Investigation into The July 1999 Outages and General Service Reliability of Delmarva Power & Light Company

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Prepared for:

The Delaware Public Service Commission Staff

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1. Introduction

Exponent Failure Analysis Associates (Exponent) and Synapse Energy Economics (Synapse) were retained on October 29, 1999 by the Delaware Public Service Commission (PSC) to investigate all relevant matters related to Delmarva Power & Light Company's d.b.a. Conectiv Power Delivery (DP&L's) supply of electric service during the period July 4-6, 1999, including rotating load shedding (rolling outages) on July 6; and to examine DP&L's ability to provide adequate, safe, and proper service over a reliable transmission and distribution network.

Exponent and Synapse's investigation included the following:

- Preliminary reports by GDS Associates (on behalf of Staff) and by Slater Consulting (on behalf of DPA) as well as DP&L's responses to these reports were reviewed.
- A draft report prepared by a PJM Root Cause Analysis Review Team, an interim report by the US Department of Energy's Power Outage Study Team, and a preliminary report by the Maryland Public Service Commission Staff were reviewed.
- DP&L's responses to data requests that had been submitted by the PSC (116 prior data requests), and by the Delaware Public Advocate (14 prior data requests) were reviewed.
- Thirty-five key DP&L employees, including personnel from electric systems operation, transmission and distribution system planning, generating plant operations, electrical engineering and maintenance, load forecasting, system protection, interconnections and arrangements, and DP&L management were interviewed by Exponent and Synapse at DP&L's facilities on December 15, 16, and 17, 1999. Additional documents received during these interviews were reviewed.
- Three personnel from PJM, including the Chair of PJM's Root Cause Analysis Review Team, were interviewed by Exponent at PJM's facilities on January 10, 2000.
- DP&L's responses to additional data requests submitted by Exponent and Synapse (59 data requests), by the Delaware Public Advocate (13 data requests), by the DEUG (12 requests) and by the PSC Staff (2 requests) were reviewed.
- Preliminary power-flow studies were conducted at the request of Exponent and Synapse by a member of the Department of Energy's Power Outage Study Team. The results of these studies were reviewed.

This report is based on the above work.

2. DP&L System

2.1 DP&L, NERC, MAAC and PJM

DP&L is a regulated public electric and gas utility. DP&L's main electric utility business activities are generating, purchasing, delivering, and selling electricity.

Electric utilities formed the North American Electric Reliability Council (NERC) in 1968 to coordinate, promote, and communicate about the reliability of their generation and transmission systems. NERC's members are ten Regional Councils encompassing virtually all of the electric systems in the continental United States, Canada, and a portion of Baja California Norte, Mexico. The members of the Regional Councils are electric systems from all ownership segments of the industry: investor-owned, federal, provincial, municipal, state, rural electric cooperative, independent power producers, and power marketers [www.nerc.com].

The Mid-Atlantic Area Council (MAAC) is one of the NERC Regional Councils. The MAAC Region includes all of Delaware and the District of Columbia, major portions of Pennsylvania, New Jersey, and Maryland, and a small part of Virginia. The MAAC Region consists of 15 Full Members, including DP&L, and 32 Associate Members serving over 22 million people in a 48,700 square mile area. [MAAC 1997, DEUG 1-3]. [1]

PJM is the Independent System Operator (ISO) for the MAAC Region. The PJM ISO is defined by a set of integrated agreements, including the Reliability Assurance Agreement (RAA). The RAA was established to ensure that adequate capacity resources will be planned and made available to provide reliable service to loads within PJM, to assist other parties during emergencies, and to coordinate planning of capacity resources [MAAC 1997, DEUG 1-3].

2.2 Peninsula Geography

Figure 1 shows the Delmarva peninsula, which contains Delaware and sections of Maryland and Virginia. DP&L separates the peninsula into two regions, the New Castle Region in the north and the Bay Region in the south. The New Castle Region represents about 50% of the total peninsula load and 50% of the local generating capacity, but only about 20% of the peninsula area. Load and generation in the Bay Region are more dispersed, with about 50% of the total load and local generating capacity in the remaining 80% of the peninsula [Slater 1999].

In the New Castle Region, DP&L has approximately 179,000 retail and wholesale customers not including the Northeast District ("Conowingo"), which has approximately 41,000 customers. In the Bay Region, DP&L has approximately 226,000 retail and

[1] See "References"

wholesale customers [Staff 9-1]. The Delmarva peninsula has a population of approximately 1.2 million and covers an area of 6,000 square miles [DOE 2000].

In addition to DP&L, other load-serving entities on the Delmarva peninsula include ODEC, DEMEC, and the cities of Dover and Easton.

2.3 Transmission

Figure 2 shows an electric transmission system map of the Delmarva peninsula, dated July 14, 1999. Transmission on the peninsula includes 230, 138, and 69-kV lines with a 500-kV line from Red Lion to Keeney Substation.

At the northern end of the peninsula, there are four transmission-line ties to the PJM system, one 500-kV tie from Red Lion Substation to PSE&G and three 230-kV ties to PECO.

Transmission-line ties from the New Castle region to the Bay region include three 230-kV ties (two from Keeney to Steele Substation and one from Red Lion to Cedar Creek Substation) and one 138-kV tie (from Keeney to Townsend Substation).

DP&L's 1999 Transmission and Distribution Projects List includes transmission-substation capacity upgrades for the Bay Region. One specific project is the installation of a 150-Mvar Static Var Compensator (SVC) at the Nelson Substation with an in-service date of May 31, 2000 [Staff 10-2]. In addition, following the events of July 4-6, 1999 DP&L has accelerated installation dates of the following Bay Region transmission projects [DPA 4-2]:

1. Indian River 150 Mvar SVC, now scheduled for completion on June 15, 2000 (had been scheduled for completion in June 2003).

2. Indian River 50 Mvar Capacitor now scheduled for completion on June 15, 2000 (had been scheduled for completion in June 2001).

3. Steele second 230-138 kV autotransformer, now scheduled for completion after the summer of 2000 (had been scheduled for completion in June 2003 timeframe).

Completion of the above projects as well as other transmission projects will increase the voltage support available on the transmission system, particularly in the Bay Region, and therefore help to maintain adequate voltage levels on the peninsula [DPA 4-2].

2.4 Generation

Figure 3 shows the location of generating plants on the peninsula. Additional DP&L generating capacity is located off the peninsula at the Keystone and Conemaugh coal plants in western Pennsylvania and the Salem and Peach Bottom nuclear plants in New Jersey and Pennsylvania, respectively [Slater 1999].

Table I lists the generating units by fuel type, along with purchased power and dispatchable stand-by generators. The capacities shown are DP&L's maximum net capacities by season. DP&L tests the MW capacity of each unit during the winter and summer on an annual basis. Summer MW capacities are based on a 91° F ambient temperature. DP&L does not perform annual tests of Mvar capabilities of its generating units [Staff 8-30.2].

As shown in Table I, total summer generating capacity is 3,604 MW, which includes 2,627 MW of local (on-peninsula) capacity, 458 MW of remote capacity, 510 MW of net purchases (on July 6, 1999), and 9 MW of peak management dispatchable generators. The last time new generation went into service on the Delmarva peninsula was 1993, when Hay Road Unit 4 first operated [Staff 8-30.1].

Table II lists proposed generating capacity additions on the Delmarva peninsula that are listed on the PJM web site (pjm.com). The Commonwealth Chesapeake Company generating capacity addition shown in Table II is Non Utility Generation (NUG) that is planned for installation in New Church, VA, in two stages: (1) 135 MW in service in the summer of 2000; and (2) total capacity of 300 MW in service by 2001. The DP&L generating capacity addition is planned to duplicate the existing units at Hay Road: three 112-MW gas-turbine driven units planned for operation in June 2001; and a 175-MW steam-turbine driven unit planned for operation in 2002. Feasibility studies have also been completed for a 100-MW NUG in Kent County, DE (STATOIL Energy Inc.) and a 1000-MW generating capacity addition in Cecil County, MD (Old Dominion Electric Cooperative) [Staff 4-81].

Completion of the NUG in New Church, VA will aid in keeping pace with load growth in the Bay region, in reducing power transfers and transmission losses on transmission ties to the Bay Region, and in providing voltage support for the Bay Region. However, any of the generating capacity additions shown in Table II could be canceled, and any of the expected in-service dates could be delayed.

2.5 Loads

During the last twenty years, peak loads on the Delmarva peninsula have occurred during the summer months. Table III shows actual and weather-normalized historical peak loads for the peninsula for the years 1976 through 1999. These peak loads include all load serving entities on the peninsula except the Northeast District ("Conowingo") of the New Castle Region [Staff 8-30.2].

Weather-normalized summer peak loads are calculated by fitting approximately 80 actual daily peak loads to their linear regression line. The result is a statistically smoothed number that theoretically averages weather effects [Staff 2-2].

As shown in Table III, actual summer peak load for the peninsula excluding Conowingo increased from 1990 through 1999 at an annual rate of 3.41%, from 2,404 MW in 1990 to

3,253 MW in 1999.[2] During the same period, the weather-normalized summer peak load excluding Conowingo increased at an approximate annual rate of 2.51%, from 2,395 MW in 1990 to about 2,993 MW in 1999 [Staff 8-30.2].

DP&L's 1998 forecast for the 1999 weather-normalized summer peak load for the peninsula excluding Conowingo was 3,300 MW. Compared with Table III, this forecast is 47 MW higher than the actual 1999 summer peak load, and 307 MW higher than the weather-normalized summer peak load [DPA 3-2 and Staff 9-4].

DP&L's forecast made in February, 1999 for the next five years, 2000-2004, for the entire Delmarva peninsula including Conowingo, shows an annual growth in summer peak load of 1.85% per year, from 3,508 MW in the year 2000 to 3,775 MW in 2004 [Staff 2-3].

DP&L's planning and analysis of the bulk transmission system during the next ten years, 2000-2010, currently assumes an annual growth in company summer peak load of 1 to 2 %. In addition, DP&L's planning and analysis assumes a higher annual growth in company winter peak load, and a higher annual growth in the non-coincident sum of individual circuit and substation peaks [Bill Mitchell Interview].

During the summer of 1999, as a result of anecdotal reports in the media and by its employees, DP&L had become aware that during the past several years many more individuals than previously had purchased air conditioners or central air conditioning. This trend accelerated in the month of July 1999. The type of load produced by air conditioners is highly reactive and would cause voltages on the electric system on the peninsula to be lower than DP&L would have predicted for the summer of 2000 [DPA 4-2.].

2.6 Active Load Management

Active Load Management (ALM) or load curtailment reduces the load on the electric system by calling on customers who have pre-arranged to reduce their electric usage in exchange for a lower rate. In most instances, the management or curtailment is subject to a Public Service Commission tariff, which specifies terms and conditions for how curtailment will occur [DP&L Response to GDS Report].

DP&L's ALM program includes: interruptible "Q" tariff loads; Peak Management (PM); "Energy For Tomorrow" (EFT); and dispatchable customer-owned generation, as follows:

1. Interruptible "Q" tariff loads (108.85 MW). DP&L has three large industrial customers in the New Castle Region that are served under its "Q" tariff: Citi Steele USA (40 MW) and BOC Gases (32.65 MW) in Claymont, DE and Occidental Chemical (36.2 MW) in Delaware City, DE. Under the terms of the

[2] The Conowingo load was 188 MW at the time of the 1999 peak load, which occurred on July 5th at 6:00 p.m.

tariff, these customers agree to reduce demand within thirty minutes when requested by DP&L's systems operation personnel [Staff 2-17].

2. Peak Management (36 MW total: 5.4 MW for 4 hours and 30.6 MW for 8 hours). When requested by DP&L's systems operation personnel, these industrial customers agree to reduce demand within thirty minutes for up to 4 or 8 hours.
3. Energy For Tomorrow (60 MW). This is a program to cycle residential customer air conditioners and water heaters. EFT is an automated ALM component which is controlled by DP&L's systems operation personnel.
4. Dispatchable Customer-Owned generation (12 MW). These include generators in both the Bay Region, such as the City of Lewes and Berlin, and in the New Castle Region, such as J.P. Morgan and Christiana.

DP&L systems operation personnel made plans during the morning of July 6 to have ALM in place during the afternoon peak load period. ALM was initiated that day starting with 5.2 MW at 11:00 a.m. and was increased to a maximum of 208.6 MW during the hours of 4:00 to 6:00 p.m. [Staff 8-30.4].

2.7 Voltage Reduction

Voltage reduction provides a means of achieving load reduction by reducing customer supply voltage, usually by 5%. Voltage reduction is implemented by adjusting the tap settings or regulating set-points of transformers at distribution substations, and is implemented remotely by systems operation personnel. Voltage reduction lowers voltages on the distribution side of the transformers and simultaneously raises voltages on the transmission side.

On July 6, 1999, DP&L did not implement voltage reduction.

2.8 Rotating Load Shedding

Rotating load shedding (rolling outages) is instituted when a certain geographic area experiences insufficient generation, an emergency-forced outage or another problem in the generation, transmission, or distribution system serving that area. Rotating load shedding means that certain circuits are disconnected from the electrical system in order to reduce the demand for electricity and prevent more widespread outages and damage to the electrical system. After a period of time, the disconnected circuits are reconnected and different circuits are disconnected. This "rotating" or "rolling" of circuits continues until the emergency has ended and the load can be safely restored.

DP&L's systems operation personnel can initiate both manual and automated load shedding.

Prior to July 6, 1999, rotating load shedding occurred on the Delmarva peninsula in September 1970, January 1994, and July 1998. The September 1970 and January 1994 load shedding followed PJM directives to shed load on a PJM system-wide basis.

The 1998 load shedding event occurred on a hot day on July 30, after a 138-kV line had sagged into a tree between the Mt. Pleasant and Townsend Substations. An initial load shed of 50 MW started at 1:05 p.m. and ended at 1:13 p.m. A second load shed of 110 MW started at 1:49 p.m. and continued on a rotating basis until 2:49 p.m., when load shedding was reduced to 60 MW. All load shedding ended at 3:30 p.m. on July 30, 1998. At the end of load shedding, there was a delay in restoring one circuit until 3:48 p.m., due to an equipment problem at North Seaford Substation [Staff 10-6, Tom Langley Interview].

On July 6, 1999, a total of 135,776 customers on the peninsula experienced outages of varying duration and frequency from rotating load shedding.

DP&L modified the rotating load shedding program after its use on July 6. The purpose of the modification was to include more MW of load in the program, make the database easier to maintain, and provide a means to manage and predict the locations that are interrupted. The program now includes 14 separate blocks of distribution circuits with each block having between 2 and 9 circuits. The total MW load of the 14 blocks is now approximately 350 MW. The system operator can initiate shedding of any block independently and set up a schedule for switching blocks. This will allow DP&L to better communicate the locations of interruptions to emergency management agencies and customers [Staff 6-6].

2.9 Under Voltage Load Shedding (UVLS)

Under Voltage Load Shedding (UVLS) is a process that uses automatic relays to shed load on the electric system when voltage levels on the system go below selected pre-set levels. UVLS was installed to protect DP&L's electric system from major outages and possible damage. The first set of UVLS relays is set to operate at 92% of nominal voltage [DP&L Response to Slater Report].

On July 6, 1999, one UVLS relay operated at 2:30 p.m. at Oak Hall Substation in the Bay Region, tripping two circuits. One circuit was returned to service at 3:50 p.m., the other at 4:42 p.m. [Dennis Callaghan Interview].

3. Summary of July 6 Outage Events

3.1 Weather Conditions

Beginning on Saturday, July 3 and extending through Tuesday July 6, 1999, much of the East Coast and in particular the Northeast experienced sustained hot and humid weather. Extreme weather was experienced from Virginia to New England and affected utilities throughout these regions. On July 6, temperatures increased to over 100° F on the Delmarva peninsula, and the PJM temperature humidity index (THI)[3] was 85.3. These unusual weather conditions are estimated by PJM to occur only once in every 25 years [PJM 12/1999, DP&L's Response to Slater Report].

3.2 High Loads

Customer demands for electricity on the Delmarva peninsula grew each day from July 2 through July 5. For the hour ending at 6:00 p.m. on July 5, actual peak load on the Delmarva peninsula excluding Conowingo reached 3,253 MW, an increase of 140 MW or 4.5% over the previous year's actual peak, but not as high as the 1999 weather normalized forecast of 3,300 MW [Staff 8-30.2 and Staff 9-4].

On July 6, customer demands further increased. Businesses which had been either closed or operating at reduced levels over the holiday weekend returned to full operation. The Delmarva peninsula peak load would have increased again on July 6, except for the effects of ALM and rotating load shedding, which reduced the peak load below the July 5 peak. At 5:00 p.m. on July 6, the peninsula load including Conowingo would have reached 3,449 MW without load shedding. The peninsula peak load excluding Conowingo would have reached approximately 3,350 MW without load shedding, which exceeded the 1999 forecast of 3,300 MW by approximately 50 MW or 1.5%. [4] [DP&L's Response to Slater Report, Staff 8-30.3, Staff 9-4].

Similarly, on July 6 PJM reached a new peak load of 51,600 MW with all ALM programs and a 5% voltage reduction in effect. This new peak load exceeded PJM's 1999 forecast peak load of 47,570 MW (with all ALM programs in effect but no voltage reduction) by almost 4,000 MW or 7.8% [PJM 12/1999].

3 THI is a composite measurement of temperature and humidity.

4 During the afternoon of July 6, 1999, a tree fell on a line in the Conowingo district. There was an outage of approximately 90 MW starting at 1:30 p.m. and ending at approximately 8:00 p.m. Therefore at 5:00 p.m. on July 6th, the Conowingo load was approximately 100 MW.

3.3 Generator Outages

As a result of damage sustained in June 1999, Indian River Unit 3 (165 MW) was not available during any part of the July 3-6 period. During the evening of July 5, Edgemoor Unit 3 (86 MW) became unavailable due to a tube leak in the boiler. This unit remained unavailable through July 6. On July 6 at 10:35 a.m., Indian River Unit 2 (91 MW) was taken off line due to a weather-related equipment failure. This unit came back on line at 4:26 p.m. that day. Four combustion turbines tripped off line during the afternoon of July 6 with varying outage durations. Finally, due to the high heat and humidity, generating units could not meet their reported Mvar output capabilities and could not run at their full MW capacities [DP&L Response to Slater Report, PJM 12/1999, Staff 10-5].

3.4 System Voltages on July 5 and 6

On high load days such as July 5 and 6, DP&L attempts to maintain a minimum voltage of 138.5 kV on 138-kV lines in the Bay Region. DP&L also attempts to maintain voltages on 69-kV lines as high as 72.5 kV in the southern Maryland and Virginia area, 70-to-71 kV in the Beach area, 71 kV in the Maryland shore area, and 70.5 kV in the Salisbury area and in Kent and Sussex Counties in Delaware. DP&L considers this operational approach necessary to reduce the effects of voltage decay later in the day, as load typically increases with heavy air conditioning and other usage as a hot, humid day progresses [DP&L Response to GDS Report].

Transmission system voltages on July 5 and 6 were below normal. On July 6, a decreasing voltage profile, monitored on an instantaneous basis by operations personnel at DP&L, was a significant factor in the decision to implement rotating load shedding after Indian River Unit 2 tripped off line that day [DP&L Response to GDS Report].

Examples are shown in Figures 4 - 7 that are representative of transmission voltages in the Bay Region on July 5 and 6. At the Bishop 138-kV substation, the hourly integrated voltage at 10:00 a.m. was 136.53 kV on July 5 and 136.52 kV on July 6. Similarly, voltages at the Indian River 138-kV Substation were 136.82 kV on July 5 and 136.74 kV on July 6. At the Kellam 69-kV Substation, the hourly integrated voltage at 10:00 a.m. was 68.92 kV on July 5 and 69.27 kV on July 6. Similarly, voltages at the Harbeson 69-kV Substation were 68.92 kV on July 5 and 69.27 kV on July 6 [DP&L Response to GDS Report].

DP&L's concern with low Bay Region voltages intensified as system operations personnel observed the declining trend in Bay Region voltage profiles at 10:00 a.m. on July 6. Voltages had decreased 1 to 2 kV on the 69-kV system over the previous hour and as much as 3.5 kV on the 138-kV system [DP&L Response to GDS Report].

As shown in Figure 8, a similar declining trend in PJM 500-kV transmission voltages occurred on July 6. At the Keeney 500-kV substation in DP&L's New Castle region, the voltage decreased from 530 to 525 kV between 10:00 and 10:30 a.m. On normal load days, the voltage at Keeney remains above 530 kV in the morning, to reduce the effects of voltage decay later in the day. As a result of the combination of high MW and Mvar loads, generation unavailability, increased dependence on the import of energy, increased transfers, limited Mvar reserve, and high system Mvar losses, the PJM bulk power system experienced a widespread drop in system voltage on July 6, beginning at approximately 12:00 noon and lasting for several hours [PJM 12/1999].

3.5 DP&L Operating Strategy

DP&L has stated the development of its operating strategy on July 6, as follows:

DP&L systems operation personnel met early on the morning of July 6 and agreed on an operating strategy for the day. At 9:18 a.m., PJM advised DP&L and other PJM members to be prepared to exercise load management (ALM) efforts by 1:00 p.m.

Based on historical experience, the highest loads were expected between 5:00 and 8:00 p.m. Because of tariff restrictions on the length of time ALM programs could be used, it was important to reserve ALM for later in the day when peak load would occur. It is also PJM's philosophy to have load management available for the period when load is the highest. Consistent with DP&L's experience and PJM's directive, as of 9:30 a.m. on July 6, DP&L planned to implement ALM later that day. Moreover, because of tariff-prescribed notice requirements, ALM would not respond fast enough to an immediate crisis [DP&L Response to GDS Report].

DP&L's strategy also called for the implementation of rotating load shedding if decreasing voltages approached low values that would initiate the UVLS relaying system. UVLS had been installed to protect the electric system from damage and prevent widespread longer-term outages. DP&L's strategy was to preserve UVLS for instantaneous protection against the most severe contingency of the loss of Indian River Unit 4 (420 MW) or the loss of the Indian River or Steele 230/138-kV autotransformers, if any of these were to occur. To avoid eroding the effectiveness of UVLS, DP&L was prepared to take immediate action by implementing rotating load shedding as lesser contingencies occurred. The strategy was to implement rotating load shedding to maintain system voltages above the trigger points for UVLS [DP&L Response to GDS Report].

Prior to the loss of Indian River Unit 2 at 10:35 a.m., DP&L systems operation personnel disabled New Castle Region circuits from the automated load shedding computer program. DP&L's strategy was to implement rotating load shedding in the Bay Region first, where low voltages would most likely be encountered following a contingency. Circuits could be re-enabled in the computer program for automated load shedding in the New Castle Region if required [John Merritt Interview].

DP&L's strategy also called for the use of rotating load shedding instead of voltage reduction on July 6. DP&L was concerned that if voltage reduction were implemented during already low transmission and distribution system voltages such as encountered on the previous day, the UVLS might be compromised. In addition, DP&L knew from experience that a 5% system voltage reduction would provide a load reduction of only about 35 MW total in both the New Castle and Bay Regions. With rotating load shedding, systems operations personnel could control both the amount and location of load shed more effectively than with voltage reduction [Frank Stratton Interview].

3.6 Sequence of Events – July 6

The sequence of events that occurred on July 6, 1999 is listed as follows [5][DP&L response to Slater Report, DP&L Response to GDS Report, Timeline entitled "Delmarva Peninsula July 6 Events" provided by DP&L, Staff 8-30.3].

7:00 a.m.	The peninsula load reached 2,364 MW.
10:00 a.m.	The peninsula load reached 3,110 MW. PJM had advised DP&L to be prepared to implement ALM by 13:00.
10:35 a.m.	Indian River Unit 2 (91-MW unit operating at 71 MW) was taken off line due to a weather-related equipment failure. This unit remained off line for 5 hours and 46 minutes, until 16:21. Moisture from an un-air conditioned space had infiltrated an air conditioned area housing control panels and caused a short circuit. The loss of Indian River Unit 2 immediately resulted in 58 alarms indicating voltages below 95%. An additional 27 low-voltage alarms sounded the following minute [DOE 2000].
10:36 a.m.	DP&L systems operating personnel initiated automated load shedding in the Bay Region, for rotation of pre-selected circuits. 60 MW were shed initially in the Bay region. Desired 20-minutes-off – 40-minutes-on intervals were maintained to a reasonable degree until 13:08.
11:00 a.m.	After transmission voltages stabilized, DP&L commenced ALM. ALM continued through the remainder of the day on July 6.
11:45 a.m.	Load shedding in the Bay Region was reduced to 45 MW.
12:30 p.m.	Load shedding in the Bay Region was increased to 60 MW.
12:49 p.m.	A combustion turbine, Edgemoor Unit 10 (13-MW unit operating at 13 MW) tripped off line. This unit remained off line for 43 minutes, until 13:32.
12:50 p.m.	A second combustion turbine, West (15-MW unit operating at 12 MW) tripped off line. This unit remained off line for 13 minutes, until 13:03.
13:00	The peninsula load reached 3,323 MW even with rotating load shedding and ALM in varying amounts.
13:01	A third combustion turbine, Christiana Unit 11 (22.5-MW unit operating at 19 MW) tripped off line. This unit remained off line for 58 minutes, until 13:59.
13:02	Load shedding was initiated in the New Castle Region and increased in the Bay Region. Total of 100 MW was shed for both regions.

[5] Loads given in the above timetable include the Conowingo load.

13:08	Total load shedding was increased to 120 MW for both regions, due to increasing demand and the effect on DP&L's system of PJM's rapidly decaying 500-kV transmission voltages. At this point, the 20-minutes-off - 40-minutes-on rotation interval was not maintained.
14:28	Tasley combustion turbine (22-MW unit operating at 22 MW) tripped off line. This unit did not come back on line on July 6.
14:30	A UVLS relay operated at Oak Hall Substation, tripping two circuits. One circuit was returned to service at 15:50, the other at 16:42 [Dennis Callaghan Interview] . Total load shedding was increased to 140 MW for both regions.
16:21	Indian River Unit 2 was returned to service. During an earlier attempt at noon to re-synchronize this unit, problems had been encountered with a synchrocheck relay. After study, the relay settings were adjusted. Additional boiler problems had also been encountered in the afternoon.
17:18	Total load shedding for both regions was reduced to 60 MW.
17:51	Total load shedding for both regions was reduced to 40 MW.
18:00	Load shedding was returned to the original 20-minutes-off-40 minutes-on interval.
18:32	Load shedding in the New Castle Region ended. Load shedding in the Bay Region was reduced to 30 MW.
19:25	Rotating load shedding ended.

In the Bay Region, 128,051 customers (56.7% of all Bay Region customers) experienced outages of varying duration and frequency from rotating load shedding on July 6. During the morning 56,918 customers were interrupted and during the afternoon 117,622 customers (many of whom had also been interrupted in the morning) were interrupted in the Bay Region.

In the New Castle Region, no customers were interrupted in the morning and 7,725 customers (3.4% of all New Castle customers) were interrupted during the afternoon.

A total of 135,776 customers on the peninsula experienced outages from rotating load shedding on July 6.

Table IV shows hourly available resources and loads from 10:00 a.m. to 8:00 p.m. on July 6, 1999. [Staff 8-30.3].

In summary, rotating load shedding was implemented on July 6, 1999, as a result of low and declining system voltages on the peninsula, particularly in the Bay Region, due to the following:

- High peninsula load. At 10:00 a.m. on July 6, the peninsula load including Conowingo reached 3,110 MW. At 5:00 p.m., the peninsula load including Conowingo would have reached 3,449 MW without load shedding. At 5:00 p.m., the peninsula load excluding Conowingo would have reached approximately 3,350 MW without load shedding, which exceeded the 1999 forecast of 3,300 MW by 50 MW or 1.5%.
- Two generating units on the peninsula – Indian River Unit 3 (165 MW) and Edgemoor Unit 3 (86 MW) – had been out of service and remained out of service on July 6.
- Indian River Unit 2 (91 MW) tripped off line at 10:35 a.m. for 5 hours and 46 minutes. Also, four combustion turbines – Edgemoor 10 (13-MW), West (15 MW), Christiana 11 (22.5 MW), and Tasley (22 MW) – tripped off line at various times during the afternoon with varying outage durations.
- Other generating units on the peninsula could not meet their reported Mvar output capabilities and could not run at their full MW capacities.
- Low PJM voltages that increased the reactive power requirements on the peninsula.

High north-to-south transmission tie-line flows and lack of voltage support created reactive power/voltage problems, particularly in the Bay Region. DP&L implemented rotating load shedding to preserve the UVLS instantaneous protection against electric system damage and to prevent widespread longer term outages.

3.7 Preliminary Power- Flow Studies

In August 1999, the US Department of Energy (DOE) formed a Power Outage Study Team (POST) to study significant electric power outages and other disturbances that occurred during the summer of 1999 in six locations in the United States, including the July 6 outage on the Delmarva peninsula. Professor Thomas Overbye, Department of Electrical and Computer Engineering, University of Illinois at Urbana-Champaign, conducted preliminary power-flow studies as a member of the DOE study team. The purpose of the power-flow studies was to gain a better understanding of the July 6 events that took place on the peninsula. The key issue was whether the outage of Indian River Unit 2 at 10:35 a.m. threatened voltage collapse across the peninsula [DOE 2000].

The starting point for Professor Overbye's work was an initial power-flow case, supplied by DP&L, that approximated system conditions as they existed immediately before the outage of Indian River Unit 2. The initial case had a peninsula load of 3,300 MW. Professor Overbye scaled back the load to 3,200 MW, for a better match to the load profile of 10:35 a.m., and set generator MW outputs to the maximum values indicated in the preliminary report of the Delaware Public Service Commission [DOE 2000].

The results of Professor Overbye's preliminary power-flow studies are given in the DOE's interim report, dated January 2000. These results show that with Indian River Unit 2 in service, producing 77 MW and 20 Mvars, the voltage profile across the peninsula was relatively good on July 6. The lowest 69-kV voltage was 0.962 per unit at Lewes Substation, which is located close to Delaware Bay, north of the Indian River plant. Of approximately one hundred and fifty 69-kV buses, only six had voltages below 0.97 per unit.

The results also show that with Indian River Unit 2 out of service, the voltage profile across most of the peninsula changed dramatically. The lowest 69-kV voltage was now just 0.91 per unit (again at Lewes). Eight 69-kV voltages were below 0.93 per unit and forty were below 0.95 per unit. Overall, the voltages at fifty-six buses were below 0.95 per unit, which is the DP&L threshold for low-voltage alarms.

The results also show that with Indian River Unit 2 out of service, a peninsula load of 3,200 MW is very close to the point of maximum loadability, when voltages could collapse toward zero and emergency actions would be needed to avoid catastrophic failure. The preliminary power-flow studies substantiate the prudence and decisiveness of DP&L's action to implement rotating load shedding at 10:36 a.m. and avert a system voltage collapse that would have resulted in more widespread and longer term outages [DOE 2000].

After the DOE study team issued its interim report, Exponent retained Professor Overbye to perform additional power-flow studies. The purpose of the additional studies was to investigate the impact of additional voltage support on system voltages on the peninsula immediately following the loss of Indian River Unit 2 at 10:35 a.m. on July 6. The impact of two transmission upgrade cases that are currently on DP&L's Transmission and Distribution Projects List was considered. Case 1 considered the addition of a 150-Mvar SVC at the Nelson 138-kV substation, and Case 2 considered the Case 1 addition plus the addition of a 150-Mvar SVC and 50-Mvar capacitor at the Indian River 230-kV Substation. These projects are currently scheduled for completion on or before June 15, 2000.

The results of Professor Overbye's additional power-flow studies are included in Appendix C of this report. These results show that with Indian River Unit 2 out of service at 10:35 a.m. on July 6 and with Case 1, the addition of the SVC at Nelson Substation, there are no 69-kV voltages below 0.95 per unit. This case indicates that the addition of the Nelson SVC prevents the low voltages seen on July 6 after the Indian River Unit 2 outage. Also, with the Case 1 addition the point of voltage collapse is pushed out from a peninsula load of 3,200 MW to 3,500 MW.

As shown in Table IV, the peak load that would have occurred on the peninsula on July 6 without rotating load shedding was 3,449 MW, which occurred at 5:00 p.m. As such, the results of Professor Overbye's additional power-flow studies indicate that, had the 150-Mvar SVC been in service, rotating load shedding could have been avoided for the entire day.

Case 2 includes the Nelson SVC and also adds another SVC as well as a capacitor at Indian River Substation. As with Case 1, the Case 2 additions also prevent the low voltages seen after the Indian River 2 outage. Also, the Case 2 additions push out the point of voltage collapse to 3,770 MW. These studies indicate that, had the 150-Mvar SVC at Nelson Substation as well as the 150-Mvar SVC and 50-Mvar capacitor at Indian

River Substation all been in service on July 6, rotating load shedding could have been avoided for the entire day.

It is emphasized that the power-flow studies performed by Professor Overbye given in the DOE interim report as well as those given in Appendix C of this report are based on an initial power-flow case that approximates conditions on the Delmarva peninsula as they existed on July 6. PJM is currently preparing a power-flow case that accurately represents the conditions that existed on July 6 throughout the PJM system, including conditions on the Delmarva peninsula. When the PJM power-flow case is released, additional studies can be performed to assess Professor Overbye's preliminary results.

4. DP&L Transmission Planning

During the 1990s, DP&L performed annual Transmission and Distribution (T&D) Ten Year Planning Studies intended to present plans for future capital additions and improvements required to assure cost effective and reliable T&D systems in the New Castle and Bay Regions for a period of ten years and beyond. Portions of the transmission plans from these Ten-Year Studies are excerpted here for the years 1993 – 1997 [Staff 10-2 and 4-101].

4.1 1993 T&D Ten Year Planning Study

<u>*Transmission*</u>

The addition of major generation in the southern part of our system is critical to reduce increasing north-south tie line flows, improve reactive/voltage problems and increase our system import capability.

The proposed 300 MW unit at Dorchester has a significant impact on future transmission projects. The projects which would most likely be advanced with the delay or elimination of Dorchester include upgrading several 230-138 kV and 138-69 kV autotransformers, upgrading numerous existing 138 kV lines, the addition of a new 138 kV line and a new North-South 230 kV line. Additionally, a 150 MVAR Static Var Compensation (SVC) device and a major project to increase our system import capability would both be needed by the year 2000. The estimated cost to advance the necessary transmission projects, build an SVC device and increase our system import capability would be $50 to $70 million (1993 dollars) if the Dorchester project was canceled or delayed.

As stated above, Delmarva Power & Light (DP&L) system planners raised their concern as early as 1993 about potential reactive power/voltage problems that could occur as load grew if major generation were not added in the Bay Region. A 150-Mvar SVC and a major project to increase system import capability were projected for need by the year 2000.

4.2 1994 T&D Ten Year Planning Study

The coincident company peak load used for analysis of the bulk transmission system is expected to have an annual load growth of 1.7 percent in the summer and 2.3 percent in the winter from 1993-2003. The non-coincident sum of individual circuit and substation transformer peaks is expected to have an annual load growth of 2.6 percent in the summer and 2.9 percent in the winter from 1993-2003.

Transmission

Even with the record peak demand levels from this past winter and near record peak demand levels from this past summer, slight changes in load projects have not impacted the in-service dates of most transmission projects. Corporate-wide capital budget cuts had the biggest impact on in-service dates with many T&D projects being deferred a year or more.

The addition of major generation in the southern part of our system is critical to reduce increasing north-south tie line flows, improve reactive/voltage problems and increase our system import capability.

The proposed 150 MW CT at Vienna in 2001 and 300 MW unit at Dorchester in 2004 have a significant impact on future transmission projects. The projects that would most likely be advanced with the delay or elimination of these generation additions on the peninsula include:

A 200 MVAR Static Var Compensation (SVC) unit device at Piney Grove in 2000.

Again, DP&L system planners raised their concern for potential reactive power/voltage problems that could occur as load grew if major generation were not added in the Bay Region. The need for a 200-Mvar SVC at Piney Grove Substation in the Bay Region was projected by 2000 if additional generation were to be delayed or canceled. Timing for installation of this SVC was based in part on a 1.7% annual growth in (coincident) summer peak load from 1993 to 2003. However, weather-normalized summer peak load actually grew at an annual rate of 3.07% from 1993 to 1999 [Staff 8-30.2].

In 1994, corporate-wide capital budget cuts had the biggest impact on in-service dates with many T&D projects being deferred a year or more.

4.3 1995 T&D Ten Year Planning Study

The coincident company peak load used for analysis of the bulk transmission system is expected to have an annual load growth of 1.5 percent in the summer and 1.6 percent in the winter from 1994-2004. The non-coincident sum of individual circuit and substation transformer peaks is expected to have an annual load growth of 2.7 percent in the summer and 2.1 percent in the winter from 1994-2004.

Transmission.

Corporate-wide capital budget constraints continue to have a big impact on in-service dates with many T&D projects being deferred a year or more.

The addition of major generation in the southern part of our system is critical to reduce increasing north-south tie line flows, improve reactive/voltage problems and increase our system import capability.

The proposed 150 MW CT and 300 MW at Dorchester have a significant impact on future transmission projects. The projects that would most likely be added or advanced with the delay or elimination of these generation additions on the peninsula include:

A 200 MVAR Static Var Compensation (SVC) device at Piney Grove in the late 1990's.

The major transmission project in the DP&L service territory in the short term will be the addition of a 500-230 kV transformer at Red Lion in May 1997. This project is required to serve the increasing peninsula load including DP&L native load, ODEC, DMEC, Dover and Easton, as well as through flows on the 230 kV to other LDV companies.

Again, DP&L system planners raised their concern for potential reactive power/voltage problems that could occur as load grew if major generation were not added in the Bay Region. The need for a 200-Mvar SVC at Piney Grove Substation in the Bay Region was projected in this study by the late 1990s if additional generation were to be delayed or canceled. This was moved up from the 1994 study, which projected need for a 200-Mvar SVC by 2000. Timing for installation of this SVC was based in part on a 1.5% annual growth in (coincident) summer peak load from 1994 to 2004. However, weather-normalized summer peak load actually grew at an annual rate of 3.12 % from 1994 to 1999 [Staff 8-30.2].

In 1995, corporate-wide capital budget cuts continued to have a big impact on in-service dates with many T&D projects being deferred a year or more.

4.4 1996 T&D Ten Year Planning Study

The coincident company peak load used for analysis of the bulk transmission system is expected to have an annual load growth of 2.7 percent in the summer and 3.1 percent in the winter from 1995-2005. The non-coincident sum of individual circuit and substation transformer peaks is expected to have an annual load growth of 3.2 percent in the summer and 3.8 percent in the winter from 1995-2005

Transmission

Corporate-wide capital budget constraints continue to have a big impact on in-service dates with many T&D projects being deferred a year or more.

The addition of major generation in the southern part of our system is critical to reduce north-south tie line flows, improve reactive/voltage problems and increase our system import capability.

Without any new generation plans until 2005, the following projects had to be added or advanced:

A 200 MVAR Static Var Compensator (SVC) device at Steele substation in May 2000.

Again, DP&L system planners raised their concern for potential reactive power/voltage problems that could occur as load grew if major generation were not added in the Bay Region. A 200-Mvar SVC at Steele (formerly planned for Piney Grove) Substation in the Bay Region was projected for need in this study by May 2000 if additional generation were to be delayed or canceled. Timing for installation of this SVC was based in part on a 2.7% annual growth in (coincident) summer peak load from 1995 to 2005. This timing seems inconsistent with the 1995 T&D planning study, which assumed a lesser, 1.7% annual growth in summer peak load and projected an earlier need - by the late 1990s - for a 200-Mvar SVC in the Bay Region. The weather-normalized summer peak load actually grew at an annual rate of 2.4 % from 1995 to 1999 [Staff 8-30.2].

In 1996, corporate-wide capital budget cuts continued to have a big impact on in-service dates with many T&D projects being deferred a year or more.

4.5 1997 T&D Ten Year Planning Study

> *The coincident company peak load used for analysis of the bulk transmission system is expected to have an annual load growth of 1.25 percent in the summer and 3.4 percent in the winter from 1996-2006. The non-coincident sum of individual circuit and substation transformer peaks is expected to have an annual load growth of 2.9 percent in the summer and the winter from 1996-2006.*
>
> *Transmission*
>
> *Corporate-wide capital budget constraints continue to have a big impact on in-service dates with many T&D projects being deferred a year or more.*
>
> *The addition of major generation in the southern part of our system is critical to reduce north-south tie line flows, improve reactive/voltage problems and increase our system import capability.*
>
> *As load growth in the Bay Region continues over time without new generation, additional reactive power sources are necessary. The strategy to supply these sources is to install distribution line capacitors for the increased load and transmission capacitors for the increased losses due to the increase in transfers. Once capacitors have been installed to maintain pre-contingency voltage profiles, dynamic reactive power sources are needed to respond rapidly for system contingencies in the absence of new generation. An SVC can provide this type of response. By the year 2000, the existing generators will not have enough reactive power capability to provide the system with the necessary dynamic response needed to avoid dropping significant load for a major outage. As load continues to grow in the Bay Region without additional generation, SVCs will be needed to supply a source of dynamic power. System studies demonstrate, and recent system voltage problems corroborate, the area most vulnerable is the 138 kV in the Steele, Church, Cheswold, Harrington areas. Present plans call for an SVC at Steele substation in 2000 and a second unit at Piney Grove in 2006. Both SVCs are 200 MVAR and are planned on the 138 kV bus.*

Again, DP&L system planners raised their concern for potential reactive power/voltage problems that could occur as load grew if major generation were not added in the Bay Region. A 200-Mvar SVC at Steele Substation in the Bay Region was projected in this study for need by May 2000 if additional generation were to be delayed or canceled. Timing for installation of this SVC was based in part on a 1.25 % annual growth in (coincident) summer peak load from 1996 to 2006. However, weather-normalized summer peak load actually grew at an annual rate of 5.75 % from 1996 to 1999 [Staff 8-30.2].

In 1997, corporate-wide capital budget cuts continued to have a big impact on in-service dates with many T&D projects being deferred a year or more.

DP&L did not prepare a formal T&D Ten Year Planning Study report in 1998 or 1999. In 1998 and 1999, DP&L prepared five-year plans in the form of tables for transmission projects in the Bay and New Castle Regions in two versions. One version assumed there would be no additional generation at New Church, and the other version assumed there would be such a facility.

Among the current transmission projects in the Bay Region is the installation a 150-Mvar SVC, now at the Nelson Substation, with an in-service date of May 31, 2000 [Staff 10-2]. In addition, following the events of July 4-6, 1999 DP&L has accelerated installation dates of the following Bay Region transmission projects [DPA 4-2]:

1. Indian River 150 Mvar SVC, now scheduled for completion on June 15, 2000 (had been scheduled for completion in June 2003).

2. Indian River 50 Mvar Capacitor now scheduled for completion on June 15, 2000 (had been scheduled for completion in June 2001).

3. Steele second 230-138 kV autotransformer, now scheduled for completion after the summer of 2000 (had been scheduled for completion in June 2003 timeframe).

5. MAAC Reliability Assessment[6]

In addition to DP&L's internal T&D planning studies for assuring reliable T&D systems on the peninsula, DP&L participates with other members of the Mid-Atlantic Area Council (MAAC) in performing reliability assessments of the MAAC system. The purpose of MAAC is to ensure the adequacy, reliability, and security of the bulk electric power supply system of the Region through coordinated operations and planning of the generation and transmission facilities.

Adequacy is defined as the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account uncertainty of system transmission, generation and load elements.

Security is defined as the ability of the electric system to withstand sudden disturbances such as electric short circuits and dynamic swings, or unanticipated loss of system elements.

MAAC performs an assessment study on a periodic basis to evaluate the performance of the planned MAAC system and to ensure that the system is in compliance with MAAC reliability principles and standards. The MAAC assessment for the 1999/2000 planning period was based on load forecasts, generation and transmission plans submitted by MAAC members as of June 1, 1997.

There are seven sections of MAAC criteria, based on NERC operating and planning guides, that require independent testing and assessment. Three of these sections are: Installed Generating Capacity Requirements (Section I); Network Transfer Capability (Section VII); and General Requirements (Section III). These three sections are discussed in the following sections.

5.1 Installed Generating Capacity Requirements

Section I of the MAAC criteria states that sufficient MW generating capacity shall be installed to ensure that each year for the MAAC system the probability of occurrence of load exceeding the available generating capacity shall not be greater, on the average, than one day in ten years. This probability of occurrence is referred to as the one-day-in-ten-year Loss-of-Load-Probability (LOLP).

PJM conducts an annual reliability study to determine the PJM generation reserve requirement such that the LOLP is not greater than the one-day-in-ten-years. The study uses a probabilistic analysis, which considers (among other factors) the characteristics of loads, load forecast uncertainty, the scheduled maintenance requirements and forced outage rates of generating units, and the effects of connections to other Regions.

6 This section is based on the report entitled, "1997 MAAC Reliability Assessment, Final Report", dated June 1998 [MAAC 1998].

Table V shows the results of recent PJM reserve requirement studies for the planning periods 1994 through 1999. As shown, the calculated generation reserve requirement decreased from 21.3% for the 1994 planning period to 18.9% for the 1999 planning period. Primarily due to lower forced outage rates and reduced weekly maintenance of generators, the general trend has shown a decreasing PJM generation reserve requirement. Based on the load forecasts, generation and transmission plans submitted by MAAC members, all of the generation reserve requirements shown in Table V are calculated so that the LOLP is not greater than one-day-in-ten years.

PJM's Reliability Assurance Agreement committee approved generation reserve requirements that are slightly higher than the calculated requirements shown in Table V. For the 1999 planning period, the approved generation reserve requirement was 20.0 %, versus the calculated requirement of 18.9% [Staff 10-8, Katharine Olinchak Interview].

DP&L complied with MAAC's installed generating capacity requirements for the 1999/2000 planning period.

5.2 Network Transfer Capability

Installed Generating Capacity Requirements (Section I of the MAAC criteria) implicitly assume that all generation resources are equally deliverable to all load sites. That is, Section I assumes that demand is not limited by transmission capability.

Network Transfer Capability (Section VII) focuses on the transfer of power into areas or sub-areas with capacity shortages. Section VII imposes a deliverability test to insure that power can be transferred to MAAC areas and sub-areas.

The Network Transfer Capability criterion states that the amounts of power to be interchanged between areas or sub-areas within MAAC shall be limited such that applicable ratings and stability limitations are not exceeded. Assessment of Network Transfer Capability is focused on the Capacity Emergency Transfer criterion. Capacity Emergency Transfer is defined as the amount of power that can be transferred into an area for capacity shortages and shall be limited as follows:

- For base case conditions, the loading of all system components shall be within normal ratings, stability limits, and normal voltages
- For single contingencies, the system shall be able to absorb the initial power swing.
- After the initial swing, the loading of all facilities shall be within short-time emergency and voltage limits.

Testing the Capacity Emergency Transfer criterion has two parts: the Capacity Emergency Transfer Objective (CETO); and the Capacity Emergency Transfer Limit (CETL).

The CETO of any MAAC area or sub-area is defined as the amount of MW capacity that the area or sub-area must be able to import during localized capacity emergency conditions so that the probability of loss of load in that area or sub-area due to insufficient tie capability, shall not be greater than one day in twenty-five years (i.e., LOLP is not greater than one-day-in-25-years).

The CETL of a MAAC area or sub-area is defined as the amount of MW that an area or sub-area can actually import during localized capacity emergency conditions. The ability of the transmission to deliver power under emergency conditions is simulated and the limit of the capability is referred to as the CETL.

Every area and sub-area must be able to import its CETO. Hence the CETO/CETL Deliverability test for a given area or sub-area is passed when its CETL equals or exceeds its CETO.

Table VI shows the CETO and CETL in the Delmarva peninsula (the DP franchise area) for the 1996/97, 1998/9, 1999/2000 and 2003/04 planning periods and in the southern part of the peninsula (peninsula sub-area) for the 1999/2000 and 2003/04 planning periods. The peninsula sub-area is the same as the Bay Region for 1999/2000 and 2003/04 planning period [Staff 4-80].

As shown in Table VI, the CETO shows an increasing trend versus time for both the peninsula and peninsula sub-area, primarily due to load growth and the lack of new generating facilities on the peninsula during these years. The increasing CETO shows a trend of increasing reliance on off-peninsula generation to meet generation reserve requirements.

Table VI also shows that both the peninsula and peninsula sub-area passed the CETO/CETL test for all planning periods. That is, the CETL equals or exceeds the CETO in both the peninsula and peninsula sub-area. However, the CETO/CETL margin for the peninsula sub-area reduces to zero for the 1999/2000 planning period. If a 200-Mvar SVC had been installed in the Bay Region by the 1999/2000 planning period, the CETO/CETL margin would have been 250 MW [MAAC 1998].

The "1997 MAAC Reliability Assessment" report dated June 1998 states the following:

> *The conversion of the Steele-Vienna 138 kV line to 230 kV operating voltage and the installation of reactive reinforcements highlighted by a 200-MVAR Static Var Compensator (SVC) at Steele, are required to meet the CETO/CETL test. These projects' scheduled in-service dates, which had an in-service date of May 1, 2000 when this analysis was performed, have been moved up. The scheduled conversion date of the Steele-Vienna line upgrade is June 1, 1999. The scheduled completion date for the Steele 200 MVAR SVC project is still May 2000.* [MAAC 1998, page 42.]

The Steele-Vienna line upgrade was completed before July 6, 1999. PJM has confirmed that, with the Steele-Vienna line upgrade alone (without the 200 Mvar SVC at Steele), the peninsula sub-area passes the CETO/CETL test for the 1999/2000 planning period, however with zero margin [Response to GDS Report (Appendix 5), Staff 4-80].

Planned transmission reinforcements and the possibility of new generation in the Bay Region will likely increase the CETO/CETL margin this year so that the margin will not be as tight in the Bay Region during the summer of 2000 as it was during 1999.

5.3 General Requirements

Section III of the MAAC reliability criteria defines (1) voltage support and reactive requirements and (2) the requirements for coordination of generation and transmission planning.

Voltage Support and Reactive Requirements

MAAC defines voltage support and reactive requirements, consistent with NERC requirements, as follows:

> *Sufficient megavar capacity with adequate controls shall be installed in each system to supply the reactive load and loss requirements in order to maintain acceptable emergency transmission voltage profiles during all of the above contingencies.*

The contingencies are:

- Single contingency event – Loss of any single transmission line, generating unit, transformer, bus, circuit breaker, or single pole of a bipolar dc line.
- Second contingency event – The subsequent loss of any remaining generator or transmission line following the outage of a single facility and after the system has been readjusted to be within normal voltage and thermal limits.
- More probable multiple facility outage events – The loss of any double circuit line, bipolar DC line, faulted circuit breaker or combination of facilities resulting from a line fault coupled with a stuck breaker.

Generation and Transmission Coordination

Installation of generation and transmission is required to be coordinated to achieve the MAAC reliability requirement that the probability of loss of load shall not be greater than one day in ten years.

The "1997 MAAC Reliability Assessment" report states the following:

> *The planned conversion of the Steele-Vienna upgrades that alleviate contingency overloads and the installation of planned reactive reinforcements in the Delmarva Peninsula Subarea are required to be in service by the 1999/2000 planning period for that Subarea to be in compliance with Section III criteria.* [MAAC 1998, page 4.]

When rotating load shedding was implemented on July 6, 1999, the Vienna-Steele 138-to-230 kV line upgrade had already been completed. In addition to this upgrade, the 1997 MAAC Reliability Assessment recognized the need for installation of reactive reinforcements in the Bay Region that would be in service by the 1999/2000 planning period. [MAAC 1998].

The MAAC Section III assessment of the Peninsula Subarea for the 1999/2000 planning period was based on load forecasts, planning assumptions, and system upgrades projected in 1997. A single-contingency loss of Indian River Unit 4 (420 MW) followed by a second-contingency subsequent loss of Indian River Unit 3 (165 MW) during a forecasted peninsula summer peak load in the range of 3,400-to-3,490 MW would seem to be more severe than the actual conditions that existed when rotating load shedding was implemented at 10:36 a.m. on July 6, 1999. At that time, total generation out of service (Edgemoor Unit 3, Indian River Units 2 and 3) was 342 MW, the remaining generation on the peninsula was derated by 171 MW due to high ambient temperatures and humidity, and the peninsula load was less than 3,300 MW [Slater Report, DP&L Response to Slater Report].

However, it is apparent that the MAAC Section III assessment for the 1999/2000 planning period used generator Mvar limits that were higher than the unit Mvar capabilities that existed on July 6, 1999. Total Mvar output of the generating units in service on the peninsula at 10:41 a.m. on July 6 was only 527 Mvars, 468 Mvars less than the total capability of 995 Mvars. High temperatures on July 6 reduced the Mvar output capabilities as well as the MW capacities of generators. Also, increased air-conditioning loads on the peninsula during 1999 resulted in reactive loads that were higher than the loads assumed in the MAAC assessment for the 1999/2000 planning period. In addition, PJM transmission voltages were lower than normal at 10:36 a.m. on July 6, 1999. [PJM Draft Report, Staff 10-5]

6. Divestiture of DP&L's Generation Assets and Implications for Reliability

6.1 DP&L's Plans to Divest Generation Assets

DP&L is currently in the process of selling a portion of its power plants to independent generation companies. It recently signed an agreement to sell 1,875 megawatts of fossil-fired generation assets to NRG Energy. The sale includes the Indian River station (784 MW), and the Vienna station (170 MW), both of which are located on the Delmarva peninsula. These two stations represent 36 percent of the roughly 2,627 MW of DP&L's current capacity located on the peninsula. The sale to NRG also includes a number of power plants located off the Delmarva peninsula, including the Keystone, Conemaugh, England and Deepwater stations. [Conectiv 1/19/2000.] Furthermore, DP&L has tentatively sold its shares in the Peach Bottom and Salem power plants. [Staff 4-70.]

DP&L's plan to sell some of its power plants raises some questions about what role these power plants will play in ensuring reliability in the future. Will the new owners provide generation to customers on the Delmarva peninsula, or will they find other customers more profitable? Will the new owners provide reactive power support as needed to maintain the reliability of the DP&L transmission system? Will the new owners respond to emergency conditions as quickly and as cooperatively as DP&L would? How will the new owners be coordinated with the transmission and generation planning practices of DP&L and PJM?

These questions are especially pertinent to the Indian River plant. This plant plays an instrumental role with regard to reliability because of its location and its contribution to reactive power in the Bay Region on the Delmarva peninsula.

6.2 DP&L and PJM Requirements Regarding Divested Generation Assets

In responses to discovery on this issue, DP&L notes that it "expects that the planned sale of electric generation units will have no impact on reliability of service within the service territory." [Staff 4-90.] DP&L is negotiating an Interconnection Agreement that will require the new owners to abide by PJM and MAAC standards and procedures. This Agreement should provide DP&L with significant influence over key operating practices related to reliability, such as plant dispatch, maintenance, equipment outages, voltage support and response to emergency procedures. [DEUG 1-4.]

The Agreement will also require the new owners to provide three-year notice of planned retirement or intent to sell outside of the PJM control area. [Staff 4-91.] In addition, "MAAC notification procedures must be followed by the buyer for a material change in the net output of a unit or retirement of a unit. An application must be made to MAAC to reduce or retire a unit. MAAC will not allow a reduction or retirement unless sufficient generation and/or transmission capacity is in its place." [DEUG 1-4.]

In a letter to Bruce Burcat notifying the Commission of the sale of the Indian River and Vienna units, the Company describes in more detail why it believes that the reliability of the DP&L system will be assured after the sale. The letter explains that DP&L will enter into a power purchase agreement with NRG, covering the period during which DP&L will be the default service provider. The letter then describes three scenarios in which the power from these plants might be sold after ownership is transferred to NRG, and concludes that the integrity of the electric system will be preserved in each case:

- If the Indian River and Vienna units are running and the output from the units is being sold to someone other than the Company, that generating output would automatically provide electric system support, at no cost to DP&L....
- [U]nder current Federal Energy Regulatory Commission-approved tariffs and interconnection agreements, if the output from these plants is under contract within PJM and the units are not running, DP&L and PJM have the right to order these units to run during local or regional system emergencies at the then-effective locational marginal price (LMP) or based on the unit's operating cost, whichever is higher....
- [I]f the output from these plants is under contract outside of PJM and the units are not running, the interconnection agreement between DP&L and NRG gives the Company the right to order these units to run during such emergencies and pay for the output as if the units were a PJM resource, using PJM pricing procedures described above. [Letter from Mack Wathen to Bruce Burcat, January 19, 2000.]

Our review of DP&L's draft Interconnection Agreement confirms DP&L's assertions. Appendix D (confidential) includes a summary of some key provisions of the draft Interconnection Agreement. If the new owners of the DP&L power plants meet all the provisions of this agreement, then the sale of the plants should not introduce new reliability issues on the Delmarva peninsula.

In addition to the Interconnection Agreement with DP&L, the new owners of DP&L's power plants will be a PJM member and will therefore be required to abide by the PJM "Operating Agreement." This agreement requires, among other things, that members:

- [C]ooperate with other Members in the coordinated planning and operation of the facilities of its System within the PJM control area so as to obtain the greatest practicable degree of reliability...
- [C]oordinate the installation of its electric generation and Transmission Facilities with those of such other Members.
- Coordinate with the other Members, the Office of the Interconnection and with others in the planning and operation of the regional facilities to secure a high level of reliability and continuity of service...

- Cooperate with the other Members and the Office of the Interconnection in the implementation of all policies and procedures established pursuant to this agreement for dealing with Emergencies...
- Cooperate with the members of MAAC to augment the reliability of the bulk power supply facilities of the region and comply with MAAC and NERC operating and planning standards, principles and guidelines and the PJM manuals.
- Cooperate with the Office of the Interconnection's coordination of the operating and maintenance schedules of the Member's generation and Transmission Facilities.
- Cooperate with the other Members and Office of the Interconnection in the analysis, formulation and implementation of plans to prevent or eliminate conditions that impair the reliability of the Interconnection. [PJM 9/9/1999, Section 11.3.2.]

In other words, the new owners of DP&L's power plants will be subject to the same obligations and requirements as DP&L with regard to system planning, maintenance, operation and reliability. In theory, these contractual obligations should ensure that the sale of DP&L's power plants do not exacerbate reliability problems on the peninsula.

The GDS report on the July outages expressed concern that the divestiture of the Indian River and Vienna plants could lead to reliability problems. The authors concluded that DP&L's requirement for a three-year notice of intent to retire the plants or sell their power outside of the PJM control area was too short. They refer to the Company's response to Staff Data Request 4-85 that indicates that a new power plant has a lead time of at least forty months. [GDS 1999, pages 31-33.]

We agree that a three-year notice is too short to allow for the siting, permitting and construction of a new power plant on the Delmarva peninsula, and that a longer notice period would be preferable. However, there does not appear to be a significant risk of these plants being retired soon. It is unlikely that NRG would retire plants that it recently paid so much to acquire. In addition, the Vienna and Indian River sites provide opportunities for building new generation capacity in the event that one or more of the units is retired.

The greatest risk associated with this short notification period is that NRG might decide to sell the power from the Indian River or Vienna units outside of the PJM control area. However, this outcome is unlikely to create significant reliability problems, as described in the letter to Bruce Burcat from the Company. As long as the divested units continue to be designated as PJM Capacity Resources, the owners would continue to have an obligation to sell their energy within the PJM control area.[7] According to DP&L, NRG will be required to maintain the Indian River and Vienna plants as PJM Capacity

[7] A Capacity Resource is a generating facility that is committed to meeting loads within PJM and which satisfies a Load Serving Entity's capacity obligation under the PJM Reliability Assurance Agreement. [PJM MMU 1999.]

Resources. [Roberta Brown Interview.] For these reasons we are less concerned that the three-year notification period is too short.

There is a risk that NRG could sell the Indian River or Vienna plants to another generation company, and that new company would not be required to abide by the same Interconnection Agreement. However, the language of the Interconnection Agreement appears to prevent this outcome. Appendix D (confidential) describes why this is so.

6.3 Experience With Divestitures in Other States

A review of the divestiture of power plants in other states indicates that reliability is rarely considered when state regulatory commissions review utility divestiture plans.[8] While state commissions tend to have responsibility over maintaining reliability of the electricity system, the divestiture of power plants is generally assumed to not create any new reliability problems. It is assumed that the reliability standards and requirements established by the state commission, NERC and the relevant Independent System Operator will apply to the new owners of the plant as they have applied to the previous owners, and as they will apply to other independent generation companies. We came across two exceptions to this trend, as described in the following sections.

Divestitures in the District of Columbia

The District of Columbia Public Service Commission (DC PSC) recently investigated reliability issues when Potomac Electric Power Company (PEPCO) proposed to divest three power plants located in the DC area. The DC PSC asked the PJM Market Monitoring Unit (MMU) to investigate whether the sale of these plants would create market power and reliability problems. The MMU prepared a report to the DC PSC which presents some results that may be applicable to the DP&L units as well. [PJM MMU 1999.]

The MMU study performed a CETO/CETL analysis of the DC area transmission system in 2006, assuming no new generation or transmission upgrades. The MMU study determined that two of the units in question will likely be "must run" for reliability purposes during the 2006 peak demand periods, and that the third unit will likely be must run for reliability purposes during peak demand periods if one or both of the other two plants are out of service.

The MMU study then found that must run status creates the potential for the exercise of market power.[9] However, in the case of these three plants, "the existing PJM rules

[8] This conclusion is based on research and interviews with regulatory commission staff and other interested parties in Connecticut, District of Columbia, Illinois, Maine, Maryland, Massachusetts, New York, Pennsylvania, and Washington.

[9] Market power and reliability issues are inextricably linked. It is easier to exercise market power in circumstances where reliability risks are highest (e.g., peak periods, tight capacity markets, transmission load pockets). In addition, one option for exercising market power is through withholding of capacity resources in order to drive up the market price for electricity. Withholding of capacity resources can clearly exacerbate reliability problems.

mitigate market power in most cases, and market power would be detectable in the remaining cases." The study concludes that the "sale of the plants does not create market power associated with must run status. This potential ability to exercise market power exists regardless of the owner of the plants." [PJM MMU 1999, page 4.]

The MMU study notes that market power and reliability problems would be more likely if the units are no longer designated as PJM Capacity Resources. If the units are not Capacity Resources, the new owners could refuse to run the plant, potentially leading to both market power and reliability problems. Similarly, the study notes that such problems will also arise if the new owners decide to permanently remove from service any of the three plants in question. On the other hand, reliability and market power problems could be mitigated or resolved by the addition of generation capacity or transmission capability.

The conclusions of the MMU study can only be applied to the Delmarva peninsula in a limited way. The unique load, transmission and capacity characteristics of the DC area and the DP&L area could lead to different conclusions regarding reliability and market power. In addition, the MMU study was not able to assess problems associated with local voltage support -- an issue that is of critical importance to the Indian River plant on the Delmarva peninsula.

One of the key findings of the MMU study was that the sale of the power plants in question should not exacerbate reliability problems. If the financial incentives, contractual obligations, and reliability requirements are not changed from one owner to the next, then there should be little or no change in the potential for reliability problems. This conclusion is likely to be true for DP&L's plants as well.

An analysis of whether the divestiture of DP&L's power plants is likely to increase or decrease market power problems is beyond the scope of this report. The Commission should request the PJM MMU to conduct a market power analysis of the DP&L plants, similar to the study performed for the DC PSC.

The MMU study also concludes that the risk of market power and reliability problems is significantly reduced if the new owner is required to maintain the power plants as Capacity Resources. This conclusion is likely to be true for DP&L's plants as well.

Divestitures in New York City

The New York Public Service Commission recently approved the sales of Consolidated Edison Company's (Con Ed) generation assets located in New York City. Because New York City is a transmission load pocket, there were concerns that the asset sales could provide the new owners with the potential to exercise market power. The NY PSC required Con Ed to place certain restrictions on the asset sales in order to mitigate market power problems.

Con Ed was required to sell the plants to three separate generation companies.[10] In addition, Con Ed was required to develop market power mitigation measures governing

[10] By coincidence, one of them is NRG Energy.

the sale of capacity, energy and certain ancillary services from all generation facilities located in New York City. These mitigation measures included price controls to ensure that new owners do not demand above-market prices in times when generation and transmission in the city becomes tight. Furthermore, the generation units are required to make spinning reserves available and meet availability requirements, in order to prevent the deterioration of reliability within the New York City load pocket. [NY PSC 6/1999 and 7/1999.]

While the NY PSC's requirements regarding Con Ed's divestitures focus mostly on market power issues and only tangentially on reliability issues, the NY experience provides some lessons for this DP&L proceeding. In particular, the PSC's emphasis on mitigating market power is noteworthy. A similar emphasis on market power may be appropriate with regard to the sales of the generation assets on the Delmarva peninsula. If there is little or no potential for market power, then the risk of reliability problems is greatly reduced.

6.4 Conclusion

Our review suggests that DP&L is taking a prudent and practical approach with regard to reliability issues associated with the divestiture of its power plants. The Interconnection Agreement appears to address concerns raised about reliability, and the MAAC and PJM standards and requirements should further encourage the new owners to operate the plants in a way that promotes reliability and stability on the Delmarva peninsula. DP&L's divestiture activities appear to create no more reliability risks than those of other utilities selling generation assets in other parts of the country.

However, the sale of generation assets does create increased uncertainty and risk regarding how responsible, cooperative, and competent the new power plant owners will be. Simply increasing the number of power plant owners on the peninsula increases the complexity of maintaining reliability – particularly under emergency conditions. While it may, in theory, be in the best interests of NRG to abide by DP&L, PJM, and MAAC requirements and procedures, in practice NRG may not have the capability, willingness and financial interest to meet those obligations as well as DP&L has in the past. This increased uncertainty is part of a broader development associated with the restructuring of the electricity industry in general, and therefore is addressed in more detail in Section 7.1.

In sum, while DP&L appears to be taking a prudent approach in selling some of its generation assets, this activity – by its very nature – increases the risk of reliability problems on the peninsula. We recommend that the Commission follow up on the on-going sale of power plants to ensure that the terms and conditions of the sale will minimize any problems with reliability. For example, the Commission should review a final copy of the Interconnection Agreement to ensure that it contains all of the reliability- related provisions of the current draft. The Commission should ensure that NRG Energy will indeed be committed to maintaining the Indian River and Vienna plants as Capacity Resources. In any future investigations of market power on the peninsula, the Commission should investigate the specific financial incentives and market power opportunities associated with NRG Energy's ownership of the Indian River and Vienna plants.

7. Maintaining Future Reliability

7.1 Industry Restructuring and Reliability Implications

With the introduction of competition in the electricity industry, the roles and responsibilities for ensuring reliability are shifting among different market actors. In the past, reliability standards were determined by NERC, the NERC regional councils (e.g., MAAC) and some power pools (e.g., PJM). Vertically integrated utilities held the responsibility for meeting such standards. Regulatory commissions would periodically require utilities to report on their load forecasts, their generation plans and their capability for ensuring a reliable supply of electricity. Integrated Resource Planning processes were sometimes used (as in the case of Delaware) to provide a formal procedure for the Commission and other interested parties to oversee the utilities' planning process and their ability to maintain reliability.

With electricity industry restructuring, the regulated utilities are playing a smaller role, and the responsibility for ensuring reliability is dispersed among many more market actors. The reliability standards are still determined by NERC, MAAC and PJM, but now they are applied to independent generation companies, load serving entities (LSEs) and regulated distribution utilities. PJM's load and capacity requirements are allocated to all LSEs based on their customers' contributions to peak loads. [Staff 4-80.] LSEs then have the responsibility of providing sufficient capacity to meet their load requirement, through owned generation, bi-lateral power contracts, or short-term purchases from the PJM capacity market. LSEs can take many forms, including generation companies, power marketers, load aggregators, and (as in the case of DP&L) regulated distribution companies acting as the provider of standard offer or default services.

This changing market structure has introduced a number of risks and uncertainties that are likely to reduce electric system reliability. With responsibility for reliability resting with more market participants, there is greater risk that some of them will not have the resources, information, finances, interest or technical capabilities for meeting their obligations. With less long-term planning and more reliance upon market forces, there is greater risk that independent market actors will be unprepared for emergency conditions or that market signals will be insufficient to maintain the generation, transmission and distribution infrastructure necessary to ensure reliability. With more independent market actors involved, there is a greater risk that communication protocols and systems will not be sufficient to ensure that all of the critical agents are adequately informed and working in sync before, during and after emergency conditions occur.

An interim report from the US Department of Energy (DOE) concluded that electricity restructuring has created new threats to reliability, and that industry and regulators have not reacted and evolved quickly enough to counteract these threats. The purpose of the study was to investigate a number of electricity outages that occurred during the summer of 1999, including the outages on the Delmarva peninsula. Some of the key findings of the study are directly relevant to the issue of reliability in Delaware:

> The reliability events during the summer of 1999 demonstrate that the necessary operating practices, regulatory policies, and technological tools for dealing with the changes [of restructuring] are not yet in place to assure an acceptable level of reliability.... The operation of the electric system is more difficult to coordinate in a competitive environment, where a much larger number of parties is participating.
>
> Unfortunately, the development of reliability management reforms, tools, technologies and operating procedures has lagged behind economic reforms in the electric industry.... In anticipation of competitive markets, some utilities have adopted a strategy of cost cutting that involves reduced spending upon reliability. In addition, responsibility for reliability management has been disaggregated to multiple institutions, with utilities, independent system operators, independent power producers, customers and markets all playing a role. The overall effect has been that the infrastructure for reliability assurance has been considerably eroded.
>
> [M]any of the team's findings are similar to those from investigations of past outages.... The problem is not that we have not learned from past outages. Rather it is that in many instances, we have not taken the necessary steps to design and implement the solutions. [DOE 2000, page S-1 and S-2.]

DP&L staff shares this concern about increased competition leading to reduced reliability. When asked during an interview about the DOE report quoted above, Roberta Brown, Vice President of Power Systems at DP&L, agreed with the general conclusion that recent changes in the electricity industry have increased the risks and uncertainties associated with reliability. In fact, she noted that this trend has been building for many years as the industry has become more cost-conscious, and that the rate of change has accelerated recently with the introduction of competition in the electricity industry. [Roberta Brown Interview.]

Ms. Brown noted that the time has come for a regional, if not national, public policy debate about how best to ensure reliability in the electricity industry. She suggested that the debate include participation from a variety of electricity industry stakeholders, and that it address some critical questions that have not been addressed in restructuring debates to date. One such critical question is how to draw the appropriate balance between reliability and cost. Another critical question is how have customers' expectations for reliability changed, and how should those various expectations be addressed by the competitive electricity market. [Roberta Brown Interview.]

The North American Electric Reliability Council (NERC) has also expressed grave concerns recently about the reduction in electricity reliability as a result of industry restructuring. NERC believes that the former practice of voluntary compliance with NERC standards will no longer be effective in a market where the key players are competing with each other. The Council recommends that Congress pass federal legislation to establish an "independent, industry self-regulatory electric reliability organization to ensure continued reliability of the interstate and international high-voltage transmission grids." [NERC 12/1999, page 1.] In a letter to Thomas Bliley, Chairman of the House Commerce Committee, NERC makes its concerns about reliability clear:

> The existing scheme of voluntary compliance with industry rules is simply no longer adequate. NERC is seeing a marked increase in the number and seriousness of violations of its reliability rules, yet there is little or no effective recourse under the current voluntary model to correct this behavior. This past summer, the actions of certain control areas in the Eastern Interconnection clearly demonstrated that we are facing a real and immediate crisis. The users and operators of the system, who used to cooperate voluntarily under the regulated model, are now competitors without the same incentives to cooperate with each other and comply with voluntary reliability rules.
>
> Market participants are increasingly asking the Federal Energy Regulatory Commission (FERC) to make decisions on reliability issues for which FERC does not have either the technical expertise or direct, clear statutory authority....
>
> The bottom line is that not a single bulk power system reliability standard can be enforced effectively today, by NERC or the Commission [FERC]. The rules must be mandatory and enforceable, and fairly applied to all participants in the electricity market. [NERC 12/1999, page 1.]

Given NERC's critical role in establishing and overseeing reliability standards in the electricity industry, these words should be taken seriously by legislators, regulators, utilities, and electricity market competitors. NERC believes that these concerns are so important that they should be addressed immediately by federal legislation, and should not wait for Congress to pass comprehensive restructuring legislation. [NERC 12/1999.]

7.2 Reliability Within the PJM and DP&L Systems

Generation Planning

Restructuring changes have already had an effect on DP&L. In its generation planning process, DP&L has relied increasingly upon power purchases and less upon its own generation facilities. In its 1995 Integrated Resource Plan (IRP), the Company had plans for building four new combustion turbines (155 MW each) by 2006, followed by a new coal unit in 2006 and a second new coal unit in 2009 (310 MW each). [DPL 1995.] By the time of its 1997 IRP, DP&L had adopted a different strategy where it would rely exclusively upon short-term power purchases to meet new load through 2006.[11] The 1997 IRP notes that "planning in the midst of the restructuring of the electric utility industry requires that the selected resource plan avoid long-term commitments while meeting the needs of existing customers and balancing risks." More recently, during the course of this proceeding, DP&L noted that the advent of retail competition has transformed its IRP process into a "risk management" process. [Staff 8-21.]

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[11] DPL's need for new generation resources was reduced between 1995 and 1997 because Old Dominion Electric Cooperative planned to reduce its purchases from DPL in 1999 and terminate them in 2002. Also, DPL's municipal wholesale customers were expecting to utilize other sources of power after their contracts expire around 2003. [DPL 1996.]

While this strategy of relying increasingly upon purchases might be appropriate from the perspective of minimizing the costs and risks associated with generation facilities, it creates new risks regarding reliability. This is particularly true if other market actors and LSEs are also relying increasingly upon purchases. NERC emphasizes its concern about this development in a recent Reliability Assessment report:

> This trend [increasing reliance on capacity purchases from undisclosed sources] puts increased dependence on the capacity margins of others and on the demand diversity within each interconnection. Delivering those resources to deficient areas may become more and more difficult as the transmission system continues to become increasingly constrained. Although uncertainties and assumptions have always been a part of long-term transmission studies, the level of uncertainty has increased tremendously. Purchases from undisclosed resources and the reluctance of generation developers to disclose plans for future capacity additions are making modeling for long-term transmission analysis virtually impossible. [NERC 1998, page 7.]

As described above in Section 5, DP&L's CETO/CETL margins have been declining over time. The Bay Region margin for the 1999/2000 planning period was zero. While a zero margin passes MAAC's reliability criteria, MAAC notes that this condition requires “careful monitoring.” [MAAC 1999, page 3.] This decline in DP&L's CETO/CETL margins is one indication of how actors in competitive markets tend to operate closer to required standards in order to keep costs down. Again, while this strategy might make sense from a pure business perspective, it provides less protection with regard to reliability.

With the passage of the Electric Utility Restructuring Act of 1999, DP&L now has a different level of responsibility for providing generation services to its customers. It is no longer responsible for those customers that choose alternative generation companies; it is only responsible for those customers that remain on default service. After the transition period, DP&L may have even less responsibility for providing generation service to customers. DP&L now has two generation functions: a regulated default service and an unregulated "merchant" generation business.

In both of these generation functions, the Commission and other interested parties are likely to have less influence and oversight with regard to reliability than they have in the past. There currently is no formal regulatory review process. During interviews and in response to discovery responses, DP&L was unwilling to provide information regarding how it will plan for and provide generation services associated with its merchant generation business. [Staff 8-24.] DP&L was more forthcoming with information regarding its default service. [Staff DRs 8-20 through 8-23 and 9-8 through 9-12.] However, it was reluctant to release the one internal study it has performed addressing the costs and risks associated with the default services. [Staff 9-10.] DP&L eventually provided a redacted version of this study, following additional requests from the Commission Staff.

A large portion of DP&L’s customers can be expected to remain on default services, and it will be important to ensure that adequate generation plans are in place to meet their needs. In general, DP&L appears to have sufficient generation resources available to reliably serve default customers.[12] However DP&L's decision to plan for default services with a nine percent reserve margin, instead of the roughly 19 percent reserve margin used by PJM, is cause for concern. [Staff 9-9] On the other hand, it appears that DP&L will have sufficient generation resources to serve default customers, even assuming a 19 percent reserve margin.[13] [Staff DRs 8-22, 8-23, and 9-8.] DP&L's plans for adding three new 112-MW gas-turbine driven units at Hay Road in 2001 and a 175-MW steam-driven unit at Hay Road in 2002 will also help contribute to generation reserves.

We believe that the Commission should monitor the Company's default service business over time to ensure an adequate level of reliability. One of the most critical issues in reliability planning is in striking the appropriate balance between costs and reliability. Without oversight or guidance from the Commission, there is a risk that DP&L will emphasize cost reductions at the expense of reliability.

The Commission may also wish to monitor in some fashion DP&L's merchant generation business. It could be argued that reliability of this competitive aspect of DP&L's business will be addressed through other fora (MAAC, PJM, contractual obligations), and that it is not within the Commission's jurisdiction. However, the competitive electricity market is still undergoing significant transformations. There are many ways in which the competitive markets might not yet be mature enough to assure reliability -- even of merchant functions -- without regulatory oversight.

In sum, recent restructuring activities within PJM and Delaware have increased the uncertainties and risks associated with generation and transmission reliability. Increased reliance upon purchases, reduced planning margins, less generation planning, less opportunity for the Commission and other parties to oversee whatever generation planning there is -- all create more uncertainty and risk. Customers in Delaware may be even more at risk than elsewhere in the region, because of the fact that the Delmarva peninsula is a load pocket.

Distribution Planning

Adequate planning, maintenance and operation of the distribution system is also necessary to ensure that electricity reaches customers reliably. As a regulated monopoly provider of distribution services, DP&L has full responsibility for ensuring the reliability of the distribution system. Consequently, the reliability issues pertaining to the distribution system are somewhat different than those pertaining to the generation system. Distribution reliability does not involve the coordination and cooperation of many disparate entities with different interests. It does, however, require that DP&L provide adequate management attention, financial resources and personnel resources to maintenance, inspections, repairs, and upgrades of its distribution facilities.

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[12] A complete assessment of the DPL default service generation planning process is beyond the scope of this study.

[13] The availability of default service generation will depend on the amount of power purchases available to DPL – both from the new owners of DPL's divested plants and from the PJM market in general.

Unfortunately, recent changes due to electricity industry restructuring can increase the threats and uncertainties associated with distribution service reliability. Distribution utilities may have little financial incentive to emphasize distribution reliability. Price caps or rate freezes can create financial incentives to reduce spending on staff and equipment, creating potential threats to reliability.

DP&L has noted that "corporate budgetary constraints" have hindered and delayed certain distribution and transmission projects in recent years -- suggesting that management may be cutting costs related to reliability upgrades. [MD PSC Staff 1999.] As described in Section 4, budgetary constraints have delayed the installation of various transmission upgrades – upgrades that could have played an instrumental role in mitigating the July 1999 outages. Investigations in other states also indicate that utilities in recent years have reduced staffing levels, performed fewer inspections, and deferred necessary but non-emergency repairs in response to cost-cutting pressures. [UWUA 1999.] Clearly, this trend will lead to increased customer outages and lower levels of reliability.

In general, the reliability of the distribution system is subject to increasing risks and uncertainties as the electricity industry becomes more competitive. Consequently, the Commission should play a role in overseeing DP&L's distribution reliability efforts, and in providing DP&L with the proper financial incentives to maintain a safe, reliable system.

7.3 Additional Measures for Promoting Reliability

Electricity restructuring not only creates new risks associated with reliability, it also creates new opportunities. With more actors, more flexibility and more customer involvement in the industry, it may now be possible to develop measures, policies and markets that help to improve reliability. Some of such options are briefly summarized below.

Load Management

As described in Section 2.6, DP&L has four programs in place to assist in managing load to improve reliability. However, as was discovered during the outages of July 6, there are some important limitations to the existing programs. In particular, the tariffs covering existing load management programs have limits on the duration of the outage that can be imposed on interruptible customers. Because of this duration limitation, DP&L decided not to utilize certain load management resources at some critical points in the morning of July 6, in order to save those resources for peak load periods later in the day.

With the introduction of retail competition, customers may be interested in a greater variety of load management options, with varying levels of obligations at varying levels of cost. On the other hand, some customers may seek increased levels of reliability, and be less willing to interrupt load upon request from DP&L. Either way, it will be important for DP&L to monitor such changes in customer attitudes over time and modify its load management programs accordingly.

Demand-Side Bidding

Demand-side bidding is a practice that allows customers to bid into the electricity spot market to interrupt their demand, for a certain price. Such customers would bid directly against generation companies, but instead of providing generation to the grid, they would remove load. This sort of bidding is analogous to traditional utility-run interruptible rate programs. However, demand-side bidding is far more flexible than interruptible rate programs, and therefore may offer many more opportunities for reducing load and improving reliability. Demand-side bidding does not require involvement of the distribution company, is not limited by terms and conditions in tariffs, does not require regulatory approval of tariffs, allows customer to more actively participate in the energy market, and allows customers greater discretion regarding how much load they are willing to interrupt and for what price.

Energy Efficiency

Improved energy efficiency can play a role in reducing peak electricity demands.[14] Electricity loads will be reduced, and reliability improved, for each electric end-use whose efficiency is improved. Energy efficiency is often very cost-effective, whereby the cost of achieving the efficiency savings is significantly less than the cost of generating and delivering the electricity. Energy efficiency also results in environmental benefits by reducing the emissions of power plants.

Certain end-uses play a critical role during peak periods. For example, air conditioning systems place a large electrical demand during peak periods, and can be one of the primary factors leading to reliability problems during a heat wave. DP&L staff have noted that a substantial increase of air conditioning in residential beach homes has been a large factor in the Company's recent peak load growth. [Interview with DP&L staff, 10/29/99.]

Some end-uses, such as air conditioners and electric motors, place a higher demand on reactive power than other end-uses. [Staff 2-41.] Energy efficiency programs targeted to these end-uses will provide greater reliability benefits in regions such as the Delmarva peninsula that sometimes suffer from reactive power shortages.

A few key programs targeted to some critical end-uses and customer types may produce significant reliability gains very cost-effectively. With a restructured electricity market, it may be necessary to evaluate a variety of approaches – beyond those of the past that focused on utility demand-side management programs.

Distributed Generation

The term "distributed generation" refers to electricity generation technologies that are relatively small in size and can be deployed close to customers within the distribution

[14] The term "energy efficiency" is used to describe technologies or practices whereby a given electricity service (e.g., heat, light, motor power) is provided using less electricity than under conventional technologies. It is not used to describe a reduction in electricity service.

system, as opposed to on the transmission system. Such generation technologies can be installed by customers, in order to reduce overall electricity costs and improve reliability, or they can be installed by the local distribution company as a low-cost means of addressing demands on the distribution system.

There are many different types of distributed generation technologies, including small engines, small turbines, fuel cells, wind mills, and photovoltaics. Distributed generation is expected to play an increasing role in the restructured electricity market, as customers seek a variety of options for meeting their electricity needs, distribution companies seek opportunities to reduce costs, and manufacturers of generation technologies seek new markets.

7.4 The Commission's Role in Maintaining Reliability

The increasing risks and uncertainties associated with electricity reliability dictate that regulatory commissions continue to provide some regulatory oversight of electricity planning and production activities. While the integrated resource planning processes of the past may no longer be applicable to a decentralized industry, there is still a need -- if not an increased need -- for regulators to ensure that electricity will be provided to customers in a safe and reliable fashion.

The Electric Utility Restructuring Act of 1999 makes it clear that the Commission still has an important role to play in ensuring reliability in Delaware. Section 1002(a) states

> The General Assembly declares that the following interdependent standards shall govern the Commission's review and approval of each public utility's restructuring plan, oversight of the transition process and regulation of the restructured electric utility industry pursuant to this chapter.
>
> > (1) The reliability of electric service to all Customers in this State shall be maintained.

Many important questions regarding future reliability remain unanswered. What changes should be made to the existing infrastructures, institutions and standards to ensure reliability in a more competitive electricity market? How much additional costs should customers (or society) be required to pay in order to maintain or enhance reliability? How much of a role can new market-based mechanisms and incentives play in promoting reliability? How much of a role should state regulatory commissions play in future reliability efforts?

These are difficult questions, and answers will not be readily available. We recommend that this Commission make reliability assurance a high priority during these transition years to a competitive market, and potentially beyond. At a minimum, the Commission and Staff should seek to participate in regional and national debates about reliability and industry planning.[15] Sponsoring and participating in debates at regional (i.e., PJM) levels will be especially important.

In the short term, while these difficult questions are being sorted through, the Commission should take some concrete steps to help ensure future reliability in Delaware. The most direct step would be to apply reliability performance standards to the electric utilities. Reliability performance standards would provide DP&L with a set of clearly-defined benchmarks for an acceptable level of reliability. These benchmarks could include indices used by DP&L in the past (such as the System Average Interruption Frequency Index, the System Average Interruption Duration Index, and the Customer Average Interruption Duration Index), and they could include other types of indices. The performance standards should include penalties for substandard or unacceptable levels of reliability performance. These penalties would provide a clear financial incentive for the electric utilities to maintain at least the level of reliability dictated by the standards.

There are many advantages of establishing reliability performance standards at this time. For example:

- Once they are designed and in place, reliability performance standards require less regulatory oversight than alternative regulatory approaches to reviewing generation, transmission and distribution plans. They focus on a few key benchmarks of customer needs, and allow the utility to identify the best means of achieving those benchmarks.
- Reliability performance standards provide direct financial incentive to offset the cost-cutting incentives created by price caps or price freezes.
- Reliability performance standards should help prevent future outages. However, if such outages do occur, performance standards can provide clear, direct resolution to questions about responsibility and corrective actions.
- Reliability performance standards can be applied to the regulated utilities over which the Commission will continue to have jurisdiction. These utilities can, in turn, use their influential roles in the industry to encourage improved reliability standards among other market actors (e.g., the new owners of their power plants, other members of PJM).
- Reliability performance standards provide the Commission with a means of striking the appropriate balance between increased costs and increased reliability.
- Reliability performance standards can be designed to provide direct compensation to those customers that are affected by reliability problems.
- As long as they maintain acceptable levels of reliability, utilities will not be harmed by performance standards. They will only be harmed if reliability performance deteriorates.

[15] The DOE is sponsoring a national debate and a series of workshops in conjunction with its interim report on last summer's outages. [DOE 2000.] This is an example of the sort of debate that the Commission and Staff should participate in and monitor in the future.

Many other regulatory commissions have begun to implement reliability performance standards, particularly in response to new risks associated with retail competition, price caps, and price freezes. Utilities in as many as sixteen other states have some form of reliability performance standards. In addition to these states, at least twelve states require some form of reliability performance reporting to regulatory commissions. Five utilities currently offer customers guarantees to restore power within a given time after outages. [JBS Energy 1999, Appendix 1.] Many regulatory commissions have included reliability performance standards in performance-based ratemaking (PBR) mechanisms, as a means of offsetting the cost-cutting incentive that comes with such mechanisms. [Synapse 1998.]

The Maryland Public Service Commission recently conducted an investigation into the Maryland utilities' response to recent major outages. One of the findings of the investigation was that performance standards might play a role in preventing future outages. The MD PSC directed the Commission Staff, utilities, Office of People's Counsel, and other interested parties to evaluate whether performance standards would enhance reliability or mitigate the effects of future outages. [MD PSC 1999, page 61.] If Delaware were to take a similar approach, DP&L could be provided with consistent benchmarks and incentives from both states.

8. Conclusions and Recommendations

8.1 Summary of Conclusions

The July 1999 Outages

1. On July 6, 1999, DP&L implemented rotating load shedding as a result of low and declining system voltages on the peninsula, particularly in the Bay Region, due to the following:
   - High peninsula load. At 10:00 a.m. on July 6, the peninsula load including Conowingo reached 3,110 MW. At 5:00 p.m., the peninsula load including Conowingo would have reached 3,449 MW without load shedding. At 5:00 p.m., the peninsula load excluding Conowingo would have reached approximately 3,350 MW without load shedding, which exceeded the 1999 forecast of 3,300 MW by 50 MW or 1.5%.
   - Two generating units on the peninsula – Indian River Unit 3 (165 MW) and Edgemoor Unit 3 (86 MW) – had been out of service and remained out of service on July 6.
   - Indian River Unit 2 (91 MW) tripped off line at 10:35 a.m. for 5 hours and 46 minutes. Also, four combustion turbines – Edgemoor 10 (13-MW), West (15 MW), Christiana 11 (22.5 MW), and Tasley (22 MW) – tripped off line at various times during the afternoon with varying outage durations.
   - Other generating units on the peninsula could not meet their reported Mvar output capabilities and could not run at their full MW capacities. DP&L's reported Mvar limits of its generating units on the peninsula were higher than obtainable under the conditions that existed on July 6. DP&L does not validate via testing actual limits on reactive output of its generating units.
   - Low PJM voltages that increased the reactive power requirements on the peninsula.

   High north-to-south transmission tie-line flows and lack of voltage support created reactive power/voltage problems, particularly in the Bay Region. DP&L implemented rotating load shedding to preserve the UVLS instantaneous protection against electric system damage and to prevent widespread longer-term outages.

2. DP&L's operating strategy on July 6,1999 was proper. DP&L planned the following operating strategy:
   - Implement Active Load Management (ALM) later in the day when peak load would occur.

- Implement rotating load shedding if decreasing voltages approached low voltages that would initiate the Under Voltage Load Shedding (UVLS).
- Preserve UVLS for instantaneous protection against severe contingencies so as to protect the electric system from damage and widespread longer-term outages.
- Use rotating load shedding instead of voltage reduction. With already low system voltages, DP&L was concerned that voltage reduction might compromise UVLS.

3. Preliminary power-flow studies show that under the conditions that existed at 10:36 a.m. on July 6, 1999, with a peninsula load of 3,200 MW and loss of Indian River Unit 2, the system was very close to the point of maximum loadability, when voltages could collapse toward zero and emergency actions would be needed to avoid a catastrophic failure. The preliminary power-flow studies substantiate the prudence and decisiveness of DP&L's action to implement rotating load shedding at 10:36 a.m. and avert a system voltage collapse that would have resulted in more widespread and longer-term outages.

4. Preliminary power-flow studies also indicate that if a 150-Mvar Static Var Compensator (SVC) had been installed at Nelson Substation in the Bay Region and in service on July 6, 1999, the low voltages encountered after the Indian River Unit 2 outage would have been eliminated. Also, the point of voltage collapse would have been pushed out from a peninsula load of 3,200 MW to 3,500 MW. If the 150-Mvar SVC had been in service, rotating load shedding could have been avoided for the entire day.

5. Preliminary power-flow studies further indicate that if a 150-Mvar SVC had been installed at Nelson Substation and a 150-Mvar SVC as well as a 50-Mvar capacitor had been installed at Indian River Substation in the Bay Region and these had been in service on July 6, 1999, the point of voltage collapse would have been pushed out from a peninsula load of 3,200 MW to 3,770 MW. These SVCs and capacitor would have provided additional reactive reinforcement and voltage support in the Bay Region, and would have eliminated the need for rotating load shedding for the entire day.

DP&L Transmission Planning

6. Delmarva Power & Light (DP&L) system planners raised their concern as early as 1993 about potential reactive power/voltage problems that could occur as load grew. In DP&L's 1993 Transmission and Distribution Ten Year Planning Study, a 150-Mvar SVC and a major project to increase system import capability were projected for need by the year 2000 if major generation were not added in the Bay Region.

7. In DP&L's 1995 Transmission and Distribution Ten Year Planning Study, the need for a 200-Mvar SVC at Piney Grove Substation in the Bay Region was projected by the late 1990s if additional generation were to be delayed or canceled. This was moved up from the 1994 study, which projected need for a 200-Mvar SVC by 2000. Timing for installation of this SVC was based in part on a 1.5% annual growth in

(coincident) summer peak load from 1994 to 2004. However, weather-normalized summer peak load actually grew at an annual rate of 3.12 % from 1994 to 1999.

8. DP&L's 1996 and 1997 Transmission and Distribution Ten Year Planning Studies pushed back the need for a 200-Mvar SVC in the Bay Region to May 2000, as load continued to grow without additional generation in the Bay Region.

9. DP&L's Transmission and Distribution Ten Year Planning Studies for the years 1994 – 1997 verify that corporate-wide capital budget cuts continually had a significant impact on in-service dates with many T&D projects being deferred a year or more. DP&L did not prepare a formal Transmission and Distribution Planning Study during 1998 and 1999.

10. It is apparent that budget constraints and corporate management decisions played a key role in the necessity of DP&L's systems operation personnel to implement rotating load shedding on July 6,1999, which affected many customers in Delaware and in other areas of the Bay Region.

11. Following the outages this past summer and the Commission's opening of this investigation, DP&L has now taken some steps to reduce the probability that rotating load shedding will occur during the summer of 2000. DP&L's 1999 Transmission and Distribution Projects List currently includes the installation of a 150-Mvar SVC at the Nelson Substation with an in-service date of May 31, 2000. In addition, DP&L has accelerated installation dates of the following Bay Region transmission projects:
    - Indian River 150 Mvar SVC, now scheduled for completion on June 15, 2000 (had been scheduled for completion in June 2003).
    - Indian River 50 Mvar Capacitor now scheduled for completion on June 15, 2000 (had been scheduled for completion in June 2001).
    - Steele second 230-138 kV autotransformer, now scheduled for completion after the summer of 2000 (had been scheduled for completion in June 2003 timeframe).

    Completion of the above projects as well as other transmission projects will increase the voltage support available on the transmission system, particularly in the Bay Region, and therefore help to maintain adequate voltage levels on the peninsula.

MAAC Reliability Assessment

12. DP&L complied with MAAC's Installed Generating Capacity requirements for the 1999/2000 planning period.

13. An increasing CETO for the planning periods 1996/97, 1997/98,and 1998/99 as well as the projected CETO for 2003/04 shows a trend of increasing reliance on off-peninsula generation to meet generation reserve requirements.

14. Completion of the proposed generation in New Church, VA will aid in keeping pace with load growth in the Bay region, in reducing power transfers and transmission

losses on transmission ties to the Bay Region, and in providing voltage support for the Bay Region. However, this and other generating capacity additions planned for the peninsula could be canceled, and expected in-service dates could be delayed.

15. DP&L complied with MAAC's Network Transfer Capability requirements for the1999/2000 planning period. However, the margin of network transfer capability (the CETO/CETL margin) for the Bay Region was reduced to zero for the 1999/2000 planning period. If a 200-Mvar SVC had been installed in the Bay Region by the 1999/2000 planning period, the CETO/CETL margin would have been 250 MW.

16. In 1997, MAAC recognized the need for installation of planned reactive reinforcements in the Bay Region that would be in service by the 1999/2000 planning period in order for DP&L to comply with MAAC's Voltage Support and Reactive Requirements.

The Divestiture of DP&L's Generation Assets

17. DPL is taking a prudent approach with regard to reliability issues associated with the divestiture of their power plants. The draft Interconnection Agreement and the MAAC and PJM standards should address reliability concerns. Delmarva's divestiture activities do not create more reliability risks than those of other utilities selling generation assets in other parts of the country.

18. However, the sale of generation assets does create uncertainty and increased risk regarding how responsible, cooperative, and capable the new power plant owners will be. Simply increasing the number of power plant owners on the peninsula increases the complexity of maintaining reliability – particularly under emergency conditions. This increased uncertainty is part of a broader development associated with the restructuring of the electricity industry in general.

Maintaining Reliability in the Future

19. Electricity industry restructuring activities increase the risks and uncertainties associated with reliability. The regulations, institutions, standards and protocols necessary to ensure reliability may not have evolved sufficiently to keep pace with the restructuring changes. The industry is increasingly influenced by many new market players, less long-term planning, greater reliance upon unpredictable market signals, less regulatory oversight, and increased need for complex communication systems. All of these changes increase the risk that reliability will deteriorate in the future.

20. In a competitive electricity market, generating companies often have an incentive to maintain as little capacity as is necessary to meet reliability requirements. This trend can already be seen in DP&L's increasing reliance upon purchases, declining reserve margins and declining CETO/CETL margins.

21. Distribution companies subject to a price cap have an incentive to reduce or postpone transmission and distribution investments that might enhance reliability. DP&L has postponed some key transmission and distribution upgrades as a consequence of budgetary constraints – upgrades that could have played a critical role in mitigating the July 1999 outages. The reliability problems created by such cost-cutting incentives are exacerbated when the distribution utility is located on a load pocket, such as the Delmarva peninsula.

22. In the restructured electric market, DP&L will offer a regulated default service and a competitive merchant generation service. DP&L has already demonstrated a reluctance to share information about how it plans to provide these services, particularly with regard to the merchant business. While it appears that DP&L will have sufficient generation capacity to provide these services, it will be important for the Commission to play a role in overseeing these services, especially during the transition period.

8.2 Summary of Recommendations

The Divestiture of DP&L's Generation Assets

The Commission should follow up on the on-going sale of power plants to ensure that the terms and conditions of the sale will minimize any problems with reliability. For example, the Commission should review a final copy of the draft Interconnection Agreement to ensure that it contains all of the reliability-related provisions of the current draft. The Commission should ensure that NRG will indeed be committed to maintaining the Indian River and Vienna plants as Capacity Resources.

The Commission should request that the PJM Market Monitoring Unit perform a market power and reliability analysis of the Indian River and Vienna units, similar to the analysis that was performed for the DC PSC.[16] In addition, in any future investigations of market power on the peninsula in general, the Commission should investigate the specific market power issues associated with NRG's ownership of the Indian River and Vienna plants.

Maintaining Reliability in the Future

Due to the geographic constraints of DP&L's transmission system, the uncertainties raised by a deregulated generation market, and DP&L's prior decisions to forgo or delay planned transmission projects because of budget constraints, it is recommended that the Commission develop detailed reliability requirements to ensure the future reliability of DP&L's transmission system.

The Commission should make reliability a high priority, especially during the transition to a competitive market. Although the Electric Utility Restructuring Act of 1999 has defined the "transition period" as running through 2003 (for DP&L), the electricity market might not be fully competitive by that time. The Commission should continue to

[16] On January 31 the Commission authorized the Staff to make such a request to the PJM MMU.

keep reliability as a high priority at least until the market is determined to be fully competitive.

In the short-term, the Commission should establish a generic proceeding to investigate opportunities for regulatory policies and mechanisms to maintain reliability in the future. First and foremost, the Commission should assess the opportunities for applying performance standards to DP&L. The Commission should also assess additional measures for promoting reliability, including transmission and distribution reinforcements, improved ALM programs, demand-side bidding, energy efficiency, and distributed generation resources.

The Commission should encourage DP&L to more accurately report Mvar capabilities of its generating units during summer ambient temperatures on the peninsula, and to validate unit reactive output limits via testing.[17]

In the long-term, the Commission and Staff should participate in and sponsor local, regional and national investigations into reliability and electricity industry planning. Such investigations should pursue at least the following central questions:

- In what ways should regulatory policies, PJM practices, and NERC and MAAC reliability standards be modified to keep pace with the industry changes due to restructuring.
- What is the appropriate balance between reliability and cost? What financial incentives and market signals are needed to encourage companies to achieve the appropriate balance?
- What level of reliability is appropriate from society's perspective? How much reliability do customers expect or demand? What are the opportunities for allowing customers to pay for higher (or lower) levels of reliability for higher (or lower) costs?
- What market mechanisms can be employed to enhance reliability?
- How should information systems and emergency response protocols be modified to account for the complexities of the competitive electricity market?

[17] The PJM Root Cause Analysis Team has recommended that a common standard be established within MAAC for generator steady-state and post-contingency (15-minute) Mvar capability definition, determination methodology, testing and operational reporting requirements [PJM 12/1999.].

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Appendix A Figures

Appendix B Tables

Appendix C Preliminary Power Flow Study

Appendix D Confidential Material