

**REBUTTAL TESTIMONY  
OF  
SCOTT GASS  
ON BEHALF OF  
VIRGINIA ELECTRIC AND POWER COMPANY  
BEFORE THE  
STATE CORPORATION COMMISSION OF VIRGINIA  
CASE NO. PUE-2007-00031**

1 **Q. Please state your name and business address.**

2 A. My name is Scott Gass and my business address is 15 Shannon Way, Royersford,  
3 Pennsylvania 19468.

4 **Q. Have you previously filed testimony in this proceeding?**

5 A. Yes. I have filed written direct testimony on behalf of Dominion Virginia Power.

6 **Q. Please describe the purpose of your rebuttal testimony.**

7 A. My rebuttal testimony is offered to rebut the direct testimony of James Bouford, a witness  
8 for CPV Warren, LLC ("CPV Warren") and Hyde Merrill a witness for the Piedmont  
9 Environmental Council.

10 **Q. Will you be using the same terms in your rebuttal testimony as set forth in your**  
11 **direct testimony?**

12 A. Yes. In addition, I may define other specific terms in my rebuttal testimony.

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**I. SUMMARY OF REBUTTAL TESTIMONY**

15 **Q. Please summarize the main themes of your rebuttal testimony.**

16 A. Mr. Bouford's testimony presents the basis for CPV Warren's contentions that PJM's  
17 identification of transmission system reliability violations is inaccurate and that, based on  
18 a number of assumptions Mr. Bouford has elected to make (including the placement into

1 service of two proposed CPV projects), those reliability violations can be addressed  
2 without the need to construct the 502 Junction-Mt. Storm-Meadow Brook-Loudoun line  
3 (“502 Junction-Loudoun” Line or the “project”). Dr. Merrill questions the modeling  
4 assumptions of proposed generation projects and also the application of the PJM  
5 generation and load deliverability tests and their relationship to NERC Planning  
6 Standards.

- 7 • In Section II of my rebuttal testimony, I will prove that PJM’s identification of  
8 the transmission system reliability violations in PJM’s 2006 Regional  
9 Transmission Expansion Plan (“RTEP”) was correctly performed and  
10 continues to be valid, and was not based on “overly conservative”  
11 assumptions as Mr. Bouford suggests. I will also demonstrate that the 2006  
12 RTEP appropriately considered the availability of new generation that could  
13 reasonably be applied to the transmission system before the identified  
14 reliability violations arise.
- 15 • Section III of my rebuttal testimony focuses upon Mr. Bouford’s assertion that  
16 two proposed, CPV-sponsored generation projects, together with various other  
17 system modifications, could alleviate the need to construct the 502 Junction-  
18 Loudoun Line. I will demonstrate that (i) Mr. Bouford’s analysis relies upon  
19 assumptions that are both uncertain and, consequently, not justifiable in the  
20 context of PJM’s reliability criteria violation analysis (either in 2006 or now);  
21 and (ii) in failing to apply important system-stressing tests Mr. Bouford’s  
22 analysis is significantly less rigorous than the PJM approach. I conclude that  
23 Mr. Bouford’s analysis is not a reliable basis upon which the Commission

1 could conclude that the 502 Junction-Loudoun Line is not needed to address  
2 the June 2011 transmission system reliability violations that PJM has  
3 identified.

4 **II. THE 2006 RTEP AND PJM'S IDENTIFICATION OF**  
5 **NERC RELIABILITY CRITERIA VIOLATIONS**

6 **Q. Before addressing Mr. Bouford's limited criticisms of PJM's findings in the 2006**  
7 **RTEP, please identify your role in that process.**

8 A. As I indicated in my direct testimony, in my role as PJM's Manager, Transmission  
9 Planning, I supervised the creation of the 2011 base case for the 2006 RTEP as well as  
10 the power system studies that determined the need for the 502 Junction-Loudoun Line.  
11 Based on PJM's reliability analyses, PJM determined that there are eleven electric  
12 reliability problems that are likely to occur beginning in 2011 and one electric reliability  
13 problem that is likely to occur in 2014 (electrical occurrence #9) if the 502 Junction-  
14 Loudoun Line is not built. In Attachment SG-1 to my direct testimony, I identified each  
15 of these projected reliability problems, expressing them in terms of an identified  
16 "electrical occurrence" (in each case, an outage of an existing transmission facility,  
17 sometimes combined with the unavailability of a significant generator or other  
18 transmission facility) and the resulting "electrical result" that would occur without the  
19 502 Junction-Loudoun Line or an equally timely and effective solution.

20 **Q. What were the electrical results of the identified electrical occurrences?**

21 A. For eight of the twelve electrical occurrences (occurrences #1 through #8), a major 500  
22 kV backbone line – the Mt. Storm-Doubs line – is projected to exceed its emergency  
23 rating and overload. Electrical occurrence #9 results in the Pruntytown - Mt. Storm 500  
24 kV line exceeding its emergency rating and overloading. Electrical occurrences #10,

1 #11, and #12 are projected to result in voltage support problems around the Meadow  
2 Brook substation. The Bates White report, on page 47, paragraph 129, confirms the 500  
3 kV circuit overloads:

4 In summary, Bates White has conducted an independent study to verify  
5 DVP's own analysis and to determine the need for the proposed  
6 Loudoun Line. The results of Bates White's study verify DVP's own  
7 reliability study results: *i.e.*, without additional system improvements,  
8 the existing system will experience reliability violations on major 500  
9 kV lines that are critical to reliably meeting the expected demand  
10 growth on the PJM mid-Atlantic region and the northern Virginia area.

11 **Q. What is the relationship between these findings and NERC reliability criteria?**

12 A. Mandatory reliability standards developed by the North American Electric Reliability  
13 Corporation ("NERC") and approved by the FERC, together with PJM's reliability  
14 planning standards and those of relevant transmission owners, are the criteria that must be  
15 used – and that PJM did use – to assess the overall reliability of the transmission system  
16 and identify the system upgrades needed to prevent those problems from occurring.

17 **Q. How does this context inform your evaluation of Mr. Bouford's testimony?**

18 A. Reiterating PJM's identification of these reliability standards offers a useful context of  
19 what Mr. Bouford criticized in PJM's efforts and, significantly, what he did not criticize.

20 **Q. What do you mean?**

21 A. First, let me discuss what Mr. Bouford's direct testimony did and did not address. As it  
22 relates to PJM's identification of reliability violations in the 2006 RTEP, Mr. Bouford  
23 raised three concerns: (i) his criticism of two of the reliability violations relating to the  
24 Meadow Brook substation (electrical occurrences #11 and #12); (ii) his identification of a  
25 purportedly "inappropriate assumption" in connection with electrical occurrence #9

1 (involving an overload on the Pruntytown-Mt. Storm 500 kV line), and (iii) more  
2 generally, his assertion that PJM's assessment of the availability of generation was  
3 skewed in a way that overstated the identified reliability violations. For this last point,  
4 Mr. Bouford did not suggest any way in which those alleged overstatements affected the  
5 outcome of PJM's efforts.

6 So, apart from his criticisms of the Meadow Brook-related reliability violations (which I  
7 will dispel below), Mr. Bouford has *not* asserted that PJM's identification of the  
8 reliability violations was incorrectly performed. This is especially relevant for the nine  
9 electrical occurrences that result in overloads of the critical Mt. Storm-Doubs and  
10 Pruntytown-Mt. Storm lines.

11 **Q. Please address Mr. Bouford's contentions relating to electrical occurrences #11 and**  
12 **#12.**

13 **A.** At page 6 of his direct testimony, Mr. Bouford contends that PJM misapplied the relevant  
14 NERC Reliability Standard, TPL-003-0. Specifically, Mr. Bouford asserts that because  
15 these two contingencies involve the simultaneous outage of separate transmission  
16 elements with no physical connection between them, they do not result in reliability  
17 violations under the relevant NERC criteria.

18 Mr. Bouford is incorrect. PJM studied electrical occurrences #11 and #12 as NERC  
19 Category C3 contingencies, and the low voltage conditions that were identified are  
20 violations of NERC reliability standards. To understand why this is so, one must  
21 appreciate that the relevant NERC criteria allow for "manual system adjustments" after  
22 the occurrence of the first Category B contingency and before the occurrence of the  
23 second Category B contingency. However, if a manual system adjustment – including a

1 re-dispatch of generation or a curtailment of firm transfer – is not sufficient to resolve the  
2 reliability problem, then the reliability standard is violated for this “n-1-1” contingency.<sup>1</sup>  
3 This is exactly the analysis that PJM performed. PJM determined that in the case of  
4 electrical occurrences #11 and #12, the manual system adjustments PJM studied were not  
5 sufficient to resolve the reliability problem. Thus, even though the two identified  
6 electrical occurrences were not assumed to be caused by the same event (such as the  
7 single stuck breaker Mr. Bouford describes), PJM determined that a manual system  
8 adjustment between the two Category B contingencies would be insufficient to resolve  
9 the problem, and therefore in each situation a NERC Category C3 violation was correctly  
10 identified.

11 **Q. Was a dynamic reactive device such as a static var compensator (SVC) considered**  
12 **as an option to resolve the voltage problems identified for electrical occurrences #11**  
13 **and #12?**

14 A. Yes, an SVC was considered as an option. However, the cost to interconnect the 502  
15 Junction–Loudoun 500 kV Line into the Meadow Brook substation was estimated to cost  
16 \$20 million while the cost of an SVC was estimated at \$35 million. Interconnecting the  
17 project into Meadow Brook resolved the voltage problems and was less expensive than  
18 an SVC and therefore was selected as the preferred alternative.

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<sup>1</sup> Some clarification of the way NERC Category C3 contingencies are described is warranted. Although the term “n-2” is sometimes used to describe NERC Category C3 contingencies, that term is susceptible to misinterpretation as relating uniquely to two simultaneous contingencies without any ability for manual system adjustment. The term “n-1-1” is a better descriptor of this kind of Category C3 analysis, as it reflects the ability to apply manual system adjustments.

1 Q. Do you agree with Mr. Bouford's statement on page 7 of his testimony that electrical  
2 occurrence #9 should not have been included as one of the reliability problems in  
3 Attachment SG-1?

4 A. No. In my view, Mr. Bouford's testimony on this point resorts to "revisionist history" to  
5 reach his conclusion, and in any event is more remarkable for what it *doesn't* say.

6 At page 7 of his direct testimony, Mr. Bouford contends that electric occurrence #9 in  
7 Attachment SG-1, which results in an overload of the Pruntytown-Mt. Storm 500 kV line,  
8 "would only occur if the Amos to Bedington 765 kV line and the Bedington to  
9 Kemptown 500 kV line, both of which are included in PJM's 2007 RTEP and with in-  
10 service dates of June 1, 2012, are not built." Mr. Bouford characterizes my failure to  
11 recognize the Amos-Kempton line as an "inappropriate assumption" that has produced  
12 an "error" in my direct testimony. What Mr. Bouford doesn't mention, however, is that  
13 my direct testimony was prepared, and the analyses it describes were performed, *before*  
14 the PJM Board considered and approved the Amos-Kempton line (also called "PATH")  
15 in June 2007. Stated differently, the fact that the Amos-Kempton line was, for the first  
16 time, included in PJM's **2007** RTEP has no bearing whatsoever on the fact that it was not  
17 included or assumed in PJM's 2006 RTEP, the results of which are outlined in my direct  
18 testimony and its Attachment SG-1. The 2007 RTEP, as Mr. Bouford knows, had not  
19 been prepared or approved at the time my direct testimony in this case was submitted.  
20 Accordingly, there was (and is) no "error" in my testimony or Attachment SG-1, as Mr.  
21 Bouford asserts; furthermore, there was no logical reason for me to present any basis for  
22 assuming that Amos to Kempton will not be built. To suggest otherwise is to invite a  
23 serious misunderstanding of the analyses described in my testimony.

1 **Q. But doesn't the inclusion of Amos-Kemptown in the 2007 RTEP require you to**  
2 **reconsider your support for your direct testimony and the reliability violations**  
3 **identified in the 2006 RTEP?**

4 A. Not in the slightest. Although I left PJM to join PowerGEM in November 2006, and was  
5 not involved in the preparation of the studies underlying PJM's 2007 RTEP, the  
6 reliability violations arising from those studies do nothing to undermine the analyses  
7 conducted in support of the 2006 RTEP on which the need for the 502 Junction-Loudoun  
8 Line in this case has been premised. PJM's analyses of the need for major transmission  
9 system improvements is a dynamic process, and, as Mr. Herling observes in his rebuttal  
10 testimony in this case, there are situations in which previously-announced transmission  
11 upgrades may be determined no longer to be necessary in subsequent RTEPs. I am  
12 generally aware, however, that the 502 Junction-Loudoun Line remains an important and  
13 assumed component in PJM's 2007 RTEP, and that Mr. Herling has asserted that both  
14 502 Junction-Loudoun Line and Amos-Kemptown are independently needed to resolve  
15 reliability violations identified in that document.

16 **Q. You suggested that Mr. Bouford's contentions were just as notable for what they did**  
17 **not say. What do you mean?**

18 A. Mr. Bouford's unwarranted criticism of the PJM 2006 RTEP was levied only at electrical  
19 occurrence #9. The Commission should note that Mr. Bouford's criticism apparently  
20 does not extend to any of the other electrical occurrences identified in my Attachment  
21 SG-1 – particularly the eight occurrences that result in an overload of the Mt. Storm-  
22 Doubts line.

1 **Q. Please address Mr. Bouford's assertion, on page 8 of his testimony, that PJM**  
2 **overstated reliability violations found in the 2011 base case.**

3 A. None of Mr. Bouford's contentions is demonstrated to have any impact on the results of  
4 PJM's identification of reliability violations in the 2006 RTEP; indeed, Mr. Bouford does  
5 not even attempt to explain why his criticisms are relevant in that regard. In any event,  
6 however, Mr. Bouford's assertions are inaccurate.

7 Mr. Bouford first asserts that PJM inappropriately excluded generators in the eastern PJM  
8 interconnection queue without a signed interconnection services agreements ("ISA") but  
9 included two proposed generators in the western PJM interconnection queue that did not  
10 have signed ISAs at the time the 2006 RTEP was completed. He implies that among the  
11 "excluded eastern generators" that were not considered, the "CPV Warren and CPV St.  
12 Charles Projects" should have been included. (Bouford at p. 8.)

13 There was nothing inappropriate, however, about PJM's inclusion and exclusion of  
14 generators in the 2006 RTEP. The PJM baseline model includes all active generation  
15 projects that have proceeded beyond the System Impact Study. Those generation projects  
16 that have proceeded beyond the System Impact Study but have not executed an ISA are  
17 included in the basecase but are modeled as off-line. Since they are modeled as off-line,  
18 the generators can only contribute to reliability problems for the PJM generation  
19 deliverability test and they have no impact on the reliability problems identified through  
20 the PJM load deliverability test and the Dominion Virginia Power's planning criteria. As  
21 such, modeling of the N12 and M26 coal-fired generation projects in Western PJM as  
22 off-line in the 2006 RTEP basecase had no impact on the PJM Load Deliverability results  
23 for electrical occurrences #1 through #4 in my Attachment SG-1 and also had no impact

1 on the Dominion Virginia Power's planning criteria results for electrical occurrences #5  
2 through #8 in Attachment SG-1. Furthermore, for purposes of resolving reliability  
3 problems, PJM only includes capacity resources that have executed ISAs, because as Mr.  
4 Herling's rebuttal testimony explains, PJM's experience demonstrates that projects have  
5 a high degree of cancellation prior to execution of an ISA.

6 The CPV Warren and CPV St. Charles projects referenced by Mr. Bouford had not even  
7 entered the PJM interconnection queue until months after the 502 Junction-Loudoun Line  
8 had been approved by the PJM Board.

9 **Q. To conclude this section of your testimony, please address Dr. Merrill's assertion on**  
10 **page 31 of his direct testimony, that the driver for the Loudoun line is not reliability,**  
11 **but rather economic, and that the dispatches in the PJM databases used in the**  
12 **studies reflect the objective of the owners of western coal-fired plants.**

13 **A.** First and foremost, I personally supervised the analysis that was performed to determine  
14 the need for the 502 Junction-Loudoun Line and I can unequivocally state that the driver  
15 for the Project was not economics. The driver for the Project as explained on page 14 of  
16 my direct testimony was based on violations of NERC Reliability Standard TPL-002 and  
17 TPL-003. Furthermore, the western coal fired generation projects without an ISA did not  
18 contribute towards the Load Deliverability violations for electrical occurrences 1 through  
19 4 and Dominion Virginia Power's planning criteria violations for electrical occurrences  
20 #5 through #8. To state that the dispatches in the PJM databases reflect the objective of  
21 the owners of western coal-fired plants illustrates Dr. Merrill's complete  
22 misunderstanding of the studies that were performed.

1                   **III. MR. BOUFORD'S ASSERTIONS OF THE IMPACT OF CPV**  
2                   **PROJECTS ON NEED ANALYSIS**

3           **A. Summary of Mr. Bouford's Analyses and Underlying Assumptions**

4   **Q. Mr. Bouford next opines on the impact of the proposed addition of the CPV projects**  
5   **on the NERC reliability violations you identified. Before we analyze Mr. Bouford's**  
6   **findings, please summarize his approach.**

7   **A.** As I will explain below, Mr. Bouford applies so many different assumptions and so much  
8   predicate information, and fails to use such important testing procedures, that it is  
9   difficult for me to agree that his analyses even approximate the rigor PJM applied in the  
10   2006 RTEP or, for that reason, can be meaningfully compared with PJM's analysis of the  
11   need for the 502 Junction-Loudoun Line. To understand my concerns, it may be helpful  
12   to provide some context for Mr. Bouford's approach.

13   First, after substituting a different "base case" for the 2011 case used in the 2006 RTEP,  
14   Mr. Bouford assumed that the CPV Warren Facility will go on line by June 2011 using its  
15   138 kV interconnect. Using these data and assumptions, Mr. Bouford opined that some  
16   (but not all) of the identified reliability violations would be resolved (Bouford at p. 11-12  
17   and Attachments B and C.)

18   Second, Mr. Bouford "analyzed the system for 2012" (Bouford at 15) by using the 2012  
19   base case from PJM's 2007 RTEP, in which he further assumes that the Amos to  
20   Kempton line will be in service by June 2012. Based on these additional assumptions,  
21   Mr. Bouford asserts that none of the *2011* reliability violations expressed in my direct  
22   testimony will exist in *2012*.

1 Finally, using all of these same assumptions, Mr. Bouford further assumes that the CPV  
2 St. Charles Facility will *also* be in service by June 2011, and that this combination of  
3 assumptions addresses reliability problems in both 2011 and 2012. (Bouford at p. 16)

4 **B. Mr. Bouford's Assumptions and Methods are Unsupportable.**

5 1. **Mr. Bouford Failed to Apply PJM's Load Deliverability and**  
6 **Generation Deliverability Tests.**

7 **Q. Before you address the assumptions underlying Mr. Bouford's analysis, is there a**  
8 **fundamental concern you have with his approach?**

9 A. Yes, there is. Apart from the advisability of the assumptions Mr. Bouford has used, I am  
10 most concerned by his unexplained refusal to apply the PJM "load deliverability" and  
11 "generation deliverability" tests to any of his analyses. In my view, this omission  
12 completely undermines Mr. Bouford's opinions for five of the electrical occurrences and  
13 results identified in my Attachment SG-1.

14 **Q. What are the load deliverability and generation deliverability tests, and why were**  
15 **they important to PJM's identification of NERC reliability violations?**

16 A. The direct testimony filed in support of the Commission's certification of the 502  
17 Junction-Loudoun Line devoted significant attention to the role of these procedures. Mr.  
18 Herling's direct testimony explained that in order to ensure compliance with NERC  
19 Category A and B reliability standards, PJM applies the "more rigorous deliverability  
20 criteria" of these two tests:

21 PJM tests for both load deliverability and generation deliverability.  
22 The load deliverability test evaluates the capability of the  
23 transmission system to deliver energy from the remainder of the  
24 PJM region to a portion of the PJM region experiencing higher  
25 than normal unavailability of generating capacity. The generation  
26 deliverability test evaluates the capability of the transmission  
27 system to deliver energy from a grouping of generators  
28 experiencing higher than normal availability to the remainder of

1 the PJM region experiencing lower than normal generator  
2 availability. The deliverability tests establish a link between  
3 generation resource adequacy for the region and the transmission  
4 adequacy necessary to deliver the generation resources to loads.

5 (Herling direct testimony, at p.10.)

6 I also discussed the importance of the load deliverability and generation deliverability  
7 tests at pages 8 and 9 of my direct testimony. I explained that the load deliverability test  
8 examines defined load zones within the PJM region and considers the ability of the  
9 transmission system to deliver adequate power to those zones during a generation  
10 capacity emergency. The generation deliverability test stresses the system to assure that  
11 capacity resources can be delivered to the remainder of the system at peak load.  
12 Importantly, both tests are conducted by simulating the transmission system as it is  
13 expected to exist during future time periods.

14 **Q. Is PJM's application of the load deliverability and generation deliverability tests**  
15 **permissible under the NERC reliability standards?**

16 **A.** Yes. PJM's generation deliverability and load deliverability tests are the accepted  
17 procedures by which PJM studies NERC Category B contingencies, including those  
18 analyzed in electrical occurrences #1 through #4 and #9 in Attachment SG-1. The  
19 applicable NERC standards empower the planning authority (in this case, PJM) to  
20 conduct assessments that, in order "to be valid . . . shall . . . cover critical system  
21 conditions and study years as deemed appropriate by the responsible entity."<sup>2</sup> In

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<sup>2</sup> See NERC Standard TPL-002-0 (governing Category B contingencies) at Section R1.3.2 and prefatory text, a copy of which is attached to this rebuttal testimony as Rebuttal Attachment SG-1. See also the NERC Planning Committee's 10-12-07 interpretation of Section R1.3.2, which confirms that "[t]he selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority/Transmission Planner." A copy of this document is as Rebuttal Attachment SG-2 to this rebuttal testimony.

1 fulfillment of this requirement, PJM has applied the load deliverability and generation  
2 deliverability tests consistently for RTEP baseline studies, generation interconnection  
3 studies and merchant transmission interconnection studies on the PJM system for over  
4 seven years. These deliverability tests are set forth in PJM's Regional Planning Process  
5 Manual M14B, Attachment E.

6 **Q. Why is PJM's application of these two tests so critical?**

7 A. The generation and load deliverability tests are PJM's method to stress the PJM  
8 transmission system to assure reliability under "critical system conditions" as provided  
9 for in NERC Standard TPL-002-0 Section R1.3.2. Any analysis of NERC reliability  
10 violations within PJM that does not apply the load deliverability and generation  
11 deliverability tests does not adequately study the required critical system conditions, and  
12 therefore any such analysis is invalid.

13 **Q. Dr. Merrill on page 28 of his direct testimony has claimed that the tests depend on**  
14 **assumptions, calculations, and data that have apparently not been justified, made**  
15 **public, or subject to independent peer review or regulatory approval. Do you agree**  
16 **with his statement?**

17 A. No. The PJM Planning Committee and the PJM Markets and Reliability Committee do  
18 review and approve any changes to these tests. Also, PJM members whether they are  
19 generation owners, transmission owners, or end use customers all have the ability to  
20 request modifications or clarifications to the procedures through the committee processes.  
21 As stated previously, the assumptions and explanations of the PJM deliverability tests are  
22 contained in Manual M14B, Attachment E which are available publicly. Furthermore,  
23 the base cases that were developed through application of these procedures and used for  
24 identification of the reliability problems were provided through discovery. As for

1 regulatory approval, the NERC Planning Committee in Rebuttal Attachment SG-2 has  
2 made it clear that the “selection of the credible critical generation dispatch for modeling  
3 of critical system conditions is within the discretion of the Planning  
4 Authority/Transmission Planner.”

5 **Q. Did Mr. Bouford apply either the load deliverability test or the generation**  
6 **deliverability test to his analysis of any of the NERC reliability violations you**  
7 **identified?**

8 A. Not only did he fail to identify them, his testimony does not even acknowledge their  
9 existence or the importance of PJM’s application of them in the 2006 RTEP process. In  
10 fact, he did not apply either of these test.

11 **Q. But couldn’t Mr. Bouford have used the 2006 RTEP generation and load**  
12 **deliverability base cases that TrAILCo provided in discovery in this case?**

13 A. Yes, Mr. Bouford could have accessed the base cases Dominion Virginia Power provided  
14 in discovery, and then could have modified those cases to account for any sensitivities he  
15 wanted to study. For reasons that are not apparent in his testimony, Mr. Bouford elected  
16 not to undertake this effort.

17 **Q. In your view, Mr. Gass, how does Mr. Bouford’s failure to apply the load**  
18 **deliverability and generation deliverability tests affect the usefulness of his analysis?**

19 A. Even without considering the other assumptions Mr. Bouford made, I believe that his  
20 failure to apply these two important tests renders invalid – and thus of no benefit to the  
21 Commission – all of his analyses relating to electrical occurrences #1 through #4 and #9  
22 of my Attachment SG-1. This applies to Mr. Bouford’s opinions expressed for these  
23 electrical occurrences as they appear in Attachments B through K of Mr. Bouford’s direct  
24 testimony. Each of these electrical occurrences involves the electrical result of an

1 overload on a 500 kV back bone line: the Mt. Storm-Doubs line (in the case of electrical  
2 occurrences #1 through #4) and the Pruntytown-Mt. Storm line (in the case of electrical  
3 occurrence #9). It is worth noting, however, that even without applying these tests and  
4 the critical system conditions they model, Mr. Bouford's Attachment B results – those  
5 that purport to identify system reliability problems using a different, 2007 case – *still*  
6 indicate loadings above 92% of Mt. Storm-Doubs 500 kV line's emergency rating for  
7 electrical occurrences 1, 2 and 4.

8 **2. Mr. Bouford Used a Different Base Case than the Base Case**  
9 **PJM Prepared for the Assessment of Reliability Violations.**

10 **Q. What is the next of Mr. Bouford's assumptions you wish to discuss?**

11 A. My direct testimony indicates that PJM used a 2011 base case in the 2006 RTEP. Each  
12 year PJM develops a "baseline" RTEP case that is used to look at system reliability five  
13 years into the future. The baseline RTEP case includes load profiles based on the latest  
14 available PJM load forecast, updates transmission topology using the latest information  
15 available, and models all generators and merchant transmission projects that have  
16 proceeded beyond the System Impact Study. PJM uses this baseline RTEP case to  
17 determine any future reliability problems and to evaluate and recommend solutions to all  
18 identified problems. The 'baseline' analysis and the resulting solutions to any reliability  
19 problems then serve as the base system for conducting Feasibility Studies and System  
20 Impact Studies for generation and merchant transmission interconnection projects. For  
21 the Commission to properly evaluate PJM's identification of the reliability criteria  
22 violations, the 2011 'baseline' case from the 2006 RTEP is the appropriate base case to  
23 use.

1 Mr. Bouford, on the other hand, elected to ignore the 2011 base case, instead choosing to  
2 use what he describes repeatedly in his direct testimony as the “2011 case from the PJM  
3 2007 RTEP.” He contended that he used “the PJM 2007 RTEP base case” because it  
4 provides, in his view, a “more current and accurate” representation of the transmission  
5 system. (Bouford at p. 11.)

6 **Q. Mr. Bouford’s identification of this case suggests that it is the primary “base case”**  
7 **that PJM used in the 2007 RTEP. Is this accurate?**

8 A. No. Although one cannot discern this from Mr. Bouford’s testimony, PJM’s 2007 RTEP  
9 is intended to look at system reliability on a five-year horizon, and focuses primarily on  
10 the 2012 timeframe. It does not include or reference a 2011 base case to reach its  
11 conclusions. In reviewing Mr. Bouford’s testimony, this fact left me wondering exactly  
12 what base case Mr. Bouford was referencing. Had Dominion Virginia Power not asked  
13 Mr. Bouford this question in a data request, it would have been impossible to identify the  
14 base case Mr. Bouford used.

15 **Q. How did Mr. Bouford respond to this data request?**

16 A. Mr. Bouford identified this case as “RTEP 2011 BASECASE 2<sup>nd</sup> Rev. on 02/07/06, 2011  
17 NON\_DIVERSIFIED 50/50 LOAD MODEL” that was last modified on June 25, 2007.<sup>3</sup>

18 **Q. Did Mr. Bouford defend his assertion that the base case he used is more accurate**  
19 **than PJM’s 2011 base case used in the RTEP?**

20 A. No, he did not, and I cannot confirm his assertions in this regard. However, there is a  
21 serious reason to question the applicability and relevance of the base case Mr. Bouford

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<sup>3</sup> See CPV Warren’s response to interrogatory #25 of Dominion Virginia Power’s First Set of Data Requests to CPV, a copy of which is attached to this rebuttal testimony as Rebuttal Attachment SG-3.

1 used. Simply put, the base case Mr. Bouford refers to as the 2011 case from the PJM  
2 2007 RTEP (Bouford at p. 10) that he used *was not updated* to reflect the most recent  
3 PJM 2007 load forecast. Updating the case to include the PJM 2007 load forecast would  
4 result in increased loadings on Mt. Storm-Doubs 500 kV in 2011 due to the increased  
5 load growth projections for Allegheny Power, Dominion Virginia Power and the Mid-  
6 Atlantic Region as compared to the PJM 2006 load forecast. In other words, while the  
7 base case Mr. Bouford used may have been updated to reflect changes in generation as  
8 compared with the 'baseline' case PJM used in the 2006 RTEP, it does *not* include  
9 updated load growth projections based on the PJM 2007 load forecast. This fact refutes  
10 Mr. Bouford's assertion, stated at page 11 of his testimony, that his base case correctly  
11 incorporates, among other things, "updated load projections."

12 **Q. Are there any other relevant concerns you have about the base case Mr. Bouford**  
13 **used?**

14 A. Another concern is apparent from the description of Mr. Bouford's case, meaning the  
15 nature of the load model incorporated into it. The case Mr. Bouford selected assumed a  
16 "50/50" load model, which means that the actual peak load that will occur in 2011 has a  
17 50% chance of being greater than the forecasted peak and a 50% chance of being less  
18 than the forecasted peak. By contrast, when PJM analyzes the system for the load  
19 deliverability test PJM uses a "90/10" load model which means that the actual peak load  
20 that will occur in 2011 has only a 10% chance of being greater than the forecasted peak.  
21 Consequently, Mr. Bouford's base case applies significantly less stress to the  
22 transmission system than did the load deliverability case PJM used.

23 **Q. In his testimony, did Mr. Bouford identify or control for differences in the type of**  
24 **load model used?**

1 A. No; to the contrary, his testimony states that the base case he used was, to quote his  
2 language, “from the PJM 2007 RTEP.” It is not surprising, then, that Mr. Bouford’s  
3 testimony does not attempt to identify or account for these differences.

4 **Q. What should the Commission take away from this discussion?**

5 A. The Commission should recognize that no matter what other assumptions Mr. Bouford  
6 incorporated into his analysis, the use of the base case Mr. Bouford selected tended to  
7 *minimize* the existence and extent of reliability violations as compared with the ‘baseline’  
8 cases PJM uses in the RTEP process. In this sense, Mr. Bouford’s approach has the same  
9 weakness inherent in his failure to apply the load deliverability and generation  
10 deliverability tests: all else equal, it applies less stress on the transmission system than  
11 does PJM in its analyses. However, the ramifications of Mr. Bouford’s selection of a  
12 base case are felt not only in the case of the NERC Category B violations shown in  
13 Attachment SG-1 for electrical occurrences #1 through #4 and #9 – they apply equally to  
14 Mr. Bouford’s opinions on all of the electrical occurrences identified in Attachment  
15 SG-1.

16 **3. Mr. Bouford Assumed the Certification and Construction of**  
17 **the Amos-Kempton Line in Several of His Analyses.**

18 **Q. What other assumptions has Mr. Bouford made that you think the Commission**  
19 **should understand?**

20 A. Another significant assumption in Mr. Bouford’s analysis is the inclusion in the 2012  
21 RTEP of the Amos-Kempton line. The Commission should consider whether, in the  
22 context of evaluating solutions to identified reliability violations occurring in *2011*, it is  
23 appropriate to consider solutions that, in the best of all worlds, will not be in service until  
24 *2012*. While I have not been involved in the preparation of PJM’s 2007 RTEP, Mr.

1 Herling's rebuttal testimony in this case makes it quite clear that both the 502 Junction-  
2 Loudoun Line and the Amos-Kempton line are included in the 2007 RTEP as being  
3 needed to solve reliability violations in 2012, and that neither project obviates the need  
4 for the other.

5 **4. Mr. Bouford Assumed that Both the CPV Warren Facility and**  
6 **the CPV St. Charles Facility Will Be In-Service by June 2011.**

7 **Q. What assumptions did Mr. Bouford make about the availability and in-service dates**  
8 **of the two proposed CPV Warren facilities?**

9 A. At various points in his analysis, Mr. Bouford assumed that or both of the proposed CPV  
10 Warren and the CPV St. Charles generation facilities will be in service by June 2011.  
11 While I am not in a position to evaluate the factual basis for these assumptions today, I do  
12 wish to comment on the value of these assumptions in the context of PJM's 2006 RTEP.

13 PJM's exclusion of each of these projects from the 2006 RTEP was entirely justified.

14 PJM's baseline models include all active generation projects that have proceeded beyond  
15 the System Impact Study. However, for purposes of resolving reliability problems, PJM  
16 only includes capacity resources with an executed ISA. As Mr. Herling explains in his  
17 rebuttal testimony, PJM's experience demonstrates that projects have a high probability  
18 of cancellation prior to execution of an ISA. Therefore, prior to the signing of an ISA,  
19 PJM does not include that generation in its analysis to determine the appropriate  
20 resolution of system reliability problems.

21 For these reasons, neither CPV project was included in the 2006 RTEP. Not only did  
22 neither project have an executed ISA as a PJM capacity resource at the time the 2006  
23 RTEP was prepared, the CPV St. Charles project did not enter the PJM interconnection

1 queue until October of 2006 (queue position R17), while the CPV Warren project entered  
2 the queue in January of 2007(queue position R77).

3 **C. Summary of Analysis of Mr. Bouford's Opinions**

4 **Q. Please summarize your response to Mr. Bouford's testimony.**

5 A. I strongly disagree with most of Mr. Bouford's contentions, and stand behind PJM's  
6 identification of transmission system reliability violations in the 2006 RTEP. Not only  
7 are his criticisms of that work unjustified, but his own conclusions about the ability of the  
8 proposed CPV facilities to address those problems are plagued with unrealistic  
9 assumptions and incomplete analyses which, taken together, inappropriately tend to  
10 minimize the reliability violations PJM identified in 2006 and, according to Mr. Herling,  
11 the 2007 RTEP continues to support.

12 In my view, the Commission should be very concerned about the identified reliability  
13 problems that directly affect major transmission lines serving northern Virginia and the  
14 mid-Atlantic region. As noted in the Bates White report on page 4 paragraph 10:

15 The results of the Bates White study indicate that without the proposed  
16 Loudoun Line, NERC and DVP reliability criteria cannot be met in  
17 either 2011 or 2016. In other words, there is a need to improve the  
18 existing power system to reliably serve the expected demand growth in  
19 both 2011 and 2016. The Applicants' proposed Loudoun Line would  
20 fully resolve the expected reliability violations in 2011."

21 PJM's 2006 RTEP showed an overload on the Mt. Storm-Doubs 500 kV circuit under  
22 *three* separate planning tests: PJM's load deliverability and generation deliverability  
23 tests and Dominion Virginia Power's planning criteria. Additionally, Mt. Storm-Doubs  
24 500 kV was identified as being overloaded for four different contingencies. These  
25 results overwhelmingly indicate a reliability problem in 2011 for a number of system

1 conditions and various contingencies. While all these results indicate a reliability  
2 problem, the test resulting in the most severe (highest % loading) on Mt. Storm-Doubs  
3 500 kV was the PJM load deliverability procedure for an outage of either Mt. Storm-  
4 Greenland Gap 500 kV (electrical occurrence #1) or Greenland Gap-Meadowbrook 500  
5 kV (electrical occurrence #2). In either contingency, the Mt. Storm-Doubs 500 kV line is  
6 loaded to **106%** of the emergency rating, or 156 MVA above the 2598 MVA conductor  
7 rating, a very significant violation. Even when Mr. Bouford's many unjustified  
8 assumptions are indulged, and when CPV Warren is assumed to be available by June  
9 2011, Mr. Bouford *still* projects (in Attachment C to his testimony) a reliability problem  
10 on the Mt. Storm-Doubs line unless further system improvements are made. (Bouford at  
11 p. 11-12.) Notwithstanding Mr. Bouford's testimony, it is my view that PJM, Dominion  
12 and TrAILCo have effectively demonstrated that serious reliability issues exist affecting  
13 major transmission lines, and the Commission should act affirmatively to address them.

14 **Q. Does this conclude your rebuttal testimony?**

15 **A. Yes, it does.**

**Standard TPL-002-0 — System Performance Following Loss of a Single BES Element**

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**A. Introduction**

1. **Title:** System Performance Following Loss of a Single Bulk Electric System Element (Category B)
2. **Number:** TPL-002-0
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
4. **Applicability:**
  - 4.1. Planning Authority
  - 4.2. Transmission Planner
5. **Effective Date:** April 1, 2005

**B. Requirements**

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:
  - R1.1. Be made annually.
  - R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
    - R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
    - R1.3.5. Have all projected firm transfers modeled.



**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

**Compliance Monitor:** Regional Reliability Organizations.  
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

**1.2. Compliance Monitoring Period and Reset Timeframe**

Annually.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

**E. Regional Differences**

1. None identified.

**Version History**

<b>Version</b>	<b>Date</b>	<b>Action</b>	<b>Change Tracking</b>
0	April 1, 2005	Effective Date	New

Standard TPL-002-0 — System Performance Following Loss of a Single BES Element

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup>	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
<b>A</b> No Contingencies	All Facilities in Service	Yes	No	No
<b>B</b> Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No <sup>b</sup> No <sup>b</sup> No <sup>b</sup> No <sup>b</sup>	No No No No
	Single Pole Block, Normal Clearing <sup>c</sup> : 4. Single Pole (dc) Line	Yes	No <sup>b</sup>	No
<b>C</b> Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing <sup>c</sup> : 1. Bus Section	Yes	Planned/ Controlled <sup>c</sup>	No
	2. Breaker (failure or internal Fault)	Yes	Planned/ Controlled <sup>c</sup>	No
	SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> : 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled <sup>c</sup>	No
	Bipolar Block, with Normal Clearing <sup>c</sup> : 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :	Yes	Planned/ Controlled <sup>c</sup>	No
	5. Any two circuits of a multiple circuit towerline <sup>c</sup>	Yes	Planned/ Controlled <sup>c</sup>	No
SLG Fault, with Delayed Clearing <sup>c</sup> (stuck breaker or protection system failure):	6. Generator	Yes	Planned/ Controlled <sup>c</sup>	No
	7. Transformer	Yes	Planned/ Controlled <sup>c</sup>	No
	8. Transmission Circuit	Yes	Planned/ Controlled <sup>c</sup>	No
	9. Bus Section	Yes	Planned/ Controlled <sup>c</sup>	No

## Standard TPL-002-0 System Performance Following Loss of a Single BES Element

<p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p>	<p>3Ø Fault, with Delayed Clearing<sup>c</sup> (stuck breaker or protection system failure):</p> <ol style="list-style-type: none"> <li>1. Generator</li> <li>2. Transmission Circuit</li> <li>3. Transformer</li> <li>4. Bus Section</li> </ol>	<p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul>
	<p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>5. Breaker (failure or internal Fault)</li> </ol>	
	<ol style="list-style-type: none"> <li>6. Loss of towerline with three or more circuits</li> <li>7. All transmission lines on a common right-of way</li> <li>8. Loss of a substation (one voltage level plus transformers)</li> <li>9. Loss of a switching station (one voltage level plus transformers)</li> <li>10. Loss of all generating units at a station</li> <li>11. Loss of a large Load or major Load center</li> <li>12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required</li> <li>13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate</li> <li>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</li> </ol>	

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.



**Interpretation of TPL-002-0 Requirements R1.3.2 and Requirement R1.3.12 and the identical requirements (Requirements R1.3.2 and Requirement R1.3.12) in TPL-003-0 for MISO**

**Request for Interpretation received from MISO on August 9:**

*MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.*

*MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.*

**R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.

**The following interpretation of TPL-002-0 and TPL-003-0 R1.3.2 was developed by the NERC Planning Committee on September 12, 2007:**

TPL-002 and TPL-003 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions. The selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority/Transmission Planner.

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 received from MISO on August 9:**

*MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed? If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?*

*The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?*

*If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by*

# NERC

NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

*NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard?*

**R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

**The interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on September 12, 2007**

TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed are within the discretion of the Planning Authority/Transmission Planner.

Virginia Electric and Power Company d/b/a Dominion Virginia Power  
Case No. PUE-2007-00031  
CPV Warren, LLC Responses to Virginia Electric and Power Company d/b/a Dominion  
Virginia Power's Interrogatories and Requests for Production of Documents (First Set)

Rebuttal  
Attachment SG-3

INTERROGATORY NO. 25

On page 11 of Mr. Bouford's testimony, he indicated in lines 5 -7 "I used the more current and accurate representation of the system provided by the PJM 2007 RTEP base case."

- (a) Is the case referenced, "PJM 2007 RTEP" a summer 2012 base case?
- (b) Is this case what Mr. Bouford used as the TRC Result Column on Attachment B?
- (c) If yes please provide a copy of this case in electronic format in PSSE Raw format listing version type.

RESPONSE TO INTERROGATORY NO. 25

- a. Yes. The case is identified as:

PJM - 2011-01-31-07  
Case Modified Date 6/25/07 3:24 PM  
RTEP2011s\_final\_nondiversified\_2wndg\_wfe1000\_122006.sav  
Case Title Block :  
RTEP 2011 BASECASE 2ND REV. ON 02/07/06  
2011 NON\_DIVERSIFIED 50/50 LOAD MODEL

- b. The case referenced in a. above was used to develop the results presented in the TRC Result Column in Attachment B.
- c. See "PJM-2011 Base Case: RTEP2011s\_final\_nondiversified\_2wndg\_wfe1000\_122006.raw" contained on disk labeled: "TRC: December 27, 2007, Virginia Electric & Power Interrogatories to CPV Warren (1st Set)." The disk has been marked as "Confidential Information" and will be provided pursuant to the Protective Agreement in this proceeding.

PREPARED BY: James D. Bouford  
TITLE: Manager of Power System Studies  
COMPANY: TRC Engineering

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