailment event records for smaller units. More stringent rules in today's market require more complete reporting. The newer data therefore undoubtedly includes outage events that would not have been recorded before 1999, making the availability appear lower now simply because of better record keeping.
- Small units tend to operate at lower capacity factors. This means that they are less exposed to wear and tear and hence should have lower forced outage factors. Furthermore, since they are not called upon to generate for long periods of time, maintenance can be performed without declaring a formal outage.

For example, one smaller unit had equivalent availability factors (EAF) of 98% - 100% in 1999 and 2000. But it only operated an equivalent of 2% - 5% of the time. To compare its availability to that of a unit that was required to operate more often, or to average its availability with such a unit, would be misleading.

These problems are not unique to New England. The North American Electric Reliability Council warns that its published data on smaller unit types (combustion turbines, jet engines, and diesels) is of questionable accuracy.

Incidentally, it is in part for these reasons that statistics in this study are generally averages weighted by each unit's capacity, rather than simple averages. The weighting gives less credence to inherently less accurate small unit statistics than to those from larger units.

Initial Market Effects

In summary, the lower availability of the pumped storage units in 1998 and 2000 is due to 10-year planned maintenance cycles and has nothing to do with competitive market factors.

The decline in computed availability for conventional hydro, jet (aero derivative) engines, combustion turbines, and diesels is probably due at least in part to improved record keeping in the new market. These statistics are inherently less accurate and less meaningful than statistics for other unit types. New rules associated with the competitive market require more stringent reporting of outages and curtailments. The 1999 and 2000 data therefore undoubtedly includes events that would not have been recorded in the earlier system.

Section 6: Correlation of Availability with Seasons and Demand has Increased

The seasonal availability matches seasonal demand better now than it did under the former market structure.

Total system availability sometimes shows a weekly cycle, with WEAF slightly lower on the weekends. There is no apparent repetitive daily cycle of higher and lower availability.

Seasonal Availability Correlations

Some outages are totally random and unpredictable. But power companies have long tried to do as much planned maintenance as possible during low-demand months. They have also made repairs more rapidly during the peak-demand months. Sometimes plants limp along with mechanical difficulties during the peak-demand months that would have called for outages had they occurred during the spring or fall.

Fig. 6.1 shows this effect both before and after the new competitive market in New England opened on May 1, 1999. The WEAF tracks the monthly demand better during 1999 and 2000 than it did during the pre-market period.

This observation is supported by a correlation analysis. From 1995 to 1998, the correlation coefficient, R, between average monthly WEAF and peak monthly demand was 0.52. From May 1999 through December 2000 the same correlation coefficient was 0.82. [7]

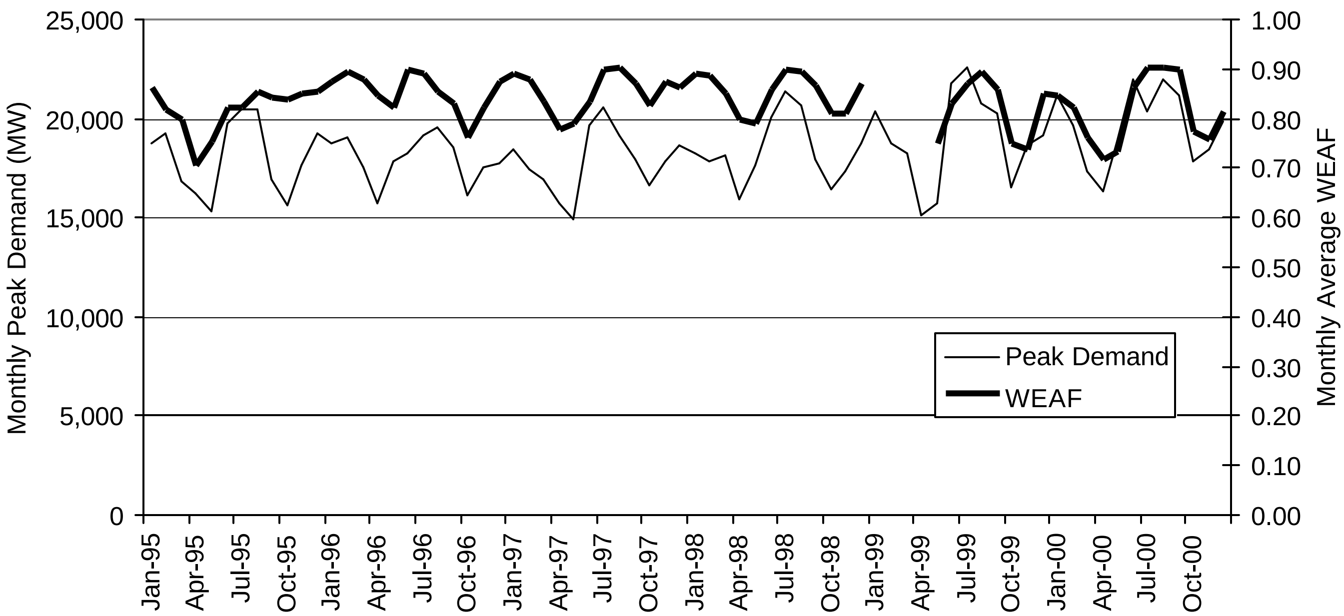
The WEAF curve in 1999-2000 has more pronounced peaks and valleys than it did in earlier years. Two explanatory mechanisms have been found.

- In the competitive market some plant owners apparently are focusing attention on being available during the high demand/high price months.[8]
- Centralized maintenance scheduling by ISO-NE changed in 1999, with more outages scheduled in the depths of the off-peak season and further away from the peak summer months.

[7] The data analyzed was for units totaling about 26,000 MW. The Millstone units were excluded. Availability data was not available for the first four months of 1999. Seasonal variations in unit capacities due to changes in ambient temperature were accounted for. The correlation coefficient can have values between –1 and 1. A correlation of 1 means that when the demand is high, the availability is high. A correlation of –1 means that when demand is high, availability is low. A correlation of 0 means that variations in availability are independent of variations in demand.

[8] Plant managers in four of the seven power plants visited as part of this project volunteered that they see a shift in corporate focus from “maximize availability” to “maximize availability when it is worth the most.”

Figure 6.1
Monthly Peak Demand and Monthly Average Availability (WEAF)
(Excluding Millstone Point Units)



In any event the WEAF in 1999-2000 was 9 percentage points higher on average during the peak months (June-August and December-February) than during the off-peak months. This is a significant improvement from earlier years, when this difference was only 5 percentage points.

Table 6.1 and Fig. 6.2 show the WEAF for the summer and fall months, excluding the Millstone and new combined cycle units. (Data associated with summer and fall is available for every study year.) The data shows improved summer availability and lower fall availability during 1999 and 2000 compared to previous years.

Table 6.1
Average WEAF
(excluding Millstone Point
and new combined cycle units)

	Summer	Fall
1995	83%	84%
1996	87%	80%
1997	87%	85%
1998	88%	82%
1999	87%	79%
2000	89%	80%

Hourly Availability

In Fig. 6.3 the available capacity is plotted for the entire month of April 2000. Daily and weekly demand cycles are clearly visible. There is not much evidence of a weekly availability cycle

Fig. 6.4 shows available capacity, demand, and energy clearing price (ECP) for each hour for May 2000, when New England experienced its highest-ever price spike. The driving force is no mystery: unusually high demand was well over the available capacity.[9] Fig. 6.4 also shows the extreme volatility of ECP. Note that the ECP axis is logarithmic.

Figure 6.2
WEAF w/o Millstones
and w/o New Combined-cycle Units

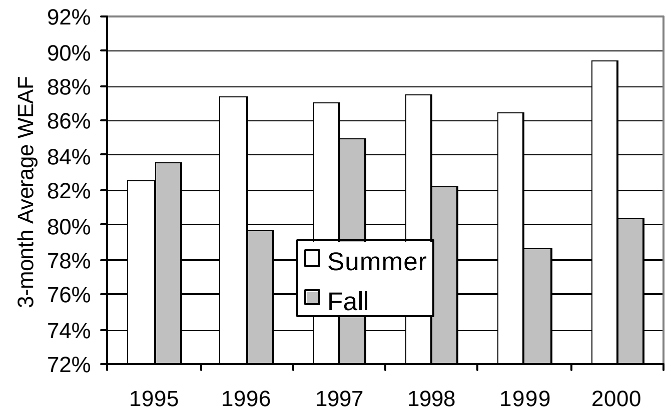


Fig. 6.3
Sample Demand and Availability Cycles
(April 1-30, 2000)

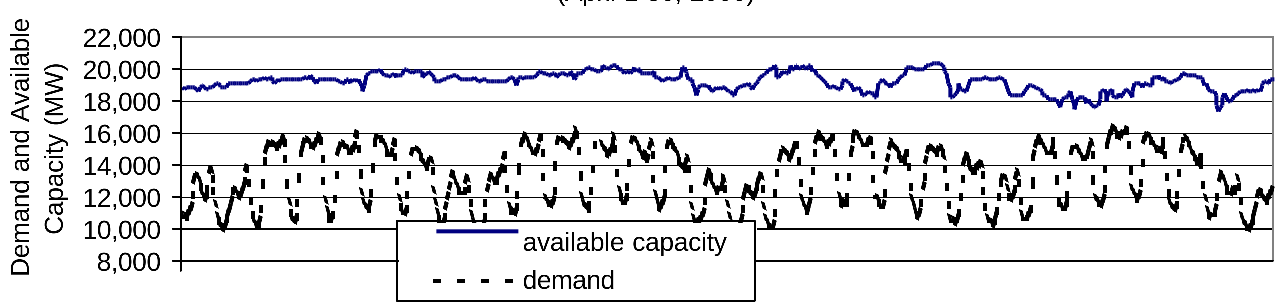


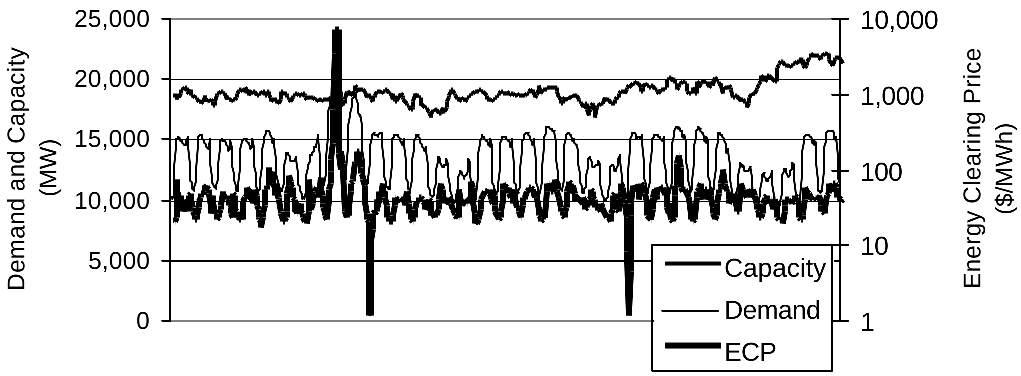
Fig. 6.4 also reveals a faint weekly availability cycle, with WEAF slightly lower on weekends. This is particularly evident in the third and fourth weeks. This cycle was not visible a month earlier (Fig. 6.3). Nonetheless, the major systematic variations in available capacity (essentially bid high operating limit – HOL) tend to be seasonal, as was shown in Fig. 6.1.

To sum up, although plant availability is highly correlated with seasonal demand cycles, it exhibits practically no correlation at all with daily cycles. This is because random forced outages or curtailments can occur at any time and hence are not cyclical. Planned

[9] In Fig. 6.4 the energy clearing price curve hides the demand curve for Monday, May 8, when the ECP reached $6,000/MWh. The demand peaked at 18,696 MW when available capacity was 17,765 MW. The next day both peak demand and available capacity were higher (18,883 and 18,716 MW, respectively) but ECP peaked at $151/MWh. That night the ECP was negative.

outages or curtailments of significant duration are scheduled well in advance to fit the seasonal demand cycles. Planned outages, which may be of several weeks' duration, tend to begin on Friday or Saturday and end early Monday morning, so they may overlap on weekends. This is the cause of the relatively weak weekly availability cycles that can be seen in Fig. 6.4 and that exist in some other months as well.

Fig. 6.4
Hourly Demand, Available Capacity, and Energy Clearing Price
(May 1-31, 2000)



Section 7: Changes in Maintenance Practices

Data on maintenance expenditures from FERC reports shows annual maintenance spending at some New England plants is in essence level from 1995 to 1999. This cannot be extrapolated to all of New England, however.

Senior staff members at seven power plants representing 32% of New England's fossil-fired capacity were interviewed. These interviews revealed no general pattern of reducing maintenance, or of managing maintenance very differently, in the new market. They recognize the market incentive to maximize availability when it is worth the most, instead of maximizing year-round availability.

Section 5 identified two changes that seem to have affected the scheduling of maintenance: more strict avoidance by ISO-NE of scheduling maintenance during peak summer months, and the market incentive to have plants available during peak demand (presumably peak price) periods.

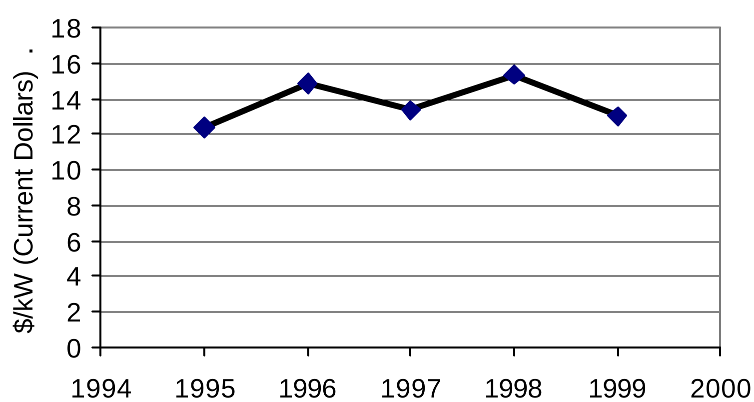
Regional Maintenance Spending

Data on maintenance expenditures can be found in FERC Form 1, which utilities are required to file each year. Independent power producers are not required to file it. As generating units were sold to non-utility generating companies – much of which happened in 1998 and 1999 – they stopped filing FERC Form 1. So while plenty of data was available for 1995, by 1999 the number of plants in the Form 1 database dropped sharply, making comparisons with earlier years more difficult.

Fig. 7.1 shows maintenance expenditures for a set of units for which five years' data was available. With fluctuations from year to year, this data shows a very slight upward trend.

While the data in Fig. 7.1 was consistent from year to year, there is still a bias: these are units that were not sold and that continue to be owned by integrated utilities.

Fig. 7.1
Annual Maintenance Expenses
(Same units each year, no nuclear, ~5,700 MW)



It is not possible to extrapolate from Fig. 7.1 and conclude that maintenance expenditures did or did not increase or decrease in general. All that can be said is that for a significant sample of New England units, there is no evidence of a recent significant drop in maintenance expenditures in recent years.

Company Changes in Maintenance Practices

The study team visited seven New England plants whose combined capacity is a significant fraction (approximately 32%) of the region's fossil-fired generating capacity. The plants were selected to capture as wide a cross section of parameters and characteristics as possible: high availability, low availability, utility owned, divested, steam, combined cycle (new and old), etc. While we found no evidence of a pattern of regional changes in maintenance practices, each company sets its own maintenance practices, and these change as conditions change.

We found that some plants maintain a high inventory of spare parts. Several units continue to suffer the effects of boiler feed water salt-water induction incidents some years ago. At least one plant has significantly reduced its personnel roster. Staff at several plants opined that the new owners seemed to have more money available for maintenance than the former owners did.

Probably the most significant observation of the visits: personnel at four of the seven plants volunteered that corporate management seems to be more interested in high availability *when the market price is high* than in high availability in general. It would be surprising if this were not so. This is a reasonable position in New England's market. It is probably in the interests of the customer as well.

Note that regulated utilities generally had a slightly different availability incentive. Public utility commissions tended to look at annual availability statistics. Allowed rate of return might reflect higher or lower annual availability.

How might this shift in emphasis affect maintenance practices? During the spring and fall, with ample reserves and presumably lower prices, plant managers have less incentive to pay overtime, etc., in order to shorten outages. During the summer and winter, they have higher incentives to do so. If they respond to these incentives, availability should be lower during spring and fall and higher in summer and winter – this has been observed and commented upon earlier in this report.

Furthermore, if plant managers respond to the reduced incentive to maintain high annual availability, annual availability is likely to drop at the same time that summer and winter availability rises. This also has been observed and commented upon earlier in this report.

Section 8: Data, Sources, and Consistency of Statistics

> Data analyzed in this study was provided by ISO-NE, by the North American Electric Reliability Council (NERC), and by commercial data vendors. Most of the data was not designed for plant reliability studies. The sources were all inconsistent with each other to some extent.
>
> Most of the project man-hours were spent getting the data right. In particular, the main source of pre-1999 availability data is ISO-NE's NABS (NEPOOL Automated Billing System). This database was discontinued when the new market began. Now the MIS (Market Information System) fills a similar role. Though the two systems are different, after considerable tuning and benchmarking the database developed from NABS, MIS, and other sources is trustworthy.
>
> ISO-NE should maintain this database and keep it current for use in future studies.

Data Sources

The following were the main sources of data for this study:

- ISO-NE's NEPOOL Automated Billing System (NABS) contains accounting and event data for the pre-market period, ending April 30, 1999. The data analyzed begins in January 1995. Data procedures were changed in January 1999, so the last four months of NABS data is inconsistent with the previous four years. The effort needed to develop data for these four months was not justified by the additional insights that it might provide. In developing availability data from NABS we therefore excluded data for January–April 1999.
- ISO-NE's successor Market Information System (MIS) contains similar accounting and event data for the post-market period beginning May 1, 1999. The data developed from MIS covers the period through December 2000.
- The Generating Unit Availability Data System (GADS) is a voluntary database and reporting system. NERC maintains it. Many utilities in North America contribute operating and outage/curtailment data. Data on plants amounting to a bit more than half of New England's capacity was made available for one or more years between 1995 and 1999. Not all plants had supplied data for all years. Because there was little post-market data, and because even in the early years data on many plants was not available, the GADS data was not useful for most of the statistical analyses. It was used to benchmark the NABS and MIS data, as described below.

- FERC Form 1 data covering the same period was purchased from Resource Data International (RDI). This included data on maintenance expenses for more than half of New England's capacity in the early years, but coverage declined to about 5,700 MW in 1999 as generating units were sold and no longer had to file Form 1.
- Monthly fuel cost data collected by the US Department of Energy (DOE) also was purchased from RDI. This covered essentially every power plant in New England from 1995 through June 2000.
- Data on equipment in each plant was purchased from Utility Data Institute (UDI), who has been collecting it for many years.

Other data was made available by ISO-NE. All of this was input to a unified database for future ISO-NE work. Combining data from different sources was surprisingly difficult and took much longer than was expected.

Lack of Useful "Outage Cause" Data

A goal of this study was to categorize outages by cause and look for patterns in that information. As the data-gathering phase progressed, it became apparent that cause information was not available in a useful form.

NERC GADS forms do have a blank for reasons for outages. NERC also has a detailed list of outage causes for each equipment type. Unfortunately, none of this detailed information is required, and as a result, very few plants submitted it.

ISO-NE has some internal systems that capture reasons for outages, notably the ISO Short Term Outage Database. There were several problems that prevented the use of this data.

- The data recording practices changed over time. Initially, most of the outage cause information was recorded for forecasting purposes and was not updated to reflect what actually occurred.
- Later data captured actual events, but could not be correlated with the hourly data from the MIS database.
- Finally, the ISO-NE outage cause data was strictly textual. Any statistical analysis would have required someone first to read thousands of outage descriptions and code them into categories manually.

For these reasons no analysis was done on outage causes, and only limited analyses of forced versus planned outages could be done. Cause data should be available in usable form in the future from the GADS database. New England power plants are required to provide GADS input data, though it will take years to build up useful amounts of data, and it is not clear that they are submitting the required data – there are no sanctions for failure to do so. We understand that in response to interim recommendations from this study ISO-NE has modified its data collection procedures to capture more cause data. It is important that such data be collected and maintained. This study was hampered by lack of such data.

New England Generating Units

Some of the observations made later in this section (and earlier in this report) reflect the special character of New England's generation mix.

Table 8.1 shows that New England has many small generating units. More than half of the region's units are smaller than 30 MW. In the NERC GADS database, 80% of the fossil steam units are 100 MW or larger. In New England, 80% of the units are 100 MW or smaller. These units account for only 22% of the MW capacity. They account for most of the difficulty in data analysis, some of which is described below and in Section 5.

Table 8.1
Most New England Generators are Small (5/1999)

Unit Size (MW)	Number of Units	% of System MW
0-30	160	9%
31-50	36	6%
51-100	26	7%
101-500	45	44%
Over 500	11	34%
Totals	278	100%

Data Consistency and Rationalizing

Data in the different source databases was collected in different ways for different purposes and with differing levels of precision. In particular, the two principal ISO-NE databases (NABS and MIS) are quite different.

Inconsistencies Between NABS and MIS Units

One problem in analyzing the available data was to resolve inconsistencies in unit identification between the NABS and MIS systems.

- The two systems used different identification numbers, and the names of the units were not necessarily the same, so simply matching one NABS unit to one MIS unit could not always be done.
- Physical units were aggregated to form accounting units. A unit in NABS could correspond to several units in MIS, or vice versa. This was particularly prevalent for run-of-river hydro units and diesels, but it occurred elsewhere as well.

Rationalizing Data

Rationalizing data and ensuring that it was interpreted correctly was an important activity in this project.

Fig. 8.1 compares weighted equivalent availability factor statistics from NABS and MIS to weighted availability factor from GADS. The availability factor is generally 0.02 or 0.03 higher than the equivalent availability factor, so the statistics from the three sources seem consistent – except that the 1999 GADS data point seems a bit high. National average data from GADS is included for interest. The New England statistics in Fig. 8.1 were computed for a common set of units for which data was available in each database for each year.

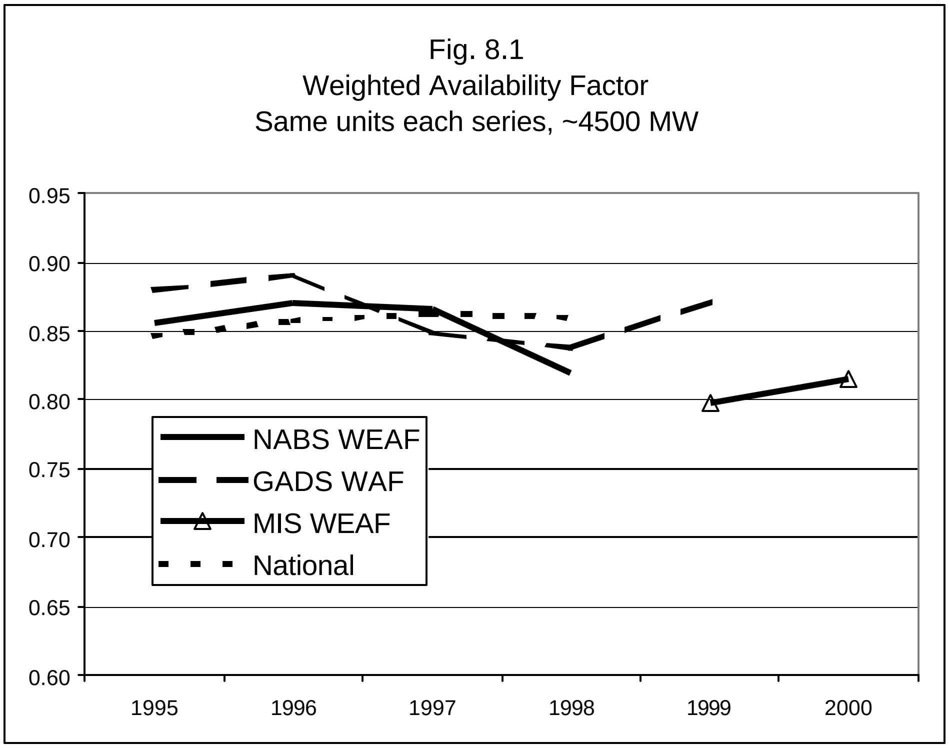


Figure 8.2 compares data developed from the MIS system to "Morning Report"[10] data published each day by the ISO-NE control center. These two independent data series agree closely. We would expect minor discrepancies because MIS covers 24 hours and the Morning Report is a snapshot or sample.

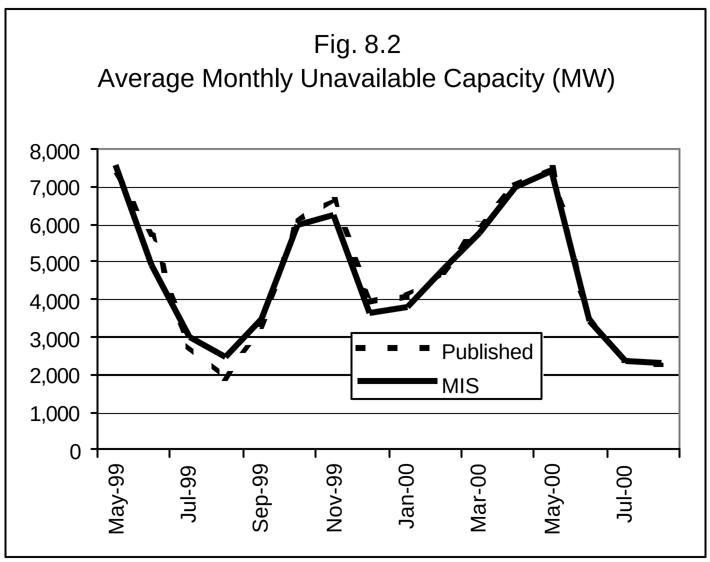
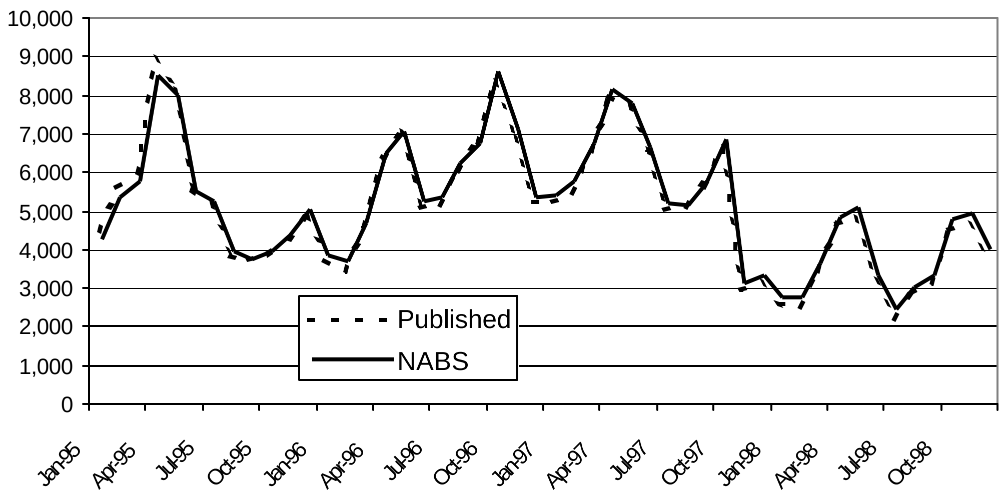


Figure 8.3 benchmarks Morning Report data to data developed from the NABS system. The data derived from NABS also agrees closely with the published Morning Report data.

[10] ISO-NE system operations and its predecessors have published the Morning Report daily for many years. Formerly circulated on paper, it is now posted on the web. It is a snapshot of the current day's demand and capacity situation. It includes installed generating capacity, outages, etc.

Fig. 8.3
Average Monthly Unavailable Capacity (MW)



Maintaining a Database

This study was able to reach significant conclusions, in spite of less-than-ideal databases, but at the dint of considerable effort. These conclusions include a solid picture of how much availability has changed recently and why this has occurred. Because of this study, ISO-NE can take appropriate and well-founded action with regard to system reliability.

It is important for ISO-NE to capture availability-related data and to keep a historical database. This project created such a database. We urge ISO-NE to maintain it.

One way of doing this is to link to the NERC GADS data structure. In the past, most utilities in North America contributed data to GADS voluntarily. With restructuring this has become less universal. New England's NEPOOL System Planning Rules & Procedures (SPRP 1), which was implemented in 2000, require that all New England generating units modeled in the energy management system submit availability event data in GADS format.

It is important that this be done. GADS is the most polished database available for capturing reliability and certain other engineering data on New England's units. The present study would have been significantly easier to carry out had GADS data on all units been available.

Nonetheless, for purposes of studying unit reliability, we see no point in requiring small units to contribute. This is an unnecessary burden with dubious benefits. We recommend that the reporting threshold be perhaps 30 MW.

Appendix A – Glossary and Definitions

Available Hours	AH	Sum of all SH, RSH, pumping hours, and synchronous condensing hours
Equivalent Availability Factor	EAF	See equations below
Equivalent Planned Derated Hours	EPDH	Sum of the planned derated hours multiplied by the size of each reduction, all divided by SCC
Equivalent Unplanned Derated Hours	EUDH	Sum of the products of UDH and the size of each reduction, all divided by SCC.
FERC Form 1		A report containing equipment, operating, and financial data, filed annually by utilities subject to regulation by the US Federal Energy Regulatory Commission
Forced Outage		NERC: an outage that requires that a unit be removed from service immediately or within six hours
Generating Availability Data System	GADS	NERC's major database on generating unit outage and performance information
Maintenance Outage		NERC: an outage that can be deferred beyond the end of the next weekend, but that requires that the unit be removed from service . . . before the next planned outage
Market Information System	MIS	An ISO-NE system, the primary source for post-market outage and performance data
NEPOOL Automated Billing System	NABS	An ISO-NE system, the primary source for pre-market outage and performance data
North American Electric Reliability Council	NERC	A non profit organization dedicated to promoting the reliability of electricity supply in North America and sponsored by organizations representing all segments of the electric power industry

Period Hours	PH	Number of hours a unit was in the active state; a unit generally enters the active state on its commercial date
Planned Outage		NERC: an outage that is scheduled well in advance and is of a predetermined duration, lasts for several weeks, and occurs only once or twice a year
Reserve Shutdown Hours	RSH	Number of hours a unit was available for service but not electrically connected to the transmission system for economic reasons
Seasonal Claimed Capability	SCC	Capacity a unit can sustain over a specified period, minus the losses due to station service or auxiliary loads, recognizing seasonal (especially ambient) conditions
Service Hours	SH	Number of hours a unit was electrically connected to the transmission system
Unplanned Derated Hours	UDH	Sum of all hours during forced deratings and maintenance deratings plus any scheduled derating extensions of any maintenance deratings
Weighted Availability Factor	WAF	Same as WEAF except that only full outages are considered – derated hours are ignored
Weighted Equivalent Availability Factor	WEAF	See formulas below

Equivalent Availability Factor (EAF) for a single unit:

$$EAF = \frac{Equivalent\ \ Available\ Hours}{Period\ \ Hours} \times 100$$

$$EAF = \frac{AH - (EUDH + EPDH)}{PH} \times 100$$

Weighted Equivalent Availability Factor (WEAF) for a set of N units:

$$WEAF = \frac{\sum_{i=1}^{N} (EAF_{unit\,i} \times SCC_{unit\,i})}{\sum_{i=1}^{N} SCC_{unit\,i}}$$