BEFORE THE

MISSOURI PUBLIC SERVICE COMMISSION

In the Matter of the Joint Application of Entergy Arkansas, Inc., Mid South TransCo LLC, Transmission Company Arkansas, LLC and ITC Midsouth LLC for Approval of Transfer of Assets and Certificate of Convenience and Necessity, and Merger and, in connection therewith, Certain Other Related Transactions	)))))))))))))))	**File No. EO-2013-0396**

DIRECT TESTIMONY AND EXHIBITS

OF

DOUGLAS C. COLLINS

ON BEHALF OF ITC MIDSOUTH LLC

APRIL 2013

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EXHIBIT LIST

Exhibit DCC-1: **ITC Midwest LLC - State of the System Report, December 7, 2008 ("*Report*")**

Exhibit DCC-2: **Storm and Restoration Pictures from July 2011 Straight-line Wind Storm**

Exhibit DCC-3: **Midwest ISO (2006-09) Eastern Iowa Transmission Reliability Study ("*Eastern Iowa Study*")**

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Douglas C. Collins. My business address is 6750 Chavenelle Road, Dubuque, Iowa 52002.

Q2. BY WHOM ARE YOU PRESENTLY EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by ITC Holdings Corp. ("*ITC*") as President of ITC Midwest LLC ("*ITCMW*"), a wholly-owned subsidiary of ITC. I also hold the position of Vice President with ITC. In this position, I report directly to Linda Blair, Executive Vice President and Chief Business Officer. As President of ITCMW, I am ultimately responsible for the success of ITCMW in meeting the expectations of our utility customers and regulators. As such, I spend a great deal of time interacting with ITCMW's customers, regulators, and (to some extent) large industrial customers that interconnect at a transmission voltage. I also spend much of my time in Cedar Rapids, Iowa at ITCMW's headquarters, interacting with the ITCMW project management, design, real estate, and legal staff. I also travel to Des Moines, Iowa and St. Paul, Minnesota quite often to meet with our regulators and other state government officials, as well as coordinate with our regulatory staff in these locations.

Q3. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I received a Bachelor of Science degree in Electrical Engineering from Iowa State University in 1983.

Q4. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. Prior to joining ITCMW, first as Executive Director and then as President, I was employed by Alliant Energy Corporate Services, Inc. ("***AECS***"), a service company subsidiary of Alliant Energy Corporation ("***Alliant Energy***"), as Director of System Planning. In that position, most of my time was spent working for Alliant Energy's wholly-owned utility subsidiaries, Interstate Power and Light Company ("***IPL***") and Wisconsin Power and Light Company. In my role as Director of System Planning at AECS, I represented Alliant Energy in connection with several regional industry groups, including the Minnesota/Wisconsin Power Supplier Group, the Mid-Continent Area Power Pool ("***MAPP***") Engineering Committee, the MAPP Transmission Studies Working Group, the MAPP Regional Transmission Committee, and the North American Electric Reliability Corporation ("***NERC***") Planning Reliability Model Task Force. I am also past Chairman of the MAPP Regional Transmission Committee. I have served as Chairman of the Midwest Independent Transmission System Operator, Inc. ("***MISO***") Transmission Owners Committee, Vice Chairman of the MISO Advisory Committee, and Vice Chairman of the Mid-America Incorporated Network, Inc. Planning Committee.

Q5. HAVE YOU TESTIFIED IN PRIOR PROCEEDINGS?

A. Yes. I have testified before the Iowa Utilities Board (*"IUB"*), the Public Service Commission of Wisconsin, the Minnesota Public Utilities Commission (*"MPUC"*), the Illinois Commerce Commission, and the Federal Energy Regulatory Commission (*"FERC"*) on issues relating to transmission planning (both on a regional and state basis), transmission reliability, transmission constraints, and federal policy regarding transmission development and divestiture.

Additionally, I am testifying in Texas, Louisiana, New Orleans, Arkansas, and Mississippi regarding the transaction that is the subject of this proceeding.

Q6. WERE YOU INVOLVED IN THE SALE OF IPL'S TRANSMISSION ASSETS TO ITC MIDWEST IN 2007 (*"IPL TRANSACTION"*) AS PART OF YOUR WORK AT IPL?

A. Yes. I was significantly involved with the IPL Transaction. I worked on the Asset Sale Agreement, the Distribution Transmission Interconnection Agreement, and the Large Generator Interconnection Agreement. I also served as a witness in state regulatory proceedings in Iowa, Minnesota, and Illinois. After all regulatory approvals were received and the IPL Transaction closed in December 2007, I began employment with ITC as Executive Director of ITCMW. In 2010, my title was changed to President of ITCMW. Having worked with transmission system planning on both sides of the IPL Transaction, I can speak to changes brought about by ITCMW's approach to maintaining, operating, and expanding the transmission system over the last four years and the benefit ITC's "best in class" practices have brought to customers served on the ITCMW system.

Q7. ARE YOU SPONSORING ANY EXHIBITS IN THE FILING?

A. Yes. I am sponsoring the following Exhibits:

Exhibit DCC-1: ITCMW State of the System Report, December 7, 2008 ("***Report***")

Exhibit DCC-2: Storm Damage and Restoration Pictures from July 2011 Straight-line Wind Storm

Exhibit DCC-3: Midwest ISO (2006-09) Eastern Iowa Transmission Reliability Study ("***Eastern Iowa Study***")

II. PURPOSE OF TESTIMONY

Q8. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. On December 4, 2011, Entergy Corporation and ITC entered into agreements under which Entergy will separate and then merge the electric transmission businesses of the Entergy Operating Companies[1] into ITC. I will generally refer to this separation and merger collectively as the "***ITC Transaction***" or "***Transaction***." My direct testimony supports the Joint Application by providing a real world example of what ITC, as an independent transmission company with available resources and a singular focus, can achieve in a relatively short period of time with regard to enhancing system performance and making needed investment. While the other ITC witnesses in this proceeding

[1] The Entergy Operating Companies are Entergy Arkansas ("EAI"), Inc., Entergy Louisiana, LLC ("ELL"), Entergy Gulf States Louisiana, L.L.C. ("EGSL"), Entergy Mississippi, Inc., Entergy New Orleans, Inc., and Entergy Texas, Inc..

describe how ITC operates and the benefits that will accrue if the ITC Transaction is approved, my testimony demonstrates how ITC's philosophy, resources, and singular focus on transmission have benefited ITCMW's customers since the company was formed and how ITCMW diligently works to meet the commitments made to the jurisdictions it serves. Specifically, my testimony describes the work that has been done to-date to improve, rebuild, and expand the IPL transmission system acquired by ITC in December 2007 and the benefits customers are beginning to see as a result of this work towards operational excellence. My testimony supports the public interest determination to be made in this proceeding by the Missouri Public Service Commission, because it demonstrates that ITC follows through on the commitments it makes to the jurisdictions it serves, is responsive to the transmission wants and policy objectives of its jurisdictions, and is successful in meeting those objectives, including improving system reliability and efficiency through proactive maintenance and investment focused on lowering energy costs through removal of transmission constraints.

III. SUMMARY OF TESTIMONY

Q9. PLEASE SUMMARIZE YOUR TESTIMONY.

A. For the last four years, ITC has worked to improve the former IPL transmission system through proactive maintenance and focused investment. ITC has been successful in improving the operations of the ITCMW system, as evidenced by decreasing sustained and momentary outages on the system. Although work remains to be done, the experience at ITCMW demonstrates that ITC has the skills, expertise, and capital to properly maintain and operate EAI's transmission facilities and to enhance them through cost-effective and focused investment for the benefit of customers. My testimony speaks to the many improvements ITC has made to the ITCMW transmission system in a very short period of time, and ITCMW's dedication to the capital investment commitments made to the jurisdictions during the hearings held on the IPL Transaction. Notably, since close of the IPL Transaction, ITCMW has:

1) reduced sustained outages from those experienced in 2008 (the last year IPL operated and maintained the system[2]) by 50% in 2009, 24% in 2010, and 58% in 2011;

2) implemented proactive maintenance and vegetation management programs which, over the last three years – 2009, 2010, and 2011 – corrected over 8,700 structural violations on its transmission system. In addition, ITCMW managed the vegetation (i.e., trimmed or removed trees and other vegetation that could potentially interfere with its transmission lines) on 37% of the system in 2009, 34% of the system in 2010, and 37% in 2011;

3) achieved top decile performance in 2011 for momentary outages on its 115 kV and 161 kV systems according to the SGS Statistical Services Transmission Reliability Benchmarking Study ("***SGS Study***");

4) experienced no momentary outages on its 345 kV facilities during 2011;

2 Under the Transition Services Agreement entered into between ITCMW and IPL at the time the Transaction closed, IPL agreed to continue to operate and maintain the system for one year following close, allowing ITCMW time to get crews in place.

5) achieved the second quartile for average circuit outage duration, achieving an average circuit outage duration of 116 minutes, compared to an average of 202 minutes for its peers;

6) invested approximately $891 million from December 2007 through March 2012, to improve the ITCMW transmission system by upgrading and improving existing lines and substations, constructing new lines to serve load growth, improve reliability, lower energy costs, and provide interconnection for new load and generation;

7) completed 32 major substation upgrades and expansions, rebuilt approximately 400 miles of existing lines (most at a higher capacity), and replaced three major transformers;

8) completed construction of 26 new substations, 26 miles of new line, and added four major transformers;

9) started construction on a 345 kV transmission line that is expected to reduce <u>annual</u> load and production costs by approximately $108 million at a <u>total</u> estimated cost for the line of $123 million; and

10) completed 16 new generator interconnects in four years, adding approximately 2,200 megawatts of renewable energy production capacity to the grid.

Q10. BASED ON YOUR EXPERIENCE WITH THE IPL TRANSACTION, DOES ITC HAVE THE TECHNICAL ABILITY, FINANCIAL STRENGTH, AND

SUFFICIENT RESOURCES TO OWN, OPERATE, AND RELIABLY MAINTAIN EAI'S TRANSMISSION SYSTEM?

A. Yes. I have observed ITCMW implement operations and maintenance practices that have improved reliability and enhanced storm restoration efforts. ITCMW has also carried through with its commitments to invest capital to improve reliability and reduce congestion on the transmission system formerly owned by IPL. I believe that significant benefits will accrue to the customers of the current EAI region if the Transaction is approved. These benefits are detailed in the testimonies of ITC witnesses Messrs. Joseph Welch, Jon Jipping, Cameron Bready, and Thomas Vitez.

IV. OVERVIEW OF IPL TRANSACTION AND SYSTEM

Q11. PLEASE PROVIDE A GENERAL OVERVIEW OF THE IPL TRANSACTION.

A. On January 18, 2007, IPL entered into an Asset Sale Agreement with ITCMW, a newly formed subsidiary of ITC, for the sale of IPL's transmission assets in Iowa, Minnesota, Illinois, and Missouri. The IPL Transaction included all transmission assets on the IPL system that were 34.5 kV and above. Regulatory approvals for the IPL Transaction were obtained from the state regulatory commissions in Iowa, Minnesota, Illinois, and Missouri, as well as FERC and the Department of Justice.

Q12. PLEASE DESCRIBE THE ITCMW SYSTEM.

A. The ITCMW transmission system is located in parts of Iowa, Minnesota, Illinois, and Missouri and covers approximately 53,400 square miles of service territory. As of year-end 2011, the ITCMW transmission system consisted of approximately 6,600 miles of transmission lines including approximately:

- 376 miles of 345 kV lines;
- 1,540 miles of 161 kV lines;
- 323 miles of 115 kV lines;
- 2,695 miles of 69 kV lines; and
- 1,670 miles of 34.5 kV lines.

In addition to its line miles of transmission, ITCMW also owns 261 substations.

Q13. WHAT WAS THE CONDITION OF THE IPL TRANSMISSION SYSTEM AT THE TIME OF THE IPL TRANSACTION?

A. The IPL transmission system at the time of the IPL Transaction was in significant need of additional maintenance and investment. The poor condition of the IPL transmission system at the time of the IPL Transaction is evidenced by the State of the System Report included as **Exhibit DCC-1**. This report was completed by ITC within the first year of close of the IPL Transaction.

Q14. WHAT ARE THE HIGHLIGHTS OF THE REPORT?

A. The following summarizes the Report's findings and conclusions made in the course of auditing and investigating the IPL transmission system shortly after the IPL Transaction closed:

- Aging Infrastructure: The Report found that the IPL transmission system was an aged system that was in need of immediate, thorough, and proper maintenance in order to fulfill ITCMW's commitment to improve reliability. The system required infrastructure replacements due to assets being at, or near, the end of their useful life.
- Renewable Energy: The Report found that the IPL transmission system was not adequate to integrate proposed new renewable generation.
- Congestion: The Report found that portions of the transmission system required upgrade and that new lines needed to be built to reduce the present constraints.
- Outages: The Report concluded that, since acquiring the system and tracking its performance, ITCMW had experienced a high number of transmission outages on the system, which impacted customers and must be addressed.
- Targeted Remedial Measures: The Report also concluded that maintenance practices applied to the transmission system needed to be fully executed, enhanced, and accelerated in certain areas. Further, the Report found that ITCMW would need to address particular problem areas in the previous stewardship of the transmission system including:

  1) backlogs in corrective maintenance;
  2) backlogs in implementing appropriate vegetation management;
  3) environmental management deficiencies;
  4) implementation of an asset security and cyber security program that complies with best practices; and

5) deficiencies in the 34.5 kV network, which were recognized as being in need of rebuilding (including new poles and wires) for improved reliability and overall enhanced system capability.

ITCMW also found that, although maintenance was planned by IPL, it was often not fully implemented and executed.

Q15. AT THE TIME OF THE TRANSACTION, DID IPL BELONG TO MISO?

A. Yes. As a fully integrated utility, IPL has belonged to MISO since MISO's inception and continues to belong to MISO in its changed structure as a generation and distribution company.

Q16. DID THE IPL TRANSACTION PROVIDE ADDITIONAL BENEFITS TO THE SYSTEM BEYOND THOSE REALIZED THROUGH MISO MEMBERSHIP?

A. Yes, as my testimony demonstrates, ITCMW's proactive and preventive maintenance practices, outage cause analysis (which focuses on maintenance and replacement of aging infrastructure on problem circuits), and investment in additional transmission capacity, have improved the reliability performance of the acquired system. As evidenced by the condition of the IPL transmission system at the time of IPL Transaction (see **Exhibit DCC-1**), IPL's membership in MISO did little to ensure that IPL's transmission system was adequately maintained and that needed investment was being made.[3] By focusing solely on transmission and engaging in best practices, ITCMW is working towards the same performance excellence currently enjoyed by ITC's world-class transmission operating subsidiaries in Michigan, namely International Transmission Company ("*ITCT*") and Michigan Electric Transmission Company LLC ("*METC*"). Please refer to the direct testimonies of ITC witnesses Messrs. Joseph Welch and Jon Jipping for more information regarding ITCT and METC.

V. WORKING TOWARDS OPERATIONAL EXCELLENCE

Q17. HAS ITCMW BEEN WORKING TOWARDS OPERATIONAL EXCELLENCE?

A. Yes. ITCMW has implemented proactive maintenance and vegetation management programs which identify and correct problems on the system before they result in a sustained outage. For example, over the last three years – 2009, 2010, and 2011 – ITCMW corrected over 8,700 probable violations on its transmission system as defined in the Iowa Electric Safety Code (Iowa Administrative Code 199 – Chapter 25). In addition, ITCMW, based upon its three year vegetation management cycle, managed the vegetation on 37% of the system in 2009, 34% of the system in 2010, and 37% in 2011. Further, ITCMW has aggressively labored to complete the work detailed in its annual Operations and Maintenance Plan filed with the IUB each December preceding the year

3 MISO has no ability or charge to invest in transmission facilities or ensure existing facilities are adequately maintained.

the plan is in effect. Although completion of the plan is not an IUB requirement, ITCMW has (on average) been successful in completing 98% of the planned inspection and maintenance work envisioned by its plans filed with the IUB for the years 2009, 2010, and 2011. The inspection and maintenance plans filed with the IUB are distinct from the maintenance plans described by ITC witness Mr. Jon Jipping in that the plans filed by ITCMW include the goal of correcting any probable violations within 90 days of detection. As stated previously, 98% of the time ITCMW has achieved this self-imposed deadline. This is the case regardless of the number of damaging storms experienced and restoration costs incurred by ITCMW in a particular year. In contrast, IPL consistently completed only 30% of the planned maintenance and repair work envisioned by its filed plans when it owned the transmission system. Due to ITCMW's singular focus on transmission, it has the resources available to insure the proper maintenance and inspection of its transmission facilities even during years with significant storm activity.

Q18. HAVE OUTAGE RATES IMPROVED SINCE ITCMW ACQUIRED THE SYSTEM?

A. Yes, through ITCMW's proactive maintenance approach, as described in the direct testimony of ITC witness Mr. Jon Jipping, ITCMW has reduced sustained outages from 2008 levels (the last year IPL operated and maintained the system under the Transition Services Agreement with ITCMW) by 53% in 2009, 24% in 2010, and 58% in 2011. Sustained outages increased in 2010 over 2009 levels due to severe weather in 2010 including:

1) the highest number of thunderstorms observed since 1993;
2) a major ice storm in January resulting in seven sustained outages;
3) six tornadoes on June 22 contributing to 30 outages for the month; and
4) six tornadoes on July 25 contributing to 22 outages for the month.

Q19. WHAT OTHER ITC PRACTICES HAVE LED TO IMPROVED OUTAGE PERFORMANCE ON THE ITCMW SYSTEM?

A. As described in the testimony of ITC witness Mr. Jon Jipping, ITC focuses its work plan on the worst performing circuits and directs its resources to either maintaining or rebuilding these circuits depending on the need. ITC tracks outages by circuit and performs a monthly outage cause analysis of each sustained and momentary outage on the system to prioritize rebuilds and identify problem circuits for inspection and possible maintenance. These monthly outage cause analyses have been instrumental in identifying the poorest performing circuits on the ITCMW system such that they can be more thoroughly maintained or replaced, as needed.

Q20. HOW DOES ITCMW COMPARE TO ITCT AND METC IN OUTAGE PERFORMANCE?

A. As discussed by ITC witness Mr. Jon Jipping, ITCMW is in the third quartile of outage performance, compared to ITCT and METC, which have achieved the first quartile outage performance in the SGS Study. The SGS Study defines outage performance as the frequency of sustained outages per circuit in voltage classes 69 kV and above. For higher voltage facilities, ITCMW's outage performance compares favorably with ITCT, METC, and its peers. ITCMW's 115 kV and 161 kV systems achieved top decile performance in 2011 for momentary outages (moving up from top quartile in 2010). Further, ITCMW is within the second quartile for average circuit outage duration, achieving an average circuit outage duration of 116 minutes compared to an average of 202 minutes for its peers. Finally, ITCMW's 345 kV facilities had no momentary outages during 2011 according to internal data collected. While there is room for further improvement of the system's reliability, ITCMW's outage performance improved in 2011 and is on track for further improvement in 2012 with only 16 sustained outages occurring in the first four months of the year. I am confident as we continue to implement our proactive maintenance plan, focus on vegetation management and rebuild the parts of our system that are at end of life, outages will continue to decline as they have in systems owned and operated by ITC for longer periods of time.

Q21. HAS ITCMW HAD MAJOR STORMS SINCE ACQUIRING THE SYSTEM?

A. Yes, several major storms have occurred since ITCMW acquired the system, beginning with the storms that resulted in the summer flood of 2008 in Cedar Rapids and Iowa City and continuing with ITCMW's most recent significant storm, the straight-line wind storm occurring during the summer of 2011. **Exhibit DCC-2** provides pictures of the damage caused by that wind storm in the summer of 2011, three days before ITCMW experienced a historic peak on its system.

Q22. WHAT IS A STRAIGHT-LINE WIND STORM, AND WHAT DAMAGE DID THE 2011 STORM CAUSE?

A. A straight-line wind storm is similar to a tornado except that it pushes debris in the same direction the wind is blowing. In contrast, tornado damage will scatter the debris in a variety of different directions because the winds of a tornado are rotating violently. In July of 2011, ITCMW's system in east-central Iowa experienced damage from winds reported to be up to 130 miles per hour. According to the National Oceanic and Atmospheric Association, this storm was the most widespread and damaging in east-central Iowa since 1998. On ITCMW's transmission system, the storm damaged or destroyed over 300 structures on nine 161 kV lines, two 69 kV lines, and twenty 34.5 kV lines.

Q23. WHEN WAS SERVICE RESTORED TO ITCMW'S CUSTOMERS?

A. By redirecting approximately 200 contractors from maintenance and new construction work in Iowa, ITCMW restored service within 72 hours to all transmission customers able to take power. ITCMW focused on transmission restoration, while IPL and the rural electric cooperatives ("***RECs***") in the area focused on distribution and end-use customer issues. IPL, the RECs, and ITCMW collaborated on field operations, supply chain and management support to return customers to service as quickly as possible.

Q24. WILL THIS PRACTICE OF COLLABORATION BE MODELED IF THE TRANSACTION IS APPROVED?

A. Yes. ITCMW's collaboration with IPL and its REC and municipal utility customers during storm response and restoration illustrates ITC's commitment to work with its customers to ensure that service is restored safely and in a timely manner. For the ITC Transaction, it is my understanding that certain Entergy Transmission Business[4] employees, facilities, and world-class practices in storm response will be transferred to ITC. ITC's successful practice of customer collaboration, along with the transfer and adoption of the Entergy Operating Companies' best in class restoration practices performed by the same expert employees familiar with the facilities, will ensure that the highest standards of storm response excellence are maintained.

Q25. IS ITCMW EFFECTIVE IN RESTORING THE SYSTEM AFTER A DAMAGING STORM, AND WHAT FACTORS ACCOUNT FOR THIS EFFECTIVENESS?

A. Yes, ITCMW is very effective in restoring the system after damaging storms. Consistent with ITC's overarching philosophy on storm restoration as discussed in the testimony of ITC witness Mr. Jon Jipping, ITCMW's number one priority is getting customers back on line safely after a damaging storm. ITC's supply chain is critical to ensuring all materials, including steel structures and conductors, are on site whenever a storm results in the need to restore the system. Several warehouses and pull-out sites across ITCMW's footprint provide replacement conductors and structures closer to the outage. ITCMW also has specially designed, temporary emergency structures available, as well as the valuable assistance of our alliance suppliers.

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[4] The total transmission business of the Entergy Operating Companies including their transmission assets, business practices, and employees that will become part of ITC.

Q26. WHAT COMPANIES SERVE AS ALLIANCE SUPPLIERS TO ITCMW?

A. Alliance suppliers include Hydaker-Wheatlake Powerline Supply (*"**Hydaker**"*), MJ Electric and MYR Group. Use of alliance suppliers allows ITCMW to respond efficiently to a storm event, lessening downtime. The alliance suppliers are able to quickly participate in recovery efforts because they are familiar with ITCMW's safety practices, operating requirements and procedures. For example, Hydaker manages a pole yard serving the ITCMW system which has the ability to deliver poles to 90% of the ITCMW region within four hours or less. ITC's alliances effectively expand ITCMW's available capital and equipment pool by reducing inventory needed to address major storm events and thus mitigating storage costs. For more information on alliance partnerships, please refer to the direct testimony of ITC witness Mr. Jon Jipping.

VI. COMMITMENT TO INVEST TO IMPROVE RELIABILITY AND REMOVE TRANSMISSION CONGESTION

Q27. WAS ADDITIONAL TRANSMISSION INVESTMENT NECESSARY ON THE ITCMW SYSTEM AT THE TIME OF THE IPL TRANSACTION?

A. Yes, it was, because no significant investment had been made in the IPL transmission system for many years. While IPL had been able to maintain a minimally acceptable level of reliability in the provision of its transmission service, its focus was not on its transmission system. In fact, one of the primary benefits cited for the sale of the system to ITCMW was ITCMW's singular focus and commitment to the transmission system. The Order in the IUB Docket approving the IPL Transaction states as follows:

> One of the main driving forces in this docket is the need to build and upgrade transmission in IPL's service territory. No party to the proceeding disputes the need for at least some additional transmission, and IPL indicated it will only build for reliability reasons, not to relieve constraints that are not related to reliably serving IPL's customers. (Order in IUB Docket No. SPU-07-11, September 20, 2007, p. 38, "Order Terminating Docket and Recommending Delineation of Transmission and Local Distribution Facilities" ("***IUB Order***")).

Q28. HOW MUCH CAPITAL HAS ITC INVESTED IN ITS ITCMW TRANSMISSION SYSTEM SINCE THE SYSTEM WAS ACQUIRED FROM IPL?

A. From December 2007 through March of 2012, ITC has invested approximately $891 million to improve the ITCMW transmission system. This investment has primarily been needed to upgrade and improve existing lines and substations, construct new lines to serve load growth and improve reliability, and provide interconnection for new load and generation.

Q29. PLEASE DESCRIBE SOME OF THE WORK COMPLETED ON THE ITCMW SYSTEM SINCE THE CLOSE OF THE IPL TRANSACTION?

A. In its first four years of operation, ITCMW focused its work on rebuilding and increasing the capacity on its transmission system to improve reliability, remove transmission constraints, and facilitate access for new generation. To this end, ITCMW completed 32 major substation upgrades and expansions, rebuilt approximately 400 miles of existing lines (most at a higher capacity), and replaced three major transformers. With regards to new transmission facilities, ITCMW completed construction of 26 new substations, 26 miles of new line, and added four major transformers.

Q30. WHAT INVESTMENTS ARE CURRENTLY BEING MADE BY ITCMW TO IMPROVE RELIABILITY AND REMOVE TRANSMISSION CONSTRAINTS?

A. Major projects under construction in the ITCMW territory include:

1) upgrading 80 miles of 115 kV line to 161 kV from Cedar Rapids, Iowa to Boone, Iowa due to age and condition of the line and to satisfy the need for new transmission capacity in the area (expected completion by year-end 2012);
2) constructing a new 11 mile 161 kV line loop in the core of Cedar Rapids, Iowa to improve system reliability (expected completion by year-end 2012);
3) building 10 miles of new 161 kV transmission line north of Cedar Rapids, Iowa, to support new load in the area (expected completion in 2013);
4) constructing a new 80 mile 345 kV line from Salem Substation to Hazleton Substation to improve reliability in eastern Iowa and improve market efficiency by reducing transmission constraints (expected completion in mid-year 2013);
5) rebuilding 28 miles of 161 kV line in Minnesota (at the same voltage) due to age and condition of the existing line (expected completion by year-end 2012); and
6) rebuilding 50 miles of 115 kV line to 161 kV from Marshalltown, Iowa to Iowa Falls, Iowa due to age and condition of the line and to provide needed capacity for new generation in the area (expected completion by year-end 2012).

Q31. WHAT SPECIFIC INVESTMENT COMMITMENTS DID ITCMW MAKE TO ITS MINNESOTA REGULATORS AS PART OF THE IPL TRANSACTION?

A. As part of a Minnesota-jurisdictional Settlement approved by the MPUC in Docket No. E001-PA-07-540, ITCMW committed to construct specific projects intended to improve the reliability and efficiency of the transmission system, relieve transmission constraints, and lower the overall cost of delivered energy for end-use consumers. The first of these projects was the rebuild of the Arnold-Vinton-Dysart-Washburn 161 kV line ("***Arnold-Vinton Rebuild***"). ITCMW committed to re-conductor and rebuild this 47-mile line within two years of closing the IPL Transaction (approximately December 31, 2009).

Q32. DID ITCMW MEET THIS COMMITMENT?

A. Yes. The Arnold-Vinton Rebuild was completed prior to the end of December 2009 and is currently in service.

Q33. WHAT OTHER SPECIFIC INVESTMENT COMMITMENTS WERE MADE AS PART OF THE SETTLEMENT?

A. ITCMW committed to use all commercially reasonable best efforts to construct the Salem-Lore-Hazleton 345 kV line (***"S-H" Line"***) by the later of December 31, 2011, or three years following the approval of the MISO Board of Directors, which occurred in December 2008.

Q34. DID ITCMW MEET THIS COMMITMENT?

A. Yes, ITCMW used all commercially reasonable best efforts to complete the S-H Line, which is currently under construction and anticipated to be in service by mid-2013. The project completion has changed from the original schedule due to delays in receiving required siting approvals from the state jurisdiction and court challenges related to condemnation of a few select land parcels to acquire needed easement rights.

Q35. WHY IS THE COMMITMENT TO BUILD THE S-H LINE RELEVANT TO THIS PROCEEDING?

A. The commitment to proceed with the construction of the S-H Line is significant, because it demonstrates ITC's willingness to invest the capital to build projects that have an economic benefit for customers and to improve the reliability of the transmission systems it owns.

Q36. PLEASE DESCRIBE THE S-H LINE.

A. The proposed S-H Line is an approximately 80 mile 345 kV electric transmission line designed to upgrade ITCMW's transmission system in eastern Iowa. When completed, the S-H Line will connect ITCMW's Hazleton Transmission Substation in Buchanan County, Iowa to ITCMW's Salem Transmission Substation in Dubuque County, Iowa. The S-H Line was modeled in 2006 as a solution to transmission constraints in eastern

Iowa in MISO's Eastern Iowa Study, included as **Exhibit DCC-3**. As explained in **Exhibit DCC-3**, the need for the line was recognized for several years prior to 2006.

Q37. WHAT CAUSED THE CONSTRAINTS ON THE EASTERN IOWA SYSTEM AND HOW DO THESE CONSTRAINTS AFFECT CUSTOMERS?

A. Signs of congestion on IPL's eastern Iowa transmission system (now owned by ITCMW) began around the year 2000 as more and more regional power sales became common across the Midwest. The power flows associated with these sales often resulted in congestion on IPL's transmission lines. Prior to the start of the MISO market, this congestion was addressed through NERC Transmission Loading Relief ("***TLR***") procedures. These procedures curtailed transmission service for both power sales and networked native load. From 2001 through the end of 2004, facilities within the IPL control area experienced NERC TLR non-firm curtailments for over 5,000 combined hours. Also, throughout this same period, firm curtailments occurred for over 200 hours. The result of these curtailments was higher cost generation being dispatched to serve load, ultimately resulting in higher costs to customers. Since the inception of the MISO market, the TLR procedures (within the market) have largely been replaced with classifying congested facilities as "binding." Binding constraints result in MISO uneconomically re-dispatching generation to avoid the constraint, ultimately resulting in higher costs to customers. As further evidence of the constraints on the eastern Iowa transmission system, MISO's Independent Market Monitor designated the area the S-H

Line is designed to serve as a Narrowly Constrained Area ("*NCA*") and FERC confirmed this designation in 2007.

Q38. WHAT REDUCTIONS IN ANNUAL LOAD AND PRODUCTION COSTS WERE MODELED FOR THE S-H LINE AS PART OF THE EASTERN IOWA STUDY?

A. The Eastern Iowa Study found that the construction of the S-H Line would reduce <u>annual</u> load and production costs by approximately $108 million (See page 59 of the Eastern Iowa Study, **<u>Exhibit DCC-3</u>**). This annual cost reduction compares to a <u>total</u> estimated cost of the line of $123 million. In addition, the construction of the S-H Line, plus adding a second Salem 345/161 kV 448 transformer, addresses nearly all of the constraints causing the NCA designation.

Q39. WAS THE S-H LINE ALSO APPROVED FOR CONSTRUCTION THROUGH MISO'S MIDWEST TRANSMISSION EXPANSION PLAN ("*MTEP*") PROCESS AS DESCRIBED IN THE DIRECT TESTIMONY OF ITC WITNESS MR. THOMAS VITEZ?

A. Yes. The S-H Line was included in Appendix A of the MTEP08 Report which, by definition, means that MISO has studied the project, evaluated alternatives to the project, recommended the project to the MISO Board of Directors, and the project was approved by the MISO Board of Directors for construction.

Q40. GIVEN THE SIGNIFICANT ECONOMIC BENEFITS PROJECTED FROM CONSTRUCTION OF THE S-H LINE AND THE RECOGNIZED RELIABILITY NEED FOR THE LINE, WHY DID IPL NOT CONSTRUCT THE LINE?

A. Internal competition for investment capital within IPL prevented IPL from making the significant investment needed to support the demands being placed on the transmission system by market transactions, including the need for the S-H Line. IPL's focus was to build transmission facilities to reliably serve its firm load and to meet applicable planning standards, not to relieve constraints on the transmission system to lower energy costs through more economic dispatch. That being said, I believe IPL would have ultimately initiated the significant efforts needed to get the land use rights and siting approvals to build the S-H Line, given the need and projected customer benefits resulting from its construction.

Q41. WHAT INVESTMENT COMMITMENTS DID ITCMW MAKE TO THE IUB AS PART OF THE IPL TRANSACTION?

A. ITCMW committed to the IUB, as part of the IPL Transaction, that it would rebuild IPL's 34.5 kV system to 69 kV standards within five to seven years from close, in comparison to the sixty years projected under IPL's investment plan. After discussions with ITCMW's transmission service customers (comprised of municipal utilities, RECs, and IPL), ITCMW proposed extending the rebuild schedule to 12 years to moderate the cost impacts on those customers. This change was communicated to the IUB, which agreed the delay was in ITCMW's customers' best interest due to the significant investment

ITCMW's customers must also make to upgrade their distribution substations to interconnect to a 69 kV system and replace their distribution under-build, which resides on many of ITCMW's 34.5 kV facilities.

Q42. WHY IS THE TIMELY REBUILD OF THE 34.5 KV SYSTEM IN IOWA DEEMED NECESSARY BY THE IUB?

A. At the time the IPL Transaction closed, the 34.5 kV system in Iowa was in poor shape, outdated and subject to frequent outages. Outages on the 34.5 kV system often lead to end-use customer outages due to the radial nature of the facilities.[5] In addition, lack of compatible equipment makes 34.5 kV facilities, including conductors and transformers, difficult to maintain. Further, most of the 34.5 kV facilities in Iowa do not have a static wire, making them vulnerable to lightning strikes.

Q43. WHAT BENEFITS RESULT FROM CONVERTING A 34.5 KV TRANSMISSION SYSTEM TO A 69 KV TRANSMISSION SYSTEM?

A. A 69 kV operated system can be designed and operated as a networked system limiting customer outages and providing timely backup service to communities during planned and unplanned outages. Further, an upgraded 69 kV line includes a static wire providing protection against lightning-related outages. In addition, a 69 kV system promotes

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[5] A radial line is one that is capable of carrying power in only one direction, similar to a one-way street.

Iowa's alternative fuels industry by enabling the interconnection of significant energy users (such as ethanol and biodiesel plants) which often over-burden the existing 34.5 kV system. From a public policy perspective, the 34.5 kV system serves rural areas that are economically disadvantaged and slow to recover from economic downturns. As such, the upgrade of the system has been deemed an economic development tool for rural Iowa.

Q44. HOW DID ITCMW'S CUSTOMERS BENEFIT FROM EXTENDING THE REBUILD SCHEDULE TO TWELVE YEARS?

A. ITCMW was ready, willing, and able to meet a five to seven-year rebuild schedule as committed to the IUB. Subsequent to the closing of the IPL Transaction, however, ITCMW discovered, through various planning studies and customer coordination, that an extension in the schedule would give customers an opportunity to budget for and convert their substations to accommodate a 69 kV system as the system was being rebuilt. Rebuilding with voltage conversions enables the 34.5 kV system in Iowa to be redesigned allowing the retirement of more 34.5 kV lines than is possible under the in-place upgrade envisioned during the IPL Transaction, ultimately saving customers an estimated $93 million (in 2007 dollars) for capital investment that would have otherwise been included in ITCMW's rate base. The IUB agreed that the cost advantage of a twelve year upgrade schedule outweighed the benefits of the earlier committed schedule of five to seven years.

Q45. WHAT PROGRESS HAS ITCMW MADE IN MEETING THIS COMMITMENT?

A. ITCMW is on course with its customers to get the system rebuilt in 12 years from the time the IPL Transaction closed in December 2007.

VII. SUCCESS IN INTERCONNECTING NEW GENERATION

Q46. ITC WITNESS MR. THOMAS VITEZ'S TESTIMONY SPEAKS TO ITC'S PLANNING APPROACH TO INTERCONNECTING NEW GENERATION. HAS ITCMW BEEN SUCCESSFUL IN INTERCONNECTING NEW GENERATION TO THE TRANSMISSION GRID?

A. Yes. In its first four years of operation, ITCMW completed 16 new generator interconnects, adding approximately 2,200 MW of renewable energy production capacity to the grid. This additional capacity is more than the total installed renewable capacity existing in Iowa in 2007 prior to closing the IPL Transaction.

Q47. IS RENEWABLE ENERGY IMPORTANT TO THE JURISDICTIONS WHICH ITCMW SERVES?

A. Yes. Renewable energy is important to economic development in the jurisdictions in the ITCMW territory. Transmission capacity is the most significant limiting factor in providing an outlet for additional renewable generation in Iowa and Minnesota. According to the Iowa Wind Energy Association, the wind industry in Iowa currently employs at least 3,000 full-time workers in the manufacture, operation and maintenance of wind turbines, with an estimated annual payroll of $70 million. Because transmission plays a critical role in the advancement of renewable energy, ITCMW has been responsive to the policies of its jurisdictions by entering into several interconnection agreements with wind developers, most of which have resulted in ITCMW constructing needed upgrades to the transmission system.

Q48. DOES ITC FAVOR RENEWABLE ENERGY OVER OTHER FORMS OF ELECTRICITY GENERATION?

A. No. ITC is neutral towards electricity generation sources and will work diligently to satisfy any interconnection requests. To date, only renewable generators have requested interconnection on ITCMW's system. However, the policies of the jurisdictions in the ITCMW footprint are very focused on advancing renewable energy for economic development purposes.

VIII. INTERACTING WITH CUSTOMERS AND COMMUNITIES

Q49. ITC WITNESSES MESSRS. JOSEPH WELCH, JON JIPPING, AND THOMAS VITEZ SPEAK TO ITC'S COMMITMENT TO TRANSPARENCY AND WORKING WITH CUSTOMERS TO ENSURE THE BEST TRANSMISSION PROJECTS ARE PLANNED, DESIGNED, AND CONSTRUCTED. HAS THIS COMMITMENT BEEN REALIZED AT ITCMW?

A. Yes. ITCMW personnel have long-standing, close working relationships with the REC and municipal utility customers we serve, in addition to IPL. A dedicated "Stakeholder Relations" group serves as a single point of contact for RECs, municipal utilities, and IPL. This group performs a number of functions including:

1) providing timely communications for planned outages such that coordinated maintenance can be accomplished;
2) providing ongoing and proactive communications on unplanned outages;
3) arranging for conference calls and meetings to address service issues or other concerns that may arise;
4) tracking and bringing to resolution service issues or other concerns;
5) holding semi-annual "Partners in Business" (*"PIB"*) meetings to provide updates on capital and maintenance plans, energy policy, rates, preparedness, capital investment plans, and legislative and regulatory updates. At the autumn PIB meetings, regulatory and accounting staff provides detail on the projected rate for the following year including projected elements of rate base, O&M and A&G expenses, taxes, load, and revenue credits. Please see the testimony of ITC witness Mr. Thomas Wrenbeck for more information on how ITC projects revenue requirements and sets rates on a forward-looking basis.

In addition, ITCMW's Planning and Operations Departments hold frequent meetings with the corresponding departments of their REC and investor-owned utility customers to ensure strong communications and coordination in these areas. ITCMW personnel, including myself, also meet on a quarterly basis with personnel at the Duane Arnold Nuclear Center which is the only nuclear power plant connected to ITCMW's transmission facilities.

Q50. DO YOU PERSONALLY HAVE INVOLVEMENT WITH ITCMW'S STAKEHOLDERS?

A. Yes. ITC's Chief Operating Officer Jon Jipping, ITC's Vice President of Operations Beth Howell and I all meet quarterly with the Vice President of Operations for IPL. I also meet more frequently with the IPL liaison to ITCMW, and have continual involvement with Central Iowa Power Cooperative, for which ITCMW provides maintenance and operational services. I personally attend the PIB meetings to talk to other ITCMW stakeholders, and also speak to IPL's largest industrial customers at IPL's biannual transmission stakeholder meetings. Additionally, I make myself available for meetings with representatives of all the RECs and municipal customers we serve. These same customers are always invited to participate in our biannual PIB meetings and often take advantage of this opportunity.

Q51. WHAT ONGOING INTERACTION DOES ITCMW HAVE WITH STATE REGULATORS?

A. While ITCMW is rate regulated by FERC, we maintain close working relationships with the regulators in the states that we serve. ITCMW has dedicated regulatory personnel in each jurisdiction responsible for ensuring:

1) ongoing communications on ITCMW activities and projects;
2) ongoing and proactive communications on industry issues;
3) an open communications path to address issues and concerns that may arise; and

4) 100 percent compliance with the requirements of the jurisdictions, including timely and accurate filings as required or requested.

Q52. DOES ITCMW SEEK TO ENHANCE THE ECONOMIC CONDITIONS IN THE STATES AND COMMUNITIES IT SERVES?

A. Yes. ITCMW, like ITC's other operating subsidiaries, works to promote the economy of the states and communities in which it operates by recruiting qualified employees within the state, contracting with local vendors when competitive, and actively participating in community activities (both through employee time and donations). Key highlights of ITCMW's economic impact and community involvement follow.

1) ITCMW currently employs more than 80 people in the ITCMW service area in good paying jobs such as engineering. ITCMW's primary field operations and maintenance contractor employs approximately 180 field personnel across the region.

2) ITCMW paid $6.8 million in property taxes in Iowa and Minnesota in 2011, and is projected to pay approximately $7.4 million in 2012.

3) Due to its construction and maintenance programs, ITCMW purchases more than $30 million in supplies and materials annually from more than 100 vendors in Iowa and Minnesota. To date, eight vendors have set up operations in the ITCMW service area – employing 258 people to serve ITCMW.

4) ITCMW actively participates in community activities and has donated more than $1 million to community organizations, contributing to the quality of life in those communities.

5) ITCMW works with state regulatory, administrative and legislative leaders to help implement regulatory outcomes and legislation that promote improved energy reliability and efficiency.

6) ITCMW works with its utility-customers to build positive relationships with large industrial customers interconnected to the transmission system through its stakeholder relations group.

7) ITCMW works closely with state and local police, municipal officials, fire and emergency preparedness personnel to establish training and communications in the event of emergencies.

Q53. WITH REGARD TO THE PROPOSED ITC TRANSACTION, WHAT DOES YOUR EXPERIENCE WITH ITCMW INDICATE TO YOU?

A. Based on my experience, upon completion of the Transaction, ITC's Arkansas operating company will adopt the same type of proactive, robust maintenance and investment philosophy in the EAI footprint as was done with ITCMW to enhance reliability and improve the economics of energy supply.

Q54. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes it does.

STATE OF Iowa)
) SS.
COUNTY OF Linn)

BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION

In the Matter of the Joint Application of Entergy Arkansas, Inc., Mid South TransCo LLC, Transmission Company Arkansas, LLC and ITC Midsouth LLC for Approval of Transfer of Assets and Certificate of Convenience and Necessity, and Merger and, in connection therewith, Certain Other Related Transactions	)	File No. EO-2013-0396

AFFIDAVIT OF DOUGLAS C. COLLINS

COMES NOW Douglas C. Collins, of lawful age, sound of mind and being first duly sworn, deposes and states:

1. My name is Douglas C. Collins; I am President of ITC Midwest, LLC ("ITCMW"), a wholly-owned subsidiary of ITC Holding Corp. and Vice President of ITC Holding Corp.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony in the above-referenced case.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge, information and belief.

Douglas C. Collins
Douglas C. Collins

SUBSCRIBED AND SWORN to before me, a Notary Public, this 24th day of April, 2013.

Karen J. Voss
Notary Public

My Commission Expires:
(SEAL)

Karen J Voss
Iowa Notarial Seal
Commission Number 767816
My Commission Expires April 28, 2014

BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION

In the Matter of the Joint Application of Entergy Arkansas, Inc., Mid South TransCo LLC, Transmission Company Arkansas, LLC and ITC Midsouth LLC for Approval of Transfer of Assets and Certificate of Convenience and Necessity, and Merger and, in connection therewith, Certain Other Related Transactions	))))))))	File No. EO-2013-0396

EXHIBIT DCC-1

STATE OF THE SYSTEM REPORT

DCC-1

ITC MIDWEST LLC

STATE OF THE SYSTEM REPORT

DECEMBER 7, 2008

(As filed with the Iowa Utilities Board

in Docket No. SPU-07-11 on December 8, 2008)

FILED WITH
Executive Secretary

DEC - 8 2008

IOWA UTILITIES BOARD

Date: December 8, 2008

Company Name: ITC Midwest, LLC

Subject Matter: State of the System Report

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December 8, 2008

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Judi Cooper, Executive Secretary
Iowa Utilities Board
350 Maple Street
Des Moines, IA 50319-0069

RE: **State of the System Report**
ITC Midwest, LLC
Docket No. SPU-07-11

Dear Secretary Cooper:

In compliance with the requirements of the "Order Terminating Docket and Recommending Delineation of Transmission and Local Distribution Facilities" (Final Order) issued in Docket No. SPU-07-11 on September 20, 2007, ITC Midwest, LLC (ITC Midwest) hereby submits for filing a report entitled "State of the System Report" (Transmission Report).

On December 20, 2007, ITC Midwest acquired the high-voltage electric transmission system formerly owned by Interstate Power and Light Company. The transaction was deemed approved by the Iowa Utilities Board by operation of law shortly after the issuance of the Final Order.

In seeking approval of the transaction in Minnesota, ITC Midwest committed to perform an analysis of the condition of the transmission system and identify any related plans for remedial measures, and to submit a report on the results thereof to the Minnesota Public Utilities Commission. In the Final Order, the Board essentially required that commitments for the benefit of customers made by ITC Midwest in other jurisdictions be extended to Iowa customers as well. The Transmission Report, which is also being filed with the Minnesota Public Utilities Commission this same day, is being filed in this docket to comply with that requirement.

Very truly yours,

Philip E. Stoffregen

ITC Midwest, LLC

State of the System Report

December 7, 2008

I. EXECUTIVE SUMMARY

On December 20, 2007, ITC Midwest, LLC ("ITC Midwest") acquired the high-voltage electric transmission system formerly owned by Alliant Energy's Interstate Power and Light Company ("IPL") operating company. In seeking approval of the transaction, ITC Midwest committed to perform an analysis of the condition of the transmission system and identify any related plans for remedial measures and to submit this analysis within twelve months of the transaction's closing. ITC Midwest is furnishing the following report to the Minnesota Public Utilities Commission, the Iowa Utilities Board and certain other parties in fulfillment of that commitment. The goal of this report is to provide ITC Midwest's assessment of the condition of its transmission system. ITC Midwest's assessment, in addition to fulfilling the commitments identified above, also provides a baseline from which ITC Midwest will base its future maintenance and capital plans. The matters discussed in the report below, including the discussion of past practices related to maintaining the system, are encompassed in this report as a necessary part of accurately assessing the current condition of the transmission system and related measures needed for going forwards, and for that purpose specifically.

A. Highlights of Report Findings

The following points sum up ITC Midwest's findings and conclusions made in the course of auditing and investigating the state of the transmission system in compliance with and furtherance of the reporting requirements outlined above:

- Aging Infrastructure: The transmission system is an aged system that requires immediate, thorough, and proper maintenance in order to fulfill ITC Midwest's commitment to improve reliability. The system requires infrastructure replacements due to assets being at or near end of their useful life.

- Renewable Energy: The existing system is not adequate to integrate new proposed renewable generation.

- Congestion: Portions of the ITC Midwest transmission system must be upgraded and new lines built to reduce the present constraints.

- Outages: Since acquiring the system and tracking its performance, ITC Midwest has experienced a high number of transmission outages on the system, which impact customers and must be addressed.

- Targeted Remedial Measures: Maintenance practices applied to the transmission system must be fully executed, enhanced, and accelerated in certain areas. The company also will need to address particular problem areas. Highlights of those problem areas are as follows:

  1. Backlogs in corrective maintenance;

  2. Backlogs in implementing appropriate vegetation management;

  3. Environmental management deficiencies;

  4. Implementation of an asset security and cyber security program that complies with best practices.

  5. Deficiencies in the 34.5 kV network. These system facilities have long been recognized as being in need of rebuilding (including new poles and wires) for improved reliability and overall enhanced system capability.

B. Methodology and Sources

In analyzing the condition of the transmission system, ITC Midwest has relied on various sources of information, including:

1. Observations and analysis of the actual performance of the transmission system.

2. Physical inspections of equipment.

3. Analytical reports provided by third-parties, including R.W. Beck and Black & Veatch, as discussed below;

4. Expert operational and technical knowledge and analysis conducted by ITC Midwest personnel who have long experience working with the system.

5. Available historical maintenance records kept by IPL, as well as IPL's Cascade maintenance data base

6. Reviews of historical maintenance practices, provided in available records and as reported by former IPL employees with knowledge of IPL maintenance practices.

7. Transmission system assessments reports and plans.

C. Assessment of System Baseline

Through its investigation and analysis, conducted in part to meet the requirements of this report, ITC Midwest has determined that past maintenance practices on the transmission system (including routine maintenance and inspection programs) were planned, but may not have always been completely executed or implemented. This supposition has been corroborated by the company thorough on-the-ground audit and inspection of the physical state of the system, as documented in this report.

Overall, when records are matched to the physical state of the system, it is clear that maintenance items were often identified, but often were repaired only to address immediate system performance exigencies or as required by a regulatory agency. It appears that system maintenance was often undertaken based on a prioritized list of identified exigent problems. Moreover, it also appears that this list was only attended to subject to budget and resource limitations.

D. Action Plan

Based on the assessments contained in this report, ITC Midwest intends to change the historic approach to maintenance of the system. ITC Midwest will concentrate its maintenance program on preventative maintenance while also systematically addressing the identified problem areas to improve system reliability and performance. These changes will result in a more efficient maintenance program over the long term and reduce requirements for and costs of unplanned, reactive and corrective maintenance activities.

The remainder of this report is organized as follows:

- Part II provides an overview of ITC Midwest and its maintenance and system planning principles;
- Part III sets out a description of analyses performed on the conditions of the transmission system, and the performance of the system;
- Part IV gives a description of historical maintenance practices applied to the transmission system and ITC Midwest's planned maintenance activities; and

- Part V discusses ITC Midwest's review of the need for the addition of new facilities to be added to the transmission system.

II. ITC MIDWEST OVERVIEW: MAINTENANCE AND SYSTEM PLANNNG PRINCIPLES

ITC Midwest was formed as a subsidiary of ITC Holdings Corp. to acquire the high-voltage electric transmission system formerly owned by IPL. Through the transaction, ITC Midwest acquired approximately 6,800 miles of transmission lines, at voltages of 34.5 kV and above, and approximately 208 transmission substations, as well as certain equipment installed at approximately 110 substations owned by neighboring utilities. As a result, ITC Midwest connects more than 700 communities in Iowa, southern Minnesota and northwest Illinois, an area of nearly 53,000 square miles.

ITC Midwest is currently working to complete the transition to take full responsibility for maintenance, construction and operational control of the former IPL transmission system, as well as initiating responsibility for planning and implementing improvements.

As noted throughout this report, ITC Midwest's maintenance program, on a going-forward basis, will seek to reduce and eliminate as much reactive and unplanned maintenance activity as possible. This approach not only results in the least number of system outages on the transmission system, but also delivers high reliability. This approach, which is consistent with all applicable industry standards, facilitates operation of the transmission system in a "least vulnerable" state. Under this approach, when system elements must be taken out of service, outages can be planned for those times when the system can reliably handle such system conditions. This also reduces the impact on customers because unplanned outages and associated costs are reduced. In addition, a fully and properly maintained system has a resiliency to abnormal system and environmental conditions, such as typical or even occasionally extreme weather events. Finally, ITC Midwest will concentrate on fulfilling its environmental, security, public safety and community presence responsibilities. The company will strive to take care of its property and buildings with the same level of care as it takes toward stewardship of the transmission system.

From a system planning perspective, ITC Midwest annually performs transmission planning assessments that meet or exceed all North American Electric Reliability Corporation ("NERC") Planning Standard Requirements. These assessments identify transmission upgrades required to maintain transmission security and adequacy over a minimum 1 to 10 year time frame. In compliance with FERC Order No. 890 and

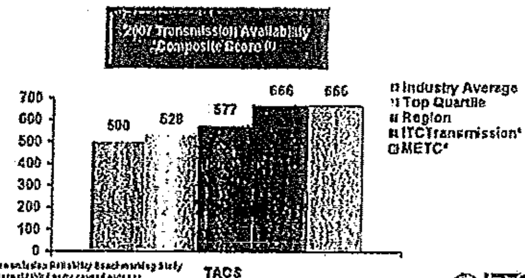
Attachment FF of the Midwest Independent System Operator, Inc. ("MISO") Transmission and Energy Markets Tariff ("TEMP"), ITC Midwest submits all proposed capital improvement projects to the MISO for stakeholder review and for approval by the MISO board of directors through the MISO Transmission Expansion Plan (MTEP) process. Changing loading patterns on the transmission system, infrastructure improvement and replacements, new generation, firm transmission usage, and market flows are all contributors to the on-going need to evaluate transmission system performance. This on-going evaluation results in properly identifying the transmission facility upgrades required to maintain and improve the transmission service ITC Midwest provides.

International Transmission Company ("ITC*Transmission*") and Michigan Electric Transmission Company LLC ("METC"), ITC Midwest's affiliate companies in Michigan, have a track record of employing similar maintenance programs, with positive results. In addition, as shown in the following slides, the latest SGS Statistical Services Transmission Reliability Benchmarking Study shows the Michigan ITC operating companies, ITC*Transmission* and METC, are top performers for reliability in three important measures: Average Circuit Outages – both Sustained and Momentary – and the Transmission Availability Composite Score. ITC Midwest will implement programs to ensure that the same best practices achieved at its Michigan affiliates are also adhered to and performed by ITC Midwest.

ITC

Operational Excellence

- ITC's goal is best-in-class system performance for all operating subsidiaries
  - Michigan systems are in the Top Quartile and better than regional performance when looking at the composite score for all voltages in the SGS Transmission Reliability Benchmarking Study



(1) 2007 SGS Transmission Reliability Benchmarking Study
* [illegible]

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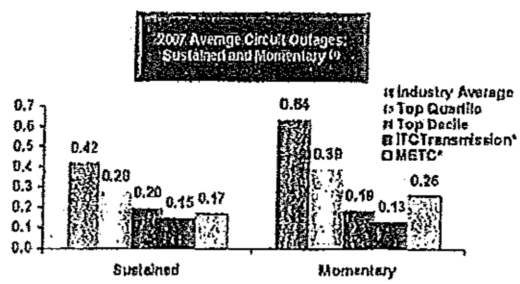
ITC

Operational Excellence

- ITC's goal is best-in-class system performance for all ITC operating subsidiaries
  - Our Michigan systems achieved Top Decile performance for sustained outages.
  - *ITCTransmission* is also Top Decile in momentary outages while METC is Top Quartile.



(1) 2007 SGS Transmission Reliability Benchmarking Study
* [illegible]

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ITC

III. TRANSMISSION SYSTEM CONDITION EVALUATION CRITERIA AND SYSTEM PERFORMANCE ASSESSMENT

A. Evaluation Criteria

In analyzing the state and condition of the transmission system, ITC Midwest utilized several industry standard assessment criteria.

First, the performance of the system is a key indicator of the system's condition; as the condition of the system deteriorates so will its performance. System performance can be analyzed through a review of outages, as well as the instances in which reactive or corrective maintenance (i.e., repairing broken equipment) was required.

Second, physical inspections of equipment provide data on the physical condition of the assets. To help complete a review of the condition of the system, ITC Midwest also has been able to access the accumulated knowledge of employees with prior extensive experience working on its transmission system.

Third, a review of historical maintenance practices employed with respect to the system, and available records of maintenance completed, is important to determine to what extent the existing equipment has been maintained. ITC Midwest considered these various sources of information in its description of the overall condition of the transmission system.

B. System Performance Assessment

A fundamental measure of system performance is outages. Reducing the incidence of outages is especially important on the ITC Midwest system because all distribution load substations are directly connected to the transmission system. The vast majority of the load is connected to 34.5 kV and 69 kV transmission lines, many of which are operated in such a manner that this results in the loss of service to an entire community when a line outage occurs.

ITC Midwest has been recording momentary and sustained outages on the transmission system during calendar year 2008. The table below summarizes the outages experienced through November 1, 2008, along with comparisons to outages experienced on transmission systems of ITC Midwest's affiliate transmission companies.

Company	Sustained Outages	Momentary Outages
ITC*Transmission*	6	36
METC	36	73
ITC Midwest	295	1141

More specifically, the ITC Midwest 34.5 kV system recorded 837 outages, of which 156 were sustained and 681 were momentary type outages. Additionally there were 599 outages on the 69 kV and higher system, of which 139 were sustained and 460 were momentary. While 60 to 70 percent of these momentary and sustained outages are reported as related to weather, such categorization is not reliable as there has been no formal investigation process for momentary outages. Available details on the cause of the sustained outages show a substantial number are related to vegetation contact. A large percentage of the momentary outages are suspected to be due to vegetation contact as well, but as stated earlier, these outages have not been formally investigated. While weather may have been the initiating event for many of these outages, we believe that many of those may have been prevented through better vegetation management practices.

According to records transferred to ITC Midwest, IPL recorded and investigated causes for sustained outages on the 34.5 kV and 69 kV+ systems. However, while that data provides some descriptions of outage causes, it does not identify specific lines or pieces of equipment involved in the failure. More specific information would help in the assessment of equipment condition trends. While the data has limited value in identifying issues with particular equipment, it does indicate numerous outages on the low-voltage transmission system historically. Sustained outage data on the higher voltages does appear to have been better documented.

Unfortunately, IPL did not record or keep any records of momentary outages. Without such baseline data, it is not possible to look at historic outage trends over time to determine if degrading system maintenance contributed to increasing levels of momentary outages. However, as noted above, the sheer level of ITC Midwest momentary outages in 2008 (1141), as compared to ITC*Transmission* (36) and METC (73) suggests that, at least, further study and analysis regarding momentary outages is required.

ITC Midwest will be using the momentary and sustained outage information data that ITC Midwest collected during 2008 as its performance measure baseline. These data will support and dictate the initiation and prioritization of certain maintenance and capital system improvements going forward.

C. Physical Inspections

ITC Midwest undertook and/or commissioned three separate inspection programs to evaluate and detail the condition of the ITC Midwest transmission system. As noted below, the reviews were undertaken by: (1) ITC Midwest; (2) RW Beck; and (3) Black & Veatch. The company initiated or commissioned each inspection program to assess slightly different (yet, somewhat overlapping) aspects of the system. ITC Midwest undertook an overall facilities inspection in keeping with its practices in Michigan, RW Beck performed a diligence report for the company's use prior to its purchase of the system based on an asset sampling, and Black & Veatch conducted a system security assessment.

Although each of the three assessments was different in its focus, each one identified similar trends regarding the state of system maintenance and equipment conditions. The inspection programs and resultant reports are described below. Importantly, the engineers hired by ITC Midwest who have direct previous experience in maintenance activities on the ITC Midwest system provided invaluable input on the condition of the system to each of these three efforts. Finally, field personnel, including linemen, electricians, technicians and foremen with extensive experience on the ITC Midwest transmission system also provided very important input and guidance to these assessments.

1. ITC Midwest System Review

The most comprehensive inspection program was initiated by ITC Midwest in the early spring of 2008. The goal of this effort was to thoroughly inspect the facilities (both lines and substations) to determine the condition of the equipment and to assess the equipment's actual condition as compared to IPL's historical maintenance records. IPL provided ITC Midwest with an extract of their substation equipment maintenance management data base called Cascade as part of the asset sale. The Cascade system contains the maintenance plan and frequencies for substation assets, as well as historical records of past maintenance activities.

In this inspection effort, ITC Midwest employed a similar program to the one successfully used by METC following its acquisition by ITC Holdings Corp.

ITC Midwest assembled and directed a team of qualified and highly experienced personnel from the company and several consultants to review the facilities and equipment, plus the environmental and physical security conditions, of each site where

ITC Midwest owns equipment. In particular, these inspections encompassed every substation containing equipment owned by ITC Midwest, including substations owned by third parties that contain ITC Midwest-owned equipment. In addition, ITC Midwest performed a comprehensive line inspection pursuant to the existing IPL scheduled inspection process.

a. Substation Analysis

The ITC Midwest substation inspection program in particular identified equipment deficiencies that, if left uncorrected, would likely or potentially lead to more severe equipment fault and/or degraded system conditions. These deficiencies have been catalogued, and are now included within an omnibus list of corrective maintenance items to be performed by ITC Midwest (discussed later in this report). Substation maintenance is of particular concern to the company and, in December 2008 when it takes over system maintenance and operations, ITC Midwest will be conducting its own ongoing substation inspection and maintenance program, which will be a follow-on to the effort reported here, and will be used to uncover any additional issues to be remedied. The present IPL substation maintenance plan, as well as the results of the ITC Midwest inspection, will be used in determining substation maintenance activities going forward, such as adjusting inspection frequencies and preventative and predictive maintenance activities.

Substation power equipment deficiencies included:

- minor leaks (i.e., non-reportable spill to the Iowa Department of Natural Resources and Environmental Protection Agency);
- equipment missing some non-critical parts;
- equipment which had only partial repairs completed,
- a lack of general upkeep; and
- signs of age degradation (especially on circuit breakers at the 34.5 kV and 69 kV level).

With respect to leaks, 27 percent of the station transformers and 8 percent of the oil circuit breakers were found to have at least one notable oil leak. ITC Midwest's experience is that this frequency of leakage is too high and should be addressed.

In addition, several substations were found to contain spare power equipment materials (e.g., breaker or transformer oil-filled bushings, insulators, etc.). This extra equipment appears to have been salvaged from decommissioned equipment. This salvaged equipment was assessed to be in questionable condition (due to age, method of storage, and exposure to the elements). The spare equipment located in the substations identified as transmission equipment will be disposed of or moved to central warehouse facilities for proper storage, if deemed useful.

b. Line and Pole Analysis

Line inspections found deficiencies consistent with reports from IPL's inspection program; however some of the deficiencies appear to have been present for some time, i.e. greater than the inspection cycles reported by IPL which means they were not corrected once found and would have still existed when the line segment was again inspected according to the schedule. The line inspections also determined that many areas were in immediate need of vegetation management. Notably, this finding was not revealed in the R.W. Beck initial diligence report sampling described below. The lines inspected during ITC Midwest's review were selected by ITC Midwest and its contractors, using both the IPL-scheduled inspection plan and by targeting areas of known system performance problems. These issues are discussed later in the report.

c. Miscellaneous Property and Environmental Analysis

The company also found physical substation site deficiencies with the buildings and grounds including:

- broken windows and doors,
- damaged or poor lighting,
- non-working air conditioning units and heaters,
- broken locks, fence tensioning and barbed wires broken or missing,
- fence ground wires missing,
- gravel washouts and/or major depressions requiring yard stone,
- roof leaks,
- major vegetation encroachment,
- absent or poorly visible station or line equipment identification; and
- missing operator or station drawings.

These deficiencies pose a threat to general integrity of equipment that is part of the transmission system, a threat to the safety and security of the transmission system, and increase in the potential impact on public safety from high voltage electrical equipment.

Environmental deficiencies within substations included past spills needing follow-up remediation, oil containment deficiencies, residual rain water in catch basins needing to be pumped out, and minor equipment leaks. ITC Midwest's assessment is also that past compliance with Spill Prevention Control and Countermeasure ("SPCC") regulations was not to industry standard.

Overall, the condition of the transmission substations is characterized as primarily fair, with some locations in poor condition and a small group in good condition. Some equipment degradation based on age and performance is likely at end of useful life and there is a need for some facilities to be replaced. The majority of the rest of the electrical equipment and sites need proper and thorough maintenance to restore the equipment to a condition consistent with industry standards.

All of the 345 kV, 161 kV and 115 kV lines were aerial inspected. Portions of these lines identified from the aerial inspection were then inspected on foot. The remaining inspections focused on the 69 kV and 34.5 kV portions of the system. The lines inspected during this review were selected in part based on areas of known system performance problems. As discussed above, the vast majority of outages are at these lower voltage levels. Approximately 70% of the 34.5 kV and 69 kV portions of the system were inspected.

In general, the 345 kV, 161 kV and 115 kV lines are in good condition, with some portions of the 161 kV and 115 kV systems showing significant signs of age. The 34.5 kV and 69 kV lines were found to have many deficiencies, as expected, since some circuits have poor performance. Some of the deficiencies appear to have been present for some time, before they were reported-on for the first time by the prior owner's personnel.

The line inspections also determined that many areas of the system were in immediate need of vegetation management. Taken together, the condition of the lines themselves and the vegetation management issues identified lead ITC Midwest to make the assessment that the 34.5 kV and 69 kV system lines are in generally poor condition. With a proper vegetation management program, and maintenance of the lines, the condition is expected to greatly improve. In contrast to the substation equipment, however, significant portions of these lines will need to be replaced as they are at end of their useful life.

2. R.W. Beck Study

As part of a financial, due diligence process prior to ITC Midwest's acquisition of the transmission system, R.W. Beck, Inc. performed a limited sampling review of certain system facilities. The review included site reviews of certain of the electric transmission lines and substation assets of IPL prior to the acquisition. The field review was not intended to be a detailed inspection of all equipment, but rather a general observation of the condition of the system based on limited samples.

R. W. Beck personnel reviewed a sample of the transmission lines and substations. IPL's staff selected substations and lines across the entire system for the review. The sample size was approximately 35% of the substations and less than 6% of the transmission lines.

Typically, a series of three or four structures were evaluated at two separate locations along each sample line section. Sixty two (62) representative substations were entered and evaluated.

R. W. Beck defined their condition ratings as: Obsolete (Recommend immediate replacement), Poor (Remaining life; replace soon), Fair (Remaining life; maintenance required soon), Good (Remaining life; recommend routine maintenance), Very Good (Remaining life; recommend routine inspection) and Excellent (Remaining life; new or recent construction).

R. W. Beck noted on the sampled transmission lines that generally good structure, grounding and maintenance practices were observed; however they recommended that the pole inspection program be accelerated to a minimum of a 10-year cycle as parts of the system are over 40 years old. R. W. Beck noted that some of the oldest structures are in the northern part of the system and show a lot of deterioration. On the samples of the 69 kV system that were evaluated, nearly 50% of lines were deemed to be in Fair (maintenance required soon) or Poor (replace soon) condition. For both the 34.5 kV and 69 kV systems, R. W. Beck recommended a systematic replacement program due to the age of these portions of the system. This is consistent with ITC Midwest's planned conversion of the 34.5 kV system and reliability improvements to the 69 kV system. Nearly 60% of the 115 kV system was rated Fair (maintenance required soon), with a high priority recommendation for replacement based on the fact that most poles were at or near 50 years old. The rights-of-way sampled for the R.W. Beck report did identify areas that were well maintained, with some examples of poorly maintained rights-of-way. A few minor encroachments of rights-of-way by the public were observed.

R. W. Beck noted that the 62 substations reviewed appeared to be in generally good condition (recommend routine maintenance). Minor oil leaks were observed and a larger than expected amount of equipment was identified as needing general physical maintenance. A number of substation yards were soft and had considerable puddling and washing. Most of the major equipment in the sampled substations was observed to be in fair (maintenance required soon) to Good condition (recommend routine maintenance). Minor substation equipment condition was consistent with the condition of major equipment. R. W. Beck noted the lack of oil containment at most locations, recommending a review of the requirements in 40 CFR Part 112 (Oil Pollution Prevention Regulation). ITC Midwest noted this concern as well during inspections and is evaluating oil containments and remediation of this issue. Overall, R. W. Beck rated 44% of substation equipment as being in "Good" condition, but still recommending that routine maintenance was required, and 29% as "Fair" condition, with maintenance required "soon."

This financial due diligence review provided a decent snapshot of the system, and is generally in line with what has been observed by ITC Midwest and Black & Veatch. Overall, the R.W. Beck report highlighted the need for thorough and proper maintenance programs on the system, but noted that some portions of the system required immediate maintenance or replacement.

3. Black & Veatch Study

A third inspection program was a vulnerability assessment, completed by Black & Veatch for the purposes of complying with the NERC Critical Infrastructure Protection Program. The assessment was conducted from June to August of 2008. The inspection included 83 key ITC Midwest substations. This vulnerability assessment applied the Sandia National Laboratories' "Risk Assessment Methodology" (RAMSM). The vulnerability assessment considered critical assets and features of ITC Midwest's electrical substation facilities with respect to the mission objectives and facility prioritization. The risk assessment methodology was used to evaluate the overall system effectiveness versus the design basis threat ("DBT"), identify vulnerabilities, and recommend countermeasures that ITC Midwest should consider regarding security of their facilities. Teams consisting of security specialists from Black & Veatch conducted the assessment.

Substation and control building condition assessment was included as part of the survey, with an emphasis on physical security conditions. This is important not only for the physical security of the transmission assets, but also for public safety. The assessment identified many actionable facilities maintenance items. Consistent with the two previously discussed assessment activities, a notable number of the substations were identified with similar maintenance issues associated with fences (broken portions, gaps under the fence, holes, etc.), poor window and door conditions (broken or latch problems), control building water leakage, rodent problems and system grounding maintenance issues. Vegetation encroachment on the exterior of substation fences was identified as a security threat and source for vandalism.

Like the previous assessment, this vulnerability assessment had a specific purpose, focusing only on physical security and potential vulnerabilities. It confirms ITC Midwest's own assessment on the need for a thorough and proper maintenance program for all aspects of the company's transmission system facilities, not just transmission electrical equipment.

IV. Review of Transmission System Maintenance Practices and Planned Going-Forward Routine and Remedial Maintenance

As stated earlier in this report, ITC Midwest's maintenance program will seek to reduce and eliminate as much reactive and unplanned maintenance activity as possible. This approach will result in the most efficient method of achieving the highest level of reliability that can be provided in an economic manner. A fully and properly maintained transmission system has a resiliency to abnormal system and environmental conditions, such as typical and occasionally extreme weather events.

What follows is a description, for each category of maintenance activities, of:

- past maintenance plans and practices by IPL;
- the status of each category of maintenance, and
- ITC Midwest's future maintenance plans.

The categories of equipment for which maintenance practices were examined are as follows:

- Lines
- Vegetation Management
- Substations
- Power Transformers
- Breakers (oil, gas)
- Batteries
- Relays

- Circuit Switchers, Disconnects and Pole Top Switches
- Potential Devices and Arresters
- Capacitor Banks

A review of the status of maintenance performed on the transmission system, as well as the planned maintenance needed going forward, is another important indicator of the condition of the system, as noted above. As part of each maintenance category, ITC Midwest anticipates some equipment replacement and/or upgrades. These activities may not be strictly considered "maintenance," but may ultimately be classified as "capital expenditures" from an accounting perspective. However, the accounting for that activity does not affect what the system objectively requires from a performance perspective. In some cases, work can be performed without the need for full equipment replacement and capital expenditures; other times, this is not the case. Thus, what will be assessed is the need for replacing equipment at the end of its useful life. These assessments will be done as part of the ITC Midwest maintenance program.

By way of background, ITC Midwest employs Utility Line Construction Services ("ULC") to perform the outage response/repair, and the scheduled maintenance of the ITC Midwest transmission system. ULC works for ITC Midwest and is a dedicated maintenance and emergency response organization. ULC's priority is to respond to and repair outages and perform regularly scheduled maintenance of the ITC Midwest system. ULC, in order to support its work for ITC Midwest, has hired a significant number of former IPL employees who are very familiar with the operational characteristics and location of the ITC Midwest transmission system. ULC has the necessary specialty equipment and tools to maintain and repair the system regardless of weather, ground conditions, terrain, or system configuration.

1. **Lines**

a. **Lines: Historic Maintenance**

As reported by IPL, IPL performed its line inspections in accordance with the Iowa Utilities Board Iowa Administrative Code and NERC Reliability Standards. IPL reports that all lines operated at 34.5 kV or above were visually inspected at least annually for damage and to determine the condition of the overhead line insulators. A combination of driving, walking and aerial inspection methods were typically utilized for these inspections. Ground inspections were substituted for aerial inspections in highly populated areas, where low altitude flight is restricted by Federal Aviation Regulations. IPL reported that it visually inspected some electric transmission lines and facilities more frequently based on operating experience.

IPL reported that transmission (34.5 kV and higher) poles had the butt end of the poles inspected and tested on a ten year plan beginning after the line has been in service twenty years. These additional tests may have included sounding, boring, ground line exposure, and, if applicable, pole treatment. In addition, transmission lines were required to be foot patrolled (pole-to-pole) and poles visually inspected every five years, 20% of the transmission system (34.5 kV or greater) per year.

Corrective maintenance was scheduled to cure deficiencies noted during the inspection process.

IPL did not have a formal program to climb structures and perform a detailed inspection and repair as part of a preventative maintenance program. Examples of the types of defects identified during a line patrol inspection are: rotten arms, damaged insulator, buried anchor eye, loose ground wire, broken static/ neutral bonding, down guy insulator needed, down guy bonding, blown arrestor, bad or leaning poles, etc.

b. Lines: ITC Midwest Maintenance Plan

ITC Midwest will augment the IPL line maintenance plan, in addition to following the guidelines set forth by the Iowa Utilities Board Iowa Administrative Code and NERC Reliability Standards. ITC Midwest will add preventative maintenance practices that will improve the safety and reliability of its system based on the previous inspection plans. For example, in addition to past IPL practices, ITC Midwest will visually inspect the 100 kV and higher transmission system twice a year in order to find immediate issues with the bulk power portion of the system.

In addition, ITC Midwest will perform "climbing inspections" as part of its routine maintenance, and perform a detailed inspection and repair of all structure items. Climbing inspections provide a closer inspection of the condition of the conductor and mounting hardware than a ground visual inspection provides. In addition if loose hardware is identified it can be tightened at the time of the inspection, rather than having to schedule a return at a later date. Line outages will also be used as an indicator that a circuit needs an inspection.

As an example, if a circuit is experiencing momentary or sustained outages, the line will be subject to a climbing inspection. Along with the repair and pole top inspection, insulators will be inspected for failure, all expended arresters will be replaced and additional arresters added if deemed necessary for improvement of the circuit's performance. This inspection will take place as soon as the line can be taken out of service. This type of program can improve system performance and reduce the need for later corrective maintenance activity. For example, based on findings from a line failure on the OGS-Montezuma 345 kV line in 2007, it is probable that the failure and resultant conductor damage that occurred would have been prevented with such a detailed climbing inspection.

Lastly, ITC Midwest is implementing a centralized maintenance management data base. This data base will be used to track maintenance of the entire ITC Midwest system, both lines and substations. This data base is being populated with historical substation data provided by IPL and a significant amount of new data being collected through ongoing field inspections. The centralized maintenance management data base will provide an efficient platform for monitoring line maintenance and corrected deficiencies that would impact system reliability. The data base will also be a tool for identifying future maintenance or replacement programs.

2. Vegetation Management

a. Vegetation Management: Historic Maintenance

IPL conducted an annual inspection program for transmission lines greater than 100 kV. The annual inspection program was discussed with ITC Midwest personnel. Deficiencies were documented and assigned to work crews for remediation. Prioritization was based on threat to the system. After completing a trim on the transmission lines greater than 100 kV, the line rights-of-way were herbicide sprayed every two years to minimize re-growth.

IPL had a vegetation management program for the system below 100 kV that was designed to achieve a three (3) year trim cycle. ITC Midwest understands that the 3 year trim cycle was expanded to more of a 4 to 5 year program at the 34.5 kV and 69 kV level based on available budget and resources. Several years of minimal trimming have resulted in areas of the system having only partial trims and often only 1 to -2 feet of clearance on untrimmed circuits. The number of weather-related momentary and lock-out outages reported in system performance metrics appear to affirm that there are significant vegetation clearance problems on the 34.5 kV and 69 kV system.

IPL represented that all reported vegetation management deficiencies were completed for 2007 across the territory. ITC Midwest has observed that adequate trimming appears to have been completed in some areas, while ITC Midwest site inspections show a number of line locations with line-to-vegetation clearance problems. The recent ITC Midwest vegetation inspection shows that a three-year cycle for trimming is inadequate based on past practices and due to the growth rates of the vegetation in this area.

b. ITC Midwest Vegetation Management and Maintenance Plan

ITC Midwest has performed a detailed system inspection during 2008 and has recognized the need to increase the system trim cycle from three years to two years. Additionally, these accelerated trim cycles will include trimming of entire circuits rather than limited trim of portions of a circuit. The objective of ITC Midwest's Vegetation Management Plan is to eliminate vegetation-caused outages to the transmission system, consistent with the expectations of the NERC Reliability Standards. ITC Midwest will meet these objectives by maintaining acceptable clearances between conductors and adjacent vegetation. In addition, effective right-of-way management includes inspection for, and mitigation of, other rights-of-way based causes of outages, such as encroachment, vandalism, and incompatible use. Many 34.5 kV and 69 kV circuits have immediate needs and are currently being "hot-spot trimmed" to deal with only the most urgent clearance needs. Although this is not the most cost efficient way to manage a program, as opposed to a program more focused on preventative maintenance, hot-spot trimming is currently required to avoid vegetation contact with lines, and related outages.

ITC Midwest has developed an Annual Plan which indicates planned vegetation management work, by circuit, for the year. The Annual Plan is flexible enough to accommodate a schedule change due to capital projects, community involvement, additional right-of-way, and other system issues These variations from the plan are documented and the Annual Plan is updated accordingly.

The Annual Plan is initially developed prior to the start of each year by the ULC Foresters under the direction of the ITC Midwest Maintenance Specialist. Each ULC Forester submits a draft proposal for their region to the ITC Midwest Maintenance Specialist. When it is necessary to make an adjustment to the Annual Plan, the ULC Foresters will submit the change to the ITC Midwest Maintenance Specialist. The ITC Midwest Maintenance Specialist will review the change, and if the change is acceptable, update the Annual Plan by either adding the new work requested or removing work from the plan. Work is scheduled from the Annual Plan when and where necessary to continually improve vegetative conditions compatible with electric reliability and safety.

ITC Midwest employs an integrated vegetation management program directed by ULC Foresters with assistance from Planners. Vegetative conditions are assessed and the most appropriate control method is scheduled as needed to meet objectives. Control methods may include manual, mechanical, biological, chemical, and cultural techniques. Choice of control option(s) is typically based on established rights, thresholds, effectiveness, environmental impact, site characteristics, worker and public health and safety concerns and economics.

ULC Foresters or Planners personally contact affected property owners to explain the intended vegetation management work. If personal contact cannot be made with the affected property owner a door hanger is left to provide them with contact information. Planners evaluate the sites and assess the current vegetative situation and schedule the most appropriate management tool in a prescriptive fashion. All tree removals on private property not covered by an easement require the landowner's permission. Planners secure signed permission from property owners for tree removal on easements as required.

3. Substations (General)

a. Substations (General): Historic Maintenance

IPL used a maintenance management data base, called Cascade, to identify substation equipment maintenance status, inspection frequencies, inspection plans and historical records of maintenance activities. IPL reported to the Iowa Utilities Board that they would inspect the transmission substations at least quarterly. As part of the quarterly inspection process, the following activities were performed:

- Physical inspection of the site proper, including fence, warning signs and grounds;
- Physical inspection of the control building, including station power, DC power, building facilities;
- Physical inspection of the equipment, including bus and manual switches, bus supports and lightning arrestors;
- Major equipment as listed below have specific inspection requirements that go beyond the quarterly inspection process; and
- Battery water levels.

In addition to the quarterly site inspections, IPL had set up a maintenance schedule for major equipment based on several factors, such as industry recommendations, past equipment experience and resource availability. The details supporting the major substation equipment are contained in the following sections of this report.

IPL performed an annual infrared inspection of all transmission substations. The infrared inspection included major equipment, disconnects, switches, substation arresters and electrical power connections in order to identify overheated equipment, which is a very reliable indicator of impending failure. In substations, failures of equipment and connections due to overheating will not only cause outages, but will result in significant equipment damage. While the infrared inspection is an important tool, it is more critical that items found during inspection are repaired.

ITC Midwest understands that corrective maintenance was given precedence over preventative maintenance, with the exception of scheduled maintenance for regulatory requirements. Field personnel report that because of resource limitations, only minimal work was accomplished when any maintenance was performed. Essentially, if field personnel identified additional issues with a particular piece of equipment, they were instructed that unless the issue had an immediate effect on performance, they were to not proceed with the extra work.

Another example of this constrained situation is illustrated in the substation maintenance report issued by IPL. As one would expect, IPL tracked the scheduled maintenance plan, but also had another tracked item call "*Work Plan*", with the definition that this is the work committed to by IPL Maintenance Managers. 2008 year to date data for substation maintenance shows 70% of the maintenance plan completed, with 85% of the Work Plan completed. Such reporting by IPL to ITC Midwest reveals a known and systemic limitation in completing the defined maintenance plan.

Any deficiencies identified during the inspection process that could not be corrected at the time of the inspection were listed for corrective maintenance. The corrective maintenance may have required specialty tools or resources, an equipment outage or other action.

IPL reported 1,670 substation corrective maintenance items not being completed at the end of 2007. The information provided did not easily allow for separation between the Minnesota and Iowa territories. This corrective maintenance work was carried over into 2008. As mentioned before, while planned inspections are a key aspect of any maintenance program, it is more important that deficiencies found during these inspections are addressed and corrected.

ITC Midwest has been made aware of additional needs for corrective maintenance of its equipment in other substations, which have so far not been addressed by the owners of the substation that have both ITC Midwest's and another owner's equipment located there (also known as "shared substations"). ITC Midwest has taken these communications seriously and will schedule the corrective actions for 2009.

b. Substations (General): ITC Midwest Maintenance Plan

ITC Midwest is implementing a centralized maintenance management data base that will be used across the ITC Midwest system. The centralized maintenance management data base will provide an efficient platform for monitoring substation maintenance and corrected deficiencies that would impact system reliability and will provide a tool to identify future maintenance or replacement programs.

ITC Midwest has decided to initially use substation maintenance frequencies formerly employed by IPL. While the maintenance frequencies are in line with industry standards, it is not clear from the performance data if the program is able to drive good system performance. As such, it is expected that maintenance frequencies will be adjusted based on ITC Midwest's ongoing working experience with the system, continued review of past maintenance histories, and the objective of improving system reliability.

Equally important, ITC Midwest intends to address the numerous corrective maintenance items identified in the inspections. ITC Midwest has arranged for the proper amount of field resources so that these issues can be addressed. Given the sheer number of corrective maintenance items, the potential complexity to conduct the repairs, and the constraints of the system that limit scheduling of equipment outages, it likely will take two to three years to eliminate the back-log of existing corrective maintenance problems.

In addition to the information gathered in the discussed assessments, ITC Midwest will use the results of quarterly inspections to identify facilities maintenance needs. Such items would include fence repair, building, roof, plumbing and HVAC repairs, locks and keys, site grading and stone replacement. Routine Facilities items include snow plowing, dust control, mowing, and general site and building cleanup. Prompt and thorough attention to these non-electrical system items are important for transmission system security, as well as being a good neighbor by taking care of buildings and grounds appearance.

The environmental plan will include all aspects of environmental matters for ITC Midwest assets. For compliance, ITC Midwest will conduct environmental audits and develop and revise Spill Prevention Control and Countermeasure ("SPCC") plans at all

ITC Midwest owned sites and shared sites. In addition, ITC Midwest will make all necessary Tier II Reports (reports submitted to the Local Emergency Planning Committees ("LEPC") and Iowa Department of Natural Resources), hazard notifications and plans, and develop company environmental procedures if needed specific to ITC Midwest. Finally, threatened and endangered species related activities permitting will be conducted (usually in conjunction with vegetation management).

In the event of an environmental incident (reportable or non-reportable), such as an oil spill, ITC Midwest will have the resources to conduct spill response and clean up. We will conduct as necessary PCB sampling, and waste management for all maintenance and construction activities.

4. Power Transformers

a. Power Transformers: Historic Maintenance

IPL scheduled annual power transformers inspections using their Cascade equipment management data base. This annual inspection included a visual inspection, infrared scan, oil samples, acoustic and vibration monitoring. After the initial inspection and review of the inspection information, further testing may have been performed and an outage scheduled to investigate any abnormal readings. The additional testing may have included: Doble power factor and excitation testing, transformer turns ratio, DC insulation testing, and DC winding resistance testing. These additional tests were not conducted on a defined interval plan, and were done when crews and transformer shutdown opportunities were available. All these tests are standard industry practice and identify potential equipment problems.

b. Power Transformers: ITC Midwest Maintenance Plan

ITC Midwest will utilize a similar initial predictive maintenance inspection. In addition, ITC Midwest will attempt to schedule 10% of the power transformers to be taken off-line each year in order to complete a full series of tests, which would include: Doble power factor and excitation testing, transformer turns ratio, DC insulation testing, and DC winding resistance testing. As a good preventative maintenance practice, the tests will provide a base line health of the transformer assets.

5. Breakers (Oil, Gas)

a. Breakers: Historic Maintenance

For breaker maintenance, IPL planned to perform annual minor maintenance and inspection on every circuit breaker using their Cascade equipment maintenance management data base. IPL also had a major non-intrusive maintenance program. If IPL did not have available resources to accomplish the major non-intrusive work in the scheduled year it was delayed to the subsequent year. This practice has created a back-log on some maintenance of breakers during the last few years.

IPL performed oil circuit breaker annual inspections which included oil dielectric and level checks and bushing inspections. IPL also scheduled oil circuit breaker major non-intrusive maintenance every six years. This major non-intrusive maintenance included a dissolved gas lab analysis of the oil, timing and travel testing of the mechanism movement, contact resistance, mechanism maintenance and trip testing.

There are 481 oil breakers on the system. IPL has reported 100% of all scheduled annual circuit breaker maintenance has been completed.

The table below identifies number of major circuit breakers scheduled for non-intrusive maintenance in 2007. The information provided did not differentiate between oil and gas circuit breakers.

	Majors Scheduled	Majors Complete	Majors Carried Over	%Carried Over
Minnesota	78	71	7	10%
Iowa	159	113	46	29%

For gas breakers, IPL performed annual inspections on SF6 circuit breakers which included pressure checks and bushing inspections. IPL also scheduled SF6 breakers for major non-intrusive maintenance every eight years. This major non-intrusive inspection included a timing and travel testing of the mechanism movement, contact resistance, mechanism maintenance and trip testing.

There are 535 gas breakers on the system. IPL reported that all circuit breakers annual visual inspections were completed. Any maintenance activities that were generated from the annual inspection that could not be corrected at the time of the annual inspection, were identified as a corrective maintenance task that was scheduled to be performed at a later date.

The table below identifies the number of major circuit breakers scheduled for non-intrusive maintenance in 2007. The information provided did not differentiate between oil and gas circuit breakers. The normal schedule for this non-intrusive maintenance is an eight year cycle.

	Majors Scheduled	Majors Complete	Majors Carried Over	% Carried Over
Minnesota	78	71	7	10%
Iowa	159	113	46	29%

b. Breakers: ITC Midwest Maintenance Plan

ITC Midwest will initially start the annual and major non-intrusive scheduled circuit breaker maintenance program in 2009 following the IPL inspection practices listed in the circuit breaker type specific sections below. In addition, ITC Midwest will perform power factor testing as a routine test when performing the circuit breaker major maintenance as a recognized good industry preventative maintenance practice.

ITC Midwest is starting with more circuit breaker major maintenance than it would normally have to do in 2009 because of the scheduled maintenance work not completed by IPL in the past couple of years. Typically, ITC Midwest could plan to have an average of 70 oil breakers and 40 gas breakers to perform major maintenance on in a given year. For 2009, the number of scheduled major maintenance tasks will be closer to 110 oil breakers and 40 gas breakers. System constraints and other scheduled capital construction activities will result in working off this backlog over the next few years.

ITC Midwest plans to initially follow the IPL annual maintenance program for oil circuit breakers. In addition to the IPL major non-intrusive maintenance program steps on oil circuit breakers, ITC Midwest will perform Doble power factor testing and structured operating mechanism lubrication. For oil circuit breakers rated over 100 kV, the tanks will be dropped and an internal interrupting assembly inspection and maintenance will be performed. These steps were not performed on a consistent basis by IPL, and are considered a good industry practice for portions of the system greater than 100 kV.

For gas circuit breakers, ITC Midwest plans to initially follow the IPL annual maintenance program. ITC Midwest will maintain the major non-intrusive major inspection program at eight years. In addition to the IPL major non-intrusive maintenance program steps on gas circuit breakers, ITC Midwest will perform Doble power factor testing and structured operating mechanism lubrication. These steps were not performed on a consistent basis by IPL, and are considered a good practice to assess the condition of this important equipment.

6. Battery Systems

a. Battery Systems: Historic Maintenance

IPL scheduled quarterly visual inspections on substation batteries and chargers through their Cascade equipment maintenance management data base.. This visual inspection included looking at the battery set, interconnecting battery straps and charger. In addition, batteries and chargers were annually tested using a battery resistance test on the battery set. This annual test included a visual inspection of the battery set and charger physical condition, cell resistance testing, and interconnecting battery strap testing. If an anomaly on the battery resistance test was identified either an additional load test was performed to determine battery condition or the battery set was scheduled for replacement.

b. Battery Systems: ITC Midwest Maintenance Plan

ITC Midwest will implement the same annual testing and quarterly inspections of batteries. Batteries and charger are annually tested using a battery resistance test on the battery set. This annual test includes a visual inspection of the battery set and charger physical condition, cell resistance testing, and interconnecting battery strap testing. If an anomaly on the battery resistance test is identified either an additional load test is performed to determine battery condition or the battery set is scheduled for replacement.

7. Relays

a. Relays: Historic Maintenance

The IPL relay testing plan was to test and recalibrate, if needed, every relay in their database every five years as part of the NERC Reliability Standards program as identified in their Cascade equipment maintenance management data base. IPL's position on scheme testing, (that is testing the relay, power source, communications path (if applicable) and device to be operated as a complete integrated unit), was that if the control center did not allow the circuit breaker to be taken out of service, only the relay would be tested. The electromechanical relay test included taking the relay out of the case and giving it a thorough test by inputting voltages and currents and making sure relays were in good mechanical order and operated according to the specified relay setting. Microprocessor based relays were tested by using commands via the front serial port to ensure that the relay has not lost its integrity and that outputs are still fully functional. Solid state relays were tested by testing their commands and settings to ensure the relay had not lost its integrity and that the outputs were still functional.

There are approximately 5,224 electromechanical, 1,024 microprocessor and 878 solid state relays on the system. IPL reported the scheduled relay testing was 50% complete in Minnesota and 80% complete in Iowa. IPL has reported that the relays that were carried over from 2007 were successfully tested by the end of the first quarter 2008.

b. ITC Midwest Relay Maintenance Plan

ITC Midwest will continue to test and recalibrate, if needed, every relay in their database every five years. Additionally, as part of the NERC Reliability Standards requirement for equipment 100 kV and greater, ITC Midwest will implement a complete scheme test every ten years which includes insulation and conductor strength ("Megger") testing cables, tripping devices from all relays, and insuring that the scheme works as designed and installed. Potential devices will also be power factor tested during this ten year cycle test to determine the device health. This additional testing will begin in 2010, after test plans are written and approved in 2009.

8. Circuit Switchers, Disconnects and Pole Top Switches

a. Circuit Switchers, Disconnects and Pole Top Switches: Historic Maintenance

IPL verbally stated that they did not have a circuit switcher, disconnect or pole top switch defined maintenance program and repairs were handled on a reactive maintenance basis only. It is ITC Midwest's understanding that the IPL philosophy was to operate these devices to failure, then repair or replace them as deemed necessary.

There are 61 circuit switchers and approximately 2000 pole top switches on the system. There are an undetermined number of disconnects on the system. ITC Midwest is currently conducting an inventory of these devices.

IPL did not report any maintenance results for circuit switchers, disconnects or pole top switches.

b. Circuit Switchers, Disconnects and Pole Top Switches: ITC Midwest Maintenance Plan

ITC Midwest plans to implement a major inspection program on circuit switchers for substation capacitor banks on a three year cycle and for circuit switchers for transformers on a six year cycle. Circuit switchers will be tested similarly to circuit breakers. The plan assumes outages can be scheduled on the circuit switchers to remove them from service to test them. ITC Midwest is investigating a program to perform routine maintenance on disconnects and pole top switches.

This new program is important given the outage performance of the system. Some of these devices are automatic, and intended to operate in the event of a problem on a transmission line it is protecting; thereby removing from service the transmission line it is connected to. Non-automatic, manual devices are used not only for routine maintenance in order to safely shutdown sections of line, but also during emergency restoration to get customers back in service. If these devices are not properly maintained, momentary outages can turn into sustained outages, which take longer to restore.

9. Potential Devices and Arresters

a. Potential Devices and Arresters: Historic Maintenance

IPL verbally stated they did not have a defined maintenance program for substation arresters or line and bus potential devices. Maintenance on these items was performed on a reactive basis and deficiencies were usually found with the annual infrared scans done at each substation. It is ITC Midwest's understanding that the IPL philosophy was to operate these devices to failure, then repair or replace them as deemed necessary.

These devices on the system are not recorded in the IPL equipment maintenance database. It is the intent of ITC Midwest to inventory and add these devices to the ITC Midwest centralized maintenance management data base going forward.

b. Potential Devices and Arrestors: ITC Midwest Maintenance Plan

ITC Midwest will test potential devices on relay protection schemes over 100 kV once every ten years in conjunction with the mandatory NERC Reliability Standards program

10. Capacitor Banks

a. Capacitor Banks: Historic Maintenance

IPL verbally stated that they had no formal planned visual inspections of their substation capacitor banks. It is ITC Midwest's understanding that some field service areas would conduct visual inspections. If a visual inspection was done, it was limited to looking for blown fuses and leaking oil.

b. Capacitor Banks: ITC Midwest Maintenance Plan

ITC Midwest will initially implement an annual visual inspection for all capacitor banks including those out on the lines. ITC Midwest also plans on taking each capacitor bank off line and testing it every three years based on the experience of the other ITC subsidiaries. A visual only inspection cannot determine the electrical integrity of the capacitor bank; an electrical test is required.

V. TRANSMISSION SYSTEM: NEW FACILITIES NEEDS ASSESSMENT

As mentioned in Part II above, ITC Midwest annually performs transmission planning assessments that meet or exceed all NERC Planning Standard Requirements. These assessments identify transmission upgrades required to maintain transmission security and adequacy over a minimum one to ten year time frame. Examples of system conditions that drive the need for new facilities are: changing loading patterns on the transmission system, new load interconnections, infrastructure improvement and replacement, new generation, increased firm transmission usage, and changing market flows. Provided below are the significant drivers of the ITC Midwest transmission facility improvements that are currently identified.

A. Generator Interconnections

The ITC Midwest system is being heavily impacted by the number and cumulative capacity of requests for generator interconnections. Approximately 800 to 1000 MW of new generation will be connected to the ITC Midwest transmission system in 2008. Associated with this new generation are changing flow patterns which are impacting the performance of the transmission system.

A summary of generation interconnection projects on the ITC Midwest system in the MISO interconnection queue is as follows:

<u>80 projects in construction or under study</u>

- Iowa 46 projects
- Minnesota 31 projects
- Illinois 3 projects

<u>11,000 MW of new generation</u>

- Iowa 8,000 MW
- Minnesota 2,500 MW
- Illinois 500 MW

<u>Renewable Projects</u>

- Iowa 83%
- Minnesota 99%
- Illinois 78%

Requests for interconnection on the ITC Midwest transmission system are functionally processed by MISO. Requests for interconnection generally proceed through a series of significant milestones. The first phase begins with the planning studies to determine the impact of the proposed generation to the existing transmission system along with identifying upgrades to mitigate any resulting congestion. Second, detailed engineering and construction estimates of the upgrades, along with an Interconnection Agreement, are provided to the customer. The final phase is the execution of the Interconnection Agreement along with payments by the Interconnection Customer to begin the construction of facilities. The amount of time to progress through the MISO queue can be several years. At the end of the process, customers have the ability to "suspend" their project for up to three years.

ITC Midwest has been increasingly impacted by Interconnection Customers requesting interconnection before the identified transmission upgrades can be completed. In some cases, an Interconnection Customer serves notice that they are coming out of suspension but request a commercial operating date that is sooner than the time required to complete the necessary transmission upgrades to enable the new generation to have firm service for delivery to all loads within the MISO. In other cases, the Interconnection Customer desires commercial operation dates that are sooner than the time it takes to complete the MISO interconnection process. In addition, ITC Midwest has begun to see several areas of the system, most notably in southwest Minnesota and in central Iowa, where the amount of time needed to construct network upgrades is extended due to the need to upgrade several lines in a geographic region and the complexity of scheduling multiple transmission system outages simultaneously.

Due to the flows coming out of the number of new generator interconnections in southwest Minnesota, ITC Midwest has proposed to rebuild the Lakefield-Heron Lake 161 kV line in 2010 as part of the MISO Transmission Expansion Plan (MTEP). Based upon knowledge of congestion in southwest Minnesota, ITC Midwest has also proposed to MISO that the 161 kV line between Lakefield and Adams substations be rebuilt to a higher capacity of 345 kV. Because further generation interconnections are likely, ITC Midwest proposes that this construction allow for the addition of a second 345 kV circuit on this transmission path. Recent MISO generator interconnection studies indicate a lack of transmission capacity in southwest Minnesota. More recently, MISO studies have indicated that in spite of the addition of a 345 kV line from Lakefield to Adams, the resulting transmission system will be insufficient to accommodate the amount of future generation requesting interconnection in southwest Minnesota. ITC Midwest will continue to work with MISO to identify appropriate upgrades to mitigate the existing congestion in southwest Minnesota and to properly plan for the volume of generation requesting interconnection in southwest Minnesota and Northwest Iowa.

B. Narrow Constrained Area

ITC Midwest owns a majority of the transmission facilities that comprise the Southeastern Minnesota/Northern Iowa/Southwestern Wisconsin Narrow Constrained Area ("NCA"). ITC Midwest additionally owns a few of the transmission facilities that comprise the WUMS NCA. An NCA is an electric area within which one or more suppliers are expected to be pivotal (i.e. have potential for market control) for at least five hundred (500) hours per year due to transmission system constraints ("Binding Transmission Constraints"). NCA's are identified by the MISO Independent Market Monitor (IMM) to ensure that these suppliers with market power within the NCA cannot raise prices substantially above competitive levels and therefore distort the normal market process within the MISO system.

C. NCA Monitored Facilities

To address the transmission constraints that define these NCAs and as part of ITC Midwest's acquisition of transmission assets from IPL, ITC Midwest agreed on two projects which will significantly reduce congestion in eastern Iowa. The first project is a rebuild of Arnold-Vinton-Dysart-Washburn 161 kV line to higher capacity by the end of 2009. The second project is construction of the Salem-Hazleton 345 kV line to be completed by the end of 2011.

D. 34.5 to 69 kV "Rebuild Initiative"

There are approximately 2,270 miles of lines operated at 34.5 kV on the ITC Midwest system. Approximately 943 miles of the 34.5 kV system is currently built to 69 kV specifications, leaving approximately 1327 miles of line that is both operated at and constructed to 34.5 kV specifications. The lines that are both constructed and operated at 34.5 kV are typically characterized as older lines constructed in the mid 1950's, without a shield wire protection for lightning. Increased loading on the aged 34.5 kV system has resulted in operating difficulty during efforts to meet voltage and loading requirements while the system is experiencing abnormal events known as "contingencies" and at times during system normal conditions. Rebuilding of the 34.5 kV system to 69 kV standards will remove the aged infrastructure condition issues, add shield wire for improved lightning performance, replace conductor with anti-galloping conductor, and allow for conversion to 69 kV operation. Operation at 69 kV will decrease voltage drop, providing better voltage during both contingency and normal operation and reduce system losses.

The new 69 kV system will allow network operation of these lines to further enhance system reliability while also increasing ITC Midwest's ability to provide timely system restoration to communities during outages. ITC Midwest will lay out plans and begin conversion of this 34.5 kV system to a networked 69 kV system and it expects that an overall rebuild and conversion plan can be developed within two years. ITC Midwest additionally expects that such a plan will result in the elimination of several hundred miles of existing 34.5 kV. Conversion plans will be closely coordinated with interconnected transmission and load serving entities. The 34.5 kV rebuild initiative was a commitment to the Iowa Utilities Board during the regulatory proceeding that approved this transaction and was projected to be completed in five to seven years.

VI. Conclusion

ITC Midwest is committed to being a responsible transmission system owner and operator, and dutifully maintaining a reliable and capable transmission system. In this report, ITC Midwest provides a current assessment of its transmission system, following its first 12 months of owning those assets, and a report on practices ITC Midwest intends to employ to remedy apparent weaknesses in the system. As explained above, ITC Midwest's assessment is that its transmission system is an aged system that requires acute attention to proper maintenance, and completion of other system upgrades and capital investments. As an independent transmission company solely focused on transmission, ITC Midwest is dedicating to employing the measures outlines in this report to improve reliability and system performance, reduce outages, relieve congestion, interconnect additional generation resources, and generally improve the transmission system for the good of customers.

CERTIFICATE OF SERVICE

I hereby certify that, in accordance with the rules of the Iowa Utilities Board, I have this day served the foregoing document on the persons and parties identified in the attached service list.

Dated in Des Moines, Iowa, on December 8, 2008.

Philip E. Stoffregen

Philip E. Stoffregen

INTERSTATE POWER AND LIGHT COMPANY AND
ITC MIDWEST LLC

Docket No. SPU-07-11

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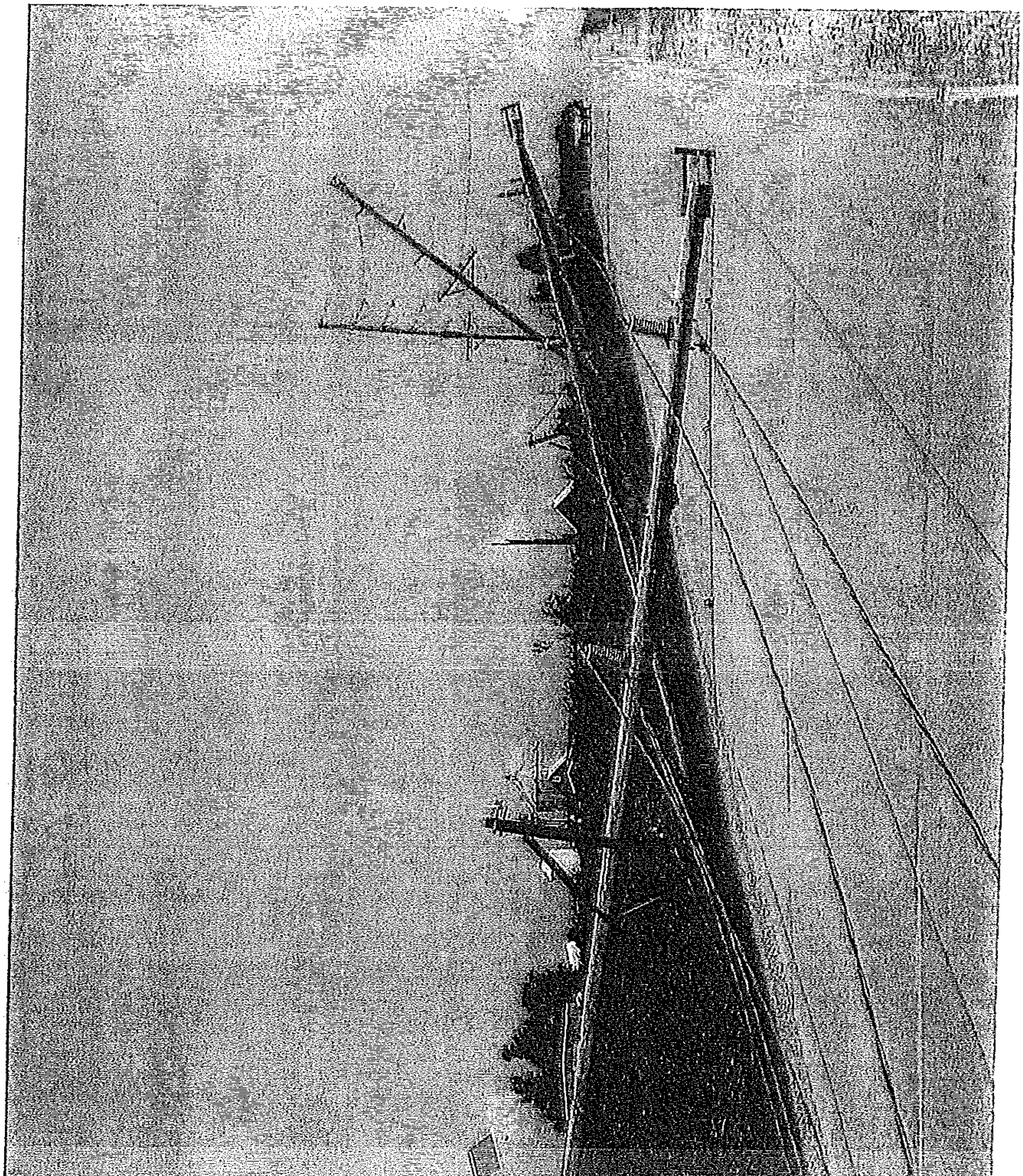
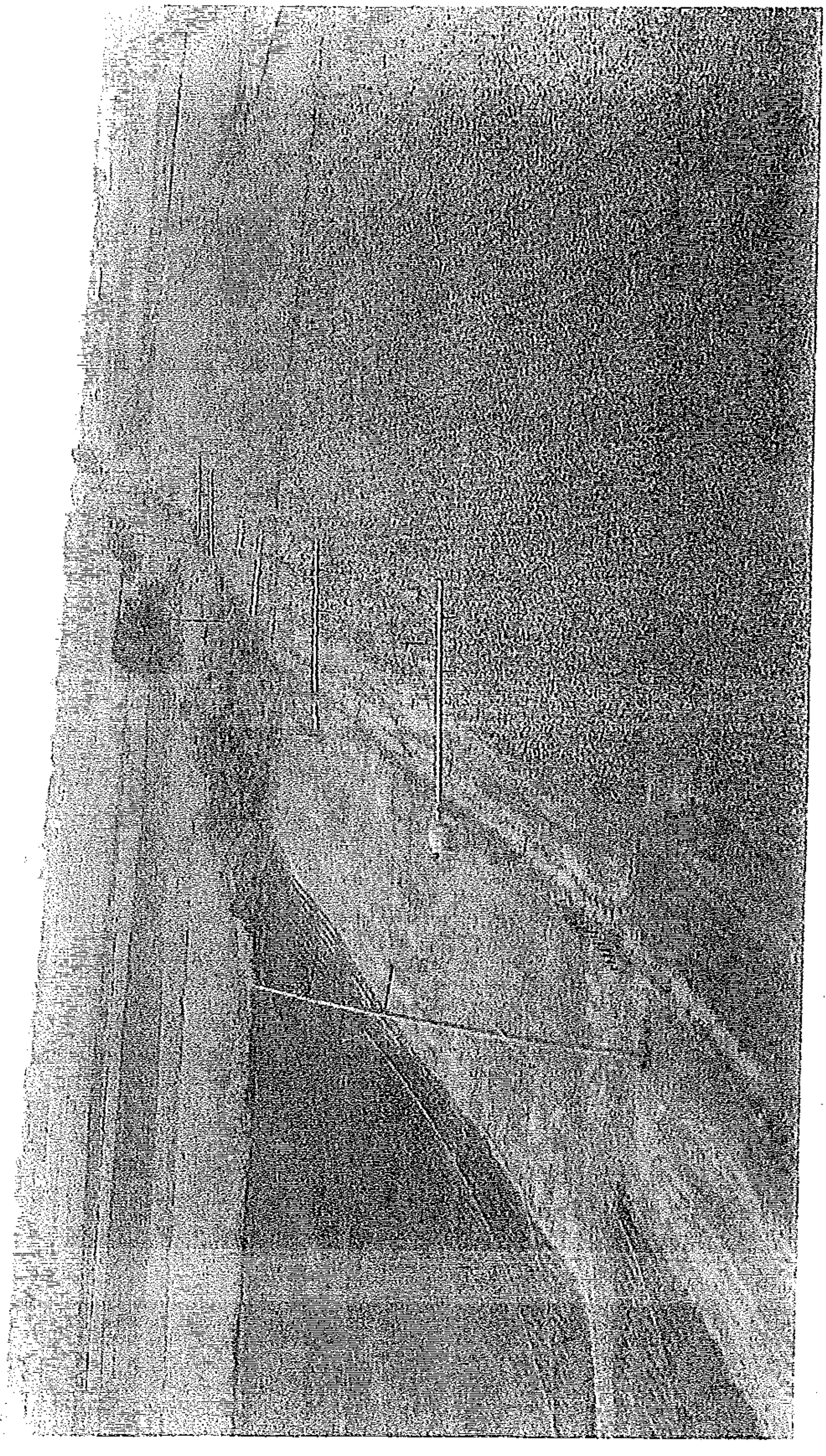
BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION

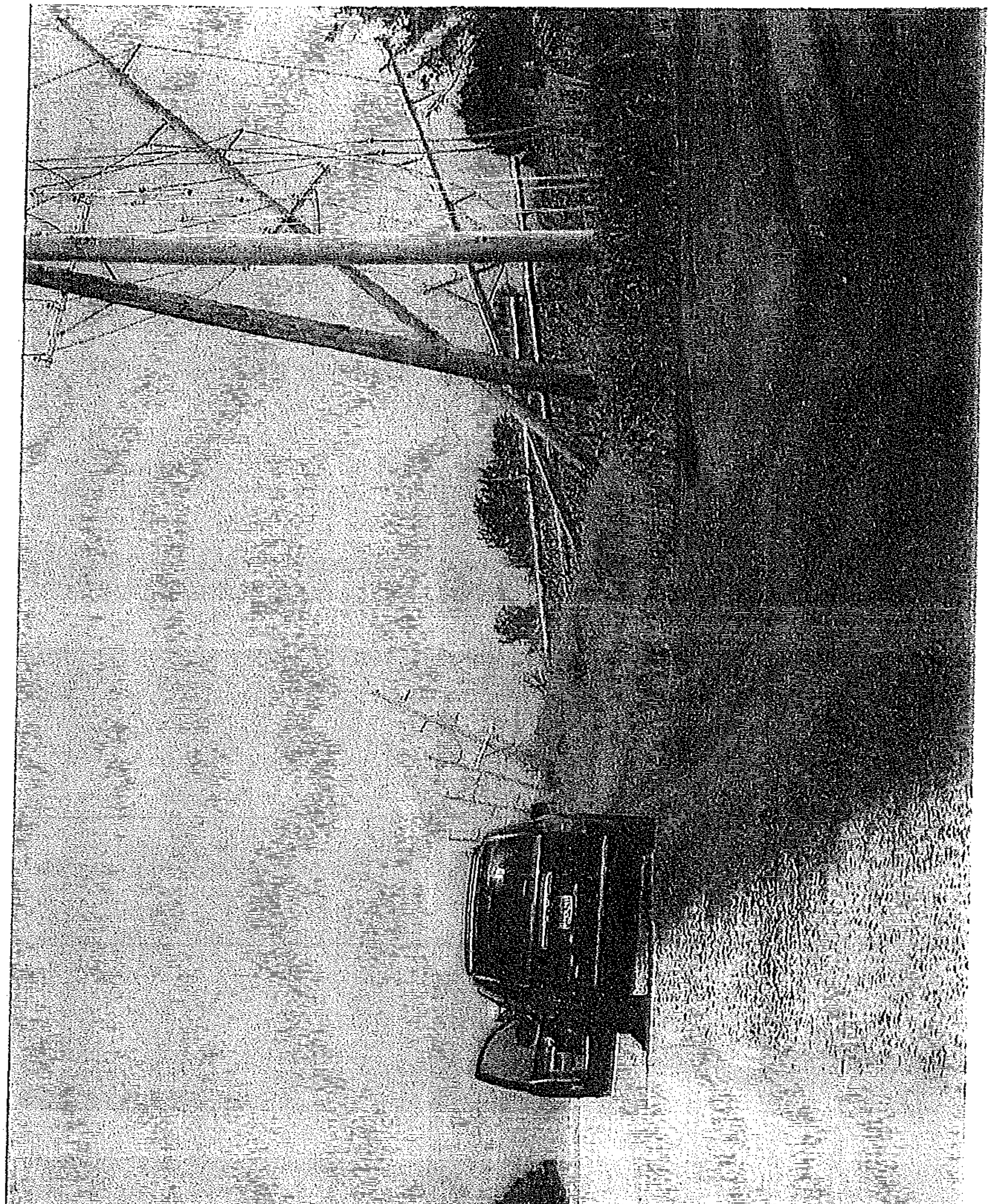
In the Matter of the Joint Application of Entergy Arkansas, Inc., Mid South TransCo LLC, Transmission Company Arkansas, LLC and ITC Midsouth LLC for Approval of Transfer of Assets and Certificate of Convenience and Necessity, and Merger and, in connection therewith, Certain Other Related Transactions	))))))))	File No. EO-2013-0396

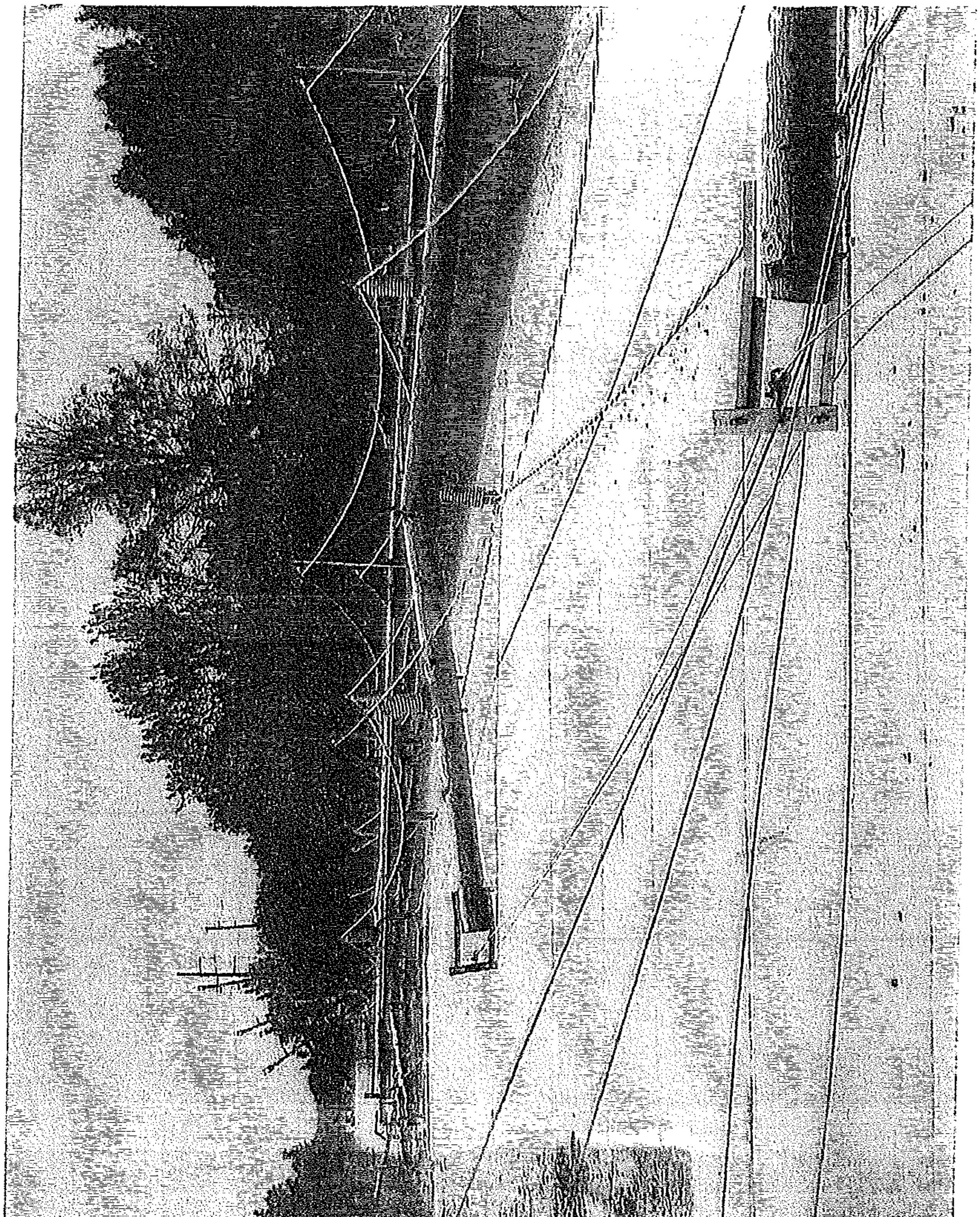
EXHIBIT DCC-2

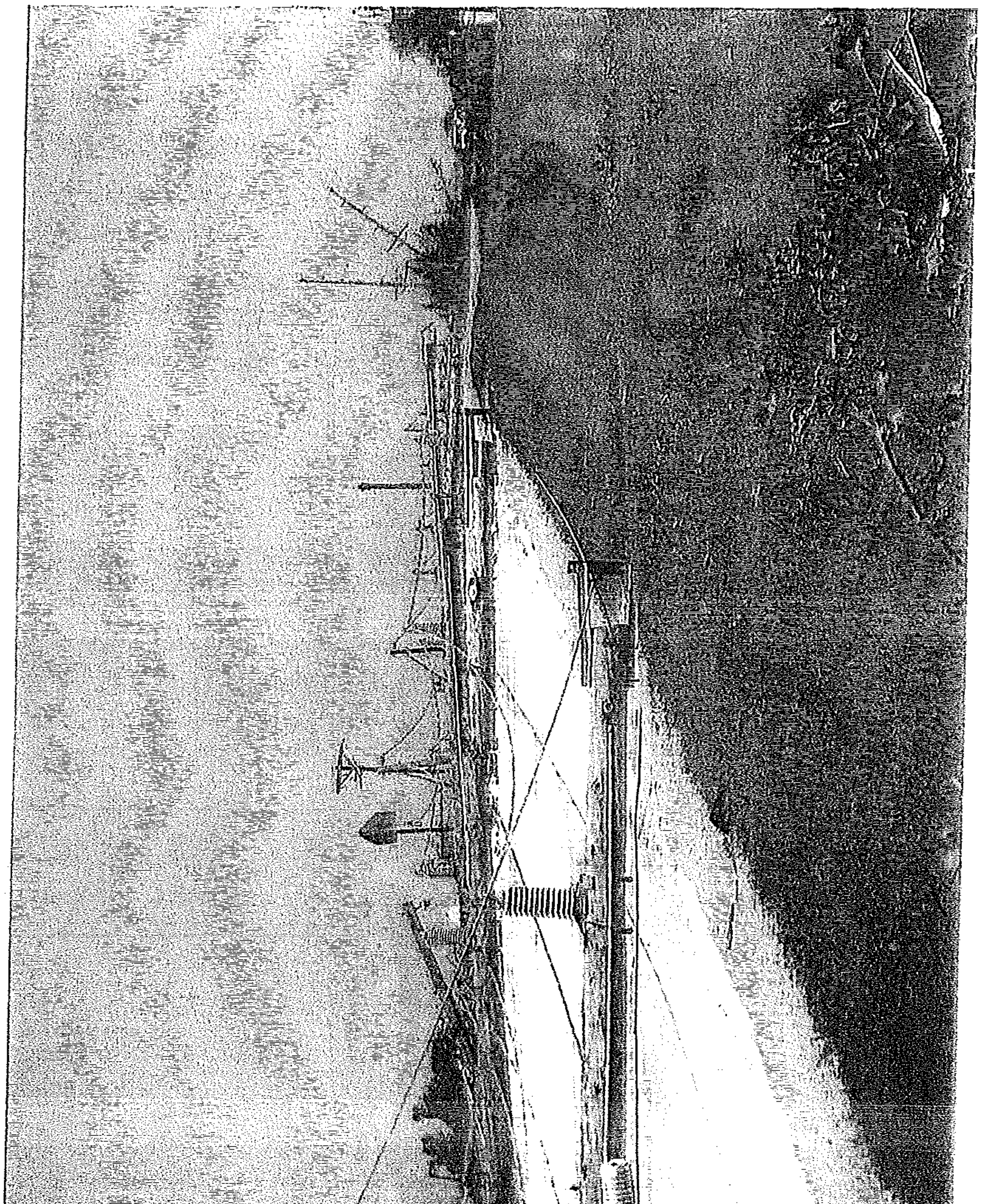
STRAIGHT-LINE WIND STORM

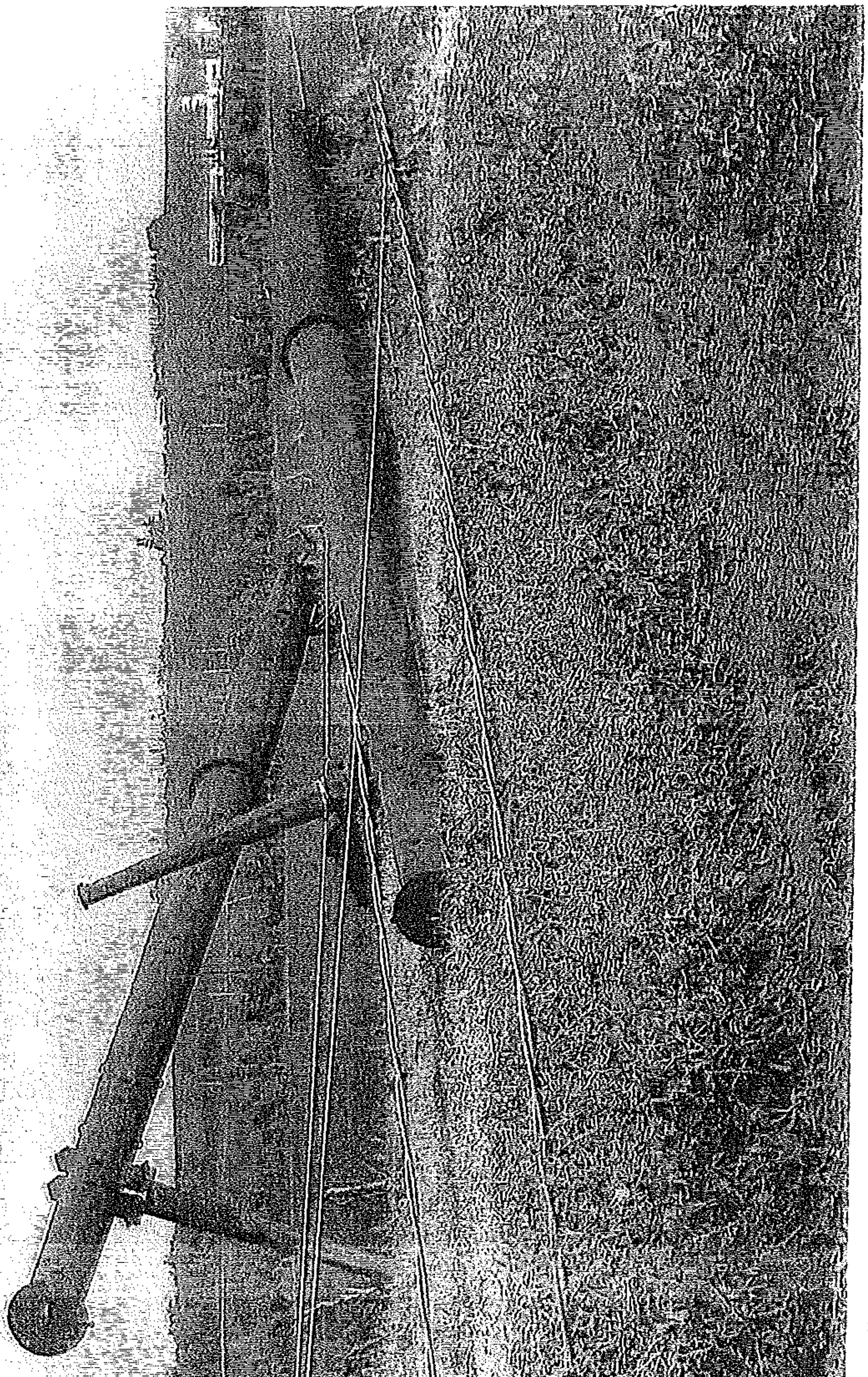


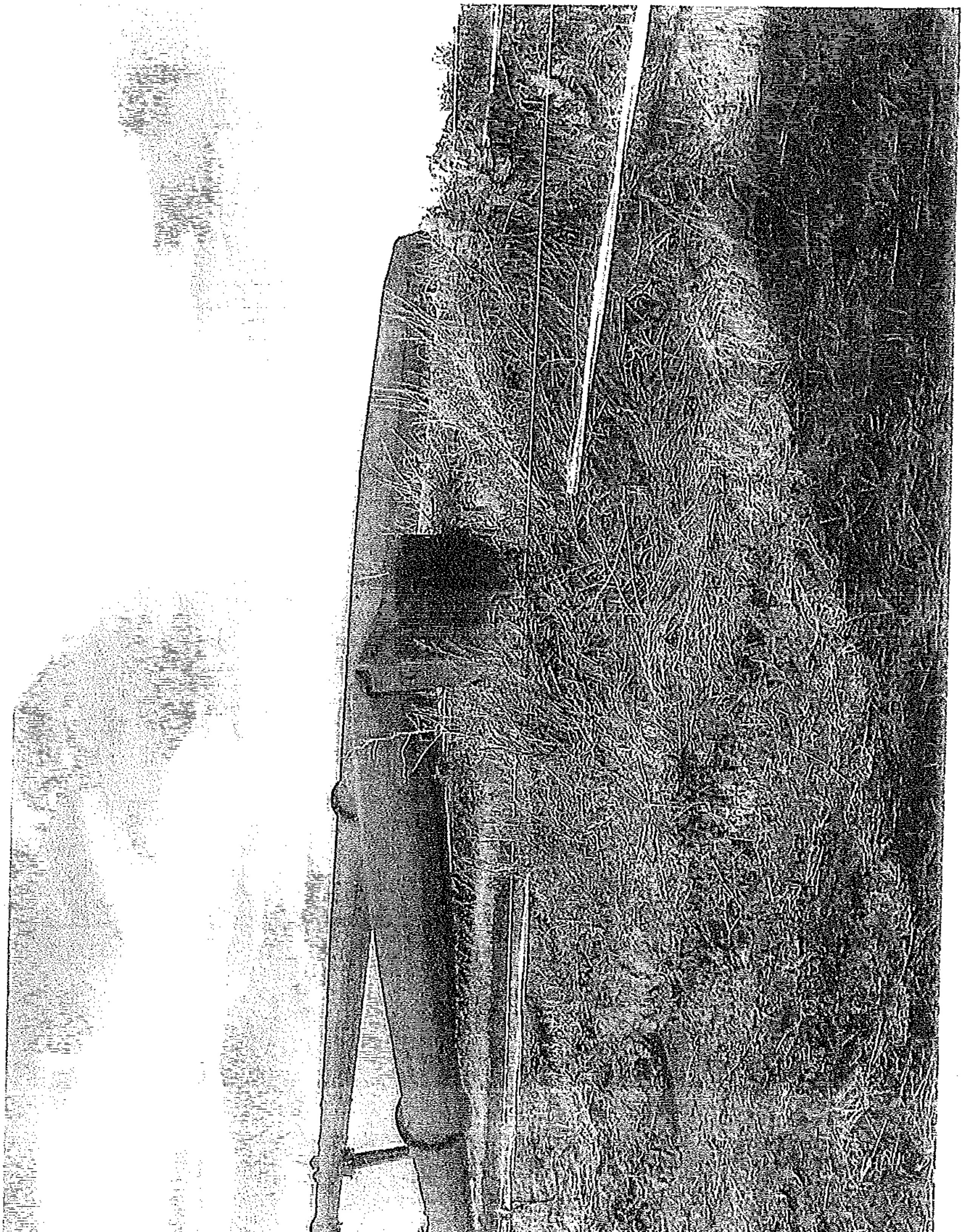


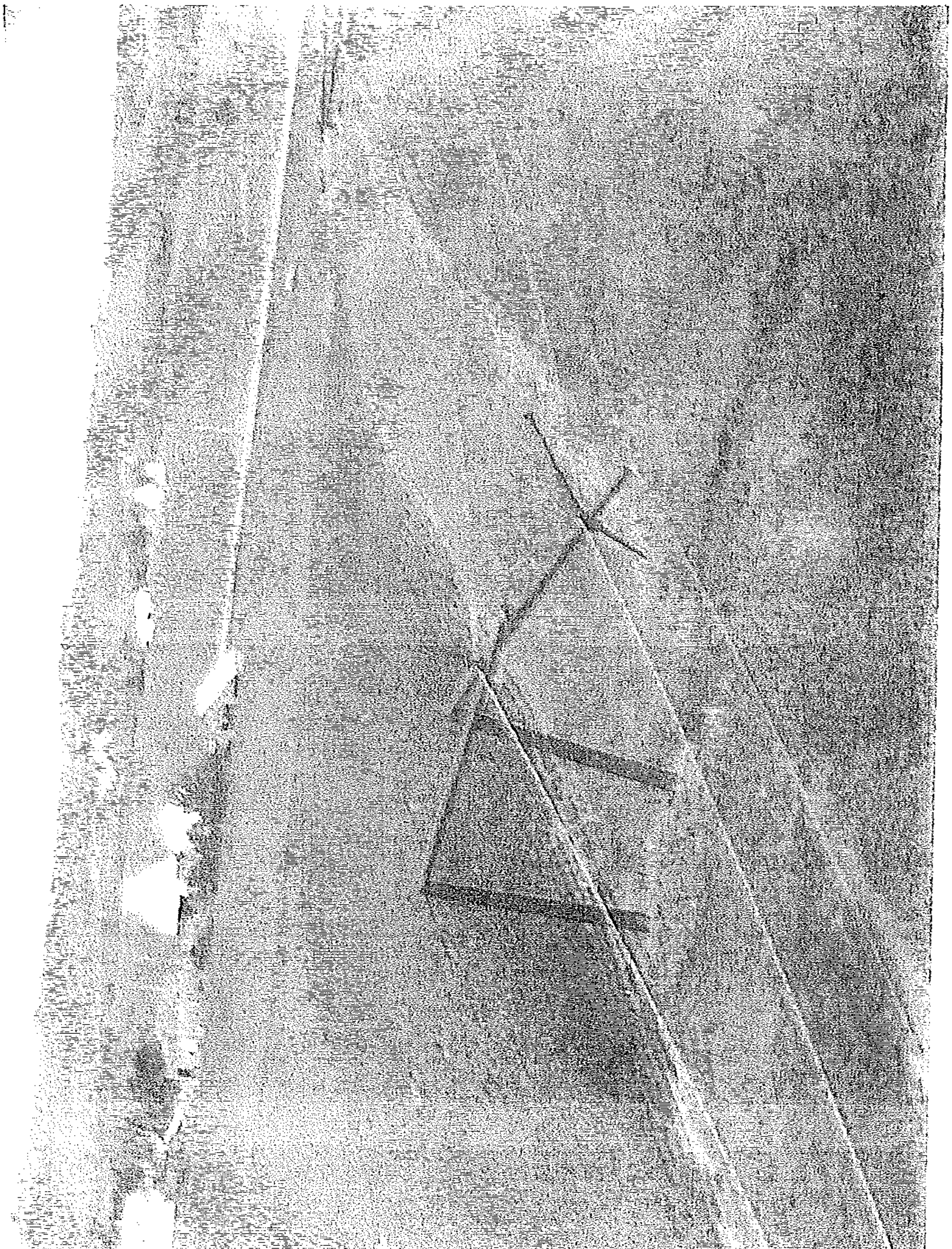


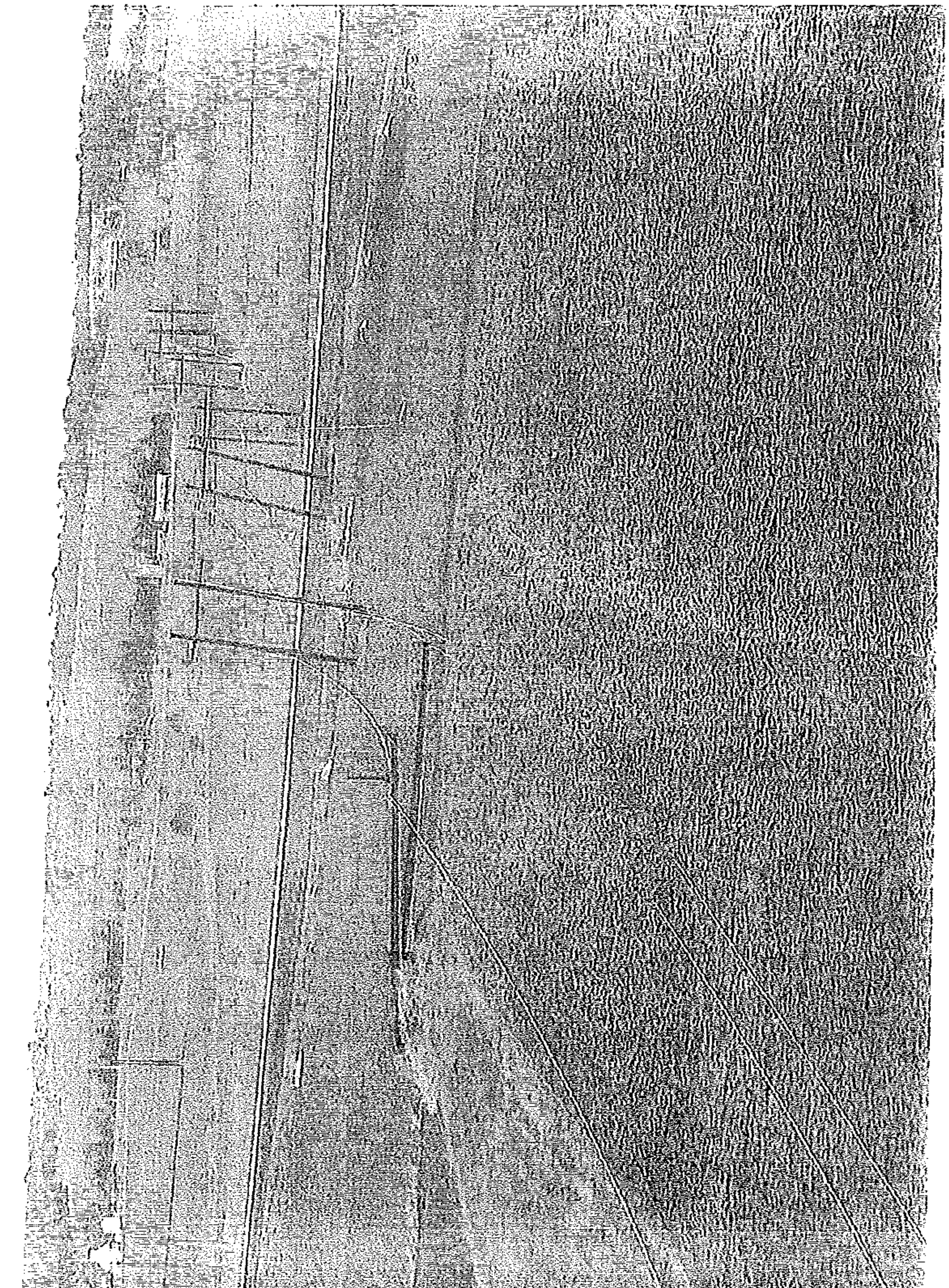


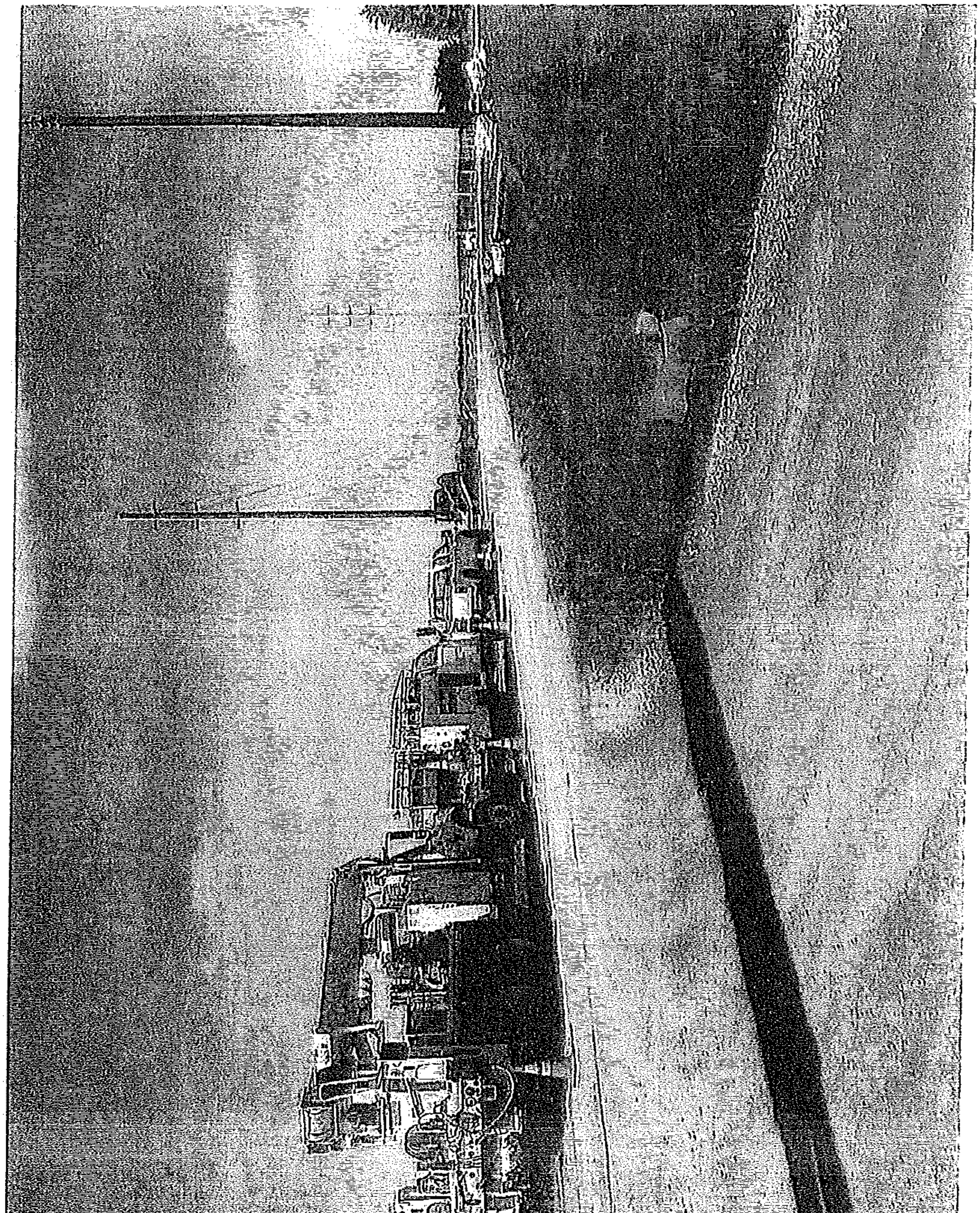


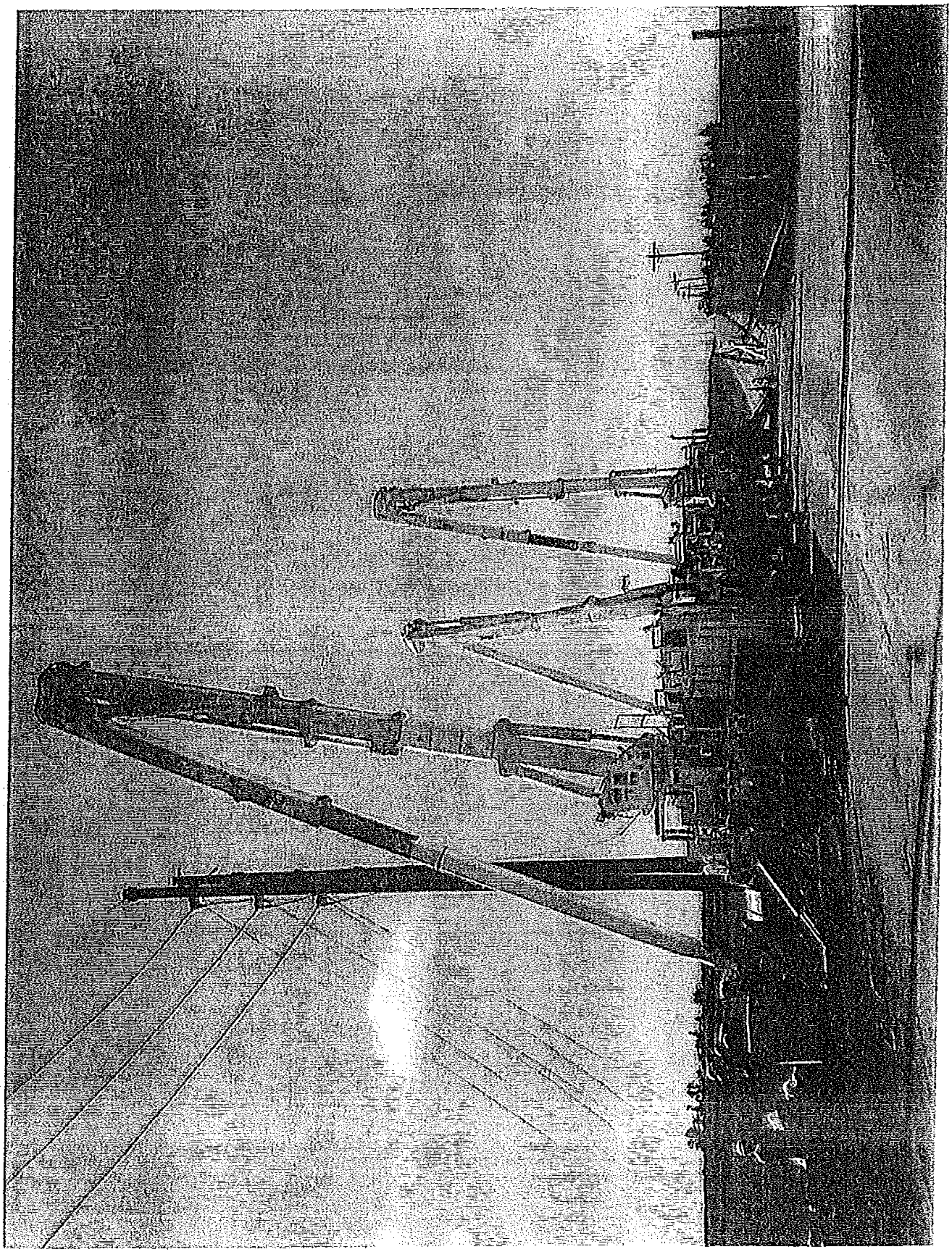


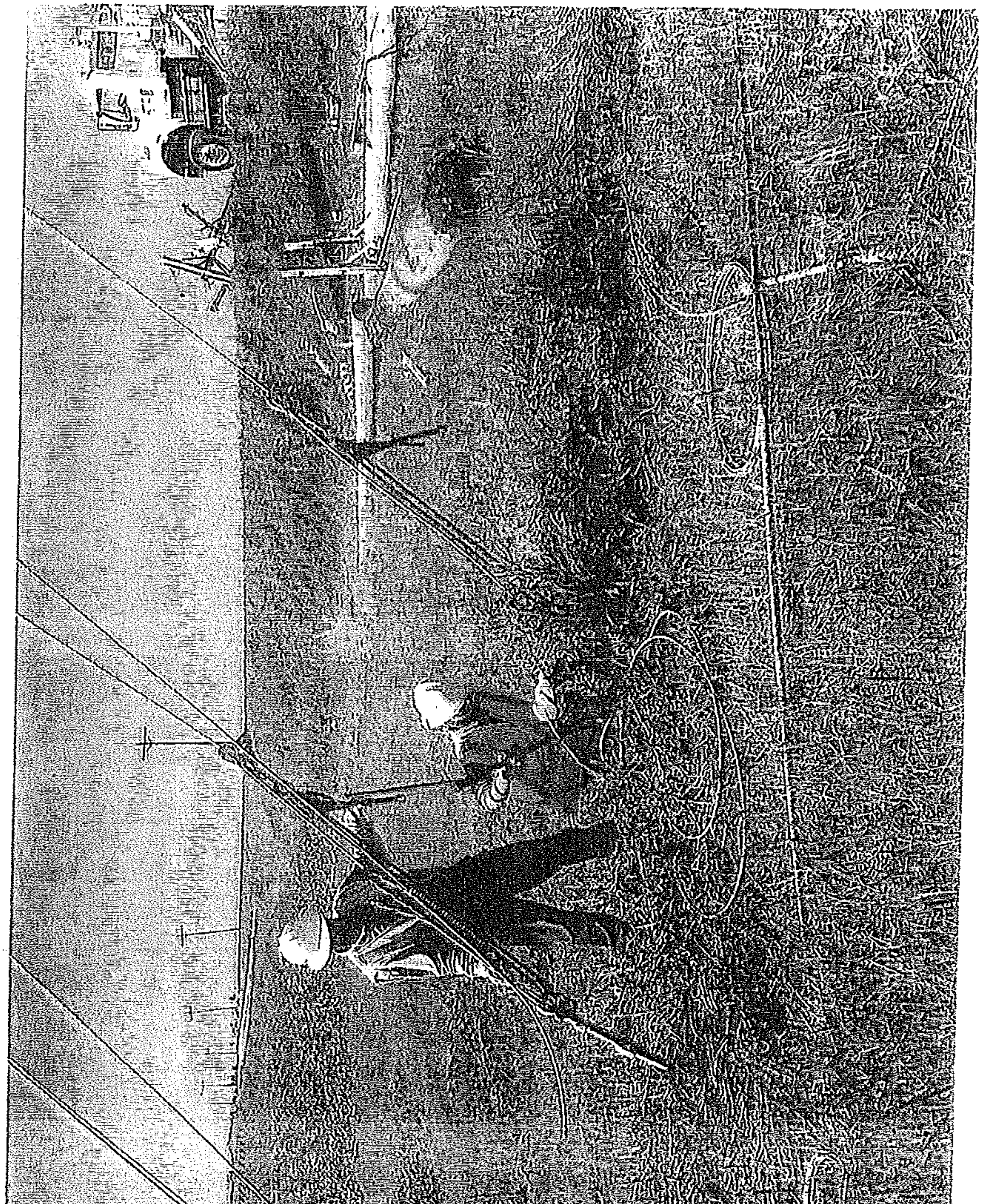


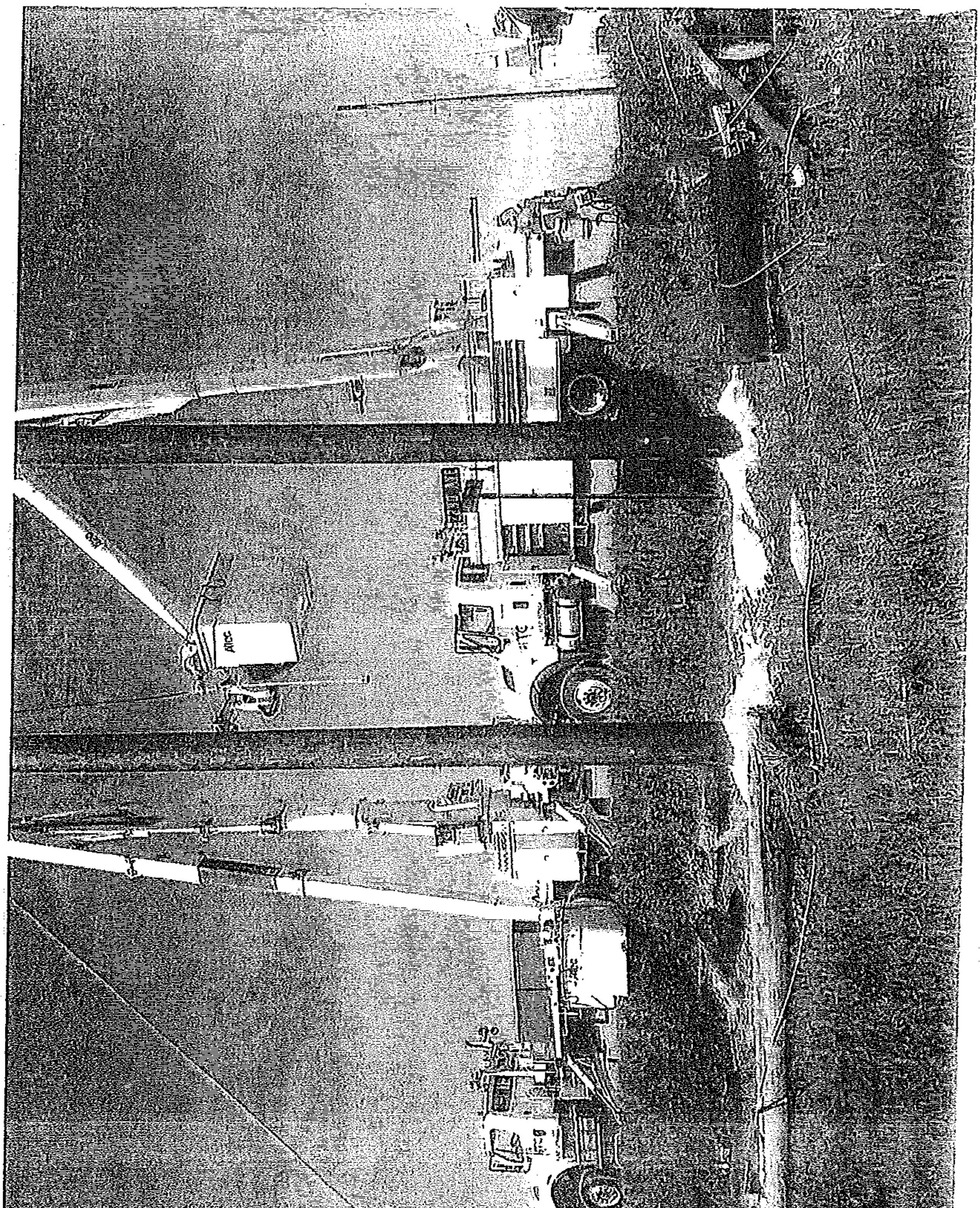











Altec

BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION

In the Matter of the Joint Application of Entergy Arkansas, Inc., Mid South TransCo LLC, Transmission Company Arkansas, LLC and ITC Midsouth LLC for Approval of Transfer of Assets and Certificate of Convenience and Necessity, and Merger and, in connection therewith, Certain Other Related Transactions	))))))))	File No. EO-2013-0396

EXHIBIT DCC-3

EASTERN IOWA STUDY

Exhibit DCC-3

Midwest ISO (2006-09) Eastern Iowa Transmission Reliability Study

("Eastern Iowa Study")

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Midwest ISO (2006-09)

Planning Technical Report

Eastern Iowa Transmission Reliability Study

Midwest Independent Transmission System Operator, Inc.
701 City Center Drive Carmel, IN 46032   1125 Energy Park Drive St. Paul, MN 55108
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Keywords

Eastern Iowa
Reliability
AC Contingency Analysis
Transfer Analysis
Market Wide Analysis
Voltage Analysis
Stability Analysis
System Impact

MISO

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Executive Summary

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TABLES

FIGURES

1. Introduction

1.1 Background

The transmission system of eastern Iowa is comprised mainly of 161, and 69 kV facilities, but in addition there are facilities rated 345, 115, and 34.5 kV.

Beginning in the latter part of the 1990's with the advent of the open access energy market, the eastern Iowa transmission system began to realize additional stress as regional power flow patterns have increased from the south and southeast directions to the north and northwest.

On September 9, 2003, Alliant wrote to North American Electric Reliability Council (NERC) and the Midwest ISO (MISO) about Alliant's concerns regarding "the transmission reservation coordinating process used by various transmission service providers and the resultant equity impacts of the lack of coordination when transmission congestion develops. Alliant noted that it 'has borne the operational consequences and the significant costs of TLR's,' resulting from this less than desirable level of coordination between entities selling transmission service because the transmission system is over subscribed" [1].

In November 2003, the Alliant West TLR Task Force (AWTTF) was created by NERC to develop specific recommendations for market and operating practices to address problems associated with Transmission Loading Relief (TLR) curtailments in the Alliant West region expected in summer 2004. The AWTTF final report was released in March, 2004. In that report, both short term and long term recommendations were included. One of long term recommendations for planning is "MISO, working with other transmission providers, shall lead an investigation to determine what aspects of the various transmission service request processes caused overselling of AFC for summer 2004 for the Alliant West flowgates and make recommendation to the appropriate authorities to prevent overselling from happening in future years" [1].

This Eastern Iowa Transmission Reliability Study is to address the above mentioned NERC long term planning recommendation. The study is desired to:

1. Identify bulk transmission (100 kV and above) needs to support the sub-transmission system, with respect to load serving;
2. Identify reliability concerns on the bulk transmission system due to the impacts of power transfers; Address key operational issues in the region that have been seen over the last few years.

There are two objectives in this study:
1. With thorough and comprehensive analysis, gain an understanding of the interactions of the eastern Iowa transmission system with respect to varying load and market levels and their impacts on reliability for the near term and long term planning horizons;
2. Develop a responsible, comprehensive and cost effective transmission plan for eastern Iowa system that will address all needs of the transmission system to accommodate both the near term and long term horizons.

1.2 Study Region

The geographic region of eastern Iowa system for load serving purpose will include the transmission system east of Cedar Rapids, north of Davenport, the Alliant West (ALTW) system in Illinois and Hazleton to the north (Figure 1, blue circle). Flowgates and the bulk transmission system outside of, but having influence on this region, will be considered for the power transfer portion of the study (Figure 1, green circle).

The one-line power flow diagram of eastern Iowa system (2011 summer peak base case) is shown in Figure 2.

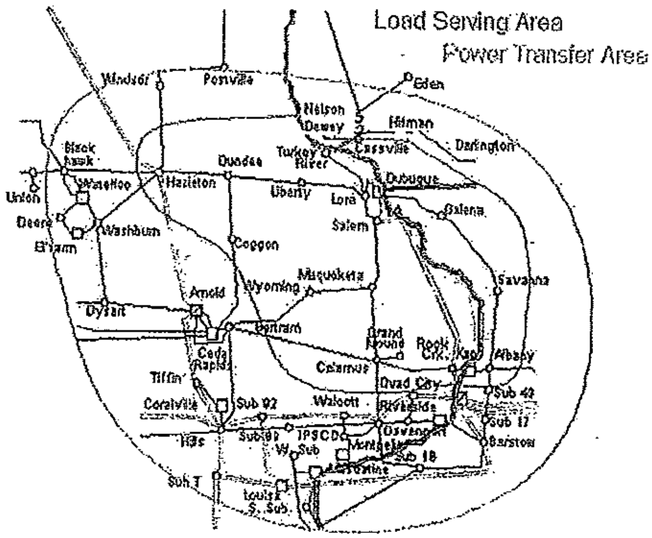

Figure 1: Geographic Region of Eastern Iowa System

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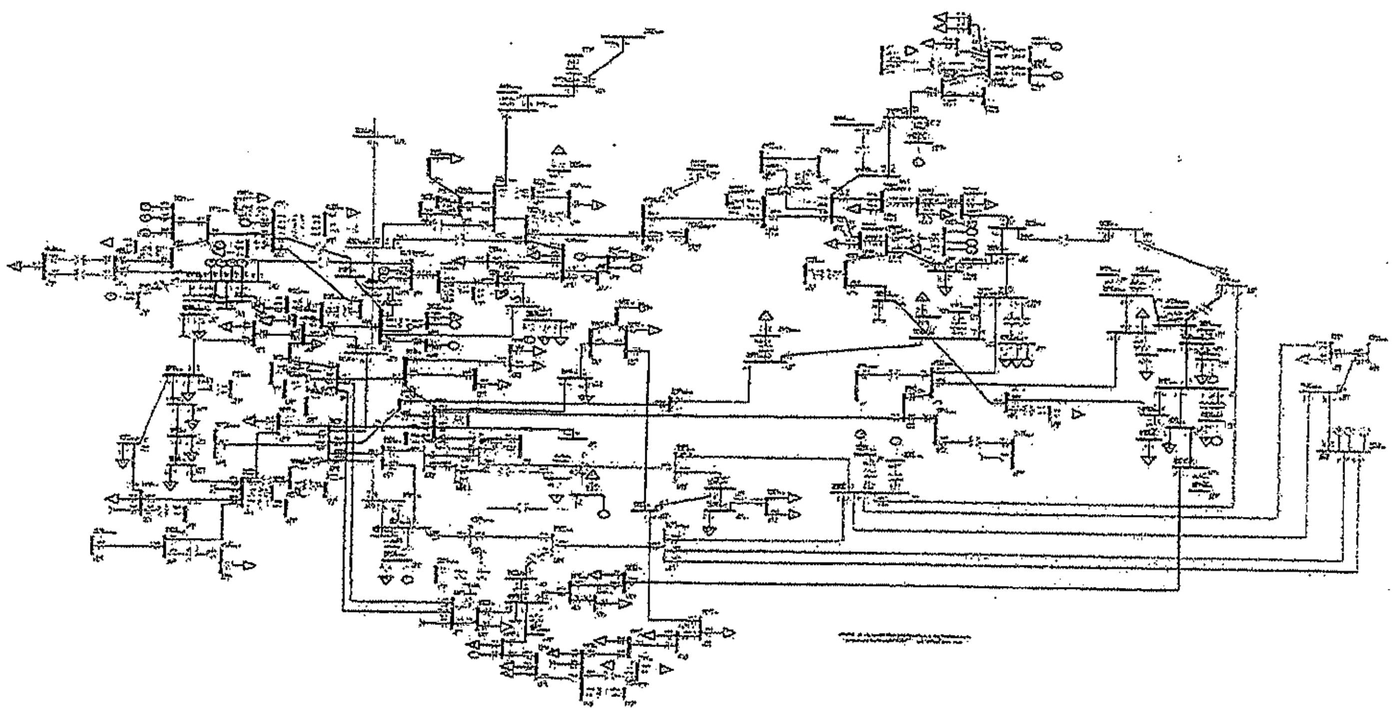

Figure 2: One-Line Diagram of Eastern Iowa 2011 Summer Peak Power Flow

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1.3 Historical Flow Pattern in Eastern Iowa

Historically after later 1990's with open access energy market, south-north and east-west flow patterns are often seen in the eastern Iowa region, especially during winter peak and summer peak periods.

Figure 3 is the historical hourly flow pattern on the Arnold - Hazleton 345 kV line during November 2005 and July 2006. A few items to note are:

1. The dominant flow pattern on Arnold – Hazleton 345 kV line is from south to north, i.e., from Arnold to Hazleton;

2. During this period, the maximum S-N flow on Arnold - Hazleton 345 kV line is 646.9 MW at 17:22 on December 17, 2005;

3. Below is a table for hourly occurrence of Arnold - Hazleton flow above 500 MW. It is known that high level flow on Arnold - Hazleton 345 kV line is usually seen during winter peak periods(December to March) and summer peak periods (June to August).

Month	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	July 1-9, 2006
Occurrence	26	9	32	24	1	6	20	2

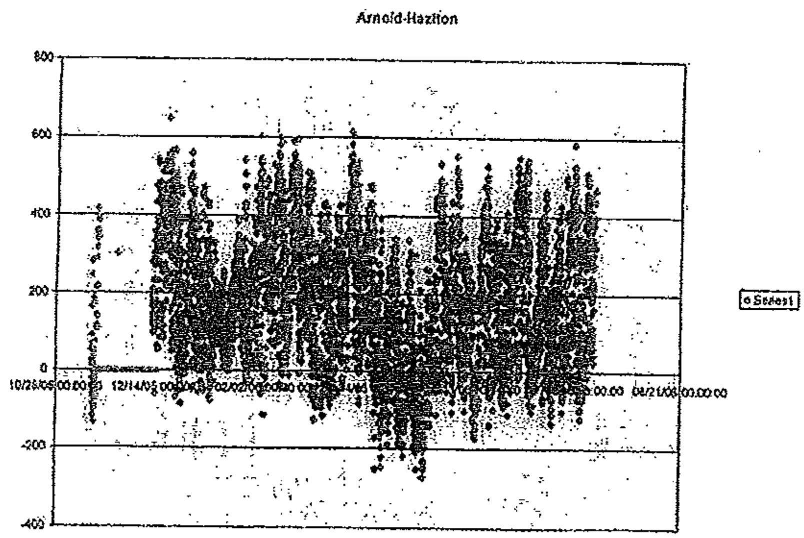

Figure 3: Historical Hourly Flow on Arnold – Hazleton 345 kV Line

Figure 4 is a historical 10-minute flow pattern on Montezuma - Bondurant 345 kV line during June 2005 and August 13, 2006. A few notes are:

1. The dominant flow pattern on the Montezuma – Bondurant 345 kV line is from east to west, i.e., from Montezuma to Bondurant;

2. The maximum flow on the Montezuma - Bondurant 345 kV line is 670.2 MW at 7:10 on December 5, 2005 during June 2005 and December 2005. During January 2006 and August 13, 2006, the maximum flow on this line is 605.8 MW at 18:30 on February 17, 2006.

3. Below is a table for 10-minute occurrence of Montezuma – Bondurant E-W flow above 500 MW. It is noticed that high level E-W flow on Montezuma – Bondurant 345 kV line is usually seen during winter peak periods (November to February) and summer peak periods (June to August).

Month	Jun 2005	Jul 2005	Aug 2005	Sep 2005	Oct 2005	Nov 2005	Dec 2005	Jan 2006	Feb 2006	Mar 2006	Apr 2006	May 2006	Jun 2006	Jul 2006	8/1/06 - 8/13/06
Occurrence	116	61	5	22	12	20	454	17	90	0	9	0	114	62	74

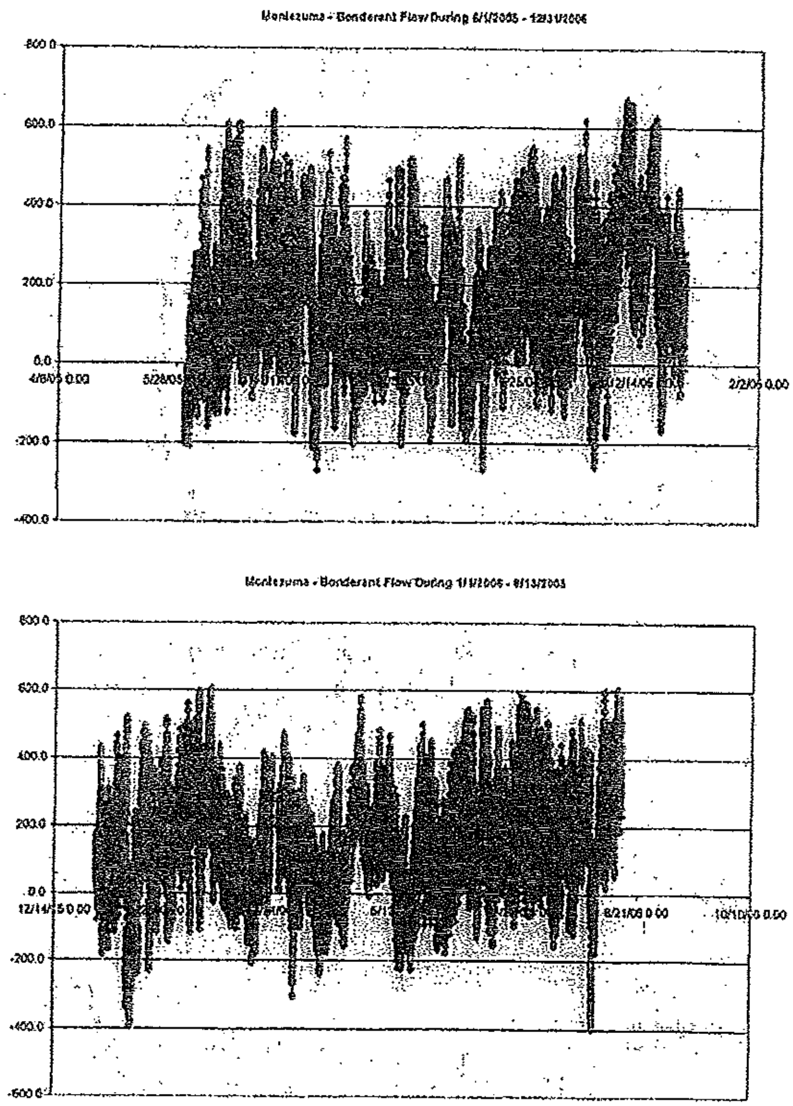

Figure 4: Historical 10-Minute Flow on Montezuma – Bondurant 345 kV Line between June 2005 and August 13, 2006

2. Models, Input Files, and Criteria

2.1 Models

Eastern Iowa transmission reliability study is performed for the years of 2011 and 2015. In each year, three scenarios are developed:

1. Summer peak scenario;
2. Heavy transfer flow from south to north, with benchmark flow on the Arnold to Hazleton 345 kV line at the 600 MW level;
3. Heavy transfer flow from east to west, with benchmark flow on the Montezuma to Bondurant 345 kV line at the 450 MW level.

2011 summer peak model (base model) is based on the MTEP06 phase-2 model. The baseline reliability projects with reliability needs verified by MISO are included. Regional beneficial projects are not included nor are projects not verified by MISO to be based upon reliability needs of the system. Some additional updates are made:

1. Some rating corrections on 69 kV lines;
2. Add a second Galena 161/69 kV transformer in DPC;
3. Change Amana T – Amana 69 kV line to normal open;
4. Add and dispatch each 15 MW generator at 69 kV buses ADM100 (34330) and ADM (34333);
5. Add a 8.2 Mvar switched shunt at bus Wauknip8 (34418);
6. Change Burr TP – Locust 69 kV line to normal close;

The 2011 heavy south to north transfer model (S-N transfer model) is developed from the 2011 base model with some generators in Ameren (AMRN), Northern Illinois (NI) turned on and redispatched. The participation factors for these generators being redispatched are based upon their Pmax, their high distribution factors on the Arnold to Hazleton 345 kV line, and their available capacity (Pgen < Pmax or offline) for redispatch. Table A.1 in Appendix A lists all these generators and their sensitivities and impact on Arnold-Hazleton line. To keep the power balance, generation in Xcel Energy (XEL), Minnesota Power & Light (MP), and Otter Tail Power (OTP) is uniformly scaled down roughly at the ratio of 4:1:1. Table 1 lists the changes of generation and Net Scheduled Interchange (NSI) in these areas.

The 2011 heavy east to west transfer model (E-W transfer model) is developed from the 2011 base model with some generators in NI turned on and redispatched in a method consistent with that used for the S-N transfer model (as described above). Table A.2 in Appendix A lists all of these generators and their sensitivities and impact on Montezuma-Bondurant line. To keep the power balance, generation in Western Area Power Administration (WAPA), Nebraska Public Power District (NPPD), and Omaha Public Power District (OPPD) are uniformly scaled down roughly at the ratio of 1:1:1. Table 2 lists the changes of generation and Not Scheduled Interchange (NSI) in these areas.

Area	Base Case		S-N Transfer Case		Generation Change
	Generation (MW)	NSI (MW)	Generation (MW)	NSI (MW)	
AMRN	13087.8	-684	14275.5	503.7	1187.7
IP	5202.1	654	5202.1	654.0	0.0
CILC	1223.6	-7	1223.5	-7.0	0.0
NI	26430.2	877	27122.3	1569.1	692.1
XEL	8611.8	-2535	7358.6	-3788.2	-1253.2
MP	1888.7	88	1575.4	-225.3	-313.3
OTP	2025.8	-26	1712.6	-339.3	-313.3

Table 1: Comparison between Base Case and S-N Transfer Case

Area	Base Case		E-W Transfer Case		Generation Change
	Generation (MW)	NSI (MW)	Generation (MW)	NSI (MW)	
NI	26430.2	877	28346.8	2793.6	1916.6
WAPA	4632.1	1246	2325.9	607.1	-638.9
NPPD	2964.8	-415	1996.5	-1053.9	-638.9
OPPD	2635.4	-97	3993.2	-735.9	-638.9

Table 2: Comparison between Base Case and E-W Transfer Case

The 2015 summer peak model (2015 base model) is developed from 2011 summer peak model (2011 base model) with ALTW load scaled up by 10%. Since the ALTW 2011 summer peak control area load level is assumed at 4682 MW, the ALTW control area 2015 summer peak load level is set at

5150 MW level. The ALTW power mismatch due to load increasing in 2015 is picked up by turning on and fully dispatching the following generators in ALTW control area as shown in Table 3. These generators were sufficiently remote from the study area so as not to affect the study's conclusions:

Bus Name	Gen_ID	MW
M-TOWN 6	34068_4	125
DENMARK6	34180_1	125
HANCWIND	34548_1	100
FOXLK53G	34011_3	96

Table 3: Generation Redispatch in 2015

The 2015 model with heavy transfers from south to north (S-N transfer model) is developed from the 2015 base model using a methodology consistent with that used to develop the 2011 south to north transfer model. The flow on the Arnold to Hazleton 345 kV line is benchmarked at 600 MW's.

The 2015 model with heavy transfers from east to west (E-W transfer model) is developed from the 2015 base model using a methodology consistent with that used to develop the 2011 east to west transfer model. The flow on the Montezuma to Bondurant 345 kV line is benchmarked at 450 MW's.

The flows of some key branches in 2011 and 2015 base models are shown in Table 4.

Base Model	Montezuma-Bondurant (MW)	Arnold-Hazleton (MW)	Salem 345/161 Xfmr (MW)
2011	64.9	276.1	261.2
2015	40.5	253.5	273.5

Table 4: Branch Flows in 2011 and 2015 Base Models

2.2 Input Files

All 100 kV and above branches in the eastern Iowa system are monitored for thermal and voltage violations. Some sub-transmission and distribution systems are also monitored. The eastern Iowa subsystem is defined in Appendix B.1. Flowgates and bulk transmission facilities outside of, but having influence on the eastern Iowa system are also monitored for the power transfer portion of the study. The total number of flowgates is 28 and they are listed in Table 5.

The specifically specified category B and C contingencies are described in Appendix B.2 and B.3.

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NERC ID	TYPE	Book of Flowgates Name	Winter TRM	Winter CBM	Winter Rating	Summer TRM	Summer CBM	Summer Rating	Control Area	Monitored Element	Contingent Element
3712	OTDF	Dundee 161-115 for Arnold-Hazleton 345kV	1.5	0	75	1.5	0	75	ALTW	DUNDEE 5 161 DUNDEE 7 115 1	HAZLTON3 345 ARNOLD 3 345 1
3724	OTDF	Arnold-Vinton 161 for D.Arnold-Hazleton 345	21.2	0	335	20.02	0	276	ALTW	ARNOLD 5 161 VINTON 5 161 1	ARNOLD 3 345 HAZLTON3 345 1
3705	OTDF	Arnold-Hazelton 345 for Wemp-Paddock 345	14.34	0	717	14.34	0	717	ALTW	ARNOLD 3 345 HAZLTON3 345 1	WEMPL; B 345 PAD 345 345 1
3705b	OTDF	Arnold-Hazelton 345 for Wemp-Rockdale 345	14.34	0	717	14.34	0	717	ALTW	ARNOLD 3 345 HAZLTON3 345 1	WEMPL; B 345 PAD 345 345 1
3728	OTDF	Dysart-Washburn 161 for D.Arnold-Hazleton 345	28.38	0	334	27.22	0	276	ALTW	DYSART 5 161 WASHBRN5 161 1	ARNOLD 3 345 HAZLTON3 345 1
3744	OTDF	Vinton-Dysart 161 flo Arnold-Hazelton 345	21.2	0	335	20.02	0	276	ALTW	VINTON 5 161 DYSART 5 161 1	ARNOLD 3 345 HAZLTON3 345 1
3738	OTDF	8th St.-Kerper 161 flo Wempletown-Paddock 345	4.46	0	223	4	0	200	ALTW	8TH ST.5 161 KERPER 5 161 1	WEMPL; B 345 PAD 345 345 1
3738b	OTDF	8th St.-Kerper 161 flo Wempletown-Rockdale 345	4.46	0	223	4	0	200	ALTW	8TH ST.5 161 KERPER 5 161 1	WEMPL; B 345 PAD 345 345 1
3739	OTDF	8th St.-Kerper 161 flo Arnold-Hazleton 345	4.46	0	223	4	0	200	ALTW	8TH ST.5 161 KERPER 5 161 1	ARNOLD 3 345 HAZLTON3 345 1
3725	OTDF	Sub 56(Davnprt)-E.Calamus161 for Quad-RockCr345	24.98	0	279	23.86	0	223	ALTW	DAVNPRT5 161 E CAL T5 161 1	QUAD ; 345 ROCK CK3 345 1
3758	OTDF	Hazleton T21 345/161kV flo Hazleton T22 345/161kV	4.48	0	224	4.48	0	224	ALTW	HAZLTON3 345 HAZLTON5 161 1	HAZL S 5 161 HAZLTON3 345 2
3707	OTDF	Lore-Turkey River 161 (flo) Wempletown-Paddock 345	47.82	0	271	46.2	0	200	ALTW	LORE 5 161 TRK RIV5 161 1	WEMPL; B 345 PAD 345 345 1

3761	OTDF	Lore-Turkey River 161 (flo) Wempletown-Rockdale 345	5.42	0	271	4	0	200	ALTW	LORE 5 161 TRK RIV5 161 1	WEMPL; R 345 ROE 345 345 1
6108	OTDF	TURKEY RVR-CASSVILLE FLO WEMP-PADDOCK.	50.62	0	271	49.2	0	200	ALTW, DPC	TRK RIV5 161 CASVILL5 161 1	WEMPL; B 345 PAD 345 345 1 MIN 69 69 CRAWHALL 69 1
6108b	OTDF	TURKEY RVR-CASSVILLE FLO WEMP-Rockdale 345	50.62	0	271	49.2	0	200	ALTW, DPC	TRK RIV5 161 CASVILL5 161 1	WEMPL; B 345 PAD 345 345 1 MIN 69 69 CRAWHALL 69 1
3715	OTDF	Quad Cities-Rock Creek 345/MEC Cordova-Sub 39	19.12	0	958	19.12	0	956	CE, ALTW	QUAD ; 345 ROCK CK3 345 1	MECCORD3 345 E MOLIN3 345 1
3716	OTDF	Rock Creek 345/161 TR for Quad-Sub 91 345	8.96	0	448	8.96	0	448	ALTW	ROCK CK3 345 ROCK CK5 161 1	QUAD ; 345 SUB 91 3 345 1
3717	OTDF	Rock Creek-Dewitt 161 Quad Cities-Sub91 345	4.46	0	223	4	0	200	ALTW	ROCKCKW5 161 DEWITT 5 161 1	QUAD ; 345 SUB 91 3 345 1 SB 91 5 161 SUB 91 3 345 1
3718	OTDF	RockCreek-Dewitt 161 for meccord3-sub39 345kV	4.46	0	223	4	0	200	ALTW	ROCKCKW5 161 DEWITT 5 161 1	MECCORD3 345 E MOLIN3 345 1
3719	OTDF	Salem 345/161 (flo) Quad Cities-Sub 91	6.72	0	336	6.72	0	338	ALTW	SALEM 3 345 SALEM N5 161 1	QUAD ; 345 SUB 91 3 345 1
3720	OTDF	Salem 345/161 TR for MEC Cordova-Sub 39 345kV	28.12	0	336	28.12	0	336	ALTW	SALEM 3 345 SALEM N5 161 1	MECCORD3 345 E MOLIN3 345 1
3721	OTDF	Salem 345/161 for Quad-Sub 91 TR	28.12	0	336	28.12	0	336	ALTW	SALEM 3 345 SALEM N5 161 1	QUAD ; 345 SUB 91 3 345 1 SUB 91 3 345 SB 91 5 161 1
3736	OTDF	Salem 345/161 flo Wempletown-Paddock 345	28.12	0	336	28.12	0	336	ALTW	SALEM 3 345 SALEM N5 161 1	WEMPL; B 345 PAD 345 345 1
3736b	OTDF	Salem-Julian Center 161 (flo) Wempletown--Rockdale 345	28.12	0	336	28.12	0	338	ALTW	SALEM 3 345 SALEM N5 161 1	WEMPL; B 345 FAD 345 345 1

3746	OTDF	Salem-Julian Center 161 (flo) Wempletown-Paddock 345	6.7	0	335	6	0	300	ALTW	SALEM N5 161 JULIAN 5 161 1	WEMPL; B 345 PAD 345 345 1
3746b	OTDF	Salem-Julian Center 161 (flo) Wempletown-Rockdale 345	6.7	0	335	6	0	300	ALTW	SALEM N5 161 JULIAN 5 161 1	WEMPL; B 345 PAD 345 345 1
3737	OTDF	Alliat Hills 345/161 Xfmr flo Tiffin-Duane Arnold 345	5.52	0	276	5.04	0	252	ALTW	HILLS 3 345 HILLSIES 161 1	TIFFIN 3 345 ARNOLD 3 345 1

Table 5: Flowgate List for Eastern Iowa Study

Based on NERC Planning Standards, two types of contingencies are simulated:

1. NERC Category B contingencies which defined as the loss of a single element;
2. NERC Category C contingencies which are defined as the loss of two or more (multiple) elements.

The engineering software for use in this study is Power Technologies, Inc. PSS/E version 29.0.0, MUST 7.0, and NewEnergy Associates PROMOD 9.0.3.

Cases representing pre-contingency conditions are solved with automatic control enabled for LTCs, phase shifters, DC taps, and switched shunts. In addition, area interchange is enabled. Cases representing post-contingency conditions are solved with area interchange disabled (fixed) while other options are kept the same.

Other important solution options are:

Contingency Flow Change Cutoff:	1 MW
Contingency Voltage Change Cutoff:	1%
AC Mismatch Change Cutoff:	1 MW

2.3 Criteria

NERC Transmission Planning Standards TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 effective on April 1, 2005 are generally applied to test the system. The Alliant Energy Transmission System Planning criterion [2] is used if different from NERC planning criteria. MRO criterion is used on MidAmerican Energy and CIPCO facilities.

All eastern Iowa facilities 100 kV and above (also including some facilities below 100 kV) are monitored for thermal violations. Loading is compared against both normal and emergency branch ratings. Steady state thermal violations are cited if branch loadings exceed normal ratings under system intact conditions or if branch loadings exceed emergency ratings under contingencies.

Voltages at buses 100 kV and above (also including some facilities below 100 kV) are monitored in the eastern Iowa region. Under system intact conditions, buses are monitored for voltages above

105% or below 95% of nominal. Under post-contingency conditions, generally, buses are monitored for voltages above 110% or below 90% of nominal.

3. AC Contingency Analysis

The transmission system defined in the eastern Iowa study region is monitored for thermal impacts. Loading is compared against both the normal and emergency branch ratings. Steady state thermal violations are cited if branch loadings exceed normal ratings.

Voltages at buses defined in the study region are monitored. Under pre-contingency condition, buses are monitored for voltages above 105% or below 95% of nominal. Under post-contingency conditions, buses are monitored for voltages above 110% or below 90% of nominal.

Results in section 3 are all listed in Appendix C.

3.1 Base Case AC Contingency Analysis

3.1.1 Under Normal Conditions

A) 2011 Base Case

Under normal conditions, there are no thermal violations. There are two low voltage violations in ALTW Liberty area on the 69 kV system. The low voltage buses are HOPREG8 and SANDSPR8, listed in Table C.1-1. (Documentation shown later in the study shows that these low voltages were due to modelling errors).

B) 2015 Base Case

One of the Hazleton 161/69 transformers was shown to be overloaded in the 2015 base case (Table C.1-2). There were no voltage violations after model corrections were included.

3.1.2 Under Category B Contingencies

A) 2011 Base Case

Under category B contingencies, overloads were shown on the Hazleton 224 MVA, 345/161 kV transformer, each of the Hazleton 161/69 kV transformers, and several 69 kV lines in the Postville and PCI areas. See Table C.1-4.

There is no voltage violation under category B contingencies after modelling corrections were applied.

B) 2015 Base Case

Overloads under category B contingencies include, the Hazleton 224MVA, 345/161 kV transformer, the Hazleton 161/69 kV transformers, the Salem 345/161 kV transformer, and the Dundee 161/115 kV transformer. The Hiawatha/Fairfax area had several 161 and 69 kV line overloads. In the Postville area, one 161/69 transformer and one 69 kV line were shown with overloads. See Table C.1-5.

The table documents the increased loadings of facilities between the 2011 and 2015 base cases. The Salem 345/161 kV transformer is impacted by about 17 MW. Lines in the Hiawatha/Fairfax area are also shown to be significantly impacted by the load growth represented between the two base cases, with the PCI East – Oakridge line showing a 30 MW increase in loading.

There is no voltage violation under category B contingencies in 2015 base case.

3.1.3 Under Category C Contingencies

A) 2011 Base Case

Under category C1 (bus outage), C2 (breaker failure) and C5 (common tower outage) contingencies, overloads occurred on the Hazleton 161/69 kV transformers, the Salem 345/161 kV transformer, the Lansing 161/69 kV transformer, and several 69 kV lines in the Postville, Salem/Lore, and Fairfax/PCI areas. See Table C.1-6.

For double (category C3) contingencies, criteria allow for the transmission system and transmission system operators to make adjustments to the system as preparation for a second contingency. This system adjustment can not be simulated by PSS/E or MUST when performing bulk contingency analysis. *With this limitation in mind, the output of the study was screened for thermal violations above 125%.*

Table C.1-7 shows some typical thermal overloads especially on the 100 kV and above system, under category C3 contingencies. Besides the thermal overloading issues identified in category C1/C2/C5 contingencies, thermal overloads are also identified in the Turkey River, Beaver Ch./Albany, Tiffin areas as well as the Dundee - Coggon 115 kV line.

Under the C2 contingency "ALTW-C-NW-DUNDEE 161 BUS -STUCK BREAKER", several low voltage violations occur on the 69 kV system along the Hazleton - Salem line. This is shown in Table C.1-8.

Under C3 automatic double contingencies, several low voltage violations on the 100 kV and above system are identified. They are in Savanna/York, Fairfax/Hiawatha, Postville areas, and along the Hazleton - Lore 161kV line as well as the Dundee - Marion 115 kV line. See Table C.1-9.

B) 2015 Base Case

Again, tables document the increased loadings of facilities between the 2011 and 2015 base cases. Under category C1/C2/C5 contingencies, the Salem 345/161 kV transformer is impacted by 17 MW in the 2011 case compared to the 2015 base case. Overloads on the Hazleton 161/69 kV transformers and the Lansing 161/69 kV transformer are aggravated. The Arnold - Fairfax 161 kV line, Dundee 161/115 kV transformer are newly overloaded in the 2015 case. Several 69 kV facilities are overloaded in the Postville, Fairfax/Hiawatha, Tiffin, Beaver Ch./Rock Creek areas and along the Hazleton - Lore 161 kV line. See Table C.1-10.

Under C3 automatic double contingencies, the Hazleton - Lore 161 kV line, the Dundee - Marion 115 kV line, the Fairfax/Hiawatha area, the Tiffin area, and the Rock Creek/Beaver Ch. area are most impacted by represented load increases in the 2015 base model. See Table C.1-11.

Under the C2 contingency "ALTW-C-NW-DUNDEE 161 BUS -STUCK BREAKER", low voltage violations occur on 69 kV facilities along the Hazleton - Salem line. This is shown in Table C.1-12.

Under C3 automatic double contingencies, low voltages in the areas of Savanna/York, Fairfax/Hiawatha, and along the Hazleton - Lore 161kV line and the Dundee - Marion 115 kV line are most aggravated by ALTW control area load increase. See Table C.1-13.

3.2 South-North Transfer Impact

3.2.1 Under Normal Conditions

A) 2011 S-N Case

In the 2011 S-N Case, the Hazleton 161/69 kV and the Salem 345/161 kV transformers are overloaded under normal conditions. See Table C.2-1.

B) 2015 S-N Case

Not surprisingly, the Hazleton 161/69 kV and the Salem 345/161 kV transformers are more overloaded under normal conditions in 2015. No other constraints are identified.

Two new low bus voltages at bus "RICE 8" and "PFEILRE8" are identified. See Table C.2-3.

3.2.2 Under Category B Contingencies

In both the 2011 and 2015 S-N cases, under different category B contingencies, the Salem 345/161 kV transformer has up to a 5.6% TDF impact with respect to the south-north transfer. Also, the Albany - Savanna 161 kV line, the Dysart - Washburn 161 kV line, the Tiffin - Arnold 345 kV line, the E Calamus - Maquoketa 161 kV line, the SWAMPFX7 - Dundee 115 kV, the Galena 161/69 kV transformer, the Salem/Lore and Fairfax/Hiawatha areas are overloaded.. See Table C.2-4.

There are no voltage violations under category B contingencies in the 2011 S-N transfer case. But in the 2015 S-N transfer case, three low voltage violations occur at buses "SALEM 3 345", "ROCK CK3 345", and "PFEILRE869.0", see Table C.2-5

3.2.3 Under Category C Contingencies

Under category C contingencies, the Salem transformers, the Hazleton transformers, the Albany - Savanna 161 kV line, the Dysart - Washburn 161 kV line, the Tiffin - Arnold 345 kV line, the E Calamus - Maquoketa 161 kV line, the SWAMPFX7 - Dundee 115 kV line, and the Salem/Lore, Hazleton, and Fairfax/Hiawatha areas are overloaded. Also the Quad Cities/Rock Creek line is impacted by a 14.7% TDF under south-north transfer. See Table C.2-6 for typical thermal constraints largely impacted by S-N transfer in 2011.

Under category C contingencies, low voltage violations are observed in the Lansing, Salem/Lore, Rock Creek, Fairfax/Hiawatha, Postville, and Galena areas as well as areas along the Hazleton –

Salem and Bertram - Maquoketa lines with up to a 4.6% contingency voltage decrease under south-north transfer. See Table C.2-7.

3.3 East-West Transfer Impact

3.3.1 Under Normal Conditions

A) 2011 E-W Case

In the 2011 E-W case, the Salem 345/161 kV transformer is overloaded at 105% under normal conditions. See Table C.3-1.

B) 2015 E-W Case

Besides the Salem 345/161 kV transformer overload, one of the Hazleton 161/69 kV transformers is also overloaded in 2015. See Table C.3-3.

One new low bus voltage at bus "PFEILRE8" is identified. See Table C.3-4.

3.3.2 Under Category B Contingencies

In both the 2011 and 2015 E-W cases, under different category B contingencies, the Salem 345/161 kV transformer has up to 4.0% TDF impact with east-west transfer. Also, the Salem/Lore area, the E Calamus - Maquoketa 161 kV line, and the York - Savanna 161 kV line are overloaded. See Table C.3-5.

There is no voltage violation under category B contingencies in 2011 E-W transfer case. But in 2015 E-W transfer case, two low voltage violations at buses "SALEM 3 345" and "PFEILRE869.0" are identified, see Table C.3-6.

3.3.3 Under Category C Contingencies

Besides the impact of E-W transfers on the Salem 345/161 kV transformer, under category C contingencies, the Salem/Lore area, the Rock Creek/Quad Cities area, the Rock Creek - E Calamus 161 kV line, the E Calamus - Maquoketa 161 kV line, the York - Savanna 161 kV line, the Hazleton - Blackhawk 161 kV line are overloaded. Particularly, the Quad Cities/Rock Creek line is impacted by 19.5% TDF under a category C contingency with respect to the east-west transfer. Table C.3-7 shows typical thermal violations under category C contingencies impacted by the E-W transfer in 2015.

Under category C contingencies, low voltage violations are observed in the Salem/Lore, Rock Creek, Fairfax/Hiawatha, Postville, and Galena areas as well as buses along the York - Savanna line and the Bertram - Dundee line, with up to a 3.6% voltage impact under E-W transfer. Table C.3-8 lists typical voltage violations under category C contingencies largely impacted by E-W transfer in 2015.

3.4 Impacts on Flowgates

To create the heavy transfer models, different incremental transfers from East (NI) to West (WAPA, NPPD, OPPD) or from South (AMRN, NI) to North (XCEL, MP, OTP) were applied to the 2011 or 2015 base models. They are listed in Table 6:

Transfer Model	Incremental Transfer from Corresponding Base Model (MW)
2011 E-W	1916.6
2011 S-N	1879.8
2015 E-W	2036.6
2015 S-N	2031.8

Table 6: Incremental Transfer to Create Heavy Transfer Models

These impacts to flowgates as a result of these transfers are listed in Appendix D.

ALTW load increase between 2011 and 2015 years also has impact on the flowgates as listed in Appendix D.

Based on the flowgate impact analysis, a few important notes are:

1. The east-west transfer has most impact on flowgates "3705_Arnold-Hazelton 345 for Wemp-Paddock 345", "3705b_Arnold-Hazelton 345 for Wemp-Rockdale 345" and "3715_Quad Cities-Rock Creek 345/MEC Cordova-Sub 39". The Transfer Distribution Factors (TDF) are all about 7%;
2. The south-north transfer has the most impact on flowgates "3705_Arnold-Hazelton 345 for Wemp-Paddock 345" and "3705b_Arnold-Hazelton 345 for Wemp-Rockdale 345". The TDF are all about 7%.
3. Both the east-west transfer and south-north transfers have about the same (7%) TDF impact on Quad Cities-Rock Creek flowgate, but south-north transfer has more impact on Arnold-Hazleton flowgates;
4. Both east-west and south-north transfers have more than 3% TDF on all flowgates with the Salem 345/161 transformer as a monitored element, where some of these flowgates are overloaded in all these transfer cases. The south-north transfer has more impact on Salem 345/161 transformer than the east-west transfer;

5. Flowgate "3725_Sub 56(Davnprt)-E.Calamus161 for Quad-RockCr345" is overloaded in all transfer cases except 2011 E-W transfer case. The south-north transfer has 1% more impact on this flowgate than the east-west transfer, but both transfers have less than 3% TDF on this flowgate;
6. Flowgate "3728_Dysart-Washburn 161 for D.Arnold-Hazleton 345" is overloaded in the 2011 and 2015 south-north transfer cases. The south-north transfer has a 6.4% TDF on this flowgate.
7. The 10% ALTW control area load increase has the most impact (28.1 MW) on flowgate "3715_Quad Cities-Rock Creek 345/MEC Cordova-Sub 39". It also has more than a 10 MW impact on flowgates "3725_Sub 56(Davnprt)-E.Calamus161 for Quad-RockCr345", "3716_Rock Creek 345/161 TR for Quad-Sub 91 345", and several Salem 345/161 transformer flowgates.

3.5 First Contingency Incremental Transfer Capacity (FCITC)

FCITC is calculated by comparing a particular branch loading under the same contingency between the transfer case and base case under system intact and category B contingencies. The final FCITC is the minimum value of these calculated FCITC values. No category C contingencies will be considered in FCITC calculation. To more accurately capture transfer impact, a 2% TDF cut-off is adopted, i.e., FCITC is only calculated when the branch under the contingency has at least 2% TDF value for the transfer.

For example, if branch A (emergency rating is 2000 MVA) is loaded at 1900 MVA under contingency B in 2011 base case, and it is loaded at 2100 MVA under the same contingency in 2011 S-N transfer case (S-N incremental transfer level is 1879.8 MW as shown in Table 6), the Transfer Distribution Factor for branch A under contingency B with 1879.8 south-north transfer is calculated as:

$$DF = \frac{2100-1900}{1879.8} * 100 = 10.6\%$$

The particular $FCITC_i$ for branch A under contingency B is:

$$FCITC_i = \frac{2000-1900}{10.6} * 100 = 943.4 \text{ MW}$$

So the final FCITC for 2011 S-N transfer study should be:

$$FCITC = Min(FCITC_i)$$

3.5.1 FCITC Calculation in 2011 Year

In 2011 year FCITC calculation, the most constrained facility is the Salem 345/161 transformer under both the south-north transfer and east-west transfer. The FCITC for 2011 S-N transfer is 75.2 MW, and the FCITC for 2011 E-W transfer is 88.2 MW. The second most constrained facility is the Kerper 5 - 8th St. 161 kV line under both transfers. If the Salem transformer constraint could be resolved, the FCITC under S-N transfer would be 997.3 MW due to Kerper 5 - 8th St. 161 kV line constraint, and the FCITC under E-W transfer would be 1697.4 MW due to the same constraint. See Tables E.1 and E.2 in Appendix E for some typical constraints. The same constraint under different contingencies is only listed one time in the Tables.

The constraints to prevent incremental transfer from south to north are the Arnold - Tiffin 345 kV line, the Dysart - Washburn 161 kV line, the York - Savanna 161 kV line, the Genoa - Lac Tap5 161 kV line, as well as the Salem/Lore and E Calamus areas.

The number of constraints to prevent incremental transfer from east to west is fewer than that in S-N transfer. Those constraints are in Salem/Lore area and E Calamus - Maquoketa 161 kV line.

3.5.2 FCITC Calculation in 2015 Year

In 2015 year FCITC calculation, the most constrained facility is still the Salem 345/161 kV transformer both under south-north transfer and east-west transfer. The FCITC values for 2015 year are negative under both S-N transfer and E-W transfer. See Tables E.3 and E.4 in Appendix E.

The constraints to prevent incremental S-N and E-W transfers in 2015 year are similar to those in 2011 year.

4. MISO Market Wide Analysis

Under MISO market operation, generation offered into the MISO market is committed and dispatched based on Security Constrained Economic Dispatch (SCED) rule. The PROMOD analysis is based on a simulation of electric system operations and regional power markets using the PROMOD IV® production costing and power flow model. The model was used to project hourly production costs, generation revenue, hourly load LMP and hourly loading profiles of major transmission lines.

PROMOD IV® includes an hourly chronological dispatch algorithm that minimizes costs while simultaneously adhering to a wide variety of operating constraints. PROMOD IV® integrates chronological production costing and detailed power flow analysis. The model represents power system operations in the Eastern Interconnect, which includes representations of the operation of the 5,000 generating units that are 1 MW or larger, 40,000 transmission buses and 50,000 transmission lines. The model calculates and can track location-specific, hourly prices for up to 8,000 specific locations.

The model captures the dynamics of the marketplace through its ability to determine the effects of transmission congestion, fuel costs, generator availability, bidding behaviour and load growth on market prices. PROMOD IV® performs an 8760-hour commitment and dispatch recognizing both generation and transmission impacts at the bus-bar (nodal) level. PROMOD IV forecasts hourly energy prices, unit generation, revenues and fuel consumption, bus-bar and zonal energy market prices, external market transactions, transmission flows, losses and congestion prices.

Some lines are overloaded for different hours in PROMOD 8760-hr simulation with Security Constrained Economic Dispatch (SCED). These lines are mainly:

1) Cordova - Nelson 345 kV line being constrained for 1013 hrs, about 1/8 time of a year
2) Genoa - Lac Tap 161 kV line being constrained for 600 hrs, about 6.8% time of a year
3) Dysart - Washburn 161 kV line being constrained for 116 hrs
4) Dundee 161/115 kV transformer being constrained for 48 hrs
5) E Calamus - Davenport 161 kV line being constrained for 48 hrs
6) Galena 161/69 kV #1 transformer being constrained for 41 hrs

Overloaded lines under 8760-hr SCED dispatch are shown in Table 7.

High shadow price flowgates with $1k and up are shown in Table 8. These flowgates are:

1) 3428_Galesburg 161/138 Xfm #2 flo Electric Jct.-Nelson B 345, annual shadow price is 448.99 K$
2) 3264_Nelson-Nelson RT FLO Nelson-Dixon B, annual shadow price is 84.94 K$
3) 505_Cordova-Nelson (15503) 345 kV line l/o Quad Cities-H471 345 kV line, annual shadow price is 19.3 K$
4) 6085_Genoa-Coulee 161 (flo) Genoa-Lake Tap-Marshland 161, annual shadow price is 14.43 K$
5) 4188_Turkey River-Cassville 161 (flo) Wempletown-Paddock 345 + Op Guide, annual shadow price is 3.59 K$
6) 3712_Dundee 161-115 for Arnold-Hazleton 345kV, annual shadow price is 3.54 K$
7) 6148_Genoa-LaCrosse-Marshland flo Genoa-Coulee, annual shadow price is 2.06 K$
8) 3227_0404 Quad-H471 for 15503 Cordo-Nelson, annual shadow price is 1.26 K$

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FROM	36284	69523	34087	34135	64425	69505	39010	64350	34018	34028	69527	69527	34033	69523	69523
BUS	CORDO; B	GENOA 5	DYSART 5	DUNDEE 5	DAVNPRTS	GALENA 5	NED 161	HILLS 3	HAZLTON3	LORE 5	HARMONY5	HARMONY5	TRK RIV5	GENOA 5	GENOA 5
TO	35362	69535	64269	34133	34909	69165	39020	34110	34019	34033	68726	68726	69503	69507	34021
BUS	NELSO; B	LAC TAP5	WASHBRN5	DUNDEE 7	E CAL T5	GALENA8	NED 138	HILLSIE5	HAZLTON5	TRK RIV5	HARMNY.	HARMNY	CASVILL5	SENECA 5	LANSINGW
CIRCUIT	1	1	1	1	1	1	1	1	1	1	1	2	1	1	1
RATING	1530	279	276	56	200	67	210	252	224	200	30	30	200	304	223
hours above ratings	1013	600	116	48	48	41	18	13	11	9	6	3	7	4	4

Table 7: Eastern Iowa Facilities Overloaded for Hours under PROMOD SCED

CONSTRAINT																
From Bus		To Bus		Event	HOURS AT MAX	SUM OF FLOWGATE PRICE AT MAX		AVG PRICE AT MAX		HOURS AT MIN	SUM OF FLOWGATE PRICE AT MIN		AVG PRICE AT MIN		Total Hours at constraint	Total flowgate price at constraint (K$)
Bus Name	Bus ID	Bus Name	Bus ID													
GALESBR5	64411	GALESBRG	32415	251	3078	K$	-448.99	$	-145.87	0	K$	0	$	0	3078	448.99
NELSO; R	37039	NELSO;RT	37037	199	544	K$	-84.94	$	-156.13	0	K$	0	$	0	544	84.94
CORDO; B	35284	NELSO; B	36362	146	754	K$	-19.3	$	-25.6	0	K$	0	$	0	754	19.3
GENOA 5	69523	COULEE 5	60302	404	483	K$	-14.43	$	-29.87	0	K$	0	$	0	483	14.43
TRK RIV5	34033	CASVILL5	69503	43	386	K$	-3.59	$	-9.3	0	K$	0	$	0	386	3.59
DUNDEE 5	34135	DUNDEE 7	34133	37	0	K$	0	$	0	41	K$	3.54	$	86.41	41	3.54
GENOA 5	69523	LAC TAP5	69535	307	142	K$	-2.06	$	-14.53	0	K$	0	$	0	142	2.06
QUAD ;	36382	H471 ;	36358	145	119	K$	-1.26	$	-10.61	0	K$	0	$	0	119	1.26

Table 8: Constrained Flowgates in Eastern Iowa with Total Price 1 k$ and up

5. Eastern Iowa Study Findings

Based on the AC contingency analysis, flowgate impact study, FCITC calculation, and MISO market wide PROMOD analysis, here are the findings in eastern Iowa system:

1) At system intact conditions, low voltage violations are found at HOPREC8 and SANDSPR8 69 kV buses;

2) Under category B contingencies, thermal violations are found in the Hazleton 345/161 and 161/69 kV transformers, the Salem 345/161 kV transformer, the Dundee 161/115 kV transformer, the Fairfax/Hiawatha and Postville areas. There is no voltage violation under category B contingencies;

3) Under category C1/C2/C5 contingencies, thermal violations are found in the Hazleton 161/69 kV transformers, the Salem 345/161 kV transformer, the Lansing 161/69 kV transformer, the Arnold - Fairfax 161 kV line, and the Dundee 161/115 kV transformer. Several 69 kV thermal violations are found in the Fairfax/Hiawatha, Postville, Salem/Lore, Tiffin and Beaver Ch./Rock Creek areas, as well as along Hazleton - Lore line. Under the C2 contingency "ALTW-C-NW-DUNDEE 161 BUS-STUCK BREAKER", several low voltage violations are identified in 69 kV buses along Hazleton - Lore line;

4) Besides thermal violations identified in category C1/C2/C5 contingencies, under category C3 automatic double contingencies ,newly overloaded facilities are identified in the Marion - Dundee 115 kV line and in the Turkey River, Beaver Ch./Albany and Tiffin areas. Low voltage violations are found on the York - Savanna 161 kV line, the Marion - Dundee 115 kV line, in the Fairfax/Hiawatha and Postville areas, and on some 69 kV buses along Hazleton - Lore line;

5) The 10% ALTW load increase in 2015 has significant impact on Salem 345/161 kV transformer, the Marion - Dundee 115 kV line, the York - Savanna 161 kV line, the Hiawatha/Fairfax and Rock Creek/Beaver Ch. areas, and also along the Hazleton - Lore line;

6) The south-north transfer has significant impact on the Salem 345/161 kV transformer, the Albany - Savanna 161 kV line, the Dysart - Washburn 161 kV line, the Tiffin - Arnold 345 kV line, the E Calamus - Maquoketa 161 kV line, the Marion - Dundee 115 kV line, the Galena 161/69 kV transformer, the Salem/Lore area, the Hazleton, Quad Cities/Rock Creek and Fairfax/Hiawatha areas;

7) The east-west transfer has significant impact on the Salem 345/161 kV transformer, the E Calamus - Maquoketa 161 kV line, the York - Savanna 161 kV line, the Rock Creek - E Calamus 161 kV line,

the Hazleton - Blackhawk 161 kV line, and the Salem/Lore, Quad Cities/Rock Creek and Fairfax/Hiawatha areas;

8) The S-N transfer has up to 5.6% TDF impact on the Salem 345/161 kV transformer, compared with 4.0% TDF impact with E-W transfer;

9) Both the E-W and S-N transfers have the greatest impact on flowgates "3705_Arnold-Hazelton 345 for Wemp-Paddock 345", "3705b_Arnold-Hazelton 345 for Wemp-Rockdale 345", "3715_Quad Cities-Rock Creek 345/MEC Cordova-Sub 39". The TDF are all about 7%;

10) Both E-W and S-N transfers have more than 3% TDF on the Salem 345/161 flowgates. The S-N transfer has more impact than the E-W transfer.

11) The 10% ALTW load increase has most impact (28.1 MW) on flowgate "3715_Quad Cities-Rock Creek 345/MEC Cordova-Sub 39";

12) For both S-N and E-W FCITC calculations, the Salem 345/161 kV transformer is the most limiting element;

13) S-N transfer has most impact on Hills - Sub T 345 kV line (22.3% TDF), the Arnold - Hazleton 345 kV line (18.7% TDF), and Arnold - Tiffin 345 kV line (16.8% TDF);

14) In MISO market wide analysis, the most constrained facilities are the Cordova - Nelson 345 kV line, the Genoa - Lac Tap 161 kV line, the Dysart - Washburn 161 kV line, the Dundee 161/115 kV transformer, and the E Calamus - Davenport 161 kV line;

15) Correspondingly, eastern Iowa flowgates with monitored branches of Cordova - Nelson, Genoa - Coulee, Turkey River - Cassville, Dundee 161/115 kV transformer, Genoa - Lac Tap, Quad Cities - H471 have more than $1k total flowgate price.

Figure 5 shows the geographic locations of all the above identified system issues (thermal overloading or low voltage violation) in eastern Iowa system. In this diagram, red represents issues identified in the 2011/2015 summer peak base case, and green represents issues only occurring in the heavy S-N or E-W transfer scenarios. Circles represent areas with several identified constraints, and lines represent branches with overloading and/or low voltage issues.

Figure 5 shows that system issues are widely spread in eastern Iowa system. Also it is noted that although most of issues (red) occur in 2011/2015 summer peak base cases, some of issues (green) are only identified in S-N or E-W heavy transfer scenarios. When system reliability solutions are being developed, load serving issues in base case (2011/2015 summer peak base case) are mainly focused, while S-N or E-W transfer impact and load growth impact are closely monitored. The branches with overloading only in transfer scenarios are listed in Table 9 with some typical overloading examples.

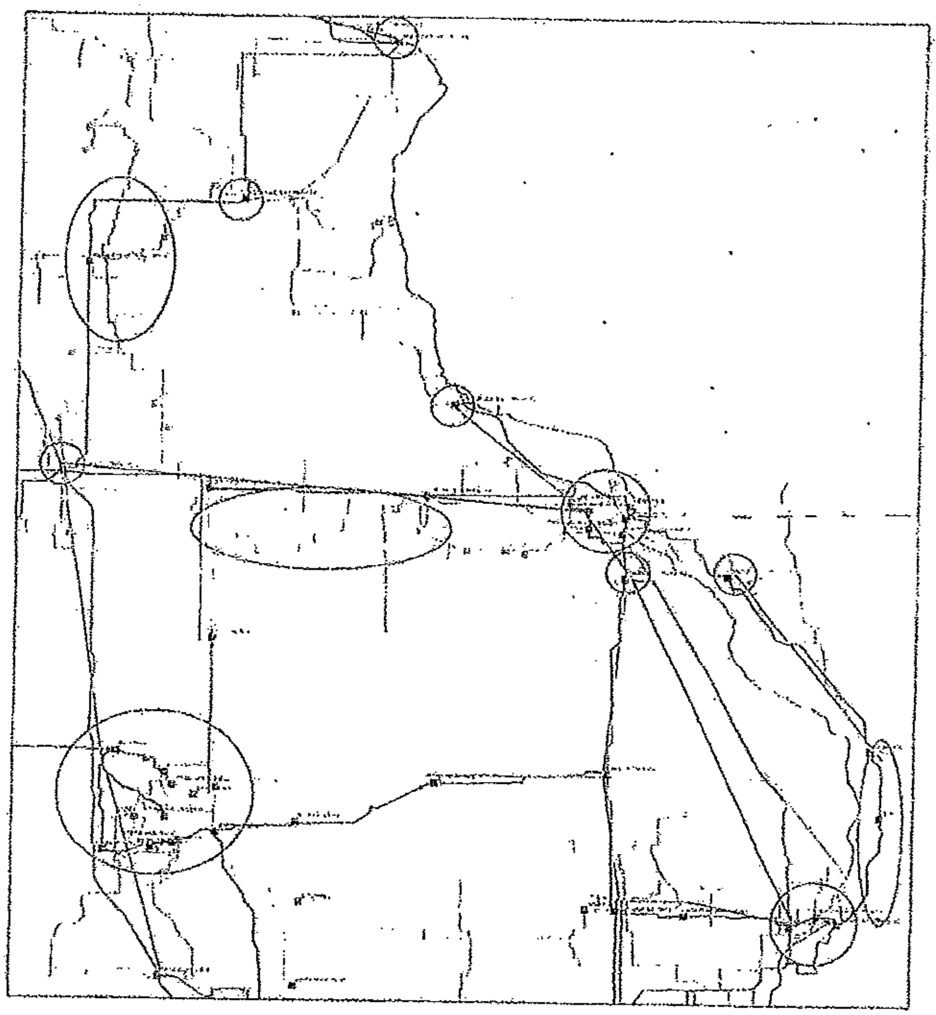

Figure 5: Geographic Locations of Identified System Issues in Eastern Iowa

** From bus **.** To bus ** CKT	ContMVA	BaseFlow	Rating	Loading%	Contingency	Category
34908 KERPER 5 161 34028 LORE 5 161 1	230.2	98.8	200.0	115.1	34030 SALEM N5 161 34508 JULIAN 5 161 1	B
34908 KERPER 5 161 34032 8TH ST.5 161 1	245.7	113.7	200.0	122.9	34030 SALEM N5 161 34508 JULIAN 5 161 1	B
34508 JULIAN 5 161 34027 CNTRGRV5 161 1	339.5	201.3	326.0	104.2	34031 SO.GVW.5 161 34034 SALEM S5 161 1	B
69523 GENOA 5 161 69535 LAC TAPS 161 1	327.0	179.2	306.9	106.6	D:ADAMS 3-PL VLCY31 +COULEE 5-GENOA 51	C3
34109 BERTRAM5 161 34110 HILLSIE5 161 1	363.3	133.1	276.0	131.6	D:ARNOLD1G-ARNOLD 51 +ARNOLD 3-TIFFIN 31	C3
34120 CALAMUS7 115 34121 E CALMS7 115 1	83.9	28.7	80.0	104.9	D:ARNOLD1G-ARNOLD 51 +ARNOLD 3-TIFFIN 31	C3
34121 E CALMS7 115 34122 E CALMS5 161 1	85.3	29.5	84.0	101.5	D:ARNOLD1G-ARNOLD 51 +ARNOLD 3-TIFFIN 31	C3
34093 ARNOLD 3 345 64352 TIFFIN 3 345 1	888.3	541.5	717.0	123.9	D:ARNOLD1G-ARNOLD 51 +BERTRAM5-HILLSIE51	C3
64350 HILLS 3 345 64352 TIFFIN 3 345 1	973.9	634.8	956.0	101.9	D:ARNOLD1G-ARNOLD 51 +BERTRAM5-HILLSIE51	C3
64350 HILLS 3 345 64408 SUB T 3 345 1	1161.7	635.3	956.0	121.5	D:ARNOLD1G-ARNOLD 51 +HILLS 3-SUB 92 31	C3
64355 CRLRIDG5 161 64360 SB PIC 5 161 1	390.7	14.2	335.0	116.6	D:ARNOLD1G-ARNOLD 51 +HILLS 3-TIFFIN 31	C3
34044 ALBANY 5 161 34046 YORK 5 161 1	244.4	134.7	200.0	122.2	D:ASBURY 5-CNTRGRV51 +SO.GVW.5-SALEM S51	C3
64269 WASHBRN5 161 64657 WASHMID869.0 1	98.8	46.0	83.3	118.6	D:DR NE 5-WASHBRN51 +EL FARM5-WASHBRN51	C3
64250 BLKHAWK5 161 34019 HAZLTON5 161 1	205.4	72.6	200.0	102.7	D:HAZL S 5-WASHBRN51 +DYSART 5-WASHBRN51	C3
34091 ARNOLD 5 161 34093 ARNOLD 3 345 1	479.0	95.6	448.0	106.9	D:HAZLTON3-ARNOLD 31 +ARNOLD1G-ARNOLD 51	C3
34087 DYSART 5 161 64269 WASHBRN5 161 1	360.6	184.6	276.0	130.6	D:HAZLTON3-ARNOLD 31 +LANSINGW-LANS5 4G1	C3
34031 SO.GVW.5 161 34032 8TH ST.5 161 1	397.4	173.5	306.0	129.9	D:HAZLTON3-ARNOLD 31 +SALEM N5-JULIAN 51	C3
34026 ASBURY 5 161 34027 CNTRGRV5 161 1	394.3	179.3	326.0	121.0	D:HAZLTON3-ARNOLD 31 +SO.GVW.5-SALEM S51	C3
34026 ASBURY 5 161 34028 LORE 5 161 1	360.4	146.5	326.0	110.5	D:HAZLTON3-ARNOLD 31 +SO.GVW.5-SALEM S51	C3
34508 JULIAN 5 161 34027 CNTRGRV5 161 1	417.1	201.3	326.0	127.9	D:HAZLTON3-ARNOLD 31 +SO.GVW.5-SALEM S51	C3
64269 WASHBRN5 161 34020 HAZL S 5 161 1	214.7	65.1	210.0	102.3	D:HAZLTON5-BLKHAWK51 +DYSART 5-WASHBRN51	C3
34126 MOOKETA5 161 34127 WYOMING5 161 1	173.0	53.9	167.0	103.6	D:HILLS 3-SUB 92 31 +HILLS 3-SUB T 31	C3
64359 SB JIC 5 161 64351 HILLS 5 161 1	370.1	97.0	282.0	131.3	D:HILLS 3-TIFFIN 31 +SB EIC 5-SB YIC 51	C3
64359 SB JIC 5 161 64361 SB UIC 5 161 1	349.0	64.2	299.0	116.7	D:HILLS 3-TIFFIN 31 +SB EIC 5-SB YIC 51	C3
64360 SB PIC 5 161 64361 SB UIC 5 161 1	314.9	27.5	299.0	105.3	D:HILLS 3-TIFFIN 31 +SB EIC 5-SB YIC 51	C3
64356 SB EIC 5 161 64362 SB YIC 5 161 1	320.5	48.5	225.0	142.5	D:HILLS 3-TIFFIN 31 +SB JIC 5-SB UIC 51	C3
64357 SB GIC 5 161 64360 SB PIC 5 161 1	280.2	18.1	225.0	124.5	D:HILLS 3-TIFFIN 31 +SB JIC 5-SB UIC 51	C3

64357 SB GIC 5 161 64362 SB YIC 5 161 1	299.5	29.0	225.0	133.2	D:HILLS 3-TIFFIN 31 +SB JIC 5-SB UIC 51	C3
64355 SB EIC 5 161 64351 HILLS 5 161 1	343.2	96.3	238.0	144.2	D:HILLS 3-TIFFIN 31 +SB PIC 5-SB UIC 51	C3
34093 ARNOLD 3 345 34018 HAZLTON3 345 1	768.1	600.5	717.0	106.9	D:LANSINGW-LANS5 4G1 +DYSART 5-WASHBRN51	C3
64405 SUB 91 3 345 64438 SB 91 5 161 1	675.5	260.6	630.0	107.3	D:MECCORD3-E MOLIN31 +DAVNPRT3-SUB 91 31	C3
64438 SB 91 5 161 64439 SBHYCS 161 1	365.3	131.1	335.0	109.0	D:MECCORD3-E MOLIN31 +DAVNPRT3-SUB 91 31	C3
64404 DAVNPRT3 345 64681 SB56MIDS 161 1	561.8	266.5	558.0	100.7	D:MECCORD3-E MOLIN31 +DAVNPRT3-WALCOTT31	C3
34029 SALEM 3 345 34036 ROCK CK3 345 1	616.0	403.8	598.0	103.0	D:MECCORD3-E MOLIN31 +SUB 91 3-QUAD ; 1	C3
34035 ROCKCKW5 161 34037 ROCK CK5 161 1	386.4	171.2	330.0	117.1	D:MECCORD3-E MOLIN31 +SUB 91 3-QUAD ; 1	C3
34038 BVR CH 5 161 34042 BVR CH65 161 1	385.5	208.1	335.0	115.1	D:MECCORD3-E MOLIN31 +SUB 91 3-QUAD ; 1	C3
34122 E CALMS5 161 34124 DEWITT 5 161 1	265.5	74.8	192.0	138.3	D:MECCORD3-E MOLIN31 +SUB 91 3-QUAD ; 1	C3
64422 SB 49 5 161 34038 BVR CH 5 161 1	231.3	13.3	223.0	103.7	D:MECCORD3-E MOLIN31 +SUB 91 3-QUAD ; 1	C3
36773 GARDE; 138 37076 H71 ;BT 138 1	205.1	51.2	182.0	112.7	D:ROCK CK3-QUAD ; 1 +BVRCH52G-BVR CH651	C3
64422 SB 49 5 161 64414 SB 17 5 161 1	250.5	39.0	223.0	112.3	D:ROCK CK3-QUAD ; 1 +BVRCH52G-BVR CH651	C3
34037 ROCK CK5 161 34042 BVR CH65 161 1	298.6	75.4	266.0	112.3	D:ROCK CK3-QUAD ; 1 +E CALMS5-E CAL T51	C3
64400 MECCORD3 345 64403 E MOLIN3 345 1	1392.7	483.3	1333.0	104.5	D:ROCK CK3-QUAD ; 1 +SUB 91 3-QUAD ; 1	C3
64403 E MOLIN3 345 64680 SB39MID5 161 1	728.2	338.7	628.0	116.8	D:ROCK CK3-QUAD ; 1 +SUB 91 3-QUAD ; 1	C3
34126 MQOKETA5 161 34034 SALEM S5 161 1	264.8	62.6	223.0	118.5	D:SALEM 3-ROCK CK31 +ALBANY 5-YORK 51	C3
69505 GALENA 5 161 34043 SAVANNA5 161 1	206.4	91.7	167.0	123.6	D:SALEM 3-ROCK CK31 +SALEM S5-MQOKETA51	C3
34030 SALEM N5 161 34034 SALEM S5 161 1	381.1	167.3	335.0	113.8	D:SALEM N5-JULIAN 51 +SUB 91 3-QUAD ; 1	C3
34028 LORE 5 161 34033 TRK RIV5 161 1	207.9	121.8	200.0	104.0	WEMPLETON 345	C5

Table 9: Typical Examples of Branches with Overloading only in S-N or E-W Heavy Transfer Scenarios

6. Solution Development and Comparison

All the identified system issues in eastern Iowa system are addressed in this Chapter. The possible solutions for these issues could be:

1. Model correction;
2. Generation redispatch;
3. Interruptible load;
4. System reconfiguration;
5. Possible and practicable load shedding;
6. Future facility upgrades, including transmission/transformer/terminal equipment/shunt capacitor (etc.) upgrades, or future generation addition.

6.1 Proposed Solutions

6.1.1 Model Corrections

After reviewing the AC contingency analysis results, further model errors were identified and corrected. These corrections include:

1. Correct load "15" at 34.5 kV bus "SANDSPR9" from P = 12.7 MW, Q=8.7 MW to P = 12.7 MW, Q = 4.5 MW in 2011 base model. This eliminates the two low voltage violations at buses "HOPREC8" and "SANDSPR8" under system normal conditions;
2. Correct ratings of 69 kV line "POSTVIP8" - "POST" (34444 - 68748) from 25/28 to 45/45 MVA;
3. Correct ratings of 115 kV line "DUNDEE 7" - "COGGON 7" (34133 - 34131) from 60/60 to 75/75 MVA;
4. Correct ratings of 161/115 kV transformer "DUNDEE 5" - "DUNDEE 7" (34135 - 34133) from 56/56 to 75/75;
5. Correct 69 kV line "NO LIBER" - "NO LIBR" (34856 - 34762) from normally closed in the model to normally open. This will affect thermal loading results in the Cedar Rapids area to some degree.

6.1.2 Initial Facility Upgrade Proposals

Based on the initial AC contingency analysis, flowgate impact study, FCITC calculations, and MISO market wide PROMOD analysis, the following system issues may only be addressed by facility upgrade solutions due to their overloading levels and the impact of S-N and E-W transfers and load growth:

1. Overloading on two Hazleton 161/69 kV transformers under category A, B & C contingencies;
2. Overloading on Salem 345/161 kV transformer under category B and C contingencies;
3. Overloading on Hazleton 345/161 kV #1 transformer (224 MVA) under category B and C contingencies;
4. Overloading in the Fairfax/Hiawatha area under category B & C contingencies;
5. Overloading in the Lore/8th St./Turkey River areas under category C contingencies;
6. Overloading on Marion - Swampfx7 – Coggon - Dundee 115 kV line under category C contingencies;
7. Overloading on E. Calamus - Rock Creek 161 kV line under category C contingencies;
8. Overloading in Beaver Ch./Albany area under category C contingencies;
9. Overloading on Rock Ck 345/161 kV transformer under category C contingencies;
10. Overloading on Beaver Ch. – York - Savanna 161 kV line under category C contingencies;
11. Low voltage violations in the Beaver Ch./York/Savanna areas under category C contingencies - especially in heavy transfer scenarios;
12. Low voltage violations in the Fairfax/Hiawatha areas under category C contingencies;
13. Low voltage violations in the Dundee/Liberty areas under category C contingencies;
14. Low voltage violations at Salem and Rock Ck under heavy transfers for category B & C contingencies;

To address the above eastern Iowa system issues, the following four transmission options are proposed and their performances are compared:
Option 1: New Hazleton – Salem 345 kV line with a second Salem 345/161 kV transformer;
Option 2: New Hazleton – Lore - Salem 345 kV line with a Lore 345/161 kV transformer;
Option 3: New Cassville - Liberty 161 kV line;
Option 4: New Hazleton - Salem 161 kV line;

Besides these four options, the following two facility upgrades are also proposed and added;
1. Replace two Hazleton 161/69 kV transformers. The new recommended ratings are 74.7/74.7 MVA. This addresses the overloading problem on these two transformers;

2. To address the overloading problem between Hiawatha and Coggon, a new 161/115 kV substation named "Lewis Fields" (bus 34561) is proposed. A new 161 kV line from "Hiawatha" to "Lewis Fields" is to be built, and this new substation is tapped on the 115 kV line between the Swamp Fox and Cogan substations ("SWAMPFX7" - "Coggon"). The Lewis Fields substation bus will be relatively close to the Swamp Fox substation (tap point at 5% of the line distance between Swamp Fox and Coggan).

6.1.3 Performance Comparison among Four Options Based on AC Contingency Analysis

AC contingency analysis is performed on the 2011 summer peak base model to compare the four proposed transmission options.

1. The following describes the results when comparing option 1 (Salem – Hazleton 345 kV Line) and option 2 (Salem – Lore [new 345/161 kV sub] – Hazleton 345 kV Line)

a) Option 1 shows less loading on the Salem - Rock Ck - Quad 345 kV line, Dundee 161/115 kV transformer, and Lore - Turkey River 161 kV line.

Option 2 shows less loading on the two Hazleton 345/161 kV transformers, the Julian – Salem - S. Grandview - 8th St. 161 kV lines, the DBQ 8th Street 161/69 kV transformer, the Beaver Ch. – Albany – Savanna - York 161 kV lines, Hazleton - Dundee 161 kV line and Rock Creek 345/161 kV transformer

See Table F.1 and F.2 in Appendix F.

b) Option 2 provides better voltage than option 1. The 161 kV Dundee bus voltage is 3.84% higher and the Postville 161 kV bus voltage is 0.82% higher than what option 1 can provide under contingency. Observation of Table F.3 shows that this is a significant difference at Dundee..

c) Option 1 shows significant flowgate reductions across the Lore-Turkey River, Turkey River-Cassville and Quad Cities –Rook Creek flowgate by 12 to 22% when compared to option 2.

Option 2 shows significant flowgate reduction across the Salem – Julian, 8th Street - Kerper, Hazleton 345/161 kV Xfmr, Salem 345/161 kV Xmfr and Rock Creek 345/161 kV Xfmr by 3.5 – 95.5% compared to option 1.

There are no overloaded flowgates in either option 1 or option 2. See Table F.4 for the complete listing.

The following observations are also listed:

a) The limitation on Salem - Rock Ck - Quad Cities 345 kV line is due to CT's and conductor inside the substations. The line conductor rating is 1246 MVA. It should be a relatively inexpensive upgrade to get a significantly higher rating on this line. So for a relatively small amount of money spent on substation upgrades a noticeable benefit of option 1 can be mitigated if option 2 is pursued.

b) The limitation on Julian – Salem - S. Grandview - 8th St. - DBQ 8th 8 161 kV line is due to conductor rating between these substations. So it will be expensive to upgrade this 161 kV line. Option 2 dramatically lowers the flows on these flowgates over option 1.

c) Loading on the two Hazleton 345/161 kV transformers is lower with option 2. Since Hazleton #1 transformer will be replaced anyway due to its overloading issues it does mitigate somewhat the benefits of option 2. Having said that, option 2 is still a benefit to help reduce the Hazleton #2 transformer loading.

d) Loading on the Beaver Ch. – Albany – Savanna - York 161 kV lines is lower with option 2. The Beaver Ch. - Albany 161 kV line is rated at 223 MVA and limited by terminal equipment (CT, wave trap, and some substation jumpers). The line conductor rating is 240 MVA. The Albany - York 161 kV line is rated at 200 MVA and limited by the line conductor. The Savanna - York 161 kV line is rated at 167 MVA and limited by terminal equipment (CT, switch, wave trap, and some substation conductor). The line conductor rating is 200 MVA. So the lower line loading provided by option 2 is beneficial. See Tables F.1 and F.2.

e) Voltage improvement on 161 kV "Dundee" bus with option 2 is also beneficial as show in Table F.3;

f) Flowgate performance with option 2 is better than option 1 especially for the Salem – Julian and 8th St. – Kerper flowgates as shown in Table F.4;

g) Loading on Lore - Turkey River 161 kV line with option 1 is lower. This line is rated at 200 MVA and limited by line conductor. With the second Wempletown - Paddock 345 kV line in service in 2005 the overloading of the Lore - Turkey River line for loss of Wempletown - Rockdale or

Wempletown - Paddock 345 kV line is mitigated. Even so option 1 is still beneficial over option 2 under this condition.

Overall, option 2 is generally a better solution than option 1 based on the above comparisons and observations. Also the cost of other impacted follow-up facility upgrades by option 2 is less.

Furthermore, performance of an option 1A is also investigated. Option 1A is a variant of option 1. Instead of installing a second Salem 345/161 kV transformer, the pre-existing Salem transformer will be replaced by a larger transformer (ratings as 448/448 MVA) in option 1A. None of the overloads Julian – Salem - S. Grandview - 8th St. - DBQ 8th under option 1 is caused by any contingency involving Salem transformer, so the performance on Dubuque 161 kV system is the same between option 1 and 1A.

Given that the biggest advantage of option 2 is the much less loading in Dubuque 161 kV system, and that option 1A has the same/similar performance as option 1, option 2 is also better than option 1A.

2. The following describes the results when comparing option 1 (Salem – Hazleton 345 kV Line) and option 3 (Cassville – Liberty 161 kV Line) or 4 (Salem – Hazleton 161 kV Line,

With option 3 and other two facility upgrades (replacement of two Hazleton 161/69 kV transformers, and building a new Lewis Fields161/115 kV substation and a new 161 kV line from Hiawatha to Lewis Fields) mentioned in section 6.1.2, thermal loading on typical branches is shown in Table F.5. Some important notes are:

a) With Hazleton 345/161 kV #1 transformer replacement and installation of a second Salem 345/161 kV transformer, there will be no thermal/voltage violation under category B & C contingencies (except C3) for 2011 summer peak base case;
b) The overloading or potential overloading on the E. Calamus - Rock Creek 161 kV line is not mitigated by option 3;
c) The overloading or potential overloading on Davenport - Maquoketa 161 kV line is not mitigated by option 3;
d) The overloading or potential overloading on 161 kV system in the Dubuque 8th St. area is not mitigated by option 3;

e) The Hazleton 345/161 kV #2 transformer will be potentially overloaded;

f) The Beaver Ch. - Albany - York - Savanna 161 kV line will still be overloaded under category C contingencies;

g) Coggon – Dundee 115 kV line will still be overloaded under category C contingencies;

h) Overloading in the Fairfax/Hiawatha area is not mitigated by option 3.

Table F.6 compares overloads between option 3 and option 1. The major differences are:

a) Option 3 only mitigates some local issues in the Cassville/Turkey River/Liberty areas. Option 1 mitigates not only the system issues along Hazleton - Salem line but also overloading issues on the E. Calamus - Rock Creek 161 kV line, the Davenport-Maquoketa 161 kV line, and the Coggon – Dundee 115 kV line. Option 1 also mitigates the overloading issues on the Beaver Ch. – Albany – York - Savanna 161 kV line;

b) Furthermore, if option 2 is chosen, it will also mitigate the 161 kV system issues in the Dubuque 8th St. area;

c) For option 3, the second Salem 345/161 kV transformer will still need to be added, or the pre-existing transformer will still have to be replaced by a larger one (448/448 MVA).

Comparing option 3 with option 1 or 2, and considering the impact from east-west and south-north transfers and load growth, option 3 is not a reliable option.

System performance of option 4 is quite similar to that of option 3. The details are skipped here.

6.1.4 Interruptible Loads Solution

According to NERC planning criteria, category C violations allows for 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 electric power transfers.

Besides transmission option 2, replacement of two Hazleton 161/69 kV transformers, and building Lewis Fields 161 kV substation and new 115 kV line from Lewis Fields to SwampFox mentioned in Section 6.1.2, applicability and feasibility of relying on interruptible loads (loads which have contract to be interrupted if needed) and generation redispatch are first investigated for remaining category C contingency (especially C3 double contingencies) violations identified in eastern Iowa system. If interruptible load shedding and generation redispatch are not sufficient to mitigate the category C contingency violations, and load shedding is not applicable to mitigate the overloads, transmission projects will be further proposed.

Some of the major interruptible loads mainly located in the areas of Fairfax/Hiawatha, 8th St./DBQ are listed in Table 10.

BUS & BUS #	PR.CRK1G - 34092	BEVERL39 - 34160	WILMSBG9 - 34153	MILLCRK8 -34337	OAKRIDGE - 34760	CNTRGRV -34027	HIAWATA9 - 34112	J.DEERR - 34466
Interruptible MW	5.8	12.4	2.7	2.6	4.6	2.8	12.2	12.0

Table 10: Major Interruptible Loads in Eastern Iowa

Table G.1 lists some typical identified system issues after including option 1 and two other proposed facility upgrades listed in section 6.1.2. In this table, we can see the main issues are in the areas of Fairfax/Hiawatha, 8th St./DBQ. Also the last column "Interruptible Load Relief" lists the maximum loading relief from eight major interruptible loads for these identified thermal overloading issues. It is calculated based on sensitivities on an identified constraint by interruptible load shedding.

From Table G.1, it is demonstrated that it is not feasible and sufficient to rely on these interruptible loads for mitigating the identified thermal overloading problems.

6.1.5 Generation Redispatch Solution

The Generation redispatch solution is also investigated for remaining category C contingency violations in eastern Iowa.

Generators in ALTW, ALTE, and MGE are included for sensitivity analysis on the total 72 identified constraints after adding option 1 and the two facility upgrades listed in section 6.1.2. Only generators with sensitivity values more than 2% on a constraint are considered to be redispatched for this constraint mitigation. Table G.2 lists these 72 identified constraints, the maximum loading relief through generation redispatch, and whether generation redispatch is applicable to mitigate the constraint (loading relief is significantly larger than overloading MW).

From Table G.2, some observations are listed below:

1. For overloading in the Lansing area under category C3 contingencies, backing off Lansing generators ("LANS5 4G22.0", "LANS5 3G22.0") will provide enough mitigation;

2. Overloading in the Fairfax/PCI area can not be mitigated by generation redispatch, so further facility upgrades are necessary;
3. Overloading in the Dubuque 8th St. area normally can not be fully mitigated by redispatching "DBQ 8TH869.0" generation. Since option 2 eliminates these overload issues it is demonstrated to be a better solution than option 1 in this regard;
4. Overloading in Beaver Ch. system under category C3 contingencies can normally be mitigated by backing off generation of "BVRCH52G20.0".

6.1.6 System Reconfiguration Solution

For some of 69 kV system loading or low voltage violations under category C contingencies, a practical way to mitigate these violations is to open a normally-closed branch or close a normally-open branch. This often done at the 69 kV level, while ensuring it will not cause other violations. Table G.3 demonstrates the applicability and feasibility of this system reconfiguration for mitigating the thermal and voltage violations of these 72 constraints.

6.1.7 Further Facility Upgrade Proposals

For category C violations, if generation redispatch, and/or interruptible loads, and/or system reconfiguration can not mitigate the violations, and if the impacted loads are not designed or allowed to be shed for whatever reason, facility upgrades have to be proposed to address these category C violations. With all this in mind, analysis shows that the following additional facility upgrades are proposed:

1. Add a second Fairfax 161/69 kV transformer. This new transformer has the same design as the pre-existing Fairfax #1 transformer and the ratings are 205/205 MVA. This second Fairfax transformer will mitigate the related overload issues in the Fairfax/PCI area under category C contingencies;
2. In the Fairfax/Hiawatha area in Cedar Rapids, if the 161 kV Arnold - Fairfax and PCE – Bertram lines are opened, potential voltage collapse is indicated and this double contingency is not solved in PSS/E. To resolve this issue, a new 345 kV "BEV345T" (34555) substation is proposed to be built and tapped to the Arnold -Tiffin 345 kV line. This was modelled to be tapped on the 345 kV line at distance a bit closer to Arnold than Tiffin (Arnold sub [40% of line] – New 345 kV Sub – Tiffin [60% of line]). A new 345/161 kV transformer and a new 161 kV line will connect this new substation to Beverly 161 kV bus (34107);
3. Replace the Hazleton 345/161 kV #1 transformer with the same design as Hazleton 345/161 kV #2 transformer. The new ratings are 335/335 MVA;

4. Replace the limiting CTs and conductors inside the substations for Quad Cities - Rock Creek - Salem 345 kV lines so the line rating can be raised to the same as conductor rating between these substations. The new ratings of this 345 kV line will be 1246/1246 MVA. Upgrade substation conductor so the Rock Creek 345/161 kV 448 MVA transformer is the limiter for this branch;
5. Under the stuck breaker contingency (C2) "ALTW-C-NW-DUNDEE 161 BUS -STUCK BREAKER" at Dundee 161 kV bus, both Dundee - Liberty and Liberty - Lore 161 kV will be tripped and Dundee 161 kV bus will be disconnected. This is because there is no breaker at Liberty 161 bus. This contingency causes a lot of low voltage violations and thermal overloading in Dundee and Liberty 69 kV system. To resolve this issue, breakers are proposed to be installed at both ends of Liberty 161 kV bus. The new "ALTW-C-NW-DUNDEE 161 BUS -STUCK BREAKER" contingency is defined as:

```
CONTINGENCY 'New-ALTW-C-NW-DUNDEE 161 BUS -STUCK BREAKER'
    TRIP LINE FROM BUS 34135 TO BUS 34129 CKT 1    /* 'DUNDEE 5' 161KV TO
'LIBERTY5' 161kV
DISCONNECT BUS 34135    /* DUNDEE 161KV BUS OUTAGE
END
```

6. Upgrade terminal equipment for 69 kV line KIRK JT – Fairfax - NURSRYR (34749 – 34149 - 34896) so that the ratings are conductor limited to 103/103 MVA between substations;
7. Upgrade terminal equipment for 115 kV line Prairie Creek - Marion (34099-34103) so that new ratings are conductor limited 198/198 MVA between substations. Rebuild 115 kV line Marion - Swampfx7 - Coggon to a 198/198 MVA rating. The present line conductor is limited to 76 MVA;
8. Replace Dundee 161/115 kV (34135 - 34133) transformer (upgrade CT's) to a larger 112/112 MVA unit. It is presently a 75 MVA transformer;
9. Upgrade 69 kV line Peosta – Amocoil - Lore (34505 – 34460 - 34464) with new ratings as 80/80 MVA. This line is presently limited to 40 MVA.

6.1.8 Feasibility Study on Building New BEV345T - Beverly 161 kV Line

To build a new 345 kV "BEV345T" substation which is tapped between the Arnold – Tiffin 345 kV line, a new 345/161 kV transformer, and a new 161 kV line connecting from this new substation to Beverly, one routing option is to use the existing Blairstown – Prairie Creek 115 kV line Right Of

Way (ROW), i.e., tearing lown the old aged Blairstown – Prairie Creek 115 kV line and building the new BEV345T – Beverly 161 kV line.

With all proposed eastern Iowa projects added into the 2011 and 2015 summer peak base models, DC contingency analysis was performed to study whether it is feasible to build BEV345T – Beverly 161 kV line using the ROW of Blairstown – Prairie Creek 115 kV line. Two scenarios are studied and DCCC results are compared. These two scenarios are:

Scenario 1: Blairstown – Prairie Creek 115 kV line is out of service
Scenario 2: Blairstown – Prairie Creek 115 kV line is in service

Branch loadings under all category A, B and C contingencies are compared between these two scenarios. Table G1.1 and G1.2 in Appendix G1 list all branches with loading changes more than 5% of rating in 2011 and 2015 summer peak base models with all proposed eastern Iowa projects included. Some notes are listed from this comparison:

1. If Blairstown-Prairie Creek 115 kV line is out of service, loadings on Prairie Ck – Bertram 115 kV line, Prairie Ck – Marion 115 kV line, Ston PT – 6th St 115 kV line, Ston PT – Prairie Ck 115 kV line are increased by 5% ~20% of rated values under different category C3 contingencies compared with those with Blairstown-Prairie Creek 115 kV line in service;
2. Overloads were found on Prairie Ck – Bertram 115 kV line, Ston PT – Prairie Ck 115 kV line under category C3 contingencies;
3. Ston PT – 6th St 115 kV line is loaded at maximum 94% under C3 contingency.
4. All three 115 kV lines of Prairie Ck – Bertram, Ston PT – Prairie Ck, and Ston PT – 6th St have lines use 785 ACSR conductor which is rated at 197 MVA. Currently these three lines have lower ratings limited by substation conductor. It should be relatively inexpensive to replace limiting substation conductor and raise the ratings of these three lines to 197 MVA, which is sufficient for all category A, B and C contingencies. Having said that, review of the tables shows that if this is done there isn't a great deal of margin left over on the upgrades lines under second contingency. The highest flow shown under contingency is 185 MVA on the Prairie Creek – Bertram 115 kV line. This would imply that at some point in the foreseeable future some of this 4.7 mile line may be the first to have to be upgraded to a higher rating.

In conclusion, it is feasible to tear down Blairstown – Prairie Creek 115 kV line and build BEV345T – Beverly 161 kV line on the same ROW, if substation conductor of three 115 kV lines can be upgraded to raise ratings to 197 MVA.

6.1.9 Further Analysis on Proposed Transmission Option 2

Regarding the proposed 345 kV transmission option 2 (new Hazleton – Lore - Salem 345 kV line with a Lore 345/161 kV transformer), there are two follow-up questions listed below:

1. What will be the outstanding issues in eastern Iowa system if the option 2 is not taken?
2. Instead of building this line, is it more economical to develop several small projects to address these eastern Iowa outstanding issues?

In order to answer these questions, AC analysis was performed on the 2011 summer peak models with and without this new line and results were compared to identify what the remaining outstanding issues will be if this 345 kV line is not built. All other proposed projects listed in Section 6.1.7 plus two projects listed in Section 6.1.2 (Initial Facility Upgrades Proposals) are included in the compared models. So the only difference in the models is whether transmission option 2 is included or not.

For the ACCC analysis on the 2011 summer peak base model without option 2, branch loadings over 90% of rating is monitored. Bus voltages below 0.95 p.u. are also monitored. This is to catch all loading and voltage issues or potential issues since transfer impact or load growth impact should also be considered when developing a transmission solution. For the ACCC analysis on the 2011 base model with option 2, branch loading over 60% of rating is monitored. This is to calculate the branch loading difference between loading with and without this new Salem – Lore(new sub) - Hazleton 345kV line (option 2). Also bus voltages below 0.95 p.u. are monitored. Table H.1 in Appendix H lists branch overloading or potential overloading in 2011 summer peak base case with loading increase more than 5% of rating without transmission option 2. Table H.2 lists bus voltage violation or potential violation in 2011 summer peak base case with voltage decrease more than 0.01 p.u. without transmission option 2. From Table H.1 and H.2, it is noted that the following are major issues in eastern Iowa system without transmission option 2:

1. Overloading on Salem 345/161 kV transformer;

2. Overloading of 161 kV system in Dubuque area: Salem N – Julian – Center Grove 161 kV line, Salem – So.GVW.5 – 8th St – DBQ 8th8 161 kV line, 8th St – Kerper 5 161 kV line;
3. Overloading of 161 kV system in the west of Rock Creek: E Calamus – DeWitt – Rock Creek 161 kV line, Rock Creek 161/69 kV transformer;
4. Overloading of 161 kV system in the north of Beaver Ch: Beaver Ch – Albany – York – Savanna 161 kV line, Beaver Ch 161/69 kV transformer;
5. Overloading on 161 kV line Davenport – E Cal T5 – E Calamus – Maquoketa;
6. Overloading on 115 kV line Coggon – Dundee
7. Overloading on 161 kV lines SB EIC 5 – Hills 5 and SB 91 – SB 79
8. Potential voltage violation in Salem area: 34029_SALEM 3_345 kV, 34030_SALEM N5_161 kV, 34034_SALEM S5_161 kV, 69505_GALENA 5_161 kV
9. Potential voltage violation in the Lore/Dubuque area: 34026_ASBURY 5_161 kV, 34027_CNTRGRV5_161 kV, 34028_LORE 5_161 kV, 34031_SO.GVW.5_161 kV, 34032_8TH ST.5_161 kV, 34908_KERPER 5_161 kV, 34508_JULIAN 5_161 kV
10. Voltage violation or potential violation along Beaver Ch. – Savanna line: 34038_BVR CH 5_161 kV, 34042_BVR CH65_161 kV, 34043_SAVANNA5_161 kV, 34046_YORK 5_161 kV, 34359_SAVANNA8_69 kV, 68741_MTCARROL_69 kV, 68742_PALISADE_69 kV
11. Voltage violation or potential violation along Dundee – Liberty line: 34135_DUNDEE 5_161 kV, 34129_LIBERTY5_161 kV, 34697_PFEILRT8_69 kV, 34698_PFEILRE8_69 kV, 34856_NO LIBER_69 kV, 34857_HOLIDAY_69 kV, 34858_CVLE TAP_69 kV, 34859_CORALV R_69 kV, 34860_HRTLNDTP_69 kV, 34861_HERTLAND_69 kV;
12. Potential voltage violation in Rock Creek area: 34036_ROCK CK3_345 kV, 34035_ROCKCKW5_161 kV
13. Potential voltage violation along Wyoming – Mt. Vernon line: 34127_WYOMING5_161 kV, 34053_MT VERN5_161 kV;
14. Potential voltage violation along Turkey River – Nelson Dewey line: 34033_TRK RIV5_161 kV, 39959_GRANGRAE_69 kV;
15. Potential voltage violation in Tiffin 69 kV system: 34862_TIFFIN R_69 kV, 34864_TIFFIN_69 kV;

Without transmission option 2, there are a few other facilities with loading increase more than 5% of their rating but loaded between 80% and 90%. These facilities are:

1. 34018 HAZLTON3 345 34019 HAZLTON5 161 1
2. 34018 HAZLTON3 345 34020 HAZL S 5 161 2
3. 34026 ASBURY 5 161 34027 CNTRGRV5 161 1
4. 34030 SALEM N5 161 34034 SALEM S5 161 1
5. 34035 ROCKCKW5 161 34037 ROCK CK5 161 1
6. 34037 ROCK CK5 161 34042 BVR CH65 161 1
7. 34106 PCI 5 161 34109 BERTRAM5 161 1
8. 34110 HILLSIE5 161 64350 HILLS 3 345 1
9. 34126 MQOKETA5 161 34034 SALEM S5 161 1
10. 34135 DUNDEE 5 161 34020 HAZL S 5 161 1
11. 34423 MONONA_869.0 68748 POST 69.0 1
12. 34908 KERPER 5 161 34028 LORE 5 161 1
13. 64422 SB 49 5 161 34038 BVR CH 5 161 1
14. 64422 SB 49 5 161 64414 SB 17 5 161 1
15. 69505 GALENA 5 161 34043 SAVANNA5 161 1

Flowgate loading is also compared in the 2011 summer peak base model with or without transmission option 2. Loadings are compared on 27 eastern Iowa flowgates and the results are listed in Table H.3. Most of flowgates have more loading without transmission option 2. This is consistent with branch loading comparison result in Table H.1. But loading on flowgates with monitored branches of Quad Cities – Rock Creek 345 kV line, Lore – Turkey River 161 kV line, or Turkey River – Cassville 161 kV line are lower without transmission option 2. With transmission option 2, loadings on these flowgates are increased by up to 13% of the rating. As mentioned in Section 6.1.7, rating on Quad Cities – Rock Creek 345 kV is proposed to be uprated to conductor rating by replacing some terminal equipment, so loading increase on this line with option 2 is not an issue. Loading increase on flowgates associated with Lore – Turkey River – Cassville 161 kV line will be analyzed in Chapter 7.

Table H.4 lists facility rating (line conductor rating or transformer rating) for branches listed in Table H.1 with loading increase more than 5% of rating without option 2. Most of these branches have current rating the same or very close as facility rating, so their ratings are mostly limited by line conductor or transformer. As found and stated in Section 5, 10% ALTW load increase has significant impact on Salem 345/161 kV transformer, Marion – Dundee 115 kV line, York – Savanna 161 kV line, Hiawatha/Fairfax area, Rock Creek/Beaver Ch. area, and along Hazleton – Lore line. South –

North transfer has significant impact on Salem 345/161 kV transformer, Albany – Savanna 161 kV line, Dysart – Washburn 161 kV line, Tiffin – Arnold 345 kV line, E Calamus – Maquoketa 161 kV line, Marion – Dundee 115 kV line, Galena 161/69 kV transformer, Salem/Lore area, Hazleton area, Quad Cities/Rock Creek area, Fairfax/Hiawatha area. East-West transfer has significant impact on Salem 345/161 kV transformer, E Calamus - Maquoketa 161 kV line, York - Savanna 161 kV line, Rock Creek - E Calamus 161 kV line, Hazleton - Blackhawk 161 kV line, Salem/Lore area, Quad Cities/Rock Creek area, Fairfax/Hiawatha area. All these facilities/areas significantly impacted by load growth and transfers have loading increase more than 5% of rating or voltage decrease more than 0.01 p.u. under contingencies without transmission option 2. Without transmission option 2, most of these facilities/areas are loaded more than 90% of their ratings under contingencies, all others are loaded more than 80% of ratings. Considering all the above, the overloading or potential overloading facilities should mostly be replaced by higher rating facilities if transmission option 2 will not be implemented. Compared with the cost of transmission option 2, the total cost of all these small projects will be higher. So considering system reliability performance in far future (assuming 40-year life time of a 345 kV line) and cost of total projects, it is recommended to build a new Hazleton – Lore – Salem 345 kV line with a 345/161 kV transformer at Lore (transmission option 2) instead of building a bunch of small projects.

6.1.10 Proposing Projects for System Near-Term Needs

It may take 7 to 10 years to build a major 345 kV line. So the question here is before a new Hazleton – Lore – Salem 345 kV line with a Lore 345/161 kV transformer is built, what near-term issues in eastern Iowa system are. Besides transmission option 2, some other small projects are also proposed in Sections 6.1.7 and 6.1.2 to address the remaining outstanding issues after option 2 is taken. If some of these small projects are built in the near term first, can they address near-term eastern Iowa system issues especially under category A and B contingencies?

To answer these questions, AC contingency analysis was performed in 2011 and 2015 summer peak base models without including any proposed projects in eastern Iowa study. Only NERC category A and B contingencies are considered. Table I.1 in Appendix I lists typical examples of thermal violations under category A and B contingencies in 2011 and 2015 summer peak base cases. No bus voltage was found below 0.9 p.u. under category A and B contingencies in these two base cases. For the thermal violations with voltage 100 kV and above, the following projects mainly proposed in Sections 6.1.7 and 6.1.2 are recommended to be built first to address these system near-term issues:

1. Replace Salem 345/161 kV transformer with a larger 448/448 MVA transformer. This is an additional project to address Salem transformer numerous overloading issues under category B and C contingencies before transmission option 2 is built;
2. Replace Hazleton 345/161 kV #1 transformer with a larger 335/335 MVA transformer;
3. Replace two Hazleton 161/69 kV transformers with two larger 74.7/74.7 MVA transformers;
4. Build a new 345 kV "BEV345T" substation and tapped to 345 kV line Arnold – Tiffin at 40% distance away from Arnold. Add a new 345/161 kV transformer and build a new 161 kV line connecting the new substation to Beverly 161 kV bus. This will mitigate overloading on Arnold – Fairfax and PCI – Bertram 161 kV lines under category B contingencies. Also it will prevent potential voltage collapse when the area of Fairfax/Hiawatha loses one 161 kV line ARNOLD 5 - FAIRFAX51 connected to Arnold and another 161 kV line PCI 5 - BERTRAM51 connected to Bertram.
5. Build a new 161 kV substation "Lewis Fields" (34561) and a new 161 kV line from "Hiawatha" to "Lewis Fields". This new "Lewis Fields" substation is tapped to the 115 kV line "SWAMPFX7" - "Coggon" at 5% distance away from SWAMPFX7 via a new 161/115 kV transformer. This will address thermal overloading issues on Prairie Creek - Marion 115 kV line and Marion - Swampfx7 115 kV line;
6. Add a second Fairfax 161/69 kV transformer. This new transformer has the same design as the pre-existing Fairfax #1 transformer and the ratings are 205/205 MVA. This second Fairfax transformer will mitigate thermal overloading on Fairfax 161/69 kV #1 transformer under contingencies;
7. Upgrade substation conductor for three 115 kV lines of Prairie Ck – Bertram, Ston PT – Prairie Ck, and Ston PT – 6th St so that new ratings become 197/197 MVA limited by line conductor rating, if the new 161 kV line BEV345T - Beverly will be built using the ROW of Blairstown – Prairie Creek 115 kV line.

6.1.11 New Transformer Capacity Consideration

Two new 345/161 kV transformers are proposed to be added at Lore (option 2) and "BEV345T" (between Arnold – Tiffin) in the proposed eastern Iowa projects. Since Hazleton 345/161 kV #1 transformer (224/224 MVA) is proposed to be replaced by a larger 335/335 MVA transformer, and Salem 345/161 kV transformer (335/335 MVA) may be replaced by a larger 448/448 MVA transformer to address near-term system issues, one legitimate question here is whether these two replaced transformers can be installed in "BEV345T" and Lore, i.e., install 224/224 MVA original Hazleton transformer at "BEV345T" and install 335/335 MVA original Salem transformer at Lore.

With all proposed eastern Iowa projects added into 2011 and 2015 summer peak base model, and with the assumption of 224/224 MVA transformer at "BEV345T" and 335/335 MVA transformer at Lore, DC contingency analysis was performed to evaluate the maximum loading at Lore and "BEV345T" transformers under all category A, B and C contingencies. Table J.1 and J.2 in Appendix J list top 5 loadings at "BEV345T" and Lore transformers. A few notes are:

1. 335/335 MVA transformer at Lore is sufficient to meet system reliability need;
2. 224/224 MVA "BEV345T" transformer is loaded 96% at maximum in 2011 summer peak base case and overloaded at 111% at maximum in 2015 summer peak base case under the same double contingency (C3) "D:ARNOLD 5-FAIRFAX51 +PCI 5-BERTRAM51". The second and third maximum loadings are 81% and 70% in 2011 summer peak base case, and 91% and 78% in 2015 summer peak base case, under the corresponding C3 double contingencies "D:ARNOLD1G-ARNOLD 51 +ARNOLD 5-ARNOLD 31" and "D:ARNOLD1G-ARNOLD 51 +PCI 5-BERTRAM51";
3. There is no overloading on 224/224 MVA "BEV345T" transformer under all category A, B and C contingencies in 2011 summer peak base case;
4. In 2015 summer peak base case, there is no thermal overloading on 224/224 MVA "BEV345T" transformer under all category A, B and C contingencies except C3 double contingencies;
5. In 2015 summer peak base case, 224/224 MVA "BEV345T" transformer is overloaded at 111% of rating under the double contingency (C3) "D:ARNOLD 5-FAIRFAX51 +PCI 5-BERTRAM51". Generation redispatch and system reconfiguration are tested and they are not sufficient to mitigate this overloading.

In conclusion, 335/335 MVA transformer is capacity sufficient to be installed at Lore. 224/224 MVA "BEV345T" transformer is tentatively capacity sufficient up to 2012 year. After that, a larger 335/335 MVA transformer is recommended to be installed at "BEV345T".

6.2 Project Economic Comparison based on PROMOD Analysis

As it is noticed in Section 6.1, the proposed projects can resolve all or part of the reliability issues in eastern Iowa region. These projects may also have economic values on the following aspects:

1. Reduce the regional annual production cost (generation cost) since more generation are dispatched economically to serve loads if transmission constraints are reduced;

$$\text{regional annual production cost} = \sum_{i=1}^{8760}\sum_{j=1}^{M} C_{ij}$$

where

C_{ij} is fuel cost of generator j during hour i

M is the number of total generators

2. Reduce the regional annual load cost since congestion component of LMP (Locational Marginal Price) is reduced with more constraints mitigated and energy component of LMP is also reduced with more economical generation dispatched;

$$\text{regional annual load cost} = \sum_{i=1}^{8760}\sum_{j=1}^{N} LMP_{ij} * L_{ij}$$

where

L_{ij} is MW amount of load j during hour i

LMP_{ij} is LMP at bus of load j during hour i

N is the number of total load buses

Economic performances of four transmission options are compared with PROMOD analysis in 2011 base scenario. Also when four transmission options are compared, the other small projects proposed in Sections 6.1.2 and 6.1.7 are also included since they are necessary no matter which option is finally chosen. These four transmission options are again listed here:

Option 1: New Hazleton - Salem 345 kV line with a second Salem 345/161 kV transformer;
Option 2: New Hazleton – Lore - Salem 345 kV line with a Lore 345/161 transformer;
Option 3: New Cassville - Liberty 161 kV line;
Option 4: New Hazleton - Salem 161 kV line;

6.2.1 Cost and Saving Comparison

Table 10 lists the annual load cost, annual production cost and annual production cost saving in the whole eastern Iowa region with each of the four projects.

Eastern Iowa	Annual Load Cost ($)	Annual Production Cost ($)	Annual Production Cost Saving($)
Base Case	787,563,185	403,445,100	0
Option 1	711,431,595	371,157,592	32,287,508
Option 2	710,762,706	371,140,130	32,304,971
Option 3	711,489,862	372,845,837	30,599,263
Option 4	712,199,786	372,439,461	31,005,640

Table 11: Annual Cost and Saving Comparison among Four Transmission Options

where annual production cost saving is the difference between annual production cost with each option and base case.

Form Table 11, the followings are observed,

1. Option 2 has the most annual production cost saving ($32,304,971) and least annual load cost ($710,762,706). Option 1 is ranked the second, with $17,463 less annual production cost saving and $668,889 more annual load cost;
2. Option 4 has more annual production cost saving than option 3 though it has more annual load cost than option 3;
3. Comparing option 2 with option 4, option 2 has about 1.3 million more annual production cost savings than option 4. Considering 40-year life time of a 345 KV line, the total production cost saving will be about 52 million dollars;
4. Option 2 has about $1.4 million less annual load cost than option 4. So the total load cost will be saved by 56 million dollars during 40 years comparing option 2 with option 4.

So on the production cost saving and load cost aspect, option 2 is the most economical project among the four transmission options.

6.2.2 LMP Comparison

LMP at some typical buses in eastern Iowa are also compared. With no generator and load added/deleted from the system, low annual average LMP indicates less system constraint and more economical generation dispatched.

A load hub is established with all load buses in eastern Iowa system. The hourly hub LMP is calculated as:

$$\text{eastern Iowa hub LMP} = \frac{\sum_{j=1}^{N} LMP_j * L_j}{\sum_{j=1}^{N} L_j}$$

where

L_j is MW amount of load j during one particular hour

LMP_j is LMP at bus of load j during one particular hour

N is the number of total load buses

In Appendix K, Figure K.1 shows the annual average LMP comparison at some buses with each transmission solution. The detailed data is listed in Table K.1. Figure K.2 shows the annual maximum LMP comparison at some buses with each transmission solution. The detailed data is listed in Table K.2. Figure K.3 shows the annual minimum LMP comparison at some buses with each transmission solution. The detailed data is listed in Table K.3.

A few notes are listed below,

1. Eastern Iowa hub annual LMP is the least with option 2. Also LMP at most buses are the least with option 2;
2. Option 2 has the smallest annual maximum LMP at eastern Iowa hub and most buses;

From this LMP comparison, it is illustrated that option 2 has least system constraint and most economical generation dispatched in eastern Iowa region.

6.3 System Loss Comparison

Real power losses and reactive power losses are calculated in the control area basis of ALTW, MEC, ALTE, MGE, and MPW for eastern Iowa 2011 summer peak base case with four different transmission options as stated previously. These loss results are compared against the original 2011 summer peak base case (without any proposed transmission upgrades) and the loss changes are shown in Table 12. Note that negative value means loss decrease compared with the original base case, and positive value means loss increase.

	Option 1		Option 2		Option 3		Option 4	
Control Area	Delta_P (MW)	Delta_Q (MVAR)	Delta_P (MW)	Delta_Q (MVAR)	Delta_P (MW)	Delta_Q (MVAR)	Delta_P (MW)	Delta_Q (MVAR)
ALTW	-1.56	-26.63	-1.28	-26.99	-1.90	-16.15	-2.00	-17.96
MEC	-2.19	-19.86	-2.21	-20.34	-0.08	0.08	-0.30	-1.62
ALTE	-0.40	-4.43	0.04	-2.96	0.26	1.18	-0.01	-0.34
MGE	-0.04	-0.38	-0.07	-0.79	-0.03	-0.30	-0.01	-0.07
MPW	0.01	-0.02	0.01	0.00	-0.01	-0.08	-0.01	-0.08

Table 12: Loss Change with Different Transmission Options

Based on the loss change comparison result in Table 12, the following conclusions are drawn:

1. All these four transmission options will reduce the real power losses in the control areas of ALTW and MEC. Loss changes in other control areas are minor;

2. Because both option 1 and 2 have a proposed 345 kV transmission line from Hazleton to Salem, and this line will facilitate power transfer through Iowa, the ALTW real power loss reduction of option 1 or 2 is a little smaller compared with option 3 or 4. But reactive loss reduction is much larger than that in option 3 or 4. This indicates that voltage profile in ALTW and MEC will be greatly improved;

3. Option 1 has more real power loss reduction (about 0.28 MW in ALTW) than option 2, but option 2 has more reactive power loss reduction (about 0.46 MVAR in ALTW) than option 1. Since all these real power loss and reactive power loss reductions are small, the performance of option 1 and 2 is similar in the loss reduction perspective.

6.4 Recommended Solution

Four different transmission solutions are proposed and their performance in AC contingency analysis, PROMOD market wide analysis, and system loss reduction are analyzed and compared. A few findings are repeated here:

1. In the aspect of AC contingency analysis, option 2 is better than option 1. Compared with option 1, loading on two Hazleton 345/161 kV transformers, Julian – Salem - S. Grandview - 8th St. - DBQ 8thS 161 kV line, Beaver Ch. – Albany – Savanna - York 161 kV line, Hazleton - Dundee 161 kV line and Rock Creek 345/161 transformer are less with option 2;
2. In the aspect of production cost saving and load cost of eastern Iowa under MISO market wide dispatch, option 2 has the most annual production cost saving and least annual load cost among four transmission options;
3. In the aspect of LMP reduction, option 2 has least annual LMP in eastern Iowa hub and most buses in eastern Iowa system. This also indicates that option 2 has least system constraints and most economical generation dispatched;
4. In the aspect of system loss reduction, option 1 and option 2 have similar performance.

To resolve the identified eastern Iowa system issues, different transmission solutions are compared and their performance is evaluated. Option 2 is selected from four different transmission options based on the reliability/economic comparison. The possibility and cost of doing a bunch of small upgrades instead of implementing option 2 is also investigated. From perspectives of system reliability performance and cost of all projects, it is recommended to build transmission option 2 instead of building a bunch of small projects. Applicability and feasibility for the solutions of generation redispatch, system reconfiguration, interruptible loads and load shedding are investigated and tested. For system issues without solutions of generation redispatch, etc., transmission solutions are investigated and tested. Based on this comparison and study, the following solutions are recommended to resolve the eastern Iowa system issues:

1. Build a new Hazleton – Lore - Salem 345 kV line with a Lore 345/161 kV 335/335 MVA transformer (option 2). This resolves a lot of thermal and voltage violations under category B and C contingencies in the whole system;
2. Replace two Hazleton 161/69 kV transformers. The new ratings are 74.7/74.7 MVA. This address the overloading problem on these two transformers under category B and C contingencies;

3. Build a new 161 kV substation "Lewis Fields" (34561) and a new 161 kV line from "Hiawatha" to "Lewis Fields". This new "Lewis Fields" substation is tapped to the 115 kV line "SWAMPFX7" - "Coggon" at 5% distance via a new 161/115 kV transformer. This addresses the overloading and low voltage issues between Hiawatha and Coggon,

4. Add a second Fairfax 161/69 kV transformer. This new transformer has the same design as the pre-existing Fairfax #1 transformer and the ratings are 205/205 MVA. This second Fairfax transformer will mitigate the related thermal overloading issues in the area of Fairfax/PCI;

5. When the area of Fairfax/Hiawatha lose one 161 kV line "ARNOLD 5" - "FAIRFAX5" connected to Arnold and another 161 kV line "PCI 5" – "BERTRAM5" connected to Bertram, potential voltage collapse is indicated and this double contingency is not solved. To resolve this issue, a new 345 kV "BEV345T" (34555) substation is to be built between 345 kV line Arnold-Tiffin at 40% distance away from Arnold. A new 345/161 kV transformer (recommended rating of 335/335 MVA but 224/224 MVA transformer can be tentatively used up to 2012 year) and a new 161 kV line will connect this new substation to Beverly 161 kV bus (34107);

6. Replace the Hazleton 345/161 kV #1 transformer with the same design as Hazleton 345/161 kV #2 transformer. The new ratings are 335/335 MVA. This addresses the overloading problem on this transformer when the second Hazleton 345/161 kV transformer is lost;

7. Replace the limiting facility of CTs and conductor inside the substations for 345 kV line Quad Cities-Rock Creek-Salem so the line rating can be raised to the same as conductor rating between substations. The new ratings of this 345 kV line will be 1246/1246 MVA. This resolves the potential line overloading under numerous contingencies;

8. Upgrade substation conductor so the ratings of Rock Creek 345/161 kV transformer are 448 MVA limited by transformer itself. This addresses the transformer overloading under category C contingencies;

9. Under stuck breaker contingency (C2) "ALTW-C-NW-DUNDEE 161 BUS -STUCK BREAKER" at Dundee 161 kV bus, both Dundee-Liberty and Liberty-Lore 161 kV will be tripped and Dundee 161 kV bus will be disconnected. This is due to no breaker at Liberty 161 bus. The contingency causes a lot of low voltage violations and thermal overloading in Dundee and Liberty 69 kV systems. To resolve this issue, breakers are proposed to be installed at both ends of Liberty 161 kV bus;

10. Upgrade terminal equipment for 69 kV line KIRK JT – Fairfax - NURSRYR (34749 – 34149 - 34896) so that the ratings become 103/103 MVA limited by conductor rating between substations. This resolves the 69 kV line overloading under category C contingencies;

11. Upgrade terminal equipment for 115 kV line Prairie Creek - Marion (34099 - 34103) so that new ratings become 198/198 MVA limited by conductor rating. Rebuild 115 kV line Marion - Swampfx7 - Coggon to the new rating as 198/198 MVA. This resolves line overloading issues under category B contingencies with heavy transfer or category C contingencies;

12. Replace Dundee 161/115 kV (34135 - 34133) transformer with new ratings as 112/112 MVA. This resolves transformer overloading under category B contingencies with heavy transfer or overloading under category C contingencies;

13. Upgrade 69 kV line Peosta – Amocoll – Lore (34505 – 34460 – 34464) with new ratings as 80/80 MVA. This resolves line overloading issue under category C contingencies;

14. For thermal overloading in the area of Lansing under category C3 contingencies, backing off Lansing generators ("LANS5 4G22:0", "LANS5 3G22:0") will provide enough mitigation;

15. Thermal overloading in the area of Beaver Ch. can be mitigated by backing off generation of "BVRCH52G20.0";

16. Thermal overloading of the 161 kV line Hazleton – Blackhawk under category C3 contingency can be mitigated by turning on generation at "EL FARMS 161", or "GT SUB 869:0", or "FLOYD 869.0";

17. Numerous 69 kV line overloading can be mitigated via system reconfiguration of opening a normal-closed line or closing a normal-open line.

18. Upgrade substation conductor for three 115 kV lines of Prairie Ck – Bertram, Ston PT – Prairie Ck, and Ston PT – 6th St so that new ratings become 197/197 MVA limited by line conductor rating, if the new 161 kV line BEV345T - Beverly will be built using the ROW of Blairstown – Prairie Creek 115 kV line.

19. There are some severe low voltage issues in Grand Mound area. Since ALTW is currently doing a planning study for this local area, the system issues in Grand Mound and their possible transmission solutions are not considered in this eastern Iowa study. Up to date, one possible transmission solution being considered is to build one 161 kV substation between E Calamus – DeWitt 161 kV line 5% distance away from E Calamus and build one 2 miles new 161 kV line between the new substation and Grand Mound with normal-open.

Table 13 lists system thermal/voltage issues mitigated by each of these recommended projects.

Since it usually takes about 7 to 10 years to build a major 345 kV transmission line, to address the system near-term issues especially thermal violations in 100 kV and above system, the following projects are recommended to be built first:

1. Replace Salem 345/161 kV transformer with a larger 448/448 MVA transformer. This is an additional project to address Salem transformer numerous overloading issues under category B and C contingencies before transmission option 2 is built;
2. Replace Hazleton 345/161 kV #1 transformer with a larger 335/335 MVA transformer;
3. Replace two Hazleton 161/69 kV transformers with two larger 74.7/74.7 MVA transformers;
4. Build a new 345 kV "BEV345T" substation and tapped to 345 kV line Arnold - Tiffin at 40% distance away from Arnold. Add a new 345/161 kV transformer and build a new 161 kV line connecting the new substation to Beverly 161 kV bus. This will mitigate overloading on Arnold – Fairfax and PCI – Bertram 161 kV lines under category B contingencies. Also it will prevent potential voltage collapse when the area of Fairfax/Hiawatha loses one 161 kV line ARNOLD 5 - FAIRFAX51 connected to Arnold and another 161 kV line PCI 5 - BERTRAM51 connected to Bertram.
5. Build a new 161 kV substation "Lewis Fields" (34561) and a new 161 kV line from "Hiawatha" to "Lewis Fields". This new "Lewis Fields" substation is tapped to the 115 kV line "SWAMPFX7" - "Coggon" at 5% distance away from SWAMPFX7 via a new 161/115 kV transformer. This will address thermal overloading issues on Prairie Creek - Marion 115 kV line and Marion - Swampfx7 115 kV line;
6. Add a second Fairfax 161/69 kV transformer. This new transformer has the same design as the pre-existing Fairfax #1 transformer and the ratings are 205/205 MVA. This second Fairfax transformer will mitigate thermal overloading on Fairfax 161/69 kV #1 transformer under contingencies;
7. Upgrade substation conductor for three 115 kV lines of Prairie Ck – Bertram, Ston PT – Prairie Ck, and Ston PT – 6th St so that new ratings become 197/197 MVA limited by line conductor rating, if the new 161 kV line BEV345T - Beverly will be built using the ROW of Blairstown – Prairie Creek 115 kV line.

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Project	Thermal/Voltage Issues Mitigated
Build a new Hazleton – Lore - Salem 345 kV line with a Lore 345/161 kV 335/335 MVA transformer (option 2)	Salem 345/161 xfmr ovrloading
	161 kV system overloading in Dubuque area: Salem N – Julian – Center Grove 161 kV line, Salem – So.GVW.5 – 8th St – DBQ 8th8 161 kV line, 8th St.– Kerper 5 161 kV line
	161 kV system thermal overloading in the west of Rock Creek: E Calamus – DeWitt – Rock Creek 161 kV line
	Thermal overloading on Rock Creek 161/69 kV transformer
	161 kV system thermal overloading in the north of Beaver Ch: Beaver Ch – Albany – York – Savanna 161 kV line
	Thermal overloading on Beaver Ch 161/69 kV transformer
	Thermal overloading on 161 kV line Davenport – E Cal T5 – E Calamus – Maquoketa
	Thermal overloading on 115 kV line Coggon – Dundee
	Thermal overloading on 161 kV lines SB EIC 5 – Hills 5 and SB 91 – SB 79
	Potential voltage violation in Salem area
	Potential voltage violation in Lore/Dubuque area
	Voltage violation or potential violation along Beaver Ch. – Savanna line
	Voltage violation or potential violation along Dundee – Liberty line
	Potential voltage violation in Rock Creek area

	Potential voltage violation along Wyoming – Mt. Vernon line
	Potential voltage violation along Turkey River – Nelson Dewey line
Replace two Hazleton 161/69 kV transformers	Thermal overloading on two Hazleton 161/69 kV transformers
Build a new 161 kV substation "Lewis Fields" to be tapped to the 115 kV line "SWAMPFX7" - "Coggon" at 5% distance via a new 161/115 kV transformer. Also build a new 161 kV line from "Hiawatha" to "Lewis Fields"	Thermal overloading on Prairie Creek - Marion 115 kV line
	Thermal overloading on Marion - Swampfx7 115 kV line
	Thermal overloading on Coggon - Dundee 115 kV line
	Thermal overloading on Dundee 161/115 kV transformer
	Thermal overloading on Hazleton 345/161 #1 transformer
	Low voltage between Hiawatha and Coggon
Add a second Fairfax 161/69 kV transformer	Thermal Overloading on Fairfax 161/69 kV #1 transformer
	Thermal Overloading on PCI 161/69 kV transformer
	Thermal overloading on PCI East - Oak Ridge 69 kV line
Build a new 345 kV "BEV345T" substation and tapped to 345 kV line Arnold -Tiffin at 40% distance away from Arnold. Add a new 345/161 kV transformer and build a new 161 kV line connecting the new substation to Beverly 161 kV bus	Potential voltage collapse when the area of Fairfax/Hiawatha loses one 161 kV line ARNOLD 5 - FAIRFAX51 connected to Arnold and another 161 kV line PCI 5 - BERTRAM51 connected to Bertram.
	Thermal overloading on Arnold - Hiawatha 161 kV line
	Thermal overloading on Arnold - Fairfax 161 kV line
	Thermal overloading on Hiawatha 161/69 transformer
	Thermal overloading on PCI - Bertram 161 kV line

	Thermal overloading on E. Calamus - Maquoketa 161 kV line
	Low voltage in Fairfax/Hiawatha area
Replace the Hazleton 345/161 kV #1 transformer with the same design as Hazleton 345/161 kV #2 transformer	Thermal overloading on Hazleton 345/161 #1 transformer
Replace the limiting facility of CTs and conductor inside the substations for 345 kV line Quad Cities-Rock Creek-Salem so the line rating can be raised to the same as conductor rating between substations	Thermal overloading on Quad Cities - Rock Creek - Salem 345 kV line
Install two breakers at both ends of Liberty 161 kV bus.	Low voltage and thermal overloading in Dundee and Liberty 69 kV system under Dundee stuck breaker contingency
Upgrade terminal equipment for 69 kV line KIRK JT – Fairfax - NURSRYR (34749 – 34149 - 34896) so that it is limited by line conductor rating	Thermal overloading on KIRK JT – Fairfax - NURSRYR 69 kV line
Upgrade terminal equipment for 115 kV line Prairie Creek - Marion (34099-34103) so that new ratings become 198/198 MVA limited by conductor rating. Rebuild 115 kV line Marion - Swampfx7 - Coggon to the new rating as 198/198 MVA	Thermal overloading on Prairie Creek - Marion - Swampfx7 - Coggon 115 kV line
Replace Dundee 161/115 kV transformer with new ratings as 112/112 MVA	Thermal overloading on Dundee 161/115 kV transformer
Upgrade 69 kV line Peosta – Amocoil - Lore with new ratings as 80/80 MVA	Thermal overloading on Peosta – Amocoil - Lore 69 kV line

Table 13: Thermal/Voltage Issues Mitigated by Each of Eastern Iowa Recommended Projects

7. Solution Verification

All the recommended solutions in Section 6.4 for Eastern Iowa system are added into the originally developed 2011 summer peak base model, 2011 S-N transfer model, 2011 E-W transfer model, 2015 summer peak base model, 2015 S-N transfer model, 2015 E-W transfer model. In this chapter, the eastern Iowa transmission system performance will be checked and verified via AC steady-state contingency analysis (including FCITC), PROMOD analysis for MISO market-wide dispatch, voltage stability analysis, and dynamic stability analysis.

7.1 Verification via AC Steady-State Contingency Analysis

7.1.1 2011 Summer Peak Base Case

Table L.1 lists branch thermal loading above 97% under system intact, category B & C contingencies in 2011 summer peak base case. The same monitored branch is only listed one time for the highest loading with one contingency. From this table, some notes are listed below:

1. There is no branch loaded above 97% under system intact and category B contingencies;
2. Branch overloading is only observed under some category C3 (automatic double contingencies) contingencies. All these branch overloads can be mitigated by system reconfiguration or generation redispatch. For example, the Turkey River 161/69 kV transformer overloading (34033 TRK RIV5 161 34465 TURK RV869.0 1) under double contingency (D:HAZLTON5-WINDSOR51 +LANSINGW-LANSING51) can be mitigated via either opening the overloaded transformer or backing down generation of LANSING869.0, LANS5 3G22.0;
3. Fairfax 161/69 kV transformers #1 and #2 are loaded at 99.1% under double contingency (one Fairfax transformer contingency with one PCI transformer contingency). One simple solution is to replace these Fairfax 161/69 kV transformers with bigger transformers. The recommended ratings for these bigger transformers should be 250/250 MVA.

There is no 100 kV and above voltage violation under any contingency. There are a few 69 kV bus voltage violations (most are about 0.89 p.u.) under category C3 double contingencies. Since system reconfiguration or generation redispatch are not simulated for these automatic double contingencies, and the 69 kV bus voltage is close to the low voltage limit (0.9 p.u.), these 69 kV voltage violations are ignored.

Table L.2 lists the eastern Iowa flowgate loading. There are only three flowgates with high loading above 60%, which are flowgate 3758 (3758_Hazleton T21 345/161kV flo Hazleton T22 345/161kV), 3725 (3725_Sub 56(Davnprt)-E.Calamus161 for Quad-RockCr345), and 3761 (3761_Lore-Turkey River 161 (flo) Wempletown-Rockdale 345).

For the non-converged contingencies (contingencies not solved by MUST), all of them can be manually solved. None of them cause any thermal overloading or voltage violations.

Based on the above, it is concluded that with the recommended transmission solutions in service, the eastern Iowa system is performing reliably under AC contingency analysis during 2011 summer peak base scenario. But as it is pointed previously, Fairfax 161/69 kV transformers should be replaced by bigger transformers with ratings as 250/250 MVA.

7.1.2 2011 S-N Transfer Case

In 2011 south-north heavy transfer scenario, there are several thermal violations under category B contingencies. They are listed in Table L.3. From this table, we can see that,

1. Salem 345/161 kV transformer is overloaded at 111.4% under the contingency of "34029 SALEM 3 345 34920 LORE345 345 1". Under the same contingency, Salem 345/161 kV transformer is only loaded at 81% in 2011 summer peak base case. As it is found in Section 5, both south-north and east-west transfers have significant impact on Salem 345/161 kV transformer. The simple solution is to replace this Salem transformer with a 448/448 MVA larger transformer;
2. Other category B thermal violations can be mitigated by generation redispatch or system reconfiguration.

Under category C (except C3 double contingency) contingencies, all branch thermal violations are listed in Table L.4. It is very clear that all these violations can be mitigated by generation redispatch or system reconfiguration.

Considering the probability of occurrence of heavy south-north transfer scenario (flow on Arnold-Hazleton 345 kV line at 600 MW), and the probability of occurrence of C3 double contingencies, the probability of occurrence of these particular C3 double contingencies under heavy S-N transfer scenario is deemed very low. Hence thermal violations under C3 contingencies are not studied in S-N transfer case.

There is no bus voltage violation under any contingencies except C3 contingency. There are three 100 kV and above bus voltage violations under category C3 contingencies. All these three bus voltage violations can be mitigated by fixing the transformer tap. See Table L.5. No significant 69 kV bus voltage violations under category C3 contingencies.

Table L.6 lists all eastern Iowa flowgate loading under 2011 S-N transfer scenario. Flowgate 3725 (3725_Sub 56(Davnprt)-E.Calamus161 for Quad-RockCr345) is loaded at 99.4%, followed by flowgate 3761 (3761_Lore-Turkey River 161 (flo) Wempletown-Rockdale 345) loaded at 89.7% and flowgate 3728 (3728_Dysart-Washburn 161 for D.Arnold-Hazleton 345) loaded at 81.2%.

All non-converged contingencies (contingencies not solved by MUST) can be manually solved.

It is concluded that with the recommended transmission solutions in service, the eastern Iowa system is performing reliably with a few limited number of generation redispatch and system reconfiguration under AC contingency analysis in 2011 S-N heavy transfer scenario. But as it is stated previously, one solution for Salem 345/161 kV transformer overloading is to replace it with a 448/448 MVA transformer.

7.1.3 2011 E-W Transfer Case

Several thermal overloads were found in 2011 east-west heavy transfer scenario under all contingencies except C3 double contingency. They are listed in Table L.7. It is clear that except Salem 345/161 kV transformer overloaded at 105% under the contingency of "34029 SALEM 3 345 34920 LORE345 345 1", other branch thermal overloading can all be mitigated by generation redispatch or system reconfiguration. So it is also shown that Salem 345/161 kV transformer should be replaced by a 448/448 MVA transformer.

There is no bus voltage violation under any contingencies except C3 contingency. There are only several 69 kV bus voltage violations under category C3 contingencies. All these violated bus voltages are around 0.89 p.u..

Flowgate loading under 2011 E-W scenario is listed in Table L.8. Flowgate 3725 (3725_Sub 56(Davnprt)-E.Calamus161 for Quad-RockCr345) is the most loaded flowgate, which is loaded at 88.7%. The second most loaded flowgate is flowgate 3758 (3758_Hazleton T21 345/161kV flo Hazleton T22 345/161kV), which is loaded at 81.4%. Flowgate 3715 (3715_Quad Cities-Rock Creek 345/MEC Cordova-Sub 39) is the third most loaded flowgate, which is loaded at 77.7%.

All non-converged contingencies (contingencies not solved by MUST) can be manually solved. From the above, it is concluded that with the recommended transmission solutions in service, the eastern Iowa system is performing reliably with under AC contingency analysis in 2011 E-W heavy transfer scenario, with Salem 345/161 kV transformer being replaced by a 448/448 MVA transformer.

So based on the AC contingency analysis, with the recommended transmission solutions in service, and furthermore, Fairfax 161/69 kV transformer replaced by a 250/250 MVA transformer and Salem 345/161 kV transformer replaced by a 448/448 MVA transformer, eastern Iowa transmission system is reliable under three scenarios (summer peak base, S-N transfer, E-W transfer) in 2011.

7.1.4 2015 Summer Peak Base Case

The following AC contingency analysis for 2015 three scenarios is assuming Salem 345/161 kV transformer being replaced by a 448/448 MVA transformer.

Table L.9 lists branch thermal overloading under system intact, category B & C contingencies in 2015 summer peak base case. The same monitored branch is only listed one time for the highest loading with one contingency. From this table, some notes are listed below:

1. There is no branch overloading under system intact, category B contingencies, and category C (except C3 double contingency) contingencies;
2. Branch overloading is only observed under some category C3 (automatic double contingencies) contingencies. Most of these branch overloading can be mitigated by system reconfiguration or generation redispatch. For example, the Lansing 161/69 kV transformer overloading (34022 LANSING5 161 34023 LANSING869.0 1) under double contingency (D:LANSINGW-GENOA 51 +LANSING5-POSTVIL51) can be mitigated by backing down generation of LANS5 4G22.0, LANSING869.0, LANS5 3G22.0;

3. Fairfax 161/69 kV transformers #1 and #2 are overloaded at 111.2% under double contingency (one Fairfax transformer contingency with one PCI transformer contingency). PCI 161/69 kV transformer is overloaded at 102.8% under double contingency (D:ARNOLD 5-FAIRFAX51 +BEVERLY5-FAIRFAX51). The simplest solution is to replace Fairfax 161/69 kV transformers and PCI transformer with bigger transformers. The recommended ratings for these bigger transformers should be 250/250 MVA.

There are several 100 kV and above bus voltage violations under C3 double contingencies. These are listed in Table L.10. A few notes are:
1. Fix transformer tap at 1.0 is a good solution for bus voltage violations at "POSTVIL5", "SO.GVW.5", "8TH ST.5", and "KERPER 5";
2. For bus voltage violations at "MARION 7" and "DRYCREK7", it is a good solution to install a switched shunt at 115 kV bus "MARION 7";
3. There are a few 69 kV bus voltage violations (most are around 0.89 p.u.) under category C3 double contingencies. Since system reconfiguration or generation redispatch are not simulated for these automatic double contingencies, and the 69 kV bus voltage is close to the low voltage limit (0.9 p.u.), these 69 kV voltage violations are ignored.

Table L.11 lists the eastern Iowa flowgate loading. There are only three flowgates with high loading above 60%, which are 3725 (3725_Sub 56(Davnprt)-E.Calamus161 for Quad-RockCr345) loaded at 73.5%, flowgate 3758 (3758_Hazleton T21 345/161kV flo Hazleton T22 345/161kV) loaded at 65.8%, and 3761(3761_Lore-Turkey River 161 (flo) Wempletown-Rockdale 345) loaded at 62.8%.

All the non-converged contingencies (contingencies not solved by MUST) can be manually solved. None of them cause any other thermal overloading or voltage violations.

Based on the above, it is concluded that with the recommended transmission solutions in service, the eastern Iowa system is performing reliably under AC contingency analysis during 2015 summer peak base scenario. One additional project is to replace Fairfax 161/69 kV transformers and PCI transformer with bigger transformers. The recommended ratings for these bigger transformers should be 250/250 MVA.

7.1.5 2015 S-N Transfer Case

Table L.12 lists all branch thermal violations under category B and C (except C3) contingencies. For information purpose, overloading on Fairfax 161/69 kV transformers and PCI 161/69 kV transformer under a double contingency of the other two transformers out of service is also listed. A few notes are:

1. There are several thermal violations under category B contingencies. All these violations can be mitigated by generation redispatch or system reconfiguration;
2. PCI 161/69 kV transformer is overloaded under the Bus outage "34111 FAIRFAX5 161" (category C1). For other branch overloading under category C (except C3) contingencies, all of them can be mitigated by generation redispatch or system reconfiguration;
3. Fairfax 161/69 kV transformers, PCI 161/69 kV transformer should be replaced by 250/250 MVA transformers;
4. Salem 345/161 kV transformer should be replaced by a 448/448 MVA transformer.

There is no bus voltage violation (69 kV and up) under all contingencies except C3 double contingencies. There are several 100 kV and above bus voltage violations under C3 double contingencies. These are listed in Table L.13. Except bus voltage violations at "DRYCREK7" and "MARION 7", which can be resolved by installing a switched shunt at "MARION 7" 115 kV bus, other voltage violations can all be mitigated by fixing the transformer tap at 1.0 position.

There are a few 69 kV bus voltage violations (most are around 0.88 p.u., 0.89 p.u.) under category C3 double contingencies. Since system reconfiguration or generation redispatch are not simulated for these automatic double contingencies, and the 69 kV bus voltage is close to the low voltage limit (0.9 p.u.), these 69 kV voltage violations are ignored.

Table L.14 lists the eastern Iowa flowgate loading. Flowgate 3725 (3725_Sub 56(Davnprt)-E.Calamus161 for Quad-RockCr345) is overloaded at 108.1%. As it is stated in Table L.12, generation redispatch can be a good solution by turning on "EL FARM5 161" or backing down "RIVSID5G15.0". The other three flowgates loaded above 80% are: flowgate 3761 (3761_Lore-Turkey River 161 (flo) Wempletown-Rockdale 345) loaded at 88.6%, flowgate 3728 (3728_Dysart-Washburn 161 for D.Arnold-Hazleton 345) loaded at 84.2%, and flowgate 3715 (3715_Quad Cities-Rock Creek 345/MEC Cordova-Sub 39) loaded at 83%.

All the non-converged contingencies (contingencies not solved by MUST) can be manually solved.

From the above analysis, under 2015 S-N heavy transfer scenario, with Salem 345/161 kV transformer replaced by a 448/448 MVA transformer and PCI, Fairfax 161/69 kV transformers replaced by 250/250 MVA transformers, eastern Iowa system is reliable with a few limited number of generation redispatches or system reconfigurations based on AC contingency analysis.

7.1.6 2015 E-W Transfer Case

Table L.15 lists all branch thermal violations under category B and C (except C3) contingencies in 2015 E-W heavy transfer scenario. For information purpose, overloading on Fairfax 161/69 kV transformers and PCI 161/69 kV transformer under a double contingency of the other two transformers out of service is also listed. A few notes are:

1. All these thermal overloading can be mitigated by generation redispatch or system reconfiguration;
2. Again, PCI and Fairfax 161/69 kV transformers should be replaced by 250/250 MVA transformers.

There is no bus voltage violation (69 KV and above) under all contingencies except C3 double contingencies. There are several 100 KV and above bus voltage violations under C3 double contingencies. These are listed in Table L.16. Except bus voltage violations at "DRYCREK7" and "MARION 7" 115 kV buses, which can be resolved by installing a switched shunt at "MARION 7" bus, other voltage violations can all be mitigated by fixing the transformer tap at 1.0 position. Again, 69 kV bus voltage violations under double contingencies are ignored.

Table L.17 lists the eastern Iowa flowgate loading. Flowgate 3725 (3725_Sub 56(Davnprt)-E.Calamus161 for Quad-RockCr345) is loaded at 96.7%, followed by flowgate 3715 (3715_Quad Cities-Rock Creek 345/MEC Cordova-Sub 39) loaded at 81% and flowgate 3758 (3758_Hazleton T21 345/161kV flo Hazleton T22 345/161kV) loaded at 80.5%.

All the non-converged contingencies (contingencies not solved by MUST) can be manually solved.

In conclusion, under the 2015 E-W heavy transfer scenario, with the Salem 345/161 kV transformer replaced by a 448/448 MVA transformer and PCI, Fairfax 161/69 kV transformers replaced by 250/250 MVA transformers, eastern Iowa system is reliable with a few limited number of generation redispatch or system reconfiguration based on AC contingency analysis.

7.2 Verification via FCITC Calculation

With all the recommended solutions in Section 6.4 added into the 2011 summer peak base model, 2011 S-N transfer model, 2011 E-W transfer model, 2015 summer peak base model, 2015 S-N transfer model, 2015 E-W transfer model, First Contingency Incremental Transfer Capacity (FCITC) is re-calculated for 2011 year and 2015 year under south-north transfer and east-west transfer. Only system intact and category B contingencies are considered. FCITC is calculated on the monitored branches with at least 2% TDF value for the transfer under the system intact or contingency.

7.2.1 FCITC Re-Calculation in 2011 Year

As stated in Section 2.1, 2011 S-N transfer case is created from 2011 base case by increasing south-north transfer up to 1916.6 MW so that flow on Arnold to Hazleton 345 kV line is benchmarked at 600 MW. 2011 E-W transfer case is created from 2011 base case by increasing east-west transfer up to 1879.8 MW so that flow on Montezuma to Bondurant 345 kV line is benchmarked at 450 MW.

In 2011 year FCITC calculation, the most constrained facility is Salem 345/161 kV transformer (assume Salem transformer has not been replaced) both under south-north and east-west transfer. The FCITC for 2011 S-N transfer is 1190.5 MW, and the FCITC for 2011 E-W transfer is 1528.6 MW.

For 2011 S-N transfer, if Salem 345/161 kV transformer is replaced by a 448/448 MVA transformer, the following facilities are still preventing further south-north transfer up to 600 MW flow on Arnold – Hazleton 345 kV line since their FCITC values are less than 1916.6 MW. See Table 14.

** From bus ** ** To bus ** CKT	ContMVA	Rating	Contingency	Loading in 2011 Base	DF	FCITC
34029 SALEM 3 345 34030 SALEM N5 161 1	373.1	335.0	34029 SALEM 3 345 34920 LORE345 345 1	269.2	5.5	1190.5
69523 GENOA 5 161 69535 LAC TAPS 161 1	312.9	306.9	60302 COULEE 5 161 69523 GENOA 5 161 1	244.1	3.7	1715.9
34909 E CAL T5 161 64425 DAVNPRT5 161 1	227.9	223.0	34036 ROCK CK3 345 36382 QUAD ; 345 1	149.4	4.2	1762.5
34043 SAVANNAS 161 34046 YORK 5 161 1	167.2	167.0	34029 SALEM 3 345 34036 ROCK CK3 345 1	112.7	2.9	1856.9
34122 E CALMS5 161 34909 E CAL T5 161 1	200.8	200.0	34036 ROCK CK3 345 36382 QUAD ; 345 1	118	4.4	1861.6
34122 E CALMS5 161 34126 MOOKETAS 161 1	176.9	176.0	34029 SALEM 3 345 34036 ROCK CK3 345 1	96.8	4.2	1872.7
3725:3725_Sub 56(Davnprt)-E.Calamus161	221.7	223.0		148.1	3.9	1913.0

Table 14: Other Constrained Facilities besides Salem XFMR for 2011 Year S-N Transfer

For 2011 E-W transfer, if Salem 345/161 kV transformer is replaced by a 448/448 MVA transformer, there is no other facility preventing further east-west transfer up to 450 MW on Montezuma - Bondurant 345 kV line.

7.2.2 FCITC Re-Calculation in 2015 Year

As stated in Section 2.1, 2015 S-N transfer case is created from 2015 base case by increasing south-north transfer up to 2036.6 MW so that flow on Arnold to Hazleton 345 kV line is benchmarked at 600 MW. 2011 E-W transfer case is created from 2015 base case by increasing east-west transfer up to 2031.8 MW so that flow on Montezuma to Bondurant 345 kV line is benchmarked at 450 MW.

In 2015 year FCITC calculation, the most constrained facility is Salem 345/161 kV transformer (assuming Salem transformer has not been replaced) both under south-north and east-west transfer. The FCITC for 2011 S-N transfer is 1146.9 MW, and the FCITC for 2011 E-W transfer is 1540.4 MW.

For 2015 S-N transfer, if Salem 345/161 kV transformer is replaced by a 448/448 MVA transformer, the following facilities are still preventing further south-north transfer up to 600 MW flow on Arnold – Hazleton 345 kV line since their FCITC values are less than 2036.6 MW. See Table 15.

** From bus ** ** To bus ** CKT	ContMVA	Rating	Contingency	Loading In 2016 Base	DF	FCITC
34029 SALEM 3 345 34030 SALEM NS 161 1	307.7	335.0	34029 SALEM 3 345 34920 LORE345 345 1	266.7	6.0	1146.9
34909 E CAL T5 161 64425 DAVNPRT5 161 1	251.1	223.0	34036 ROCK CK3 345 36382 QUAD ; 345 1	167	4.1	1352.9
34122 E CALMS5 161 34909 E CAL T5 161 1	222.7	200.0	34036 ROCK CK3 345 36382 QUAD ; 345 1	133.8	4.4	1513.0
3725:3725_Sub 56(Davnprt)-E.Calamus161	241.1	223.0		164.4	3.8	1552.3
34122 E CALMS5 161 34126 MQOKETA5 161 1	189.1	176.0	34029 SALEM 3 345 34036 ROCK CK3 345 1	103.8	4.2	1719.8
34043 SAVANNA5 161 34046 YORK 5 161 1	176.0	167.0	34029 SALEM 3 345 34036 ROCK CK3 345 1	116.5	2.9	1724.5
69523 GENOA 5 161 69535 LAC TAP5 161 1	312.9	306.9	60302 COULEE 5 161 69523 GENOA 5 161 1	238.7	3.7	1867.5

Table 15: Other Constrained Facilities besides Salem XFMR for 2015 Year S-N Transfer

For 2015 E-W transfer, if Salem 345/161 kV transformer is replaced by a 448/448 MVA transformer, there is no other facility preventing further east-west transfer up to 450 MW on Montezuma - Bondurant 345 kV line.

7.2.3 Some Conclusions from FCITC Re-Calculation

Based on the FCITC re-calculation for south-north transfer and east-west transfer in 2011 and 2015 years, Salem 345/161 KV transformer is the most constrained facility which prevents these transfers. If Salem transformer is replaced by a 448/448 MVA transformer, there will be no facility preventing east-west transfer. Also FCITC value will be increased by more than 500 MW for south-north transfer in 2011 year and 200 MW for south-north transfer in 2015 year.

7.3 Performance in MISO Market Wide Dispatch

With the eastern Iowa recommended solutions in Section 6.4 added into the 2011 summer peak base model, MISO market wide dispatch is simulated for 8760 hours in 2011 year using PROMOD and system performance is analyzed. Table N.1 compares the annual branch overloading hours with and without the recommended solutions in eastern Iowa.

From Table N.1, it is noted that overloading hours in most branches are greatly reduced with the recommended projects in place. But there are two branches with increased overloading hours. These two branches are:

1. Lore - Turkey River 161 kV line overloading hours are increased from 9 hours to 171 hours;
2. Turkey River - Cassville 161 kV line overloading hours are increased from 7 hours to 93 hours

As they are listed in Table L.4 and L.12, these two branches are also overloaded under Category C5 contingency "WEMPLETON 345" with heavy south-north transfer in 2011 and 2015. For the overloading on Lore - Turkey River line, generation redispatch by backing down generation at "DBQ 8^{TH}869.0" OR "BVRCH52G20.0" is a solution. Overloading on Turkey River - Cassville line can be mitigated by backing down generation at "BVRCH52G20.0" or "PRAR CK7 115".

Table N.2 compares flowgate shadow price with and without the recommended solutions in eastern Iowa. It is clear to see that,

1. Total annual shadow price at constraint for most flowgates are reduced dramatically with the recommended eastern Iowa solutions in place;
2. Again, annual shadow price at flowgates with monitored branch of Lore - Turkey River 161 kV line or Turkey River - Cassville 161 kV line is increased.
3. Annual shadow price at flowgate 6148 "6148_Genoa-LaCrosse-Marshland flo Genoa-Coulee" is increased a little from 2.06 K$ to 2.65 K$.

Based on the above PROMOD analysis, the eastern Iowa system can perform well under MISO market dispatch with the recommended solutions in place. Flow loading on Lore - Turkey River 161 kV line and Turkey River - Cassville 161 kV line should be closely watched and investigated.

7.4 Impact on Neighboring Systems by Eastern Iowa Recommended Transmission Solutions

The impact on surrounding systems (ALTW, MEC, ATC-ALTE, ATC-WPS, DPC, MPW) with eastern Iowa recommended transmission projects implemented is analyzed in this section. The impact is mainly analyzed based on comparison of AC contingency analyses between 2011 summer peak base model with eastern Iowa projects and without eastern Iowa projects. In addition, WUMS (Wisconsin Upper Michigan System) import capability is also analyzed and compared. Impact sensitivities are investigated based on a few assumptions. Solutions are further investigated.

Five additional flowgates were added for monitoring loading impact by eastern Iowa transmission projects. These five flowgates are in MEC and ALTW and described in Table O.1.

7.4.1 Comparison on Branch Loadings and Bus Voltages

AC contingency analysis was performed on 2011 summer peak base models with eastern Iowa projects or without eastern Iowa projects. 100 kV and above systems and 69 kV and above tie lines are monitored under system intact and category B contingencies. Branch thermal loadings above 50% of rating are compared and branches with loading change more than 5% of rating are listed for further analysis. To capture situations of loading changes from above 50% to below 50% of rating, ACCC results from 2011 summer peak base case without eastern Iowa projects are compared against results with eastern Iowa projects, and vice versa. Bus voltages are monitored within 0.95 and 1.05 p.u. range in 100 kV and above systems. When any bus voltage is out of the range under category A and B contingencies, it is compared with and without eastern Iowa projects. Bus voltage deviations more than 0.01 p.u. are listed for impact analysis.

Table O.1-1 and O.1-2 list all branches with loading changes more than 5% with eastern Iowa projects included. From these two tables, a few notes are listed below:

1. For thermal overloading issues identified in eastern Iowa system (Chapter 5), their branch loadings are all decreased significantly with eastern Iowa recommended projects included. For example, Salem 345/161 kV transformer, Hazleton 345/161 kV transformer, Rock Creek 345/161 kV transformer, Arnold 345/161 kV transformer, Dundee 161/115 kV transformer, Fairfax/Hiawatha area, Salem/Lore area, Albany – Savanna 161 kV line, Arnold – Dysart 161 kV line, Dysart – Washburn 161 kV line, Arnold – Tiffin 345 kV line, Rock Creek – E. Calamus 161 kV line, Davenport - E. Calamus – Maquoketa – Salem 161 kV line, Dundee – Hazleton 161 kV line;

2. With eastern Iowa projects included, most of loading decreases occur on ALTW branches, but several branches in other systems also see some significant loading decrease. For example, NOM 138 - ALB 138 – TOWNLINE 138 kV line in WUMS has about 11% loading decrease, SB 31T 5 - E MOLINE, SB 31T 5 - SB 28 5, and SB 17 5 - SB 28 5 161 kV lines in MEC have about 9% loading decrease;

3. The following branches have loading increase more than 5% of their ratings with eastern Iowa projects included:

a) Lore – Turkey River – Cassville – Nelson Dewey 161 KV line

b) Quad Cities - Rock Creek 345 kV line

c) Hazleton 345/161 kV #1 transformer

d) Hazleton – Blackhawk 161 kV line

4. All the above branches with loading increase have maximum loading below 70% of rating under category A and B contingencies with eastern Iowa projects included;

5. Since Quad Cities – Rock Creek 345 kV line is recommended to be uprated by replacing terminal equipment and Hazleton 345/161 kV #1 transformer will be replaced, loading increase on them is not an issue.

6. As discussed in Section 7.1, in 2011 and 2015 base scenarios, there is no thermal overloading on Lore – Turkey River – Cassville – Nelson Dewey 161 kV line and Hazleton – Blackhawk 161 kV line under all category A, B and C (except C3) contingencies. Category C3 thermal overloading on these two lines can all be mitigated by generation redispatch. Under S-N and E-W transfer scenarios, these two lines are overloaded under a few category C (including non-C3) contingencies but they are not overloaded under category A and B contingencies;

Table O.1-3 and O.1-4 list all flowgate loading changes with eastern Iowa projects included. These flowgate loading change results are consistent with branch loading comparison results. With eastern Iowa projects included, loading increase is only seen on flowgates with monitored element associated with Lore – Turkey River – Cassville line, Hazleton 345/161 kV #1 transformer, or Quad Cities – Rock Creek line.

Table O.1-5 lists significant bus voltage increases (>0.01 p.u.) with eastern Iowa projects included for voltages below 0.95 p.u. without eastern Iowa projects. It is noted that with eastern Iowa projects included, voltage at Salem 345 kV bus has up to 0.083 p.u. increase, voltage at Dundee 161 kV bus has up to 0.029 p.u. increase, voltage at Fairfax 161 kV bus has up to 0.026 p.u. increase, and voltages at Rock Creek 345 kV bus, Beverly 161 kV bus, PCI 161 kV bus, Dundee 115 kV bus all have more than 0.01 p.u. increase.

Based on the above branch loading and bus voltage comparison, it is also demonstrated that all identified eastern Iowa system issues can be addressed and resolved by the recommended solutions. Except loading increase on Lore – Turkey River – Cassville – Nelson Dewey 161 kV line and Hazleton – Blackhawk 161 kV line, the eastern Iowa projects have no adverse impact on neighboring systems.

7.4.2 WUMS Import Capability

Historically, Wisconsin Upper Michigan system relies on its power import capability to meet the load serving need. So impact on WUMS import capability with eastern Iowa projects included is also evaluated.

Eastern Iowa project impact on WUMS import capability was studied on 2011 summer peak base model. In that model, 1100 MW net scheduled interchange was modelled as firm power import for WUMS system, i.e., WUMS has 1100 MW net import modelled in the 2011 base case. To evaluate eastern Iowa project impact on WUMS import capability, FCITC was calculated from source subsystem (Ameren, ComEd, MEC, TVA) to sink subsystem (WUMS) and compared among five different scenarios. These five scenarios are:

Scenario 1 - without EITSG Project: 2011 summer peak base case without eastern Iowa projects;

Scenario 2 - with EITSG Project (Option 1): 2011 summer peak base case with transmission option 1 (Hazleton – Salem 345 kV line) and all other eastern Iowa projects included;

Scenario 3 - with EITSG Project (Option 2): 2011 summer peak base case with transmission option 2 (Hazleton – Lore - Salem 345 kV line) and all other eastern Iowa projects included;

Scenario 4 - EITSG Project (Option 2) + G527_Off: 2011 summer peak base case with transmission option 2 (Hazleton – Lore - Salem 345 kV line) and all other eastern Iowa projects included, plus assuming new 161 kV transmission line Liberty – Nelson Dewey associated with generator interconnection project G527 is in service and new 300 MW generator proposed to be built at Nelson Dewey (G527) is offline;

Scenario 5 - EITSG Project (Option 2) + G527_On: 2011 summer peak base case with transmission option 2 (Hazleton – Lore – Salem 345 kV line) and all other eastern Iowa projects included, plus assuming new 161 kV transmission line Liberty – Nelson Dewey associated with generator interconnection project G527 is in service and new 300 MW generator proposed to be built at Nelson Dewey (G527) is fully dispatched.

Generator interconnection request G527 is proposing to build a 300 MW power plant at Nelson Dewey. To date, facility study has been finished and Liberty – Nelson Dewey 161 kV line was identified as a necessary transmission line to be built with this 300 MW power plant. Since the generator interconnection agreement has not been signed yet and there are some uncertainties for this plant to be built, FCITC calculations under scenarios 4 and 5 are for purposes of sensitivity analysis and further solution identification.

Table O.2-1 lists the calculated total import capability of WUMS under five scenarios. Top five most limiting constraints for WUMS importing are listed for each scenario. A few observations are listed below:

1. Figure 6 shows WUMS latest one-year hourly average real time exporting MW level. From this recent one-year real time data, it is very clear that WUMS was importing power most of the time and the maximum hourly average importing MW was about 2741 MW in the most recent year. The calculated WUMS FCTTC under scenario 1 (2011 base scenario) is 3180 MW. Before 2011 summer, several projects in WUMS such as construction of the 200+ mile 345-kV between the Arrowhead (Duluth, MN) and Gardner Park (Wausau, WI) substations, along with the addition of Weston Unit 4 (550 MW), Oak Creek Expansion Phase I and II units (650 MW each) and the 2nd 345-kV between Northern Illinois and South Central Wisconsin (Wempletown-Paddock) are expected to be in service. They are the contributing factors to the increase in import capability over historical capabilities reflected in Figure 6;

2. With transmission option 2 and other eastern Iowa projects included (scenario 3), WUMS FCTTC is 2470 MW and reduced by about 700 MW compared with 3180 MW FCTTC in 2011 base scenario;

3. With transmission option 1 and other eastern Iowa projects included (scenario 2), WUMS FCTTC is 2934 MW and reduced by about 250 MW compared with FCTTC in scenario 1;
4. In scenario 4, if the new Liberty – Nelson Dewey 161 kV line is built, even with option 2 and other eastern Iowa projects included, WUMS FCTTC is 3370 MW and increased by about 200 MW compared with FCTTC in scenario 1;
5. In scenario 5, if generator interconnection project G527 will be built and in service (a new 300 MW generator fully dispatched at Nelson Dewey and a new Liberty – Nelson Dewey 161 kV line), with option 2 and other eastern Iowa projects included, WUMS FCTTC is 3063 MW and slightly decreased by about 120 MW compared with 3180 MW FCTTC in scenario 1;
6. Under five scenarios, WUMS import capability is mostly limited by constraints on Cassville – Turkey River 161 kV line and Lore – Turkey River 161 kV line with the contingency of Seneca – Genoa 161 kV line. Another limiting constraint is Paddock 345/161 kV transformer with the contingency of Wempletown – Paddock 345 kV line.
7. If transmission option 2 and other eastern Iowa projects will be built, WUMS import capability will be maintained almost the same as previous FCTTC if the new 300 MW power plant and its related transmission project in generator interconnection request G527 will also be built. If the new generator and transmission line associated with generator interconnection request G527 will not be built, a new Liberty - Nelson Dewey 161 kV line will be a good solution to maintain WUMS import capability.

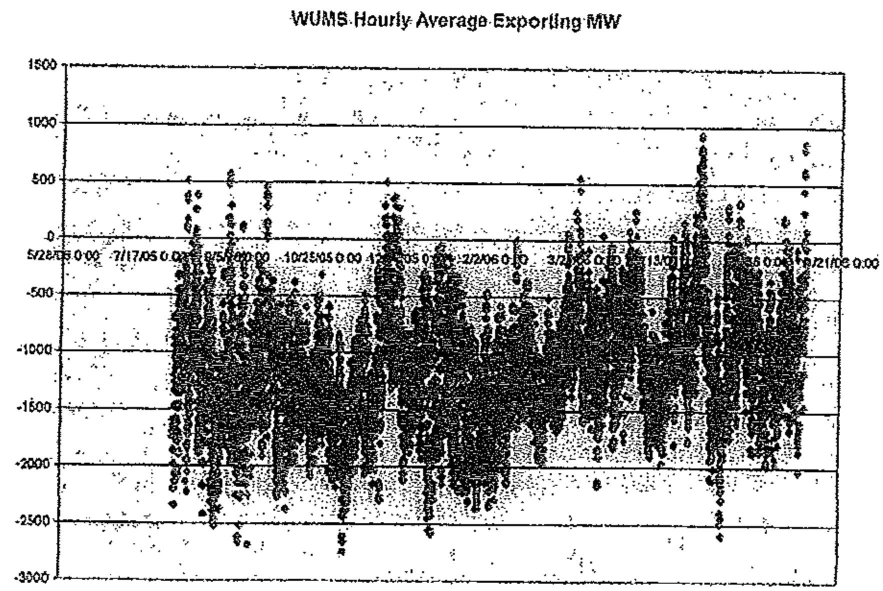

Figure 6: Real Time WUMS Hourly Average Exporting MW during Recent One Year

7.4.3 Further Study on Liberty – Nelson Dewey Line

There are a few follow-up questions to be answered regarding the new Liberty – Nelson Dewey 161 kV line. These questions are:

1. With the transmission option 2 and other eastern Iowa recommended projects included, WUMS import capability can still be maintained at a little higher level if the new Liberty – Nelson Dewey 161 KV line is added. If we assume transmission option 2 will be implemented, can the new Liberty – Nelson Dewey 161 kV line replace a few small projects recommended in Eastern Iowa?
2. If Liberty – Nelson Dewey 161 kV line is added, will it have adverse impact on eastern Iowa system?

To answer these two questions, two models were developed from 2011 summer peak base model. The first model only includes transmission option 2, i.e., Hazleton – Lore – Salem 345 kV line with a 345/161 kV transformer at Lore. The second model includes transmission option 2 and new Liberty – Nelson Dewey 161 kV line. DC contingency analysis results from these two models are compared for all branches with loading more than 80% of rating. Branches with loading changes more than 5% of rating are reported in Table O.3-1.

From Table O.3-1, it is observed that

1. Loading on Lore – Turkey River – Cassville – Nelson Dewey 161 kV line under category A, B and C contingencies is reduced by up to 30% of rating with new Liberty – Nelson Dewey 161 kV line added;
2. Loading on Phoenix – Menomin – T Kieler – Kaiser 69 kV line under category A, B and C contingencies is also reduced significantly with new Liberty – Nelson Dewey 161 kV line added. As discussed in Section 7.1, thermal overloading on Menomin – T Kieler – Kaiser 69 kV can be mitigated by system reconfiguration (open the overloaded line);
3. There is no adverse impact on eastern Iowa system if new Liberty – Nelson Dewey 161 kV line is added, i.e., there is no branch in eastern Iowa system with loading increase more than 5% of rating.

Based on all these analyses, with eastern Iowa recommended projects implemented, the new Liberty – Nelson Dewey 161 kV line can significantly reduce the flow on Lore – Turkey River – Cassville –

Nelson Dewey 161 kV line. Also it can maintain WUMS import capability at a little higher level than the original one.

7.5 Real Time Binding Constraints and TLRs

High incidence of TLR (Transmission Loading Relief) and persistently Real Time (RT) bound hours are often indicative of lower system reliability margins. During pre-market (before April 2005) system operation, TLR is a main procedure to control flows and prevent system reliability violations. There are nine TLR levels defined in NERC TLR procedure. With TLR level 3A and above, flow schedules are changed to mitigate system reliability issues. So TLR level 3A and above are only analyzed here. After MISO energy market is commenced, security constrained economic dispatch (SCED) is becoming a primary process for controlling security constraints on Day Ahead (DA) and Real Time operational basis. All pre-defined binding constraints are honoured to avoid reliability violations when SCED process is directing an economic dispatch. If some constraints are bound in real time operation, corresponding bound hours and shadow price (generation redispatch cost) are reflecting the congestion severity.

92 flowgates and RT binding constraints in eastern Iowa or having influence on eastern Iowa region are examined. These 92 flowgates and RT binding constraints have the most called-on TLR hours or RT bound hours. Their names and definitions are listed in Table P.1.

Level 3A and above TLR hours called on these flowgates from January 2001 to April 2005 (pre-market) and from April 2005 to April 2006 (post-market) are examined. RT bound hours on these 92 flowgates and binding constrains from April 2005 to April 2006 are also examined because MISO Energy Market has been in operation since April 2005. Average Annual Hour-of-Year of total 92 flowgates and binding constraints during 1/1/2001 and 3/31/2005 are added up and there are top 16 flowgates with FG-HR more than 1% of total eastern Iowa TLR hours. Figure 7 is a diagram of average annual TLR hours of these top 16 eastern Iowa flowgates. Similarly, in the period of April 2005 to April 2006, there are top 19 flowgates or binding constraints with either TLR hours or RT binding hours more than 1% of total eastern Iowa congested hours. The congested hours of these top 19 flowgates and binding constraints are shown in Figure 8.

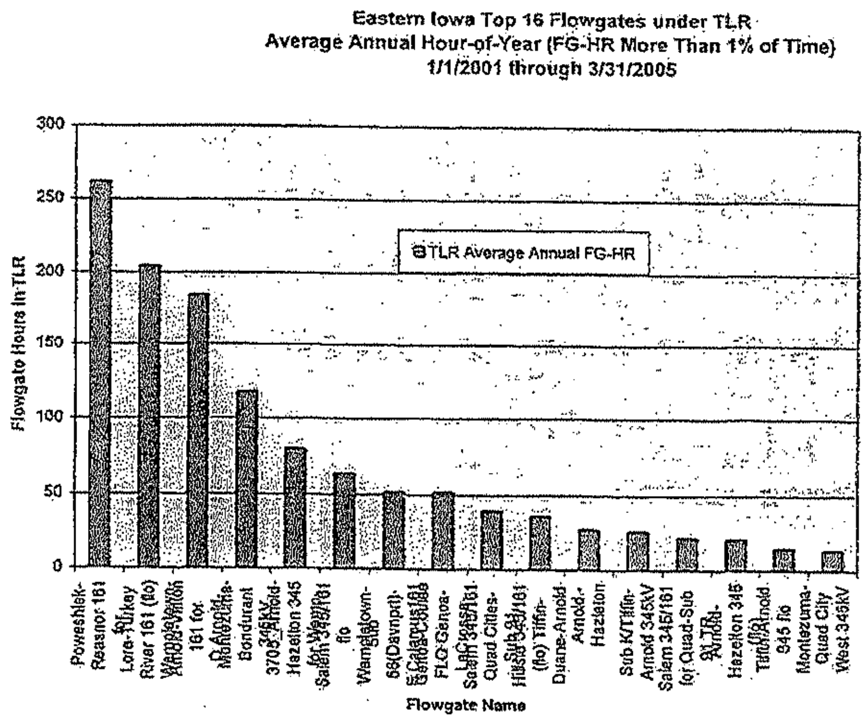

Figure 7: Average Annual Hour-of-Year (FG-HR More Than 1%) of Top 16 Eastern Iowa Flowgates (1/1/2001 – 3/31/2005)

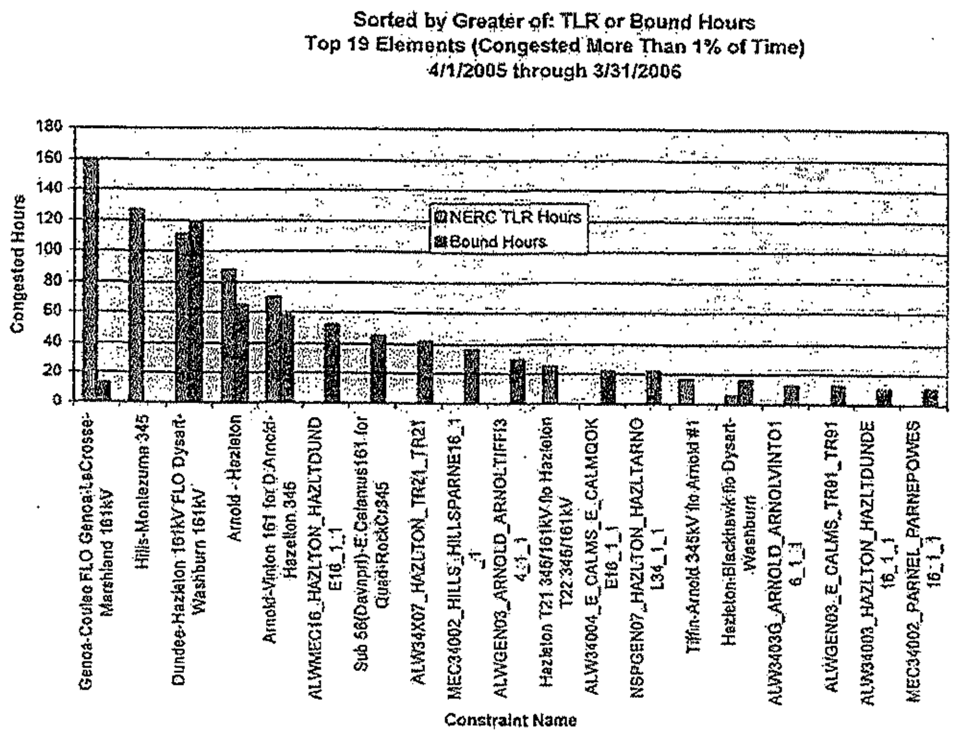

Figure 8: TLR or Bound Hours (Congested More Than 1% of Time) of Top 19 Eastern Iowa Constraints (4/1/2005 – 3/31/2006)

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From January 2001 to April 2005, the top 16 flowgates in eastern Iowa with most hours of TLR 3A and up called on are listed below:

Top Sequence	Flowgate Name
1	Poweshiek-Reasnor 161 for Montezuma-Bondurant 345
2	Lore-Turkey River 161 (flo) Wempletown-Paddock 345
3	Arnold-Vinton 161 for D.Arnold-Hazelton 345
4	Montezuma-Bondurant 345kV
5	3706 Arnold-Hazelton 345 for Wemp-Paddock 345
6	Salem 345/161 flo Wempletown-Paddock 345
7	Sub 56(Davnprt)-E.Calamus161 for Quad-RockCr345
8	Genoa-Coulee FLO Genoa-LaCrosse-Marshland 161kV
9	Salem 345/161 Quad Cities-Sub 91
10	Hillsie 345/161 (flo) Tiffin-Duane-Arnold 345
11	Arnold - Hazleton
12	Sub K/Tiffin-Arnold 345kV
13	Salem 345/161 for Quad-Sub 91 TR
14	Arnold-Hazelton 345 (flo) Montezuma-Bondurant 345
15	Tiffin-Arnold 345 flo Montezuma-Bondurant 345
16	Quad City West 345kV

Table 16: Top 16 Eastern Iowa Flowgates with Average Annual Hour-of-Year (FG-HR) More Than 1% (1/1/2001 – 3/31/2005)

From April 2005 to April 2006, the top 19 flowgates and binding constraints in eastern Iowa with most congested hours (TLR or bound hours) are listed below:

Top Sequence	Flowgate Name
1	Genoa-Coulee FLO Genoa-LaCrosse-Marshland 161kV
2	Hills-Montezuma 345
3	Dundee-Hazleton 161kV FLO Dysart-Washburn 161kV
4	Arnold - Hazleton
5	Arnold-Vinton 161 for D.Arnold-Hazelton 345
6	ALWMEC16_HAZLTON_HAZLTDUNDE16_1_1
7	Sub 56(Davnprt)-E.Calamus161 for Quad-RockCr345
8	ALW34X07_HAZLTON_TR21_TR21
9	MEC34002_HILLS_HILLSPARNE16_1_1
10	ALWGEN03_ARNOLD_ARNOLTIFFI34_1_1
11	Hazleton T21 345/161kV flo Hazleton T22 345/161kV
12	ALW34004_E_CALMS_E_CALMOOKE16_1_1
13	NSPGEN07_HAZLTON_HAZLTARNOL34_1_1
14	Tiffin-Arnold 345kV flo Arnold #1

15.	Hazleton-Blackhawk flo Dysart-Washburn
16.	ALW3403G_ARNOLD_ARNOLVINTO16_1_1
17.	ALWGEN03_E_CALMS_TR91_TR91
18	ALW34003_HAZLTON_HAZLTDUNDE16_1_1
19	MEC34002_PARNEL_PARNEPOWES16_1_1

Table 17: Top 19 Eastern Iowa FGs or Constraints with TLR or Bound Hours More Than 1% (4/1/2005 – 3/31/2006)

Figures 6 and 7 characterize the massive amount of TLR history and RT constraints bound record. Average TLR statistics during 1/1/2001 and 3/31/2006 are focused. Figures listed in Appendix P have detailed monthly TLR patterns for some of top eastern Iowa flowgates from January 2001 to September 2005. These figures can help understand the system situations when TLRs were called on.

A few observations are listed below based on the Figures in Appendix P:

1. Most TLRs were called on these flowgates during summer peak and winter peak time. Heavy S-N and E-W transfers are also often seen during summer peak and winter peak periods;
2. Most TLR hours are on TLR level 3A, which is, curtail transactions using Non-firm Point-to-Point transmission service to allow transactions using higher priority Point-to Point transmission service;
3. Some flowgates have significant potions of TLR 5A and 5B hours among its total TLR hours. These flowgates are: FG "Poweshiek-Reasnor 161 for Montezuma-Bondurant 345", FG "Salem 345/161 flo Wempletown-Paddock 345", FG "Salem 345/161 Quad Cities-Sub 91", FG "Arnold – Hazleton". These flowgates are also in the top 16 flowgate list with average annual Hour-of-Year (FG-HR) more than 1% during 1/1/2001 – 3/31/2005.

As worthy and valuable verification, it is necessary to check whether recommended eastern Iowa projects or other planned/proposed projects will address these historical TLR issues or RT binding constraints. Table 18 lists the projects recommended in this eastern Iowa study or other planned / proposed projects, which will address issues associated with top 16 flowgates from January 2001 to April 2005 and top 19 flowgates and RT binding constraints from April 2005 to April 2006.

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NERC ID	Flowgate/Binding Constraint Name	Transmission Projects for Solution
3704	Poweshiek-Reasnor 161 for Montezuma-Bondurant 345	Poweshiek - Reasnor 161 kV line has been upgraded to 326 MVA in June 2005
3707	Lore-Turkey River 161 (flo) Wempletown-Paddock 345	Second Wempletown - Paddock 345 kV line is in service in Spring 2005
3724	Arnold-Vinton 161 for D.Arnold-Hazelton 345	Transmission option 2, "Lewis Fields" 161 kV substation project, Beverly 345 kV substation project recommended in eastern Iowa study
6088	Montezuma-Bondurant 345kV	This line is owned by MEC.
3705	3705_Arnold-Hazelton 345 for Wemp-Paddock 345	Second Wempletown - Paddock 345 kV line is in service in Spring 2005. Also loading on Arnold - Hazleton 345 kV line will be reduced by transmission option 2 recommended in eastern Iowa study
3736	Salem 345/161 flo Wempletown-Paddock 345	Second Wempletown - Paddock 345 kV line is in service in Spring 2005. Also loading on Salem 345/161 kV xfrm will be greatly reduced by transmission option 2 recommended in eastern Iowa study
3725	Sub 56(Davnprt)-E.Calamus 161 for Quad-RockCr345	Transmission option 2 recommended in eastern Iowa study
6085	Genoa-Coulee FLO Genoa-LaCrosse-Marshland 161kV	Genoa - Coulee 161 kV line will be upgraded in June 2008
3719	Salem 345/161 Quad Cities-Sub 91	Transmission option 2 recommended in eastern Iowa study
11764	Hillsie 345/161 (flo) Tiffin-Duane-Arnold 345	Transmission option 2 recommended in eastern Iowa study
3706	Arnold - Hazleton	Transmission option 2 recommended in eastern Iowa study
6124	Sub K/Tiffin-Arnold 345kV	Transmission option 2, "Lewis Fields" 161 kV substation project, Beverly 345 kV substation project recommended in eastern Iowa study
3721	Salem 345/161 for Quad-Sub 91 TR	Transmission option 2 recommended in eastern Iowa study
3749	Arnold-Hazelton 345 (flo) Montezuma-Bondurant 345	Transmission option 2 recommended in eastern Iowa study
11775	Tiffin-Arnold 345 flo Montezuma-Bondurant 345	Transmission option 2, "Lewis Fields" 161 kV substation project, Beverly 345 kV substation project recommended in eastern Iowa study
6081	Quad City West 345kV	QC West 345 and 161 kV upgrades proposed by MEC
12146	Hills-Montezuma 345	This line is owned by MEC.
13256	Dundee-Hazleton 161kV FLO Dysart-Washburn 161kV	Transmission option 2 recommended in eastern Iowa study
NA	ALWMEC16_HAZLTON_HAZLTDUNDE16_1_1	Transmission option 2 recommended in eastern Iowa study
NA	ALW34X07_HAZLTON_TR21_TR21	Hazleton 345/161 kV #1 xfmr replacement, transmission option 2 recommended in eastern Iowa study
NA	MEC34002_HILLS_HILLSPARNE16_1_1	Reconductor and substantially rebuild the Hills – Parnell 161 kV line proposed by MEC
NA	ALWGEN03_ARNOLD_ARNOLTIFFI34_1_1	Transmission option 2, "Lewis Fields" 161 kV substation project, Beverly 345 kV substation project recommended in eastern Iowa study
3755	Hazleton T21 345/161kV flo Hazleton T22 345/161kV	Hazleton 345/161 kV #1 xfmr replacement, transmission option 2 recommended in eastern Iowa study
NA	ALW34004_E_CALMS_E_CALMOOKE16_1_1	Transmission option 2, Beverly 345 kV substation project recommended in eastern Iowa study

NA	NSPGEN07_HAZLTON_HAZLTARNOL34_1_1	Transmission option 2 recommended in eastern Iowa study
13350	Tiffin-Arnold 345kV flo Arnold #1	Transmission option 2, "Lewis Fields" 161 kV substation project, Beverly 345 kV substation project recommended in eastern Iowa study
13323	Hazleton-Blackhawk flo Dysart-Washburn	Loading on Dysart - Washburn 161 kV line will be reduced by transmission option 2, Beverly 345 kV substation project recommended in eastern Iowa study
NA	ALW3403G_ARNOLD_ARNOLVINTO16_1_1	Transmission option 2, "Lewis Fields" 161 kV substation project, Beverly 345 kV substation project recommended in eastern Iowa study
NA	ALWGEN03_E_CALMS_TR91_TR91	Transmission option 2, Beverly 345 kV substation project recommended in eastern Iowa study
NA	ALW34003_HAZLTON_HAZLTOUNDE16_1_1	Transmission option 2 recommended in eastern Iowa study
NA	MEC34002_PARNEL_PARNEPOWES16_1_1	Reconductor and substantially rebuild the Parnell – Poweshiek 161 kV line proposed by MEC. Also loading on Hills 345/161 kV xfmr will be reduced by transmission option 2 recommended in eastern Iowa study

Table 18: Top Eastern Iowa Flowgates and Binding Constraints Associated with Their Transmission Solutions

Some conclusions can be drawn from Table 18:

1. The recommended eastern Iowa projects are good transmission solutions to address real time system issues such as chronic TLRs and binding constraints in that region;
2. Most of eastern Iowa operational issues can be resolved by transmission option 2 recommended in eastern Iowa study;
3. "Montezuma-Bondurant 345kV" and "Hills-Montezuma 345" are the only two flowgates without any planned/proposed transmission solutions. These two flowgates are owned by MEC.

7.6 Voltage Stability Performance

7.7 Dynamic Stability Performance

8. Conclusion

References

[1] "Alliant West TLR Task Force Final Report", NERC, March 26, 2004

[2] "Alliant Energy Transmission System Planning Criteria", ALTW 2006 FERC Form 715 Part 4_1, April 1, 2006