$53,000 at the California-Oregon border. The factors contributing to the rising trend and the price spikes are discussed in the remainder of this section.

Although prices spiked to extraordinary levels on December 11 and 12, as shown in Figure 10, it is not clear how much power was purchased at these prices, and we lack available information to determine the degree of exposure of utilities and their customers in the Northwest. Based on the volumes reported in Megawatt Daily, however, it does appear that overall quantities bought diminished as prices spiked (see Figure 11.) The quantities reported in Megawatt Daily do not represent estimates of total market quantities, but only the actual quantities included in the price survey. If changes in these quantities are representative of general changes in the market, they do show a marked reduction in purchase quantities beginning in the first week of December when the market began to founder and prices started their path to extreme values.

Weather and Hydro Conditions

As noted in the last section, Northwest weather and climatic factors, specifically temperatures and stream flow conditions, did not appear to be critical factors over the
summer or during the early fall. But temperature, precipitation and stream flow conditions changed for the worse during November and early December.

Figure 12 shows the monthly temperature rankings from September to December in three western regions, showing that the entire west experienced an extremely cold November. Nationwide, November was reported as the second coldest November of the 106 on record, with only the winter of 1911 being colder. Idaho, Wyoming, Utah and Arizona experienced their second coldest winters on record, and California and Colorado their third coldest.\(^9\)

Figure 12 shows general temperature conditions, but doesn't show how closely related concerns about weather during the week of December 11 were in early December when prices started to rise. Forecasts during the first week of December anticipated a "polar pig" arriving the next week and bringing record-breaking temperatures for the entire west. The frigid temperatures were forecast to last the entire week \(^9\). These forecasts combined with a series of Stage 2 emergencies at the California ISO, fueled the trading on Friday, December 7, when prices for power delivered on Monday, December 11, rose to $4,000 at Mid-Columbia. During the week beginning Monday, December 11, the extreme cold arrived, but the extreme conditions did not last quite as long as predicted, with a moderating trend through the week. Prices subsided as temperatures moderated.

Extreme cold was not the only weather-related factor in the power shortages and high prices. Precipitation in the Northwest, which had been at least at normal levels in September and October, fell to low levels in November and December (see Figure 13) raising growing concerns about the available hydropower at the normal peak winter period in January or February. The precipitation conditions were accompanied by a significant shift in stream flow conditions from normal to low levels through November. The Figure 14 shows how the average stream flow index for Washington fell rapidly until mid-December, reinforcing other demand and supply conditions leading up to the December price spikes.

\(^9\)Natural Gas Intelligence, December 11, 2000, based on reported information from Salomon Smith Barney.

Figure 12. Rank of Regional Temperatures


Figure 13. Rank of Regional Precipitation

Source: NOAA website, www.ncdc.noaa.gov/tempclimate/research/taq3
Other Factors Contributing to High Prices and Price Spikes

Several other key factors contributed to the power shortage and price events. There were no emergency conditions at the California ISO in October, permitting power prices to moderate somewhat. As power shortage concerns deepened in December, California experienced a return of emergency conditions. These conditions show up clearly in Figure 15, which plots the hours under each of the emergency stages for the days in November and December. The emergencies were a result of worsening supply and demand conditions, but they fed back into the market, creating additional market stress about the ability to find supplies to meet demand and making the market aware of the vulnerable status of the California ISO.
Environmental factors continued to exert further stress during the period. For natural gas supply, they affected both price and quantity. First, prices for NOx permits continued at high levels (see Figure 16) in Southern California. The rules governing the use of these permits make it difficult to directly estimate the impact of their prices on generation costs, but prices at the levels seen since August 2000 are bound to exert upward cost pressure on prices in Southern California and influence power prices in the west when gas is on the margin. Given the conditions in California, gas could be expected to be on the margin much of the time. The impact can be particularly pronounced under emergency conditions, when older units with very high NOx emissions rates are needed to meet load.

Second, environmental restrictions could prohibit certain plants from running at any price. When plants are subject to hard limits on output of NOx emissions, special waivers are needed to permit the plants to run. The need to obtain permits, and the negotiated outcomes that arise, make the environmental component of power pricing an even more uncertain exercise than it is under more normal conditions. This condition occurred during critical times in November and December: 2000 MW of AES gas-fired capacity were taken offline at the end of November under regulatory pressure to install
scrubbers. This capacity was returned to service after the high prices on December 11, when AES reached an agreement with the South Coast Air Quality Management District that eased penalties and permitted the capacity to return.

Finally, there are environmental requirements to maintain flow levels for the protection of fish populations which limit the use of water for power generation. As stream flows diminish, the need to release a certain amount of water to preserve the environment will have a major impact on the available energy from hydropower in the Northwest. The water level behind Grand Coolee Dam in the Northwest is the second lowest of the last 25 years, approaching the level in 1989, a level far below all other years from 1975 to date.\textsuperscript{12}

Outages were commonly cited by the California ISO as a contributing factor in California emergencies, and appear to have been important in other geographic areas as well. The only systematic outage data available for this study were from the California ISO for December. These data show that outages were high during the first week in December, but were lower in the remainder of the month (see Figure 17.) The specific relationship between these outages and power shortages and prices cannot be determined

\textsuperscript{12}Assessing the 2001 Outlook, Northwest Power Planning Council
from these data. The high level of outages during the week of December 4 to 10 probably contributed additional market stress as prices began to rise, and the lower level during the week of December 11 to 18 probably contributed to the relatively swift fall of prices from the highest levels. It is difficult to draw any further conclusions from these data, and no conclusions can be systematically extended to the Northwest.

Although we lack detailed quantitative information outside California, it appears, from trade press reports, that some scheduled maintenance was delayed from October to November out of concerns that high temperatures would last through October. The normal winter period is January, so a large amount of planned maintenance was still being performed in December. These conditions are consistent with the level of planned maintenance shown in the California ISO data in Figure 17. In addition, three large nuclear units were out of service for scheduled maintenance at the same time in November. One of them, Diablo Canyon-1 was delayed for two weeks, finally returning around November 22. None of these conditions is inherently suggestive of a pattern of withholding. Even when specific requests to delay maintenance were granted, the results could be mixed. Maintenance on Diablo Canyon-2, scheduled for 4 days at the beginning of December, was delayed until the second weekend in December, from

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December 9th to 11th. As a result the unit went down for maintenance, just as the power price for Monday, December was spiking to $4000 at Mid-Columbia. The unit came back into service late in the day on Monday, in time to contribute to moderating prices during the week, but too late to help mitigate the dramatic spike on Monday.

Combining the Factors: a Descriptive Statistical Analysis

Several of the factors discussed in this section were quantified and developed as a daily time series of prices and conditions. The time series was then used to quantify the relationship between power prices and these factors. The following factors were used in a statistical analysis of on-peak, day-ahead power prices reported in Megawatt Daily for the Mid-Columbia delivery point:

- Temperature Conditions in the Northwest. The temperature in Seattle as reported by the Accuweather.

- Emergency Conditions in California. For this purpose, the presence of emergency conditions was measured by the number of minutes in Stage 2 emergency each day, using data from the California ISO.

- Stream Flow Conditions. This measure used daily stream flow information for Washington. Two separate measures were constructed: an average index for each day across all streams, and a percentage of streams with flows below the 25th percentile.

These operating variables were used in a regression analysis to explain the price of power at Mid-Columbia. Using a statistical measure known as the coefficient of determination, or \( R^2 \), these variables are highly significant and explain 94 percent of the variation in the Mid-Columbia power price. This result confirms the belief that these fundamental operating conditions were important in explaining the price of power.

Obtained and made public by the Natural Resources Defense Council, March/April 2002
Preliminary Summer 2001 Reliability Assessment

INTRODUCTION

The purpose of this report is to provide a preliminary assessment of the Nation’s electricity supply and delivery systems this summer.

The North American Electric Reliability Council (NERC), formed in 1968, is responsible for ensuring the reliability of the North American bulk power system. NERC works with all segments of the electric power industry and relies on a system of voluntary efforts and “peer pressure” to ensure compliance with its reliability standards. NERC is comprised of ten regional reliability councils encompassing virtually all of the continental United States, Canada, and the northern portion of Baja California Norte.

NERC defines the reliability of the interconnected bulk power system in terms of two basic, functional aspects:

Adequacy — The ability of the electric system to supply the demand and energy requirements of customers at all times.

Security — The ability of the electric system to withstand sudden disturbances such as unanticipated loss of system elements (e.g., generating units, transmission lines, etc.)

Generally speaking, adequacy refers to the amount of generating capacity available to meet system loads, while security encompasses to the day-to-day operation of the power grid.

Each year, NERC produces three reliability assessments: a ten-year reliability assessment which focuses primarily on the overall adequacy of generating and transmission resources, and two seasonal assessments (Summer and Winter) which provide much more detailed information regarding the state of the power grid for the upcoming season. NERC is now just beginning its Summer 2001 Assessment, which will be released in May 2001. Much of the data in this memo is taken from NERC’s most recent ten-year assessment (released in October, 2000). As such, this information should be considered preliminary and subject to change as summer approaches.

This report looks at electric reliability primarily as a function of adequacy. However, security concerns are discussed where they have been identified. Assessments of the adequacy of electricity generating supplies typically compare peak demand and the generating capacity available to meet peak demand. The difference between capacity and peak demand is the capacity margin (measured as a percent of total capacity). We first look at capacity margins at the national level then regional levels, and progress down to specific regions of concern.
NATIONAL OUTLOOK

HISTORICAL CAPACITY AND DEMAND

• Figure 1 shows total capacity, summer peak demand, and capacity margins for the U.S. over the past decade. Since 1990, summer capacity margins have fallen from 22% to just under 15% in 2000.

• From 1990 to 1999, peak demand has grown, on average, 2.5% per year, while total generating capacity has grown an average of 0.8% per year. Between 1989 and 1998, U.S. transmission capacity, as measured by transmission miles per MW of peak demand, decreased by 16.2 percent.

• According to the North American Electric Reliability Council (NERC), peak load for Summer, 2000 was just under 686,000 megawatts (MW), while the available capacity was roughly 755,000 megawatts, resulting in a capacity margin of 14.6%.

• This decline in capacity margins; however, does not necessarily mean that the U.S. bulk power system is less reliable today than in the past. There are many reasons why lower capacity margins can result in the same level of reliability (e.g., power plants today are less likely to suffer from unexpected equipment failures).

SUMMER 2001

• NERC’s most recent forecast for Summer, 2001, projects peak load will be 702,000 megawatts (assuming “normal” weather), while available capacity will be 782,000 megawatts, resulting in a small increase in this summer’s national capacity margin compared to last summer.

• From January, 2000, through February, 2001, NERC seasonal assessments indicate that a net total of 26,500 megawatts of capacity will be added. This amounts to a 4% increase in capacity.

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1Historical data (1990-1999) is from the North American Electric Reliability Council (NERC), Electricity Supply & Demand 2000. Note that final data for 2000 are not yet available. Data for 2000 and 2001 are projections from the NERC 2000 Ten-Year Reliability Assessment.
FIGURE 1: U.S. Capacity and Peak Demand: 1990-2001

- Summer Peak Demand
- Total U.S. Capacity
- Summer Capacity Margin

[Graph showing U.S. capacity and peak demand from 1990 to 2001 with bars and line graph representing different metrics over the years.]
REGIONAL OUTLOOK

While national estimates of peak demand and capacity can provide a starting point for a discussion of projected generation adequacy, these figures provide very little information regarding reliability because electricity markets and infrastructure have distinctive regional characteristics. Supply shortages in one region are often masked by surpluses in other regions when examining national data. Thus, region-by-region assessments are essential for identifying where generation capacity may be inadequate to meet peak demand.

Regional reliability assessments typically focus on the three major interconnections — the Eastern Interconnection, the Western Interconnection, and Texas (ERCOT). These three major interconnections are further broken down into ten NERC regional reliability councils (see Figure 2) NERC projections for peak demand and capacity in each NERC region for Summer 2001 are provided in Table 1. (As noted previously, these data are preliminary and subject to change as summer approaches and updated projections are received by NERC.)

FIGURE 2: NERC Regional Map
<table>
<thead>
<tr>
<th>REGION</th>
<th>EXISTING CAPACITY As of Summer '99 (Megawatts)</th>
<th>CAPACITY ADDITIONS Jan 2000 through Feb 2001 (Megawatts)</th>
<th>PROJECTED CAPACITY FOR SUMMER 2001* (Megawatts)</th>
<th>PROJECTED PEAK DEMAND FOR SUMMER 2001 (Megawatts)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ECAR</td>
<td>105,980</td>
<td>3,717</td>
<td>108,426</td>
<td>99,562</td>
</tr>
<tr>
<td>ERCOT</td>
<td>59,504</td>
<td>6,594</td>
<td>69,639</td>
<td>56,501</td>
</tr>
<tr>
<td>FRCC</td>
<td>38,243</td>
<td>2,125</td>
<td>41,141</td>
<td>38,445</td>
</tr>
<tr>
<td>MAAC</td>
<td>57,703</td>
<td>1,215</td>
<td>59,902</td>
<td>51,762</td>
</tr>
<tr>
<td>MAIN</td>
<td>51,710</td>
<td>3,145</td>
<td>58,694</td>
<td>52,128</td>
</tr>
<tr>
<td>MAPP**</td>
<td>32,951</td>
<td>79</td>
<td>33,168</td>
<td>33,490</td>
</tr>
<tr>
<td>NPCC</td>
<td>58,621</td>
<td>2,127</td>
<td>64,443</td>
<td>54,170</td>
</tr>
<tr>
<td>SERC</td>
<td>150,254</td>
<td>4,810</td>
<td>161,155</td>
<td>156,533</td>
</tr>
<tr>
<td>SPP</td>
<td>42,643</td>
<td>651</td>
<td>44,071</td>
<td>40,127</td>
</tr>
<tr>
<td>WSCC</td>
<td>135,872</td>
<td>2,014</td>
<td>141,715</td>
<td>119,130</td>
</tr>
<tr>
<td>TOTAL</td>
<td>733,481</td>
<td>26,485</td>
<td>782,454</td>
<td>701,848</td>
</tr>
</tbody>
</table>

Source: NERC Electricity Supply & Demand 2000.

*Projections for Summer 2001 include additional capacity that might be added after February 2001 but before summer. Final data on capacity additions for 2000 is not yet available. Estimates of capacity additions through Feb 2001 (column 4) are based on ongoing NERC projections made throughout 2000. Some of these plants may not have in fact started operation in 2000.

**Data are for the U.S. only. Additional capacity in MAPP is located in Canada, giving the MAPP region an adequate overall capacity margin.

Table 2 provides new capacity data for each state.
Areas of Concern

CALIFORNIA

SUMMARY: California's electric power system, which has been experiencing unprecedented and increasingly frequent problems, is likely to experience even greater problems during the summer of 2001. The projected summer peak demand, which is a function of forecasted temperature and other parameters, is likely to be about 50% higher than current (winter) peak demands. Projected capacity shortfalls could exceed 4,000 MW (virtually every summer 2001 estimate for California projects electricity shortages, with some estimates as high as 12,000 MW), resulting in continued or even escalating energy emergencies. Under certain conditions, particularly situations involving multiple contingency events, such emergencies could lead to deep load shedding. In addition, because the Western power grid is so highly interconnected, problems in California could adversely affect the Pacific Northwest and other regions of the West. The entire Western grid will remain vulnerable to unexpected events of large magnitude (e.g., loss of key high-voltage transmission lines, loss of large generating units, disruptions in natural gas supplies, etc.). Such events could cause cascading problems that lead to widespread, uncontrolled blackouts throughout the West.

BACKGROUND: For the past six months, California's Independent System Operator (CA-ISO), the not-for-profit corporation chartered by the state to manage the flow of electricity along the long-distance, high-voltage power lines that make up about 75% of California's electricity grid, has struggled to meet daily electricity demands. The State experienced record curtailments and rolling blackouts affecting hundreds of thousands of customers in northern and central California in January, and Stage 3 emergency alerts, which are issued when operating reserves are forecasted to be less than one-and-a-half percent, have been a daily occurrence for a record 25 days.

ASSESSMENT: The California Independent System Operator (CAL-ISO) indicated in November 2000 that 2001 Summer demands could exceed available resources at the time of peak by 253 MW (mild temps) to 4,152 MW (hot temps). These projections include imports of 4,500 MW from outside the ISO, 1,421 MW of new generation, continued operation of CAL-ISO's 44,050 MW of existing generation (except for any generator maintenance outages and deratings due to low water conditions at hydro facilities), and a provision for required operating reserves. (Interruptible demands have not be subtracted from the demand forecast, but that may be academic as all of the hours of interruption allowed under these contracts were used up during the month of January.)

In the northern part of the state, hydro-powered electric generators will be limited by low water levels, as will imports from the Pacific Northwest.

California has an internal transmission constraint that limits how much power can be moved.
from the southern to northern portions of the state (Path 15). Therefore, most of the reliability problems are expected to occur in northern California.

- Summer peak load estimates forecasted by the CA-ISO are in the 45,000 MW (mild summer temperatures) to 49,000 MW range (hot summer temperatures). The peak load for normal temperatures is estimated to be in the 47,000 MW range.

- Demand growth is estimated to be between 1.8 – 2.1%, although demand in some regions of the state is growing at nearly 15%

- Summer peak demand includes electric motors driving compressors for air conditioners, which create more demanding inductive loads, rather than heating-based resistive loads, which are more easily managed. This characteristic creates system control problems that stress the grid. These problems are amplified during peak load conditions.

- In late January, PG&E had exhausted the entire 2001 annual allowance for the state’s interruptible customer program. This program, which includes about 170 commercial and industrial customers, amount to about 400 MW.

**Supply**

- The installed capacity in California as of January 1, 2000, is about 52,700 MW. Although no major power plants have been built in California in the last 10 years, nine new generating plants are currently under construction in the state. The California Energy Commission estimates that 1,800 megawatts of new capacity will begin operation this summer.

- Estimates of the required imports to meet summer peak demands range from nearly 5,000 MW (mild summer temperatures) to over 8,500 MW. Expected import capacity is projected to be about 4,600 MW. Therefore, the demand for electricity during the summer 2001 could exceed supply by up to about 4,000 MW, depending on weather conditions, levels of conservation, the availability of electricity imports, the status of generating units, and other factors.

- There has been a severe lack of snow and rain in the Northwest, which depends on hydropower for about 75% of its electricity and has been a key source of emergency power for California in recent months. The Northwest River Forecast Center (Portland) estimates the January–July flow of water through the vast Columbia River basin at only 63% of normal. As a result, hydro reserves are low and as summer demands increase in the Pacific Northwest, hydro-based imports may not be readily available. This is likely to be a major constraint for the summer.

- Plant outages were higher in summer of 2000 than during summer of 1999. Unplanned outages were 3,391 MW in August, 2000, compared to 604 MW in August 1999. This is
partly attributable to age of the generating units (82 percent of the fossil plants are over 30 years old, and 37 percent are over 40 years old), maintenance practices, and other factors. Since some plants were run beyond their normal maintenance intervals to meet winter demand, there may be an increase in forced outages over the summer months. An increase in unplanned outages could have a significant impact on available supply during peak times.

- California relies heavily on natural gas in meeting electric power requirements. Gas-fired generation accounted for 49% of power generated in the first nine months of last year. Only 16% of the natural gas consumed in California was produced in the state, leaving California highly dependent on natural gas imports into the state. California is serviced by four major pipelines. Transwestern Pipeline Co., a subsidiary of Enron Corp., operates a line from West Texas into Southern California; El Paso Corp's El Paso Natural Gas Co. runs another large pipeline largely parallel to Transwestern; PG&E Corp's PG&E Gas Transmission Co. brings gas down from Canada; and Williams Co.'s Kern River pipeline brings gas in from the Rocky Mountains.

- Working gas in storage in California is estimated to be more than 20% below the previous 5-year average. The estimated end-year level is the lowest on record. This situation has been exacerbated by the reluctance of the gas suppliers to provide additional inventory to the financially-strapped utilities. As a result, storage draw-down rates have increased even beyond the projections. If the Summer, 2001 gas demand is as strong as projected by EIA, then expectations are that the low end-winter storage levels will present a strong challenge to the North American gas supply system. Natural gas storage provides system flexibility, which is important in offsetting the load patterns of gas-fired generation. Natural gas prices in the West roughly tripled from January, 2000 to September, 2000.

**Transmission**

- The Pacific Northwest and California are electrically connected by two primary sets of transmission lines (AC and DC lines) that distribute the power generated by the federal dam system and other Northwest suppliers to California. Given the current state of the Western grid, any disruption of the AC transmission lines (a network of 500 kV transmission lines with over 4,800 MW of transfer capability) and/or the DC transmission line (a 1,000 kV line, with nearly 3,100 MW of transfer capability) could cause immediate large-scale blackouts throughout California. Such a massive perturbation to the grid would introduce instability problems that could threaten the entire Western region.

- A transmission bottleneck exists within central California on a group of high-voltage power lines (referred to as "Path 15") which often stalls the transfer of electricity from the south to the north. Congestion occurs when power demands exceed their transmission capacity of about 3,000 megawatts. Path 15 is critical because most of California's electricity reserves and large import capabilities from Arizona and Nevada (over 9,000 MW) are in the southern part of the state. Upgrades to Path 15 cannot be completed by the summer 2001.
• A number of transmission system upgrades near San Francisco and San Diego, including upgrades to transformers, are expected to be completed by the summer.

• The DC line has been the conduit through which southern California has been sending borrowed electricity back north to Oregon during off-peak hours (thus avoiding the Path 15 bottleneck). It has also been used in some instances to send power back to northern California (via Oregon and the AC transmission lines) to meet peak demands.

interdependencies

• The loss of electric power can lead to significant problems in other infrastructures that depend on that power (e.g., natural gas, oil, telecommunications, water supply systems, transportation, banking and finance, and emergency services). It would also lead to significant business and economic, agricultural, health and safety, and national security impacts. Such "cascading" problems among the interdependent infrastructures have been seen in recent weeks in California as a result of curtailments and rolling blackouts.
PACIFIC NORTHWEST

SUMMARY: The Pacific Northwest is heavily dependent on hydro-powered electric generation. Stream flows and reservoir levels are at critically low levels. The key hydro indicator in the Northwest is runoff at the Dalles Dam on the Columbia River. Current flow is about 65% of normal, and this will be the 4th worst year on record unless they get heavy spring rains. The Pacific Northwest should be able to meet its own customer demand unless weather is extremely hot, but will likely not be able to supply California with energy as they typically do in the summer.

BACKGROUND: The information for this section is provided primarily by the Bonneville Power Administration and focuses mainly on the Federal Columbia River Power System. The Northwest Power Pool (NWPP), which includes seven states and two Canadian provinces, provided some input. Overall, NWPP expects the Northwest region to just meet its forecasted firm load.

Power planning is done on the basis of serving regional firm load for critical water year planning assumptions (1936-1937) which equates to approximately 11,000 average megawatts of firm energy load carrying capability. Under average water year conditions, the additional non-firm energy available is approximately 3000 average megawatts. However, in view of present overall West Coast conditions, including the extreme water condition, the Northwest region is estimating that it will be able to just meet firm loads and required forced outage reserves with no additional margin. Should any resources be lost to the region beyond the required forced outage reserves and or load be higher than normal the Northwest region will have to look to alternatives which may include initiating emergency measures to carry operation through a period of time.

ASSESSMENT:

Water Situation (see figures 1 and 2)

- Current below average streamflows coupled with an assumption of average conditions for the remainder of the water year result in a well below normal volume forecast for the January through July period.

- The current January-July volume forecast is 67 million acre feet (MAF) or 63 percent of normal.

- If the dry conditions continue, this would be among the five lowest water years the Northwest has experienced since record keeping began.

Hydro Generation (see figure 3)
- Below average streamflow conditions have resulted in reduced Federal hydropower generation relative to recent years that experienced average and above average streamflows.

- The projected 4,000-megawatt average reduction in Federal generation compared to generation in 1995 through 1999 is roughly equal to 4 times the amount of energy consumed by the city of Seattle.

**Thermal Generation**

- Thermal generating resources in the region are expected to be normal for the summer period with no problem areas indicated in this area.

**Transmission**

- Operational transfer capabilities for moving power to and from the Northwest are based on regular seasonal studies by the Western System Coordinating Council and its members. Studies for the summer period are scheduled to be completed during the spring period.

- It is not anticipated that transmission will be a limiting factor for serving Northwest load.

**The Water Situation**

![Streamflow Comparison Chart](chart.png)
The Water Situation

January-July Runoff Above The Dalles

Million Acre Feet

Year


Obtained and made public by the Natural Resources Defense Council, March/April 2002
NEW YORK CITY

SUMMARY: Electricity supplies will be tight this summer in NYC but supplies should be adequate to serve peak summer loads. The likelihood of shedding firm load due to supply inadequacy is small. The likelihood of widespread distribution system failures similar to those that occurred in 1999 is also small.

BACKGROUND: NYC is a "load island" meaning its peak electric demand exceeds its generation resources and it has to rely on electricity imports via the transmission system. Consolidated Edison (ConEd) estimates the NYC peak load and resources for this summer are:

<table>
<thead>
<tr>
<th>In-City Generation</th>
<th>8,480 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission Imports</td>
<td>5,000 MW</td>
</tr>
<tr>
<td>Total Resource</td>
<td>13,480 MW</td>
</tr>
<tr>
<td>Peak Load</td>
<td>10,600 MW</td>
</tr>
</tbody>
</table>

- Historical summer generator availability is approximately 90 percent.
- During the summer of 1999, New York City experienced electric power outages due to stress on its distribution system during extremely hot weather and heavy load conditions. Since that time, Consolidated Edison has improved maintenance practices and inspection schedules.
- The 2000 summer peak load was 11,825 MW and the all-time summer peak was 11,850 MW in 1999.
- The in-city generation includes approximately 400 MW of new gas-fired, combustion turbines that will be installed by June 1 by the New York Power Authority to improve electric reliability over the summer. These 40-MW generator units are being installed in sets of two and are rated at 79 MW to avoid siting requirements for generation of 80 MW and greater. Currently, the largest generator in NYC is 950 MW.
- NYC has a unique summer reliability requirement when thunderstorms approach from the West and increase the risk of losing a transmission line. During "thunderstorm alerts" the system must operate based upon the contingency of losing three 345-KV transmission lines. Normally the contingency is two 345-KV lines.

ASSESSMENT: With a state-wide 18 percent capacity reserve requirement, NYC must have 12,508 MW to serve its 10,600 MW peak load. Assuming all transmission import capability is available (5,000 MW) and a 90 percent generator availability rating (90% x 8450 MW), leaves
12,632 MW to meet the peak load requirement. The 124-MW buffer (12,632 MW - 12,508 MW) is very slim. If transmission lines go out of service or an unusually high generator outage rate occurs, ConEd would be forced to implement load reduction measures, which include heightened levels of conservation, curtailment of interruptible loads, voltage reductions and, in extreme cases, shedding firm loads. The likelihood of shedding firm load in New York City due to inadequacy of supply is small. While distribution system outages are always a possibility when equipment fails, we do not anticipate significant distribution outages (similar to those of 1999) this summer in NYC.
LONG ISLAND

SUMMARY: Electricity supplies will be tight this summer on Long Island but supplies should be adequate to serve peak summer loads. The likelihood of shedding firm load due to supply inadequacy is small. The voltage instability problem that occurred in 1999 has been corrected.

BACKGROUND: Long Island is a "load island" meaning its peak electric demand exceeds its generation resources and it has to rely on electricity imports via the transmission system. KeySpan Corporation serves most of the load on Long Island. Several municipal utilities with a total of about 140 MW of generation capacity also operate on Long Island. This discussion focuses on KeySpan's system. KeySpan estimates its peak load and resources for this summer are:

<table>
<thead>
<tr>
<th>Generation Available</th>
<th>4,386 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission Imports</td>
<td>1,200 MW</td>
</tr>
<tr>
<td>Total Resource</td>
<td>5,586 MW</td>
</tr>
</tbody>
</table>

- Peak Load: 4,468 MW

- Historical summer generator availability is approximately 90 percent.

- During the summer of 1999, Long Island experienced electric power outages due to stress on its distribution system during extremely hot weather and heavy load conditions. They also experienced widespread voltage drops and near voltage collapse in the South Fork area on the eastern end of the island. The low voltage conditions resulted from the inability of KeySpan to supply sufficient generation to serve heavy loads. Contributing to the electricity supply problem was the loss of significant transmission import capability due to a large transformer failure. Since that time, KeySpan has upgraded their transmission system including the addition of a 138-KV transmission line to the South Fork area and replacement of the damaged transformer.

- The all-time summer peak load was 4,590 MW during the summer of 1999.

- The Island's generation includes a new 40-MW gas-fired, combustion turbines that will be installed by June 1 by the New York Power Authority to improve electric reliability over the summer.

ASSESSMENT: There is a state-wide 18 percent capacity reserve requirement; however KeySpan reports that it has a somewhat less operating reserve margin of approximately 500 MW. Thus, KeySpan must have 4,968 MW to serve its estimated 4,486-MW peak load. Assuming all transmission import capability is available (1,200 MW) and a 90 percent generator availability rating (90% x 4,386 MW), leaves 5,147 MW to meet the peak load requirement. The 179-MW buffer (5,147 MW - 4,968 MW) is very slim. If transmission lines go out of service, as happened
in 1999, or an unusually high generator outage rate occurs, KeySpan would be forced to implement load reduction measures, which include heightened levels of conservation, curtailment of interruptible loads, voltage reductions and, in extreme cases, shedding firm loads. The likelihood of shedding firm load on Long Island due to inadequacy of supply is small. While distribution system outages are always a possibility when equipment fails, we do not anticipate significant distribution outages (similar to those of 1999) this summer on Long Island.
SUMMARY: For the summer of 2001, generation resources in the Midwest are generally adequate, but there are some areas that may experience tight generation supplies, which will result in capacity reserve margins falling below recommended minimums. Recent transmission facility expansions are expected to keep transmission reliability parameters for much of the region within acceptable limits. There are, however, a few areas where transmission congestion may be experienced.

BACKGROUND: The northern Midwest, particularly the area around the Chicago metropolitan area, experienced numerous electric power reliability problems in the summer of 1999. These were primarily related to problems with the distribution system and were not the result of supply shortages in generation or constraints in transmission system capability. The summer of 2000 had cool temperatures, which reduced demand below expected levels. As a result, power was available for sales to other areas for most of the summer.

ASSESSMENT:

Demand

- Summer peak demands are projected to increase at between 1.5-2.0% in the region. Peak loads are projected to be 52,000 MW in MAIN, 31,200 MW in MAPP-US, and 99,600 MW in ECAR.

- The slowing of the economy has resulted in somewhat lower than expected sales of electricity in the first month of 2001. Whether this trend continues into the summer is uncertain at this time.

- Summer peak demand is driven by loads from air conditioner motors, whose performance characteristics create system control problems. These problems are amplified during peak load conditions.

Supply

- In the MAIN region of the Midwest (including Illinois, and parts of Wisconsin and Missouri) more than 3,000 MW of new capacity was added in 2,000. An additional 2,000-4,000 MW is projected to be on line before summer. The majority of the additions are in the form of peaker plants. With these additions, reserve margins expected to be within the NERC-recommended levels of 17-20%.

- In the U.S. portion of the MAPP region of the Midwest (including Minnesota, Iowa, North and South Dakota, Nebraska, and portions of Wisconsin and Idaho) generating capacity has
been judged by NERC to be inadequate. Summer reserve margins are projected to decline to 14%, which is below the recommended level.

- In the ECAR region (including Indiana, Ohio, Michigan, Kentucky, and West Virginia) capacity margins are expected to be in the 9-11% range. There is a need for substantial new generation capacity and/or import capability to meet demand. Indiana is planning on 925 MW of new merchant plant capacity to be on-line by summer. Ohio is planning for 1,330 MW of new capacity. Aging plants and environmental restrictions on coal use, which is the predominant fuel in the region, present reliability challenges.

- Nuclear units in the region are expected to be at full capacity during the summer peak period.

- The impact of merchant generation has become a concern. Uncertainties regarding size, location, and in-service dates of the new plants has become challenging for the planning process.

- In the absence of a formal independent system operator or regional transmission organization for the Midwest and with traditional utilities no longer owning many of the power plants serving the area, there is concern over how the operation of these plants is being monitored from a system reliability perspective.

**Transmission**

- In the MAIN region, transmission capacity is generally adequate. Early completion of Commonwealth Edison's Lockport-Lombard 345 kV line has relieved some of the congestion that had been experienced in this corridor in the past. The Wisconsin Upper Michigan Interconnected System import capability is, however, inadequate. The western Eau Claire- Arpin 345 kV interface within this system constrains electricity imports from the west.

- In the U.S. portion of the MAPP region, the transmission system is judged to be adequate to meet firm obligations. There may, however, be potential restrictions if outages on certain lines, particularly near Minneapolis-St. Paul, limit energy transfers from the Twin Cities to Iowa and Wisconsin.

- The transmission networks in ECAR are expected to meet adequacy and security criteria over a wide range of anticipated system conditions as long as established operating procedures are followed, limitations are observed, and critical facilities are placed in service as planned.

- Several utilities in the northern Midwest region have already acquired firm transmission rights with the intention of utilizing those rights to acquire available power from other utilities in the region. This will assist in meeting demand during periods of normal and locally high demand. However, this leaves many of these utilities susceptible to price spikes
and/or a lack of availability of generation in cases of concurrent peak demand among the region's utilities.
SOUTHEASTERN UNITED STATES

SUMMARY: Conditions in the Southeast are expected to be much the same as the last two summers – extremely tight. A number of new generators are planned to be added by the summer. However, there may be problems delivering the energy from some of these generators to the demand centers because the transmission system additions needed to connect these generators into the transmission system are lagging the construction of generators. Some existing generators are scheduled to be out of service this spring for maintenance to add emissions related equipment. This has the potential to reduce available resources at a critical time of the year.

TEXAS

SUMMARY: Texas projects adequate capacity margins, but there are still some causes for concern in the state. Texas forecasts about 8,000 MW of new generation being added for the summer, but about 2,500 MW of this new generation is in an area of West Texas that prevents it from being delivered widely throughout Texas due to limitations in the transmission system. Some of the new generation is on the border between Texas and the southeastern United States and may not be used to serve the customers of Texas.

Texas experienced prolonged, extreme temperatures last summer, which required some generators to run many more hours than normal. This could lead to increased generator breakdowns this summer (like California experienced this winter).

A retail access pilot program is scheduled to commence on June 1, 2001 in Texas, and the ten power system operating centers (Control Areas) will be consolidated into a single center. Because June is a time of heavy electrical demand in Texas, this situation bears careful watching.

THE NORTHEAST

SUMMARY: The northeastern United States experienced a very cool summer last year. If temperatures had been normal, it is very likely that New York and New England would have experienced serious electricity supply problems. While conditions have improved in this region since last summer, it is still susceptible to shortages if customer demand exceeds expectations due to abnormally hot weather, or if a significant number of generators are unexpectedly out of service.

Last summer, New York City experienced some minor supply shortages due to a lack of sufficient transmission into the city. About 440 MW of new generation will be added in distributed locations around New York City by Summer 2001, which should help alleviate this condition and contribute resources to serving total demand in the state.