LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 400

Responding Witness: John K. Wolfe

Q-400. Regarding implemented programs that contribute to operational efficiencies in distribution, as discussed beginning on page 43 of the Testimony of Paul W. Thompson, provide the following:

a. Written procedures, procedures and directives detailing all programs related to incident management.

    i. Explain how real-time information gained from SCADA DMS and AMS will be incorporated into each of these programs.

b. Written procedures, procedures and directives detailing all programs related to system/asset management.

    i. Explain how real-time information gained from SCADA DMS and AMS will be incorporated into each of these programs.

c. Written procedures, procedures and directives detailing all programs related to resource management.

    i. Explain how real-time information gained from SCADA DMS and AMS will be incorporated into each of these programs.

A-400.

a. See attached.
    i. Real-time information gathered from the SCADA, DMS, and AMS systems will be utilized to assess the condition of the LG&E electric distribution system before, during, and after an event. These systems will provide more accurate fault location predictions and provide automated and remote operations of field devices. Damage assessment will improve as it will be based on readily available real-time system data and status from field devices. This improvement will assist in determining restoration resource requirements and allow efficient utilization of those resources acquired to restore and repair the damaged areas.

b. See attached.
    i. AMS and SCADA enabled reclosers provide valuable enhancements to support asset management. Currently there is limited data available on the performance of the distribution system beyond the substation. AMS meters and SCADA enabled reclosers will provide data to allow the Company to proactively and in real time identify overloaded or malfunctioning equipment (transformers, lines, other line equipment, etc), power quality issues and other problems, such as tree contacts before they result in an outage and/or equipment failure or damage. More accurate load data outside the substation will allow lines to be configured for improved efficiency. Enhanced data improves system planning and operation and provides critical data to maximize investment in distribution assets for resiliency, reliability and capacity. SCADA enabled reclosers provide fault isolation and/or automatic service restoration to restore service to unaffected customer while reducing crew time to fault locate. AMS metering provide information on the extent of outages speeding restoration efforts and reduces truck rolls to verify service has been restored.

c. The Asset and Resource Management (ARM) software tool is utilized by Electric Distribution Operations to initiate, design, and approve planned construction and maintenance work. Jobs are assigned to field supervision to ensure work is completed as designed and on-time. A separate Work Planning organization monitors jobs in ARM and assigns a variable workforce to operation centers based on data housed in this system. ARM is not utilized for outage and restoration work so real-time data from SCADA, DMS and AMS would have limited impact on ARM tool processes and efficiencies. However, the real time data could be utilized to identify planned construction work such as identifying areas with loading or voltage issues. This information could also be used to identify failing or overloaded equipment that could be repaired or replaced on proactive planned maintenance in ARM.

1. Introduction

Purpose

The purpose of the Electric Distribution Emergency Preparedness and Response Plan (EPRP) is to establish the Company's organizational structure, associated roles and responsibilities, and high level processes to be utilized in response to emergencies and significant outage events on the Louisville Gas and Electric (LG&E) and Kentucky Utilities (KU) electric distribution systems. The procedures outlined herein shall serve as guidelines to assist the Company during restoration events and are not intended to be a detailed training tool.

The purpose of EPRP Section 1.0 is to provide personnel with an overview of the scope of the EPRP and to establish the Company's:

- Emergency Preparedness and Response Alert Levels, and the responsibilities associated with each level;
- Terminology for categorizing the scale or magnitude of emergency events, and the associated implications on associated restoration business processes and organizational structure; and
- Establish the personnel primarily responsible for execution and maintenance of this Plan and associated business processes.

Scope

The EPRP applies to all significant power outages caused by, but not limited to, severe weather, flooding, civil disturbances, fire or explosion or other major disruption of the Electric System or any instances for which the Vice President Electric Distribution or Operating Company management personnel determines the implementation of the EPRP, and the Incident Command System is required to affect safe and timely restoration of electric service.

The EPRP scope includes the Company's electric distribution service territory, and associated electric infrastructure and customers. The electric distribution service territory is divided into eleven primary Operations Centers (see Figure 1):

A. Danville Operations Center
    a. Danville Operations Center
    b. Campbellsville Crew Center
B. Earlington Operations Center
    a. Earlington Operations Center
    b. Barlow Crew Center

c. Eddyville Crew Center
d. Greenville Crew Center
e. Morganfield Crew Center

C. Elizabethtown Operations Center
D. Lexington Operations Center
   a. Lexington Operations Center
   b. Midway Crew Center
E. London Operations Center -
   a. London Operations Center
   b. Somerset Crew Center
F. Louisville Operations Center
   a. Auburndale Service Center
   b. East Service Center
G. Maysville Operations Center
   a. Maysville Operations Center
   b. Mount Sterling Crew Center
   c. Paris Crew Center
H. Norton Operations Center
   a. Norton Operations Center
   b. Pennington Gap Crew Center
I. Pineville Operations Center
   a. Pineville Operations Center
   b. Harlan Crew Center
J. Richmond Operations Center
   a. Richmond Operations Center
   b. Winchester Crew Center
K. Shelbyville Operations Center
   a. Shelbyville Operations Center
   b. Carrolton Crew Center

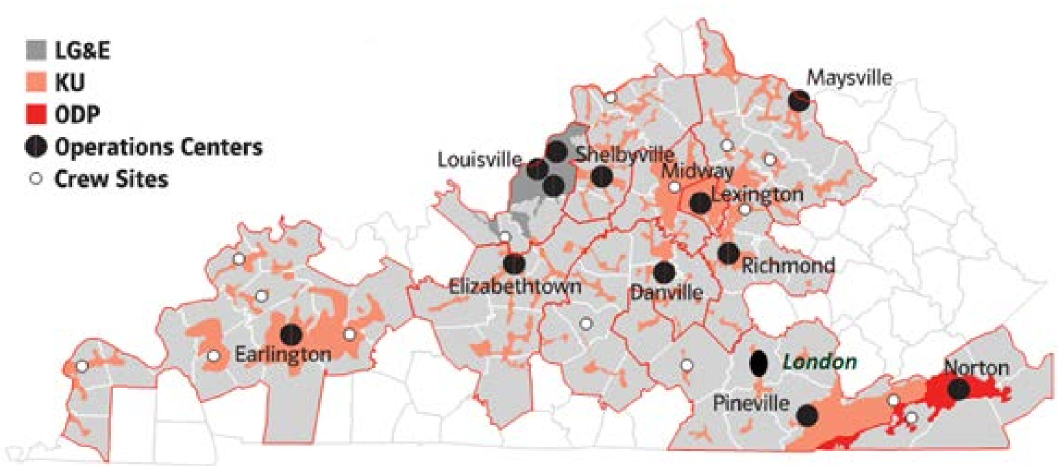


Figure 1. LG&E and KU Electric Distribution Operations Centers

Plan Development and Review

The Emergency Preparedness, Planning, and Response Team (EPPRT), as described in EPRP 1.3, shall be responsible for developing the EPRP and conducting routine reviews of the plan to assure its continued accuracy and adequacy, in accordance with the EPRP Review and Approval Schedule established in in Appendix 1.B.

Training and Qualification

The EPPRT shall have responsibility for establishing minimum training and qualification requirements for procedures covered herein. Please see the EPRP Plan Review, Training, and Exercise Schedule in Appendix 1.C.

References

None

Revisions

None

1.1. Emergency Preparedness and Response Alert Levels

The Company shall utilize an Emergency Preparedness and Response Alert Level System which categorizes, defines, and triggers specific tasks to be completed during normal and abnormal operating conditions to assure the Company is prepared to effectively and efficiently respond to emergencies and outage events on its electric distribution system.

1.1.1. **Blue Alert** – defines the planning and preparedness tasks to be completed during normal ("blue sky") operating conditions to ensure the Company is prepared to effectively respond to future emergencies and outage events on the electric distribution system.

1.1.2. **Yellow Alert** – defines the action items and preparedness tasks to be completed in advance of forecasted or impending events which could significantly impact the Company's electric distribution systems, to ensure the Company is adequately prepared to effectively and efficiently respond to associated emergencies and outage events.

A Yellow Alert will be issued 0-72 hours in advance of the following forecasts by the National Weather Service for LG&E or KU service areas:

1. Severe weather forecast
2. Extreme temperature forecast
    a. 5°F or lower
    b. 90°F or higher
3. Forecast for sustained wind speeds or wind gusts greater than 40 miles per hour
4. Forecast for ice accretion totals equal to or greater than 0.25 inches
5. Prediction for flooding

1.1.3. **Red Alert** – defines the action items and tasks to be completed in response to events which impact the Company's electric distribution system, to assure effective, efficient, and timely mitigation of hazards and restoration of service.

A Red Alert will be issued 0-12 hours in advance of the following conditions being experienced on the electric distribution system:

1. Severe weather is imminent
2. Extreme temperatures are being experienced
    a. 5°F or lower

   b. 90°F or higher
3. Sustained wind speeds or wind gusts greater than 40 miles per hour are being experienced
4. Ice accretion totals equal to or greater than 0.25 inches are being experienced
5. Flooding is occurring
6. A natural disaster is experienced
7. A significant manmade disaster is experienced

Task lists associated with each alert level shall be developed for critical storm roles and business functions as defined throughout this Emergency Preparedness and Response Plan.

1.2. Emergency Event Levels

At the onset of most significant outage events, it is difficult to accurately determine the extent of system damages prior to performance of damage assessment surveys in the field. Electric Distribution has established four emergency level definitions to help classify damage and outage levels, predict resource needs, and effectively execute organizational, safety, and communications plans.

- **Level I** - A level I emergency is defined as an outage event on the electric distribution system that is expected to be resolved within six (6) hours and requires the use of local Company personnel and resident contractors to restore service and make necessary repairs.

- **Level II** - A Level II emergency is defined as an outage event on the electric distribution system that is expected to be resolved within six (6) to twenty four (24) hours and requires the use of regional Company personnel and resident contractors. Typically, the Distribution Control Center (DCC) continues to control the electric distribution system, assign hold cards, and dispatch field crews.

- **Level III** - A Level III emergency is defined as an outage event on the electric distribution system that is expected to be resolved within twenty four (24) to seventy two (72) hours. This level of event requires the use of all available company personnel and resident contractors, and usually necessitates the utilization of off-system resources secured via mutual assistance or existing business partner relationships. This level of event also typically necessitates that the DCC decentralize event prioritizations and assignment processes to local resource managers.

- **Level IV** - A Level IV emergency is defined as an extreme outage event on the electric distribution system that will require more than seventy two (72) hours to resolve and jeopardizes the general health and welfare of customers and the communities the Company serves. This level of event requires the use of all available company personnel and resident contractors, and necessitates the utilization of off-system resources secured via mutual assistance or from existing business partner relationships. This level of event also typically necessitates that the DCC decentralize event prioritizations and assignment processes to local resource managers.

Incident Commanders and Operations Section Chiefs shall be jointly responsible for constantly monitoring outage counts and system conditions and determining the level of an outage event.

1.3. Emergency Preparedness, Planning, and Response

1.3.1. Incident Command

Electric Distribution has adopted an Incident Command System (ICS) structure for responses to emergencies and outage events (see Sections 3.0-9.0). The structure is based on components of the National Incident Management System (NIMS), and accommodates all types and sizes of emergencies. The organizational structure and associated processes also provide assurance the Company responds to events on the electric system in a timely, effective, and consistent manner. Finally, the ICS provides for standard communications during emergencies, to key stakeholders, both internal and external to the Company.

The Company's Incident Command organization contains key leadership roles, including:

- Executive Officers
- Safety Officers
- Communications Officers
- Incident Commander
- Operations Section Chiefs
- Customer Experience Section Chiefs
- Logistics Section Chiefs
- Work Planning Section Chiefs

Electric Distribution partners with Corporate Communications, Safety and Technical Training, Supply Chain, Facilities, and Customer Services to staff at least two senior leadership personnel to each key leadership role identified above.

1.3.2. Emergency Preparedness and Response Team

All personnel assigned to an IC key leadership role are also assigned to an ***Emergency Planning, Preparedness, and Response Team*** (EPPRT). The EPPRT meets monthly to develop emergency response strategies, review preparedness plans, assure completion of preparation tasks, conduct post incident reviews, and stay abreast of external (industry and customer) factors which influence emergency response processes and strategies.

The EPPRT is responsible for developing and maintaining emergency preparedness and response plans, procedures, and strategies which assure the Company effectively responds to emergencies and significant outage events on the LG&E and KU distribution systems. **See Appendix 1.A to see the Emergency Preparedness and Response Team members.**

1.3.3. Emergency Preparedness, Planning, and Response Plan

Prior to April 1st each year, all Section Chiefs shall review EPRP procedures, guidelines, and checklists for responses to significant emergencies and outage events and revise them as deemed necessary to incorporate regulatory requirements and lessons learned. Electric Distribution's Emergency Planning and Preparedness Manager shall be responsible for overseeing the review process, and ensuring completion in accordance with established schedules. During the review process, Section Chiefs or their delegate(s) shall verify employee assignments to key roles, and ensure all necessary training is provided.

Each Section Chief or responsibility area shall be responsible for reviewing assigned contact lists twice per year, including:

- All Company personnel and business partners assigned storm roles;
- Mutual aid companies and business partners;
- State, county, and local elected officials;
- State, county, and local emergency response agencies;
- Providers of key services and supplies
- Operators and managers of lodging facilities and food services;
- Medical facilities

Appendix 1.B contains the Emergency Preparedness and Response Plan Review and Approval Schedule.

1.3.4. Training

The EPPRT and Emergency Planning and Preparedness Manager are responsible for overseeing the development and execution of training plans covering the Emergency Preparedness and Response Plan. (**Appendix 1.C contains the Emergency Preparedness and Response Plan Review, Training, and Exercise Schedule.)** Each Incident Command Officer or Section Chief shall be responsible for ensuring the training plan is executed.

1.3.5. Exercises

The EPPRT and Electric Distribution's Emergency Planning and Preparedness Manager shall be responsible for overseeing the development and execution of an annual exercise or drill that tests the adequacy and effectiveness of all aspects of Electric Distribution's emergency response plan and procedures, and provide assurance that adequate qualified personnel are available to respond to Level I - IV events across the LG&E and KU footprint.

Each Incident Command Officer or Section Chief shall be responsible for conducting at least annual exercise of their responsibility areas to ensure all emergency response business processes and key roles are tested, and to provide refresher training for employees and business partners assigned to their Section.

Appendix 1.D contains a copy of the standard form to be used for documenting exercise objectives, descriptions, and results. All Exercises shall be documented on this form. Completed forms shall be submitted to Electric Distribution's Emergency Planning and Preparedness Manager, who will retain a record of the Exercise for no less than seven years.

1.3.6. After Action Reviews

At the conclusion of each Level III or IV event, a post storm After Action Review (AAR) shall be conducted by the EPPRT or their delegates to assess the effectiveness of the response and EPRP and to identify improvement opportunities that may be needed. Electric Distribution's Emergency Preparedness and Response Manager shall be responsible for collecting all submitted enhancement opportunities and working with the EPPRT to develop and prioritize action plans and assign accountability for completion. **Appendix 1.3.E contains a copy of the standard After Action Review form to be utilized.**

1.4. Weather and System Monitoring

The Electric Distribution Control Centers and Director Electric System Restoration and Distribution are responsible for monitoring weather and other conditions, evaluating their severity, and estimating their potential impacts on the electric delivery system. Any incident or event that poses a significant threat to the electric system and the deliverability of power should be immediately communicated to the Vice-President Electric Distribution Operations or their delegate and the responsible Incident Commander(s). Whenever a significant weather event or incident capable of causing interruptions to electric service does or is anticipated to occur, the Incident Commander, with support from the Operations Section Chiefs, shall establish and communicate the appropriate Alert Level, in accordance with EPRP 1.1.

1.4.1. Weather Monitoring Services

The Distribution Control Center and Director Electric System Restoration utilize the following weather services and resources to monitor and assess weather events that could negatively impact the electric system and cause a substantial loss in electric service:

1.4.1.1. Louisville National Weather Service

The Director System Restoration or a delegate and the Distribution Control Center review National Weather Service (NWS) forecasts daily (http://www.crh.noaa.gov/lmk/) to monitor and plan for events which are forecasted to cause conditions which have a history of producing outages or system damages on the LG&E and KU electric delivery systems. The Director System Restoration or a delegate utilizes NWS weather data as the primary resource for establishing Yellow and Red Alerts, as described in EPRP 1.1.

The Louisville NWS Meteorologist in Charge (MIC) notifies the Director Electric System Restoration via email [redacted] whenever the NWS plans to hold a conference call regarding forecasted or ongoing weather events which could meet severe criteria. The Director Electric System Restoration or their delegate participate in all scheduled NWS conference calls regarding weather advisories, watches or warnings which may impact the LG&E or KU service areas.

1.4.1.2. StormGeo Weather Service

The Director System Restoration and Distribution Control Center subscribe to *Storm Geo Weather service* (http://customers.stormgeo.com/portal/login) to supplement the National Weather Service weather information. StormGeo provides an outsourced 24/7/365 weather department that provides 24/7 access to meteorologists and dedicated client service team member. The service includes customized weather website configured for both Transmission and Distribution, periodic weather threat outlooks, event (storm) specific advisories and site specific alerts, approximate 450x200 mile lightning detection area, advanced lightning modeling for dangerous thunderstorms and tornado alerting, and Business Decision Guidance dashboard which is a risk assessment tool that utilizes historical weather and outage data.

1.4.1.3. Schneider Electric – MxVision Weather Sentry Online, Utility Edition

The Director System Restoration and Distribution Control Center subscribe to *Schneider Electric's MxVision Weather Sentry Utility* Edition (http://weather.dtn.com/dtnweather/common/link.do?contentId=600024&parentId=300001) to supplement the National Weather Service weather information. This service provides fifteen (15) day forecasts, which include all pertinent weather data. Also, the service provides real time weather radar, coupled with watch and warning areas, wind speeds, precipitation type, and lightning data. Finally, Weather Sentry's forecasting service provides dedicated meteorologists 24x7 to respond to weather questions. Weather questions are typically answered within 15 minutes of submission.

1.4.1.4. Sperry-Piltz Ice Accumulation Index

Whenever the National Weather Service forecasts icing in the LG&E or KU service areas, the Director Electric System Restoration and Distribution, or their delegate, and the Distribution Control Center review the Sperry-Piltz Ice Accumulation Index (http://www.spia-index.com/neIce.php) for the Northeast region, to predict system damages and impacts for forecasted ice accumulations, temperatures, and wind speeds.

1.4.1.5. Weather Underground

The Distribution Control Center utilizes Weather Underground (http://www.wunderground.com/) to supplement National Weather Service and Weather Sentry weather data, and to review or gather historical weather data associated with a significant outage event.

1.4.2. Emergency Management Situation Reports

Electric Distribution's Emergency Planning and Preparedness Manager and Business Continuity Coordinator work with Emergency Management Agencies to stay abreast of weather conditions or other events which could significantly impact the LG&E and KU electric systems. Both positions are responsible for reviewing all Emergency Situation Reports released by Kentucky or Virginia Emergency Management, and evaluating them to assess and prepare for evaluated risks.

2. Notification Procedures

Purpose

The purpose of EPRP Section 2.0 is to provide personnel with an overview of mandated reporting requirements for significant system outages. This Section is intended to supplement and not replace internal and external reporting requirements established in the Company's *Internal Notification/Emergency Response Guide* (INERG). **(A copy of the INERG is available in Appendix 2.A)**

The INERG shall be made available or provided to all Company personnel who respond to emergencies or significant outage events on the electric distribution system. It provides internal reporting requirements for emergencies and outage incidents to assure regulatory reporting requirements are satisfied, and must be adhered to by all personnel.

Scope

The scope of EPRP Section 2.0 covers all Company electric distribution facilities and customers under the jurisdiction of the Kentucky Public Service Commission or Virginia State Corporation Commission.

Responsibilities

The Manager – Distribution Control Center or his/her delegate shall have responsibility for meeting the reporting requirements established herein.

Training and Qualification

The EPPRT shall have responsibility for establishing minimum training and qualification requirements for procedures covered herein. **(Appendix 1.C contains the Emergency Preparedness and Response Plan Review, Training, and Exercise Schedule.)**

References

1. 807 Kentucky Amended Regulations(KAR) Part 5.006 Section 27
2. LG&E KU Services Company *Internal Notification/Emergency Response Guide*, rev. 03/12/2013.

Revisions

None

2.1. Kentucky Public Service Commission – Electric Outage Notification Procedures

The Kentucky Public Service Commission (KPSC) requires notification from the Company within two (2) hours following discovery of any single incident in an operations center area which results in a service interruption for four (4) or more hours to 500 or more customers.

The Distribution Control Center Manager or his/her designee shall be responsible for completing necessary electronic service interruption notifications per KPSC and internal guidelines. The following link must be used to submit KY PSC notifications: http://psc.ky.gov/Security/Account/login.aspx

(A copy of all submitted reports must be submitted internally to Company personnel listed in Appendix 2.B.)

2.2. Virginia State Corporation Commission - Outage Notification Procedures

The Virginia State Corporation Commission (VSCC) requires notification from the Company of any single incident in an operations center area which results in any outages that are thirty (30) or more minutes in duration affecting service to 10% of the customers of a utility. Notification shall be made by telephone as soon as practical during the regular business day or promptly in the morning of the following business day if the interruption occurs during non-business hours.

The Distribution Control Center Manager or his/her designee shall be responsible for completing necessary telephone and written notifications per VSCC guidelines as outlined in October 16, 1985 letter regarding Reporting of Bulk Power Supply Emergencies and Electric Power Outages. **(A copy of all submitted reports must be submitted internally to Company personnel listed in Appendix 2.B.)**

2.3. Emergency Incident Internal Notification Procedures

The procedures described herein align with the Company's *Internal Notification and Emergency Response Guide (INERG)* which is included in Appendix 2.A. The scope of this section includes INERG covered emergency incidents which may be experienced during responses to significant outage events on the electric distribution system.

2.3.1. Reportable Incidents to State Commissions

Section 2.1 and 2.2 of this EPRP establish the Kentucky Public Service Commission's and Virginia State Corporation Commission's minimum reporting requirements for covered emergency incidents. The Director Safety and Technical Training or their delegate should be notified of any Covered Emergency Incident which is reportable, or has the potential to be reportable, to the KYPSC or VSCC.

2.3.2. Sabotage Reporting

Sabotage is broadly defined as disturbances or unusual occurrences intended to cause failure, disruption, or harm to the normal business activities, property, or operations of LG&E, KU, or ODP. Employees and contract employees who are made aware of actual or suspected sabotage shall immediately contact Corporate Security.

Employees will be alerted when an incident has occurred within the Company, and will be advised on the appropriate actions to take. Employees may call designated sabotage information lines (**see Appendix 10**) to obtain necessary information regarding a reported sabotage incident.

2.3.3. Incident Investigation

The Company's Fire and Security Investigator (FSI), or their designee, should be notified of all covered emergency incidents. The FSI, or their delegate, is responsible for investigating all reported incidents. Corporate Law shall be contacted in the event the FSI or their designee is not available (see Appendix 10 for contact information).

- The Director Safety and Technical Training should be notified of any safety incident which has or will likely result in an OSHA investigation.

- The Manager Corporate Security and Business Continuity should be notified whenever there is knowledge of a fatality or newsworthy event (see Appendix 10 for contact information).

2.3.4. Media Contacts

Corporate Communications shall be contacted (see Appendix 10 for contact information) whenever an INERG covered emergency incident occurs and there is potential or known media coverage.

2.3.5. Environmental Spills or Releases

Electric Distribution Company and contractor employees should take the following actions whenever there is a release of transformer oil, petroleum product, or hazardous chemicals.

A. Identify spilled substance, spill source and affected area.
B. Notify immediate supervisor, and determine who will make necessary external notifications.
C. Stop and contain the spill if trained and qualified to do so.
D. Notify local emergency response agencies **within 15 minutes**. Call 911 if the spill triggers Reportable Quantity (RQ) procedures.
E. Notify Environmental Affairs and the appropriate regulatory authorities (see Appendix 10.0 for contact information).

When a potentially hazardous spill has occurred, the following information must be reported:

A. Name and position of the person reporting
B. Spill area description
C. Spill location, source, and cause
D. Time of spill/incident
E. Material involved
F. Corrective action(s) taken
G. Estimated spill size/quantity released

2.3.6. Asbestos Emergencies

Any employee exposed to a possible Asbestos Containing Material (ACM) shall notify their immediate supervisor or manager and designated Safety and Technical Training Specialist.

2.3.7. Critical Incident Reporting to PPL

In the event of a serious safety or security incident involving LG&E or KU that requires reporting to a regulatory authority, the PPL Security Command Center must be notified in accordance with the following:

A. Employee or Contractor Injury - Director Safety and Technical Training
B. Security Incident - Manager Corporate Security and Business Continuity

Notifications must be made within 24 hours of reporting to a regulatory authority, but timing should be accelerated based upon the severity and circumstances of the incident.

3. Incident Command System

Purpose

The purpose of EPRP Section 3.0 is to introduce the high level organizational structure, command staff, and associated responsibilities the Company shall employ when responding to significant emergencies or outage events on the electric distribution system.

Scope

The scope of EPRP Section 3.0 covers the Company's electric distribution service territory, and all personnel, business partners and off system resources utilized in response to emergencies or significant outage events on the LG&E, KU, or ODP electric distribution system.

Responsibilities

The Emergency Preparedness, Planning, and Response Team (EPPRT) shall have responsibility for assuring all resources available and assigned to assist with an emergency or significant restoration event are organized in accordance with the procedures described herein. Additionally, the EPPRT shall have responsibility for developing Alert Level Task lists for the Incident Command areas under their responsibility. **Appendix 3.B contains Alert Task Lists for key Electric Distribution Incident Command System areas.**

Training and Qualification

The EPPRT shall have responsibility for establishing minimum training and qualification requirements for procedures covered herein. **Appendix 1.C contains the Emergency Preparedness and Response Plan Review, Training, and Exercise Schedule.**

References

None

Revisions

None

3.1. Incident Command System Command Staff

Electric Distribution has adopted an Incident Command System (ICS) based structure for responses to significant emergencies and outage events on the Company's electric distribution system. The organizational structure and command staff positions of the Company's ICS are displayed in Figure 1. **(See Appendix 3.A for names, titles, and contact information of designated command staff personnel.)**

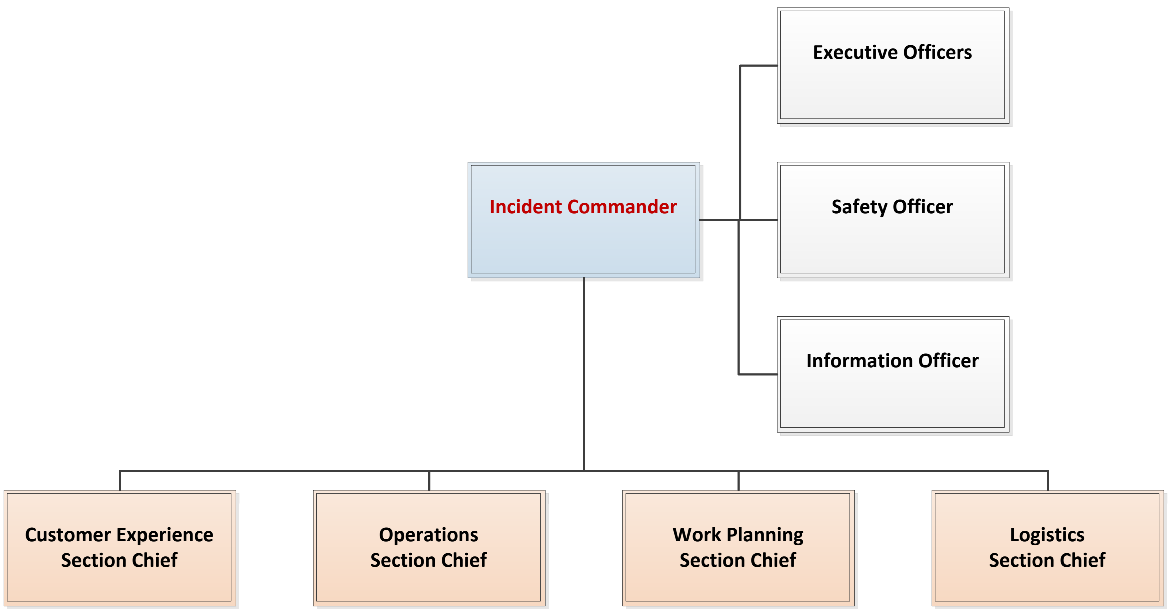


Figure 1. Incident Command System Command Structure

This structure and associated processes provide assurance the Company responds to events on the electric system in a timely, effective, and consistent manner. Finally, the ICS provides for standard communications during emergencies, to key stakeholders, both internal and external to the Company.

The chain of command throughout the ICS is used to communicate direction and maintain management control. Although direction must flow through the chain of command, members of the organization may directly communicate and work with each other to ask for or share information. ICS team members work within the ICS position descriptions and follow the designated reporting relationships, regardless of their non-emergency positions or everyday reporting responsibilities.

3.2. Executive Officers

The Vice President Electric Distribution and the Vice President Customer Services or their designee(s) shall serve as Executive Officer(s) for significant emergency response efforts associated with the Electric Distribution System. These positions shall also be responsible for serving as Executive Sponsors of the ***Emergency Planning, Preparedness, and Response Team*** (see EPRP 1.3), and overseeing the development and maintenance of Alert Level task lists **(see Appendix 3.B)** which assure the Company is sufficiently prepared to safely respond to significant electric outage events and associated emergencies.

3.2.1. Emergency Preparedness

Executive Officers shall be responsible for executing Blue Sky Task List items throughout the year to assure LG&E and KU are prepared to safely respond to all significant electric outage events and related emergencies, including:

- Ensure the Company is adequately organized, trained, and exercised to respond safely, efficiently and effectively.
- Ensure human, equipment, and material resource plans provide for effective and timely responses.
- Ensure effective communications plans are in place to provide customers, emergency responders, community leaders, and employees with timely and accurate information during events.
- Ensure the Company’s emergency planning, preparedness, and response practices align with Industry best practices.
- Ensure effective preparedness plans are in place with customers, key emergency response agencies, government leaders, and other private sector organizations.

3.2.2. Emergency Planning

Whenever a significant weather event or other disaster is forecasted, the designated Executive Officers shall be responsible for executing all Executive Officer Yellow Alert Task List items. Pre-event planning responsibilities include:

- Collaborate with the Incident Commander to evaluate threats and develop strategic response plans.
- Ensure all key Company Officers are informed of forecasted threats.
- Collaborate with the Information Officer as necessary to develop internal and external communications strategies.

- Collaborate with the Incident Commander and other Section Chiefs to ensure assigned Company personnel are executing designated Yellow Alert task items.
- Work with the Incident Commander as needed to assess and approve resource plans.

3.2.3. Emergency Response

Whenever a significant weather event or other disaster has resulted in significant customer outages and damages to the electric system, designated Executive Officers shall be responsible for executing all assigned Red Alert Task List items. During significant outage events or emergencies, Executive Officer's responsibilities include:

- Conduct continuous situational awareness meetings and communications with key internal and external leaders.
- Oversee and support execution of established emergency response plans.
- Ensure the organization is adequately organized, staffed, and positioned to respond.
- Ensure safety is tightly integrated into all response plans and procedures.
- Oversee development and execution of key internal and external communications strategies.

3.3. Information Officer

The Director of Media Relations and the Director of External and Brand Communications (or their designee(s)) shall serve as Information Officer(s) for significant emergency response efforts associated with the Electric Distribution System. These positions shall also be responsible for serving on the ***Emergency Planning, Preparedness, and Response Team*** (see EPRP 1.3), and developing and maintaining Alert Level task lists **(see Appendix 3.B)** which assure the Company is sufficiently prepared to effectively communicate internally and externally in preparation for or response to significant outage events or emergencies involving the electric distribution system.

3.3.1. Emergency Preparedness

Designated Information Officers shall be responsible for executing Blue Sky Task List items throughout the year to assure LG&E and KU are prepared to safely respond to all emergencies, including:

- Oversee development and maintenance of all tactical and strategic communication plans and procedures associated with emergency response and system restoration and repair.
- Validate position specific task lists.
- Ensure that all support staff has been identified and adequately trained.
- Work with industry leaders to develop procedures and industry guidelines for resolving inconsistent safety practices and procedures of mutual assistance utility and business partners.

3.3.2. Emergency Planning

Whenever a significant weather event or other disaster is forecasted, the designated Information Officer shall be responsible for executing all Information Officer Yellow Alert Task List items. Pre-event planning responsibilities include:

- Collaborate with the Incident Commander and Operations Section Chief to determine the predicted event level and scope.
- Assign support team members – communication professionals – to the service areas with forecasted trouble.
- Collaborate with the Executive Officer and Incident Commander as necessary to develop internal and external communication strategies.

3.3.3. Emergency Response

Whenever a significant weather event or other disaster has resulted in significant customer outages and damages to the electric system, the designated Information Officer shall be responsible for executing all assigned Red Alert Task List items. During significant outage events or emergencies, Information Officer's responsibilities include:

- Collaborate with Incident Commander and Operations Section Chief to determine actual damages and system impact.
- Collaborate with Executive Officer and Incident Commander to develop internal and external communication strategies.
- Execute key internal and external communications strategies.
- Deploy support team members – communication professionals - to the service areas with significant customer outages and damages.

3.4. Safety Officer

The Director Safety and Technical Training and Manager Electric Distribution and Transmission Safety or their designee(s) shall serve as Safety Officer(s) for significant emergency response efforts associated with the Electric Distribution System. These positions shall also be responsible for serving on the ***Emergency Planning, Preparedness, and Response Team*** (see EPRP 1.3), and developing and maintaining Alert Level task lists **(see Appendix 3.B)** which assure the Company is effectively protects customers, the public, employees, business partners, emergency responders, and all personnel supporting the Company's response to emergencies and significant outage events involving the electric distribution system.

3.4.1. Emergency Preparedness

Designated Safety Officers shall be responsible for executing Blue Sky Task List items throughout the year to assure LG&E and KU are prepared to safely respond to all emergencies, including:

- Oversee development and maintenance of all technical, tactical, and strategic safety plans and procedures associated with emergency response and system restoration and repair, which assure the safety of employees, business partners, off-system resources, and the public.
- Assist with the development, oversight, and assessment of emergency response drills and exercises which test the effectiveness of emergency response procedures.
- Validate position specific task lists.
- Ensure that all support staff has been identified and adequately trained.
- Develop and maintain off-system resource passporting processes and tailgate material.
- Work with industry leaders to develop procedures and industry guidelines for resolving inconsistent safety practices and procedures of mutual assistance utility and business partners.

3.4.2. Emergency Planning

Whenever a significant weather event or other disaster is forecasted, the designated Safety Officer shall be responsible for executing all Safety Officer Yellow Alert Task List items. Pre-event planning responsibilities include:

- Collaborate with the Incident Commander and Operations Section Chief to determine the predicted event level and scope;

- Assign support team members – safety and health professionals - to the service areas with forecasted trouble;
- Work with the Operations Section Chiefs and Incident Commander to determine if the Public Safety Response Team should be activated;

3.4.3. Emergency Response

Whenever a significant weather event or other disaster has resulted in significant customer outages and damages to the electric system, the designated Safety Officer shall be responsible for executing all assigned Red Alert Task List items. The Safety Officer has responsibility for assessing hazards and unsafe conditions associated with the incident, and developing, implementing, and monitoring an incident safety plan which assures:

- Public and personnel safety;
- All personnel responding to the incident are properly trained and qualified to perform restoration and repair activities;
- All Command Staff personnel are kept up to date on safety performance and any incidents;
- All personnel responding to the incident are aware of identified safety hazards and unsafe conditions;
- Assure a Safety Hotline is managed throughout an event to provide employees, contractors, and mutual assistance resources the opportunity to submit any safety concerns.
- All off-system resources receive safety passport training;
- Adequate safety professional representation is in the field; and
- Safety performance is monitored and reported on throughout the restoration effort.

3.5. Incident Commander

The Director Electric System Restoration shall be responsible for overseeing the ***Emergency Planning, Preparedness, and Response Team*** (see EPRP 1.3), and serving as the primary Incident Commander for significant outage event emergencies involving the Electric Distribution System. The Director of Customer Services Energy Efficiency & Smart Grid Strategy shall serve as the secondary Incident Commander. Both of the defined positions shall also be responsible for serving on the ***Emergency Planning, Preparedness, and Response Team*** (see EPRP 1.3), and developing and maintaining Alert Level task lists **(see Appendix 3.B)** which assure the Company is sufficiently prepared to safely respond to emergencies and significant electric outage events .

3.5.1. Emergency Preparedness

The primary Incident Commander, or a designee, shall be responsible for executing all Blue Sky Task List items to assure LG&E KU is adequately prepared to respond to significant outage events on the electric distribution system, including:

- Coordinating, planning, and leading monthly planning and preparedness meetings;
- Working with responsible Section Chiefs to develop preparedness, planning, and response task lists for each Incident Command Section;
- Directing, planning, and participating in annual emergency drills which exercise the Emergency Preparedness and Response Plan, and Alert Level Task lists;
- Ensuring that adequate personnel are designated and trained to fill critical Incident Command System positions; and
- Directing, leading, or supporting post incident reviews.

3.5.2. Emergency Planning

Whenever a significant weather event or other disaster is forecasted, the Incident Commander shall be responsible for establishing an Yellow Alert (see EPRP 1.1), and executing all Yellow Alert Task List items. Pre-event planning responsibilities include:

- Directing the staffing and coordination of Electric Distribution's Incident Command System Command Staff;
- Alerting the Command Staff and the Vice President – Electric Distribution Operations of Emergency Preparedness and Response Alert Level revisions and establishing the anticipated Emergency Event Level classification (see EPRP 1.2) for the LG&E KU service areas; and

- Setting up and facilitating all planning and response conference calls, with the Command Staff, and confirming that all critical pre-staging Yellow Alert tasks are completed.

3.5.3. Emergency Response

Whenever a significant weather event or other disaster has resulted in significant customer outages and damages to the electric system, the Director Electric System Restoration or their designee shall be responsible for establishing an Red Alert (see EPRP 1.1), and executing all Incident Commander Red Alert Task List items.

During response to significant outage events, the Incident Commander shall be designated by the highest ranking qualified management representative that is available to lead the Company's response at the time of an incident. The Incident Commander's authorities and responsibilities shall be transferred to more higher ranking and qualified personnel when they are available to respond and assume the role.

The Incident Commander is responsible for overall management of an incident, for ensuring compliance with applicable internal policies and government regulations, and for determining strategic and tactical objectives. The Incident Commander is ultimately responsible for public and personnel safety, resource management, and internal and external information releases.

The Incident Commander shall also be responsible for:

- Directing the staffing and coordination of Electric Distribution's Incident Command System Command Staff;
- Establishing a Command Post if one has not been set up.
- Ensuring public safety and the safety of all resources supporting system restoration or emergency response efforts.
- Maintaining communications with senior management regarding status, activities, and issues to ensure tactical responses align with strategic goals and objectives.
- Coordinating response activities with incident response emergency response agencies and government officials.
- Coordinating work activities between work groups representing various phases of operations.
- Ensuring safety performance, system status, resource levels, regulatory issues, and all external communications are logged.

- Ensuring appropriate delegation of authority has been transferred to satisfy all needed positions and optimize resources.

The Incident Commander is responsible for establishing and monitoring the incident organization. The organization should be large enough to manage the incident at hand, yet, resource use must be efficient and cost effective. Anticipated expansion or contraction of incidents shall require changes to the organization.

3.6. Operations Section Chief

The Director Electric Distribution and Director Asset Management or their designees shall serve as Operations Section Chiefs for significant emergency response efforts associated with the Electric Distribution System. Designated Operations Section Chiefs shall be responsible for serving on the ***Emergency Planning, Preparedness, and Response Team*** (see EPRP 1.3), and developing and maintaining Emergency Preparedness and Response Alert Level task lists **(see Appendix 3.B)** associated with their Section responsibilities.

3.6.1. Emergency Preparedness

Operations Section Chiefs shall also be responsible for overseeing and executing Blue Sky Task List items throughout the year to assure LG&E and KU are prepared to safely, effectively and efficiently respond to all emergencies, including:

- Overseeing the development and maintenance of effective business processes, and ensuring a sufficient number of personnel are trained and qualified, to protect the public from reported downed wires;
- Sufficiently staffing, equipping, and training personnel to perform post event damage assessments and accurately estimate restoration durations;
- Ensuring adequate facilities are available and equipped to support central resource management and work prioritization operations;
- Ensuring an adequate number of personnel and business partners are trained and qualified to support resource management and work prioritization restoration and repair processes; and
- Assisting with development of, and supporting, all exercises that test Emergency Preparedness and Response procedures.

3.6.2. Emergency Planning

Whenever a significant weather event or other disaster is forecasted, the designated Operations Section Chiefs or their delegate(s) shall be responsible for executing all assigned Yellow Alert Task List items. Pre-event planning responsibilities include:

- Ensuring all key Operations Section roles and responsibilities are filled, commensurate with the predicted Event level and response needed;
- Developing tactical plans for aligning needed resources with service areas forecasted to experience trouble;
- Collaborate with Work Planning to ensure resource availability information is available; and

- Collaborate with the Incident Commander and Work Planning to establish industry and business partner mutual assistance tactical plans.

3.6.3. Emergency Response

Whenever a significant weather event or other disaster has resulted in significant customer outages and damages to the electric system, the responsible Operations Section Chief(s) shall be responsible for executing all assigned Red Alert Task List items, including:

- Ensuring all key roles of the Operations Section (see EPRP 6.0) are filled, as needed based on the forecasted or actual outcome of an event;
- Working with Work Planning to ensure all resources are accounted for in the designated Resource Management database;
- Executing and supporting Damage Assessment Procedures to enable timely and effective gathering and assessment of system damages;
- Working with the Operations Managers and Work Planning to estimate/identify resource needs and restoration projections based on those needs;
- Developing and overseeing tactical plans which support Protect, Restore, Repair philosophies; and
- Assuring effective and efficient assignment and utilization of available resources to execute restoration and repair procedures;

3.7. Customer Experience Section Chief

The Director Customer Service and Marketing and Director Revenue Integrity or their designee(s) shall serve as Customer Experience Section Chiefs for significant emergency response efforts associated with the Electric Distribution System. These positions shall also be responsible for serving on the ***Emergency Planning, Preparedness, and Response Team*** (see EPRP 1.3), and developing and maintaining Alert Level task lists **(see Appendix 3.B)** which assure the Company is sufficiently prepared to safely respond to emergencies and significant electric outage events .

3.7.1. Emergency Preparedness

Customer Experience Section Chiefs shall be responsible for overseeing and executing Blue Sky Task List items throughout the year, including:

- Sufficiently staffing, equipping, and training personnel and business partners to assure effective responses to customer outage notifications;
- Ensuring adequate procedures are in place to identify and communicate with critical, key, and major customers during large outage events or emergencies involving the electric system.
- Ensuring adequate procedures are in place to communicate critical, key, and major customer information to internal stakeholders during large outage events or emergencies involving the electric system.
- Developing and testing business procedures for properly elevating emergency contacts.
- Assisting with development and support of all exercises that test emergency response and restoration Customer Experience procedures.
- Establishing effective relationships with key state, regional, and local emergency managers.

3.7.2. Emergency Planning

Whenever a significant weather event or other disaster is forecasted, the designated Customer Experience Section Chiefs or their delegate(s) shall be responsible for executing all assigned Yellow Alert Task List items. Pre-event planning responsibilities include:

- Ensuring all key Customer Experience Section roles and responsibilities are scheduled or filled, commensurate with the predicted Event level and response needed;

- Communicating with information technology to ensure all information Customer information systems will be available for the period where inclement weather is forecasted; and
- Communicating with the Logistics Section Chief(s) or their delegate to ensure necessary resource tracking information is available.

3.7.3. Emergency Response

Whenever a significant weather event or other disaster has resulted in significant customer outages and damages to the electric system, the responsible Customer Experience Section Chief(s) shall be responsible for executing all assigned Red Alert Task List items, including:

- Ensuring all key roles of the Customer Experience Section (see EPRP 7.0) are filled, as needed, based on the forecasted or actual outcome of an event;
- Collaborating with the Incident Commander and Information Officer to ensure consistent information is being communicated to customers, local authorities, emergency operations centers, and government entities.
- Verifying all available communications channels are working properly and allowing affected customers to identify outages and obtain restoration status information.
- Verifying with Information Technology that all necessary information systems are available;
- Assuring key customer outage statistical and performance data is tracked and provided to the Incident Commander.
- Working with Budgeting and Forecasting to ensure all necessary resource information is available for required financial reporting;
- Ensuring effective emergency management outreach to affected emergency response managers, and staffing or support of all activated Emergency Operations Centers as requested by key state, regional, or city officials.
- Ensuring effective and timely communications with major and key customers who need critical restoration information and assistance during restoration activities.
- Working with areas affected by outages or emergencies and making local business offices available for customers to provide outage information and obtain updates on their restoration status.

3.8. Logistics Section Chief

The Director Supply Chain and Director Operating Services or their designee(s) shall serve as Logistics Section Chief(s) for significant emergency response efforts associated with the Electric Distribution System. Designated Logistics Section Chiefs shall be responsible for serving on the ***Emergency Planning, Preparedness, and Response Team*** (see EPRP 1.3), and developing and maintaining Emergency Preparedness and Response Alert Level task lists **(see Appendix 3.B)** associated with their Section responsibilities.

3.8.1. Emergency Preparedness

Logistics Section Chiefs shall be responsible for overseeing and executing Blue Sky Task List items throughout the year to assure LG&E and KU are prepared to effectively and efficiently meet logistical, security, and human needs of resident and off system resources during responses to significant outages or emergencies on the electric system, including:

- Prearranging for staging areas and facilities for restoration resource management, housing, staging, and resource processing;
- Developing staging, housing, and meals contracts and business processes which assure adequate and efficient support of emergency and restoration responses;
- Ensuring an adequate number of personnel and business partners are trained and qualified to support the provision and/or set up of staging areas, meals, fueling, housing, facilities, laundry services, waste management, materials, security, etc…during responses to significant outages or emergencies;
- Assisting with the development of, and participating in all drills and exercises that test Emergency Preparedness and Response procedures.

3.8.2. Emergency Planning

Whenever a significant weather event or other disaster is forecasted, the designated Operations Section Chiefs or their delegate(s) shall be responsible for executing all assigned Yellow Alert Task List items. Pre-event planning responsibilities include:

- Ensuring all key Logistics Section roles and responsibilities are identified and staffed, commensurate with the predicted Event level and response needed and communications have been made with all personnel who might be mobilized to support an event ;
- Collaborating with the Incident Commander and Work Planning group to develop tactical plans for staging areas, meals, fueling, housing, facilities, laundry services,

waste management, materials, security, and communications as needed to support the resources needed for the event forecasted;

- Contacting, as needed, logistics vendors and business partners to discuss the pre-positioning of resources depending on the anticipated event impacts; and
- Confirming the availability of anticipated material needs, and arranging for the delivery of incremental storm kits and material trailers, as needed for operating areas forecasted to be impacted.

3.8.3. Emergency Response

Whenever a significant weather event or other disaster has resulted in significant customer outages and damages to the electric system, the responsible Logistics Section Chief(s) or their designee shall be responsible for executing all assigned Red Alert Task List items, including:

- Ensuring all key roles of the Logistics Section (see EPRP 9.0) are staffed and backed-up , as needed based on the forecasted or actual outcome of an event;
- Assuring effective and efficient assignment and utilization of available resources to execute established logistics procedures;
- Serving as a single point of contact for the Incident Commander, Operations Section Chiefs, and Work Planning Section Chiefs, for coordinating material and supply requirements, inventory management, and logistics field operations across all impacted areas;
- Identifying and estimating service and support requirements for planned and expected operations;
- Working with Work Planning to ensure adequate staging locations, hotels, meals, etc…are available for all resources accounted for in the designated Resource Management database; and
- Assisting with demobilization procedures for all off system resources.

3.9. Work Planning Section Chief

The Director Electric Reliability and Manager Design or their designee(s) shall serve as Operations Section Chiefs for significant emergency response efforts associated with the Electric Distribution System. Designated Work Planning Section Chiefs shall be responsible for serving on the ***Emergency Planning, Preparedness, and Response Team*** (see EPRP 1.3), and developing and maintaining Emergency Preparedness and Response Alert Level task lists **(see Appendix 3.B.)** associated with their Section responsibilities.

3.9.1. Emergency Preparedness

Work Planning Section Chiefs shall be responsible for overseeing and executing Blue Sky Task List items throughout the year, including:

- Overseeing the development and maintenance of emergency restoration resource management tracking databases, applications, reports, and business processes;
- Working with the Operations Section Chiefs and Incident Commander to develop business processes which support resource needs calculations and mutual assistance business processes;
- Sufficiently staffing, equipping, and training personnel to assist with resident and non-resident resource planning, acquisition, administration, and tracking;
- Ensuring adequate facilities are available and equipped to support central and decentralized resource planning and tracking business processes;
- Assisting with development of, and supporting, all exercises that test emergency response and restoration Work Planning procedures.

3.9.2. Emergency Planning

Whenever a significant weather event or other disaster is forecasted, the designated Work Planning Section Chiefs or their delegate(s) shall be responsible for executing all assigned Yellow Alert Task List items. Pre-event planning responsibilities include:

- Ensuring all key Work Planning Section roles and responsibilities are scheduled or filled, commensurate with the predicted Event level and response needed;
- Working with the Operations Section Chief and Incident Commander to calculate and equitably allocate needed resources for service areas forecasted to experience trouble;
- Collaborating with the Incident Commander and Operations Section Chief to establish industry and business partner mutual assistance tactical plans;
- Participating on necessary mutual assistance calls;

- Communicating with information technology to ensure all information systems will be available for the period where inclement weather is forecasted; and
- Communicating with the Logistics Section Chief(s) or their delegate to ensure necessary resource tracking information is available.

3.9.3. Emergency Response

Whenever a significant weather event or other disaster has resulted in significant customer outages and damages to the electric system, the responsible Work Planning Section Chief(s) shall be responsible for executing all assigned Red Alert Task List items, including:

- Ensuring all key roles of the Work Planning Section (see EPRP 8.0) are filled, as needed based on the forecasted or actual outcome of an event;
- Working with the Operations Section to ensure all resources are accounted for in the designated Resource Management database;
- Working with the Operations Section to establish area specific resource needs and availability, including line technicians, service crews, bird dogs, bull dogs, and damage assessors;
- Participating on necessary mutual assistance calls;
- Executing necessary internal resource reporting;
- Verifying with Information Technology that all necessary information systems are available;
- Working with Budgeting and Forecasting to ensure all necessary resource information is available for required financial reporting;
- Executing all mutual assistance business processes, including participating on joint mobilization mutual assistance conference calls, tracking resources from the point of release to the assignment to an operations area, and assisting the Operations Section with administratively processes arriving resources; and
- Coordinating with the Operations Section and Incident Commander to monitor and modify estimated restoration durations for local areas and at circuit levels, and helping to effectively align, secure or assign resources with system damages and outage counts.

4. Safety

Purpose

The purpose of EPRP Section 4.0 is to outline incremental safety procedures, processes, and organization setup which may be utilized during responses to emergencies, disasters, or weather events which result in significant damages and customer outages on Company electric distribution facilities. All safety policies and procedures included in the References section below shall continue to be adhered to.

Scope

The scope of EPRP Section 4.0 covers the Company's electric distribution service territory, and all personnel, business partners and off system resources utilized in response to emergencies or significant outage events on the LG&E, KU, or ODP electric distribution system.

Responsibilities

The EPPRT shall have responsibility for assuring all resources available and assigned to assist with an emergency or significant restoration event are aware and knowledgeable of all safety policies and procedures associated with the work to be performed.

Training and Qualification

The EPPRT shall have responsibility for establishing minimum training and qualification requirements for procedures covered herein. **(Appendix 1.C contains the Emergency Preparedness and Response Plan Review, Training, and Exercise Schedule.)**

References

1. LG&E and KU Energy LLC, Health & Safety Manual, Version – 3/01/2012
2. LG&E and KU Energy LLC Policy, Corporate Health and Safety Policy, Version - 12/10/08.
3. LG&E and KU Energy LLC Policy, Safety Reinforcement, Version - 12/10/08.
4. LG&E and KU Energy LLC Policy, Drugs and Alcohol, Version – 6/12/13.
5. LG&E and KU Energy LLC, Lock Out/Tag Out (LOTO) Carding and Clearance Program for Electric Transmission, Distribution, and Substation, Version – 9/11/2013.

Revisions

None

4.1. Passporting Off System Resources

During significant events on the Electric Distribution system, when significant damages and customer outages result, Electric Distribution may secure incremental off system resources to assist with restoration efforts. The Operations Director or their designee(s) shall be responsible for assuring that no off system worker is permitted to work on the LG&E and KU system until they have received prescribed safety orientation/passport training.

Each Operations Director shall be responsible for working with the Safety Officer or their designee to identify locations where Safety Specialists or an alternative qualified resource is needed to conduct standardized safety briefings with off system contractors and utility workers. In the event a Safety Specialist or alternative resource cannot be assigned to the Operations location where off system resources are assigned, the Operations Director or their designee shall be responsible for assuring a qualified person under their responsibility provides the safety orientation training.

4.1.1. Safety Passport Orientation Handbook

As part of worker qualification procedures, all off system crew leaders shall be provided a LKE Safety Passport Orientation Handbook **(see Appendix 4.A)** before being assigned work. Additionally, all off system workers must complete an Emergency Information Form, which is included in the Handbook.

The designated Safety Specialist or an alternative Company representative shall be responsible for reviewing the Handbook with off system workers and answering any related questions. In the event an off system worker identifies a LKE safety policy (such as PPE requirements) which differs or exceeds their Company's safety policy, the responsible Safety Specialist shall review the policy difference with the designated Safety Officer.

The Safety Officer shall be responsible for developing and maintaining the Safety Passport Orientation Handbook to assure its contents align with Company safety policies and philosophies.

4.1.2. Passporting Video

As part of worker qualification procedures, all off system workers shall be required to witness the Company's Safety Passport video for Electric Distribution and Transmission. Safety Specialist shall maintain copies of the passport video to be utilized as needed throughout the LG&E and KU service areas.

The Safety Officer shall be responsible for developing and maintaining the Emergency Restoration Safety Passporting video to assure its contents align with Company safety policies and philosophies.

4.1.3. Passport Bracelets

All off system workers who have submitted an Emergency Information Form, viewed the Safety Passport video, and reviewed the Safety Passport Orientation Handbook shall be provided and required to wear a Company assigned and sequentially numbered wrist band. The wrist band shall serve to provide field personnel the ability to visually determine if a field worker has obtained the necessary passport training when/if witnessed in the field working.

4.2. Independent Hold Card Procedures

During significant events on the Electric Distribution system, when large volumes of outage events and resource levels inundate Restoration Coordinators and saturate dedicated radio channels, the Distribution Control Center (DCC) and Operations Sections (OS) may elect to transfer control of all aspects of energy isolation and control procedures to qualified and approved personnel working on (operating, maintenance, repair, and construction) the electric distribution system.

The LG&E and KU Energy LLC, Lock Out/Tag Out (LOTO) Carding and Clearance Program for Electric Transmission, Distribution, and Substation, Version – 12/16/2013, establishes:

- Minimum requirements for transferring authority from the DCC to the OS;
- Documentation/record keeping requirements for field personnel; and
- Management's communications responsibilities to assure all personnel involved in the energy isolation and control process are aware of the transition to independent hold card procedures.

The Manager DCC shall be responsible for notifying the Operations Section Chiefs and Incident Commander when field resource volumes exceed the capabilities of available Restoration Coordinators to efficiently utilize field resources. The Operations Section Chief shall be responsible for coordinating with local Operations Directors to determine if Independent Hold Card Procedures can be invoked. Upon receiving confirmation from the Operations Director and approval from the Safety Officer and Incident Commander, Independent Hold Card Procedures shall be executed. **(Please see Appendix 4.B for a copy of the Company's Independent Hold Card Procedures.)**

5. Emergency Communications

Purpose

The purpose of EPRP Section 5.0 is to outline incremental internal and external communications procedures and organization setup which may be utilized by the Company during responses to emergencies, disasters, or weather events which result in significant damages and customer outages on Company electric distribution facilities.

Scope

The scope of EPRP Section 5.0 covers the Company's electric distribution service territory, and all personnel, business partners and off system resources utilized in response to emergencies or significant outage events on the LG&E, KU, or ODP electric distribution system.

Responsibilities

The Information Officer shall have responsibility for assuring all resources available and assigned to assist with an emergency or significant restoration event are aware and knowledgeable of all Corporate Communications emergency policies and procedures.

Training and Qualification

The Information Officer and Incident Commander shall have responsibility for establishing minimum training and qualification requirements for procedures covered herein. **(Appendix 1.C contains the Emergency Preparedness and Response Plan Review, Training, and Exercise Schedule.)**

References

None

Revisions

None

5.1 Internal Communications

All Sections of the Company's Incident Command System shall have responsibility for ensuring timely, accurate, and consistent communications in preparation for and response to significant outage events and emergencies involving the electric distribution system.

5.1.1 Roles and Responsibilities

5.1.1.1 Incident Commander – or their designee shall be responsible for:

5.1.1.1.1 Maintaining a constant and direct line of contact with Command Staff and Information Officer, to ensure accurate and timely information exchange, and to review communications strategies and plans;

5.1.1.1.2 Communicating and working closely with the Emergency Preparedness and Response Team to ensure accurate and timely information is given to key internal and external stakeholders;

5.1.1.1.3 Serving as the primary communications representative on the Daily Outage Briefings and at the operations command center, if one has been established to manage the emergency response; and

5.1.1.1.4 Creating and submitting Executive Summary Reports.

5.1.2 Activation

5.1.1.1 **Yellow Alert** – The Incident Commander shall have responsibility for issuing Yellow Alerts, and notifying all Command Staff personnel. Whenever a Yellow Alert has been issued, the Command Staff and Section Chiefs or their designee shall have responsibility for executing assigned Yellow Alert tasks lists and associated emergency plans which address internal communications.

Under certain circumstances, the Incident Commander may need to execute emergency communications plans in advance of a Yellow Alert notification if internal information needs regarding a forecasted threat on the electric system cannot be satisfied utilizing day-to-day business processes.

5.1.2.1 Red Alert – The Incident Commander shall have responsibility for issuing Red Alerts, and notifying all Command Staff personnel. The Command Staff and Section Chiefs or their designee shall have overall responsibility for appropriately responding to Red Alert Levels issued by the Incident Commander or their designee, including communicating to appropriate key leadership roles, and being available to assist with developing communications strategies and plans as needed to support the Company's response to significant events, and to fulfill the information requirements of key internal stakeholders.

5.1.3 Business Processes

5.1.3.1 Internal Outage Communications Tool - The Internal Outage Communications (IOC) is a suite of dashboards, reports, extractable data, and maps available for key Company personnel to view, analyze, and react to outage data. The system displays outage, wires down, priority customer, and estimated restoration time information, filterable by Network Management System (NMS) Control Zone. The system also provides key resource data from the Resource on Demand (RoD) resource management application.

5.1.3.2 Daily Outage Briefings – Outage briefings shall be held daily, normally in the morning, to review the current system status and restoration progress, safety and/or operational issues, current day work plans, and resource, material, and logistic needs. Briefings should be short and concise, but should cover whatever site specific information is needed to assure effective, timely, and safe response to emergencies and significant outages, including:

- Safety Status and Considerations
- Active outage counts
- Active wire down counts
- Restored outage totals
- Covered wire down totals
- Weather Forecast
- Critical and Key Customer Outages
- Key External Communications
- Call Volumes
- Resource Needs
- Off-System Support Status/Timing
- Supplies and Logistics Status and Needs
- Facility and Staging Area Status and Needs

5.1.3.3 Executive Summary Reports – The Incident Commander, or their delegate, shall be responsible for providing senior management with routine Executive Summary

Reports which provide summary information on the data collected from the Daily Outage Briefings and Internal Outage Communication tools. This information shall be used to help establish senior level internal and external communications strategies, plans, and messages.

5.1.4 Training and Qualifications

The Emergency Preparedness and Response Team shall be responsible for ensuring all Company personnel and business partners assigned key emergency preparedness and response roles are trained on the Company's Incident Command System and all critical communications systems, processes, and hierarchies.

5.2 External Communications

Corporate Communications shall have responsibility for working with the Emergency Preparedness, Planning, and Response Team to establish, test, and execute business procedures which provide timely, accurate, and consistent communications to customers and key stakeholders in preparation for or response to significant outage events and emergencies involving the electric distribution system.

5.2.1 Roles and Responsibilities

5.2.1.1 Information Officer –

5.2.1.1.1 Maintaining a constant and direct line of contact with designated Officers, General Counsel, and PPL Corporation (where appropriate), to ensure accurate and timely information exchange, and to review communications strategies and plans;

5.2.1.1.2 Communicating and working closely with the Incident Commander and Emergency Preparedness and Response Team to ensure accurate and timely information is given to key internal and external stakeholders;

5.2.1.1.3 Serving as the primary communications representative at the corporate command center, if one has been established to manage the emergency response;

5.2.1.1.4 Maintaining a direct line of communication with the On-Call Communications Representative to assess external communications needs and media coverage, and providing associated information to top management to assist them in communications decisions relating to the emergency;

5.2.1.1.5 Functioning as an official Company spokesperson, and if necessary, working with the appropriate Officers and Senior Managers if an alternative Company representative is elected to brief external stakeholders;

5.2.1.1.6 Overseeing the development and maintenance of standard communications templates and wording for various emergency types, to assure timely, effective, and efficient critical information provision to customers and key external stakeholders during significant emergencies and outage events;

5.2.1.1.7 Coordinating consistent information provision to state, regional, and local leaders and emergency management agencies through constant communications with key Customer Experience roles, including the Emergency Management Outreach and Critical Customer Directors in the Incident Command System.

5.2.1.2 Information Center Coordinator – responsible for:

5.2.1.2.1 Collaborating with the Incident Commander or their designee and drafting media information regarding system and outage status for review and approval by the Information Officer, before dissemination to media outlets;

5.2.1.2.2 Alerting other Communications Department staff members, using a departmental phone list to notify members outside of regular work hours, who can help in answering news media calls and in compiling appropriate background information and visuals that may be needed in responding to the media.

5.2.1.2.3 Making staff assignments to manage the preparation of media releases, compiling relevant background information, updating the company website as appropriate, monitoring and responding across social media channels, monitoring print and broadcast news coverage of the story, responding to the media telephone inquiries and requests for interviews.

5.2.1.2.4 Coordinating the drafting of media information for review and approval by the Information Officer and distributing it following approval.

5.2.1.2.5 Utilizing local and statewide media distribution lists, LG&E and KU's Internet home page, and PPL's corporate website as distribution vehicles.

5.2.1.2.6 Coordinating with Internal Communications to ensure the information is distributed simultaneously to all other LG&E and KU offices and divisions.

5.2.1.2.7 Coordinate the recording of relative message on media lines; and update when appropriate.

5.2.1.2.8 Keeping the Information Officer informed of interview requests as well as breaking news coverage.

5.2.1.2.9 Serving as a designated spokesperson for the company in responding to the media phone calls, especially in providing radio news interviews.

5.2.1.2.10 Managing the documentation of all news coverage as well as the recording and prompt transcription of any news media briefing or one-on-one interviews.

5.2.1.3 On-Call Communications Representative – responsible for,

5.2.1.3.1 Monitoring the Internal Notification Line and responding to notifications and inquiries regarding an outage event or emergency;

5.2.1.3.2 Establishing contact with the Incident Commander or designated Operations Management personnel to gather as much information as possible;

5.2.1.3.3 Assessing the severity level of an event to determine if other members of the Communications staff are needed to assist with managing internal and external information exchanges;

5.2.1.3.4 Executing call-out procedures for incremental Communications resources, as deemed necessary;

5.2.1.3.5 Serving as the initial spokesperson for the Company in responding to media inquiries about an emergency.

5.2.1.3.6 Providing Customer Service On-Call Supervision with information collected and provided externally to ensure consistency in messages being delivered to customers through various channels;

5.2.1.3.7 Keeping the Information Officer advised of any new developments and generally serving as a key source of information in making decisions on how to communicate during the crisis;

5.2.1.3.8 Providing the Information Officer, the Information Center Coordinator, and Communications Department staff members with relevant information for the development of written updates that will be provided to the media, customers (Customer Service and other customer-facing departments, as well as postings on the Company's website and social media) and employees (via e-mails and/or Intranet site updates) whenever significant or new information is confirmed.

5.2.2 Activation

5.2.2.1 **Yellow Alert** – The Incident Commander shall have responsibility for issuing Yellow Alerts, and notifying all Command Staff personnel. Whenever a Yellow Alert has been issued, the Information Officer or their designee shall have responsibility for executing assigned Yellow Alert tasks lists and associated emergency plans which address external communications.

Under certain circumstances, the Information Officer may need to execute emergency communications plans in advance of a Yellow Alert notification if external information needs regarding a forecasted threat on the electric system cannot be satisfied utilizing day-to-day business processes.

5.2.2.2 **Red Alert** – The Incident Commander shall have responsibility for issuing Red Alerts, and notifying all Command Staff personnel. The Information Officer or their designee shall have overall responsibility for appropriately responding to Red Alert

Levels issued by the Incident Commander or their designee, including communicating to appropriate key leadership roles, and being available to assist with developing communications strategies and plans as needed to support the Company's response to significant events, and to fulfill the information requirements of customers and other key external stakeholders.

5.2.3 Business Processes

5.2.3.1 **Incident Notification -** Company personnel who become aware of an emergency situation that is likely to generate news media interest should contact the Communications Department on LG&E and KU's 24-hour Internal Notification Line (**see Appendix 10**). Communications retains an *On-Call Communications Representative* 24/7 to respond to Communications issues. The On-Call Communications Representative shall be responsible for evaluating the nature and scope of the emergency situation, and determine the breadth of coverage needed from Corporate Communications to adequately respond to external requests and need for information.

5.2.3.2 **Level II-IV Events** – If an emergency appears to be Level II-IV, the On-Call Communications Representative should contact the designated Information Officer. The Information Officer shall be responsible for keeping designated Executive Officers and General Counsel apprised of emergency situations and associated communications.

As designated by the Information Officer, a Communications representative should be assigned responsibility for Communicating and working closely with the Incident Commander and Emergency Preparedness and Response Team to ensure accurate, timely, and consistent information exchanges occur with key internal and external stakeholders.

5.2.3.3 **Media Updates** – Whenever an emergency status or outage restoration update is provided to media outlets, the Information Officer should ensure a Communications Representative alerts Customer Service (Customer Experience Section) of all information provided to the news media, to ensure consistent information is being delivered to customers through various channels.

5.2.4 Training and Qualifications

The Information Officer shall be responsible for ensuring all Corporate Communications personnel are appropriately trained on external communications procedures in support of Company responses to significant outage events or emergencies involving the electric system.

5.3 Yellow and Red Alert Conference Calls

The purpose of this document is to provide conference call guidelines and protocol for preparedness and response efforts when a Yellow or Red Alert Level has been declared. The primary objective of conference calls shall be to provide an efficient forum for an exchange of information that enables safe, timely and cost-effective response to forecasted or actual threats.

5.3.1 Conference Call Initiation

5.3.1.1 Yellow Alert – The Incident Commander or their delegate shall have responsibility for initiating a conference call with the Emergency Preparedness and Response Team whenever a Yellow Alert has been declared and the possibility of a Level III or Level IV has been forecasted for the LG&E and KU electric service areas. The call should be scheduled sufficiently in advance of a forecasted event to allow Yellow or Red Alert task lists to be effectively executed.

5.3.1.2 Red Alert - The Incident Commander or their delegate shall have responsibility for initiating a conference call with the Emergency Preparedness and Response Team whenever a Red Alert has been declared for the LG&E and KU electric service areas, and a Level III or Level IV event has been experienced. Conference calls should be conducted at least twice daily throughout the duration of the restoration effort, or until the majority of customers have been restored. Every effort should be made to avoid scheduling calls during peak resource mobilization, customer communications, and work assignment periods.

5.3.2 Conference Call Guidelines

The Incident Commander or their delegate shall be responsible for moderating all Emergency Preparedness and Response Team conference calls. Additionally, the Incident Commander shall be responsible for designating note taker(s), prior to starting the conference call.

At the start of the conference call, the call moderator shall take role call to ensure all key areas of the Incident Command System are adequately represented on the call. If an area is not represented, the Incident Commander or their delegate shall be responsible for following up with those key roles as needed to exchange information with unrepresented areas.

Appendix 5.A contains a copy of the LG&E KU Emergency Preparedness and Response Conference Call Matrix and Call Checklists which should be utilized during conference calls to assure adequate information exchange occurs to effectively initiate and execute all appropriate alert level tasks and other needed response efforts.

6. Operations Section

Purpose

EPRP Section 6.0 introduces the high level organizational structure, roles, and associated responsibilities for the Operations Section of the Company's Incident Command System for responding to significant emergencies or outage events on the electric distribution system.

Scope

EPRP Section 6.0 and its Subsections cover all resources assigned to the Operations Section during responses to significant emergencies or outage events on the electric system, as defined for Level III and IV events in Figure 6.1.

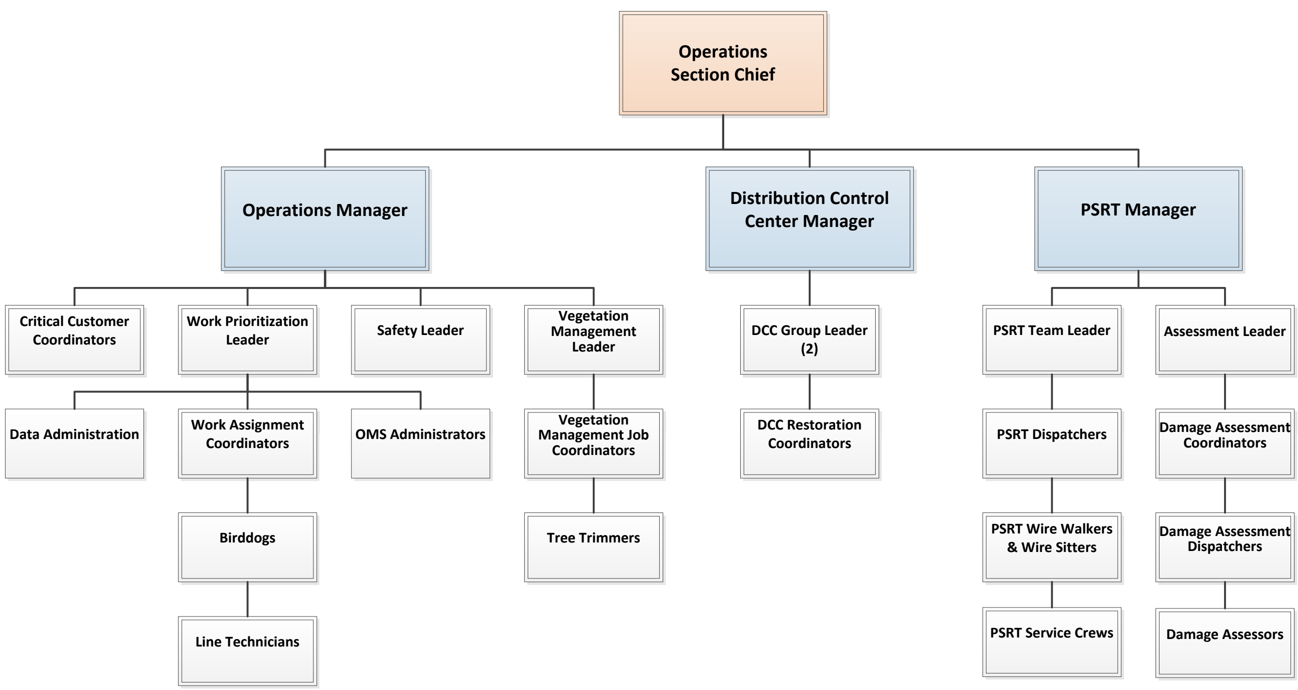


Figure 6.1 Operations Section Organization for Level III and IV events.

Responsibilities

The Operations Section of the Incident Command structure has overall responsibility for effectively managing available resources, developing and implementing plans for responding to system outages and damages, and protecting the public from damaged energy sources as described in EPRP Sections 6.0 – 6.5.

The Operations Chief has overall responsibility for overseeing and coordinating restoration and repair responses; assuring effective and efficient utilization of available resources; identifying resource needs and restoration projections based on those needs; and overseeing key roles identified in the subsections of 6.0 Operations Section.

The Emergency Preparedness and Response Team shall be responsible for developing Alert Level Task lists for all critical roles and functions under the Operations Section. **(Please see Appendix 3.B.)**

Training and Qualification

The EPPRT shall have responsibility for establishing minimum training and qualification requirements for procedures covered herein. **(Appendix 1.C contains the Emergency Preparedness and Response Plan Review, Training, and Exercise Schedule.)**

References

1. Louisville Gas and Electric Company, Terms and Conditions for Furnishing Electric Service; as filed with the Kentucky Public Service Commission; P.S.C. No. 9.
2. Kentucky Utilities Company; Rate, Terms, and Conditions for Furnishing Electric Service; as filed with the Kentucky Public Service Commission; P.S.C. No. 16.
3. Old Dominion Power Company, Terms and Conditions for Furnishing Electric Service; as filed with the Virginia State Corporation Commission; S.C.C. No. 15

Revisions

None

6.1. Resource Management

Electric Distribution Operations has developed Resource Management business processes for preparing for and responding to significant emergencies or outage events on the electric system. The primary focus of the organization during significant outage events and related emergencies is to effectively and efficiently manage and direct resources to:

- Protect the public from downed wires and damaged equipment;
- Safely restore service as quickly as possible; and,
- Repair or replace damaged facilities.

The procedures, roles, and responsibilities described herein are designed around Level III and IV events, but are scalable and transferable to all categories of events.

(Appendix 10 contains contact information for key Electric Distribution Operations personnel.)

6.1.1. Roles and Responsibilities

6.1.1.1. Operations Manager (OM) **-** or their designee, reports to the Operations Section Chief, and shall be responsible for:

6.1.1.1.1. Labor Resources - Identifying, coordinating, and managing labor resource requirements, including Line Technicians, Vegetation Management personnel, Public Safety Team members, Damage Assessors, and Resource Management personnel.

6.1.1.1.2. Restoration and Repair Planning – working with the Distribution Control Center (DCC) to develop and execute tactical responses to emergencies, including public safety, restoration prioritization, critical customer identification, work assignment, and resource allocation

6.1.1.1.3. Restoration Durations – working with field personnel and Work Planning to predict restoration durations for areas of responsibility, assessing system damages against resources, and developing communications methodology which assure times are accurately and effectively communicated to internal and external customers.

6.1.1.1.4. The Operations Manager shall have oversight of all other roles listed under this section.

6.1.1.1.5. Vegetation Management Resource Leader (VMRL) or their designee, shall be responsible for:

6.1.1.1.5.1. Resources – the VMRL shall be responsible for working with the Operations Managers to equitably and effectively allocate and utilize vegetation management resources during restoration responses.

6.1.1.1.5.2. Tactical Planning – the VMRL shall also be responsible for working with the Operations Manager to develop plans for removing vegetation which inhibits restoration, including trimming circuits before resources are available, supplementing large crews with dedicated resources, and conducting post repair cleanup on damaged circuits.

6.1.1.1.6. Work Prioritization Leader (WPL) - or their designee, shall be activated when the DCC decentralizes work prioritization and assignment to the Operations Center, and be responsible for:

6.1.1.1.6.1. Work Prioritization – developing circuit and outage restoration and repair priorities based on 911 calls, emergencies, critical customers, key customers, and total customer counts, in accordance with restoration procedures covered in the Company's tariffs.

6.1.1.1.6.2. Critical Customer Coordinator – responsible for staying abreast of critical customers impacted by system outages, and utilizing this information to help the WPL prioritize restoration and repair. This includes utilizing available information systems and reports, working with Major Accounts Representatives, the Ombudsman Team, and DCC to identify and prioritize critical customer issues that are out.

6.1.1.1.7. Work Assignment Coordinators **-** or their designee, shall be activated when the DCC decentralizes work prioritization and assignment to the Operations Center, and be responsible for:

6.1.1.1.7.1. Work Assignment – assigning bird dogs, line technicians, and vegetation management resources to outage events or circuits based on priorities established by the Work Prioritization Leader, and based on the capabilities and qualifications of available resources.

6.1.1.1.7.1.1. First Responders - working the DCC and Transmission Control Center (Simpsonville) to identify resource needs, including single-man and multiple-man truck first responders, and third shift resources, to dedicate to emergencies and necessary switching.

6.1.1.1.7.1.2. Public Works – assigning available and qualified resources to assist local governments with clearing streets and tree removal.

6.1.1.1.7.1.3. Bird Dogs – assigning qualified personnel to oversee/direct off system resources in the field and coordinate with the DCC.

6.1.1.1.7.2. Data Management – working with assigned Restoration Coordinators and Network Management Administrators to accurately track event and circuit assignments in the Network Management System, to ensure accurate restoration, outage, and system status information is available throughout the organization.

6.1.1.1.8. <u>Safety Lead</u> **–** or their designee, as assigned by the Safety Officer, shall be responsible for:

6.1.1.1.8.1. Passporting – ensure that all internal and external personnel responding to emergencies or outage events are properly passported and administrated.

6.1.1.1.8.2. Safety Oversight – work closely with the Operations Section Chief to resolve all safety issues associated with orientation and qualification of responding resources. Additionally, assist the Operations Section Chief with investigating all safety incidents.

6.1.1.1.8.3. Safety Communications – work with the Operations Section Chief to assure timely reporting of safety messages, operations practices, policy changes, or safety incidents which occur throughout the duration of restoration efforts.

6.1.1.1.9. <u>Administration Lead</u>

6.1.1.1.9.1. Work Assignment Administration – track circuit assignments to birddogs and line technicians resources;

6.1.1.1.9.2. Hot Line – answer phones dedicated to the provision of resources to field personnel, including safety, tree trimming personnel, materials, traffic control, locates, and security.

6.1.1.1.9.3. Completed Work Packets – working with bird dogs and foreman to ensure all field paperwork is properly completed upon completion of restoration and repair work, and return of work packets to the Resource Management Room/Operations Center.

6.1.1.1.9.4. <u>Network Management System(NMS) Administrator</u>

6.1.1.1.9.4.1. Estimated Restoration Durations – utilize the Storm Management Tool to update OMS with estimated restoration times.

6.1.1.1.9.4.2. Crew Assignments – record crew and birddog assignments in OMS (by circuit).

6.1.2. Activation

6.1.2.1. **Yellow Alert** – The Operations Section Chief, Incident Commander, or Operations Manager or their delegates shall have the authority to direct activation of Operations Management processes whenever a Yellow Alert has been issued by the Incident Commander or their designee. Activation of Operations Management processes shall be considered whenever a forecasted weather event or emergency is predicted to result in significant damages and a Level III or Level IV event is declared for any service area, where incremental resources, resident or non-resident, are brought in to assist with protect, restore, or repair activities. Activation may be required in advance of actual damages or outages, to assure needed resources and processes are in place to manage incremental resources, prioritize emergencies, and assign first responders, damage assessors, and public safety response personnel.

6.1.2.2. **Red Alert** - The Work Planning Section Chief, Operations Section Chief, and Incident Commander or their delegates shall have responsibility for activation of Resource Planning whenever a Red Alert has been declared, and the event has been established as Level III or IV for any Operations area.

6.1.3. Business Processes

6.1.3.1. **Resource Processing**

The Resource Management Team is responsible for ensuring all resources available to respond to an emergency are effectively and efficiently utilized. Every effort shall be made to minimize resource processing and work assignment time, and maximizing the time resources are in the field. This includes:

- Efficient check-in and check-out processing;
- Efficient birddog, materials, and vegetation resource allocation processes;
- Efficient work assignment processes;
- Establishment of centralized communications and provision of radios (as needed) to facilitate efficient communications exchanges regarding resource needs;
- Delivery of materials, meals, equipment, etc…to field crews to prevent them from having to leave the field; and,

- Provision of traffic control and security, to help minimize risks to the public and field personnel.

Electric Distribution has established a scalable and transferable Resource Management Room floor plan for managing Level III or IV events, where multiple off system resources are needed, and work prioritization and assignment responsibilities have been delegated by the DCC to an Operations Center. This floor plan allows for personnel and resources to be allocated from other operating areas to quickly and efficiently assist with managing work and resource volumes which exceed the capabilities of the local management team to manage. **Appendix 6.A displays Electric Distributions' configuration guideline for Resource Management command centers for Level III and Level IV events.**

6.1.3.2. **Work Prioritization**

The Company shall prioritize and restore outages based on applicable Service Restoration Procedures as defined in the LG&E and KU Rates, Terms, and Conditions for Furnishing Electric Service as filed with the Kentucky Public Service Commission, Virginia State Corporation Commission, and Tennessee Regulatory Authority.

Restoration Priority Levels shall be defined as follows:

I. Essential Health and Safety Uses
II. Critical Commercial and Industrial Uses
III. Residential Use
IV. Non-critical Commercial and Industrial Uses
V. Nonessential Uses

Where practical, priority uses will be considered in restoring service and service will be restored in the order I through IV as defined under these Priority Levels. However, because of the varieties of unpredictable circumstances which may exist or precipitate outages, it may be necessary to balance specific individual needs with infrastructure needs that affect a larger population of customers.

The Distribution Control Center shall have responsibility for prioritizing and assigning emergency and outage events to field personnel. During Level III and IV events, the Distribution Control Center may delegate work prioritization to an Operations Center, when multiple off system resources are being utilized, and work and resource volumes exceed the capabilities of the DCC to assign work efficiently. Operations Centers that have delegated work prioritization responsibilities shall designate an individual(s) to prioritize active customer events, as part of the Resource Management process.

6.1.3.3. **Work Assignment**

During Level III and IV events, the Distribution Control Center may also delegate work assignment responsibilities to an Operation Center(s). Operations Centers that have delegated work prioritization and assignment responsibilities shall designate an individual(s) to effectively assign event priorities with available resources, as part of the Resource Management process. Work assignment responsibilities shall include aligning available bird dogs, line technicians, and vegetation management with active outage events or circuits based on the capabilities and qualifications of available resources.

6.1.3.4. **Critical Customer Coordination**

During Level III and IV events, each Resource Management Team shall be responsible for designating a Critical Customer Coordinator(s) to assist with Work Prioritization. Assigned CCC's shall be responsible for coordinating with Major Accounts Representatives, the Ombudsman Team, and the DCC to identify and prioritize critical customers that are impacted by system outages and to communicate pertinent information to individuals assigned responsibility for work prioritization.

6.1.4. Training and Qualifications

Operations Managers shall be responsible for ensuring all personnel assigned to Resource Management roles described herein are adequately trained and exposed to necessary business processes, alert level task lists, and information systems.

6.2. Distribution Control Center

The Distribution Control Center (DCC) coordinates and directs the system restoration with the Operations Center and acts as the Electric Distribution System Operator. The goals of the DCC team are:

- To maintain safety of public and field resources and integrity of electric distribution system.
- To safely, efficiently, and timely restore service to affected customers.
- To provide timely and accurate information on outages, estimated restoration times, etc. to be communicated to customers.

6.2.1. Roles and Responsibilities (See Appendix 10 for key contact information)

6.2.1.1. Distribution Control Center Manager – (Manager Electric System Restoration and Distribution) or their designee, shall be responsible for managing and overseeing operations and control of the Electric Distribution System:

6.2.1.1.1. Resources – establish schedules to ensure maximum coverage by Restoration Coordinators in all areas for all shift periods.

6.2.1.1.2. Activation - work with the PSRT Manager and Operations Manager to activate the PSRT and Damage Assessment.

6.2.1.1.3. Execution – monitor the operations of the DCC; decentralize dispatch functions when work and resource volumes dictate, and coordinate with Operations Section Chiefs, Incident Commander and Safety Officer to invoke Independent Hold Card Procedures when work and resource volumes dictate (see Section 4.2 Independent Hold Card Procedures).

6.2.1.1.4. Reports – report critical outage data both internally and externally as required.

6.2.1.1.5. Training – ensure all DCC personnel and Assistant Restoration Coordinators are trained in system restoration processes.

6.2.1.1.6. Deactivation – ensure a deactivation plan is in place for PSRT, Damage Assessment, and the DCC

6.2.1.2. DCC Responsibilities

6.2.1.2.1. Dispatch – assure timely dispatching of events from the NMS system.

6.2.1.2.2. System Operation – assure safe operation and integrity of electric distribution system is maintained at all times.

6.2.1.2.3. Restoration – assure safe, efficient restoration of outages through proper prioritization, identification of damages to distribution facilities, and control and direction of personnel to make the system safe and restore as many customers as possible, before repairs are made.

6.2.1.2.4. Switching/Carding – oversee safe and efficient control of the distribution system to facilitate the safest, quickest restoration.

6.2.1.2.5. Communication - assure timely and accurate outage information is gathered for communicating both internally and externally.

6.2.2. Activation

6.2.2.1. Yellow Alert – The Operations Section Chief, Incident Commander, or Distribution Control Center Manager or their delegates shall have the authority to direct activation of Distribution Control Center processes whenever a Yellow Alert has been issued by the Incident Commander or their designee. Activation of DCC processes shall be considered whenever a forecasted weather event or emergency is predicted to result in significant damages and a Level III or Level IV event is declared for any service area, where incremental resources, resident or non-resident, are brought in to assist with protect, restore, or repair activities. Activation may be required in advance of actual damages or outages, to assure needed resources and processes are in place to manage incremental resources, prioritize emergencies, and assign first responders, damage assessors, and public safety response personnel.

6.2.2.2. Red Alert - The Operations Section Chief, Incident Commander, or Distribution Control Center Manager or their delegates shall have the authority to direct activation of Distribution Control Center processes whenever a Red Alert has been declared.

6.2.3. Training and Qualifications

6.2.3.1. The Distribution Control Center Manager shall be responsible for ensuring all personnel assigned to Distribution Control Center roles described herein are adequately trained and exposed to necessary business processes, alert level task lists, and information systems.

6.3. Public Safety Response Team (PSRT)

Electric Distribution has developed business processes **(see Appendix 6.B)** designed to help protect the public during weather events. The Public Safety Response Team has responsibility for overseeing and performing as first responders to 'wire down' calls. The goals of the PSRT team are to:

- Protect the public from potential hazards associated with downed power lines following major weather events;
- Relieve Fire and Police personnel assigned to wire down calls by County dispatch; and
- Gather damage assessment information in the field.

6.3.1. Roles and Responsibilities (See Appendix 10 for key contact information)

6.3.1.1. PSRT Manager or their designee, shall be responsible for overseeing the PSRT, its key roles, and PSRT functions consisting of the following:

6.3.1.1.1. Training – ensure that all wire walkers, wire sitters, service crews and damage assessors are trained. Additionally conduct refresher training for PSRT and DA dispatch teams (Lexington and Louisville) scheduled for on-call.

6.3.1.1.2. Activation – activate dispatch and field teams and ensure appropriate tracking of these resources is in place as directed by the Distribution Control Center Manager, Safety Officer, or Incident Commander.

6.3.1.1.3. Execution – monitor execution of wire down coverage and damage assessment, determine if additional resources are needed, and ensure shift rotations are established

6.3.1.1.4. Deactivation – support the DCC on clean-up, re-hooks with service crews, and deactivate field and back-office personnel as volume decreases.

6.3.1.2. LGE and KU PSRT Leaders – or their designee, shall be responsible for:

6.3.1.2.1. Process and Software Changes – review processes and make enhancements to ensure more efficient operations. Work with DCC on software changes that impact dispatcher interaction.

6.3.1.2.2. Training – conduct training sessions for all PSRT participants and ensure documentation and job aids are current. Track training history in a central repository.

6.3.1.2.3. Activation – establish callout procedures, contact lists, and schedules for dispatcher teams. Identify supervisors and managers that are required to assist in identifying field personnel for walking and sitting.

6.3.1.2.4. Execution –

6.3.1.2.4.1. Ensure proper dispatcher resources are available for storm event along with the proper number of field personnel.

6.3.1.2.4.2. Utilize a resource team to track all resources and establish appropriate shifts for multi-day events.

6.3.1.2.4.3. Support PSRT Dispatchers by responding to questions and issues that arise in the field.

6.3.1.2.4.4. Monitor Dispatcher performance and ensure proper procedures are being followed.

6.3.1.2.5. Deactivation – ensure a deactivation plan is in place and agreed to by the DCC. Ensure adequate resources are available to assist the DCC with clean-up work and re-hooks.

6.3.1.3. PSRT Dispatchers - shall be responsible for:

6.3.1.3.1. Dispatching Wire Walkers and/or Wire Sitters to wire down events.

6.3.1.3.2. Dispatching Service Crews to 'cut and clear' energized secondary/services where Wire Walkers and Wire Setters have been dispatched.

6.3.1.3.3. Utilizing proper prioritization for dispatching resources, specifically focusing on Police or Fire and energized conductor.

6.3.1.3.4. Utilizing PSRT processes and procedures to dispatch and update wire down events.

6.3.1.4. Wire Walkers - shall be able to clearly understand and identify electrical distribution infrastructure in the field to perform the following:

6.3.1.4.1. Function as 'First Responder' to wire down events dispatched by the Distribution Control Center (DCC) or PSRT.

6.3.1.4.2. Barricade appropriate area of damage to protect public and remain on site until relieved if dangerous situation exists (confirmed or potentially energized equipment).

6.3.1.4.3. Document damage assessment information from field via Mobile Application or communicate to PSRT Dispatcher verbally.

6.3.1.5. Wire Sitter - shall understand PSRT processes and procedures to perform the following:

6.3.1.5.1. Relieve Wire Walkers and remain at wire down location protecting the public until site is made safe.

6.3.1.5.2. Communicate any changes at the scene with PSRT Dispatch.

6.3.1.6. Service Crew - must be qualified to work with secondary and service conductors to perform the following:

- Relieve Wire Walkers and Wire Sitters from energized wire down events by 'cutting and clearing' or repairing the service.
- Communicate work performed at the wire down location and any follow up work to PSRT Dispatch.

6.3.2. Activation

6.3.2.1. Yellow Alert – The Safety Officer and Incident Commander or their delegates shall have the authority to direct activation of the PSRT whenever a Yellow Alert has been issued by the Incident Commander or their designee. Activation of the PSRT shall be considered whenever a forecasted weather event or emergency is predicted to result in significant damages and downed wires on the electric system.

6.3.2.2. Red Alert - The Distribution Control Center (DCC) Manager or their delegate shall have responsibility for activation of the PSRT whenever downed wire reports and field resources exceed the capabilities of Restoration Coordinator staffing levels in the Louisville or Lexington Distribution Control Centers. The Safety Officer and Incident Commander or their delegates shall also have the authority to direct activation of the PSRT whenever a Red Alert has been issued by the Incident Commander or their designee

6.3.1. Training and Qualification

6.3.1.1. PSRT Dispatchers – PSRT teams are on call for two week periods, and serve as a backup team for the next two week period. PSRT Leads provide team members refresher training on the first Monday of their two week on call period.

Training consists of all aspects of the Network Management System program (work agenda, crew assignments, the viewer, damage assessment, etc.) and associated data entry procedures for dispatching to non-mobile and mobile enabled wire-walkers. The mobile training also includes sending wire-down events to mobile wire-walkers who are set up in a training room at EOC and AOC.

6.3.1.2. Wire Walkers – All Wire Walkers must attend a training and qualification course provided by the PSRT Lead(s).

Company or Contractor personnel must demonstrate a general knowledge of electric distribution infrastructure and characteristics to be considered for a Wire Walker position. Candidates typically have field experience in electric operations or design.

All new Wire Walkers must be paired with an experienced Wire-Walker prior to being allowed to perform wire walking duties without supervision or guidance. PSRT Leads are responsible for evaluating the knowledge and abilities of Wire Walkers to perform associated responsibilities without direction or oversight.

6.3.1.3. Wire Sitters – All Wire Sitters are required to receive training provided by the PSRT Lead. A driver's license and proper PPE are the basic qualification requirements to be a wire-sitter. Most wire-sitters are pulled from LG&E Gas Operations, Asset Information, or from approved business partners.

6.3.1.4. Service Crews – All Business Partner Trainers are required to receive PSRT Service Crew training provided by the PSRT Lead and a Safety Specialist.

Service crews are typically pulled from qualified resident contractors (who may normally work in street lighting, underground and/or commercial electric) that have received the Company's Safety Passport Training.

6.4. Damage Assessment (DA)

Electric Distribution has developed business processes **(see Appendix 6.B)** to gather damage assessment information from the field. The goals of the DA team are:

- To identify and prioritize areas of the system to be assessed.
- To gather damage assessment information in the field.
- To ensure damage information data is accumulated to provide to field resources and to allow evaluation and reporting of system impacts.

6.4.1. Roles and Responsibilities (See Appendix 10 for key contact information)

6.4.1.1. PSRT Manager or their designee, shall be responsible for overseeing the DA, its key roles, and DA functions consisting of the following:

6.4.1.1.1. Training – ensure that all damage assessors are trained. Additionally conduct refresher training for PSRT and DA dispatch teams (Lexington and Louisville) scheduled for on-call.

6.4.1.1.2. Activation – activate dispatch and field teams and ensure appropriate tracking of these resources is in place as directed by the Distribution Control Center Manager, Safety Officer, or Incident Commander.

6.4.1.1.3. Execution – monitor execution of damage assessment, determine if additional resources are needed, and ensure shift rotations are established

6.4.1.1.4. Deactivation – support the DCC on clean-up and deactivate field and back-office personnel as volume decreases.

6.4.1.2. Assessment Leaders (AL) – or their designee, shall be responsible for:

6.4.1.2.1. Process and Software Changes – review processes and make enhancements to ensure more efficient operations. Work with DCC on software changes that impact dispatcher interaction.

6.4.1.2.2. Training – conduct training sessions for all DA participants and ensure documentation and job aids are current. Track training history in a central repository.

6.4.1.2.3. Activation – establish callout procedures and schedules for dispatcher teams. Identify supervisors and managers that are required to assist in identifying field personnel for assessing.

6.4.1.2.4. Execution –

6.4.1.2.4.1. Ensure adequate dispatch personnel and damage assessors are available for storm events.

6.4.1.2.4.2. Review system outages and work with Work Planning and the Work Prioritization Leader to identify circuits or parts of the system that need further damage assessment based on outages and resource availability.

6.4.1.2.4.3. Effectively track all resources and establish appropriate shift schedules for multi-day events.

6.4.1.2.4.4. Support DA Dispatchers by responding to questions and issues that arise in the field.

6.4.1.2.4.5. Monitor Dispatcher performance and ensure proper procedures are being followed.

6.4.1.2.5. Deactivation – ensure a deactivation plan is in place and agreed to by the DCC and Operations Section Chief.

6.4.1.2.6. Post Restoration Assessment - the Assessment Leader or their designee shall be responsible for reviewing system outages and working with the Work Planning Leader to identify circuits or parts of the system that need post restoration assessment based on outages and storm damages. The Assessment Leader shall work with the PSRT Leader, and Operations Manager to identify available resources for performing assessments.

6.4.1.3. Damage Assessment Coordinators – shall be responsible for:

6.4.1.3.1. Assuring adequate assessment resources are available.

6.4.1.3.2. Assigning assessment work based on established priorities.

6.4.1.3.3. Accumulating damage assessment data, and evaluating and reporting system impacts.

6.4.1.3.4. Working with Work Planning and the Resource Managers to predict resource needs and restoration durations.

6.4.1.4. Damage Assessment Dispatchers - shall be responsible for:

6.4.1.4.1. Dispatching Damage Assessors to identified areas needing assessment.

6.4.1.4.2. Utilizing proper prioritization for dispatching resources.

6.4.1.4.3. Utilizing DA processes and procedures to dispatch and update DA identified circuits/events.

6.4.1.5. Damage Assessors – shall be responsible for:

6.4.1.5.1. Conducting field assessments of assigned circuits/events.

6.4.1.5.2. Identifying and documenting system damage.

6.4.1.5.3. Working with Damage Assessment Coordinators to help predict resource (personnel, equipment, and materials) needs and estimated restoration durations.

6.4.2. Activation

6.4.2.1. Yellow Alert – The Operations Section Chief and Incident Commander or their delegates shall have the authority to direct activation of Damage Assessment processes and teams whenever a Yellow Alert has been issued by the Incident Commander or their designee. Pre staging of damage assessment teams and key roles shall be considered whenever a forecasted weather event or emergency is predicted to result in significant damages and downed wires on the electric system.

6.4.2.2. Red Alert - The Incident Commander, Operations Section Chief, Distribution Control Center (DCC) Manager or their delegate shall have responsibility for activation of Damage Assessment processes whenever outage and field reports indicate significant infrastructure damage which exceeds the capabilities of available field resources.

6.4.1. Training

6.4.1.1. Damage Assessment Dispatchers – Dispatch teams are on call for two week periods, and serve as a backup team for the next two week period. Assessment Leads provide team members refresher training on the first Monday of their two week on call period.

Training consists of all aspects of the Network Management System program (work agenda, crew assignments, the viewer, damage assessment, etc.) and associated data entry procedures for dispatching damage assessment assignments to non-mobile and mobile enabled damage assessors.

6.4.1.2. Damage Assessors – All Damage Assessors must attend an annual training and qualification course provided by Assessment Lead(s).

Company or Contractor personnel must demonstrate a general knowledge of electric distribution infrastructure and characteristics to be considered for a Damage Assessor position. Candidates typically have field experience in electric operations or design.

All new Damage Assessors must be paired with an experienced Damage Assessor prior to being allowed to perform assessment duties without supervision or guidance. Assessment Leads are responsible for evaluating the knowledge and abilities of Damage Assessors to perform associated responsibilities without direction or oversight.

6.5. Transmission Operations

Transmission Operations assesses the impact to the system and coordinates and directs the restoration of the transmission system. The goals of the Transmission Operations team are:

- To maintain safety of public and field resources and integrity of electric transmission system.
- To safely, efficiently, and timely restore service to affected customers.
- To provide timely and accurate information on outages, estimated restoration times, etc. to be communicated to customers.

6.5.1. Roles and Responsibilities (See Appendix 10 for key contact information)

6.5.1.1. Transmission Operations Lines Manager – or their designee, reports to the Transmission Operations Section Chief, and shall be responsible for:

6.5.1.1.1. Labor Resources - Identifying, coordinating, and managing labor resource requirements, including Line Technicians, Vegetation Management personnel, Damage Assessors, and Resource Management personnel.

6.5.1.1.2. Restoration and Repair Planning – working with the Transmission Control Center (TCC) to develop and execute tactical responses to emergencies, including public safety, restoration prioritization, critical customer identification, work assignment, and resource allocation

6.5.1.1.3. Restoration Durations – working with field personnel and TCC to predict restoration durations for areas of responsibility, assessing system damages against resources, and developing communications methodology which assure times are accurately and effectively communicated to internal and external customers.

6.5.1.1.4. The Transmission Operations Lines Manager shall have oversight of all other roles listed under this section.

6.5.1.2. Transmission Control Center Manager – or their designee, shall be responsible for managing and overseeing operations and control of the Electric Transmsission System:

6.5.1.2.1. Resources – establish schedules to ensure maximum coverage by System Operators in all areas for all shift periods.

6.5.1.2.2. Activation - work with the Transmission Operations Lines Manager to activate assessment personnel.

6.5.1.2.3. Execution – monitor the operations of the TCC and coordinate system restoration with Transmission Operations Lines Manager and Section Chief and Incident Commander.

6.5.1.2.4. Reports – report critical outage data both internally and externally as required.

6.5.1.2.5. Training – ensure all TCC personnel are trained in system restoration processes.

6.5.1.2.6. Deactivation – ensure a deactivation plan is in place for the TCC.

6.5.1.3. Transmission Control Center Responsibilities

6.5.1.3.1. System Operation – assure safe operation and integrity of electric transmission system is maintained at all times.

6.5.1.3.2. Restoration – assure safe, efficient restoration of outages through proper prioritization, identification of damages to transmission facilities, and control and direction of personnel to make the system safe and restoration efficient.

6.5.1.3.3. Switching/Carding – oversee safe and efficient control of the transmission system to facilitate the safest, quickest restoration.

6.5.1.3.4. Communication - assure timely and accurate outage information is gathered for communicating both internally and externally.

6.5.2. Activation

6.5.2.1. Yellow Alert – The Transmission Operations Section Chief, Incident Commander, or Transmission Control Center Manager or their delegates shall have the authority to direct activation of the Transmission Operations processes whenever a Yellow Alert has been issued by the Incident Commander or their designee. Activation of these processes shall be considered whenever a forecasted weather event or emergency is predicted to result in significant damages and a Level III or Level IV event is declared for any service area, where incremental resources, resident or non-resident, are brought in to assist with protect, restore, or repair activities. Activation may be required in advance of actual damages or outages, to assure needed resources and processes are in place to manage incremental resources, prioritize emergencies, and assign first responders.

6.5.2.2. Red Alert - The Transmission Operations Section Chief, Incident Commander, or Transmision Control Center Manager or their delegates shall have the authority to direct activation of Transmission Operations Emergency Plan processes whenever a Red Alert has been declared.

6.5.3. Transmission Alert Levels

6.5.3.1. Transmission Alert Level Declarations - Alert level declaration is normally post event and is based on the assessment of the potential impact to the LGE-KU Transmission System. The Transmission Operations Lines Manager or his designee will declare the transmission event alert level.

Conditions that could warrant declaring an alert level may include but are not limited to:

- Weather related conditions such as severe thunderstorms, intense lightning storms, tornadoes, ice/snow accumulation, high winds and flooding
- Loss of multiple transmission facilities
- Forest and brush fires
- Geomagnetic disturbances
- Any other event that may pose a threat or disruption to the bulk electric system

6.5.3.2. Transmission Alert Levels

6.5.3.2.1. Alert Level I - (Moderate Impact) It is anticipated that the pending event will have only a moderate impact to the LGE-KU Transmission System. Localized service territory outages occur.

6.5.3.2.2. Alert Level II - (Significant Impact) It is anticipated that the pending event will have a significant impact to the LGE-KU Transmission System. Multiple outages over a large portion of the LGE-KU service territory

6.5.3.2.3. Alert Level III - (Major Impact) It is anticipated that the pending event to have a major impact to the LGE-KU Transmission System. Wide spread outages with significant damage to the Bulk Electric System (BES) has occurred.

6.5.3.3. Transmission Alert Level Activities - The Alert Level declaration will trigger various actions within each line of business. Each line of business will have their own in house procedures in place to address the various Alert Levels and required actions.

6.5.3.4. Transmission Alert Level Communication - Communication of the Alert Levels to each line of business will be the responsibility of Transmission Control Center at Simpsonville. Email notification will be the primary source of communication.

6.5.3.4.1. Logging the Alert Level - Transmission control center will log the Alert Level along with start date and time in Transmission Outage Application (TOA). Transmission control center will notify each line of business of the Alert Level.

6.5.3.4.2. Changes to the Alert Level - Transmission control center will log any changes or modification to the Alert Level along with the start date and time in TOA. Transmission control center will notify each line of business of the change or modification of the Alert Level.

6.5.3.4.3. Return to Normal Operations - Transmission control center will log the "Return to Normal Operations" in TOA along with the date and time when the Alert Level has been canceled. Transmission control center will notify each line of business that the Alert Level has been canceled and is no longer active.

6.5.4. Training and Qualifications

6.5.4.1. The Transmission Operations Lines Manager and Transmission Control Center Manager shall be responsible for ensuring all personnel assigned to roles described herein are adequately trained and exposed to necessary business processes and information systems.

6.6. Estimated Restoration Times

The Emergency Preparedness and Response Team has developed business procedures for communicating estimated restoration times to customers during a significant event on the electric distribution system. The following table outlines EDO's communications commitments and responsibilities.

ERTs	Communications Commitments			
	Level I Event < 6 hours	Level II Event < 24 hours	Level III Event < 72 hours	Level IV Event > 72 hours
Ops Center Level	**0 - 6 hours**	**0 - 8 hours**	**0 - 24 hours**	**0 - 48 hours**
ERT Source	*MSRD, MDO*	*MSRD, MDO*	*OSC, WPSC*	*OSC, WPSC*
Update Responsibility	*DCC*	*DCC*	*OS*	*OS*
Local Area Level	**0 - 6 hours**	**0 - 12 hours**	**24 - 36 hours**	**48 - 72 hours**
ERT Source	*MSRD, MDO*	*MSRD, MDO*	*OSC, WPSC*	*OSC, WPSC*
Update Responsibility	*DCC*	*DCC*	*OS*	*OS*
Circuit Level	**0 - 6 hours**	**0 - 12 hours**	**24 - 36 hours**	**48 - 72 hours**
ERT Source	*MSRD, MDO*	*MSRD, MDO*	*Birddog*	*Birddog*
Update Responsibility	*DCC*	*DCC*	*OS*	*OS*
Event Level	**0 - 6 hours**	**0 - 24 hours**	**0 - 72 hours**	**0 - N hours**
ERT Source	*LT*	*LT*	*Birddog, LT*	*Birddog, LT*
Update Responsibility	*DCC*	*DCC*	*NA*	*NA*
Definitions:				
Birddogs *- Team Leader or Supervisor assigned responsibility for circuit.*			***MSRD*** *- Manager System Restoration and Dispatch*	
LT *- Line Technicians*			***OSC*** *- Operations Section Chief (IC Structure)*	
MDO *- Manager Distribution Operations*			***WPSC*** *- Work Planning Section Chief (IC Structure)*	

Table 1. Estimated Restoration Communications Schedule

6.6.1. Level I Events

During Level I events, the Distribution Control Center (DCC) will be responsible for prioritizing and assigning outage events, controlling the electric distribution system, and issuing hold cards, using established day-to-day outage response procedures. The Public Safety Response Team (PSRT) will be activated as deemed appropriate by the Incident Commander, Operations Section Chief, and Manager System Restoration and Dispatch. Work Planning will not be activated.

The Estimated Restoration Time Editor (ERTE) tool in the Company's outage management system (Network Management System – NMS) will be turned off when outage event counts exceed resource availability, as determined or approved by the responsible DCC Group Leader and the Manager System Restoration and Dispatch.

Field personnel/technicians shall be responsible for obtaining and updating estimated restoration times by Event through utilization of their mobile device, as events are assessed, resource needs are identified, and restoration durations are estimated. The Manager-System Restoration and Dispatch shall be responsible for ensuring Restoration Coordinators continuously monitor NMS to ensure Field Personnel are appropriately assigning ERTs.

As soon as attainable, but before 6 hours have elapsed, the responsible Operations Manager and Manager-System Restoration and Dispatch shall establish Operations Center Level Estimated Restoration Times, based on event level ERTs, consideration of resource levels, and input from field personnel.

6.6.2. Level II Events

During Level II Events, the Distribution Control Center will be responsible for prioritizing and assigning outage events, controlling the electric distribution system, and issuing hold cards, using established day-to-day outage response procedures. The Public Safety Response and Damage Assessment teams will be activated as deemed appropriate by the Incident Commander, Operations Section Chief, and Manager System Restoration and Dispatch. Work Planning will be activated with the PSRT, or as requested by the Incident Commander or DCC Director.

The Estimated Restoration Time Editor (ERTE) tool in the Company's outage management system (Network Management System – NMS) will be turned off when outage event counts exceed resource availability, as determined or approved by the responsible DCC Group Leader and the Manager System Restoration and Dispatch.

Field personnel/technicians shall be responsible for obtaining and updating estimated restoration times by Event through utilization of their mobile device, as events are assessed, resource needs are identified, and restoration durations are estimated. The Manager-System Restoration and Dispatch shall be responsible for ensuring Restoration Coordinators continuously monitor NMS to ensure Field Personnel are appropriately assigning ERTs.

As soon as attainable, but before 8 hours have elapsed, the responsible Operations Manager and Manager-System Restoration and Dispatch shall establish Operations Center Level Estimated Restoration Times, based on event level ERTs, consideration of resource levels, and input from field supervision. Work Planning shall be responsible for posting the ERT to the Company's Website. After the Operations Center Level ERTs are established, the DCC Restoration Coordinators shall continue to utilize NMS to update estimated restoration times by event, as field resources assess damages, estimate resource needs, and predict restoration durations.

6.6.3. Level III Events

During Level III events, the Distribution Control Center will maintain responsibility for prioritizing and assigning outage events, controlling the electric distribution system, and issuing hold cards, using established day-to-day outage response procedures until it is determined that restoration operations should be decentralized. PSRT and Work Planning will be activated. Each impacted Operations area will activate their Resource Management Rooms.

The Estimated Restoration Time Editor (ERTE) tool in the Company's outage management system (Network Management System – NMS) will be turned off when outage event counts exceed resource availability, as determined or approved by the responsible DCC Group Leader and the Manager System Restoration and Dispatch.

When formally agreed upon by the responsible Manager-Distribution Operations and Manager-System Restoration and Dispatch, and approved by the Incident Commander, Safety Officer, and Operations Section Chief, the DCC shall decentralize responsibility for prioritizing and assigning outage events to the responsible Resource Management Rooms. The Resource Management Rooms will be responsible for obtaining ERT information on all system outages and impacted circuits using information obtained from Damage Assessment teams, Wire Walkers, first responders, and Bird Dogs.

As soon as attainable, but before 24 hours have elapsed, the Operations and Work Planning Section Chiefs shall establish Operations Center Level Estimated Restoration Times, based on ERT information obtained from the Resource Management Rooms, consideration of resource levels, and input from the Operations Managers and Manager System Restoration and Dispatch. Work Planning will be responsible for utilizing the NMS Storm Management Tool to enter Operations Center level ERTs into NMS, based on information received from field resources, consideration of resources levels, and input from the Operations Section Chief. As restoration efforts progress, the Resource

Management Rooms shall be responsible for assessing system damages, restoration progress, field resources, and material availability to develop more precise restoration predictions at local and circuit levels, in accordance with Table 1.

Throughout restoration events, the Resource Management Rooms shall update circuit level ERTs three times per day, or as work is completed or situations change. Work Planning and the Operations Section will be responsible for monitoring ERTs in NMS, to assure accuracy and thoroughness.

6.6.4. Level IV Events

During Level IV events, the Distribution Control Center will maintain responsibility for prioritizing and assigning outage events, controlling the electric distribution system, and issuing hold cards, using established day-to-day outage response procedures until it is determined that restoration operations should be decentralized. PSRT and Work Planning will be activated. Each impacted Operations area will activate their Resource Management Rooms.

The Estimated Restoration Time Editor (ERTE) tool in the Company's outage management system (Network Management System – NMS) will be turned off when outage event counts exceed resource availability, as determined or approved by the responsible DCC Group Leader and the Manager System Restoration and Dispatch.

When formally agreed upon by the responsible Manager-Distribution Operations and Manager-System Restoration and Dispatch, and approved by the Incident Commander, Safety Officer, and Operations Section Chief, the DCC shall decentralize responsibility for prioritizing and assigning outage events to the responsible Resource Management Rooms. The Resource Management Rooms will be responsible for obtaining ERT information on all system outages and impacted circuits using information obtained from Damage Assessment teams, Wire Walkers, first responders, and Bird Dogs.

As soon as attainable, but before 48 hours have elapsed, the Operating and Work Planning Section Chiefs shall establish Operations Center Level Estimated Restoration Times, based on ERT information obtained from the Resource Management Rooms, consideration of resource levels, and input from the Operations Managers and Manager System Restoration and Dispatch. Work Planning will be responsible for utilizing the NMS Storm Management Tool to enter Operations Center level ERTs into NMS, based on information received from field resources, consideration of resources levels, and input from the Operations Section Chief. As restoration efforts progress, the Resource Management Rooms shall be responsible for assessing system damages, restoration progress, field resources, and material availability to develop more precise restoration predictions at local and circuit levels, in accordance with Table 1.

Throughout restoration events, the Resource Management Rooms will be responsible for updating circuit level ERTs three times per day or as work is completed or situations change. Work Planning and the Operations Section will be responsible for monitoring ERTs in NMS, to assure accuracy and thoroughness.

6.7 Conservative Operations

Electric Distribution has developed criteria and procedures for implementing Conservative Operations when forecasted or actual weather conditions, system health, natural disasters, emergency situations, or other factors pose a threat to the operability, reliability, or integrity of the electric distribution system.

6.7.1 Roles and Responsibilities

6.7.1.1 Manager Electric System Restoration and Distribution, or their designee, shall be responsible for overseeing personnel assigned responsibility for monitoring the electric distribution system, and making determination if standard Conservative Operations procedures should be implemented. If Conservative Operations are declared, the following responsibilities should be executed:

6.7.1.1.1 Advise the Director Electric System Restoration and Distribution or their designee of the need to Declare Conservative Operations.

6.7.1.1.1.1 Define the boundaries of Conservative Operations.

6.7.1.1.1.2 Define the start and end times of Conservative Operations.

6.7.1.1.2 Provide routine updates to the affected Electric Distribution Operations management team.

6.7.1.1.3 Work with Information Technology's designated representatives to suspend all work on critical computer systems, such as the Network Management System (NMS) and Mobile Applications.

6.7.1.1.4 Work with affected Operations Managers to identify and review all maintenance, construction, and testing being performed on electric distribution facilities and where appropriate, delaying or cancelling scheduled work. This includes non-essential planned maintenance, construction, operations, tree trimming, substation work, etc.

6.7.1.1.5 Assess the adequacy of Distribution Control Center staffing levels and make adjustments where necessary.

6.7.1.1.6 Work with the Incident Commander, Work Planning, and Operations Managers, where necessary, to review staffing plans/schedules for key technical and field personnel, and make adjustments where necessary.

6.7.1.2 Group Leader – Distribution Control Center, or their designee, shall be responsible for notifying the Manager Electric System Restoration and Distribution of any actual or forecasted conditions posing a threat to the operability, reliability, and safety of the electric distribution, as reported by Restoration Coordinators under their responsibility.

6.7.1.3 Restoration Coordinators shall be responsible for continuously monitoring the electric distribution system and weather conditions to identify conditions which warrant implementation of Conservative Operations. Whenever prescribed threshold conditions are observed or are forecasted to occur, Restoration Coordinators shall advise the Group Leader – Distribution Control Center.

6.7.2 Conservative Operations Criteria

The following conditions shall justify consideration and declaration of Conservative Operations procedures to protect the reliability and integrity of the electric distribution system:

- Extreme Temperatures
  - Actual or Forecasted Temperatures below 15°F
  - Actual or Forecasted Temperatures above 95°F
- Extreme Weather Conditions
  - Actual or Forecasted Ice Accretion > 0.25”
  - Actual or Forecasted Snow Accumulation >6”
  - Actual or Forecasted Wind Speeds >45mph
  - Actual or Forecasted Severe Weather
  - Actual or Forecasted Flooding
- System Health Threats
  - Observed or predicted capacity concerns
  - Observed or predicted voltage concerns
  - Loss of key power generation, transmission, or distribution facilities
- Emergencies
  - Train Derailment
  - Fire
  - Chemical Spill or other Environmental Threat
  - Explosions
  - Civil unrest
- Natural Disasters
  - Earthquakes

The Manager Electric Restoration and Distribution has the authority to declare and implement Conservative Operations procedures whenever conditions are experienced which are not identified above but pose sufficient threat(s) to the Electric Distribution system.

6.7.3 Conservative Operations Procedures

The following procedures should be executed whenever the Manager Electric Restoration and Distribution declares that Conservative Operations are needed to protect the reliability and integrity of the electric distribution system. All affected operating areas' personnel and business partners shall be notified of a Conservative Operations declaration. Where appropriate, the Manager Electric Restoration and Distribution and responsible Operations Manager, or their delegates, may elect to deviate from these procedures if risk concerns can be alleviated through alternative procedures.

6.7.3.1 Cessation of Cautions

The following cessation of cautions shall apply for all substation circuit breakers and reclosers. Cessation of cautions for distribution line reclosers will be dependent on loading, customers served, weather conditions, etc. as determined by Distribution Control Center.

6.7.3.1.1 Cautions for planned work will not be issued whenever actual or forecasted temperatures are above 100^{o}F.

6.7.3.1.2 Cautions for planned work on LG&E or KU Winter Peaking Substations will not be issued whenever actual or forecasted temperatures are below 15^{o}F.

6.7.3.1.3 Cautions for planned work on LG&E or KU Summer Peaking Substations will not be issued whenever actual or forecasted temperatures are below 5^{o}F.

6.7.3.1.4 Cautions for planned work will not be issued (for affected facilities) whenever severe weather, natural disasters, emergencies, system conditions, or other conditions pose a threat to the integrity and reliability of the electric distribution system.

6.7.3.2 Cessation of Customer Pull-Offs

6.7.3.2.1 No customers should be pulled off for planned work whenever actual or forecasted temperatures are above 100^{o}F.

6.7.3.2.2 No customers should be pulled off for planned work whenever actual or forecasted temperatures are below 10°F.

6.7.3.3 Limited Planned Customer Outage Durations

6.7.3.3.1 Planned customer outages will be allowed, but be limited in duration and customer counts whenever actual or forecasted temperatures are between 95°F and 100°F.

6.7.3.3.2 Planned customer outages will be allowed, but be limited in duration and customer counts whenever actual or forecasted temperatures are between 10°F and 15°F.

6.7.3.4 Cessation of Planned Construction, Maintenance, Testing, and Operations

6.7.3.4.1 Operations Management should give consideration to ceasing all planned construction, maintenance, testing, and operations on the electric distribution system whenever severe weather, natural disasters, emergencies, system conditions, or other conditions pose a threat to its integrity and reliability.

7. Customer Experience Section

Purpose

EPRP Section 7.0 introduces the high level organizational structure, roles, and associated responsibilities for the Customer Experience Section of the Company's Incident Command System for responding to significant emergencies or outage events on the electric distribution system.

Scope

EPRP Section 7.0 and its Subsections cover all resources assigned to the Customer Experience Section during responses to significant emergencies or outage events on the electric system, as defined for Level III and IV events in Figure 7.1.

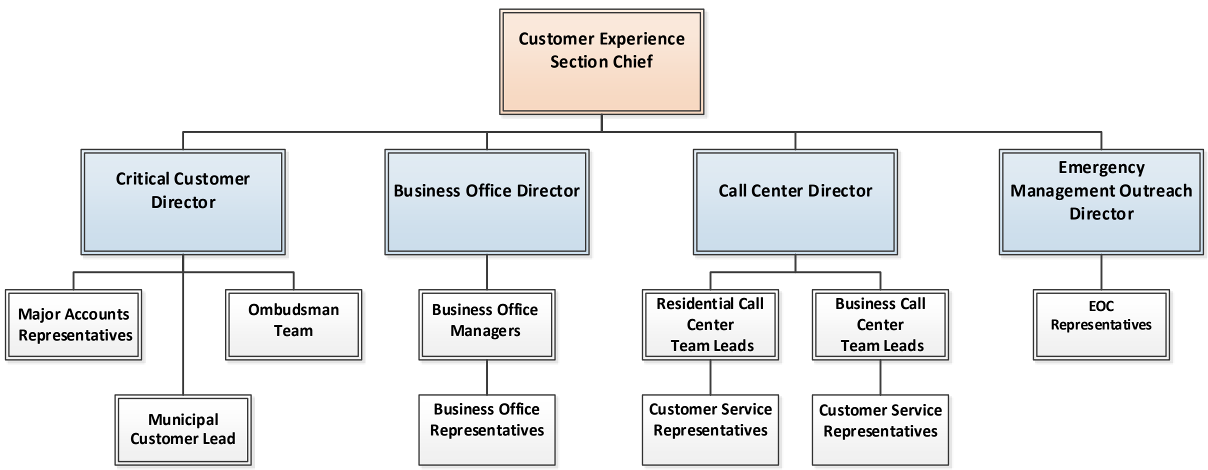


Figure 7.1 Customer Experience Section Organization

Responsibilities

The Customer Experience Section of the Incident Command structure has overall responsibility for developing and executing preparedness and response plans which focus on customers' needs during responses to significant outage events or other emergencies on the electric distribution system.

Training and Qualification

The EPPRT shall have responsibility for establishing minimum training and qualification requirements for procedures covered herein. **(Appendix 1.C contains the Emergency Preparedness and Response Plan Review, Training, and Exercise Schedule.)**

References

None

Revisions

None

7.1 Critical Customer Care

The Company's Customer Experience Section of the Incident Command System shall have primary responsibility for Ensuring adequate procedures are in place to identify and communicate with critical, key, and major customers during large outage events or emergencies involving the electric system.

7.1.1 Roles and Responsibilities (See Appendix 10 for key contact information)

7.1.1.1 Critical Customer Director – or their designee, shall report to the Customer Experience Section Chief and shall have responsibility for the following:

7.1.1.1.1 Ensuring adequate resources, technology, and procedures are in place to identify and communicate with critical, key, major, and municipal customers during large outage events or emergencies involving the electric system;

7.1.1.1.2 Ensuring adequate procedures are in place to communicate critical, key, major, and municipal customer information to internal stakeholders during large outage events or emergencies involving the electric system;

7.1.1.1.3 Collaborating with the Customer Experience Section Chief to ensure consistent information is being communicated to customers, local authorities, emergency operations centers, and government entities;

7.1.1.1.4 Verifying all available communications channels are working properly and allowing affected customers to identify outages and obtain restoration status information.

7.1.1.2 Major Account Representatives – shall be responsible for:

7.1.1.2.1 Communicating with major account customers throughout restoration efforts to ensure timely and accurate outage and restoration information is available to assist them with making critical decisions; and

7.1.1.2.2 Working with Critical Customer Coordinators and/or Work Prioritization Leads under the Operations Section to ensure Major Account customer information is considered when determining safety, restoration, and repair priorities.

7.1.1.3 Ombudsman Team Lead – shall be responsible for:

7.1.1.3.1 Serving as customer communication channel for key accounts, schools, local politicians, etc. whom need critical outage restoration information and assistance during restoration activities; and

7.1.1.3.2 Working with Critical Customer Coordinators and/or Work Prioritization Leads under the Operations Section to ensure key and critical customer information is considered when determining safety, restoration, and repair priorities.

7.1.1.4 Municipal Account Manager – shall be responsible for:

7.1.1.4.1 Coordinating with Operations to serve as a customer communication channel for municipal account customers who need critical outage restoration information and assistance during outage events and significant emergencies; and,

7.1.1.4.2 Working with Critical Customer Coordinators and/or Work Prioritization Leads under the Operations Section to ensure municipal customer information is considered when determining safety, restoration, and repair priorities.

7.1.2 Activation

7.1.2.1 Yellow Alert – The Customer Experience Section Chief or their delegate shall have authority for activating Customer Experience emergency business processes whenever a Yellow Alert has been issued by the Incident Commander or their designee. Activation of emergency Customer Experience business processes shall be considered whenever a forecasted weather event or emergency is predicted to result in significant electric system damages and customer outages. Activation may be required in advance of actual damages or outages, to assure needed resources and processes are in place to effectively respond to affected customer inquiries and reports when outages start occurring.

7.1.2.2 Red Alert - The Customer Experience Section Chief or their delegate shall have responsibility for activation of emergency Customer Experience business processes whenever a Red Alert has been declared and significant electric system damages and customer outages are occurring or expected to occur.

7.1.3 Business Processes

7.1.3.1 Major Accounts

During significant outage events, where multiple key and critical customers are impacted, Major Accounts Representatives shall be responsible for developing an understanding of their impacted customers through review of critical customer outage report, Web Work Agenda, or the Internal Outage Communications Tool.

Major Accounts Representatives with impacted customers shall be responsible for exchanging critical outage and restoration information with designated major account contacts and key internal Operations and Customer Service personnel.

During Level III and IV events, consideration should be given to strategically placing Major Accounts Representative in Resource Management Rooms to expedite the exchange of critical information regarding outages, restoration efforts, and estimated restoration times.

7.1.3.2 Ombudsman Team

During significant outage events, the Ombudsman Team will be established to coordinate and communicate with state, city, and county officials, company executives, Major Accounts Representatives, and the Emergency Planning and Preparedness Manager. Ombudsman Team shall be responsible for developing an understanding of their impacted customers through review of critical customer outage report, Web Work Agenda, or the Internal Outage Communications Tool.

Ombudsman Team shall be responsible for exchanging critical outage and restoration information with designated state, city, and county officials, Major Account Representatives and key internal Operations and Customer Service personnel.

During Level III and IV events, consideration should be given to strategically placing an Ombudsman Team member in Resource Management Rooms to expedite the exchange of critical information regarding outages, restoration efforts, and estimated restoration times.

7.1.3.3 Municipal Customer Outages

Designated Distribution and Transmission personnel (Designee) and the Municipal Account Manager are notified via text whenever a Municipal Customer experiences an outage. Upon receiving notification of a municipal outage, the Designee shall investigate and confirm the outage. Whenever a municipal outage is confirmed, the Municipal Account Manager shall contact affected municipal customers using the 24/7 Municipal Calling List, coordinate communications priorities with designated Municipal representatives, and ensure associated communications are maintained until the disturbance or outage condition is corrected.

For Transmission related interruptions, the designated Transmission employee will provide only appropriate available relevant non-public transmission function information to the Municipal Account Manager and Municipal representative, including the out-of service transmission facilities, repair progress, and an estimated restoration time. No other non-public transmission function information will be shared unless permitted under the Standards of Conduct exceptions.

(**Appendix 7.A provides a key contact information for municipal customers.**)

7.1.4 Training and Qualifications

Customer Services shall be responsible for ensuring all personnel assigned to Customer Experience roles described herein are adequately trained and exposed to necessary business processes and information systems.

7.1 Call Centers

The Company's Customer Experience Section of the Incident Command System shall have primary responsibility for ensuring adequate procedures, resources, and technology are in place to communicate safety, outage, and restoration information with impacted customers during large outage events or emergencies involving the electric system.

7.1.1 Roles and Responsibilities (See Appendix 10 for key Call Center contact information)

7.1.1.1 Call Center Director - or their designee, shall report to the Customer Experience Section Chief or their delegate, and be responsible for:

7.1.1.1.1 Activating the various call center locations for handling outage calls from customers as well as maintaining normal communications for non-affected customers.

7.1.1.1.2 Collaborating with the Customer Experience Section Chief and Incident Commander or their designees to ensure consistent and accurate information is being communicated to customers;

7.1.1.1.3 Establishing appropriate shifts and coverage levels based on call volumes;

7.1.1.1.4 Ensuring emergency calls and critical customer issues are properly elevated within the Incident Command organization through designated information systems or verbally when required;

7.1.1.1.5 Verifying all available communications channels are working properly and allowing affected customers to identify outages and obtain restoration status information.

7.1.1.1.6 Verifying with Information Technology that all necessary information systems and processes are available and functioning properly; and,

7.1.1.1.7 Tracking and communicating performance metrics during the restoration event, and providing various statistics to the Customer Experience Section Chief to be utilized by the Incident Commander.

7.1.2 Activation

7.1.2.1 Yellow Alert – The Customer Experience Section Chief or their delegate shall have authority for activating Customer Experience emergency business processes whenever a Yellow Alert has been issued by the Incident Commander or their designee. Activation of emergency Customer Experience business processes shall be considered whenever a forecasted weather event or emergency is predicted to result in significant electric system damages and customer outages. Activation may be required in advance of actual damages or outages, to assure needed resources and processes are in place to effectively respond to affected customer inquiries and reports when outages start occurring.

7.1.2.2 Red Alert - The Customer Experience Section Chief or their delegate shall have responsibility for activation of emergency Customer Experience business processes whenever a Red Alert has been declared and significant electric system damages and customer outages are occurring or expected to occur.

7.1.3 Emergency Processes

7.1.3.1 Call Center Staffing - In preparation for or response to emergencies or large outage events which may impact electric customers, the Call Center Director or their designee should collaborate with the Customer Experience Section Chief or their designee to assess the probability and scope of anticipated impacts on customers based on the projected or actual categorization (Level I – IV) of an event. Gathered information should be used to execute established on-call groups, based on the Level of event. When call-in procedures are needed, the Call Center Director or their designee shall utilize the Everbridge notification system to notify the appropriate on-call groups.

The Call Center Director is responsible for monitoring the status of emergencies and restoration efforts, and continuously assessing the appropriateness and effectiveness of resource levels and customer interfacing processes.

7.1.3.2 Call Center Business Continuity - On occasion, a primary Call-In Center work location may be unavailable during the Company's response to a significant outage event or emergency. Under this scenario, the Call Center Director shall be responsible for collaborating with the Customer Experience Section Chief and developing alternative resource staffing and call routing plans, until the primary location is available or the emergency condition is no longer in place.

7.1.4 Training and Qualifications

Customer Services shall be responsible for ensuring all personnel assigned to Customer Experience roles described herein are adequately trained and exposed to necessary business processes and information systems.

7.3 Business Offices

Local Business Offices play a critical role in supporting LG&E and KU communities and customers, especially when telephonic and electronic communication services have been impacted by severe weather, a natural disaster, or other significant emergency. The Company's Customer Experience Section of the Incident Command System shall have primary responsibility for ensuring adequate procedures and resources are in place to accommodate customer service needs with normal communications mediums are unavailable during large outage events or emergencies involving the electric system.

7.3.1 Roles and Responsibilities (See Appendix 10 for key Business Office contact information)

7.3.1.1 Business Office Director – or their designee, shall report to the Customer Experience Section Chief or their delegate, and be responsible for:

- 7.3.1.1.1 Working with areas affected by outages or emergencies and making local business offices available for customers to provide outage information and obtain updates on their restoration status.
- 7.3.1.1.2 Collaborating with the Customer Experience Section Chief and Incident Commander or their designees to ensure consistent and accurate information is being communicated to customers;
- 7.3.1.1.3 Ensuring emergencies and critical customer issues are properly elevated within the Incident Command organization through available communications mediums;
- 7.3.1.1.4 Establishing appropriate shifts and coverage levels based on outage counts and anticipated durations;
- 7.3.1.1.5 Tracking and communicating key customer traffic and outage information during the restoration event, and providing various statistics to the Customer Experience Section Chief to be utilized by the Incident Commander.

7.3.2 Activation

7.3.2.1 Yellow Alert – The Customer Experience Section Chief or their delegate shall have authority for activating Customer Experience emergency business processes whenever a Yellow Alert has been issued by the Incident Commander or their designee. Activation of emergency Customer Experience business processes shall be considered whenever a forecasted weather event or emergency is predicted to result in significant electric system damages and customer outages. Activation may be required in advance of actual damages or outages, to assure needed resources and processes are in place to effectively respond to affected customer inquiries and reports when outages start occurring.

7.3.2.2 Red Alert - The Customer Experience Section Chief or their delegate shall have responsibility for activation of emergency Customer Experience business processes whenever a Red Alert has been declared and significant electric system damages and customer outages are occurring or expected to occur.

7.3.3 Emergency Processes

7.3.3.1 Business Offices Operations – Whenever a Yellow or Red Alert is issued, the Business Office Director or their designee should collaborate with the Customer Experience and Operations Section Chiefs or their designees to assess the probability and scope of anticipated impacts on customers and normal communications channels based on the projected or actual categorization (Level I – IV) of a declared event. Collected information should be used to:

- Determine if Business Offices should be operated outside of normal business hours; and,
- Determine if resource levels in Business Offices should be supplemented to facilitate effective service for anticipated or actual increases in customer traffic.

The Business Office Director is responsible for monitoring the status of emergencies and restoration efforts and continuously assessing the appropriateness and effectiveness of resource levels, customer interfacing processes, and facility availability for Business Offices in impacted areas.

7.3.3.2 Business Availability and Functionality – When a service area has been greatly impacted by severe weather, and significant customer outages have been experienced, the Business Office Director should coordinate assessment of business offices in affected service areas to:

- Confirm the availability and physical functionality of the Business Office;
- Confirm the availability and functionality of key information and communications systems;
- Determine if temporary electric supply (generator) is needed; and,
- Determine if an alternative facility or mobile command center is needed to facilitate anticipated or actual customer traffic.

When deficiencies are identified, the Business Office Director shall coordinate with the Customer Experience, Operations, and Logistics Section Chiefs to secure whatever resource is necessary to remedy the deficiency or to identify alternatives for meeting customer needs.

7.3.4 Training and Qualifications

Customer Services shall be responsible for ensuring all personnel assigned to Customer Experience roles described herein are adequately trained and exposed to necessary business processes and information systems.

7.4. Emergency Management Outreach

Systematic and routine outreach is needed with local, regional, and state government and emergency response agencies to assure the Company is able to effectively work with said agencies during significant emergencies or outage events involving the Company's electric system.

7.4.1. Roles and Responsibilities (See Appendix 10.0 for key internal Emergency Management Outreach contact information)

7.4.1.1. Emergency Planning and Preparedness Manager (EPP Manager) – or their designee, shall be responsible for developing and executing the Company's emergency management outreach strategy and programs, and for developing Alert Level Task lists which assure LG&E and KU can effectively coordinate with emergency response agencies in their service territories when responding to emergencies or significant outage events impacting the electric distribution systems. The EPP Manager is also responsible for working closely with the Incident Commander, Customer Experience Section Chief, and key customer interfacing personnel to identify, develop, and execute critical outreach functions and assure consistent and accurate communications exchanges with key emergency management leaders in areas served by the Company during Yellow and Red alert status.

7.4.1.2. Emergency Operations Center (EOC) Representative – shall be responsible for representation of the Company in active EOC's in the LG&E and KU service areas as requested by associated emergency management representatives or as assigned by the Incident Commander or EPP Manager. The EPP Manager or their delegate shall be the primary Company representative responsible for coordinating emergency response efforts with the State Emergency Operations Center in Frankfort, with the duties of Emergency Support Function – Private Sector (ESF-16). At the County Level the EPP Manager or their delegate shall be the primary Company representative responsible for coordinating emergency response efforts in County Emergency Operation Centers with the Duties of Emergency Support Function – Utilities (ESF-12)

7.4.2. Activation

7.4.2.1. Blue Alert – the EPP Manager shall be responsible for working with Operations and Retail Management to develop and coordinate execution of emergency management outreach strategies and plans. Outreach strategies and plans should be designed to assure the Company can effectively communicate and coordinate with key local, regional, and state emergency response agencies during preparation for or response to significant emergencies or outage events involving the electric system.

7.4.2.2. **Yellow Alert –** the EPP Manager or their delegate shall be responsible for staying alert to internal Alert levels and external threats which may indicate the need to execute Yellow Alert task lists specific to emergency management outreach. Additionally, the EPP Manager shall be responsible for staying alert to emergency events or threats on the local, regional, and state level which could place the LG&E and KU distribution system under Yellow Alert. Whenever a threat is identified, the EPP Manager shall also be responsible for ensuring the Incident Commander or their delegate is aware of the threat.

7.4.2.3. **Red Alert –** the EPP Manager shall be responsible for coordinating execution of Emergency Management Outreach Red Alert Task list items whenever a Red Alert has been declared by the Incident Commander or their delegate. Additionally, the EPP Manager shall be responsible for staying alert to emergency events or threats on the local, regional, and state level which could place the LG&E and KU distribution system under Red Alert. Whenever a threat is identified, the EPP Manager shall also be responsible for ensuring the Incident Commander or their delegate is aware of the threat.

7.4.3. Emergency Management Outreach Focus Areas

The following agencies shall be the Company's primary emergency management outreach targets:

7.4.3.1. Kentucky Emergency Management (Appendix 7.C contains key Emergency Management contact information)

7.4.3.1.1. **Kentucky Emergency Management Regions** – KYEM is made up of eleven regions, each of which is assigned a Regional Response Manager**.**

7.3.1.1.1..1. Region 1 – Benton Office
7.3.1.1.1..2. Region 2 – Owensboro Office
7.3.1.1.1..3. Region 3 – Glasgow Office
7.3.1.1.1..4. Region 4 – Louisville Office
7.3.1.1.1..5. Region 5 – Frankfort Office

7.3.1.1.1..6. Region 6 – Walton Office,
7.3.1.1.1..7. Region 7 – Morehead Office
7.3.1.1.1..8. Region 8 – Hazard Office
7.3.1.1.1..9. Region 9 – London Office
7.3.1.1.1..10. Region 10 – Somerset Office
7.3.1.1.1..11. Region 11 – Lexington Office

LG&E and KU serve customers in all but Region 3. The EPP Manager is responsible for coordinating with Operations and Retail management to coordinate the Company's activities and representation in Regional Emergency Management meetings, exercises, or activations.

7.3.1.1.2. **Emergency Support Function (ESF)** – KYEM defines utilities as ESF-12 for public entities and ESF – 16 for Private Sector Utilities; LKE participates in planning meetings, drills, and staffs the Central EOC in Frankfort during emergencies involving LG&E and KU electric or gas facilities. The EPP Manager or their delegate is responsible for representing the Company on ESF-16 or ESF-12 exercises and activations.

7.3.1.1.3. **Private Sector Working Group (PSWG)** – The Company is one of the founding members of the PSWG, which is in partnership with the KYEM; the PSWG participates in State emergency planning, exercises, and responses (through the VBEOC - on control console at the State EOC). The EPP Manager or their delegate is responsible for participating in this Group.

7.3.1.1.4. **Central United States Earthquake Consortium (CUSEC)** – LG&E and KU participate with state government and the eight surrounding states on drills and emergency planning exercises for catastrophic earthquakes. The EPP Manager is responsible for determining the level of participation in this Consortium.

7.3.1.1.5. **Kentucky Emergency Response Commission (KERC)** – Under the authority of KRS 39A placed by the Director of Emergency Management Office and the Governor's appointment of the primary seated commissioners of the Commission serves as the advisory committee for the overall emergency management and emergency response program of the

Commonwealth. The EPP Manager is responsible for determining the level of participation in this Commission.

7.3.1.1.6. **Local Emergency Planning Committees (LEPC)** – all counties are required to conduct at least two emergency preparedness and planning meetings annually to qualify for Federal funding. Critical counties for LKE include Jefferson, Oldham, Bullitt, Nelson, Trimble, Owen, Clark, Fayette, Ohio, Fayette, Laurel, Bell, Christian, Muhlenberg, and Harlan. The EPP Manager is responsible for coordinating with Operations and Retail management to coordinate the Company's activities and representation in LEPC meetings, exercises, or activations.

7.3.1.2. Virginia Emergency Management Association (Appendix 7.C contains key Emergency Management contact information)

7.3.1.2.1. **Emergency Management Region –** Old Dominion Power's (ODP) service area is in the Virginia Emergency Management Region IV, which includes Wise, Dickenson, Lee, and Russell Counties. The EPP Manager is responsible for coordinating with Old Dominion Power Operations and Retail management to coordinate the Company's activities and representation in Regional Emergency Management meetings, exercises, or activations.

7.3.1.2.2. **Annual Joint Utilities Meeting** – the Virginia State Corporate Commission (VSCC) and Virginia Emergency Management Association host annual Joint Utilities Emergency Preparedness and Response meetings. The EPP Manager is responsible for coordinating with Old Dominion Power Operations and Retail management to coordinate the Company's activities and representation in these annual meetings, and any related exercises, or activations.

7.3.1.2.3. **Emergency Support Function (ESF)** – Virginia EM defines utilities as ESF-12 for public entities; LKE participates in planning meetings, and reports critical outage and customer information to the VSCC for dissemination to the Virginia EM. The EPP Manager is responsible for coordinating with Old Dominion Power Operations and Retail management to coordinate the

Company's activities and representation with ESF-12 in Virginia, and any related exercises, or activations.

7.4.4. Training and Qualifications

The EPP Manager is responsible for ensuring all personnel assigned to Emergency Management Outreach roles are adequately trained and exposed to necessary business processes and information systems.

8. Logistics Section

Purpose

EPRP Section 8.0 introduces the high level organizational structure, roles, and associated responsibilities for the Logistics Section of the Company's Incident Command System for responding to significant emergencies or outage events on the electric distribution system.

Scope

EPRP Section 8.0 and its Subsections cover all resources assigned to the Logistics Section during responses to significant emergencies or outage events on the electric system, as defined for Level III and IV events in Figure 8.1.

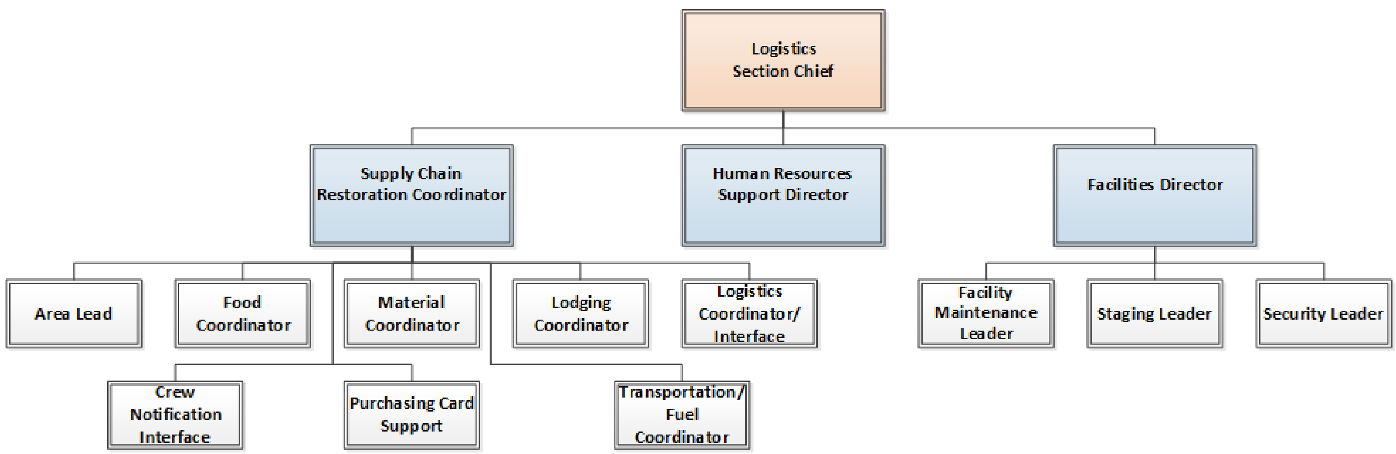


Figure 8.1 Logistics Section Organization

Responsibilities

The Logistics Section of the Incident Command structure has overall responsibility for developing and executing preparedness and response plans which assure resource and logistics needs are effectively fulfilled during responses to significant outage events or other emergencies on the electric distribution system

Training and Qualification

The EPPRT shall have responsibility for establishing minimum training and qualification requirements for procedures covered herein. **(Appendix 1.C contains the Emergency Preparedness and Response Plan Review, Training, and Exercise Schedule.)**

References

1. Supply Chain Emergency Response Manual

Revisions

None

8.1. Resources

Supply Chain (Logistics Section) has worked with Electric Distribution Operations to develop business processes which help assure the Company has adequate resources available to respond to significant outage events and emergencies on the electric distribution system. During emergency responses, Supply Chain will provide and/or coordinate the following functions for the Company:

- Procurement Activities, including:
  - Establishment of commercial terms, billing rates, and current insurance forms for nonresident/off system resources;
  - Securing adequate lodging for all affected mobilized and off system resources;
  - Securing necessary meals for all responding persons;
  - Provision of special services such as laundry, etc…
- Material Management Activities, including:
  - Storeroom operations;
  - Material logistics, including job site delivery and/or operation of mobile storerooms at established personnel staging areas.
- Coordination with Operating Services on:
  - Facility management;
  - Staging areas, including establishment and daily management;
  - Security, including National Guard escorts.
- Interface with Transportation, including:
  - Vehicle leases and rentals;
  - Miscellaneous equipment needs;
  - Vehicle fueling.

The procedures, roles, and responsibilities described herein are designed around Level III and IV events, but are scalable and transferable to all categories of events.

8.1.1. Roles and Responsibilities (See Appendix 10 for key Supply Chain contact information)

8.1.1.1. Supply Chain Restoration Coordinator – reports to or is the Logistics Section Chief(s), and has overall responsibility for developing Alert Level task lists for Supply Chain functions, and:

8.1.1.1.1. Working with Incident Commanders, Senior Management, and Operations Sections Chiefs to procure and provide identified material, transportation, equipment, meals, and general supply needs.

8.1.1.1.2. Assuring the Logistic Section Chief in the Incident Command Structure is provided sufficient data to trigger logistics processes necessary to support restoration resources.

8.1.1.1.3. Assuring the reporting needs of the Incident Command structure are satisfied;

8.1.1.1.4. Working with the Information Technology Director to assure that needed information management systems meet supply and logistics needs; and

8.1.1.1.5. Conducting internal update and planning meetings with Supply Chain personnel responsible for support functions, to include other organizational areas as necessary and needed.

8.1.1.2. **<u>Area Lead</u>** - position is responsible for managing the Supply Chain restoration support function(s) in a specific geographical area. Depending on the magnitude of the restoration effort, there may be multiple Area Leads. This position will:

8.1.1.2.1. Have an on-site presence in the affected area

8.1.1.2.2. Direct the site specific supply chain support functions, specifically Material, Lodging and Food requirements

8.1.1.2.3. Maintain constant communications with the Supply Chain Restoration Coordinator and local Operations management

The formal naming of an Area Lead(s) will be dependent upon the location of the restoration event(s).

8.1.1.3. **<u>Crew Notification Interface</u>** – or their designee, shall have overall responsibility for working with designated positions in the Work Planning Section to track internal crew mobilization and committed off system resources. The primary purpose of this position is to have a complete understanding of external crews being mobilized for the restoration effort, communicating this information to, a minimum, the (Supply Chain) Area Lead, Materials Supervisor, etc… and securing contract agreements, namely Commercial Terms, billing rates and current insurance forms. This position is also responsible for:

8.1.1.3.1. Ensuring a contract is in place to cover the work to be performed, preferably as resources are being mobilized and before work commences; and

8.1.1.3.2. Communicating the safety, business, equipment and invoicing requirements of the Company.

8.1.1.4. **Food Coordinator** - or their designee, shall have overall responsibility for helping secure adequate meals for labor resources allocated to the restoration effort. The Food Coordinator is responsible for contacting and establishing specific local restaurants, preferably in the area where either work is being performed or where crews are being lodged, in the initial stages of a restoration effort, capable of serving meals to potential external and company crews responding to a restoration event. The duration of this function will be determined by the time needed to support restoration personnel requiring the use of staging areas or as requested by local Operations Management. Food coordinator will ensure the proper use of purchasing cards for payment.

8.1.1.5. **Materials/Supplies Coordinator** - or their designee, shall have overall responsibility for managing the material support functions, including:

8.1.1.5.1. Working with area storerooms, Operations Directors, and suppliers to maintain necessary materials and supplies inventory levels, and keeping material providers advised of projected material needs based on reported system damages;

8.1.1.5.2. Overseeing local storeroom operations and material logistics;

8.1.1.5.3. Communicating with South Service Center on transformer logistics support;

8.1.1.5.4. Ensuring adequate materials are available at designated staging sites;

8.1.1.5.5. Tracking and reporting material usage;

8.1.1.5.6. Managing material return processes, post restoration.

In the event of a single location restoration effort, the Material Lead function will be performed by a delegated person. This lead will be assigned by the Supply Logistics Section Chief and typically be either a local Material Specialist, or Material Supervisor responsible for the impacted storeroom/warehouse.

In a multi-site restoration effort, a Material Lead will be assigned to each impacted area and oversee the operations of the associated storerooms/warehouses in that impacted area. Material Leads will be responsible for the material support functions (denoted above) in their assigned area. Also, a Material Supply Coordinator function will be established to work with the individual Material Leads and all affected suppliers to ensure that an adequate and optimized flow of materials to all affected sites is established and maintained throughout the restoration event.

8.1.1.6. <u>Lodging Coordinator</u> – or their designee, shall be responsible for identifying and securing the appropriate number of hotel rooms, in the appropriate areas of the restoration area, consistent with the number of external crew personnel that are responding to the event. This position will also track the number of rooms available and occupied as well as an expense recap of lodging costs throughout the restoration event and report in Electric Distribution's designated resource tracking database.

8.1.1.7. <u>Logistics Coordinator</u> – In a Level III or IV restoration event, this position is primarily responsible for interfacing with Operating Services on the establishment and operation of external staging areas.

8.1.1.8. <u>Transportation Leader</u> – or their designee, shall have overall responsibility for ensuring adequate transportation and equipment resources are available to respond to restoration efforts, including light duty vehicles, heavy duty vehicles, power operated equipment, and trailers.

The TL shall also be responsible for working with fueling stations and mobile fueling providers, as needed, to ensure adequate fuel is available for vehicles and power operated equipment during emergencies.

8.1.1.9. <u>Purchase Card Support</u> – position is responsible for ensuring Purchasing Cards are active and levels are adequately set and maintained throughout the event and will respond immediately to any administrative issues that arise.

8.1.1.10. <u>Data Collection</u> – In a Level III or IV event, this position is responsible for collecting and tracking data associated with Supply Chain restoration activities including:

- 8.1.1.10.1. Quantities of materials (poles, transformers, storm kits, etc…) and delivered - from the Material Coordinator or Area Lead.
- 8.1.1.10.2. Number of hotel rooms reserved and utilized – from the Lodging Coordinator.
- 8.1.1.10.3. Fuel consumption – from the Transportation/Fuel Coordinator.
- 8.1.1.10.4. Number of meals served – from the Food Coordinator or Logistics Coordinator.

8.1.2. Emergency Response Activation

8.1.2.1. Yellow Alert – The Logistics Section Chief, Incident Commander, or Operations Manager or their delegates shall have the authority to direct activation of 'storm response' Supply Chain processes whenever a Yellow Alert has been issued by the Incident Commander or their designee. Activation of emergency supply chain processes shall be considered whenever a forecasted weather event or emergency is predicted to result in significant damages and a Level III or Level IV event is declared for any service area, where incremental resources, resident or non-resident, are brought in to assist with protect, restore, or repair activities. Activation may be required in advance of actual damages or outages, to assure needed resources and processes are in place to enable effective management, administration, and treatment of incremental resources.

8.1.2.2. Red Alert - The Logistics Section Chief, Operations Section Chief, and Incident Commander or their delegates shall have responsibility for activation of emergency supply chain processes whenever a Red Alert has been declared, particularly when an event has been established as Level III or IV for any Operations area.

8.1.3. Key Business Processes

8.1.3.1. Contracting External Resources

During a declared weather event LG&E and KU Services Company (LKS) may call upon four categories of external resources for assistance:

- LKS's native contractors;
- Primary Mutual Assistance Partners who are members of the Southeast Electric Exchange (SEE), Great Lakes Mutual Assistance (GLMA), or Midwest Mutual Assistance (MMA);
- Secondary Mutual Assistance Partners who are not members of the SEE, GLMA, or MMA;
- Non-native contractors – typically obtained from the Mutual Assistance Utilities, comprised of two types
    - Preferred (GSA on File and Non-GSA)
    - All Others

The contracting for each of these resources shall be described as follows:

8.1.3.1.1. Native Contractors - Native Contractors are defined as contractors in which LKS has an established contract or ongoing relationship. In the event LKS requires external resources for storm restorations, LKS can rely on the contracts with these contractors as the basis for the rates these contractors will charge. For minor storms (level I or II) money is included in the contract award totals for the current overhead contractors **(see Appendix 8.A for current listing and contact information for Native Contractors)** or for other certified contractors expenses less than $50K will be covered by standard purchase orders entered by distribution operations. However for major storms (level III or IV, usually where the resource room concept is implemented), an additional requirement in using these contractors will be the completion and proper approval of a Sole Source Authorization (SSA) form to cover storm related work and the separate processing of storm related invoices.

Should a native contractor be requested to perform work outside of the scope of their standard contract, an amendment to or special storm contract may be appropriate.

Native LKS contractors mobilizing resources to a restoration event from **outside of the LKS system** will need to forward a roster and the applicable wage and equipment rates to the designated Supply Chain contact.

8.1.3.1.2. Primary Mutual Assistance Partners - LG&E KU Services (LKS) is a party to a Mutual Aid Agreement, as part of the Southeast Electric Exchange (SEE), which requires the member utilities to offer assistance (to each other) in the case of a declared weather event. Likewise, LKS is a member of the Great Lakes Mutual Assistance and Midwest Mutual Assistance groups. **(See Appendix 9.C for primary mutual assistance group members and contact information)** All member companies are required to sign the Edison Electric Institute's (EEI) Mutual Assistance Agreement. When assistance is needed from these mutual assistance group members, LKS will request assistance via a Mutual Aid conference call mechanism. No stand-alone commercial agreement is required for member utilities as a working agreement is already in place through membership in SEE or EEI.

Responding utilities will be directed to forward a copy of their roster to Work Planning, as established in EPRP Section 9.1. The only additional requirement will be the completion and proper approval of a Sole Source Agreement form to cover the work by the Crew Notification Interface or as designated by the Supply Chain Restoration Coordinator.

8.1.3.1.3. Secondary Mutual Assistance Partners - If Mutual Assistance is required from utilities that are not part of the SEE, (such as GLMA and MMA) Supply Chain will send the LKS Mutual Aid (MA) Commercial Agreement to that utility. The MA Commercial Agreement will, among other things, contain terms and conditions, request for rates, and establish LKS business requirements, i.e. housing/staging policies. In addition to the signed Commercial Agreement, a roster will be requested from the responding utility.

8.1.3.1.4. Non Native Contractors - LKS defines Non-native Contractors as all contractors that do not normally work on the LKS system that are secured by LKS to deliver assistance in response to significant outage events or other emergencies on the Company's electric distribution system. **(Please see Appendix 8.B for listing and contact information of Non Native Contractors LKE has worked with in the past.)**

These contractors are categorized into two groups – **Preferred** and **All Others**.

8.1.3.1.4.1. Preferred Non-Native Contractors - Preferred Non-Native Contractors include business partners that have been preapproved to work on the LKS system and are preferred due to their safety rules and performance, proximity to the LKS service area, and pricing. The Company already has General Service Agreements (GSA) in place for some of these contractors.

When GSA resources are secured to provide assistance during an emergency response, they should be requested to provide the following information to a designated Supply Chain contact:

- Current insurance certificate
- Applicable wage and equipment rates

Non-GSA contractors will also be asked to submit a signed GSA document (in addition to the above items), or will be allowed to mobilize under a properly approved Intent to Deviate document.

The only additional requirement will be the completion and proper approval of a SSA form to cover the work.

8.1.3.1.4.2. Other (Non-Preferred) Non-Native Contractors - When non-preferred non-native off system resources are secured to provide assistance during responses to significant outage events or emergencies, they shall be required to sign the standard LKS General Services Agreement (GSA) and LKE Storm Restoration Agreement Contract. The contractor should also be required to provide their current insurance form.

The Crew Notification Interface shall also be responsible for routing a completed Sole Source Agreement to cover the proposed scope of work.

8.1.3.2. Materials Logistics

Typically, during blue sky outage events or Level I-II emergency events, resident Company and business partner crews are able to utilize locally stored materials to restore outages and repair system damages. During Level III and IV events, incremental materials are often needed as supplemental crews are brought in to help respond, or as local crews deplete local supplies. Supply Chain has developed supplemental business processes to provide for necessary materials and supplies during restoration and repair efforts following large storms or emergencies which damage the electric distribution system. **(Please see Appendix 8.C for the Logistics Section's Emergency Response Materials Logistics business process flow, and Appendix 8.D for a listing of Storeroom locations and key contact information.)**

8.1.3.2.1. Material Leads and Coordinators

8.1.3.2.1.1. Single Location Restoration Effort

- The Material Coordinator function will be performed by a designated *Material Lead*.
- The Material Lead will be assigned by the Supply Chain Restoration Coordinator and typically be either :
    - o The local Material Specialist, or

- The Material Supervisor responsible for the impacted storeroom or warehouse

8.1.3.2.2. Multi-Site Restoration Effort

- A Material Lead will be assigned to each impacted area and oversee the operations of the associated storerooms/warehouses in that impacted area
- Material Leads will be responsible for the material support functions (denoted above) in the assigned area
- A *Material Supply Coordinator* function will be established to work with the individual Material Leads and all affected suppliers to ensure that an adequate and optimized flow of materials to all affected sites is established and maintained throughout the restoration event.
- Material Leads will communicate material requirements and material issues to the Material Supply Coordinator for resolution with the external suppliers

8.1.3.2.3. Storm Kits - "First response" Storm Kits have been developed for LG&E and KU operating areas and are stocked by the Company's electric materials vendor and in Company storeroom locations throughout the LG&E and KU service areas. These kits are assigned to non-resident resources during level II – IV emergency events, and are designed to enable off system crews to restore customer outages and make routine type repairs for a period of at least 24 hours. During this period, the Incident Commander, Work Planning, Operations Section, and Logistics Section evaluate the scope and scale of system damages and assess overall and site specific material needs. After damage assessments are completed, additional orders for specific material needs can be placed with the designated Materials/Supplies Coordinator or Lead. **(Please see Appendix 8.E for the LG&E and KU Storm Kit locations, quantities, and inventories.)**

8.1.3.2.4. **Deleted**

8.1.3.2.5. Storm Material Trailers - Storm Material Trailers have been developed to be delivered to hard hit sites or staging areas. The Company's electric materials vendor maintains these trailers, which contain a specified inventory of common storm use materials for LG&E and KU. These trailers can be delivered to job sites within four to six hours. **(Please see Appendix 8.G for an inventory of Storm Trailers.)**

8.1.3.3. Vehicles and Equipment

The Manager Transportation or their delegate shall be designated as Transportation and Fuel Coordinator during Level II-IV events, and shall be responsible for maintaining a listing of vehicles, equipment, and fuel (mobile and stations) providers that support emergency restoration efforts. The Transportation Coordinator shall work with the Logistics Section Supply Chain Coordinator to meet all internal fleet needs during responses to significant outage events or other emergencies involving the electric distribution system. **(Please see Appendix 10 for a listing of key Vehicles and Equipment contacts.)**

8.1.3.4. Lodging Setup

Hotels will be the preferred method of lodging for non-native resources providing assistance to restoration efforts or other emergencies. Supply Chain shall be responsible for designating a Lodging Coordinator during storms and maintaining a list of available lodging locations, along with detailed procedures for securing, and accounting for rooms. (Supply Chain utilizes external resources and databases (example: Convention Centers, Visitors Bureaus, etc…) to identify lodging for external resources as well as track room usage and availability on an on-going basis.)

During significant restoration events, where incremental off-system resources are brought in to assist with response efforts, Work Planning should provide the Lodging Coordinator with head counts in Electric Distribution's designated resource management software. The Lodging Coordinator is responsible for using entered resource data to determine the number, and geographic location, of required rooms. Resource/Operations Managers shall be responsible for coordinating lodging needs with Supply Chain.

If available hotels do not satisfy housing needs for incoming or active restoration workers, staging areas may be needed. Please reference Section 8.3 for Resource Staging procedures.

8.1.3.5. Restaurant/Meals Setup

Supply Chain has established business processes for setting up restaurants/meals during significant outage events or emergencies to provide necessary meals for resources supporting restoration and response efforts **(Please see Appendix 8.H for the LG&E and KU restaurant set-up procedures.)** Supply Chain is responsible for maintaining a listing of available restaurants and meal providers by Operating area, and for designating a Food Coordinator during responses to significant outage events or emergencies.

Operations Centers needing meals shall contact the Supply Chain Restoration Coordinator or Food Coordinator to invoke Restaurant Set-Up processes.

8.1.3.6. Purchasing Card Setup

8.1.3.6.1. Supply Chain Storm Purchasing Cards

Supply Chain's Storm Purchasing Cards are intended to be used primarily in Level II-IV storm events, particularly in heavily impacted areas. Supply Chain shall be responsible for ensuring that purchasing card procedures are in place to enable purchases under three primary categories:

- Hotels
- Restaurants
- Miscellaneous Materials

Operations Management personnel in need of hotels, restaurants or miscellaneous materials or supplies should notify the Supply Chain Restoration Coordinator or the appropriate designee. Supply Chain will designate central points of contact (Purchasing Card Support) that will be responsible for coordinating set up and payment of lodging, restaurants, and materials throughout the restoration period.

8.1.3.6.2. Individual Storm Purchasing Cards

Individual storm purchase cards are available for Team Leaders and Birddogs, and are intended to be used for procuring lodging, meals, and miscellaneous materials where Supply Chain Storm Purchasing Cards are not set up or available. Operations Management should contact Supply Chain's designated Purchasing Card Support to activate purchase cards, adjust limits, or assist with any related issues.

8.1.4. Training and Qualifications

8.1.4.1. Supply Chain and Operating Services management personnel shall be responsible for ensuring all personnel assigned to Logistics Section roles described herein are adequately trained on necessary business processes and information systems required to effectively fulfill procedures defined in Section 8.1.

8.3. Human Resources Support

To be developed

8.3.1. Roles and Responsibilities

8.3.1.1. Human Resources Director – or their designee, shall function as the support mechanism for employees and families of employees who are working on restoration activities, but also have crisis issues at home due to the weather event or emergency. The Human Resources Director will work with various outside entities to provide support to employees' families when in need of basic functions such as food, shelter, and home repairs.

8.3.2. Activation

8.3.2.1. Yellow Alert

To be developed

8.3.2.2. Red Alert

To be developed

8.3.3. Emergency Processes

To be developed

8.3. Facilities and Staging Areas

The Logistics Section has worked with Electric Distribution Operations, Retail, and Supply Chain to develop business processes and an organizational structure which assures adequate availability and effective operations of Company facilities and staging areas during responses to significant emergencies or outage events.

8.3.1. Roles and Responsibilities (See Appendix 10 for key Facilities and Staging contact information)

8.3.1.1. <u>Facilities Section Chief</u>– reports to or is the Logistics Section Chief(s), and has overall responsibility for development of key Alert Level Task lists for Facilities and Staging during emergencies, and:

8.3.1.1.1. Working with Incident Commanders and all other Section Chiefs to provide, operate, and maintain needed facilities and staging areas as needed or requested during Company responses to significant outage events or emergencies involving the LG&E and KU electric distribution systems.

8.3.1.1.2. Assuring the Logistic Section Chief in the Incident Command Structure is provided sufficient data to trigger logistics processes necessary to support restoration resources.

8.3.1.1.3. Assuring the reporting needs of the Incident Command structure are satisfied;

8.3.1.1.4. Working with the Information Technology Director to assure that needed information management systems meet logistics needs; and

8.3.1.1.5. Conducting internal update and planning meetings with Operating Services personnel responsible for support functions, to include other organizational areas as necessary and needed.

8.3.1.2. <u>Staging Lead</u> - position is assigned by the Logistics Section Chief, and is responsible for collaborating with the Logistics Section Chief and Lodging Coordinator to identify housing and staging needs for responding resources, and determining if incremental staging areas are needed to be set up and operated during responses to significant emergencies and outage events involving the electric distribution system.

8.3.1.3. <u>Facility Maintenance Lead</u> – position is assigned by the Logistics Section Chief, and is responsible for collaborating with the Logistics Section Chief to identify and respond to incremental facility needs in preparation for or response to significant emergencies or outage events involving the electric distribution system. This includes, but is not limited to:

- Expanding facility operations beyond normal business hours, including lighting, air conditioning, security, and facility maintenance.
- Providing for incremental janitorial services and maintenance personnel to assist with upkeep of facilities when incremental resources are brought in to support emergency response.
- Providing for traffic control and parking attendants for incremental resources.
- Providing for room reconfiguration and set up, to enable establishment of central war rooms/resource management rooms.
- Providing for backup power supplies.

8.3.1.4. **Security Leader** – typically assigned to the Manager Corporate Security or their delegate, this position is responsible for collaborating with the Logistics Section Chief, Lodging Coordinator, Staging Lead, and Operations Section Chief(s) to identify and respond to incremental security needs during responses to emergencies or significant outage events on the electric distribution system. This includes, but is not limited to providing for:

- Facility Security
- Staging Area Security
- Job Site Security/Crowd Control
- Hotel Parking Lot/Vehicle Security
- Traffic Control
- Escorting Company Personnel
- Guarding Company Assets

8.3.2. Emergency Response Activation

8.3.2.1. **Yellow Alert** – The Logistics Section Chief, Incident Commander, Customer Experience Section Chief, and Operations Section Chief or their delegates shall have the authority to direct activation of 'storm response' Operating Services business processes whenever a Yellow Alert has been issued by the Incident Commander or their designee. Activation of emergency Operating Services processes shall be considered whenever a forecasted weather event or emergency is predicted to result in significant damages, particularly when an event necessitates extended work hours and incremental non-resident resources to be brought in to assist with protect, restore, or repair activities. Activation may be required in advance of actual damages or outages, to assure needed facilities and staging areas are in place to facilitate effective management, administration, and treatment of responding resources.

8.3.2.2. Red Alert - The Logistics Section Chief, Operations Section Chief, Customer Experience Section Chief and Incident Commander or their delegates shall have responsibility for activation of emergency Operating Services emergency response processes whenever a Red Alert has been declared.

8.3.3. Emergency Business Processes

8.3.3.1. Facility Maintenance – During responses to significant outage events, the limitations of business offices, operating centers, call centers, storerooms, corporate offices, etc. and associated facility maintenance business processes may be exceeded. The Facilities Section Chief shall be responsible for working with the Incident Commander, and all other Section Chiefs to identify and react to facility needs which exceed normal physical, business processes, and human resources capabilities. The Facility Section Chief shall also be responsible for executing associated Alert Level task lists and working with Operating Services, Security, and Supply Chain to provide for incremental/needed:

- Facility maintenance support
- Janitorial services
- Security
- Debris removal or dumpsters
- Traffic and parking control
- Snow removal
- Power supply (generators) and fuel
- War room setup and breakdown
- Resource staging

8.3.3.2. Staging Areas – Resource staging areas may be needed during responses to significant outage events or emergencies involving the electric distributions system, particularly for Level III and IV events, where incremental off system resources are brought in to support response efforts. Staging areas activities include, but are not limited to the following:

- Resource check-in, safety passporting, and processing
- Housing
- Materials distribution, staging, and returns
- Food preparation and distribution
- Clothes laundering
- Debris disposal and staging
- Showers and Restrooms
- Vehicles and Equipment staging and security
- Fuel dispensing

The Facilities Section Chief shall be responsible for collaborating with the Logistics Section Chief, Incident Commander, Operations Section Chief, Supply Chain Lodging Coordinator, and Work Planning Section Chief to identify staging and housing needs and to set up and operate staging areas when needed. Factors that must be considered when evaluating staging area needs include:

- Number of personnel reporting to a single geographical location – short term and over the duration of the event
- Number and types of lodging and food accommodations available in that area.
- The relative distance of the available accommodations to the work area.

The Logistics Section will continuously coordinate with the Operations Section and Work Planning Sections as external resources are being deployed to the LG&E KU service areas. When the magnitude of responding resources approaches 300 in a single geographical local, the Logistics Section Chiefs will confer with the Incident Commander and Operations Section Chief to determine if and where a staging area should be set up. If a decision is made to establish a crew staging area, the Logistics Section Chief will coordinate with the Staging Lead to evaluate available options, establish expected use, and designate the staging location. Personnel under the Facilities Section Chief will be responsible for overseeing and coordinating set up and operation of the designated staging area. A single staging area for 300 people can typically be set up and operational within twelve to thirty-six hours.

If the staging area is needed to provide food, lodging, showers, etc…the Logistics Director will work with Supply Chain to coordinate needed services with the appropriate contractors and suppliers, and work directly with the Staging Lead on delivery and logistics.

Appendix 8.I contains key staging area information.

8.3.3.3. Security - Incremental security needs may be required during responses to emergencies or significant outage events involving the electric distributions system, particularly for Level III and IV events, where incremental off system resources are brought in to support response efforts. Security activities include, but are not limited to the following:

- Facility Security
- Staging Area Security
- Hotel Parking Lot/Vehicle Security
- Job Site Security/Crowd Control
- Traffic Control
- Escorting Company Personnel
- Guarding Company Assets

8.3.4. Training and Qualifications

8.3.4.1. Supply Chain and Operating Services management personnel shall be responsible for ensuring all personnel assigned to Logistics Section roles described herein are adequately trained on necessary business processes and information systems required to effectively fulfill procedures defined in Section 8.3.

9. Work Planning Section

Purpose

EPRP Section 9.0 introduces the high level organizational structure, roles, and associated responsibilities for the Work Planning Section of the Company's Incident Command System for responding to significant emergencies or outage events on the electric distribution system.

Scope

EPRP Section 9.0 and its Subsections cover all resources assigned to the Work Planning Section during responses to significant emergencies or outage events on the electric system, as defined for Level III and IV events in Figure 9.1.

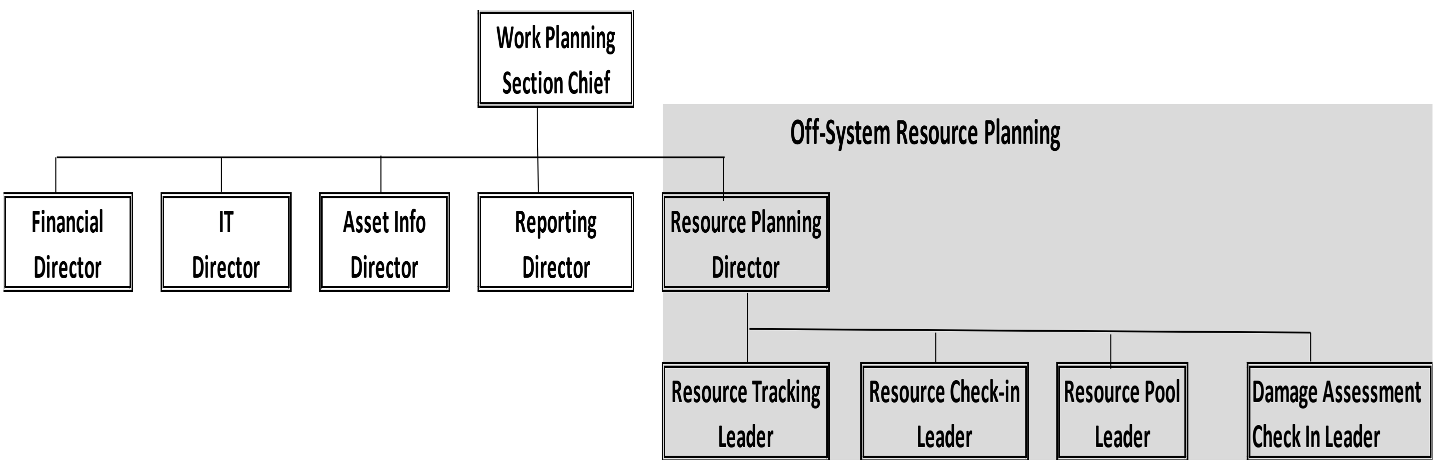


Figure 9.1 Work Planning Section Organization for Level III and IV events.

Responsibilities

The Work Planning Section shall be responsible for managing all information relevant to an incident, and assisting the Incident Commander, Operations Section, and Logistic Sections with tracking, documenting, and reporting resources, estimated restoration times, finances, and facility data.

The Work Planning Section Chief (WPSC) has central responsibility for assuring assigned Work Planning resources are properly trained, and efficient and effective business processes are in place, to provide for resource tracking, optimization, and distribution during responses to significant emergencies or outage events involving the electric system. The WPSC is responsible for working closely with the Operations Section Chiefs and Incident Commander to help identify resource needs, and predict restoration durations. This individual shall also be responsible for assuring all necessary Asset Information and Information Technology is available during emergency responses. Finally, the WPSC is responsible for working with Forecasting and Budgeting to ensure costs are accurately accounted for and all necessary financial reporting is completed.

The Emergency Preparedness and Response Team shall be responsible for developing Alert Level Task lists for all critical roles and functions under the Operations Section.

Training and Qualification

The EPRT shall have responsibility for establishing minimum training and qualification requirements for procedures covered herein. **(Appendix 1.C contains the Emergency Preparedness and Response Plan Review, Training, and Exercise Schedule.)**

References

None

Revisions

None

9.1. Resource Planning

Electric Distribution has developed Resource Planning business processes designed to assist Operations with resource tracking, allocation, and administration during emergency responses, to ensure key qualified personnel can focus their attentions on protecting the public, restoring service, and making necessary repairs. The primary focus of the Resource Planning organization is:

- Working with Operations to identify and secure resource needs;
- Maintaining a high level view of resource distribution and estimated restoration times across all service areas;
- Assisting with administratively processing off system resources during check-in and release;
- Accurately accounting for all off system resources in designated information systems;
- Monitoring the availability of inactive resident Company and Contractor resources;
- Maintaining accurate active/assigned resource counts; and,
- Working with Forecasting and Budgeting to assure all resources are accurately accounted for.

9.1.1. Roles and Responsibilities (See Appendix 10.0 for key Work Planning contact information)

9.1.1.1. Reporting Director - or their designee, shall have overall responsibility for:

9.1.1.1.1. Continuously monitoring Estimated Restoration Times (ERT) to assure adequate and equitable distribution of available resources across service areas as customer outage counts change.

9.1.1.1.2. Development and maintenance of standard spreadsheets and associated administrative processes, which provide for timely and accurate accounting and reporting of internal and external resources responding to a restoration effort.

9.1.1.1.3. Scrub resource data in the Resources on Demand system for irregularities.

9.1.1.1.4. Assuring the reporting needs of the Work Planning Chief and Financial Director are satisfied, and for working with the Information Technology Director to assure that needed information management systems meet resource planning needs.

9.1.1.1.5. Developing the Daily Alignment Report (DAR) which highlights overall objectives for the day.

9.1.1.1.6. Executive Report – responsible for compiling the executive report as needed summarizing current outages, resources on hand by classification and other information.

9.1.1.1.7. Resource Reports – responsible for identifying organizational resource reporting needs and working with Information Technology to develop reports, training tools, and job aids necessary to provide end users timely and easy access during restoration efforts.

9.1.1.1.8. Specialty Maps and Reports – generate ad-hoc reports and specialty maps as dictated by the situation.

9.1.1.1.9. Performance Metrics - accountable for development, monitoring, and reporting key performance indicators associated with resource availability and distribution.

9.1.1.2. <u>Resource Planning Director</u> **–** or their designee, shall have overall responsibility for developing Alert Level Task lists for the Work Planning Section, and:

9.1.1.2.1. Working with Incident Commanders, Senior Management, and Operations Sections Chiefs to identify resource needs across Energy Delivery based on system damage and predicted restoration durations, and for working with management personnel, mutual assistance groups, and business partners to secure, mobilize, demobilize, and track needed resources.

9.1.1.2.2. Resources - working with the Operations Directors, Operations Resource Rooms, and the Distribution Control Center Directors to establish area specific resource needs and availability, including line technicians, service crews, bird dogs, bull dogs, damage assessors, and post completion inspectors. Also, working with the Resource Transition Leader and Resource Tracking Leader to evaluate and execute alternatives for acquiring resources needed to restore service and repair system damage.

9.1.1.2.3. Communications - establishing and maintaining a central point of contact for all off system resources responding to assist, once delegated by an Incident Commander or Operations Section Chief.

9.1.1.2.4. Assuring the Logistic Chief Incident Command Structure is provided sufficient data to trigger logistics processes necessary to support restoration resources.

9.1.1.2.5. Throughout the restoration effort, responsible for assessing system wide outage counts, damage assessment information, and crew availability data to develop flexible resource allocation plans.

9.1.1.2.6. Continuously works with the Operations Chiefs, and Operations Directors to assure that proposed and executed resource allocation plans meet operational needs. This includes development of mobilization plans and release schedules for off system resources.

9.1.1.2.7. Coordinates with the Operations Resource Rooms to validate existing resources allocated to their work locations.

9.1.1.2.8. Resource Clearing House - serving as a clearinghouse for all offers of assistance by contractors and utilities not engaged by the Company; and, working with the Reporting Director to determine if offered resources are needed and should be secured.

9.1.1.2.9. Release Schedules - works with the Resource Tracking Leader to stay apprised of mobilization and release schedules which may impact off system resources, and assures off system management teams are notified on a timely basis.

9.1.1.2.10. Coordinates with the Operation Directors and Operations Resource Rooms to monitor and modify ERTs at the local area and circuit levels.

9.1.1.3. <u>Resource Tracking Leader</u> - or their designee, shall have overall responsibility for:

9.1.1.3.1. Crew Rosters - securing crew and equipment rosters and coordinating data entry into the centralized Resources on Demand system.

9.1.1.3.2. In-transit information – capturing off-system resources' departure time and location, and tracking their estimated arrival times.

9.1.1.3.3. Logistics - communicating reporting locations, directions, contact numbers, hotel and food arrangements, and provision of department of transportation exemptions where applicable for off-system crews. Also, interfaces with Logistics ICS organization (by entering lodging requirements in the central resource system) to ensure accommodations are in place for lodging, meals, transportation, security, and staging.

9.1.1.3.4. Resource Data Administration - responsible for maintaining data in the centralized spreadsheets on resident employees and local contract partners that would be utilized in response to customer outages and system damage.

9.1.1.3.5. Terms and Conditions - exchanging critical information with identified available 'off system' resources, including contract, safety, operations, and regulatory requirements and keeping the Resource Planning Director apprised of any conflicts that may eliminate an identified resource from assisting.

9.1.1.3.6. As assigned by the Resource Planning Director, responsible for working with the Resource Transition Leader and Operations Directors during restoration efforts to administrate and maintain data on internal and external resources assisting with service restoration and system repair.

9.1.1.4. <u>Resource Check-in Leader</u> – or their designee, shall have overall responsibility for:

9.1.1.4.1. Validating each individual on the roster once they arrive on-site and logging their passport ID number in the central resource system.

9.1.1.4.2. Capturing actual time of arrival in the central resource system.

9.1.1.4.3. Providing lodging and meal information, if available.

9.1.1.5. Damage Assessment Check-in Leader – or their designee, shall have overall responsibility for:

9.1.1.5.1. Instructing and assisting off-system damage assessors on how to download the mobile damage assessment application on their iPad or company loaned device.

9.1.1.5.2. Activating damage assessor log-in ID's in the central resource system.

9.1.1.5.3. Providing training on how to use the mobile application and contact information for questions once the assessors are in the field.

9.1.1.5.4. Removing access and retrieving loaned devices once the damage assessment crews are released.

9.1.1.6. Resource Pool Leader – or their designee, shall have overall responsibility for:

9.1.1.6.1. Serving as a repository for resource allocations;

9.1.1.6.2. Tracking available and unassigned personnel and business partner resources during restoration efforts;

9.1.1.6.3. Working with the Resource Leader to identify resource needs throughout the ICS;

9.1.1.6.4. Updating resource rosters to reflect assignments to roles in the ICS.

9.1.2. Activation

9.1.2.1. **Yellow Alert** – The Work Planning Section Chief, Operations Section Chief, and Incident Commander or their delegates shall have the authority to direct activation of Resource Planning whenever a Yellow Alert has been issued by the Incident Commander or their designee. Activation of Resource Planning shall be considered whenever a forecasted weather event or emergency is predicted to result in significant damages and a Level III or Level IV event is declared for any service area, where incremental resources, resident or non-resident, are brought in to assist with protect, restore, or repair activities. Activation may be required in advance of actual damages or outages, to support Operations in assuring available resources are accurately accounted for in the designated resource management database.

9.1.2.2. **Red Alert** - The Work Planning Section Chief, Operations Section Chief, and Incident Commander or their delegates shall have responsibility for activation of Resource

Planning whenever a Red Alert has been declared, and the event has been established as Level III or IV for any Operations area.

9.1.3. Business Processes

9.1.3.1. **Resource Tracking -** When Work Planning is activated, a Resource Tracking team will setup in a location designated by the Work Planning Section Chief. This team shall be responsible for tracking mutual assistance and other off-system resources that have committed to assisting in the restoration effort. Assigned Resource Tracking personnel will be responsible for making contact with designated contacts for each committed Company, to confirm crew counts, lodging requirements and estimated times of arrival, and to provide incoming resources with all necessary check-in location and other essential logistical information. All crew level information shall be entered into the Company's designated resource management database, including estimated arrival times and lodging requirements. Upon receiving crew rosters, assigned Resource Tracking personnel shall be responsible for entering detailed team member information into the designated resource management database.

The central phone number for Work Planning is listed in Appendix 10**,** and should be used to obtain resource information by all personnel unless otherwise designated by the Work Planning Section Chief**.** The central email address for the Resource Tracking team is **Storm.Resources@lge-ku.com.**

All calls made to Work Planning's central number will be forwarded to the Work Planning Section Chief's mobile phone when not under a Red Alert. Under Red Alert, and after activation of Work Planning, all calls regarding resource planning will be pushed to designated roll-over lines.

If Resource Tracking shuts down for the night, the designated central phone number must be forwarded to someone's cell phone until the day shift begins.

The designated central number and email address should be given to General Foremen as contact information while traveling. They must be manned and monitored at all times.

9.1.3.2. **Resource Check-In -** The Resource Check-in team is also activated as part of Work Planning. This team will co-locate with Safety at the location designated for safety training or “passporting” mutual assistance and other off-system crews as they arrive. The Resource Check-in team will validate each individual working on our system, will enter them into RoD if necessary and indicate their actual time of arrival.

If the check-in point does not have connectivity to the LG&E/KU network, a few personal WiFi devices are available and should be used by the Resource Check-in team(s). When you turn the device on, it will give you the network name and password. You will then need to connect your PC to this network. You will need power for prolonged use.

Refer to the job aid in Appendix 9.A as a guide on how to track mutual assistance and other off-system resources using Resources on Demand.

9.1.3.3. **Resource Pools -** In large events, there are tasks that can be delegated to every resource within the company willing to assist. These are tasks that do not require a deep understanding of the restoration process. A few examples would include working at staging sites distributing food, coordinating laundry service, and so on.

All “last minute” volunteers will be directed to the Resource Pool Leaders who will log their contact information and capabilities. Other leaders within the ICS structure needing this type of resource should contact the Resource Pool Leaders to identify resource needs and availability.

9.1.4. Training and Qualifications

9.1.4.1. **Resource Planning Directors** – the Work Planning Section Chief or their delegate(s) shall have responsibility for ensuring all personnel assigned Work Planning roles receive routine scheduled training which assures associated roles and responsibilities can be efficiently and effectively executed during Level III and IV events.

9.1.4.2. **Resource Leaders -** the Resource Planning Director or their delegate(s) shall have responsibility for ensuring all personnel assigned Resource Planning roles receive routine scheduled training which assures associated roles and responsibilities can be efficiently and effectively executed during Level III and IV events.

9.2. Mutual Assistance

Mutual assistance is an essential part of the Company's service restoration process and contingency planning. Restoring power after major storms, natural disasters, or other emergency events is a complex task, and speedy restoration requires significant logistical expertise, along with skilled workers and specialized equipment.

The electric industry's mutual assistance network serves as an effective and critical restoration resource for electric utilities because of its unique structure; it is both flexible and voluntary, empowering the network to quickly respond to major outage events in the industry. The primary goal of the network is to restore electric service in a safe, effective, and efficient manner. It also:

- Promotes the safety of employees, business partners, customers, and the public;
- Develops strong interdependent relationships among electric utilities;
- Provides a means for electric utilities to receive competent, trained employees and contractors from other experienced utilities;
- Provides predefined mechanisms for sharing industry resources expeditiously;
- Mitigates the risks and costs of member utilities related to major incidents;
- Proactively improves resource sharing during emergency conditions;
- Facilitates the sharing of best practices and technologies that help the electric industry prepare for, and respond to, emergencies;
- Enables a consistent, unified response to large scale emergency events.

The Company has developed a strong network of local and regional mutual assistance partnerships to enable swift and efficient responses to large scale outage events which exceed the capabilities of day-to-day Company resources and resident contractors. Through these partnerships, the Company is able to quickly increase the size of its workforce by accessing needed skilled labor resources and equipment from other utilities to assist with restoration efforts.

The procedures herein describe the mutual aid networks and procedures the Company shall utilize when sufficient resident and local resources are not adequate to safely and quickly restore service to customers and repair the electric delivery system.

9.2.1. Regional Mutual Assistance Groups

RMAGs are organized geographically to meet the needs of electric utility companies during large scale outages or other emergency situations. There are seven primary Investor Owned Utility RMAGs in the United States **(see the Edison Electric Institute's RMAG Map in Appendix 9.B):**

- Great Lakes Mutual Assistance Group (GLMA)
- Midwest Mutual Assistance Group (MMA)
- North Atlantic Mutual Assistance Group (NAMA)
- Southeastern Electric Exchange (SEE)
- Texas Mutual Assistance Group (TMA)
- Western Region Mutual Assistance Agreement (WRMA)
- Wisconsin Utilities Association Mutual Assistance Group (WUAMA)

LG&E and KU are members in the GLMA, MMA, and SEE RMAGs. **(See Appendix 9.C for primary mutual assistance contact information.)** The Incident Commander, Work Planning Section Chief, and Manager Electric Restoration Distribution, or their designee(s), shall be responsible for assuring the Company is adequately represented in all member RMAGs:

- Mutual assistance phone calls, whether the Company is requesting, releasing, or holding resources;
- Preparedness and planning meetings;
- Policy making decisions; and
- Reviews and responses to industry related information requests or policy/procedure reviews.

For national level events, when a *National Response Effort* has been designated by an EEI member utility, the Company shall designate GLMA as the primary RMAG for LG&E and KU. **(Please see Appendix 9.D for GLMA Group Governing Principles.)**

9.2.2. Mutual Assistance Agreements

The Company has entered into several formal mutual assistance agreements which outline the general guidelines and principles the Company and mutual assistance partners will follow when engaged in mutual assistance efforts. The Director Electric Distribution and System Restoration shall be responsible for reviewing and approving all proposed mutual assistance agreements, and for obtaining necessary reviews and approvals from Legal, Regulatory, Supply Chain, and the Vice President Electric Distribution.

9.2.2.1. Edison Electric Institute Mutual Assistance Agreement

EEI's *Suggested Governing Principles Covering Emergency Assistance Arrangements Between Edison Electric Institute Member Companies* **(see Appendix 9.E)** serve as the electric industry's foundation for describing and further developing RMAGs' mutual aid systems and business processes. These principles were developed to help EEI member utilities reduce and/or eliminate response delays and risks, and set expectations respective to pre-event, event, and post event modes, liability, and financial fairness. EEI routinely reviews and updates these principles from lessons learned and or best practices within the electric industry. EEI also maintains data on member companies who formally agree to the principles by signing their *Mutual Assistance Agreement* **(see Appendix 9.F)**.

Membership in the GLMA and MMA requires formal approval of the Edison Electric Institute Mutual Assistance Agreement. The Company signed the EEI Mutual Assistance 'Short Form' Agreement for LG&E and KU in 2006.

9.2.2.2. Southeast Electric Exchange Mutual Assistance Agreement

The SEE Mutual Assistance Committee developed, accepted, and is responsible for maintaining Mutual Assistance Procedures and Guidelines **(see Appendix 9.G)** that SEE members adhere to when engaged in mutual aid activities. LKE is a member of the SEE Mutual Assistance Committee and contributed to the development of these procedures.

LKE formally accepted (signed) SEE's *Statement of Understanding and Endorsement* **(See Appendix 9.H)** for LG&E and KU in 2005.

9.2.2.3. Pennsylvania Power and Light (PPL) Electric Utilities Mutual Assistance Agreement

The Company has entered into formal agreement with PPL Electric Utilities to follow a standard set of mutual assistance guidelines when engaged in mutual assistance with each other. The associated *Utility Services Agreement* is included in **Appendix 9.I**, and was signed by both Companies in October 2013. The principles of the agreement are based on the EEI Mutual Assistance Agreement.

9.2.2.4. Owensboro Municipal Utilities

The Company has entered into formal agreement with Owensboro Municipal Utilities to follow a standard set of mutual assistance guidelines when engaged in mutual assistance with each other. The associated *Mutual Aid Agreement* is included in **Appendix 9.J**. The principles of the agreement are based on the EEI Mutual Assistance Agreement, and were executed during 2013.

9.2.3. Regional Mutual Assistance Resource Requests

The Incident Commander, Work Planning Section Chief, Operations Section Chief or a designee shall be responsible for initiating/requesting a mutual assistance joint utilities conference call with the Company's designated Primary RMAG whenever incremental resources are needed from the Company's mutual assistance network. When making a request for resources, the designated requestor shall be prepared to provide the following information to the Primary RMAG:

- Number of workers (full time equivalents – FTE) needed by type;
  - Distribution Line Technicians
  - Transmission Line Technicians
  - Damage Assessors
  - Public Safety Responders
  - Vegetation Management Trimmers
  - Substation Technicians
  - Network Technicians
- Crew size specifications, if any;
- Equipment specifications, if any;
  - Bucket Truck
  - Material Handler
  - Digger Derrick
  - Light Duty Unit
  - Etc…
- Maximum traveling duration/distance; and,

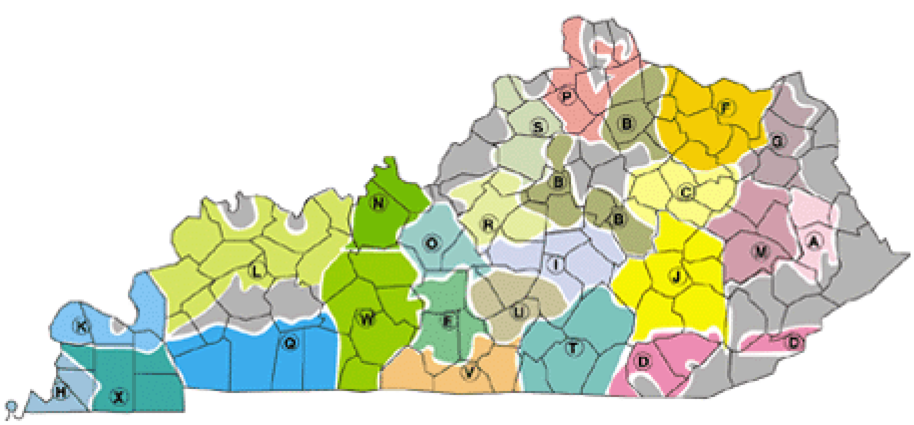
- Contractor, Union, or Non-Union requirements, if any.

If resource needs are satisfied by the Primary RMAG, then no additional resource requests shall be executed.

In the event the Primary RMAG cannot satisfy the resource needs of the Company, the Incident Commander, Work Planning Section Chief, or a designee shall request the primary RMAG to approach neighboring RMAGs to determine if additional assistance can be obtained through secondary member RMAGs. If resource needs cannot be satisfied through the Company's Primary and Secondary member RMAGs, and all other resource options have been exercised, the Incident Commander shall be responsible for requesting the Vice President – Electric Distribution to declare a National Response Effort with the Edison Electric Institute, per EEI's *National Response Event Structure and Principles Covering Mutual Assistance Arrangements between Edison Electric Institute Member Companies* **(see NRE Playbook at the following link: http://nre.groupsite.com/uploads/files/x/000/0ad/491/NRE_Playbook_September%202014%20updates%20ver%20x.pdf?1410788377).**

9.2.4. Kentucky Cooperatives

On occasion, the Company has utilized resources from Kentucky Electric Cooperatives (KEC) to assist with responding to large outage events and associated emergencies. There are 24 electric distribution cooperatives across Kentucky.



Distribution Cooperatives			
	CO-OP	HOME OFFICE	POWER SUPPLIER
A	Big Sandy RECC	Paintsville	EKPC
B	Blue Grass Energy	Nicholasville	EKPC
C	Clark Energy	Winchester	EKPC
D	Cumberland Valley Electric	Gray	EKPC
E	Farmers RECC	Glasgow	EKPC
F	Fleming-Mason Energy	Flemingsburg	EKPC
G	Grayson RECC	Grayson	EKPC
H	Hickman-Fulton Counties RECC	Hickman	TVA*
I	Inter-County Energy	Danville	EKPC
J	Jackson Energy Cooperative	McKee	EKPC
K	Jackson Purchase Energy Corporation	Paducah	Big Rivers
L	Kenergy	Henderson	Big Rivers
M	Licking Valley RECC	West Liberty	EKPC
N	Meade County RECC	Brandenburg	Big Rivers
O	Nolin RECC	Elizabethtown	EKPC
P	Owen Electric Cooperative	Owenton	EKPC
Q	Pennyrile Electric	Hopkinsville	TVA*
R	Salt River Electric	Bardstown	EKPC
S	Shelby Energy Cooperative	Shelbyville	EKPC
T	South Kentucky RECC	Somerset	EKPC
U	Taylor County RECC	Campbellsville	EKPC
V	Tri-County EMC	Lafayette, TN	TVA*
W	Warren RECC	Bowling Green	TVA*
X	West Kentucky RECC	Mayfield	TVA*

KEC has designated a single point of contact for requesting resources from and providing assistance to the KEC.

Appendix 9.C contains contact information for Municipal and Cooperative mutual assistance partners.

9.3. Finance and Accounting

Budgeting and Forecasting and Electric Distribution Operations have developed business procedures to ensure adequate financial and accounting information and processes are in place to accurately account for and forecast expenditures associated with significant outage events or emergencies involving the electric delivery system.

9.3.1. Roles and Responsibilities

9.3.1.1. Finance Director **–** or their designee, shall report to the Work Planning Section Chief, and be primarily responsible for ensuring proper accounting systems and processes are in place to track and report on emergency preparedness and response costs associated with significant outage events or emergencies. This position shall also be responsible for:

- Provide financial support to the Incident Commander, Section Chiefs, and Officers as requested;
- Establish an accurate and timely reporting and communication process for establishing charge numbers, and providing cost estimates; and
- Accumulate preparedness and response charges, and provide post-storm financial reporting.

Appendix 10.0 contains names, titles, and contact information for designated Finance Directors.

9.3.2. Activation

9.3.2.1. **Yellow Alert** – The Work Planning Section Chief or their designee shall be responsible for notifying the Finance Director of any issued Yellow Alerts.

9.3.2.2. **Red Alert** – The Work Planning Section Chief or their designee shall be responsible for notifying the Finance Director of any issued Red Alerts.

9.3.3. Business Processes

9.3.3.1. **Storm/Event Numbers –** The Finance Director shall be responsible for working with Operations and Retail and developing policies and procedures respective to the provision of accounting numbers for the purpose of charging all costs associated with preparedness for or response to a significant outage event or emergency. The Finance Director or their designee shall be responsible for advising affected Operations Centers of established project numbers within the first 24 hours of an event.

9.3.3.2. **Event Estimates –** The Financial Director or their designee shall be responsible for developing standard accounting processes, modeling tools, and timelines for calculating and reporting preparedness and response costs for significant events.

9.3.4. After Action Review – The Financial Director shall be responsible for coordinating an After Action Review with key Budgeting and Forecasting organizations and the EPRT following all significant outage events or emergencies, to identify, develop, and implement process improvement opportunities respective to IT support.

9.4. Asset Information

Asset Information and the Emergency Preparedness and Response Team (EPRT) have developed business procedures to ensure critical facility data and geographical information are readily available when the Company is preparing for or responding to a significant outage event or emergency involving the electric distribution system.

9.4.1. Roles and Responsibilities

Asset Information Director **–** or their designee, shall report to the Work Planning Section Chief, and be responsible for ensuring facility maps (electronic and hard copy), data, and records technician resources are readily available to support operations personnel responding to significant outage events and emergencies. **Appendix 10.0 contains contact information for Asset Information personnel.**

9.4.2. Activation

9.4.2.1. **Yellow Alert** – The Work Planning Section Chief or their designee shall be responsible for notifying the Asset Information Director of any issued Yellow Alerts.

9.4.2.2. **Red Alert** – The Work Planning Section Chief or their designee shall be responsible for notifying the Asset Information Director of any issued Red Alerts.

9.4.3. Business Processes

9.4.3.1. **Facility Records –** After receiving notice of a Yellow or Red Alert, the Asset Information Director shall be responsible for:

- Working with the Operations Managers of affected operations areas to identify geographical and facility information needs and sources;
- Working with Information Technology to ensure needed facility information and reporting systems are available and operating properly.
- Working with Operations Managers to efficiently allocate available Facility Records Technicians to impacted areas to assist with producing prints, collecting facility information, and pulling together Work Packets during Level III and IV events;
- Assist with pulling together circuit prints as needed for damage assessment inspections and post restoration and repair sweeps; and,
- Executing business processes which ensure documented field changes are updated in the appropriate geographical and facility information systems.

9.4.4. After Action Review – The Asset Information Director shall be responsible for coordinating an After Action Review with key Information Technology organizations and affected Operations areas to identify, develop, and implement process improvement opportunities respective to Asset Information support during emergencies.

9.5. Information Technology and Systems

Information Technology (IT) and the Emergency Preparedness and Response Team (EPRT) have developed business procedures to ensure critical information technology systems and processes are available and properly functioning when the Company is preparing for or responding to a significant outage event or emergency involving the electric distribution system.

9.5.1. Roles and Responsibilities

IT Director **–** or their designee, shall report to the Work Planning Section Chief, and be responsible for serving as the primary conduit between the business and IT during significant outage events or emergencies on the electric distribution system, and helping to ensure critical information systems and processes are available and properly functioning during preparation for or response to these significant events. **Appendix 10.0 contains contact information for key personnel in Information Technology.**

9.5.2. Activation

9.5.2.1. **Yellow Alert** – The IT Director or their designee shall have overall responsibility for appropriately responding to Yellow Alert Levels issued by the Incident Commander or their designee, including communicating to appropriate key leadership roles within IT, and being available to assist with associated needs during the Company's preparation for significant events.

9.5.2.2. **Red Alert** – The IT Director shall have overall responsibility for appropriately responding to Red Alert Levels issued by the Incident Commander or their designee, including communicating to appropriate key leadership roles within IT, and being available to assist with associated needs during the Company's response to significant events.

9.5.3. Business Processes

9.5.3.1. **IT Service Desk –** After receiving notice of a Yellow or Red Alert, IT Director shall ensure the IT Service Desk is advised of the alert status and staffed adequately. The IT Service Desk shall be responsible for ensuring adequate IT Support Technicians are placed on duty or standby, in accordance with IT's Responsibility Matrix. In some cases, IT Support Technicians shall be placed in key locations to work directly with end users. Additionally, the IT Service Desk should work with all necessary IT organizations and personnel to cease unnecessary maintenance, batch processing, development, patch installations, etc… on critical information systems, whenever these procedures could place the availability of the critical systems at risk.

9.5.3.2. **Mobile Command Trailer(s) -** If a Mobile Command Center (MCC) is needed, the Incident Commander or the Operations Section Chief shall notify IT Support, who will work with the appropriate departments and personnel within IT to contact and assign the necessary personnel to assist Operations with deployment and technical setup of the MCC.

9.5.4. After Action Review – The IT Director shall be responsible for coordinating an After Action Review with key Information Technology organizations and the EPRT following all significant outage events or emergencies, to identify, develop, and implement process improvement opportunities respective to IT support during emergencies.

EPRP Appendix 1 Introduction

LG&E KU Services
Emergency Preparedness, Planning, and Response Team

Position	Name	Title	Contact Information		
			Office	Cell	Home / Alt
Executive Sponsor	John Wolfe	VP Electric Distribution	[redacted]	[redacted]	[redacted]
Executive Sponsor	John Malloy	VP Customer Service	[redacted]	[redacted]	[redacted]
Executive Sponsor	Chris Whelan	Vice President Corporate Communications	[redacted]	[redacted]	[redacted]
Executive Sponsor	Robert Conroy	Vice President State Regulation and Rates	[redacted]	[redacted]	
Executive Sponsor	Tom Jessee	Vice President Transmission	[redacted]	[redacted]	[redacted]
Information Officer	Brian Phillips	Director Brand Adv Cust & Digtl Comm	[redacted]	[redacted]	
Information Officer	Natasha Collins	Director Media Relations	[redacted]	[redacted]	
Incident Commander	Steve Woodworth	Director Electric Distribution & System Restoration	[redacted]	[redacted]	[redacted]
Incident Commander	David Huff	Director Customer Energy Efficiency & Smart Grid	[redacted]	[redacted]	[redacted]
Customer Experience Section Chief	Cheryl Bruner	Director Customer Service and Marketing	[redacted]	[redacted]	[redacted]
Customer Experience Section Chief	Debbie Leist	Director Revenue Integrity	[redacted]	[redacted]	[redacted]
Logistics Section Chief	Butch Cockerill	Director Operating Services	[redacted]	[redacted]	[redacted]
Logistics Section Chief	Mark Schmitt	Director Supply Chain	[redacted]	[redacted]	[redacted]
Operations Section Chief	Beth McFarland	Director Asset Management	[redacted]	[redacted]	[redacted]
Operations Section Chief	Robby Trimble	Director Distribution Operations	[redacted]	[redacted]	[redacted]
Operations Section Chief	Keith Steinmetz	Director Transmission Operations	[redacted]	[redacted]	[redacted]
Safety Officer	Amanda Chambers	Manager ED and Transmission Safety	[redacted]	[redacted]	[redacted]
Safety Officer	Ken Sheridan	Director Safety & Technical Training	[redacted]	[redacted]	[redacted]
Work Planning Section Chief	Denise Simon	Director Reliability	[redacted]	[redacted]	[redacted]
Work Planning Section Chief	Shannon Montgomery	Director SAP Upgrade Project	[redacted]	[redacted]	
Emergency Preparedness and Response Manager	Keith Alexander	Emergency Preparedness and Response Manager	[redacted]	[redacted]	

Reg Generation / Transmission

Name	*Office*	*Pager*	*Mobile*	*Home*
VICE PRESIDENT - Transmission				
Tom Jessee	[redacted]		[redacted]	[redacted]
DIRECTOR - Transmission Strategy and Planning				
Chris Balmer	[redacted]		[redacted]	[redacted]
DIRECTOR - Transmission Operations				
Keith Steinmetz	[redacted]		[redacted]	[redacted]
MANAGER - Transmission Protection and Substation				
Brent Birchell	[redacted]		[redacted]	[redacted]
MANAGER - Transmission Policy and Tariffs				
Derek Rahn	[redacted]		[redacted]	[redacted]
MANAGER - System Control Center				
Ray Tompkins	[redacted]		[redacted]	[redacted]
MANAGER - Transmission Line Services				
Robby Trimble	[redacted]		[redacted]	[redacted]
MANAGER - EMS / CIP				
Richard Watson	[redacted]	[redacted]	[redacted]	[redacted]
MANAGER - Transmission Reliability Performance & Standards				
Keith Yocum	[redacted]		[redacted]	[redacted]
MANAGER - Transmission Reliability and Compliance				
Brad Young	[redacted]		[redacted]	[redacted]
WESTERN				
Daren Smiley	[redacted]		[redacted]	[redacted]
Brandon Crook	[redacted]		[redacted]	[redacted]
Tom Hines	[redacted]		[redacted]	[redacted]
BLUEGRASS				
Biff Campbell	[redacted]		[redacted]	[redacted]
Bryan Richerson	[redacted]		[redacted]	[redacted]
Tom Hines	[redacted]		[redacted]	[redacted]
CENTRAL				
Biff Campbell	[redacted]		[redacted]	[redacted]
Bryan Richerson	[redacted]		[redacted]	[redacted]
Tom Hines	[redacted]		[redacted]	[redacted]
MOUNTAIN & DOMINION POWER				
Allen Roper	[redacted]		[redacted]	[redacted]
Mike Mills	[redacted]		[redacted]	[redacted]
Tom Hines	[redacted]		[redacted]	[redacted]
LOUISVILLE GAS & ELECTRIC				
Mickey Grismer	[redacted]		[redacted]	

Troy Bess	[redacted]		[redacted]	
Tom Hines	[redacted]		[redacted]	

Emergency Preparedness and Response Plan
Review and Approval Schedule

		Review and Approval									
		R - Review; A - Approval; U - Update									
	Section	Executive Officers	Information Officer	Safety Officer	Incident Commander	Operations Section Chief	Customer Experience Section Chief	Logistics Section Chief	Work Planning Section Chief	Emergency Preparedness Manager	Review Frequency
0.0	**Table of Contents**				RA					RU	
1.0	**Introduction**				RA					RU	Annual
1.1	Emergency Preparedness and Response Alert Levels	RA			RA					RU	Annual
1.2	Event Levels	RA			RA					RU	Annual
1.3	Emergency Preparedness, Planning, and Response				RA					RU	Annual
1.4	Weather and System Monitoring				RA	RU				RA	Annual
2.0	**Emergency Notification Procedures**				RA	RU				RA	Annual
2.1	Kentucky Public Service Commission Notification Procedures				RA	RU				RA	Annual
2.2	Virginia State Corporation Commission Notification Procedures				RA	RU				RA	Annual
2.3	Internal Notification Procedures				RA					RU	Annual
3.0	**Incident Command Organization and Command Staff**				RA					RU	Annual
3.1	Command Staff	RA	RA	RA	RA	RA	RA	RA	RA	RU	Annual
3.2	Executive Officer	RA			RU						Annual
3.3	Information Officer		RA		RU						Annual
3.4	Safety Officer			RA	RU						Annual
3.5	Incident Commander				RU						Annual
3.6	Operations Section Chief				RU	RA					Annual
3.7	Customer Experience Section Chief				RU		RA				Annual
3.8	Logistics Section Chief				RU			RA			Annual
3.9	Work Planning Section Chief				RU				RA		Annual
4.0	**Safety**			RU	RA	RA					Annual
4.1	Passporting Off System Resources			RU	RA	RA					Annual
4.2	Independent Hold Card Procedures			RU	RA	RA					Annual
5.0	**Communications**		RU		RA	RA	RA				Annual
5.1	External Communications	RA	RU		RA	RA	RA				Annual
5.2	Internal Communications	RA	RA	RA	RU	RA	RA	RA	RA	RA	Annual
5.3	Yellow and Red Alert Conference Calls	RA	RA	RA	RU	RA	RA	RA	RA	RA	Annual
6.0	**Operations Section**				RA	RU					Annual
6.1	Resource Management				RA	RU					Annual
6.2	Distribution Control Center				RA	RU					Annual
6.3	Public Safety Response Team			RA	RA	RU					Annual
6.4	Damage Assessment				RA	RU					Annual
6.5	Transmission Operations				RA	RU					Annual
6.6	Estimated Restoration Times	RA	RA		RU	RA	RA	RA		RA	Annual
6.7	Conservative Operations				RA	RU					Annual
7.0	**Customer Experience Section**				RA	RA	RU				Annual
7.1	Critical Customer Care				RA		RU				Annual
7.2	Call Centers				RA		RU				Annual
7.3	Business Offices				RA		RU				Annual
7.4	Ombudsman Team				RA		RU				Annual
7.5	Emergency Management Outreach				RA		RA			RU	Annual
8.0	**Logistics Section**				RA	RA		RU			Annual
8.1	Supplies				RA	RA		RU			Annual
8.2	Human Resources Support				RU	RA		RA			Annual
8.3	Facilities and Staging Areas				RA	RA		RU			Annual
9.0	**Work Planning Section**				RA	RA			RU		Annual
9.1	Resource Planning				RA	RA			RU		Annual
9.2	Mutual Assistance				RA	RA			RU		Annual
9.3	Finance and Accounting				RA	RA			RU		Annual
9.4	Asset Information				RA	RA			RU		Annual
9.5	Information Technology and Systems				RA	RA			RU		Annual
Appendix											
1.0	**Introduction**										
1.3.i	EPRT Team Members				RA					RU	Biannual
1.3.ii	EPRP Review and Approval Schedule				RA					RU	Annual
1.3.iii	EPRP Training Schedule Matrix				RA					RU	Annual
1.3.iv	Emergency Exercise Objectives, Description, and Results Form				RA					RU	Annual
1.3.v	After Action Review Form				RA					RU	Annual
2.0	**Emergency Notification Information**										
2.1	KY PSC Notifications - Internal Reporting List				RA	RU					Biannual
2.2	VA SCC Notifications - Internal Reporting List				RA	RU					Biannual
2.3	Internal Notification/Emergency Response Guide				RA	RU					Biannual
3.0	**Incident Command Structure**										
3.1	Incident Command - Command Staff Contact Information				RA					RU	Biannual
3.2	Incident Command Sections - Alert Level Tasks	RU	RU	RU	RU	RU	RU	RU	RU	RU	Annual
4.0	**Safety Information**										
4.1	Safety Passport Orientation Handbook			RU	RA	RA					Annual
4.2	Independent Hold Card Procedures			RU	RA	RA					Annual
5.0	**Communications Information**										
5.3	LG&E-KU Emergency Conference Call Matrix				RU						Annual

Emergency Preparedness and Response Plan
Review and Approval Schedule

	Section	Review and Approval *R - Review; A - Approval; U - Update*									Review Frequency
		Executive Officers	Information Officer	Safety Officer	Incident Commander	Operations Section Chief	Customer Experience Section Chief	Logistics Section Chief	Work Planning Section Chief	Emergency Preparedness Manager	
6.0	**Operations Section Information**										
6.1	Resource Management Room Configuration Guide				RA	RU					Annual
6.2	Distribution Control Center Alert Level Task Lists					RU					Annual
6.3	Public Safety Response Team/Damage Assessment Emergency Response Process Flow			RA	RA	RU					Annual
7.0	**Customer Experience Information**										
7.1	Municipal Customer Key Contact Information						RU				Biannual
7.4.i	External Emergency Management Outreach Contact Information									RU	Biannual
7.4.ii	Emergency Management Outreach Alert Level Tasks									RU	Annual
8.0	**Logistics Information**										
8.1.i	Supply Chain Emergency Response Alert Task Lists							RU			Annual
8.1.ii	Native EDO Contractor Contact Information							RU			Biannual
8.1.iii	Non-Native Contractor Listing and Contact Information							RU			Biannual
8.1.iv	Emergency Response Material Logistics							RU			Annual
8.1.v	Storeroom Locations and Key Contact Information							RU			Biannual
8.1.vi	Storm Kit Locations, Quantities, and Inventories							RU			Annual
8.1.vii	Storm Service Kit Locations, Quantities, and Inventories							RU			Annual
8.1.viii	Storm Trailer Inventory							RU			Annual
8.1.ix	Vehicles and Equipment Key Contact Information							RU			Annual
8.1.x	Emergency Restaurant Setup Procedures							RU			Annual
8.3.i	Key Facility and Staging Contact Information							RU			Biannual
8.3.ii	Staging and Facilities Alert Level Task Lists							RU			Annual
8.3.iii	Staging Area Locations and Site Maps							RU			Annual
9.0	**Work Planning Information**										
9.1.i	Resource on Demand Job Aid								RU		Annual
9.1.ii	Work Planning Alert Level Task Lists								RU		Annual
9.2.i	EEI Investor Owned RMAGs Map								RU		Annual
9.2.ii	Primary Mutual Assistance Group Contacts				RU						Biannual
9.2.iii	Great Lakes Mutual Assistance Governing Principles				RU						Annual
9.2.iv	EEI Suggested Governing Principles Covering Emergency Assistance Arrangements				RU						Annual
9.2.v	EEI Mutual Assistance Agreement				RU						Annual
9.2.vi	Southeast Electric Exchange Mutual Assistance Guidelines				RU						Annual
9.2.vii	Southeast Electric Exchange Mutual Assistance Agreement				RU						Annual
9.2.viii	Pennsylvania Power and Light (PPL) Mutual Assistance Agreement				RU						Annual
9.2.ix	Owensboro Municipal Mutual Assistance Agreement				RU						Annual
10.0	**EPRP Contact Information**										
10.1	EPRP Contact Information	RU	RU	RU	RU	RU	RU	RU	RU	RU	Biannual

Emergency Preparedness and Response Plan
Plan Review, Training, and Exercise Schedule

		Incident Command Sections									
		R - Review Procedure; T - Train on Associated Emergency Processes; E - Exercise Emergency Processes									
	Section	Executive Officers	Information Officer	Safety Officer	Incident Commander	Operations Section Chief	Customer Experience Section Chief	Logistics Section Chief	Work Planning Section Chief	Emergency Preparedness Manager	Training Frequency
0.0	**Table of Contents**										
1.0	**Introduction**										
1.1	Emergency Preparedness and Response Alert Levels	R	R	R	R	R	R	R	R	R	Annual
1.2	Event Levels	R	R	R	R	R	R	R	R	R	Annual
1.3	Emergency Preparedness, Planning, and Response	R	R	R	R	R	R	R	R	R	Annual
1.4	Weather and System Monitoring	R	R	R	R	R	R	R	R	R	Annual
2.0	**Emergency Notification Procedures**										
2.1	Kentucky Public Service Commission Notification Procedures	R	R	R	R	R	R	R	R	R	Annual
2.2	Virginia State Corporation Commission Notification Procedures	R	R	R	R	R	R	R	R	R	Annual
2.3	Internal Notification Procedures	R	R	R	R	R	R	R	R	R	Annual
3.0	**Incident Command Organization and Command Staff**										
3.1	Command Staff	R	R	R	R	R	R	R	R	R	Annual
3.2	Executive Officer	R			R					R	Annual
3.3	Information Officer		R		R					R	Annual
3.4	Safety Officer			R	R					R	Annual
3.5	Incident Commander				R					R	Annual
3.6	Operations Section Chief				R	R				R	Annual
3.7	Customer Experience Section Chief				R		R			R	Annual
3.8	Logistics Section Chief				R			R		R	Annual
3.9	Work Planning Section Chief				R				R	R	Annual
4.0	**Safety**										Annual
4.1	Passporting Off System Resources			R,T	R,T	R,T					Annual
4.2	Independent Hold Card Procedures			R,T	R,T	R,T					Annual
5.0	**Communications**										Annual
5.1	External Communications		R,T		R,E					R,E	Annual
5.2	Internal Communications				R,E					R,E	Annual
5.3	Yellow and Red Alert Conference Calls	R,E	R,E	R,E	R,E	R,E	R,E	R,E	R,E	R,E	Annual
6.0	**Operations Section**										Annual
6.1	Resource Management				R,E	R,T,E					Annual
6.2	Distribution Control Center				R,E	R,T,E					Annual
6.3	Public Safety Response Team				R,E	R,T,E					Annual
6.4	Damage Assessment				R,E	R,T,E					Annual
6.5	Transmission Operations				R,E	R,T,E					Annual
6.6	Estimated Restoration Times				R,E	R,T,E	R,E		R,E		Annual
6.7	Conservative Operations				R,E	R,T,E					Annual
7.0	**Customer Experience Section**										Annual
7.1	Critical Customer Care						R,T				Annual
7.2	Call Centers						R,T				Annual
7.3	Business Offices						R,T				Annual
7.4	Ombudsman Team						R,T				Annual
7.5	Emergency Management Outreach									R,T,E	Annual
8.0	**Logistics Section**										Annual
8.1	Supplies				R,T,E	T,E		R,T,E			Annual
8.2	Human Resources Support										Annual
8.3	Supplies				R,T,E	T,E		R,T,E		R,E	Annual
9.0	**Work Planning Section**										Annual
9.1	Resource Planning				R,T,E	R,T,E		T,E	R,T,E		Annual
9.2	Mutual Assistance				R,T,E	R,T,E		T,E	R,T,E		Annual
9.3	Finance and Accounting								R,T,E		Annual
9.4	Asset Information								R,T,E		Annual
9.5	Information Technology and Systems								R,T,E		Annual
Appendix											
1.0	**Introduction**										
1.3.i	EPRT Team Members	R	R	R	R	R	R	R	R	R	Annual
1.3.ii	EPRP Review and Approval Schedule	R	R	R	R	R	R	R	R	R	Annual
1.3.iii	EPRP Training Schedule Matrix	R	R	R	R	R	R	R	R	R	Annual
1.3.iv	Emergency Exercise Objectives, Description, and Results Form	R,E	R,E	R,E	R,E	R,E	R,E	R,E	R,E	R,E	Annual
1.3.v	After Action Review Form	R,E	R,E	R,E	R,E	R,E	R,E	R,E	R,E	R,E	Annual
2.0	**Emergency Notification Information**										
2.1	KY PSC Notifications - Internal Reporting List					R					Annual
2.2	VA SCC Notifications - Internal Reporting List					R					Annual
2.3	Internal Notification/Emergency Response Guide	R,E	R,E	R,E	R,E	R,E	R,E	R,E	R,E	R,E	Annual
3.0	**Incident Command Structure**										
3.1	Incident Command - Command Staff Contact Information	R	R	R	R	R	R	R	R	R	Annual
3.2	Incident Command Sections - Alert Level Tasks	R,E	R,E	R,E	R,E	R,E	R,E	R,E	R,E	R,E	Annual

Emergency Preparedness and Response Plan
Plan Review, Training, and Exercise Schedule

		Incident Command Sections: *R - Review Procedure; T - Train on Associated Emergency Processes; E - Exercise Emergency Processes*									
	Section	Executive Officers	Information Officer	Safety Officer	Incident Commander	Operations Section Chief	Customer Experience Section Chief	Logistics Section Chief	Work Planning Section Chief	Emergency Preparedness Manager	Training Frequency
4.0	**Safety Information**										
4.1	Safety Passport Orientation Handbook			R,E	R,E	R,E					Annual
4.2	Independent Hold Card Procedures			R,T,E	R,T,E	R,T,E					Annual
5.0	**Communications Information**										
5.3	LG&E-KU Emergency Conference Call Matrix	R,E	R,E	R,E	R,E	R,E	R,E	R,E	R,E	R,E	Annual
6.0	**Operations Section Information**										
6.1	Resource Management Room Configuration Guide					R,E		R,E			Annual
6.2	Distribution Control Center Alert Level Task Lists					R,T,E					Annual
6.3	Public Safety Response Team/Damage Assessment Emergency Response Process Flow					R,T,E					Annual
7.0	**Customer Experience Information**										
7.1	Municipal Customer Key Contact Information					R	R			R	Annual
7.4.i	External Emergency Management Outreach Contact Information						R			R	Annual
7.4.ii	Emergency Management Outreach Alert Level Tasks						R,T,E			R,T,E	Annual
8.0	**Logistics Information**										
8.1.i	Supply Chain Emergency Response Alert Task Lists							R,T,E			Annual
8.1.ii	Native EDO Contractor Contact Information							R			Annual
8.1.iii	Non-Native Contractor Listing and Contact Information							R			Annual
8.1.iv	Emergency Response Material Logistics							R			Annual
8.1.v	Storeroom Locations and Key Contact Information							R			Annual
8.1.vi	Storm Kit Locations, Quantities, and Inventories							R			Annual
8.1.vii	Storm Service Kit Locations, Quantities, and Inventories							R			Annual
8.1.viii	Storm Trailer Inventory							R			Annual
8.1.ix	Vehicles and Equipment Key Contact Information							R			Annual
8.1.x	Emergency Restaurant Setup Procedures							R			Annual
8.3.i	Key Facility and Staging Contact Information							R			Annual
8.3.ii	Staging and Facilities Alert Level Task Lists							R,T,E			Annual
8.3.iii	Staging Area Locations and Site Maps							R			Annual
9.0	**Work Planning Information**										
9.1.i	Resource on Demand Job Aid								R,T,E		Annual
9.1.ii	Work Planning Alert Level Task Lists								R,T,E		Annual
9.2.i	EEI Investor Owned RMAGs Map				R	R			R		Annual
9.2.ii	Primary Mutual Assistance Group Contacts				R	R			R		Annual
9.2.iii	Great Lakes Mutual Assistance Governing Principles				R	R			R		Annual
9.2.iv	EEI Suggested Governing Principles Covering Emergency Assistance Arrangements				R	R			R		Annual
9.2.v	EEI Mutual Assistance Agreement				R	R			R		Annual
9.2.vi	Southeast Electric Exchange Mutual Assistance Guidelines				R	R			R		Annual
9.2.vii	Southeast Electric Exchange Mutual Assistance Agreement				R	R			R		Annual
9.2.viii	Pennsylvania Power and Light (PPL) Mutual Assistance Agreement				R	R			R		Annual
9.2.ix	Owensboro Municipal Mutual Assistance Agreement				R	R			R		Annual
10.0	**EPRP Contact Information**										
10.1	EPRP Contact Information	R,E	R,E	R,E	R,E	R,E	R,E	R,E	R,E	R,E	Annual

Emergency Preparedness and Preparedness - Key Roles Training Matrix

	Incident Commander	Safety Officer	Safety Lead	Information Officer	Information Center Coordinator	On-Call Communications Representative	Operations Section Chief	Operations (Resource) Manager	Vegetation Management Resource Leader	Vegetation Management Job Coordinator	Work Prioritization Leader	Work Assignment Coordinators	Safety Lead	Administration Lead	Network Management Administrator	PSRT Manager	PSRT Team Leader	PSRT Dispatcher	PSRT Wire Walker	PSRT Wire Sitter	Damage Assessment Lead	DCC Manager	Customer Experience Section Chief	Critical Customer Director	Major Accounts Representative	Municipal Customer Lead	Ombudsman Team	Call Center Director	Business Call Center Lead	Residential Call Center Lead	Business Office Director	Business Office Manager	Emergency Management Outreach Director	EOC Representatives	Logistics Section Chief	Supply Chain Restoration Coordinator	Area Lead	Food Coordinator	Material Coordinator	Lodging Coordinator	Logistics Coordinator/Interface	Transportation/Fuel Coordinator	Facility Director	Staging Leader	Facility Maintenance Leader	Security Leader	Work Planning Section Chief	Financial Director	Information Technology Director	Asset Information Director	Resource Planning Director	Resource Leader	ERT Leader	Resource Pool Leader
Executive Officer																																																						
Safety and Technical Training																																																						
Safety/Training Manager																																																						
Safety/Training Specialist																																																						
Corporate Communications																																																						
On-Call Communications Representative																																																						
Information Center Coordination																																																						
Corporate Communications Personnel																																																						
Electric Distribution Operations																																																						
Operations Manager																																																						
Operations Group Leaders																																																						
Operations Team Leaders																																																						
Line Technicians																																																						
Restoration Coordinator																																																						
Records Coordinators																																																						
Design Team Leaders																																																						
Design Technicians																																																						
Electrical Engineers																																																						
Network Technicians																																																						
C&M Mechanics																																																						
Asset Information Group Leader																																																						
Facility Records Technician																																																						
Restoration Coordinator																																																						
Data Analyst																																																						
Forecasting and Budgeting																																																						
Supply Chain																																																						

Emergency Preparedness an

	Passporting Off System Resources	Independent Hold Card Procedures	Resource Management	Distribution Control Center	Public Safety Response Team	Damage Assessment	Transmission Operations	Estimated Restoration Times	Conservative Operations	Critical Customer Care	Call Centers	Business Offices	Ombudsman Team	Emergency Management Outreach	Supplies	Supplies	Resource Planning	Mutual Assistance	Finance and Accounting	Asset Information	Information Technology and Systems	External Communications

EMERGENCY EXERCISE OBJECTIVES, DESCRIPTIONS, AND EXERCISE FORM

TITLE PAGE

EXECUTIVE SUMMARY

1. PURPOSE
2. MAJOR STRENGTHS
3. PRIMARY AREAS FOR IMPROVEMENT
4. CONCLUSION

EXERCISE OVERVIEW

1. EXERCISE NAME
2. EXERCISE DATE
3. SCOPE
4. PURPOSE
5. OBJECTIVES
6. SENARIO DESCRIPTION
7. PARTICIPATING GROUPS

IMPROVEMENT PLAN

CORE CAPABILITY	Issue/Area for Improvement	Corrective Action	Responsible Part	Start Date/Completion Date

After Action Review

Event: **Event Date:**

What went well (list three):

1. ______________________________

2. ______________________________

3. ______________________________

Things that did NOT go well (list three):

1. ______________________________

2. ______________________________

3. ______________________________

Comments/Suggestions to Improve:

1. ______________________________

2. ______________________________

3. ______________________________

4. ______________________________

5. ______________________________

Name: ______________ **Role:** ______________ **Date:** ______________

Please return Completed form(s) to the Emergency Planning & Preparedness Manager, Keith Alexander, via email at [redacted], or via house-mail (BOC I). Submitted forms will be reviewed by the Emergency Preparedness and Response Team for to identify and act on improvement opportunities.

EPRP Appendix 2 Emergency Notification Information

PPL companies

Internal Notification/ Emergency Response Guide

This is only a guide and does not take the place of any specialized training or official publications or communications containing governmental regulations and/or laws.

Mandatory/Immediate Incident Notification Procedures

*In order to meet external safety and regulatory requirements, LG&E and KU corporate policy mandates that the following incidents be **reported immediately** to each of the following: LG&E, KU or ODP incident investigators, safety contacts and the Corporate Law Department. All parties must be notified as soon as practicable via direct telephone or face-to-face conversations. Voice mail and/or e-mail messages are not acceptable forms of notification. These incidents include any that involve:*

- Death.
- Electrical shock.
- Burns requiring off-site medical attention.
- An injury requiring local EMS/helicopter transport.
- Exposure requiring extensive decontamination.
- An injury or fatality as a result of fire.
- Any public injury.
- Any incident with multiple injuries, regardless of extent.
- Any event requiring significant work stoppage.
- An event requiring an evacuation of a facility.
- A natural gas explosion.
- An unintentional ignition of natural gas.
- A fire at an LG&E, KU or ODP facility, where an outside fire service has been notified.
- A spill with a reportable amount, or if it is not known that the spill is less than a reportable amount.
- Electrical outages of 50,000 or more customers for ***one hour or more***. — U.S. Dept. of Energy (DOE)
- Actual or suspected physical attacks that could impact electric power system adequacy or reliability, or vandalism which targets components of any security system. — DOE
- Actual or suspected cyber or communications attacks that could impact electric power system adequacy or vulnerability. — DOE
- Electrical outages of 500 or more customers for four or more hours. — Kentucky Public Service Commission (KPSC)

- Natural gas outages of 40 or more customers for four or more hours.
- Where there is $25,000 in damage or theft. — KPSC
- Where there is $3,000 in damage or theft. — (Indiana) IURC
- Any incident requiring notification to the KPSC.
- Any incident requiring notification to the IURC.
- Any incident requiring notification to the USDOT.
- Any incident which, in the opinion of personnel on the scene, is significant.

Sabotage Reporting

- Employees and contract employees must report incidents of actual or suspected sabotage by calling the Corporate Security Control Center 24/7 at 502-627-2222.
- Sabotage is broadly defined as disturbances or unusual occurrences intended to cause failure, disruption or harm to the normal business activities, property or operations of LG&E, KU or ODP.
- Employees will be alerted when an incident has occurred somewhere in the company and advised to take appropriate actions, or they may call 866-370-7711 (toll free) or 502-627-4141 for information.

Investigation Contacts

Immediately contact Keith McBride, who has primary responsibility for all investigations. If he is unavailable, Corporate Law will direct one of the following to investigate:

- Brian Claypool
- Risk Management Services (primarily for theft and auto accidents).
- Corporate Law (accidents involving death, serious injury, fire, explosion or any significant incident).

Contact Barbara Hawkins, Manager, Corporate Health and Safety, in the event of an OSHA investigation, or an incident — such as an employee injury or possible hazardous exposure — prompts further OSHA investigation.

Contact Phil Noble regarding any fatality or newsworthy event for purposes of reporting under the company's Crisis Management Policy.

Media Contact

Inform LG&E and KU Corporate Communications of any incident with the potential to receive media coverage or where media are present or expected to be present.

Ky. PSC: 502-564-3940/502-564-1582 Fax

Contact (Electric)	Office	Cell
Steve Kingsolver	[redacted]	[redacted]
Jeff Moore	[redacted]	[redacted]
Eric Bowman	[redacted]	[redacted]

Contact (Gas)	Office	Personal	Cell
Bill Aitken	[redacted]		
Jason Brangers			
Melissa Holbrook			
Steve Samples			
Joel Grugin			
Kimra Cole			

Notification to the KPSC voice mailbox will ***not*** be considered proper notification.

U.S. Department of Transportation

Contact	Office
Reporting Line	800-424-8802

Indiana Utility Regulatory Commission

Contact	Office	Cell
William Boyd	[redacted]	[redacted]

Occupational Safety & Health

Ky. OSHA Division of Compliance	Federal OSHA Hotline
502-564-3535	800-321-6742

LG&E/KU Environmental Dept.

Contact	Office	Cell	Home
Sherry Pryor	[redacted]		
Paul Puckett			
Roger Medina			
Chem-trec	800-424-9300		

Environmental Regulatory Agencies

Ky. Dept. for Environmental Protection (if call forwards to KYDEM, be sure to make both notifications)	800-928-2380
Kentucky Division of Emergency Management (KyDEM, EHS ≥ RQ)	800-255-2587
National Response Center (Waterways, spec. PCBs, hazardous chemicals ≥ RQ)	800-424-8802
Indiana Dept. of Environmental Management	888-233-7745
Virginia Dept. of Emergency Management	800-468-8892
USEPA Region IV (KY.: PCBs ≥ 500 ppm or > 1 #PCB)	404-562-8700
USEPA Region III (VA.: PCBs ≥ 500 ppm or > 1#PCB)	215-814-9016
USEPA Region V (IN.: PCBs ≥ 500 ppm or > 1#PCB)	312-353-2318

Other Emergency Contacts

Contact	Office	Home	Other	Pager	Cell
Public Emergency Response	911				
Safety Dept. (24 hour)	502-333-1754				
Keith McBride (Company Investigator)	[redacted]			[redacted]	[redacted]
Ken Sheridan (Safety; KPSC/DOT Contact)	[redacted]			[redacted]	[redacted]
Doug Chin (H&S)	[redacted]	[redacted]			[redacted]
Brian Claypool	[redacted]				[redacted]
Troy Bess (Team Ldr., Transmission)	[redacted]				[redacted]
Amanda Chambers (H&S — Transmission)	[redacted]				[redacted]
Corp. Communications Dept.	502-627-2911			502-627-2911	
Corporate Law Dept.	502-627-3450			502-627-3444 [1]	
Jay Warren — Sr. Corporate Attorney	[redacted]				[redacted]
Greg Cornett — Assoc. Gen. Counsel	[redacted]				[redacted]
Corporate Security (main number)	502-627-2440				
Security Control Center	502-627-2222				
Phil Noble	[redacted]				[redacted]
Risk Management Services	800-372-5402				502-326-5900
Lou. Distribution Control Center	502-627-3366				
LG&E Gas Emergency Operations	502-627-4816 502-627-4362				
Lex. Distribution Control Center	859-367-1138				
Barbara Hawkins (Health & Safety)	[redacted]	[redacted]			[redacted]

1) Mark urgent/high priority.

KPSC Notification — Criteria

Notifications must be made within two hours following incident discovery.

- Gas: Fire/explosion, unintentional ignition.
- Electric: Injury, shock or burn requiring medical treatment at a hospital.
- Gas or electric: Death or any injury that requires hospitalization (admitted overnight).
- Gas or electric: Damage or theft of property (over $25,000).
- Gas: Any newsworthy incident.
- Interruption of service: Electric, 500 customers; gas, 40 customers over four hours.

KPSC Notification — Procedures

- Energy Delivery: Notify Ken Sheridan, Keith McBride or Brian Claypool.
- Energy Services: Notify Doug Chin, Ken Sheridan, Keith McBride or Brian Claypool.
- Transmission: Notify Troy Bess, Doug Chin, Ken Sheridan, Keith McBride or Amanda Chambers.

In the event none of the above is available, Corporate Law is responsible for any regulatory notification. As required, Ken Sheridan, Keith McBride and Doug Chin are responsible for DOT notification.

KPSC Outage Notification

- KU/ODP — Donna Goodrich
- LG&E electric — Charlie Hudson
- LG&E natural gas — Brian Claypool

Notify Corporate Law about ***all*** official KPSC notifications.

KOSHA Division of Compliance Notification — Criteria

- Gas or electric: Death or hospitalizations (admitted overnight) involving three or more employees in the same event. Notification must be made within eight hours of the event or hospitalizations.
- Gas or electric: Amputations or hospitalizations involving less than three employees (admitted overnight). Notification must be made within 72 hours of the event or hospitalization.

KOSHA Notification — Procedures

- Energy Delivery: Notify Keith McBride or Ken Sheridan.
- Energy Services: Notify Keith McBride or Doug Chin.
- In the event McBride, Sheridan or Hosmer are unavailable, ***Corporate Law*** is responsible for KOSHA notification.

U.S. Department of Transportation (Natural Gas Pipelines)

Notice of the following shall be made to the USDOT by telephone "at the earliest practicable moment" followed by a written report within 30 days (obtain form from Corporate Law):

- An event that involves a release of gas from a pipeline AND one of the following:
  — a death or personal injury necessitating inpatient hospitalization; or
  — estimated property damage, including cost of gas loss, of $50,000 or more.
- An event that is significant in the judgment of the operator.

Indiana Utility Regulatory Commission (Gas) Notification — Criteria

(Applies to LG&E underground natural gas storage fields in Indiana.)

Incident Reports. All incidents shall be reported to the IURC Pipeline Safety Division by telephone or electronic submission at the earliest practicable moment following discovery. This notification shall be followed by a written report upon request by the division within 20 days of the request.

An incident is defined as an event that:

- involves a release of gas from a pipeline, and
  — a death, or personal injury necessitating inpatient hospitalization; or
  — estimated property damage, including cost of gas lost, of the operator or others, or both, of $50,000 or more;
- deemed significant by the operator, such as situations involving
  — media attention;

— high-profile locations;
— large evacuations; or
— the possibility of recurrence.

(Refer to 170 IAC 5-3 section 0.5(b)(6) and section 4; LG&E OM&I procedure Gathering Data for Part 191 Incident Reporting.)

Indiana Underground Regulatory Commission (Gas) Notification — Procedures

Notify Ken Sheridan, Keith McBride or Brian Claypool. They perform telephonic notification to the IURC. In the event none are available, Corporate Law is responsible for any regulatory notification. Corporate Law is responsible for filing follow up written reports. Peter Clyde should be informed of notifications made to the IURC and provided copies of written reports submitted.(Details are outlined in LG&E OM&I procedure GN-GD-001 Gathering Data for Part 191 Incident Reporting.)

Critical Incident Reporting to PPL by LG&E and KU

In the event of a serious safety or security incident at LG&E or KU, the notification protocol to PPL is as follows:

1. In the event of an employee or contractor injury or security incident ***that must be reported to a regulatory authority***, contact:
   a. For employee or contractor injury — Barbara Hawkins
   b. Security incident — Phil Noble, or
   c. The respective delegate(s), and confirm that all internal notifications have been completed.*
2. PPL notification will be made by Barbara or Phil to the PPL Security Command Center. Notification timing may vary based on severity and circumstances of the incident, but notification to PPL should be made within 24 hours of reporting to a regulatory authority.
3. PPL Security Command Center personnel will then follow their internal notification protocol.

*The notification process to PPL ***involves no changes to current internal reporting processes***.

Environmental: Spill/Release Response

With transformer oil, petroleum product or hazardous chemical releases, take the following actions.

- Identify spilled substance, spill source and affected area.
- Call supervisor.
- Stop/contain the spill if trained or qualified to do so.
- Notify local emergency response contacts. Call 911 (or alternate number) if spill triggers Reportable Quantity (RQ), for example, a 25-gallon oil spill or any oil sheen on water, etc. Supervisor or dispatch must make a call if contacted ***within 15 minutes***.
- Notify LG&E and KU environmental contacts and regulatory authorities. If contacted within 15 minutes, LG&E and KU environmental personnel will make additional required notifications. Otherwise, site personnel must make notifications.

Spill Information Required

When a potentially hazardous spill has occurred, the following information must be reported ASAP.

- Name/position of person reporting.
- Spill area description.
- Spill location, source and cause.
- Time of spill/incident.
- Material involved (such as PCB content).
- Corrective action taken.
- Estimated spill size/quantity released.

Asbestos Emergency Guidelines

An asbestos emergency is defined as an exposure to Asbestos Containing Materials (ACM) or other material that has not been tested and possibly contains asbestos materials. ACM can be found in:

- Floor and ceiling tiles.
- Thermal insulating materials.
- Brake and clutch assemblies.
- Pipe coating.
- Old control wiring insulation.

- Transite panels.
- Roofing materials.
- Mastics/adhesives.
- Thermal seals and gaskets.

Spill Clean-up and Response

In a case where an exposure to a possible ACM occurs, the following actions must be taken immediately.

- Assume material is asbestos.
- Notify supervisor or manager.
- Keep others away from spill (barricades, etc.).
- Shut down equipment as needed.
- Identify the extent of release and establish regulated area.
- Contact the assigned safety/technical training consultant for sampling of material to confirm if the material contains asbestos.

Post-Accident Drug/Alcohol Testing

Company policy requires post-accident testing when:

- Safety equipment/protection procedures are not followed.
- Employee behavior or actions could be a factor.
- Company vehicle is involved and there is potential for litigation.
- Vehicular accident occurs, and the employee is issued a moving-traffic violation citation.

49 CFR Part 382.303 — Post Accident Testing

A DOT drug and alcohol screening is required when a CDL driver is in a commercial vehicle involved in a vehicular accident, ***and***

1. a fatality occurs.
2. a citation is received, ***and***
   a. immediate medical treatment is required away from the scene, ***and/or***
   b. one or more vehicles are towed.

Any fatality involving a commercial vehicle requires a DOT drug and alcohol screening.

If there is no fatality, the next criterion we look at is ***citation***.

If ***no*** citation is given at the scene of the accident, ***no DOT post-accident testing is performed;*** however, a company policy drug and alcohol screen may be required.

If a ***citation*** is given at the scene of the accident ***and*** immediate medical treatment is required away from the scene ***and/o***r one or more vehicles are towed, DOT post-accident drug and alcohol screens are performed.

49 CFR Part 191.3, 199.3, and 199.105 — Post Accident Testing

A DOT drug and alcohol screening is required when a PHMSA covered employee is involved in the occurrence of:

- a PHMSA (199) even where gas is released from a pipeline; or
- death or personal injury requires in-patient hospitalization; or
- property damage of $50,000, including the cost of gas lost; or
- a newsworthy event; or
- a KPSC reportable accident.

DOT Time Limitations for Post-Accident Testing

- Alcohol screening should occur within two hours, with attempts up to eight hours. Cease attempt after 8 hours.
- Drug screening must occur within 32 hours.

Notes

PPL companies

Rev. 03/12/2013

KY PSC Notifications – Internal Reporting List

Name	Email	Position
Archer, Jamie	[redacted]	Mgr Elec Sys Restore & Distrib
Bruner, Cheryl	[redacted]	Dir Customer Service
Claypool, Brian	[redacted]	Fire and Security Investigator
Coleman, Jan	[redacted]	Mgr Business Offices
Conroy, Robert	[redacted]	VP State Regulation and Rates
Crump, Travis	[redacted]	Corporate Attorney
Dimas, Jim	[redacted]	Corporate Attorney
Hollis, Kelly	[redacted]	Paralegal
Hudson, Charlie	[redacted]	Safety Specialists
Jackson, John	[redacted]	Grp Ldr Electric System Coordination
McBride, Keith	[redacted]	Fire and Security Investigator
McFarland, Beth	[redacted]	Dir Asset Management
Melton, Timothy	[redacted]	Mgr Customer Commitment
Mills, Chase	[redacted]	Reliability Engineer
Needham, Meredith	[redacted]	Paralegal
Koller, Tiffany	[redacted]	Mgr Substation Const and Maint
Scott, Mike	[redacted]	Grp Ldr Distribution Control Center
Sena, Mike	[redacted]	Grp Ldr Distribution Control Center
Sheakley, David	[redacted]	Team Ldr Distribution Control Center
Simon, Denise	[redacted]	Dir Electric Reliability
Steinmetz, Keith	[redacted]	Dir Transmission Operations
Stethen, Julie	[redacted]	Customer Commitment Coord
Trimble, Robbie	[redacted]	Dir Electric Distribution
Warren, Jay	[redacted]	Corporate Attorney
Wolfe, John	[redacted]	VP Electric Distribution
Woodworth, Steve	[redacted]	Dir Elec Sys Restore and Dist

VA SCC Notifications – Internal Reporting List

Name	Email	Position
Archer, Jamie	[redacted]	Mgr Elec Sys Restore & Distrib
Bruner, Cheryl		Dir Customer Service
Claypool, Brian		Fire and Security Investigator
Coleman, Jan		Mgr Business Offices
Conroy, Robert		VP State Regulation and Rates
Crump, Travis		Corporate Attorney
Dimas, Jim		Corporate Attorney
Hollis, Kelly		Paralegal
Hudson, Charlie		Safety Specialists
Jackson, John		Grp Ldr Electric System Coordination
McBride, Keith		Fire and Security Investigator
McFarland, Beth		Dir Asset Management
Melton, Timothy		Mgr Customer Commitment
Mills, Chase		Reliability Engineer
Needham, Meredith		Paralegal
Koller, Tiffany		Mgr Substation Const and Maint
Scott, Mike		Grp Ldr Distribution Control Center
Sena, Mike		Grp Ldr Distribution Control Center
Sheakley, David		Team Ldr Distribution Control Center
Simon, Denise		Dir Electric Reliability
Spradlin, Stewart		Mgr Norton Operations
Steinmetz, Keith		Dir Transmission Operations
Stethen, Julie		Customer Commitment Coord
Trimble, Robbie		Dir Electric Distribution
Warren, Jay		Corporate Attorney
Wolfe, John		VP Electric Distribution
Woodworth, Steve		Dir Elec Sys Restore and Dist

EPRP Appendix 3 Incident Command Structure

LG&E KU Services
Incident Command - Command Staff
Electric Restoration

Position	Name	Title	Contact Information		
			Office	Cell	Alternate
Executive Officer	John Wolfe	VP Electric Distribution	[redacted]		
Executive Officer	John Malloy	VP Customer Service			
Executive Officer	Chris Whelan	Vice President Corporate Communications			
Information Officer	Brian Phillips	Director Brand Adv Cust & Digtl Comm			
Information Officer	Natasha Collins	Director Media Relations			
Incident Commander	David Huff	Director Customer Energy Efficiency & Smart Grid Strategy			
Incident Commander	Steve Woodworth	Director Electric System Restoration and Distribution			
Customer Experience Section Chief	Cheryl Bruner	Director Customer Service and Marketing			
Customer Experience Section Chief	Debbie Leist	Director Revenue Integrity			
Logistics Section Chief	Butch Cockerill	Director Operating Services			
Logistics Section Chief	Mark Schmitt	Director Supply Chain			
Operations Section Chief	Beth McFarland	Director Asset Management			
Operations Section Chief	Robbie Trimble	Director Distribution Operations			
Safety Officer	Amanda Chambers	Manager ED and Transmission Safety			
Safety Officer	Ken Sheridan	Director Safety & Technical Training			
Work Planning Section Chief	Denise Simon	Director Electric Reliability			
Work Planning Section Chief	Shannon Montgomery	Director SAP Upgrade Project			

Reg Generation / Transmission

Name	*Office*	*Pager*	*Mobile*	*Home*
VICE PRESIDENT - Transmission				
Tom Jessee	[redacted]		[redacted]	[redacted]
DIRECTOR - Transmission Strategy and Planning				
Chris Balmer	[redacted]		[redacted]	[redacted]
DIRECTOR - Transmission Operations				
Keith Steinmetz	[redacted]		[redacted]	[redacted]
MANAGER - Transmission Protection and Substation				
Brent Birchell	[redacted]		[redacted]	[redacted]
MANAGER - Transmission Policy and Tariffs				
Derek Rahn	[redacted]		[redacted]	[redacted]
MANAGER - System Control Center				
Ray Tompkins	[redacted]		[redacted]	[redacted]
MANAGER - Transmission Line Services				
Robby Trimble	[redacted]		[redacted]	[redacted]
MANAGER - EMS / CIP				
Richard Watson	[redacted]	[redacted]	[redacted]	[redacted]
MANAGER - Transmission Reliability Performance & Standards				
Keith Yocum	[redacted]		[redacted]	[redacted]
MANAGER - Transmission Reliability and Compliance				
Brad Young	[redacted]		[redacted]	[redacted]
WESTERN				
Daren Smiley	[redacted]		[redacted]	[redacted]
Brandon Crook	[redacted]		[redacted]	[redacted]
Tom Hines	[redacted]		[redacted]	[redacted]
BLUEGRASS				
Biff Campbell	[redacted]		[redacted]	[redacted]
Bryan Richerson	[redacted]		[redacted]	[redacted]
Tom Hines	[redacted]		[redacted]	[redacted]
CENTRAL				
Biff Campbell	[redacted]		[redacted]	[redacted]
Bryan Richerson	[redacted]		[redacted]	[redacted]
Tom Hines	[redacted]		[redacted]	[redacted]
MOUNTAIN & DOMINION POWER				
Allen Roper	[redacted]		[redacted]	[redacted]
Mike Mills	[redacted]		[redacted]	[redacted]
Tom Hines	[redacted]		[redacted]	[redacted]
LOUISVILLE GAS & ELECTRIC				
Mickey Grismer	[redacted]		[redacted]	

Troy Bess	[redacted]		[redacted]	
Tom Hines	[redacted]		[redacted]	[redacted]

LG&E KU
Incident Command System
Emergency Preparedness and Planning Checklist

Topic		Task	Executive Officer	Safety Officer	Information Officer	Incident Command	Work Planning Section	Operations Section	Logistics Section	Customer Experience Section
Safety and Training										
	1	Ensure all assigned resources are adequately trained and qualified to perform assigned tasks safely.		✓	✓	✓	✓	✓	✓	✓
	2	Ensure all assigned Section resources have proper PPE to perform assigned roles and responsibilities.		✓	✓	✓	✓	✓	✓	✓
	3	Ensure processes and resources are in place to Passport off-system resources.		✓		✓	✓	✓	✓	
	4	Ensure formal procedures are in place and appropriate personnel are trained to transfer/decentralize hold card authority from the DCC to the Resource Management Rooms.		✓		✓		✓		
	5	Ensure Birddogs receive annual training on Energy Isolation and Control processes, particularly Independent Hold Card procedures.		✓		✓		✓		
	6	Ensure wire walkers, wire sitters, service crews and damage assessors receive annual training on wire walking procedures and associated personal protection equipment.		✓		✓		✓		
	7	Ensure PSRT Dispatchers receive refresher training on associated procedures prior to on-call rotations.		✓		✓		✓		
	8	Ensure plans are in place to assure safe ingress and egress patterns at staging areas.		✓		✓		✓	✓	
	9	Ensure plans are in place to adequately secure and protect staging areas.		✓		✓		✓	✓	
	##	Ensure plans and procedures are in place, and have been tested, to communicate life essential and restoration information to customers during emergencies.		✓	✓	✓		✓		✓
	##	Ensure ample supplies of safety materials are available for general use and emergencies.		✓		✓		✓	✓	
Policies and Procedures										
	1	Develop formal **storm roles and responsibilities** (task lists) for section.		✓	✓	✓	✓	✓	✓	✓
	2	Conduct **routine periodic drills** on storm roles and responsibilities to ensure adequate knowledge of associated policies, procedures, technology, and organizational hierarchy.		✓	✓	✓	✓	✓	✓	✓
	3	Conduct routine reviews of **alert level checklists** to ensure adequate alignment with emergency restoration policies, procedures, and overall strategies.		✓	✓	✓	✓	✓	✓	✓
	4	Conduct **scheduled reviews** of emergency response business processes to ensure alignment with business needs, technology, and resources, and make enhancements where necessary.		✓	✓	✓	✓	✓	✓	✓
	5	Establish, maintain, and train personnel on **Public Safety Response** business processes and technologies.		✓		✓		✓		
	6	Establish, maintain, and train personnel on **Estimated Restoration Times** business processes and technologies.				✓	✓	✓		✓
	7	Establish, maintain, and train personnel on **Damage Assessment** business processes and technologies.				✓		✓		
	8	Establish, maintain, and train personnel on **Resource Managemen**t business processes and technologies.				✓	✓	✓		
	9	Establish, maintain, and train personnel on **Work Prioritization & Assignment** business processes and technologies.				✓	✓	✓		
	##	Establish, maintain, and train personnel on **Distribution Control Cente**r business processes and associated technologies.				✓		✓		
	##	Establish, maintain, and train key personel on **Mutual Aid** business processes.				✓	✓	✓	✓	
	##	Establish, maintain, and train personnel on **Staging Areas** business processes.		✓		✓	✓	✓	✓	
	##	Establish, maintain, and train personnel on **Emergency Management Outreach** business processes and associated technologies.				✓		✓		✓
	##	Establish, maintain, and train personnel on **External Communiciations** (regulatory, media, political, emergency management, public, customers) business processes and technologies.		✓	✓	✓	✓	✓	✓	✓
	##	Establish, maintain, and train personnel on **Customer Experience** (Critical Customes, Ombudsman Teams, Major Accounts, Call Centers, Business Offices) business processes and technologies.				✓		✓		✓
	##	Establish, maintain, and train personnel on **Logistics** (materials, housing, staging, meals, laundry, byproducts disposal) business processes and technologies.							✓	
	##	Ensure adequate information systems are available to monitor system status and help manage and track resources.				✓	✓	✓		
	##	Ensure adequate information systems are available to monitor system status and help prioritize restoration efforts.				✓		✓		
Resources										
	1	Ensure adequate resources (primary and backup) are formally assigned to established storm roles and responsibilities.		✓	✓	✓	✓	✓	✓	✓
	2	Ensure formal schedules are in place to adequately and effectively allocate/assign on-call, available, or assigned personnel to emergencies and restoration efforts.		✓	✓	✓	✓	✓	✓	✓
	3	Establish baseline resource rosters in established Resource database.					✓	✓		
	4	Conduct monthly reviews of baseline resource rosters to ensure accuracy and availability for upload to resource database.					✓	✓		
Communications										
	1	Maintain accurate and readily accessible contact information for personnel assigned to storm roles.		✓	✓	✓	✓	✓	✓	✓
	2	Maintain accurate and readily accessible contact information for resident and non-resident business partners that may assist in emergency response/restoration efforts.		✓	✓	✓	✓	✓	✓	✓
	3	Establish effective and formal call-in/communications processes for personnel assigned to Section.		✓	✓	✓	✓	✓	✓	✓
	4	Ensure adequate communications mediums are available for resources during emergency operations, including radios, cell phones, land lines, lap tops, and satellite phones.		✓	✓	✓	✓	✓	✓	✓
	5	Establish centralized phone numbers in designated Resource Management Rooms for responsibility areas.						✓		
	6	Establish Event Preparedness, Planning, and Response Call protocol.				✓				
	7	Establish and distribute StormResources email address and Work Planning phone number(s) to IC, Operations, Logistics, and Customer Experience Section Chiefs.					✓			
	8	Establish and distribute essential Logistics email addresses and phone number(s) to IC, Operations, Logistics, and Customer Experience Section Chiefs.							✓	
	9	Routinely test and verify communications technology to ensure availability and proper working order.		✓	✓	✓	✓	✓	✓	✓
Logisitics										
	1	Ensure all hardware, software, office space, and communication systems are in place to conduct Section operations.				✓	✓	✓	✓	✓
	2	Ensure adequate staging area arrangements are in place to administratively process, feed, house, and stage off system resources.						✓	✓	
	3	Establish contracts/arrangements with local lodging providers.							✓	
	4	Ensure adequate availability of storm procurement cards.							✓	
	5	Estalish storm response contracts with native and preferred contractors.				✓		✓	✓	

2/2/2016 Cells marked in this color were modified

LG&E KU
Incident Command System
Emergency Preparedness and Planning Checklist

Topic		Task	Executive Officer	Safety Officer	Information Officer	Incident Command	Work Planning Section	Operations Section	Logistics Section	Customer Experience Section
Safety										
	1	Ensure all assigned Section resources have proper PPE to perform assigned roles and responsibilities.		✓	✓	✓	✓	✓	✓	✓
	2	Work with the designated Safety Officer to ensure adequate resources will be available to Passport off-system resources where needed.		✓		✓		✓		
	3	Work with the designated Safety Officer to ensure adequate resources are available to conduct field observations and address safety issues for immenent or forecasted events.		✓		✓		✓		
	4	Advise field and responding personnel of forecasted or approaching hazardous weather conditions.		✓	✓	✓	✓	✓	✓	✓
Policies and Procedures										
	1	Alert designated Section leads of an approaching or forecasted event and place them on notice for potential call-out and Emergency Preparedness and Response Plan execution.		✓	✓	✓	✓	✓	✓	✓
	2	Request Resource Managers to update resource rosters to reflect available emergency response personnel and business partners.				✓	✓	✓		
	3	Prepare to initiate execution of **Public Safety Response** business processes.		✓		✓		✓		
	4	Prepare Resource Management Rooms for activation.				✓		✓		
	5	Prepare Command Centers for activation.		✓	✓	✓	✓	✓	✓	✓
	6	Prepare to execute **Mutual Aid** business processes.				✓	✓	✓	✓	
	7	Confirm the availability of designated **Staging Areas** (Level III, IV event) for areas forecasted to have severe weather.				✓			✓	
	8	Initiate execution of **Emergency Management Outreach** business processes.			✓	✓		✓		✓
	9	Execute weather alert **External Communiciations** (regulatory, media, political, emergency management, public, customers) business processes and technologies.		✓	✓	✓	✓	✓	✓	✓
	#	Alert all key **Customer Experience** leads (Critical Customes, Ombudsman Teams, Major Accounts, Call Centers, Business Offices) and prepare to execute associated business processes and technologies.				✓		✓		✓
	#	Prepare to execute **Logistics** (materials, housing, staging, meals, laundry, byproducts disposal) business processes.							✓	
	#	Verify resource management information systems are functional/operational to help manage and track resources.				✓	✓	✓		
	#	Verify key information systems are available to monitor system status and help prioritize restoration efforts.				✓		✓		
Resources										
	1	Review key designated storm roles and responsibilities, and confirm availability of assigned personnel. Identify delegates where appropriate.		✓	✓	✓	✓	✓	✓	✓
	2	Confirm formal schedules are in place to adequately and effectively allocate/assign on-call, available, or assigned personnel/teams to the forecasted emergency or approaching event.		✓	✓	✓	✓	✓	✓	✓
	3	Review and update baseline resource rosters in the established Resource database.				✓	✓	✓	✓	
	4	Inventory and adjust storm material free-bins and kits.						✓	✓	
Communications										
	1	Conduct an Event Preparedness, Planning, and Response notification or call (when deemed necessary by the IC).				✓				
	2	Participate or delegte participation in all scheduled Event Preparedness, Planning, and Response Calls.		✓	✓	✓	✓	✓	✓	✓
	3	Alert personnel with storm roles of an approaching or forecasted event and place them on notice for call-out execution.		✓	✓	✓	✓	✓	✓	✓
	4	Alert business partners (materials, services) of an approaching or forecasted event and place them on notice for call-out execution.		✓	✓	✓	✓	✓	✓	✓
	5	Verify adequate communications mediums are available for resources for forecasted or approaching emergency, including radios, cell phones, land lines, lap tops, and satellite phones.		✓	✓	✓	✓	✓	✓	✓
Logisitics										
	1	Confirm that all hardware, software, office space, and communication systems are in place to conduct Section operations.				✓	✓	✓	✓	✓
	2	Confirm availability of predesignated staging areas.				✓		✓	✓	
	3	Confirm availability of predesignated lodging areas.				✓			✓	
	4	Alert the Logistics Section Chief of command centers, staging ares, and other physical areas that may be needed to respond to a forecasted or imminent event.				✓		✓	✓	
	5	Alert Facilities or other designated personnel to set up command centers/resource management rooms.				✓		✓	✓	
	6	Advise Security of staging areas, Operations Centers, or other areas where extended or supplemental security may be needed for forecasted or imminent events.				✓		✓	✓	
	7	Open store rooms for impacted areas.				✓		✓	✓	

2/2/2016 Cells marked in this color were modified

LG&E KU
Incident Command System
Emergency Response Checklist

Topic		Task	Executive Officer	Safety Officer	Information Officer	Incident Command	Work Planning Section	Operations Section	Logistics Section	Customer Experience Section
Safety										
	1	Ensure all assigned Section resources have proper PPE to perform assigned roles and responsibilities.		✓	✓	✓	✓	✓	✓	✓
	2	Execute Public Safety Response Team procedures.		✓		✓		✓		
	3	Execute business processes and resource plans to Passport off-system resources.		✓		✓	✓	✓	✓	
	4	Work with the Incident Commander and Operations Section Chief to execute independent hold card policies/procedures when needed.		✓		✓		✓		
	5	Execute plans to provide safe ingress and egress patterns at staging areas.		✓		✓		✓	✓	
	6	Execute plans to provide adequate security and protection of staging areas.		✓		✓		✓	✓	
	7	Execute plans and procedures that provide customers and the public life essential and public safety information.		✓	✓	✓		✓		✓
	8	Establish/participate in daily safety conference calls.		✓		✓	✓	✓	✓	✓
Policies and Procedures										
	1	Activate **Incident Command storm roles and responsibilities.**		✓	✓	✓	✓	✓	✓	✓
	2	Review and confirm execution of Red **Alert level checklist** to ensure adequate alignment with emergency restoration policies, procedures, and overall strategies.		✓	✓	✓	✓	✓	✓	✓
	5	Execute **Public Safety Response** business processes.		✓		✓		✓		
	6	Execute **Estimated Restoration Times** business processes.				✓	✓	✓		✓
	7	Execute **Damage Assessment** business processes.				✓		✓		
	8	Execute **Resource Managemen**t business processes.				✓	✓	✓		
	9	Execute **Work Prioritization & Assignment** business processes.				✓		✓		
	##	Execute **Distribution Control Cente**r emergency operations business processes.				✓		✓		
	##	Execute **Mutual Aid** business processes.				✓	✓	✓	✓	
	##	Execute **Staging Areas** business processes.		✓		✓	✓	✓	✓	
	##	Execute **Emergency Management Outreach** business processes. Establish personnel contacts at open Emergency Operating Centers.				✓		✓		✓
	##	Execute **External Communiciations** (regulatory, media, political, emergency management, public, customers) business processes.		✓	✓	✓	✓	✓	✓	✓
	##	Execute **Customer Experience** (Critical Customes, Ombudsman Teams, Major Accounts, Call Centers, Business Offices) business processes and technologies.				✓		✓		✓
	##	Execute **Logistics** (materials, housing, staging, meals, laundry, byproducts disposal) business processes.				✓			✓	
Resources										
	1	Continuously monitor response efforts to ensure adequate resources are assigned/available for Incident Command storm roles and responsibilities.		✓	✓	✓	✓	✓	✓	✓
	2	Implement schedules to adequately and effectively allocate/assign on-call, available, or assigned personnel to the emergency/restoration effort.		✓	✓	✓	✓	✓	✓	✓
	3	Monitor resources in established Resource database, against estimated restoration times.				✓	✓	✓		
	4	Mobilize materials, staging, fuel, meals vendors.				✓			✓	
	5	Open and staff storerooms in impacted service areas.				✓		✓		
	6	Continuously monitor resource management information systems to confirm availability and proper functionality.				✓	✓	✓		
	7	Continuously monitor system status and control information systems to confirm availability and proper functionality.				✓	✓	✓		✓
Communications										
	1	Execute call-in/communications processes for personnel assigned to Section.		✓	✓	✓	✓	✓	✓	✓
	2	Provide daily safety briefings/tailgates to all personnel responding to the incident.		✓	✓	✓	✓	✓	✓	✓
	3	Secure and distribute (where necessary) the communications mediums/devices needed for the emergency response, including radios, cell phones, land lines, lap tops, and satellite phones.		✓	✓	✓	✓	✓	✓	✓
	4	Establish centralized phone numbers in designated Resource Management Rooms for responsibility areas.				✓		✓		
	5	Establish Event Preparedness, Planning, and Response Call protocol.				✓				
	6	Establish and distribute StormResources email address and Work Planning phone number(s) to IC, Operations, Logistics, and Customer Experience Section Chiefs.				✓	✓			
	7	Establish and distribute essential Logistics email addresses and phone number(s) to IC, Operations, Logistics, and Customer Experience Section Chiefs.				✓			✓	
	8	Routinely test and verify communications technology to ensure availability and proper working order.		✓	✓	✓	✓	✓	✓	✓
	9	Coordinate storm communications with the Company's designated Public Information Officer.			✓	✓				
Logisitics										
	1	Ensure all hardware, software, office space, and communication systems are in place to conduct Section operations.				✓	✓	✓	✓	✓
	2	Ensure adequate staging area arrangements are in place to administratively process, feed, house, and stage secured/forecasted off system resources.				✓		✓	✓	
	3	Establish contracts/arrangements with local lodging providers.				✓			✓	
	4	Activiate and assign storm procedurement cards.				✓			✓	
	5	Secure contracts, insurance certicficates, and T&M rates for non-native and non-preferred contractors as they are mobilized to impacted area				✓			✓	

2/2/2016 Cells marked in this color were modified

EPRP Appendix 4 Safety Information

LG&E KU
PPL companies

SAFETY FIRST! NO COMPROMISE!

Safety Passport Orientation Handbook

For Restoration Purposes Only

LG&E KU
PPL companies

CAPACITOR BANK FUSING CHART

Capacitor Bank Fuse Sizes					
Bank Size	4,160V		12,470V		13,800V
(KVAR)	LG&E	KU	LG&E	KU	LG&E
300	40K	60QA	15D	20QA	15D
450	65K	100QA	20K	30QA	20K
600	100K	N/A	40K	40QA	25K
900	N/A		40K	60QA	40K
1200			65K	75QA	65K
1350			65K	N/A	65K
1500			65K		65K
1800			100K		65K
2100			100K		100K
2400			N/A		100K

UNDERGROUND FUSING CHART

PAD MOUNT TRANSFORMER FUSING CHART

Fuse Recommendations for Pad Mount Transformers				
Transformer Size		2.4 KV 1Ø or 4.16kV	7.2 KV 1Ø or 12.47kV	13.8 KV Delta (LG&E Only)
1Ø	3Ø			
10 KVA	N/A	C05	C03	N/A
15 KVA	45 KVA	C08	C03	
25 KVA	75 KVA	C10	C05	
37.5 KVA	112.5 KVA	C12	C08	
50 KVA	150 KVA	C12	C08	C08
75 KVA	225 KVA	C14	C10	N/A
100 KVA	300 KVA	C14	C10	C10
167 KVA	500 KVA	C18	C12	C12
250 KVA	750 KVA	C18	C14	C14
N/A	1000 KVA	C10CB	C14	C14
	1500 KVA	N/A	C04CB	C04CB
	2000 KVA		C05CB	C05CB
	2500 KVA		C05CB	C05CB
	3000 KVA		N/A	

BAY - O - NET FUSES

Bay-O-Net Fuse Chart			
Fuse Link	Fuse Amperage Rating	Continuous Current Rating	IIN#
C03	3 Amp	3 Amps	7000732
C05	8 Amp	8 Amps	7000733
C08	15 Amp	15 Amps	7000734
C10	25 Amp	25 Amps	7000735
C12	50 Amp	50 Amps	7000736
C14	65 Amp	65 Amps	7000737
C18	140 Amp	140 Amps	7000738
C04CB	100 Amp	165 Amps	0942586
C05CB	125 Amp	185 Amps	0942594
C10CB	Shorting Bar	200 Amps	0942601

Notes: Bay-O-Net fuses IIN#'s 7000738, 0942586, 0942594, and Shorting Bar 0942601 are an integral assembly including the link, cartridge and end plug.

BAY-O-NET FUSE

OVERHEAD FUSING CHART

Fuse Recommendations For 1Ø Pole Mount Transformers					
Transformer	2,400V		7,200V		13,800V
Size	KU	LGE	KU	LGE	LGE Only
5 KVA	3D		1D		1D
10 KVA	5D		2D		1D
15 KVA	7D		3D		2D
25 KVA	15D		5D		2D
37.5 KVA	50QA	25K	7D		5D
50KVA	60QA	40K	10D		5D
75KVA	75QA	65K	15D		7D
100KVA	100QA	65K	40QA	20K	10D
167KVA	150QA		60QA	40K	15D
250KVA	175QA		100QA	65K	40K

D-Link Fuses (LG&E & KU)	
1 D	7000710
2 D	7000711
3 D	7000712
5 D	7000713
7 D	7000714
10 D	7000715
15 D	7000716

K-Link Fuses (LG&E)	
20 K	0532460
25 K	1163727
40 K	1163735
65 K	1163743
100 K	1163751
140 K	1163760
200 K	1163778

Fuse Recommendations For 3Ø Transformer Banks With Equal Size Units							
Transformer Size	2,400V Delta	4,160V WYE		7,200V Delta	12,460 WYE		13,800V Delta
KVA	KU Only	KU	LGE	KU Only	KU	LGE	LGE Only
3-5	5D	3D		2D	1D		1D
3-10	10D	5D		3D	2D		2D
3-15	15D	7D		5D	3D		2D
2-25	50QA	15D		7D	5D		5D
3-37.5	75QA	50QA	25K	10D	7D		7D
3-50	100QA	60QA	40K	15D	10D		10D
3-75	125QA	75QA	65K	50QA	15D		15D
3-100	150QA	100QA	65K	60QA	40QA	20K	15D
3-167	200QA	150QA		100QA	60QA	40K	40D
3-250		175QA			100QA	65K	65D
3-333		200QA			125QA	65K	65D
3-500					150QA	100K	100K
3-833					175QA	140K	140K

QA-Link Fuses (KU)	
20 QA	7000717
25 QA	7000718
30 QA	7000719
40 QA	7000720
50 QA	7000721
60 QA	7000722
75 QA	7000723
100 QA	7000724
125 QA	7000725
150 QA	7000726
175 QA	7000727
200 QA	7000728

Special Application Notes: Unequal KVA unit banks and three phase banks utilizing only two transformers cannot always be fused according to the table above. See the special notes below for special applications. For any special applications not identified below, consult the Operation Center Engineering or Electric System Codes & Standards.

Y - DELTA And OPEN Y - OPEN DELTA - Equal and unequal KVA Units: Fuse each transformer the same as in 1Ø installations.

OPEN DELTA - OPEN DELTA - Equal KVA Units- Fuse each transformer the same as in 1Ø installations. Unequal KVA Units - Fuse the outside leads the same as in 1Ø installations. Fuse the common lead with the next fuse size larger than the total of 3/4 of the smaller outside fuse rating and the larger outside fuse rating. An Example: Given a 10 KVA 7200V transformer and a 50 KVA 7200V transformer to be connected open delta on the primary side: Fuse the 10 KVA transformer with a 2 amp fuse, the 50 KVA with a 10 amp fuse and the common lead with a 15 amp fuse (next size larger than (3/4*2)+10 = 11.13).

RECLOSER BYPASS FUSING CHART

Recloser Bypass Fusing		
Recloser Size	Normal Fuse For Bypassing	
(Amps)	LG&E	KU/ODP
50	30K	40QA
70	40K	50QA
100	65K	75QA
140	80K	100QA
160	80K	125QA
185	100K	150QA
200	100K	150QA

NOTE:
Bypass fuse size selected for best coordination (total clearing time of fuse to slow curve of recloser). If line current exceeds nominal fuse rating,increase fuse size.

PPL companies

Emergency Information Form

Date/time ______________________________

Name ______________________________

Address ______________________________

City ______________________________

State, ZIP ______________________________

Emergency contact ______________________________

LG&E and KU wristband number ______________________________

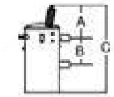
Contractor name ______________________________

Cell phone number for restoration updates (optional) ______________________________

Safety First! No Compromise!

NOTES:

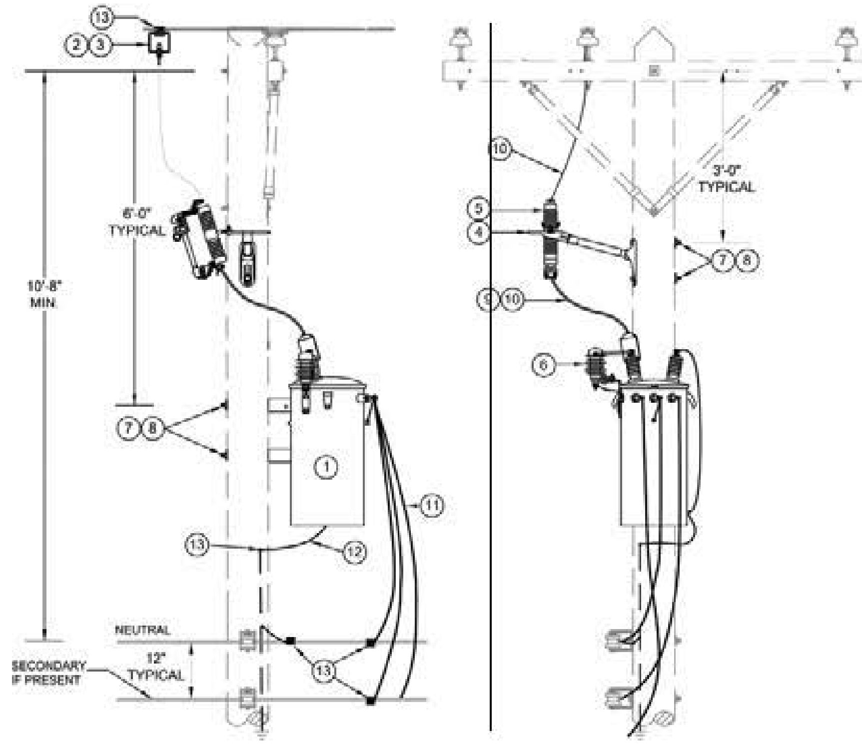
1. POLE GROUND MUST BE CONNECTED TO SYSTEM NEUTRAL, TRANSFORMER TANK, PRIMARY BUSHING, AND LIGHTNING ARRESTER GROUND, DIRECTLY OR INDIRECTLY. TYPICAL GROUNDING SHOWN. OTHER METHODS ALSO ACCEPTABLE.
2. CUTOUT TO BE MOUNTED ON SIDE OF EQUIPMENT BRACKET FARTHEST AWAY FROM TRANSFORMER. (SEE STANDARD 07 08 02)
3. TRANSFORMER SHOULD BE LOCATED IN MOST CONVENIENT QUADRANT. WHEN POSSIBLE, THE TRANSFORMER SHOULD BE PLACED IN LINE WITH THE CONDUCTORS AND ON THE SIDE OF THE POLE WHICH IS LEAST DESIRABLE FOR CLIMBING.
4. WILDLIFE PROTECTOR SHOULD ALWAYS BE INSTALLED AROUND "HOT" PRIMARY BUSHING. (SEE STANDARD 20 25 02)
5. MIN. POLE HEIGHT OF 45' TO BE USED WHEN COMMUNICATIONS CABLES ARE PRESENT.



TRANSFORMER DIMENSIONS

(KVA)	A (IN.)	B (IN.)	C (IN.) TYP.
10-50	15 +/- 3	11.25	42
75-167	15 +/-3	20.25	54

CROSSARM CONSTRUCTION



Electric System Codes & Standards

SINGLE PHASE TRANSFORMER INSTALLATION FROM POLE TOP AND CROSSARM CONSTRUCTION

20 05 02
Rev. D

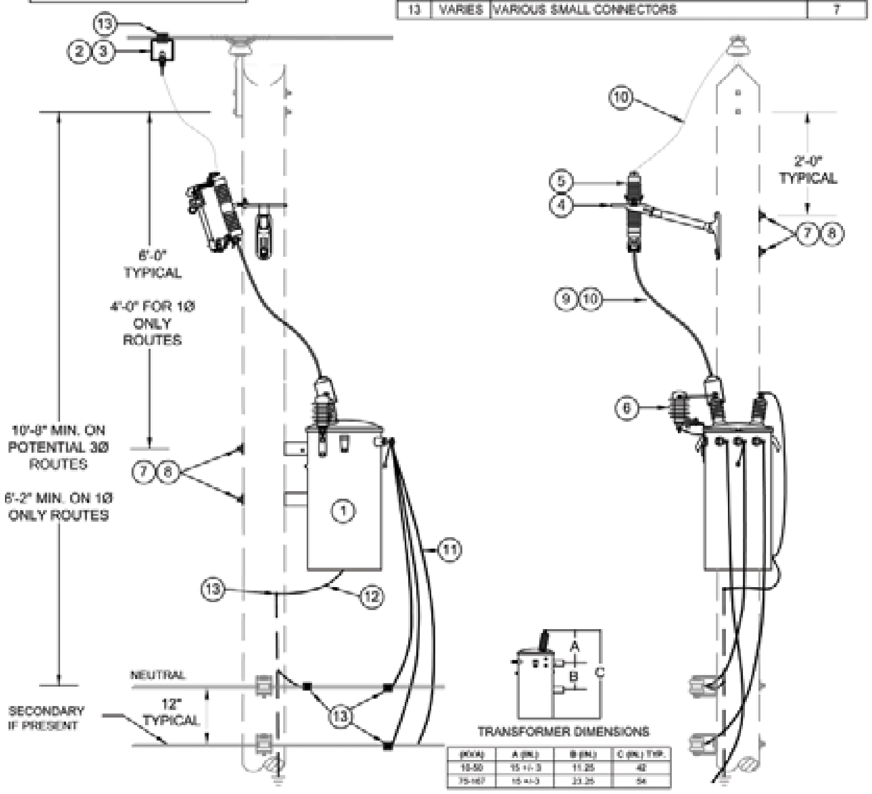
NOTES:

1. POLE GROUND MUST BE CONNECTED TO SYSTEM NEUTRAL, TRANSFORMER TANK, PRIMARY BUSHING, AND LIGHTNING ARRESTER GROUND, DIRECTLY OR INDIRECTLY. TYPICAL GROUNDING SHOWN. OTHER METHODS ALSO ACCEPTABLE.
2. CUTOUT TO BE MOUNTED ON SIDE OF EQUIPMENT BRACKET FARTHEST AWAY FROM TRANSFORMER. (SEE STANDARD 07 08 02)
3. TRANSFORMER SHOULD BE LOCATED IN MOST CONVENIENT QUADRANT. WHEN POSSIBLE, THE TRANSFORMER SHOULD BE PLACED IN LINE WITH THE CONDUCTORS AND ON THE SIDE OF THE POLE WHICH IS LEAST DESIRABLE FOR CLIMBING.
4. WILDLIFE PROTECTOR SHOULD ALWAYS BE INSTALLED AROUND "HOT" PRIMARY BUSHING. (SEE STANDARD 20 25 02)
5. MIN. POLE HEIGHT OF 45' TO BE USED WHEN COMMUNICATIONS CABLES ARE PRESENT.

MATERIAL LIST

ITEM	IN	DESCRIPTION	QTY
1	VARIES	TRANSFORMER, 1Ø	1
2	VARIES	STIRRUP,BAIL,HOT LINE,COPPER	1
3	7000591	CLAMP,HOT LINE,8-2/0,CU	1
4	7001703	BRACKET,INSULATOR/ARRESTER,18",SINGLE	1
5	7001957	CUTOUT,FUSED,15KV,NON-LOADBREAK	1
6	VARIES	ARRESTER,SURGE,DIST. CLASS (INCL. W/TRANSF.)	1
7	7000339	WASHER,CURVED,SQUARE,3"X3"X1/4"	4
8	VARIES	5/8" MACHINE BOLTS W/NUTS	4
9	7001924	GUARD,WILDLIFE,STINGER COVER (IF REQ.)	10
10	1199376	WIRE,#4,7-STR,SOFT DRAWN COPPER POLY	10
11	VARIES	WIRE, XFMR SECONDARY LEGS, POLY	20
12	7005817	CONDUCTOR,OH WIRE,4,CU,BARE,SD,SOLID	6
13	VARIES	VARIOUS SMALL CONNECTORS	7

POLE TOP CONSTRUCTION



LG&E KU PPL companies

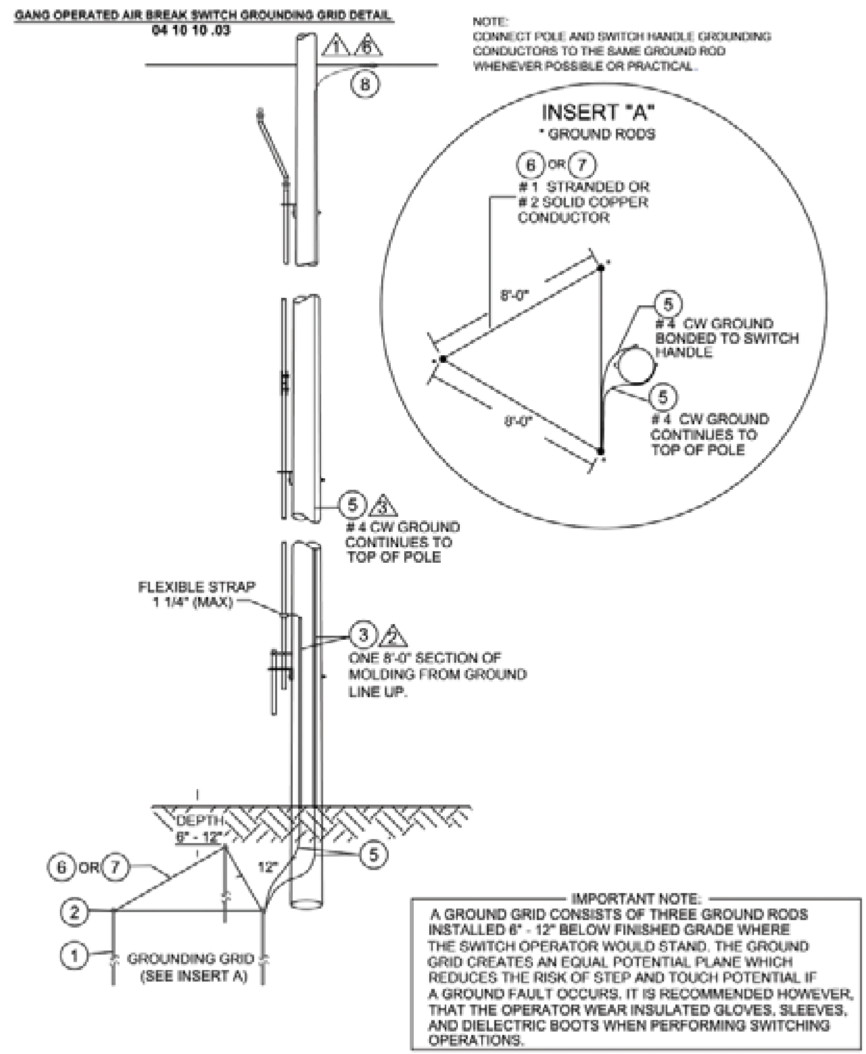
Electric Design And Construction Standards

Replaces
LGE 200502C/200504D
KU A-4-8.2/A-4-8.3

By: Hethcox/Stickler
05/07/2010
Page 1 of 2

Contents

Contents



GANG OPERATED AIR BREAK SWITCH GROUNDING GRID DETAIL
04 10 10 .03
NOTE:
CONNECT POLE AND SWITCH HANDLE GROUNDING CONDUCTORS TO THE SAME GROUND ROD WHENEVER POSSIBLE OR PRACTICAL.
INSERT "A"
* GROUND RODS
6 OR 7
1 STRANDED OR # 2 SOLID COPPER CONDUCTOR
8'-0"
5
4 CW GROUND BONDED TO SWITCH HANDLE
5
4 CW GROUND CONTINUES TO TOP OF POLE
8
5
4 CW GROUND CONTINUES TO TOP OF POLE
FLEXIBLE STRAP 1 1/4" (MAX)
3
ONE 8'-0" SECTION OF MOLDING FROM GROUND LINE UP.
DEPTH 6" - 12"
12"
6 OR 7
2
1
GROUNDING GRID (SEE INSERT A)
IMPORTANT NOTE:
A GROUND GRID CONSISTS OF THREE GROUND RODS INSTALLED 6" - 12" BELOW FINISHED GRADE WHERE THE SWITCH OPERATOR WOULD STAND. THE GROUND GRID CREATES AN EQUAL POTENTIAL PLANE WHICH REDUCES THE RISK OF STEP AND TOUCH POTENTIAL IF A GROUND FAULT OCCURS. IT IS RECOMMENDED HOWEVER, THAT THE OPERATOR WEAR INSULATED GLOVES, SLEEVES, AND DIELECTRIC BOOTS WHEN PERFORMING SWITCHING OPERATIONS.

ASSEMBLY DESCRIPTION

04 10 10 . XX

TYPE OF GROUNDING

THIS STANDARD DETAILS TYPICAL GROUNDING PRACTICES FOR DRIVEN GROUND, BUTT PLATE AND SWITCH POLE GROUND GRID.

04 10 10 . 01 DRIVEN GROUND - #4 CW. WIRE

04 10 10 . 02 BUTT PLATE / #4 CW. WIRE

04 10 10 . 03 SWITCH POLE GROUNDING

EQUIPMENT POLES

EQUIPMENT POLES ARE DEFINED AS POLES WITH TRANSFORMERS, REGULATORS, CAPACITORS, RECLOSERS, SWITCHES, LIGHTNING ARRESTERS, ETC.

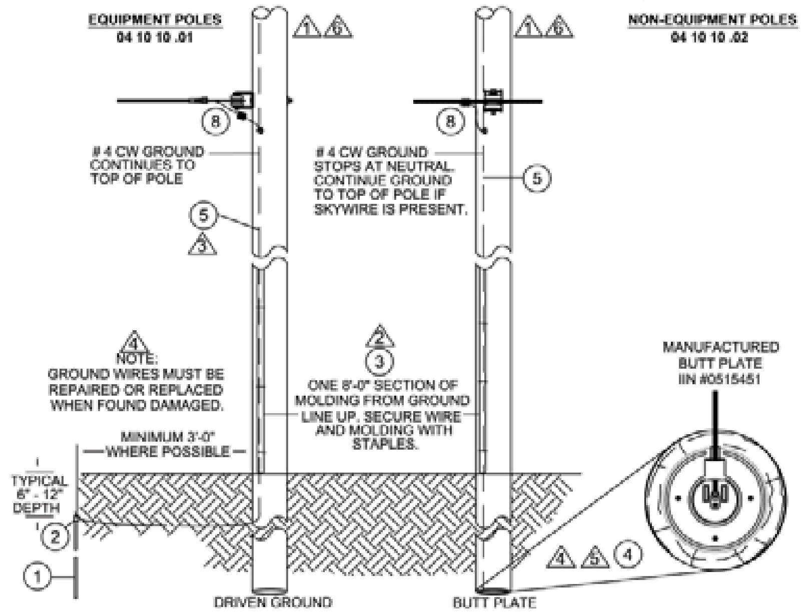
MATERIAL LIST

Item	IIN	Description	01	02	03
1	7000888	8' GROUND ROD	1		3
2	7000887	GROUND CLAMP	1		3
3	7000913	8' SECTION OF MOLDING	1	1	2
4	0515451	MANUFACTURED BUTT PLATE		1	
5	7001812	#4 CW. WIRE	*	*	*
6	7000390	#1 STR. CU. WIRE OR			*
7	7002487	#2 CU. SD/BARE SOLID			
8	VARIES	VARIOUS SMALL CONNECTORS	1	1	2

* AS REQUIRED

NOTES:

1. GROUND WIRES ARE TO EXTEND UP THE POLE TO THE HIGHEST GROUNDED PIECE OF EQUIPMENT OR THE HIGHEST GROUNDED CONDUCTOR (NEUTRAL, MESSENGER, SKYWIRE).
2. GROUND MOLDING IS ONLY REQUIRED AT GROUND LEVEL. THERE IS NO LONGER A NEED FOR A SECOND SECTION OF MOLDING IN THE NEUTRAL AREA. THIS COULD INTERFERE WITH BONDING TELECOM MESSENGERS TO THE UTILITY GROUNDING SYSTEM.
3. CW CONDUCTOR IS TO BE USED FOR GROUND LEADS. CW CONDUCTOR WILL REDUCE DAMAGE AND BROKEN GROUNDS AND LOSS DUE TO THEFT AND SHOULD BE THE STANDARD.
4. THE NESC REQUIRES A MINIMUM OF 4 DRIVEN GROUNDS PER MILE. DRIVEN GROUNDS ARE ALSO REQUIRED AT ALL EQUIPMENT POLES (SEE NOTE). BUTT GROUNDS SHOULD BE USED AT ALL OTHER LOCATIONS TO PROVIDE SUPPLEMENTAL GROUNDING.
5. WHEN EQUIPMENT IS ADDED TO A POLE THAT HAS ONLY A BUTT GROUND, A NEW DRIVEN GROUND MUST BE INSTALLED.
6. ALL METALLIC EQUIPMENT MOUNTING BRACKETS AND RACKS MUST BE BONDED DIRECTLY TO THE POLE GROUND NEAR THE EQUIPMENT.



Overview

The primary objective of LG&E and KU is the safe, quick and orderly restoration of electric power to customers. We appreciate your help and are committed to ensuring you have the safest work environment possible.

This reference manual will provide you with the following.

- Emergency procedures
- Job briefing guidelines
- Guidelines regarding traffic control on the roadway and at the staging site
- Key elements of our distribution system
- A variety of procedures that you may perform during restoration efforts
- Basic environmental guidelines for restoration
- A list of tools, materials, equipment, PPE and other miscellaneous items that you will need to bring to the site and what the company may provide
- Safety procedures
  - LOTO (Lock Out/Tag Out)
  - Grounding
  - PPE (Personal Protective Equipment)

Energy Delivery

Safety Mission Statement

No Compromise!

Ensure, without compromise, that safety excellence is the core expectation of business operations, and that management and employees are responsible and accountable for a safe work environment.

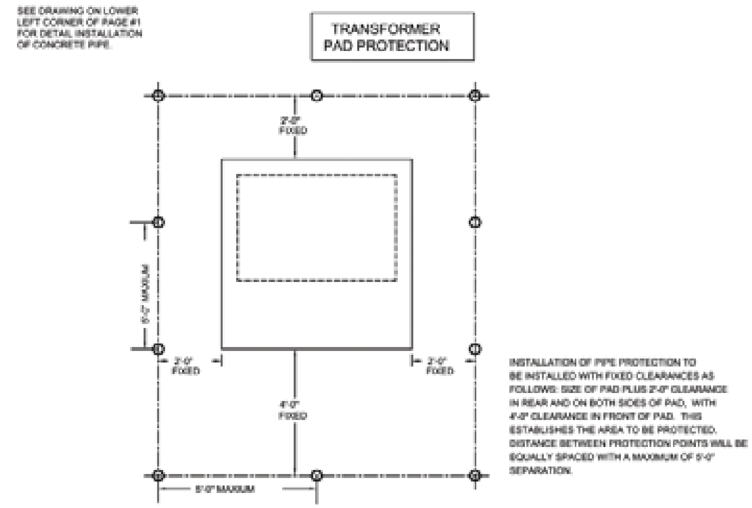
Values that support our mission statement

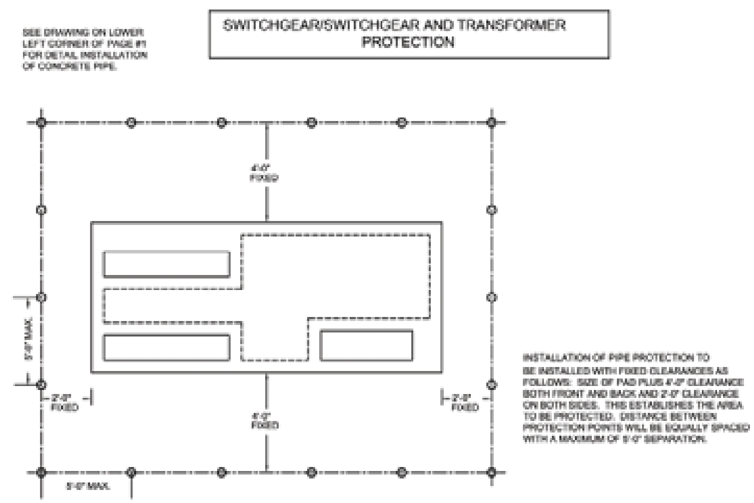
Communication. We expect management, employees and business partners to discuss safety issues and share information openly, freely and constructively. Health and safety must be given the highest priority by all workers at all times. No doubt can be left in the mind of any individual that the company is committed to, and will not compromise, the safety or health of any employee or business partner.

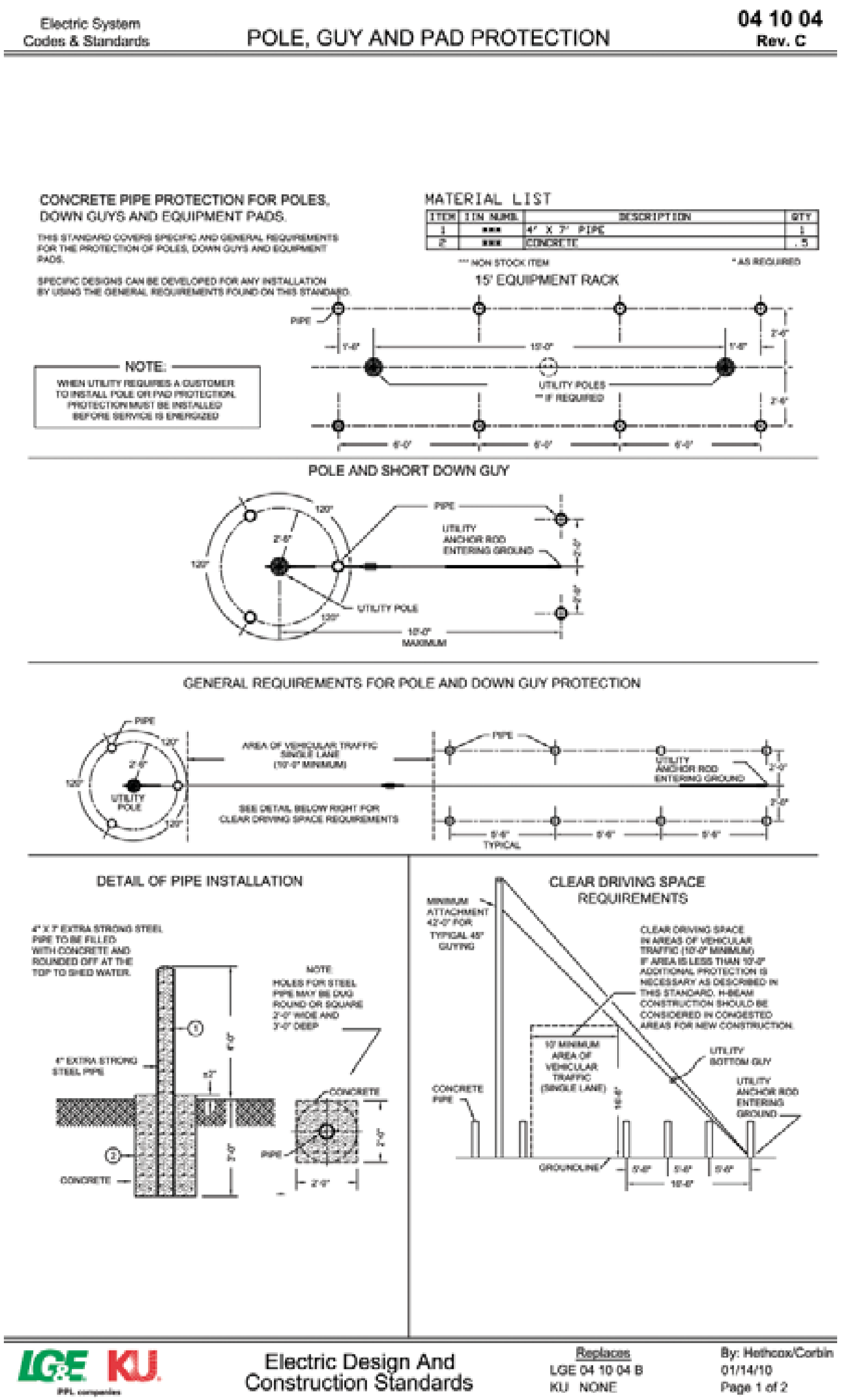
Commitment. Management is steadfast in its commitment that safety comes first and will ensure that health and safety are engrained in business planning and performance improvement activities throughout the company. We will communicate in unequivocal terms, to each and every worker, that nothing is more important than safety.

Accountability. Management, employees and business partners will be held accountable for health and safety performance. All personnel must understand and apply health and safety procedures at all times, while maintaining exemplary customer service. All of us are responsible for our own safety, as well as the safety of those around us.

Ownership. We have adopted a *No Compromise* philosophy that requires the safety and well-being of our work force to come before all else. We will maintain high operating and business safety standards. We will establish challenging goals and measure performance to continually improve health and safety results that contribute to safety excellence as a core value for business success.







General Guidelines

Safety, including your personal well-being, is the first consideration for each and every job.

- Don't work beyond your limitations.
- If you need rest, stop working.
- If you need help, contact your lead person.
- If you are unsure about the task at hand, don't continue working.
- If you are assigned work that you are not qualified to do or you feel uncomfortable performing, just say "no!"
- You must meet or exceed all applicable OSHA safety standards and your organization's safety rules.

Our philosophy, when it comes to safety, is...

No Compromise!

General Information

- Each person is required to fill out an emergency information form upon arrival.
- Each contractor also must undergo safety passport training before beginning work. Upon completion of the training, you will receive a wristband to indicate you have been certified according to our safety standards.
- You must wear the wristband at all times (24/7) while working for LG&E and KU. It identifies you as having been safety certified, and as an authorized contractor to the public and to food and lodging vendors. If one is lost or comes off, notify your lead person immediately.

Time

- Each lead person/supervisor must fill out a time sheet/crew sheet. Complete all fields. Please include the name and contact number of your general foreman, safety person or lead person on site.

Staging Areas

- Your LG&E and KU lead person will provide you the location information.
- We make every attempt to control access to the site, so always wear your wristband.
- Park only in designated areas and follow all traffic control devices.
- Always drive slowly inside the staging areas due to the high number of pedestrians, delivery vehicles and staff needed to support the staging area.
- For safety purposes, back into a parking space upon arrival to avoid backing out.
- If you must back, always use a spotter.

Job Briefings

Documented job briefings are required by our state regulatory agency — the Kentucky Public Service Commission.

- Start every job, regardless of how small, with a job briefing.
- Every person working on a job must document that he or she participated in the job briefing by signing the sheet.
- You are required to retain the job briefing form for 30 days.
- If situations change during the course of a job, another job briefing is required.
- Always note the county and the location of your work on the briefing, in the event you need to call 911.

Lead Person/BirdDog

A bird dog is a qualified lead person and is usually a company employee. However, depending on the magnitude of the event, it could be a qualified resident business partner. The roles of this person are to:

- serve as the contact point for the company;
- get you to your job site;

POLE CHART

(Pole Height - Class - Type and IIN Number)

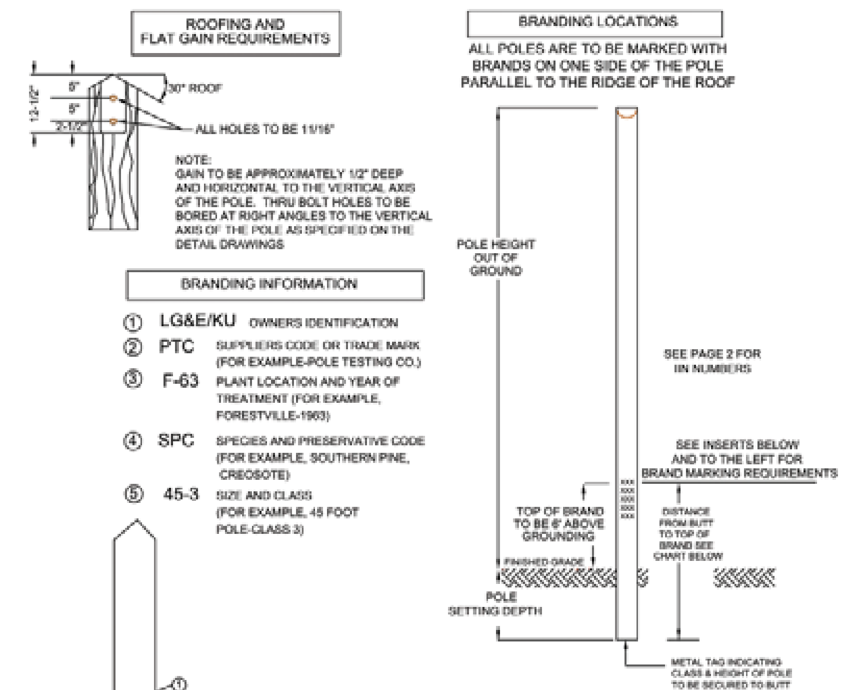
Southern Pine CCA Treated

Southern Pine CCA, Penta Or Creosote Treated

Southern Pine CCA, Penta Or Creosote Treated Or Douglas Fir Penta or Creosote Treated

	Pole Class											
Height (ft.)	H6	H5	H4	H3	H2	H1	1	2	3	4	5	6
20'												
25'												0934319
30'									7004950	1196401		7002367
35'								7002368		7002369	7002370	
40'							7002371	7002372	7004448	7002373		
45'							7002374	7002375	7002376	7002377		
50'							7002378	7002379	7002380			
55'							7002381	7002382	7002383			
60'							7002384	7002385				
65'	1247501	1247519	1247527	1196860	1196851	1196843	7002386	7005006				
70'	1247694	1247494	1197851	1197860	1196878	1247686	7002388	7002389				
75'	1247719	1247701	1197886	1197127	1197843	1247678	7002390	7002391				
80'	1247735	1247727	1247643	1197119	1197101	7006589	7002392	7006444				
85'	1247751	1247743	1247627	1197094	1197086	7006590	7002393	7004344				
90'	1197060	1247778	1247601	1247619	1197078	7006591	7002394					
95'	1247586	1247794	1247594	1197043	1197051	7006592	7002395					
100'	1247578	1247543	1197019	1197027	1196643	1197035	7001404					
105'	1247560	1247819	1196986	1196994	1196719	7006593	7001405					
110'	1247551	1247827	1196943	1196951	7006594	1196978	7001406					
115'	1196778	1247535	1196894	1247843	1196886	1247835						
120'	1196919	1196786	1196901	1247860	1196960	1247851						
125'	1196935	1196819	1196927	1247886	1197878	1247878						

Electric System Codes & Standards — GENERAL REQUIREMENTS FOR WOOD POLES — 04 01 02 Rev. D



ALL POLES SHALL BE MARKED WITH BRANDS ON SIDE PARALLEL TO THE RIDGE OF THE ROOF

ACTUAL POLE HEIGHT	POLE SETTING DEPTH	POLE HEIGHT OUT OF GROUND	DISTANCE FROM BUTT TO BRAND
25'	5'-0"	20'-0"	11'-0"
30'	5'-6"	24'-6"	11'-6"
35'	6'-0"	29'-0"	12'-0"
40'	6'-0"	34'-0"	12'-0"
45'	6'-6"	38'-6"	12'-6"
50'	7'-0"	43'-0"	13'-0"
55'	7'-6"	47'-6"	13'-6"
60'	8'-0"	52'-0"	14'-0"
65'	8'-6"	56'-6"	14'-6"
70'	9'-0"	61'-0"	15'-0"
75'	9'-6"	65'-6"	15'-6"
80'	10'-0"	70'-0"	16'-0"
85'	10'-6"	74'-6"	16'-6"
90'	11'-0"	79'-0"	17'-0"
95'	11'-6"	83'-6"	17'-6"
100'	12'-0"	88'-0"	18'-0"
105'	12'-6"	92'-6"	18'-6"
110'	13'-0"	97'-0"	19'-0"
115'	13'-6"	101'-6"	19'-6"
120'	14'-0"	106'-0"	20'-0"
125'	14'-6"	110'-6"	20'-6"

LG&E KU PPL companies — Electric Design And Construction Standards — Replaces NONE — By: Clark/Leake 06/20/2003 Page 1 of 2

- answer any questions;
- request and release clearances;
- provide information; and
- process work orders and coordinate materials for jobs.

Required PPE

LG&E and KU require you to wear certain PPE in order to work for the companies. You must have these items before you can begin work.

If your policies differ from those listed here, please contact an LG&E or KU safety representative.

- Hard hat — Make sure the hat meets safety standards.
- Safety glasses — Have ANSI Z87.1 clear and tinted.
- Overshoes — These are highly recommended, but they are not required.
- Clothing —Long-sleeve flame-resistant (FR) shirts, with a minimum of eight calories protection, are required. This can be achieved by layering a FR undershirt and outer shirt to achieve the eight-calorie minimum. Pants must be an eight-calorie minimum as well. Rain suits that will be worn in hot work situations must also be FR-rated.
- Climbing gear — Wear appropriate belt and climbers with properly sharpened gaffs.
- Fall protection — Wear appropriate fall protection devices for the work being performed, including harnesses for work from aerial platforms.
- Chaps — When using a chainsaw on the ground, wear chaps along with proper hearing and eye protection.
- Cover-up material — Have an adequate amount.
- Gloves — Gloves suitable for the work being performed must be worn. Rubber gloves and sleeves (Class 2) are required and must be worn together when:
  - Performing work on 600 volts and above while working within five feet of energized line;
  - Opening and closing or disconnecting fuses with a stick, other than a tested extendo, from the ground;
  - Installing or removing grounds;
  - Testing for primary voltage with a voltage detector with an eight-foot stick; and
  - Testing voltage on a new transformer.

  Low-voltage gloves (Class 0) must be used while working on 50 to 600 volts.

Work Zone Safety

Proper work zones must always be established and managed to ensure the safety of workers as well as the public. Follow these basic rules.

- Place work signs on both sides of the work zone. The distance and locations should be determined by road conditions, traffic and visibility.

General Information

- Always use your vehicle's emergency flashers or strobes while working on the road or shoulder.
- Utilize cones to control and direct traffic and barricade the public from the work zone.
- Use certified flaggers when necessary.
- Flags are a temporary traffic signaling device; paddles should be used as quickly as they can be made available.
- When working within 15 feet of a roadway, wear a high-visibility Class II or Class III vest.
- Always control the public's access to the work area.

Tree Work

We will make every effort to have adequate tree crews available to assist you; however, you may have to occasionally trim, fell or clear a tree. When you do:

- Chaps are required when using a chainsaw on the ground.
- Always evaluate the situation before cutting a tree.
- When felling a tree, always clear and identify your escape route.
- Use care and always determine the possible load created by the tree being cut. Limbs, conductors, cable and messengers can all release with a tremendous amount of energy if held under strain by the tree.

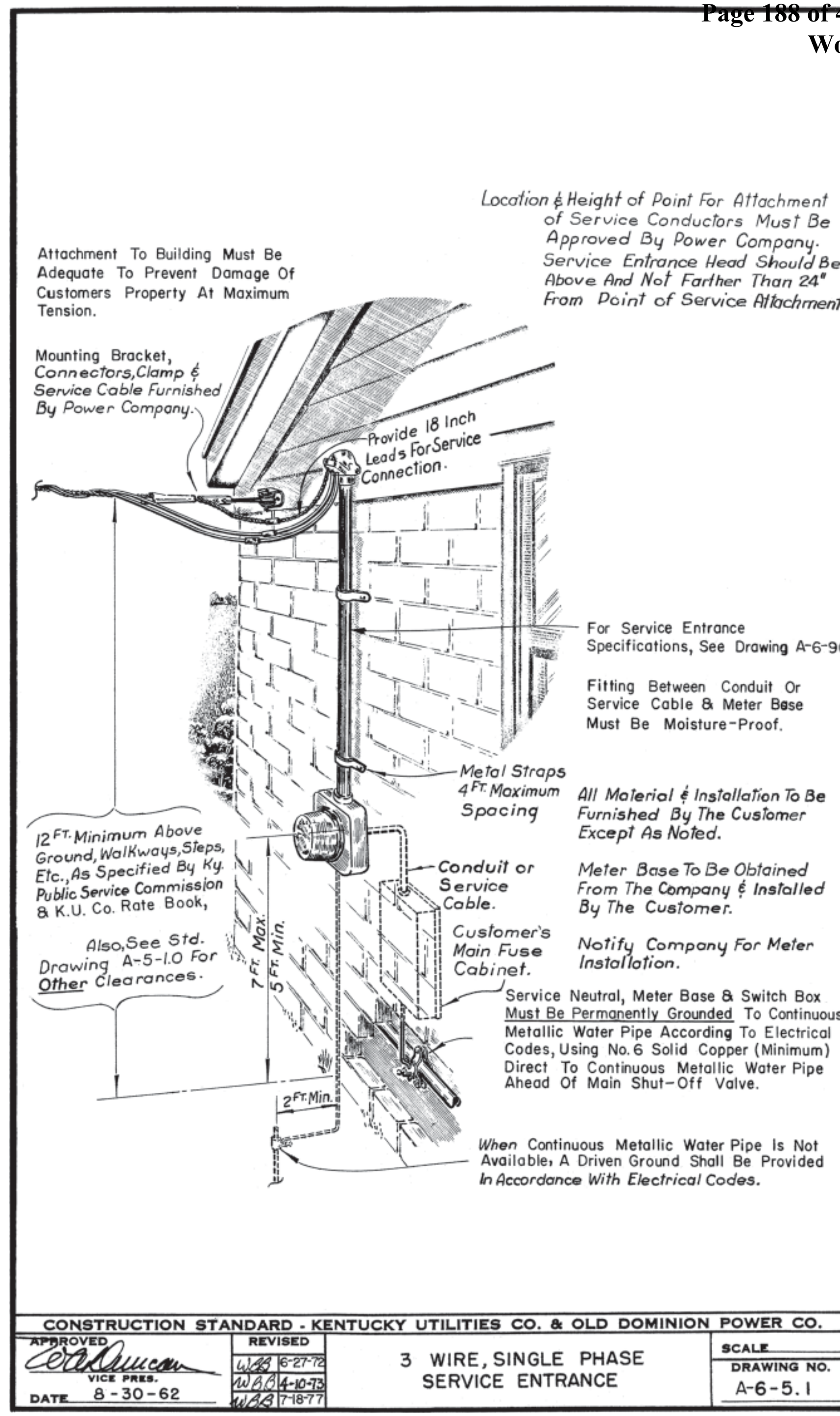
Lock Out/Tag Out (LOTO)

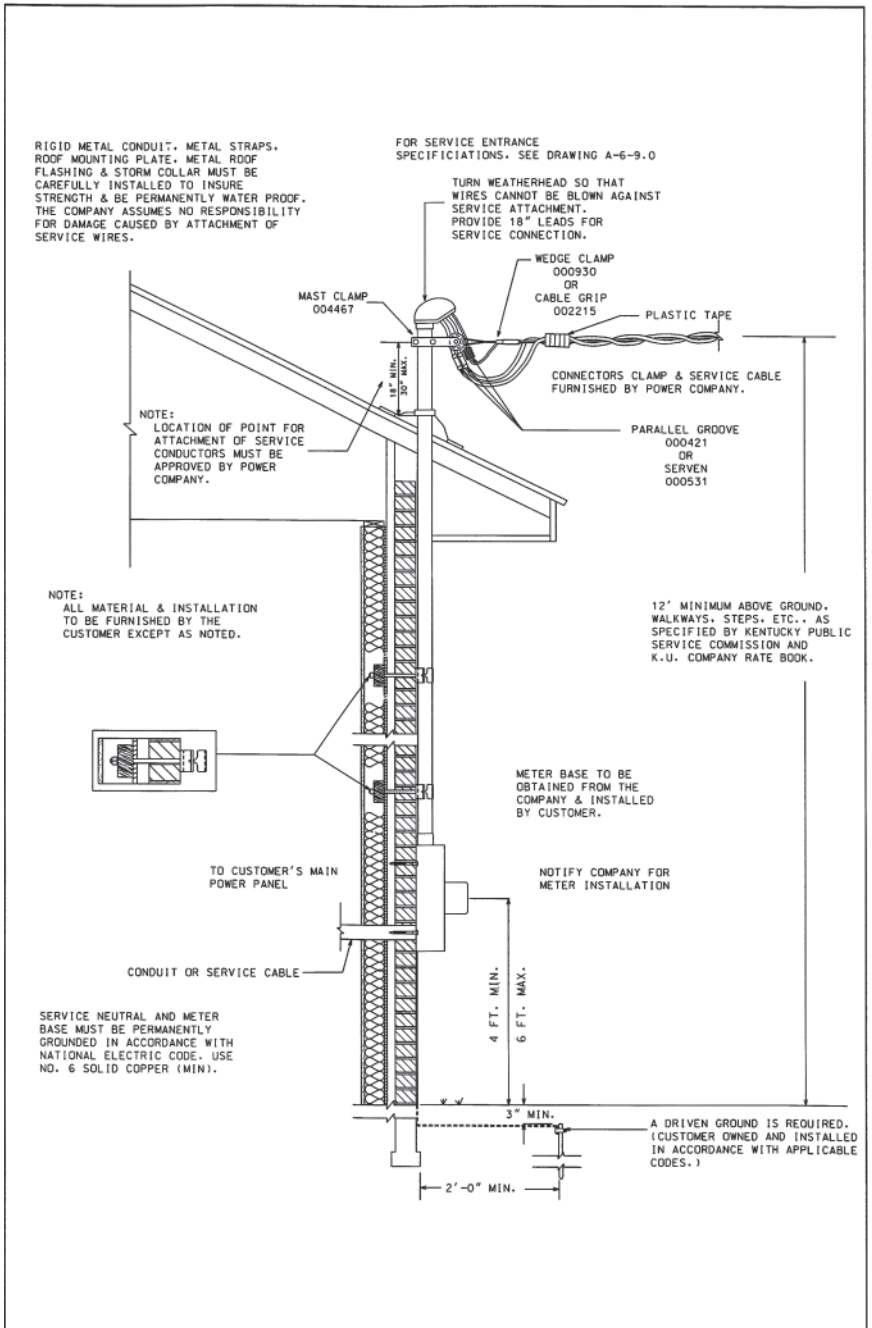
- All work clearances will be requested and released through the Distribution Control Center by the lead person in charge of the job site.
- Hold cards must be placed on the energy source devices; each opened device will have a hold card attached.
- Caution cards will be used in one-shot situations.
- Once repairs are completed, your lead person will call the Distribution Control Center to release clearance and get permission to energize the line.
- In addition to these minimum requirements, you must also follow your company's LOTO requirements.

Grounding Equipment

The following equipment should be used for grounding purposes on our systems.

- Class 2 rubber gloves and sleeves;
- voltage detector;
- eight-foot shotgun stick; and
- grounding cluster ring (when using equipotential grounding).
- **LG&E**
  — #2/0 copper grounds for the Distribution system.





CONSTRUCTION STANDARD - KENTUCKY UTILITIES CO. & OLD DOMINION POWER CO.			
APPROVED Date 10-17-96	REVISED	THREE WIRE SINGLE PHASE RESIDENTIAL MAST TYPE SERVICE ENTRANCE	Scale: Drawing Number A-6-5.0

— #4/0 copper grounds for the Transmission system.

- **KU**
  — #2 copper grounds for the Distribution system.
  — #2/0 copper grounds for the Transmission system.

Remember: If It's Not Grounded; It's Not Dead!

Grounding Methods

- Equipotential and bracket grounding methods are acceptable while working on the LG&E and KU systems. Use caution at all time while grounding.
- Place grounds as close to the work area as possible.
- Eliminate all sources of backfeed inside the bracket-grounded area by opening the transformer fuses, taplines, or fuses or by pulling meters.
- Watch out for secondary tie-breakers and remove them if possible (LG&E territory only).

Grounding Safety and Forestry Management

Line techs who work with or near tree trimmers should use special caution. They may be working under LOTO and grounds. You may be asked to ground for them or show them the location of grounds. Be sure to communicate effectively, and help ensure their safety.

Line Voltages

You will find these voltages on the LG&E and KU system.

- 34.5 kv / 22 kv / 13.8 kv delta
- 12,470 volts phase to phase / 7,200 volts phase to ground
- 4,160 volts phase to phase / 2,400 volts phase to ground

Secondary Voltages

- 120 / 240
- 120 /208
- 240 / 480
- 277 / 480

In LG&E territory, some delta banks are straight 240. (Watch out for triplex providing three-phase 240 volts.)

The Customer's Property

Be extremely mindful of the impression you leave on customers as you go about restoration work.

- Please be respectful of customers' property.
- Climb when safe and possible to avoid damage to yards and driveways.
- Document with your lead person when trucks are taken off the road in the event

General Information

damages occur.

- If you damage a customer's property, tell your lead person so the proper documentation can be filled out and repairs can be made.

Customer or Media Requests

During emergency situations, LG&E and KU constantly gather, verify and process information to share with the public though numerous media channels. It is imperative all messages be consistent and accurate. Consequently, all media information must be provided by the LG&E and KU Communications Department. If you are approached by a media person at the work site, professionally and politely direct the individual to your LG&E and KU lead person who can provide him or her with the appropriate contact information. Or, you can refer the person to the Communications Department at 502-627-4999. Do not attempt to address media questions on your own.

Environmental Compliance

Notify your lead person immediately upon discovering transformer oil spills, hydraulic oil spills, etc. Or, immediately contact LG&E and KU Environmental Affairs at 502-627-4512 (office) or 502-558-4464 (cell).

Incident Reporting

- An incident involving an employee, contractor, motor vehicle or property damage should be reported immediately to your LG&E and KU lead person.
- Make sure you are always aware of the county and your location in case you need to call 911!

Safety Communications

- Communication is critical during a major outage event.
- We will utilize numerous avenues to ensure all pertinent safety information is made available to you, our business partners.
- Daily safety bulletins will be posted at staging areas and included in work packets.
- Safety conference calls may be held daily with key personnel. (Notification will be made when these are implemented.) These calls are intended to provide your company representative with important safety information, including incident review, outage numbers and procedural updates.

Conference call protocol *— Due to the large number of participants on conference calls, it can be difficult for everyone to clearly hear the messages. We request that all callers mute their phones to prevent interruptions, unnecessary background noise or disruptions to the communication process. These calls are formatted to be one-way communication. If you have questions, please call the Safety Report Line at 502-627-3061 and leave a short message and call-back number. You will be contacted before*

TRANSFORMER OR BANK SIZE KVA	SINGLE PHASE (One Transformer)		THREE PHASE (Three Transformers)	
	Primary Voltage		Primary Voltage	
	2400	7200	4160	12470
250	175	100	---	---
333	200	125	---	---
500	300*	150	---	---
667	NOT AN ANSI STANDARD	NOT AN ANSI STANDARD	---	---
750	---	---	175	100
833	---	175	---	---
1000	---	200	200	125
1250	---	250*	---	---
1500	---	---	300*	150
1667	---	300*	---	---
2000	---	---	---	175
2500	---	---	---	175
3000	---	---	---	200
3750	---	---	---	250*
5000	---	---	---	300*

NOTES:

I. Fuse ratings are for S&C Positrol Fuse Links "QR" Speed -- TCC No.166-6 except those marked with an asterisk (*) which are Southern States type "F" links.

II. See note II. Page A-4-13.0 for proper fusing of three phase banks utilizing two transformers.

05-14-99
Files: A-4-13P1.DOC
A-4-13P1.DGN

CONSTRUCTION STANDARD - KENTUCKY UTILITIES CO. & OLD DOMINION POWER CO.

APPROVED
Date 10-10-99

REVISED

DISTRIBUTION
POWER BANK
FUSING TABLE

Scale:
Drawing Number
A-4-13.1

KVA	SINGLE PHASE (One Transformer) Primary Voltage 2400	7200	12470	THREE PHASE (Three Transformers) Primary Voltage 2400 Delta	4160 Wye	7200 Delta	12470 Wye
1.5	3	1	1	3	3	1	1
3	3	1	1	5	3	2	1
5	7	2	1	10	7	3	2
7.5	10	3	2	15	10	5	3
10	15	5	2	20	15	7	5
15	20	7	3	30	20	10	7
25	30	10	7	50	30	20	10
37.5	50	15	10	75	50	25	15
50	60	20	15	100	60	40	20
75	75	30	20	125	75	50	30
100	100	40	25	150	100	60	40
167	150	60	40	200	150	100	60
250	175	100	60	See A-4-13.1			

NOTES:

I. Fuse ratings are for S&C Positrol Fuse Links "QR" Speed -- TCC No.166-6

II. Three phase banks utilizing only two transformers cannot be fused according to the table above and are to be fused as follows:

OPEN Y -- OPEN DELTA or OPEN Y -- OPEN Y
Fuse each transformer the same as in single phase installations.

OPEN DELTA -- OPEN DELTA or OPEN DELTA -- OPEN Y
Fuse outside leads the same as in single phase installations. Fuse the common lead with the next fuse size larger than the total of 3/4 of the smaller outside fuse rating and the larger outside fuse rating. For example - Given a 10 KVA 7200V transformer and a 50 KVA 7200V transformer to be connected open delta on the primary side: Fuse the 10 KVA transformer with a 5 amp fuse, the 50 KVA with a 20 amp fuse and the common lead with a 25 amp fuse (next size larger than (3/4*5)+20=23.75).

RP
12-7-94 6:00 pm
Files: A-4-13P0.DOC
13P0BDR.DGN

CONSTRUCTION STANDARD - KENTUCKY UTILITIES CO. & OLD DOMINION POWER CO.

APPROVED	REVISED		Scale:
Date 1-25-95		DISTRIBUTION OVERHEAD TRANSFORMER FUSING TABLE	Drawing Number A-4-13.0

the next conference call.

Safety Concerns or Issues

If you have safety concerns, you can report them anonymously or leave a contact name for a response on the Safety Report Line (502-627-3061). All reports will be reviewed and addressed in a timely manner.

Restoration Conclusion

At the end of the restoration effort, please ensure you wrap up your work appropriately.

- Complete and submit all time information to the appropriate person.
- Return any work packet material to your LG&E and KU lead person.
- Return all material to the site designated by your LG&E and KU lead person.
- Return to your LG&E and KU lead person all tools and equipment we provided.

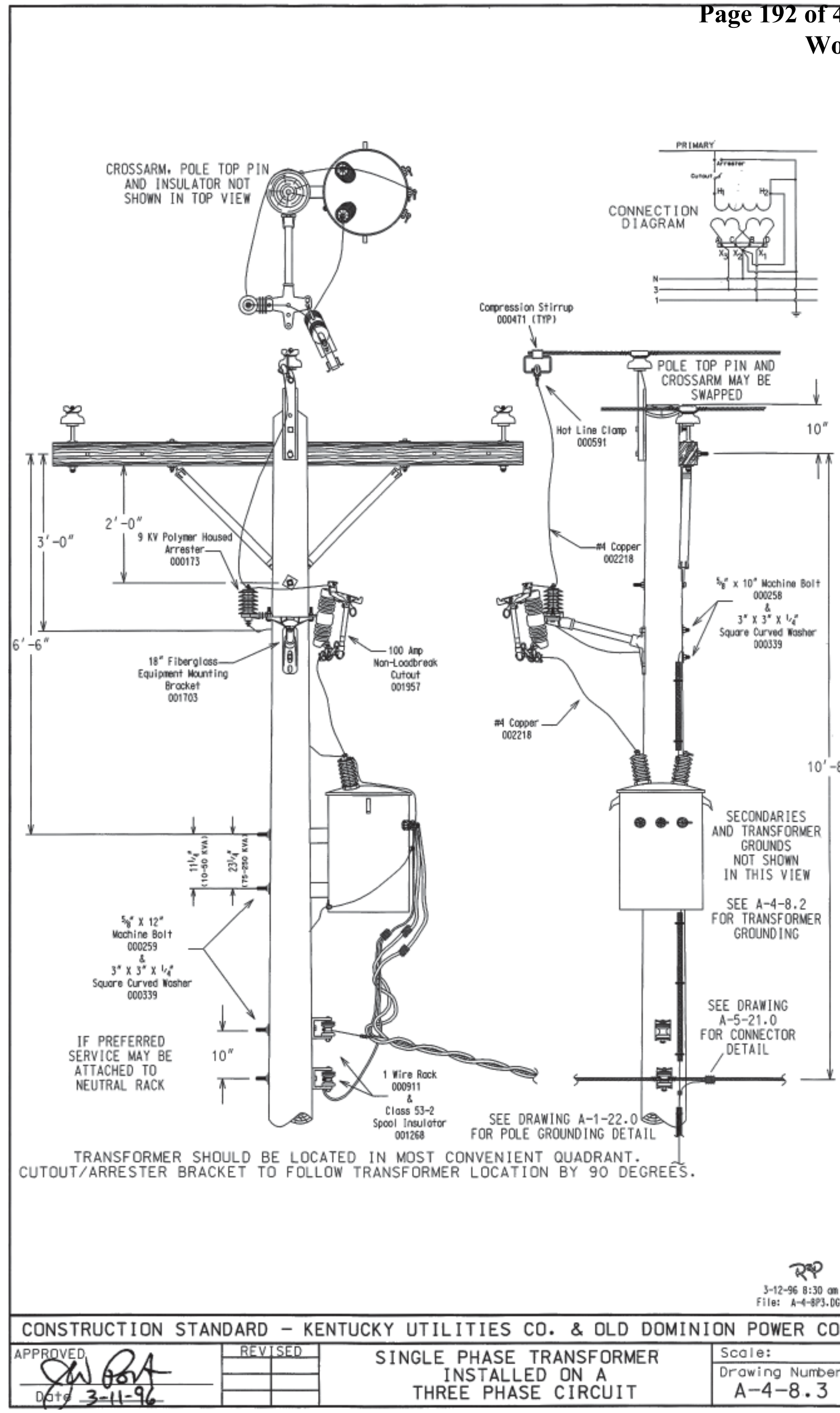
Travel Tips For The Road Home

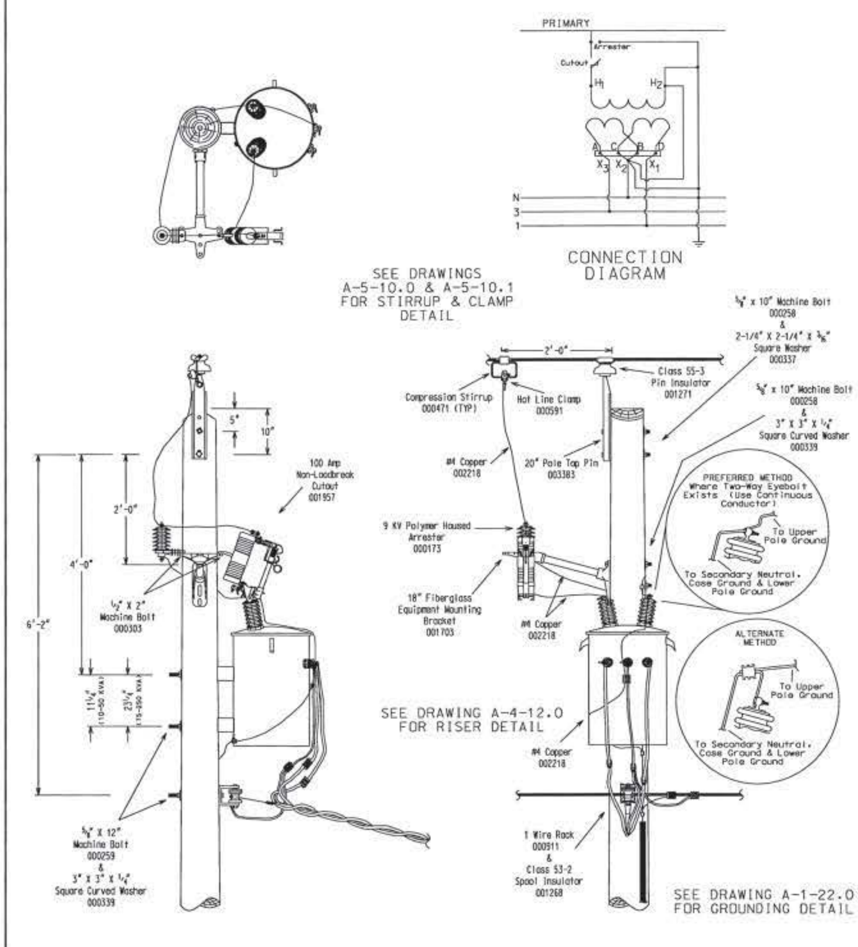
- Make sure your vehicle is ready to travel; windshield clean and clear; mirrors clean and adjusted correctly; lights clean and working.
- Complete your DOT pre-trip form.
- Ensure your drivers are rested and alert.

General Information

Thanks for your help. As you travel to your home, please remember — when it comes to your safety…

No Compromise!

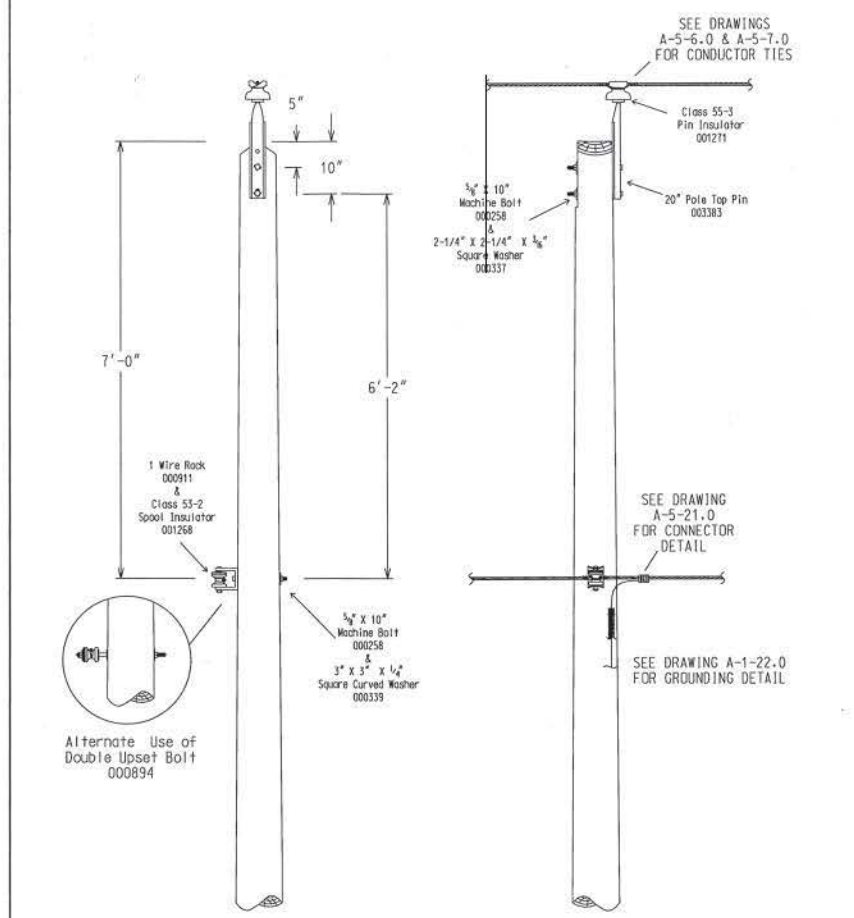




TRANSFORMER SHOULD BE LOCATED IN MOST CONVENIENT QUADRANT.
CUTOUT/ARRESTER BRACKET TO FOLLOW TRANSFORMER LOCATION BY 90 DEGREES.

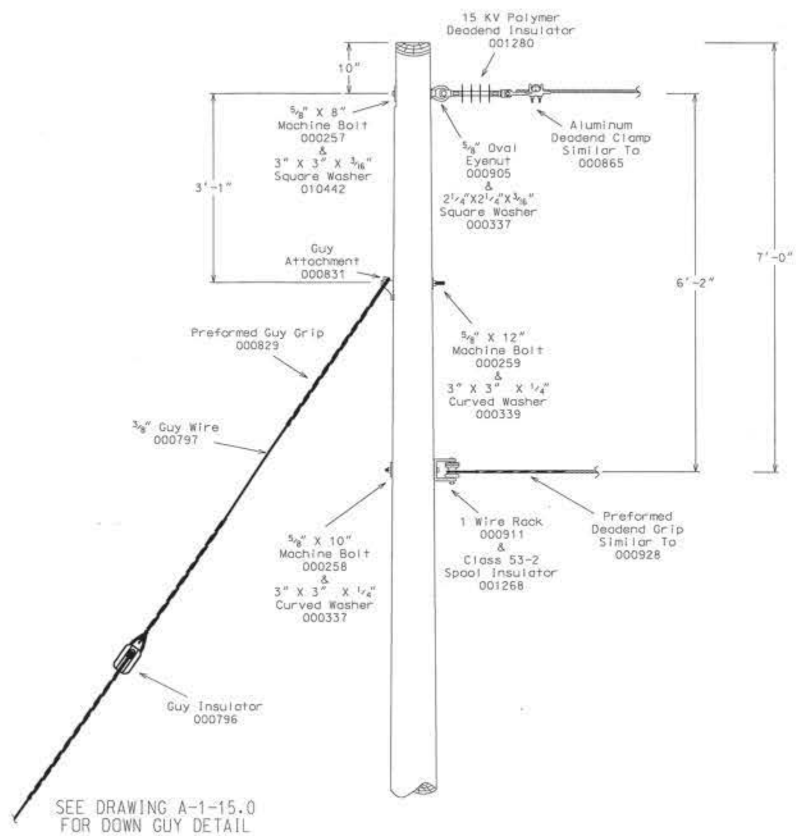
10-27-93 2:30 pm
File: A-4-8P2P.DGN

CONSTRUCTION STANDARD - KENTUCKY UTILITIES CO. & OLD DOMINION POWER CO.			
APPROVED Date 11-12-93	REVISED	SINGLE PHASE TRANSFORMER INSTALLATION	Scale: Drawing Number A-4-8.2



11-1-93 2:45 pm
File: A-1-1.DGN

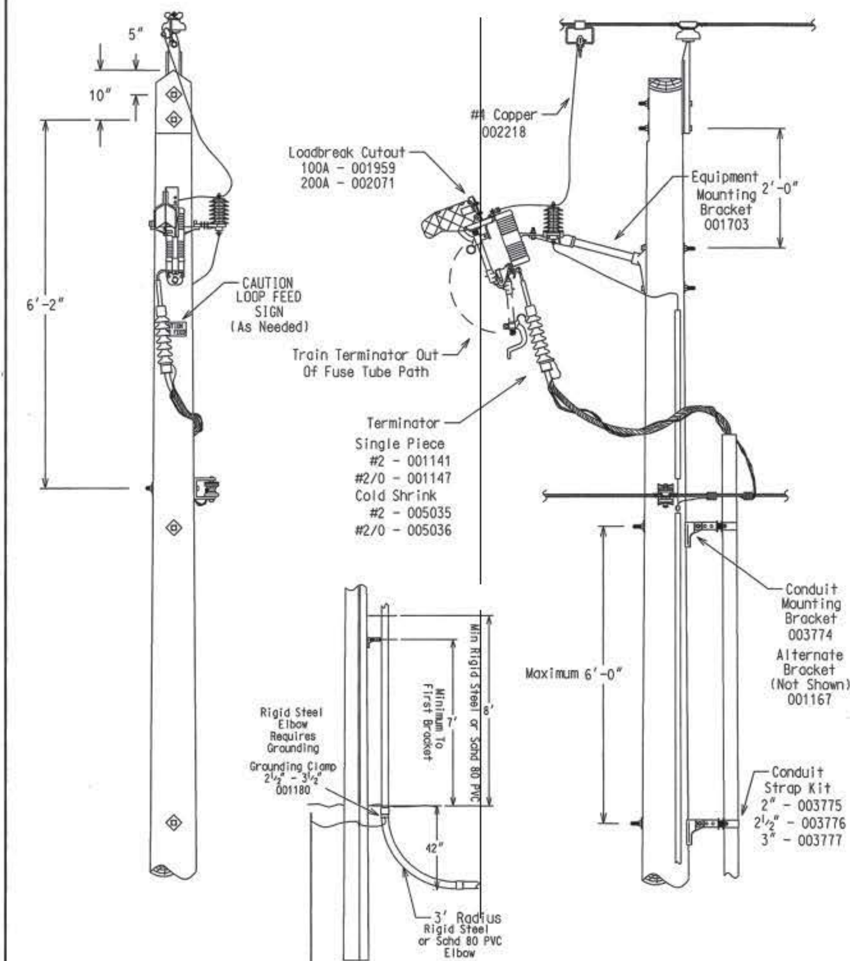
CONSTRUCTION STANDARD - KENTUCKY UTILITIES CO. & OLD DOMINION POWER CO.			
APPROVED Date 11-12-93	REVISED	SINGLE PHASE TANGENT	Scale: Drawing Number A-1-1.0



1-19-93 3:30 pm

CONSTRUCTION STANDARD - KENTUCKY UTILITIES CO. & OLD DOMINION POWER CO.

APPROVED	REVISED	SINGLE PHASE DEADEND	Scale:
Date 1-28-93			Drawing Number A-1-2.5



8-16-95 2:00pm
File: A-2-3PO.DGN

CONSTRUCTION STANDARD - KENTUCKY UTILITIES CO. & OLD DOMINION POWER CO.

APPROVED	REVISED	SINGLE PHASE RISER POLE	Scale:
Date 3-11-96			Drawing Number A-2-3.0

LENGTH OF POLE	DEPTH OF SETTING-FEET	
IN FEET	DIRT	ROCK
30	5 1/2	SAME AS DIRT
35	6	
40	6	
45	6 1/2	
50	7	
55	7 1/2	
60	8	
65	8 1/2	

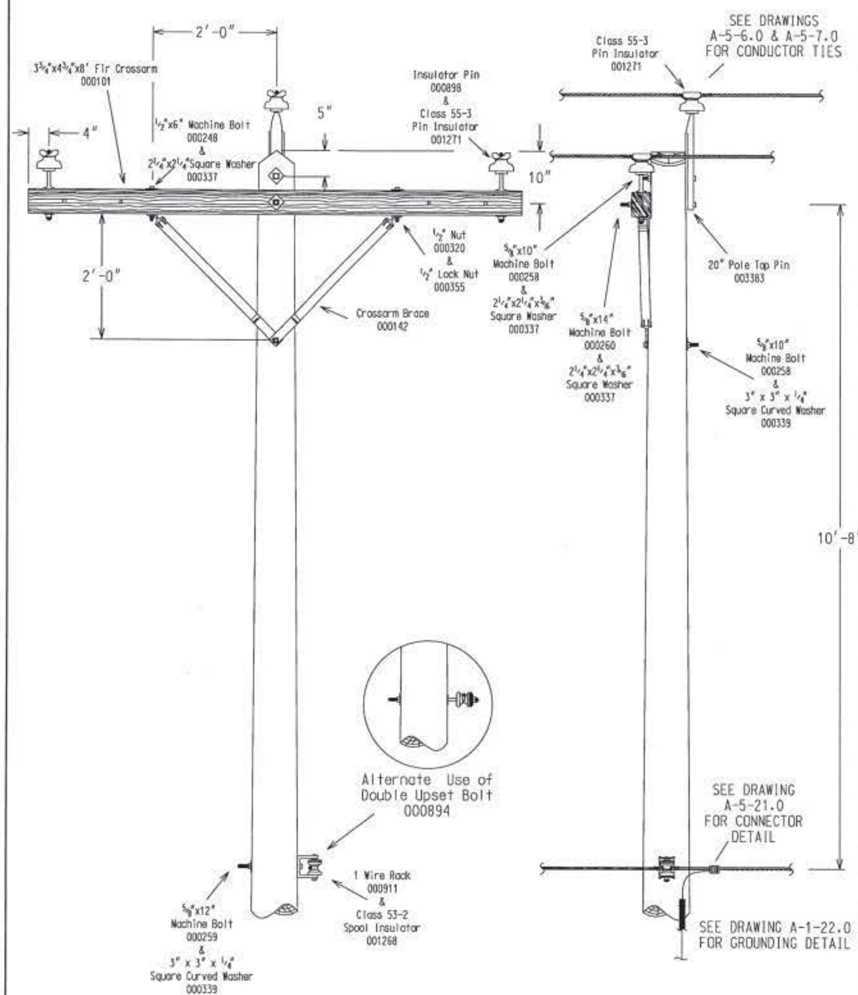
NOTE: 1. These depths shall be used for all classes of poles.

2. In soft or marshy ground, set poles deeper as required and back fill with crushed rock or gravel, but do not bank. See standard drawing 1-21.0

3. On slopes pole depth shall be measured on downhill side.

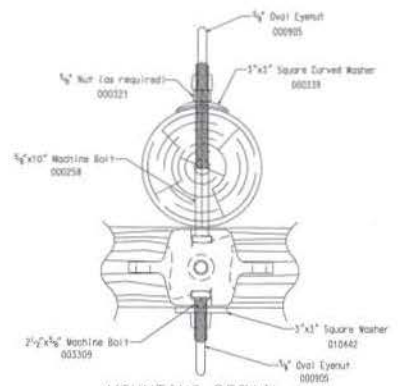
CONSTRUCTION STANDARD - KENTUCKY UTILITIES CO. & OLD DOMINION POWER CO.

APPROVED	REVISED		SCALE
VICE PRES.		POLE SETTING DEPTHS DISTRIBUTION	DRAWING NO.
DATE 5-26-58			A-1-30.0



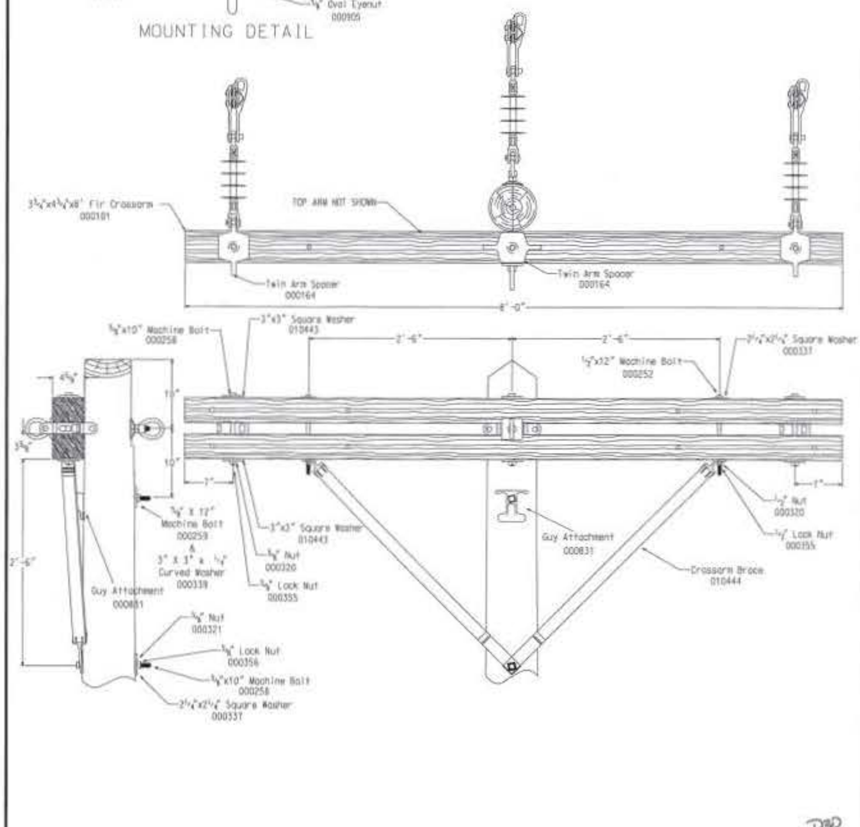
CONSTRUCTION STANDARD - KENTUCKY UTILITIES CO. & OLD DOMINION POWER CO.

APPROVED	REVISED		Scale:
		THREE PHASE TANGENT ALL CONDUCTOR SIZES	Drawing Number
Date 11-12-93			A-1-7.0



APPLICATION NOTES

1. This deadend assembly is suitable for use on #2 & #2/0 ACSR Conductors.
2. Guying requirements will vary for different guy leads. See A-1-14.0 for general guidelines.

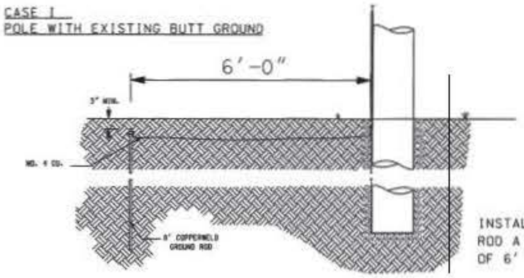


CONSTRUCTION STANDARD - KENTUCKY UTILITIES CO. & OLD DOMINION POWER CO.

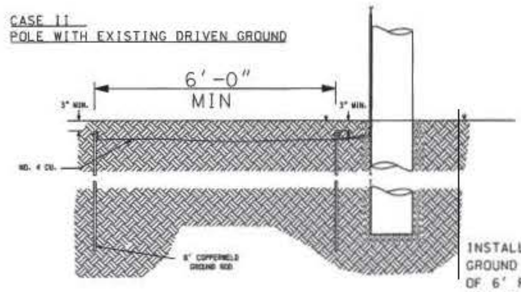
APPROVED	REVISED	THREE PHASE DEADEND FOR #2 & #2/0 ACSR DETAIL	Scale:
Date 1-29-93			Drawing Number A-1-14.1

NOTE: SEE DWG. A-1-22.0 FOR GROUND LEAD INSTALLATION TO SYSTEM NEUTRAL. ALL NOTES APPLY TO A-1-22.0 AND A-1-23.0.

CASE I
POLE WITH EXISTING BUTT GROUND



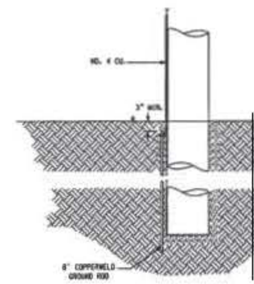
CASE II
POLE WITH EXISTING DRIVEN GROUND



APPLICATION NOTE:

A GROUND ROD IS TO BE INSTALLED IN ADDITION TO A BUTT COIL GROUND ON ALL TRANSFORMER POLES AND POLES SUPPORTING PROTECTIVE OR SWITCHING EQUIPMENT. INCLUDING CAPACITOR BANKS.

CASE III
POLE WITH NO GROUND



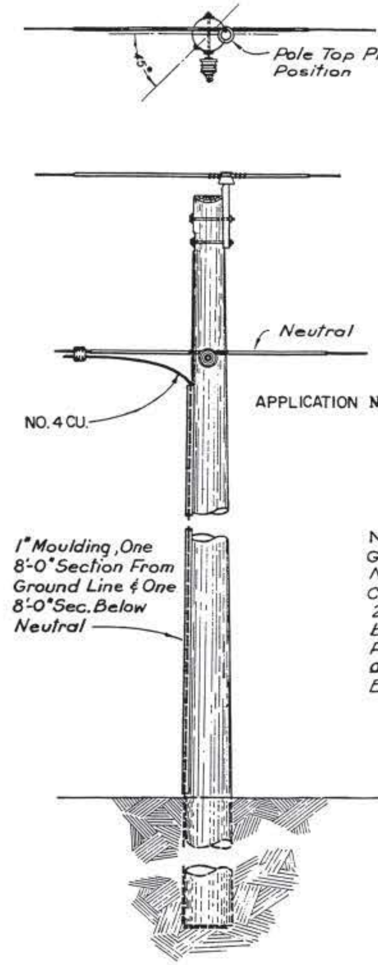
CONSTRUCTION STANDARD - KENTUCKY UTILITIES CO. & OLD DOMINION POWER CO.

APPROVED	REVISED	GROUND ROD APPLICATION PRACTICE	Scale:
Date 12-22-99			Drawing Number A-1-23.0

NOTE:
When the pole is installed near a street curb or other traveled ways, the ground wire should be rotated to one of the quadrants away from traffic.

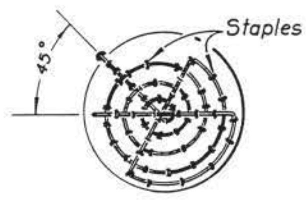
CAUTION

GROUND WIRES WHICH ARE ATTACHED TO POLES BEING SET IN OR NEAR ENERGIZED LINES SHALL BE COILED AND TEMPORARILY SECURED TO POLE AT THE GROUND LINE AND NOT EXTENDED UP THE POLE UNTIL SETTING IS COMPLETED. BEFORE REMOVAL OF POLES THAT ARE EQUIPPED WITH GROUND WIRES, SUCH WIRES MUST BE REMOVED.



APPLICATION NOTE: THIS TYPE OF GROUND TO BE INSTALLED ON EVERY NEW POLE.

NOTE:
Ground Wire to be Located on Same Side as Neutral Conductor and in Quadrant Opposite Climbing Space. Staples on Ground Wire Shall be 2 Feet Apart. Ground Wire to Clear all Hardware by 2" Min. and Shall be Stapled to Maintain This Position. Install two Sections of 8 Ft. Moulding as Shown with a Minimum Spacing of 2'-0" Between Staples.



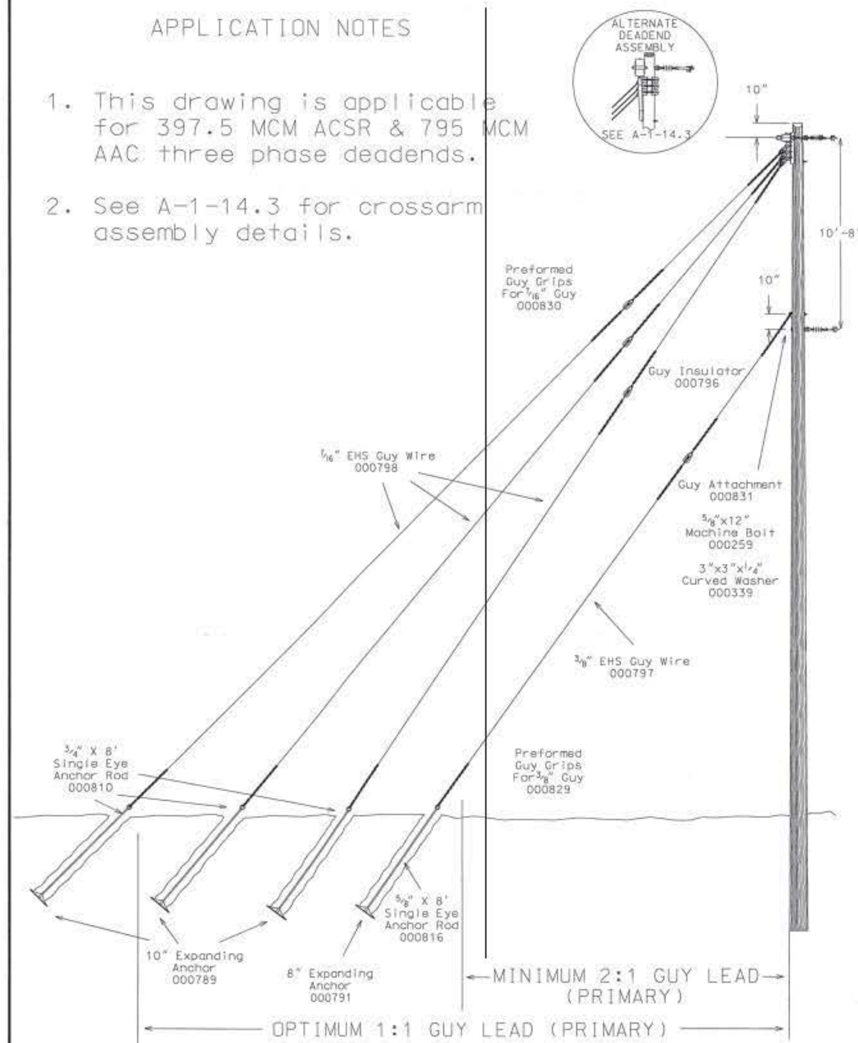
PLAN OF COIL TYPE GROUND

Ground wire must be repaired or replaced when broken or damaged.

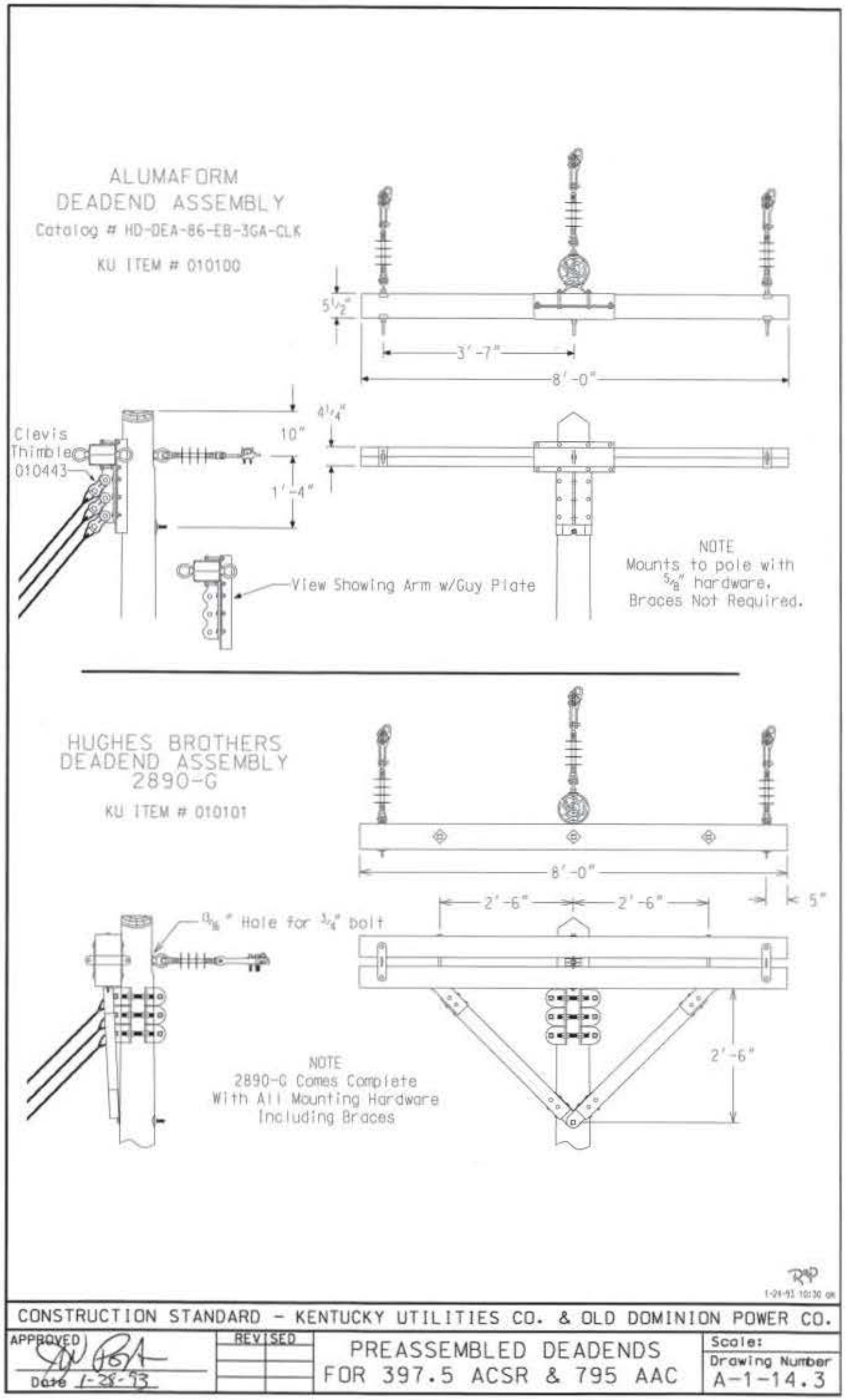
CONSTRUCTION STANDARD - KENTUCKY UTILITIES CO. & OLD DOMINION POWER CO.			
APPROVED VICE PRES. DATE 9-28-56	REVISED 2-20-98	GROUNDING ASSEMBLY BUTT COIL TYPE	SCALE ½"=1'-0" DRAWING NO. A-1-22.0

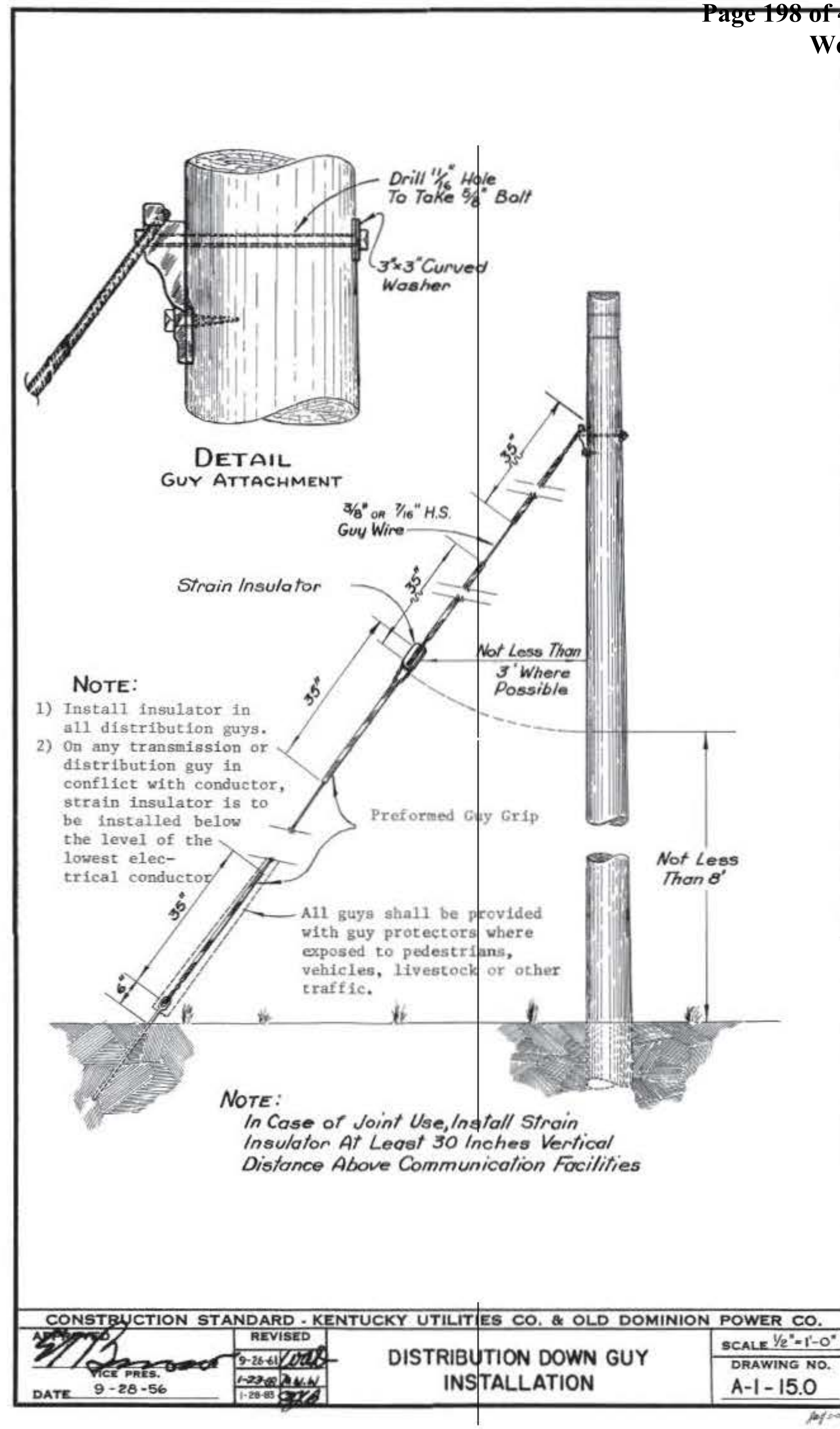
APPLICATION NOTES

1. This drawing is applicable for 397.5 MCM ACSR & 795 MCM AAC three phase deadends.
2. See A-1-14.3 for crossarm assembly details.



CONSTRUCTION STANDARD - KENTUCKY UTILITIES CO. & OLD DOMINION POWER CO.			
APPROVED Date 1-28-93	REVISED	THREE PHASE DEADEND FOR 397.5 ACSR & 795 AAC OVERVIEW	Scale: Drawing Number A-1-14.2


ALUMAFORM
DEADEND ASSEMBLY
Catalog # HD-DEA-86-EB-3GA-CLK
KU ITEM # 010100
5 1/2"
3'-7"
8'-0"
4 1/4"
10"
1'-4"
Clevis
Thimble
010443
View Showing Arm w/Guy Plate
NOTE
Mounts to pole with 5/8" hardware.
Braces Not Required.
HUGHES BROTHERS
DEADEND ASSEMBLY
2890-G
KU ITEM # 010101
8'-0"
2'-6"
2'-6"
5"
13/16" Hole for 3/4" bolt
2'-6"
NOTE
2890-G Comes Complete
With All Mounting Hardware
Including Braces
CONSTRUCTION STANDARD - KENTUCKY UTILITIES CO. & OLD DOMINION POWER CO.
APPROVED
Date 1-28-93
REVISED
PREASSEMBLED DEADENDS
FOR 397.5 ACSR & 795 AAC
Scale:
Drawing Number
A-1-14.3


Drill 11/16" Hole
To Take 5/8" Bolt
3"x3" Curved
Washer
DETAIL
GUY ATTACHMENT
3/8" or 7/16" H.S.
Guy Wire
35"
35"
35"
35"
6"
Strain Insulator
Not Less Than
3' Where
Possible
NOTE:
1) Install insulator in all distribution guys.
2) On any transmission or distribution guy in conflict with conductor, strain insulator is to be installed below the level of the lowest electrical conductor
Preformed Guy Grip
All guys shall be provided with guy protectors where exposed to pedestrians, vehicles, livestock or other traffic.
Not Less
Than 8'
NOTE:
In Case of Joint Use, Install Strain
Insulator At Least 30 Inches Vertical
Distance Above Communication Facilities
CONSTRUCTION STANDARD - KENTUCKY UTILITIES CO. & OLD DOMINION POWER CO.
APPROVED
VICE PRES.
DATE 9-28-56
REVISED
9-26-61
1-23-80
1-28-93
DISTRIBUTION DOWN GUY
INSTALLATION
SCALE 1/2"=1'-0"
DRAWING NO.
A-1-15.0

Independent Hold Card (IHC) Program

Distribution Substation

Effective Date 12/16/2013

Independent Hold Card Program

Independent Hold Cards

During significant events on the Electric Distribution system, when large volumes of outage events and resource levels inundate Restoration Coordinators and saturate dedicated radio channels, the Distribution Control Center (DCC) and Operations Sections (OS) may elect to transfer control of all aspects of energy isolation and control procedures to qualified and approved personnel working on (operating, maintenance, repair, and construction) the electric distribution system

Formal Transfer of Authority

Upon electing to transfer hold card authority, the appropriate DCC and OS leaders shall complete the Independent Hold Card Authorization Form (See Appendix, page 26) before granting permission to operate the electric distribution system under independent/individual clearance.

The DCC and OS shall determine the scope of the transfer (Company, Operations Center, Geographical Area, Substation, or Circuit), and establish the effective date and time when the Operations Section can safely assume independent hold card responsibilities. The scope shall be limited to areas where there is no possible back feed from a source outside the defined scope area.

Lead personnel shall formally authorize transfer in accordance with Independent Hold Card Authority Matrix (See Appendix A, page 27).

Upon formally transferring authority, the OS shall be responsible for communicating the transfer effective date(s) and time(s) to affected field personnel. The DCC shall be responsible for communicating the transfer to their personnel.

Each OS shall be responsible for designating qualified personnel and maintaining a separate LO/TO provider list for this purpose.

The OS shall be responsible for enforcing the requirement that qualified personnel do not operate isolation devices containing active hold cards, previously assigned a number and under control of the DCC, without receiving permission from the DCC.

Qualified personnel authorized to assume hold card responsibilities shall adhere to established lockout/tagout procedures when opening and closing devices on the electric distribution system, including:

- Conduct job briefing with all personnel working behind the isolation device(s);
- Apply hold cards in accordance with established procedures, under the authorized qualified person;

Independent Hold Card Program

- Document pertinent hold card information on the Independent Hold Card Log (See Appendix A, page 28);
- Confirm all personnel working under hold cards are in the clear and accounted for prior to operating an energy isolation device;

The DCC shall continue to be responsible for opening and closing devices in the System Tracking Application, to confirm customer counts are accurate.

- Qualified personnel opening energy isolation devices on the electric distribution system shall notify the DCC when opening devices to confirm customer counts stay accurate in the System Tracking Application.
- Qualified personnel needing to close isolation devices on the distribution system shall notify the DCC, immediately after closing the device in the field.

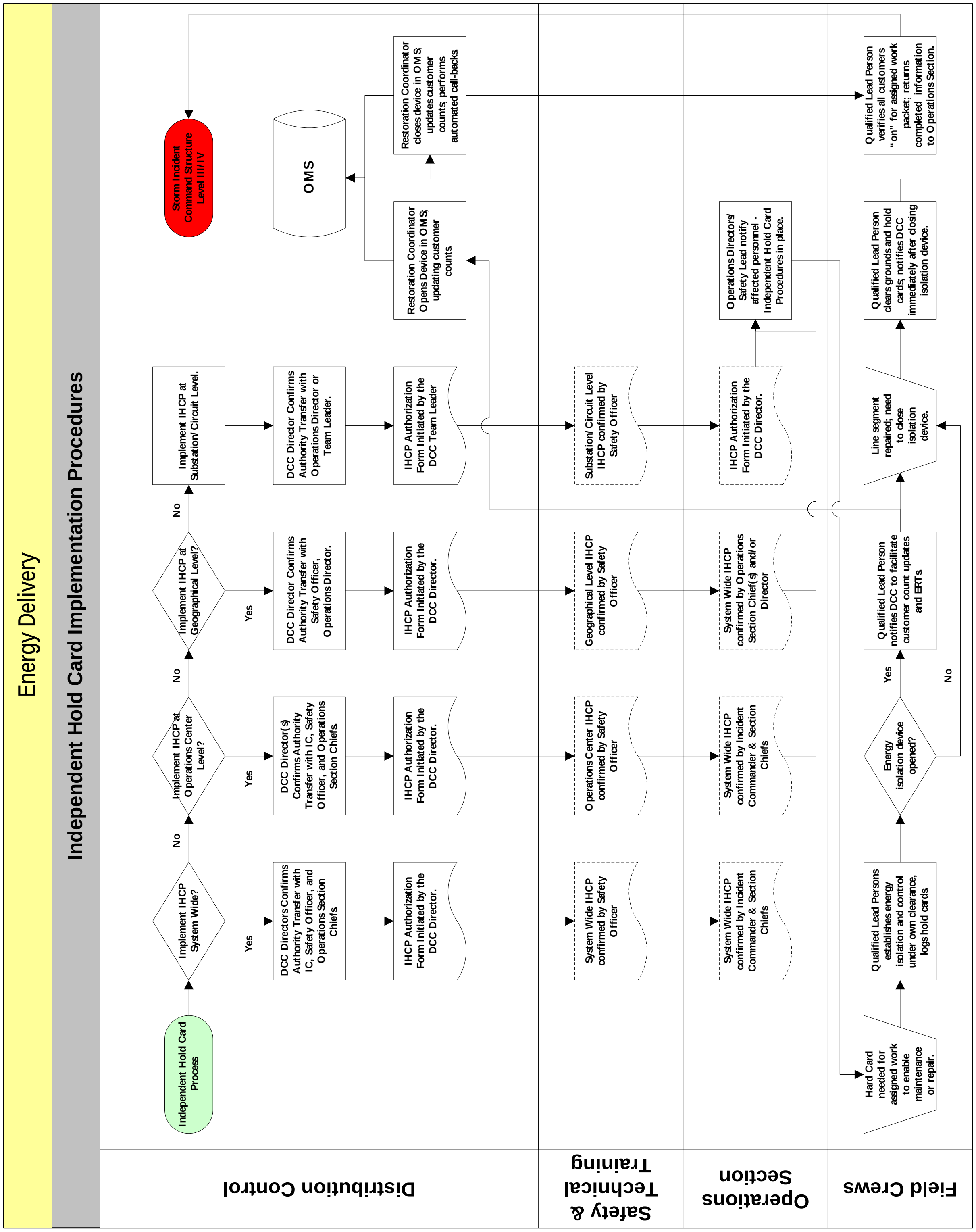
The DCC shall be responsible for confirming that field personnel requesting clearance from the Distribution Control Center are referred to the OS and made aware of the Independent Hold Card scope.

Revocation of Authority

Throughout the period in which Independent Hold Card Programs are in place, the DCC and OS shall evaluate the ability to revoke independent hold card authority, and transfer responsibility for hold cards back to the DCC. When an optimum time is identified and agreed upon, appropriate lead personnel shall document the transfer through completion of the revocation dates and signature lines on the Independent Hold Card Authorization Form.

Control of the Lockout/Tagout processes shall be transferred back to DCC upon formal completion and dissemination of the revocation effective date and time to affected personnel by the OS. Typically, all independent hold cards should be removed and all customers should be restored, prior to the DCC and OS formally transferring hold card authority back to the DCC. In the event formal transfer is deemed necessary prior to the completion of restoration work, all authorized qualified personnel still working behind independent hold cards shall be required to establish their hold cards with the DCC prior to operating an energy isolation device.

Independent Hold Card Program



Independent Hold Card Program

Independent Hold Card Authorization Form

Company Level:

☐ KU ☐ LG&E

Operations Center Level:

☐ LG&E

☐ Lexington ☐ Georgetown ☐ Versailles

☐ Maysville ☐ Paris ☐ Mount Sterling ☐ Morehead

☐ Danville ☐ Cambellsville ☐ Richmond ☐ Winchester

☐ Shelbyville ☐ Carrolton ☐ Elizabethtown

☐ Earlington ☐ Greenville ☐ Eddyville ☐ Morganfield ☐ Barlow

☐ Pineville ☐ Harlan ☐ London ☐ Somerset

☐ Norton ☐ Pennignton Gap

Geographical Area(s) Level:

______ ______ ______
______ ______ ______
______ ______ ______

Substation/Circuit(s) Level:

______ ______ ______
______ ______ ______
______ ______ ______

	Authorization	**Revocation**
Incident Commander:	______	______
DCC Director(s):	______	______
Operations Section Chief(s):	______	______
	______	______
Operations Director(s):	______	______
	______	______
	______	______
Safety Officer:	______	______
Effective: **Date:**	______	______
Time:	______	______

Independent Hold Card Program

Energy Delivery
Electric Distribution
Independent Hold Card Authority Matrix

	Authorization Scope			
	System Wide	**Operations Center**	**Goegraphical Area**	**Substation/Circuit Level**
	Authorization Level			
Incident Commander	X	X	X	
Distribution Control Center				
Director	X	X	X	X
Team Leader				X
Operations Section				
Chief	X			
Operations Director		X	X	
Team Leader			X	X
Safety				
Safety Officer	X	X		
Safety Specialist			X	X

Independent Hold Card Program

Bull Dog/Bird Dog Name: ____________________ **Storm Date:** ____________________

Card #	Installed Date & Time	Removed Date & Time	Device	OH/URD Circuit	Operating # (TLM)	Location	Person in Charge
EX. JB-1	1/30/2009 8:00	1/30/2009 16:00	FU	HK1234	101894	R/ 8006 Barbourmeade Rd	Hoskins

EPRP Appendix 5 Communications Information

LG&E KU
Emergency Preparations and Response Call Agenda

Call Details

Date:	
Time:	12:00:00 AM
Phone:	1 (877) 411-9748
Access Code:	4377288
Moderator Code:	7967

Event Name:
Event Start Date:
Peak Outages:
Current Outages:
Note Taker:

Next Call Details

Date:	
Time:	
Phone:	1 (877) 411-9748
Access Code:	4377288
Moderator Code:	7967

Incident Command Roles	Role Call		Executive Strategy	Regulatory Outreach	Community Leader Outreach	Public Safety Response Team	Worker Safety	Off System Passporting	Media	Customer Communications	Government Communications	Regulatory Communications	Command Structure	Preparedness and Response	Tactical Strategy	Distribution Lines	Distribution Control Center	Substations	System Planning/Engineering	Transmission	Forestry	Gas Distribution	Call Centers	Walk In Center	Ombudsman Team	Emergency Management Outreach	Staging	Lodging	Meals	Materials	Facilities	Security	Transportation/Fuel	Outside Services Contracts	Mutual Assistance Resources	Resource Tracking/Reporting	Information Technology	Telecommunications	Financial Reporting
Executive Officer	Thompson, Paul																																						
	Bellar, Lonnie																																						
	Wolfe, John																																						
	Malloy, John																																						
	Siemens, George																																						
	Conroy, Robert																																						
	Whelan, Chris																																						
Safety Officer	Sheridan, Ken																																						
	Chambers, Amanda																																						
Communications Officer	Collins, Natasha																																						
	Phillips, Brian																																						
Incident Commander	Woodworth, Steve																																						
	Huff, David																																						
Operations Section Chief	McFarland, Beth																																						
	Simon, Denise																																						
	Steinmetz, Keith																																						
Customer Experience Section Chief	Bruner, Cheryl																																						
	Leist, Debbie																																						
	Alexander, Keith																																						
Logistics Section Chief	Cockerill, Butch																																						
	Schmitt, Mark																																						
Work Planning Section Chief	Montgomery, Shannon																																						
	Simon, Denise																																						

Other:

Yellow and Red Alert Confernce Call Checklist (0-24 hours)

Incident Command Position	Agenda Item	Checklist
Incident Commander		
	Role Call	Confirm IC structure is in place; identify personnel and schedules for each Section Chief role; assess personnel needs for all sections.
	Weather/Emergency Condition Report	Assess weather conditions and system threats for service areas
	Industry Status	Assess Industry status to determine potential impacts to resource availability
	Command Centers	Establish location of command center(s); establish contact information
Safety		
	Public Safety (PSRT)	Provide status of PSRT efforts; number of downed wires, wire walkers, service crews, etc…
	Worker Safety	Provide safety status and expectations - safe to work?, work hours, safety considerations, incident or near miss reviews, etc…
	Passporting	Establish arrangements for passporting off system resources.
	Independent Hold Card Status	Establish whether hold card procedures will be decentralized, or if the DCC will continue to issue hold cards.
Operations Section		
	Customer Outages/Events	Provide outage counts, events, wire downs, and any other key information that is available (broken poles, etc…)
	Operations Areas Impacts	Provide overview of impact areas, by Operations Centers.
	Damage Assessment Status	Provide damage assessment status; establish DA duration and resource needs.
	Work Assignment Status	Establish whether the DCC or Resource Rooms will be assigning outage events.
	Transmission System Status	Provide an update on the transmission system.
	Local Estimated Restoration Durations	Provide an Estimated Restoration Duration by Operations Center
	Vegetation Resources	Confirm that adequate vegetation resources are available and assigned to appropriate areas.
Logistics Section		
	Hotels	Discuss needs and availability; alternatives for deltas.
	Meals	Discuss needs and availability; alternatives for deltas.
	Staging Areas	Verify condition and usability of planned staging areas; determine if alternative staging locations are needed.
	Fuel	Discuss needs and availability; alternatives for deltas.
	Materials	Discuss needs and availability; alternatives for deltas.
	Security	Provide status of security needs, assignments, threats.
	Fleet	Determine if incremental equipment or vehicles are needed
Customer Experience Section		
	Emergency Management Outreach	Discuss Emergency Management Outreach status/plans/strategy; determine if any emergency declarations have been established
	Customer Communications	Discuss call center volumes, customer environment, communications strategy
	Walk In Centers	Discuss staffing/opening of walk in centers
	Key and Critical Customers	Establish status of Ombudsman team; assess level of communciations with key and critical customers
Work Planning Section		
	Resource Status	Provide resource counts - needed, assigned, available, secured off system (mutual aid/business partners), in transit, released
	Check-In	Establish areas where resources are staging, and discuss resource needs/processes for checking in off system resources.
	Asset Information Systems	Ensure all information systems are available
	Financial Tracking	Identify financial resource for tracking resources; ensure information flow is as needed.
Communications		
	Media	Discuss media requests, communications strategy, and specific information to be provided
	Internal Communications	Discuss content and medium for information to be shared internally
	External Communications	Discuss details of information to be shared, and establish point(s) of contact
Executives/Officers		
	Regulatory Communications	Discuss details of information to be shared, and establish point(s) of contact
	Daily Storm Goals	Discuss high level response goals - safety, resources, customers, communications

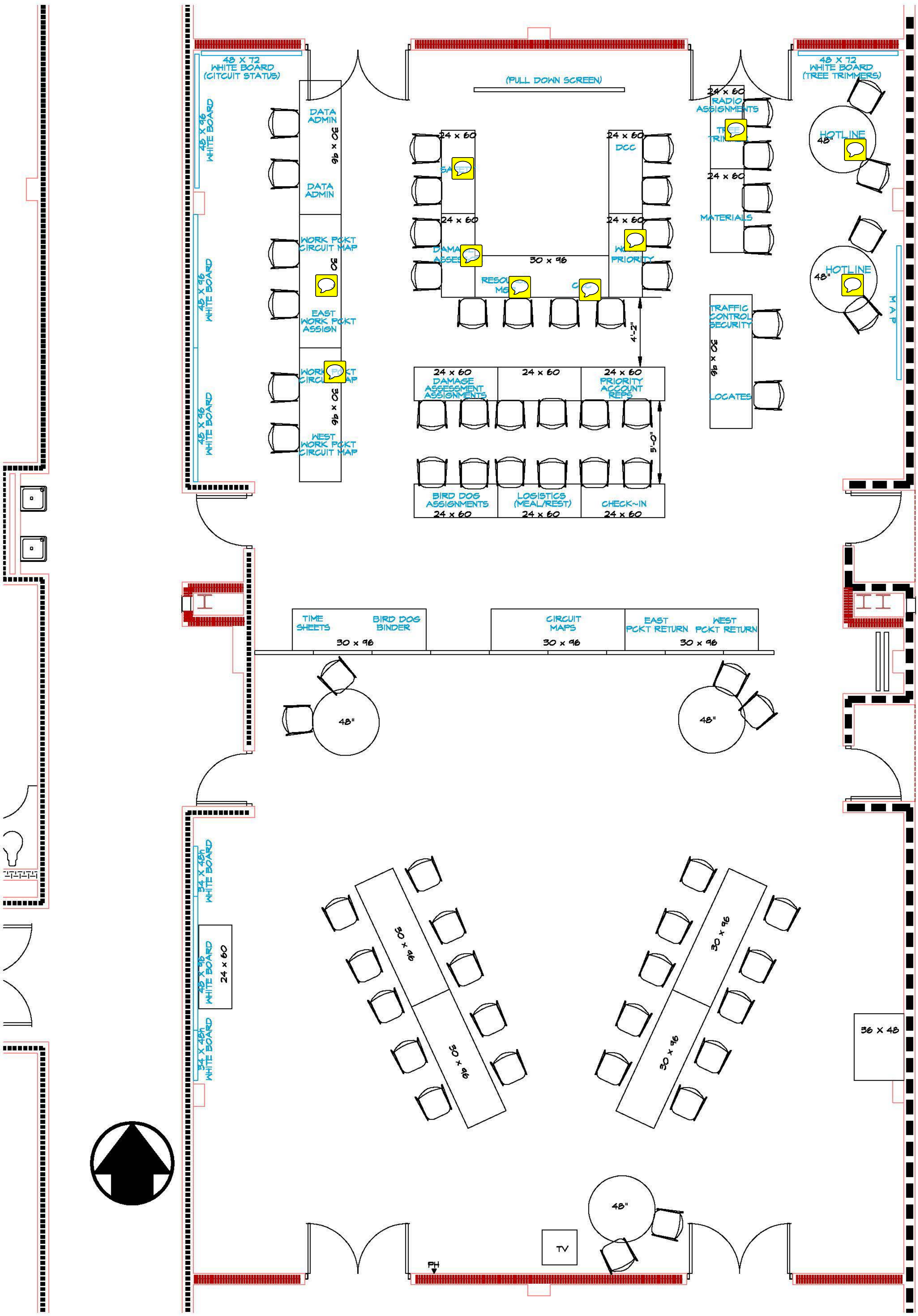
Yellow and Red Alert Confernce Call Checklist (24-48 hours)

Incident Command Position	Agenda Item	Checklist
Incident Commander		
	Role Call	Conduct role call, and determine availability of lead positions in IC structure; assess personnel needs of all sections
	Weather/Emergency Threat Report	Review status of weather/emergency threat(s) on electric distribution system
	Industry Status	Assess Industry status to evaluate the level of mutual aid that may be needed
	Mutual Assistance	Determine if mutual assistance calls should be conducted
Safety		
	Public Safety (PSRT)	Provide status of PSRT alert and preparedness efforts
	Worker Safety	Provide safety update and message(s).
	Passporting	Establish arrangements for passporting off system resources.
Operations Section		
	Customer Outages/Events	Review existing system status and assess capacity of existing resources against current and anticipated needs
	Operations Areas Impacts	Identify areas with highest risk
	Resources	Assess resource needs; determine if mutual aid/incremental off system resources are needed; determine if working resources should be allowed to go home to get rest periods, etc… set up Resource and Work Management Rooms
	Damage Assessment Status	Place damage assessment resources on alert; determine if off system damage assessors should be secured
	Transmission System Status	Eliminate planned outages/maintenance; restore system to normal operating conditions where feasible
	Vegetation Resources	Confirm that adequate vegetation resources are available and assigned to appropriate areas.
Logistics Section		
	Hotels	Reach out to hotel providers to determine availability, place on alert for possible needs
	Meals	Reach out to meal providers to determine availability, place on alert for possible needs
	Staging Areas	Reach out to predestinated staging sites and associated service providers to determine availability, place on alert
	Fuel	Reach out to fuel providers to determine availability, place on alert for possible needs; pre-fuel all vehicles
	Materials	Reach out to material providers, place on alert for possible needs, pre-order storm kits where/when deemed necessary
	Security	Place security resources on alert for possible needs
	Fleet	Place equipment and vehicle providers on alert for possible incremental needs
Customer Experience Section		
	Emergency Management Outreach	Discuss Emergency Management Outreach status/plans/strategy
	Customer Communications	Assess call center resource needs; place personnel on alert
	Walk In Centers	Assess walk in center resource needs; place personnel on alert
Work Planning Section		
	Resource Status	Provide resource counts - needed, assigned, available, secured off system (mutual aid/business partners), in transit, released
	Check-In	Establish areas where resources are staging, and discuss resource needs/processes for checking in off system resources.
	Asset Information	Ensure all critical information systems are available; determine if circuit prints or system maps should be preprinted
Communications		
	Media	Discuss media requests, communications strategy, and specific information to be provided
	Internal Communications	Discuss content and medium for information to be shared internally
	External Communications	Discuss details of information to be shared, and establish point(s) of contact
Executives/Officers		
	Regulatory Communications	Discuss details of information to be shared, and establish point(s) of contact

Yellow and Red Alert Confernce Call Checklist (48+ hours)

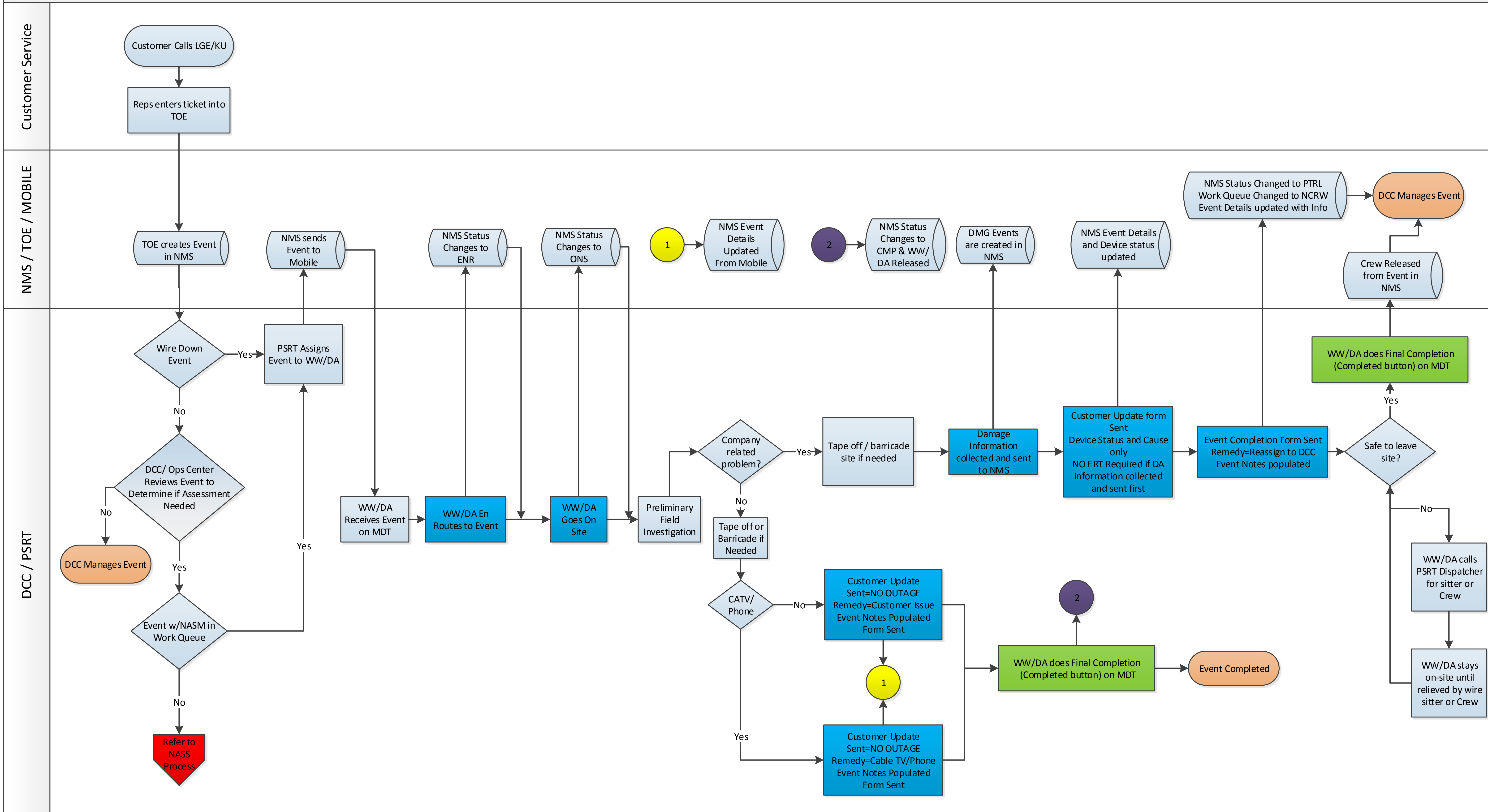
Incident Command Position	Agenda Item	Checklist
Incident Commander		
	Role Call	Conduct role call, and determine availability of lead positions in IC structure; assess personnel needs of all sections
	Weather/Emergency Threat Report	IC to review status of weather/emergency threat
	Industry Status	Assess Industry status to evaluate the level of mutual aid that may be needed
	Mutual Assistance	Determine if mutual assistance calls should be conducted
Safety		
	Public Safety (PSRT)	Provide status of PSRT alert and preparedness efforts
	Worker Safety	Provide safety update and message(s).
	Passporting	Establish arrangements for passporting off system resources.
Operations Section		
	Customer Outages/Events	Review existing system status and assess capacity of existing resources against current and anticipated needs
	Operations Areas Impacts	Assess areas with highest risk
	Resources	Assess resource needs; determine if mutual aid/incremental off system resources are needed; determine if working resources should be allowed to go home to get rest periods, etc… set up Resource and Work Management Rooms
	Damage Assessment Status	Place damage assessment resources on alert; determine if off system damage assessors should be secured
	Transmission System Status	Eliminate planned outages/maintenance; restore system to normal operating conditions where feasible
	Vegetation Resources	Confirm that adequate vegetation resources are available and assigned to appropriate areas.
Logistics Section		
	Hotels	Reach out to hotel providers to determine availability, place on alert for possible needs
	Meals	Reach out to meal providers to determine availability, place on alert for possible needs
	Staging Areas	Reach out to predestinated staging sites and associated service providers to determine availability, place on alert
	Fuel	Reach out to fuel providers to determine availability, place on alert for possible needs; pre-fuel all vehicles
	Materials	Reach out to material providers, place on alert for possible needs, pre-order storm kits where/when deemed necessary
	Security	Place security resources on alert for possible needs
	Fleet	Place equipment and vehicle providers on alert for possible incremental needs
Customer Experience Section		
	Emergency Management Outreach	Discuss Emergency Management Outreach status/plans/strategy
	Customer Communications	Assess call center resource needs; place personnel on alert
	Walk In Centers	Assess walk in center resource needs; place personnel on alert
Work Planning Section		
	Resource Status	Provide resource counts - needed, assigned, available, secured off system (mutual aid/business partners), in transit, released
	Check-In	Establish areas where resources are staging, and discuss resource needs/processes for checking in off system resources.
	Asset Information	Ensure all critical information systems are available; determine if circuit prints or system maps should be preprinted
Communications		
	Media	Discuss media requests, communications strategy, and specific information to be provided
	Internal Communications	Discuss content and medium for information to be shared internally
	External Communications	Discuss details of information to be shared, and establish point(s) of contact
Executives/Officers		
	Regulatory Communications	Discuss details of information to be shared, and establish point(s) of contact

EPRP Appendix 6 Operations Section Information


48 X 72 WHITE BOARD (CITCUIT STATUS)
(PULL DOWN SCREEN)
48 X 72 WHITE BOARD (TREE TRIMMERS)
48 X 96 WHITE BOARD
DATA ADMIN
30 x 96
24 x 60
DCC
RADIO ASSIGNMENTS
HOTLINE
48"
MATERIALS
WORK PCKT CIRCUIT MAP
30 x 96
PRIORITY
EAST WORK PCKT ASSIGN
TRAFFIC CONTROL SECURITY
LOCATES
MAP
4'-2"
DAMAGE ASSESSMENT ASSIGNMENTS
PRIORITY ACCOUNT REPS
WEST WORK PCKT CIRCUIT MAP
5'-0"
BIRD DOG ASSIGNMENTS
LOGISTICS (MEAL/REST)
CHECK~IN
TIME SHEETS
BIRD DOG BINDER
CIRCUIT MAPS
EAST PCKT RETURN
WEST PCKT RETURN
34 X 48h WHITE BOARD
36 X 48
TV
PH

PSRT / Damage Assessment Process
Assumptions: PSRT Active, Everyone on Mobile

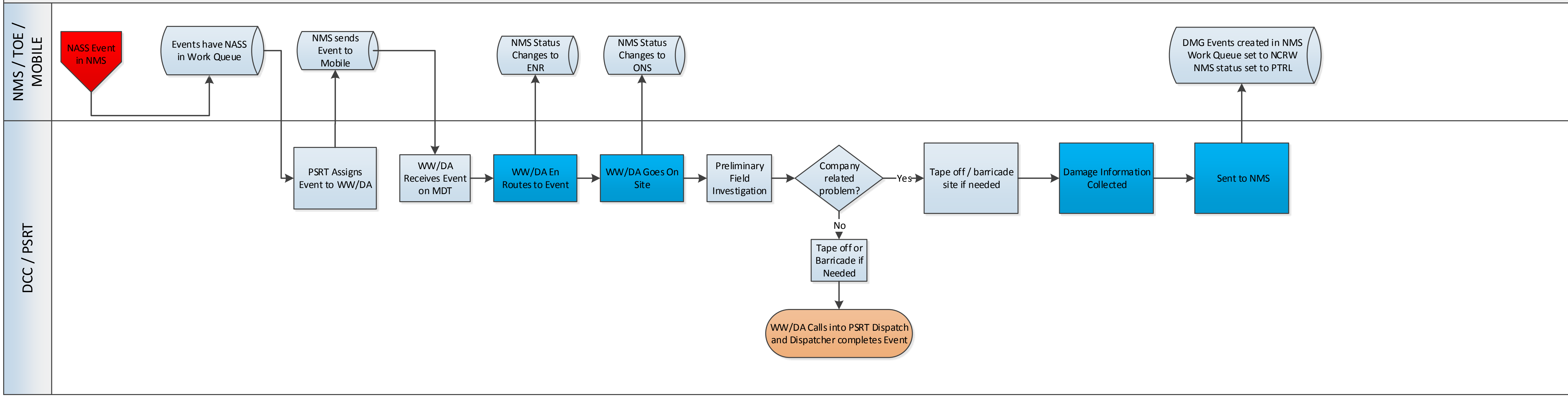
Effective Date: 9/30/2014



DCC = Distribution Control Center	MA = Mobile Application
PSRT = Public Safety Response Team	WW/DA = Wire Walker/Damage Assessor
TOE = Trouble Order Entry	MDT = Mobile Data Terminal
NASS = Event Needs Assessed	

PSRT / Damage Assessment Process
Assumptions: Events marked with NASS in Work Queue, Everyone is Mobile

Effective Date: 9/30/2014



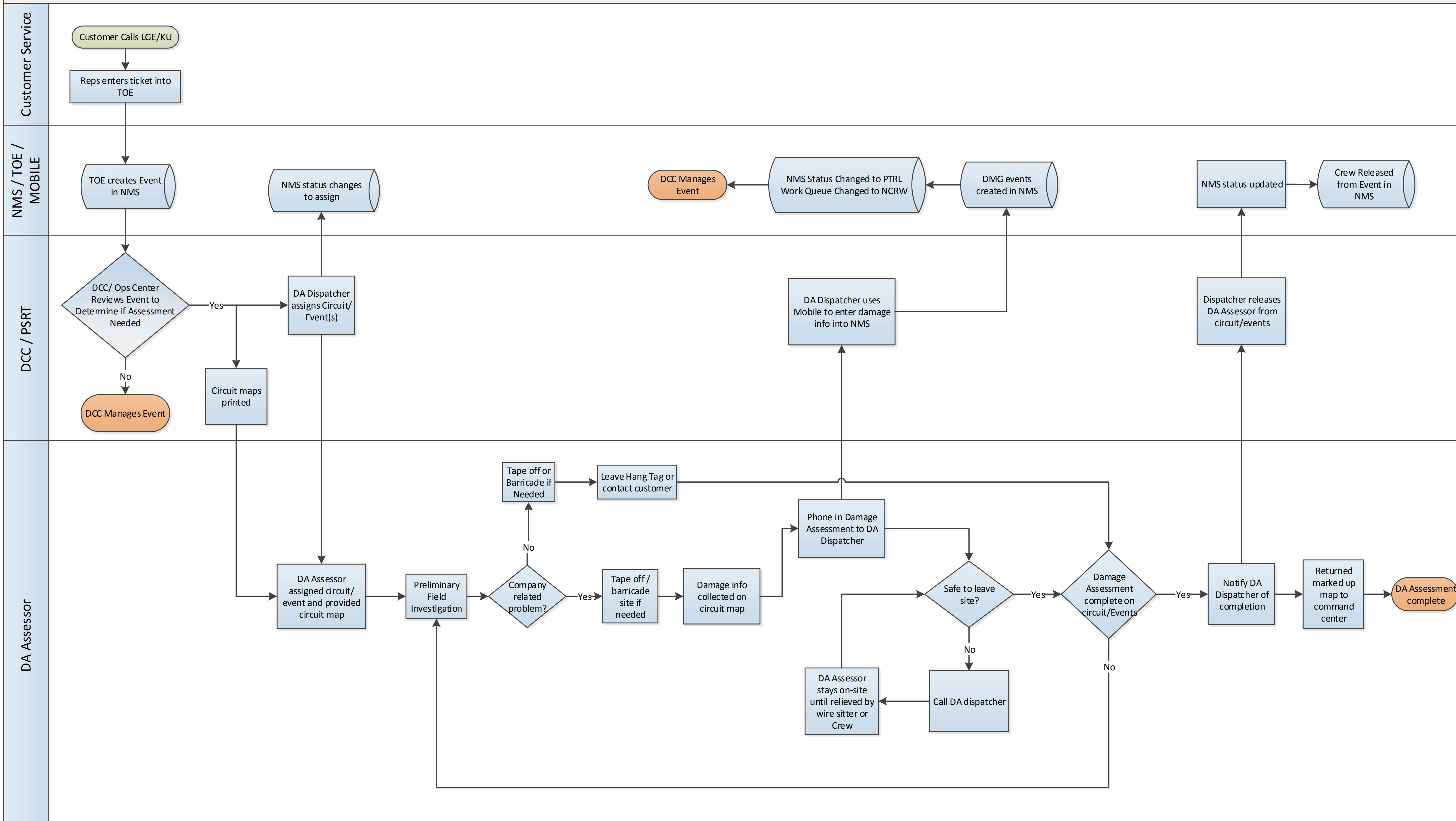
DCC = Distribution Control Center
MA = Mobile Application
PSRT = Public Safety Response Team
WW/DA = Wire Walker/Damage Assessor
TOE = Trouble Order Entry
MDT = Mobile Data Terminal

LG&E KU

PSRT / Damage Assessment Process

Assumptions: PSRT Active, Non-Mobile off system assessors, Dispatchers inputting damages during assessment

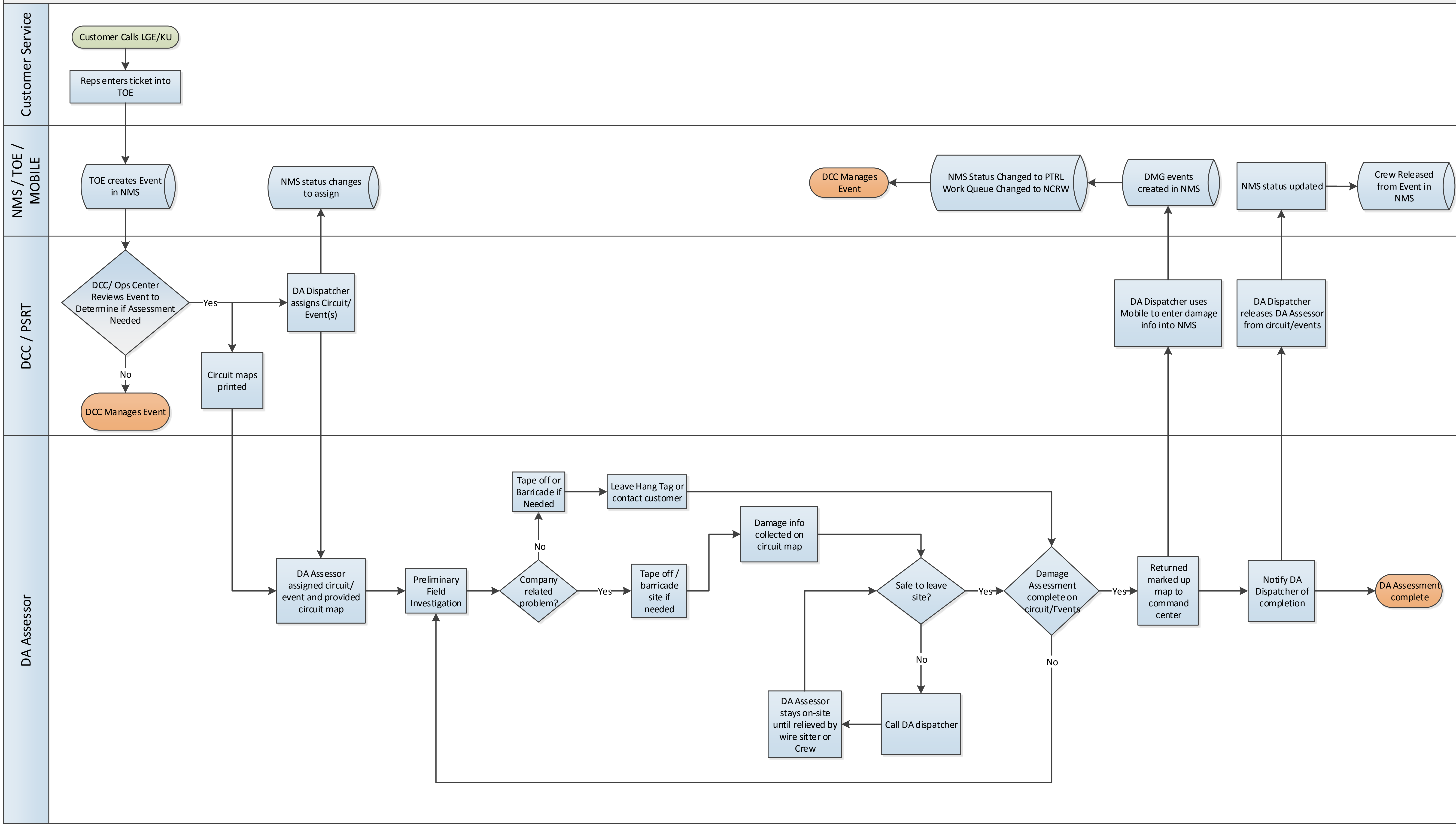
Effective Date: 9/30/2014



PSRT / Damage Assessment Process

Assumptions: PSRT Active, Non-Mobile off system assessors, Damages input after assessment completed

Effective Date: 9/30/2014



EPRP Appendix 7 Customer Experience Information

Municipal Emergency Contacts

KU Municipal	Type of Service		Name	Primary Contact #	Alternate Contact #
Barbourville Utility Commission	Transmission	(1) 69 kv sub	Josh Callihan	[redacted] cell	
Bardstown Municipal Light & Water	Distribution	(3) 12kv subs (1) 4kv sub	Jeff Mills	[redacted] cell	[redacted] office
Bardwell City Utilities	Distribution	(1) 4kv sub	Robin Phelps	[redacted] cell	[redacted] home
City of Berea	Transmission	(2) 69kv subs	Adrian Isaac	[redacted] cell	[redacted] personal cell
Corbin City Utilities Commission	Transmission	(2) 69kv subs	Ron Herd	[redacted] cell	
Falmouth City Utilities	Distribution	(1) 4 kv sub	Gary Lea	[redacted] cell	[redacted] office
Frankfort Electric & Water Plant Board	Transmission	(1) 69 kv sub	Scott Hudson	[redacted] cell	[redacted] cell #2
Madisonville Municipal Utilities	Distribution	(6) 12 kv subs	Chris Melton	[redacted] cell	[redacted] office
Nicholasville City Utilities	Transmission	(4) 69kv subs	Robert Blackford	[redacted]	
City of Paris Combined Utilities	Transmission	meters at point of service	Darren Gates	[redacted] cell	[redacted] home
				On call cell for electric distribution– [redacted]	
Providence Municipal Utilities	Distribution	(2) 4kv subs	Jack Snyder	[redacted] cell	

The individual Municipals listed have committed to be available to be contacted 24/7

Kentucky Emergency Management Contacts

Last Name	First Name	Position	Office Phone	Work Email
Dossett	**Mike**	**Director**	[redacted]	[redacted]
Knighten	**Richard W**	**Assistant Director, Operations**	[redacted]	[redacted]
Robey	**Stephanie**	**Assistant Director, Administration**	[redacted]	[redacted]
Arnold	Debborah	KCCRB Executive Director	[redacted]	[redacted]
Baggett	Michael	ECIC Duty Officer	[redacted]	[redacted]
Bobo	Richard	Area 04 Area Manager	[redacted]	[redacted]
Brukwicki	Steven	Planning Administrative Section Supervisor	[redacted]	[redacted]
Burd	Wayne	Project Manager	[redacted]	[redacted]
Compton	Patrick	ECIC Duty Officer	[redacted]	[redacted]
Croley	Jonathan	CSEPP WebEOC Administrator	[redacted]	[redacted]
Day	Sandra	Administrative & Fiscal Branch Manager	[redacted]	[redacted]
Eades	Doug	Systems Integration Manager	[redacted]	[redacted]
Estill	Connie	LEPC Program Coordinator	[redacted]	[redacted]
French	Monica	CSEPP Information and Awareness Officer	[redacted]	[redacted]
Goode	Sharon	Administrative Special III	[redacted]	[redacted]
Hamilton	Michele	Information Technologist	[redacted]	[redacted]
Hardesty	Patrick	Area 02 Area Manager	[redacted]	[redacted]
Hecker	Chris	Area 08 Area Manager	[redacted]	[redacted]
Hundley	Barbara	Area 04 Administrative Specialist III	[redacted]	[redacted]
Keithley	Tony	Operations Section Supervisor	[redacted]	[redacted]
Klaas	Mark	Operations Branch Manager	[redacted]	[redacted]
Martin	Vicki	Area 05 Area Manager	[redacted]	[redacted]
McKnight	Ron	Communications Technician	[redacted]	[redacted]
Mitchell	Jessica	Recovery Branch Manager	[redacted]	[redacted]
Napier	Tammy	KCCRB Fiscal Coordinator	[redacted]	[redacted]
Neal	Todd	Hazard Mitigation Grants Manager	[redacted]	[redacted]
ONeal	Charlie	Communications Supervisor	[redacted]	[redacted]
Pope	Beth	Program Coordinator	[redacted]	[redacted]
Rains	Jerry	Area 09 Area Manager	[redacted]	[redacted]
Roberts	Sherion	Area 02 Administrative Specialist III	[redacted]	[redacted]
Rogers	Gary 'Buddy'	Public Information Officer	[redacted]	[redacted]
Shotton	Amanda	Area 09 Administrative Specialist III	[redacted]	[redacted]
Sparks	James (Jamie)	Area 06 Area Manager	[redacted]	[redacted]

Kentucky County Emergency Management Directors

COUNTY NAME	EM NAME	EM Address	EM City	ST	Zip	Office	Fax	Email
Adair	Greg Thomas	[redacted]						
Anderson	Bart Powell	[redacted]						
Ballard	Travis Holder	[redacted]						
Barren	Tony Richey	[redacted]						
Bath	Stephanie Stewart	[redacted]						
Bell	Ben Barnett	[redacted]						
Bourbon	Mike Withrow	[redacted]						
Boyle	Mike Wilder	[redacted]						
Bracken	F. Neider Reynolds	[redacted]						
Bullitt	Mike Phillips	[redacted]						
Caldwell	David Crenshaw	[redacted]						
Campbell	William Turner	[redacted]						
Carlisle	Clarissa Viniard	[redacted]						
Carroll	Ed Webb	[redacted]						
Casey	Rick Wesley	[redacted]						
Christian	Randy Graham	[redacted]						
Clark	Gary Epperson	[redacted]						
Clay	David Watson	[redacted]						
Crittenden	Davis Travis	[redacted]						
Daviess	Richard Payne	[redacted]						
Edmonson	Patrick Prunty	[redacted]						
Estill	Fred Rogers	[redacted]						
Fayette	Pat Dugger	[redacted]						
Fleming	Dwayne Price	[redacted]						
Franklin	Tom Russell	[redacted]						
Fulton	Hugh Caldwell	[redacted]						
Gallatin	Brandon Terrell	[redacted]						
Garrard	Wendell Hatfield	[redacted]						
Grant	Richard Willoby	[redacted]						
Grayson	Ernie Perkins	[redacted]						
Green	Bill Matney	[redacted]						
Hardin	Doug Finlay	[redacted]						
Harlan	David McGill	[redacted]						
Harrison	Mike Palmer	[redacted]						
Hart	Kerry McDaniel	[redacted]						
Henderson	Larry Koerber	[redacted]						
Henry	Jody Rucker	[redacted]						
Hickman	Shadd Byassee	[redacted]						
Hopkins	Frank Wright	[redacted]						
Jefferson	Debbie Fox	[redacted]						
Jessamine	John Carpenter	[redacted]						
Kenton	Steve Hensley	[redacted]						
Knox	Michael Mitchell	[redacted]						
Larue	Dennis Wells	[redacted]						
Laurel	Albert Hale	[redacted]						
Lee	Eugene Barrett	[redacted]						
Letcher	Paul Miles	[redacted]						
Lincoln	Donnie Gilliam	[redacted]						
Livingston	Brent Stringer	[redacted]						
Lyon	Eric Nelson	[redacted]						
Madison	Carl Richards	[redacted]						
Marion	Hayden Johnson	[redacted]						
Mason	Timothy Nolder	[redacted]						
McCracken	Paul Carter	[redacted]						
McCreary	Rudy Young	[redacted]						
McLean	David Sunn	[redacted]						
Meade	Ron Dodson	[redacted]						
Menifee	Jennifer Rogers	[redacted]						
Mercer	Michael Burke	[redacted]						
Montgomery	Wesley Delk	[redacted]						
Muhlenberg	Keith Putnam	[redacted]						
Nelson	Joe Prewitt	[redacted]						
Nicholas	Calvin Denton	[redacted]						
Ohio	Charles Shields	[redacted]						
Oldham	Kevin Nuss	[redacted]						
Owen	David Lilly	[redacted]						
Pendleton	Mike Moore	[redacted]						
Pulaski	Tiger Robinson	[redacted]						
Robertson	Diane Hardesty	[redacted]						
Rockcastle	David Colson	[redacted]						
Rowan	Ronnie Day	[redacted]						
Russell	H. M. Bottom	[redacted]						
Scott	Jack Donovan	[redacted]						
Shelby	Paul Whitman	[redacted]						
Spencer	Jeff Coulter	[redacted]						
Taylor	George R. Wilson	[redacted]						
Trimble	Ronnie McCane	[redacted]						
Union	Vernon Martin	[redacted]						
Washington	Kevin Devine	[redacted]						
Webster	Jeremy Moore	[redacted]						
Whitley	Danny Moses	[redacted]						
Woodford	Keith Sluganțz	[redacted]						

Kentucky County Judge Executives

County	Name	Email	Address	Phone_Wk	Fax
Adair	Ann Melton	[redacted]			
Anderson	John Wayne Conway				
Ballard	Vickie Viniard				
Barren	Davie D. Greer				
Bath	Lowell B. Jamison				
Bell	Albey Brock				
Bourbon	Donnie R. Foley				
Boyle	Harold W. McKinney				
Bracken	Earl Bush				
Bullitt	Melanie J. Roberts				
Caldwell	Brock Thomas				
Campbell	Steven Pendery				
Carlisle	Greg H. Terry				
Carroll	Harold Tomlinson				
Casey	Ronald D. Wright				
Christian	Steve Tribble				
Clark	Henry Branham				
Clay	Joe Lewis Asher				
Crittenden	Perry A. Newcom				
Daviess	Al Mattingly				
Edmonson	N. E. Reed				
Estill	Wallace Taylor				
Fayette	Jon Larson				
Fleming	Larry H. Foxworthy				
Franklin	Ted Collins				
Fulton	David Gallagher				
Gallatin	Ken McFarland				
Garrard	John Wilson				
Grant	Darrell Link				
Grayson	Gary L. Logsdon				
Green	Misty N. Edwards				
Hardin	Harry Berry				
Harlan	Joseph A. Grieshop				
Harrison	Alex Barnett				
Hart	Terry Martin				
Henderson	Donald Hugh McCormick Jr.				
Henry	John L. Brent				
Hickman	Greg Pruitt				
Hopkins	Donald Carroll				
Jefferson	Bryan Mathews				
Jessamine	William Neal Cassity				
Kenton	Steve Arlinghaus				
Knox	J. M. Hall				
Larue	Tommy Turner				
Laurel	David Westerfield				
Lee	Steve Mays				
Letcher	Jim Ward				
Lincoln	Jim W. Adams				
Livingston	Chris Lasher				
Lyon	Wade White				
Madison	Kent Clark				
Marion	John G. Mattingly				
Mason	James L. Gallenstein				
McCracken	Van Elliott Newberry				
McCreary	Douglas Stephens				
McLean	Kelly Thurman				
Meade	Gerry Lynn				
Menifee	James D. Trimble				
Mercer	Milward Dedman				
Montgomery	Wallace Johnson				
Muhlenberg	Rick Newman				
Nelson	Dean Watts				
Nicholas	Mike Pryor				
Ohio	David Johnston				
Oldham	David Voegele				
Owen	Carolyn H. Keith				
Pendleton	Henry W. Bertram				
Pulaski	Barty Bullock				
Robertson	Billy Allison				
Rockcastle	George C. Carloftis				
Rowan	Jim Nickell				
Russell	Gary D. Robertson				
Scott	George Lusby				
Shelby	Rob Rothenburger				
Spencer	Bill Karrer				
Taylor	Eddie Rogers				
Trimble	Jerry Powell				
Union	Jody Jenkins				
Washington	John A. Settles				
Webster	James R. Townsend				
Whitley	Pascal R. White Jr.				
Woodford	John Coyle				

Virginia Emergency Management Contacts

Last Name	First Name	Agency / County	Office	Cell	email address
Richardson	William	VEMA Region IV	[redacted]		
Swinney	Jessica	Wise Co - EM			
Bailey	Alan	Lee Co - EM			
Thacker	Richard	Dickinson - EM			
Powers	Jess	Russell Co - EM			

EPRP Appendix 8 Logistics Section Information

Native Electric Distribution Operations Contractors

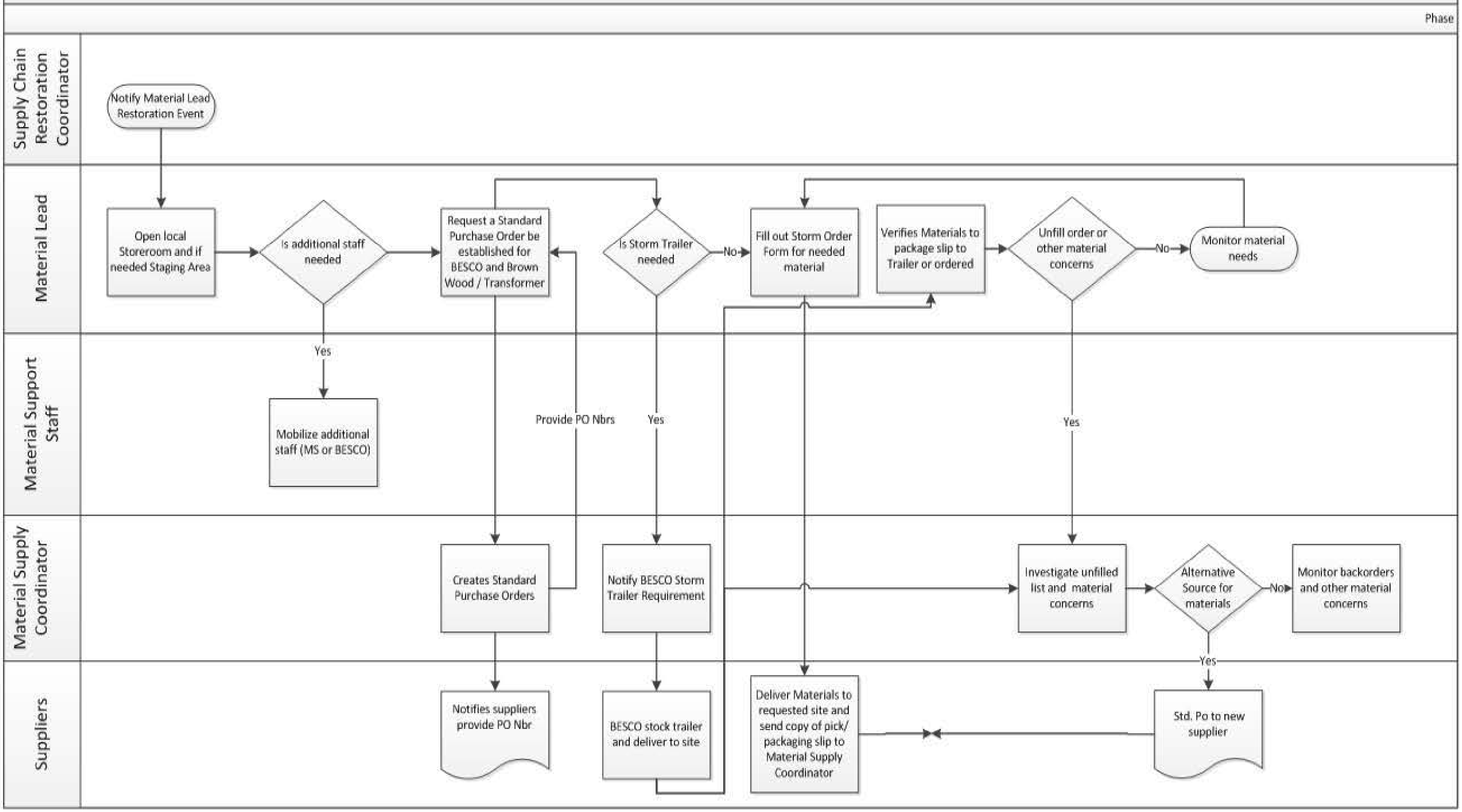
Name or Company	Title or Contact Name	Office	Mobile	Home
Brown Wood			[redacted]	
Arnold, Steve	Shipping Manager	[redacted]	[redacted]	[redacted]
Stanley, David	President	[redacted]	[redacted]	[redacted]
Brownstown				
Adkins, Kent	Inside Sales-Lawrenceburg	[redacted]	[redacted]	[redacted]
Ault, Bob	Outside Sales, KY		[redacted]	[redacted]
Deck, Greg	Owner	[redacted]	[redacted]	[redacted]
Densford, Monty	Transformer Deliveries	[redacted]	[redacted]	
Goshorn, Greg	Inside Sales-Brownstown	[redacted]	[redacted]	
Pickard, Brandon	Warehouse-Lawrenceburg	[redacted]	[redacted]	
Robinson, Jon	Purchasing	[redacted]		[redacted]
Turner, Brett	Warehouse-Brownstown	[redacted]	[redacted]	[redacted]
Turner, Scott	Purchasing	[redacted]	[redacted]	[redacted]
Howard Industries				
Prophater, Mike - Tesa	Outside Sales	[redacted]	[redacted]	[redacted]
Ward, Jack	Regional Marketing Mgr	[redacted]	[redacted]	
Overhead Contractors				
B&B Electrical Contractors	Bill Hatfield	[redacted]	[redacted]	
Bowlin Group LLC	Blevins Bowlin	[redacted]	[redacted]	
~~Delta Services LLC~~	~~Paul Jamison~~	[redacted]		
Davis H. Elliot Co. Inc.	Brian Briley	[redacted]	[redacted]	[redacted]
Groves Construction Inc.	Jeff Groves	[redacted]	[redacted]	
	John M. Morris	[redacted]	[redacted]	
~~Mastec~~	~~Barbara Harvey, Christopher Dice~~	[redacted]		
~~Par Electrical Contractors, Inc.~~	~~John Czaicki~~	[redacted]	[redacted]	
Pike Electric Inc.	Billy Joe Lowry	[redacted]	[redacted]	
Pike Electric Inc.	Stan Marion	[redacted]	[redacted]	[redacted]
~~Service Electric Company (formerly Dillard Smith Con~~	~~Brian Imsand, Mike Brusca, Scott Helton, Jeff Hunt~~	[redacted]	[redacted]	
~~Sumter Utilities Inc.~~	~~Derek Obradovich~~	[redacted]		
T&D Solutions LLC	Ryan Kolb	[redacted]	[redacted]	
The Fishel Co.	Rich Mauldin	[redacted]	[redacted]	[redacted]
	Kevin Kapp	[redacted]	[redacted]	
United Electric Co.	Jim Olliges	[redacted]	[redacted]	
Tree Trimming Contractors				
Asplundh Tree Experts Co.	Chris Wilburn	[redacted]	[redacted]	
Nelson Tree Service Inc.	John Reis	[redacted]	[redacted]	[redacted]
Phillips Tree Experts Inc.	Jim Blanchard	[redacted]	[redacted]	[redacted]
Townsend Tree Service Co.	Mick Saulman	[redacted]	[redacted]	[redacted]
Wright Tree Service	John Church	[redacted]	[redacted]	
Miscellaneous				

Non-Native Electric Distribution Operations Preferred Suppliers

	Company	Vendor		Street Address	City, State	Zip	Fax	Phone	Contact
	Asplundh Construction Corp.	69882	Certified-Negotiated	950 B TAYLOR STATION RD	GAHANNA, OH	43230	-	217-784-1438	Frank Marinelli
							-	614-626-8910	Patrick Smith
							-	-	Jared Wachter
	BBC Electrical Services Inc	69401	Certified	5467 S HWY 43	JOPLIN, MO	64804	417-206-4336	417-206-4047	Bryan Simpson
							417-206-4336	417-206-4047	Chris Couch
	Bob Ray	24895	Certified	723 Lyndon Lane	Louisville, KY	40222	502-425-7657	502-425-3072	Tee Ray
	Chain Electric	71127	Certified	1308 1/2 WEST PINE ST	HATTIESBURG, MS	39401	601 584-8320	601-545-3800	Melissa Lyman
	CW Wright Construction Co Inc	69743	Certified	11500 Ironbridge Rd	Chester, VA	23831	804-748-4099	804-768-1054	Penny Baldwin
								804-586-1380	
	Delta Services LLC	66276	Certified	4676 JENNINGS LANE	LOUISVILLE, KY	40218	502-491-2995	502-719-7787	Kevin Waldron
								502-639-4321	
	~~Dillard Smith Construction Co~~	~~58628~~	~~Certified~~	~~4001 Industry Dr~~	~~Chattanooga, TN~~	~~37416~~	~~423-490-4419~~	~~423-894-4336~~	~~Mike Landreth~~
	Disaster Resource Group	74782	Certfied	1625 N AIRWAY DR	BATON ROUGE, LA	70815		502-759-6468	Blake Martin
	Electricom LLC	72460	Restricted	1660 W HOSPITAL ROAD	PAOLI, IN	47454	-	812-723-2626	Brooke Newlin
	Fry Electric	72865	Certified	1107 SAUNDERS COURT	WEST CHESTER, PA	19380	-	610 884-1088	Steve Sarno
	Grays Power Supply LLC	74376	Certified	28726 HWY 32	OAKLAND, MS	38948	-	662-623-0477	Lisa Weeks
	Gregory Electric Company, Inc.	69380	Certified	2124 College St	Columbia, SC	29205	803-748-1102	803-748-1122	Scott Webber
								803-920-6794	Denise Estep
	Henkels and McCoy	66983	Certified - Negotiated	1620 N Broadway	Salem, IL	62881	618-548-0708	618-548-0696	Tim Pierce
				HQ-Blue Bell, PA				618-322-7490	
	Irby Construction Co.	52752	Restricted	PO Box 1819	Jackson, MS	39215-1819	601-960-7231	601-709-4729	Doug Blake
	Intercon Construction Inc	73345	Certified	5512 STATE RD 19 AND 113	WAUNAKEE, WI	53597		608-850-4820	Pat Keenan
	The LE Myers Co	69382	Restricted	401 Chestnut St	Chattanooga, TN	37402	423-265-6649	423-265-4441	Jim Bowen
	This supplier has two offices							423-605-0259	
				PO Box 51710	Indianapolis, IN	46251		317-787-8264	Tom Hargens
								317-752-2822	
	Lee Electrical Construction Inc	69858	Restricted	PO Box 55	Aberdeen, NC	28315	910-944-7294	910-944-9728	Donnie Lee
								910-695-5652	
								910-944-9728	Daryl Flippin

Email
[redacted]
[redacted]
[redacted]
[redacted]
[redacted]
[redacted]
[redacted]
[redacted]
[redacted]
[redacted]
[redacted]
[redacted]
[redacted]
[redacted]
[redacted]
[redacted]
[redacted]
[redacted]
[redacted]
[redacted]
[redacted]
[redacted]
[redacted]

Emergency Response Material Logistics



Storeroom Locations and Key Contact Information

	Name	Location	Address	City	State	Zip	Phone	Fax	Cell
**	Janet Summers	**Barlow**	[redacted]						
	Jeremy Hines	**Brownstown**	[redacted]						
**	Amy Judd	**Campbellsville**	[redacted]						
*	Mark Owens - BESCO	**Carrollton**	[redacted]						
***	Chris Mattingly	**Danville**	[redacted]						
	Michael David - BESCO	**Danville**	[redacted]						
	Greg Ekstam - BESCO	**Earlington**	[redacted]						
	Michael, Burns	**Earlington**	[redacted]						
**	Janet Summers	**Earlington**	[redacted]						
**	Janet Summers	**Eddyville**	[redacted]						
**	Amy Judd	**Elizabethtown**	[redacted]						
	Kyle Perkins - BESCO	**Elizabethtown**	[redacted]						
**	Martha Vincent	**Greenville**	[redacted]						
***	Lisa Messer	**Harlan**	[redacted]						
	Kent Adkins - BESCO	**Lawrenceburg**	[redacted]						
	Tracy Crouch	**Lexington**	[redacted]						
***	Tina Pickard	**Lexington**	[redacted]						
*	Nick Goldey- BESCO	**Lexington**	[redacted]						
*	Wyatt Turner- BESCO	**Lexington**	[redacted]						
*	Robbie Smith - BESCO	**London**	[redacted]						
	William Woodard	**Louisville**	[redacted]						
	Mark Schmitt	**Louisville**	[redacted]						
	David Young	**Louisville**	[redacted]						
****	Yvette Lee	**Louisville**	[redacted]						
	Don Kaiser	**Louisville**	[redacted]						
	Evan Motsinger	**Louisville**	[redacted]						
*	Aaron Mays - BESCO	**Louisville**	[redacted]						
*	Brent Price-BESCO	**Louisville**	[redacted]						
	Cody Stark	**Louisville**	[redacted]						
	Roger Abel -BESCO	**Louisville**	[redacted]						
*	David Luedeman - BESCO	**Louisville**	[redacted]						
*	Jeremy Rittenhouse - BESCO	**Louisville**	[redacted]						
*	Bill Sewell	**Maysville**	[redacted]						
*	Sam Curren - BESCO	**Midway**	[redacted]						
**	Martha Vincent	**Morganfield**	[redacted]						
*	Bill Sewell - BESCO	**Mt. Sterling**	[redacted]						
***	Randy Sturgill	**Norton**	[redacted]						
*	Bill Sewell - BESCO	**Paris**	[redacted]						
***	Randy Sturgill	**Pennington Gap**	[redacted]						
***	Lisa Messer	**Pineville**	[redacted]						
*	Lenny Church - BESCO	**Richmond**	[redacted]						

Storeroom Locations and Key Contact Information

	Name	Location	Address	City	State	Zip	Phone	Fax	Cell
*	Mark Owens - BESCO	Shelbyville	[redacted]						
*	Robbie Smith - BESCO	Somerset							
*	Lenny Church - BESCO	Winchester							

* Reports to Jeremy Hines / BESCO = Brownstown

*** Reports to Tracy Crouch

** Reports to Mike Burns

** Reports to N/A

**** Reports to Dave Young

Storm Kit Information

KU Storm Kit (first response)

The KU Storm Kit consists of three pallets of storm related materials. The pallets consist of one large bundle of 6A CW wire, several boxes of clamps, connectors, fuses and miscellaneous line hardware. The kit contains enough material to support 5 to 10 non-native contractor crews for the first 24 hours. The Materials Specialist will distribute materials from each pallet to the non-native crews as required. **See Storm Kits (LGE & KU) Tab for listing of materials.** The Service Storm Kits will be placed at the following locations

Danville	1 kit	Lexington	2 kits	Pineville	1 kit
Earlington	1 kit	Louisville	3 kits	Norton	1 kit
Greenville	1 kit	Midway	1 kit		

LG&E Storm Kit (first response)

The LG&E Storm Kit is a single pallet consisting of four small wire hand coils and small tub containing an assortment of clamps, connectors, fuses, and miscellaneous line hardware. The kit contains enough material to support one non-native utility/contractor crew for the first 24 hours of a restoration event. **See Storm Kits (LGE & KU) Tab for listing of materials.** The Service Storm Kits will be placed at the following locations

Auburndale	25 kits	Brownstown (IN) 15 kits

LG&E Storm Trailer Material Listing

DATE TIME	LOC	REQUESTER		
BESCO CATALOG	**IIN #**	**DESCRIPTION**	**STD PKG**	**TRAILER QTY**
88135	7000791	Anchor, Expanding, Bust 8"	6	12
7010141-ANCHOR	7010141	Anchor, Socket Drive, 12", 1" Tap	4	8
10'-LGE/KU- CROSSARM	7000102	Arm, Cross, Douglas Fir, 10'	25	10
8'-LGE/KU-CROSSARM	7000101	Arm, Cross, Douglas Fir, 8'	25	50
7000173-KU-ARRESTER	7000173	Arrester, Distribution, OH, 9kv,	1	25
SBS000303	7000303	Assembly, Bolt, SS, 1/2"x 2"	100	100
3105.6	7006552	BAND, POLE, 10,000#, 9"- 12" POLE DIAMETER, 4-WAY, 90 DEGREE	2	10
89621R10	7001963	BLADE, SOLID, 300AMP, FOR S&C CUTOUT, SPARE DISCONNECT, TYPE XS	16	16
8645 1/2	1156178	Bolt, Carriage, 1/2"x 5-1/2"	250	250
J8634-1/2	7000206	Bolt, Carriage, 3/8" x 4-1/2"	250	250
DABOLT5812	7006328	Bolt, Double Arming, 5/8" x 12"	25	100
DABOLT5814	7006329	Bolt, Double Arming, 5/8" x 14"	25	100
DABOLT5816	7000209	Bolt, Double Arming, 5/8" x 16"	25	50
DABOLT5818	7000210	Bolt, Double Arming, 5/8" x 18"	25	50
DABOLT5820	7000211	Bolt, Double Arming, 5/8" x 20"	25	50
DABOLT5822	7000212	Bolt, Double Arming, 5/8" x 22"	25	25
DABOLT5826	7000214	Bolt, Double Arming, 5/8" x 26"	25	25
DABOLT5828	7000215	Bolt, Double Arming, 5/8" x 28"	25	25
MB1207	7000249	BOLT, MACHINE, 1/2" X 7"	100	100
AF6030	7010444	Brace, Crossarm, 60"Span, 30"Drop	5	50
2045-E45-9-11	7000143	Brace, Crossarm, 72" x 36",	5	10
D-1040	7002177	BRACKET, AERIAL CABLE, ANGLE, C-TYPE, GALV.	1	5
APP-1340	472494	Bracket, Crossarm, Cutout/Arrester	10	50
G1MDA318ATB	7001703	CUTOUT/ARRESTER STYLE W/CAPTIVE BOLTS, LW, AND NUTS (& KEYHOLE)	8	48
BM-14	7002178	MESSENGER, 14" SPACING, GALVANIZED STEEL, FOR 1/4" - 5/8"	1	5
CLAM	1199519	Cable, OH, Triplex, #2, AAC, 7 Str,	500'	5000
OYSTER	1564260	Cable, OH, Triplex, #4, AAC, 7 Str,	500'	5000
MUREX	1565819	Cable, OH, Triplex, 1/0, AAC, 7 Str	250'	2500
ADS-88-N	1157901	CLAMP, DEADEND, #2-556.5 ACSR CONTOURED GROOVE - ANDERSON	20	40
SDE-125	1157960	CLAMP, DEADEND, ALUM., .62-1.125 266.8 - 1033.5 ACSR (2-BOLT)	25	50
HDC58R	7000887	Clamp, Ground Rod, Heavy Duty 5/8"	50	50
BC-2/0	7000591	Clamp, Hotline, 8-2/0 CU	50	100
MB-62	1158043	Clamp, Triplex, Secondary, Ferrous	25	25
7195	7002215	Clamp, Wedge, Service, #2-6 ACSR	25	500
7187	7005143	Clamp, Wedge, Service, 1/0-#4 ACSR,	25	500
7197	1200443	Clamp, Wedge, Service, 4/0-2/0 ACSR	25	500
337	7000911	Clevis, Extended, 3"	25	50
WR159	1200201	Connector, H-Tap, #2 - #6 ACSR #1	25	250
WR189	1199919	Connector, H-tap, 1/0-#2 - #2-#6 #2	25	500
WR179	1200219	Connector, H-Tap, 1/0-#3 - 1/0-#2	25	250
WR289	1200194	Connector, H-Tap, 1/0,2/0 -- #2-#6 #3	25	250
WR139	1200351	Connector, H-Tap, 2-4 ACSR - 8-14	25	25
WR379	1162835	Connector, H-Tap, 3/0,4/0 - #2-#6 #5	25	25
505-82	1200186	Connector, H-Tap, Comp, 3/0,4/0 #6	25	25
YHD-400	1199951	Connector, H-tap, Comp. 3/0,4/0	25	25
YHD-300	1199927	Connector, H-tap, Comp., #1-2/0- #4	25	25
1HPS	1200394	Connector, Splitbolt, Plated, CU	100	300
2B10PW	1200401	Connector, Tap, 2-bolt, #2-1/0	25	100
6-SD-CU-SPL	7000384	Copper, 6 Solid, Soft Drawn, Bare	25#	200
4A-3STR-COPPERWELD	1197501	Copperweld, 4A, 3Str, Bare, 30%	100	1000
6A-COPPERWELD- REEL	1197494	Copperweld, 6A, 3Str, Bare, 30%	100	1000
8427-16	1162151	Cover, Cold-Shrink, 250-400mcm	10	20
8428-18	1162160	Cover, Cold-Shrink, 500-800mcm 14"	10	20
C7	1162127	Cover, Tap, Compression, "D"	100	200
C710-112L	7001957	Cutout, Fused, 15KV, 100 Amp,	1	54
GD-115	1200060	Deadend, Automatic, #1 Sol. CU, 4A	50	50
GD-516	1199994	Deadend, Automatic, #1 Str. CU	50	50
GD-116	1200035	Deadend, Automatic, #1 Str. CU, 3A	50	50
GD-514	1199986	Deadend, Automatic, #2 Sol. CU	50	50
GD-114	1200178	Deadend, Automatic, #2 Sol. CU	50	50
27LD	1242960	Deadend, Automatic, #2 Str. CU	50	50
GD-4442A	1242978	Deadend, Automatic, #4 & #2 ACSR	50	50
GD-512	1199978	Deadend, Automatic, #4 Sol. CU, 8A	50	50
47FD	1200051	Deadend, Automatic, #4 Str. CU	50	50
47LD	1200001	Deadend, Automatic, #4 Str. CU, 6A	50	50
GD-511	1199960	Deadend, Automatic, #6 Sol. CU	50	50
GD-406A	1199935	Deadend, Automatic, 1/0 ACSR/AL,	50	50
GD-446A	1200027	Deadend, Automatic, 1/0 ACSR/ALUM	50	50
107LD	850127	Deadend, Automatic, 1/0 CU, 2A CW	50	50
107FD	1200043	Deadend, Automatic, 1/0 CU, 2A CW	50	50
5202	1243443	Deadend, Automatic, 12.5M Guy Wire	25	25
GD-1195A	1199719	Deadend, Automatic, 4/0, 3/0 Str.CU	25	25

BESCO CATALOG	IIN #	DESCRIPTION	STD PKG	TRAILER QTY
5201	1158494	Deadend, Automatic, 8M/10M Guy Wire	25	25
ND-0120	1158651	DEADEND, COATED, .889-.945" (336 AERIAL CABLE)	10	20
ND-0125	7003757	DEADEND, COATED, 795MCM ALUM COMPRESS	10	20
EN58	7000905	Eyenut, Oval, 5/8" Bolt	50	50
31100	1163751	Fuse, Link, 100amp, Type K, Fitall	25	100
FL3D10	7000715	Fuse, Link, 10A, Type D, Removable	25	50
31140	1163760	Fuse, Link, 140amp, Type K, Fitall	25	100
FL3D15	7000716	Fuse, Link, 15A, Type D, Removable	25	50
31200	1163778	Fuse, Link, 200amp, Type K, Fitall	25	50
31020	532460	Fuse, Link, 20amp, Type K, Fitall	25	25
31025	1163727	Fuse, Link, 25amp, Type K, Fitall	25	25
31040	1163735	Fuse, Link, 40amp, Type K, Fitall	25	50
31065	1163743	Fuse, Link, 65amp, Type K, Fitall	25	200
89521R10	7002154	FUSEHOLDER, 100 AMP, FOR S&C CUTOUT	16	32
89571R11	7001962	14.4KV, 110KV BIL, HEAVY DUTY, OUTDOOR PRIMARY	16	32
AWDE-4119	1158735	Grip, Deadend, AW Guy 12.5M AW	50	50
AWDE-4126	1218101	Grip, Deadend, AW Guy 20M AW	50	10
AWDE-4108	1158719	Grip, Deadend, AW Guy 4M AW	50	50
GA-5X	1158851	HOOK, GUY, 5/8" BOLT (REA)	50	50
GS21024CP	1163986	INSULATOR, GUY STRAIN, 24", FIBERGLASS, 21000#	5	20
HPI-15F	7001269	INSULATOR, PIN TYPE, 15KV, POLY, 1" PIN HOLE, SKY GRAY	18	180
INSULATOR-SPL-3-53-2	7001268	Insulator, Spool, 3" (Class 53-2)	25	50
401015-0215	7001280	Insulator, VeriLite, PDI-15, 15KV	15	90
3152	7000799	LINK, CONNECTING, 2 PIECE, 1/4"X2"X9-1/2", GALV ST	40	40
A7M-100-2NR	510201	795MCM AA, TIN PLATED, TWO 9/16" HOLES ON 1-3/4" CENTERS	8	16
TGP16-1B-8YPF	7000828	Marker, Guy, 8', w/One Clamp at	25	70
VP-1/2-GWM-BK8	7000913	Molding, Plastic GW, 1/2"x 8'	125	125
KVSU28	1161894	Oklip, 2-bolt, Universal	25	100
KVSU34	1161919	Oklip, 2-bolt, Universal	25	100
J207Z	1159078	Pin, Crossarm, 6-1/2", Nylon	25	25
J222Z	1159051	Pin, Crossarm, Short-Shank, NYLON	25	50
J203Z	7004088	Pin, Crossarm, Steel, 5-3/4" Nylon	25	100
AP8-6H	1159001	5/8" X 7" MACHINE BOLT, 2" SQUARE WASHER, SQUARE NUT & LOCKNUT, GALVANIZED	10	30
7006359	7006359	PIN, POLE TOP, 20" NYLON	10	30
893	1218401	PIN, SHORT-SHANK, CROSSARM, 1-3/4" (3/4" SHANK, 6" MTG. HEIGHT)	25	25
S635	376260	PROTECTOR, WILDLIFE, 4.75"X 9.00"	50	50
ANCHOR-ROD-B-D- 8X58	1159194	Rod, Anchor, Bust 5/8 x 8' Twineye	5	15
ANCHOR-ROD-SC-D- 7X34	475294	Rod, Anchor, Screw, 3/4" x 7',	5	10
615880	7000888	Rod, Ground, Copper 5/8"x 8' (UL)	5	50
J8784	1159243	Screw, Lag, Gimlet Point, 1/2 x 4"	250	25
6170000-2	7005833	Seal, Meter, Padlock, GREEN	1000	1000
ASH-55	7001094	Shackle, Anchor, 30000 LB, 2-3/4"	25	100
GL-116	7006654	Sleeve, Automatic, #1 Str. CU	50	300
GL-1140	7006668	Sleeve, Automatic, #2 Sol. CU	50	300
GL-115	7003941	Sleeve, Automatic, #2 Str. CU 4A CW	50	300
GL-112	7003939	Sleeve, Automatic, #4 Sol. CU,8A CW	50	300
GL-113	7003940	Sleeve, Automatic, #4 Str. CU,6A CW	50	300
GL-111	7003938	Sleeve, Automatic, #6 Sol. CU	50	300
GL-117	1162719	Sleeve, Automatic, 1/0 Str.CU	50	300
GL-406A	1159886	Sleeve, Automatic, 1/0-6/1 ACSR	50	300
GL-411	1159919	SLEEVE, AUTOMATIC, 336 18/1 ACSR	10	30
GL-120	7004109	Sleeve, Automatic, 4/0 Str. CU	50	50
GL-1385A	7003515	SLEEVE, AUTOMATIC, 795 AAC	10	30
CS73	7000541	Sleeve, Service, Bare, #2-#2, RED/RED	100	500
CS68	7000544	Sleeve, Service, Bare, #4-#4, ORANGE/ORANGE	100	500
CS78	3001888	Sleeve, Service, Bare, 1/0-1/0 Str, YELLOW/YELLOW	100	500
CS77	3001890	Sleeve, Service, Bare, 1/0Str-2Str, YELLOW/RED	100	500
CS76	3001885	Sleeve, Service, Bare, 1/0Str-4Str, YELLOW/ORANGE	100	500
CS72	7000542	Sleeve, Service, Bare, 2Str-4Str RED/ORANGE	100	500
ICS73-1	7000531	Sleeve, Service, Insulated, #2-#2, RED/RED	100	500
ICS72-1	7000535	Sleeve, Service, Insulated, #2-#4, RED/ORANGE	100	500
ICS68-1	7000534	Sleeve, Service, Insulated, #4-#4, ORANGE/ORANGE	100	500
ICS78-1	7010322	Sleeve, Service, Insulated, 1/0-1/0 YELLOW/YELLOW	100	500
ICS77-1	3001891	Sleeve, Service, Insulated, 1/0-2, YELLOW/RED	100	500
ICS76-1	3001889	Sleeve, Service, Insulated, 1/0-4- YELLOW/ORANGE	100	500
OH1/0-7AL	1200135	Sleeve, Tension, 1/0 str. ALUM	100	500
30010	1200151	Sleeve, TPX, Neutral, #2 Alum ACSR	100	500
30011	1200160	Sleeve, TPX, Neutral, #4 Str. Alum	100	500
GSS-24	1566778	SPREADER, SECONDARY CABLE, W/BAIL	10	20
J1672	7002254	Staple, 1-1/2", GALVANIZED	50	50
HLB2	1159527	Stirrup, Plated, #2 CU Bail Closed	100	100

BESCO CATALOG	IIN #	DESCRIPTION	STD PKG	TRAILER QTY
M3D-96BC	7010217	SWITCH, DISCONNECT, UA, 15KV, 900A, 110KV BIL, 40KA MOMETARY, W/(4) 1/2" X 2"X 13TPI CAPTIVE BOLTS & TINNED PADS, BACK PLATE, W/(4) CARRIAGE BOLTS FOR CROSSARM MTG, POLYMER POST INSULATORS, 15" POST SPACING	1	9
TNT-4-40	1244794	Tap, Mid-Span, Neutral, 336.4 ACSR-	12	12
MST41-350-4/0	1162927	Tap, Mid-Span, Secondary Service	12	12
LC-833-XB	1157894	Tap, Parallel 336-795--8-2/0	25	100
37-08180	1164451	Tape, Electrical, Vinyl 1.5 x 66'	50	200
37-09180	1164401	Tape, Electrical, Vinyl 3/4 x 66'	100	200
GA-9821L	484519	VISE-TAP, BOLTED 336-840 ACAR 3/0-397.5 ACSR TAP (2-BOLT)	25	50
GA-9843L	484494	VISE-TAP, BOLTED 795-1/0, 4/0	25	50
6813	7000337	Washer, Square, 5/8" Bolt	250	750
4-SOLID-CW-SPOOL	7001812	WIRE #4 SOLID ANNEALED 40% CONDUCTIVITY CW GROUND (427 = 50#)	25	500
2-STR-SD-INS-CU-SPL	1199386	WIRE, #2, 7 STR, SOFT DRAWN CU, POLY INS, (25# = 107')	107	535
4-STR-SD-INS-CU-SPL	1199378	WIRE, #4, 7 STR, SOFT DRAWN CU, POLY INS., 25# (175')	175	875
6-SOL-SD-INS-CU-SPL	1199360	WIRE, #6 SOLID, SOFT DRAWN CU POLY INS. 25# (285')	285	2850
1197560	1197560	WIRE, #6, 7 STR, CU HARD DRAWN (309')	309	1500
1/0-STR-SD-INS-CU-RL	1199394	WIRE, 1/0, 7 STR, SOFT DRAWN CU POLY INS, 1000# (2700')	50	250
12.5M-GUY-500	1197435	WIRE, 12.5M, 7 STR, ALUMOWELD GUY/MESSENGER	500	1500
AZUSA-CL	470935	Wire, 123.3KCM, 4/3 str, Bare AAAC	100	5000
4/0-STR-SD-INS-CU-RL	1199401	WIRE, 4/0, 7 STR, SOFT DRAWN CU, POLY INS., 1397# (1397' RL)	50	250
8M-GUY	1197401	WIRE, 8M, 7 STR, ALUMOWELD GUY/MESSENGER	500	1500
TW00011	7000941	WIRE, TIE, 4 SOLID AAC SD, BARE	25	250
1197586	1197586	WIRE,#2,7STR,BARE CU,HD	125	1250
1197578	1197578	WIRE,#4,7STR,BARE CU,HD	200	2000
J0588Z	7004467	Wireholder, Mast, Nylon (K17)	25	200
J0893Z	1163378	Wireholder, Service, 3" (NYLON	25	200

LG&E Small Storm Trailer Material Listing

BESCO CATALOG #	IIN #	DESCRIPTION	STD PKG	QTY
8'-LGE/KU-CROSSARM	7000101	Arm, Cross, Douglas Fir, 8'	25	50
7000173-KU-ARRESTER	7000173	Arrester, Distribution, OH, 9kv,	1	24
	7006328	BOLT,DOUBLE ARM,5/8"X12",ALL THREAD,GALV,W/4 SQ NUTS,STD PKG = 25 STL		25
	7006329	BOLT,DOUBLE ARM,5/8"X14",ALL THREAD,GALV,W/4 SQ NUTS,STD PKG = 25 STL		25
	7000209	BOLT,DOUBLE ARM,5/8"X16",ALL THREAD,GALV,W/4 SQ NUTS,STD PKG = 25 STL		25
2045-E45-9-11	7000143	Brace, Crossarm, 72" x 36",	5	50
G1MDA318ATB	7001703	BRACKET, SINGLE PHASE, FG, 18" CUTOUT/ARRESTER STYLE W/CAPTIVE BOLTS, LW, AND NUT (& KEYHOLE)	8	48
APP-1340	0472494	BRACKET,CUTOUT/ARRESTER,FOR 11' X-ARMS ONLY,7" LONG BOLTS,TO BE USED FOR WOOD DEADEND X-ARMS AND FIBERGLASS X-ARMS,USE IIN 7000879 FOR 8' & 10' X-ARMS		10
PSC2060674	7003631	BRACKET,CUTOUT/ARRESTER,X-ARM,COMBINATION CUTOUT & ARRESTER,ALSO FOR 11' ARMS		10
C206-0283	7000879	BRACKET,CUTOUT/ARRESTER,X-ARM,NEMA TYPE B,FOR 8' & 10' X-ARMS		20
J0893Z	1163378	BRACKET,SERVICE,WIRE HOLDER		50
CLAM	1199519	Cable, OH, Triplex, #2, AAC, 7 Str,	500'	5000
MUREX	1565819	Cable, OH, Triplex, 1/0, AAC, 7 Str	250'	5000
ADS-88-N	1157901	CLAMP, DEADEND, #2-556.5 ACSR CONTOURED GROOVE - ANDERSON	20	40
SDE-125	1157960	CLAMP, DEADEND, ALUM., .62-1.125 266.8 - 1033.5 ACSR (2-BOLT)	25	50
BC-2/0	7000591	Clamp, Hotline, 8-2/0 CU	50	100
7195	7002215	Clamp, Wedge, Service, #2-6 ACSR	25	200
7187	7005143	Clamp, Wedge, Service, 1/0-#4 ACSR,	25	200
337	7000911	Clevis, Extended, 3"	25	100
WR159	1200201	Connector, H-Tap, #2 - #6 ACSR #1	25	250
WR189	1199919	Connector, H-tap, 1/0-#2 - #2-#6 #2	25	250
WR379	1162835	Connector, H-Tap, 3/0,4/0 - #2-#6 #5	25	250
505-82	1200186	Connector, H-Tap, Comp, 3/0,4/0 #6	25	250
1HPS	1200394	Connector, Splitbolt, Plated, CU	100	100
4A-3STR-COPPERWELD	1197501	Copperweld, 4A, 3Str, Bare, 30%	100	3000
6A-COPPERWELD-REEL	1197494	Copperweld, 6A, 3Str, Bare, 30%	100	3000
C710-112L	7001957	Cutout, Fused, 15KV, 100 Amp,	1	24
31100	1163751	Fuse, Link, 100amp, Type K, Fitall	25	100
FL3D10	7000715	Fuse, Link, 10A, Type D, Removable	25	100
31140	1163760	Fuse, Link, 140amp, Type K, Fitall	25	100
FL3D15	7000716	Fuse, Link, 15A, Type D, Removable	25	100
31025	1163727	Fuse, Link, 25amp, Type K, Fitall	25	100
31040	1163735	Fuse, Link, 40amp, Type K, Fitall	25	100
31065	1163743	Fuse, Link, 65amp, Type K, Fitall	25	100
HPI-15F	7001269	INSULATOR, PIN TYPE, 15KV, POLY, 1" PIN HOLE, SKY GRAY	18	72
INSULATOR-SPL-3-53-2	7001268	Insulator, Spool, 3" (Class 53-2)	25	100
401015-0215	7001280	Insulator, VeriLite, PDI-15, 15KV	15	75
J222Z	1159051	Pin, Crossarm, Short-Shank, NYLON	25	100
J203Z	7004088	Pin, Crossarm, Steel, 5-3/4" Nylon	25	100
7006359	7006359	PIN, POLE TOP, 20" NYLON	10	50
GL-116	7006654	Sleeve, Automatic, #1 Str. CU	50	100
GL-1140	7006668	Sleeve, Automatic, #2 Sol. CU	50	100
GL-115	7003941	Sleeve, Automatic, #2 Str. CU 4A CW	50	100
GL-112	7003939	Sleeve, Automatic, #4 Sol. CU,8A CW	50	100
GL-113	7003940	Sleeve, Automatic, #4 Str. CU,6A CW	50	100
GL-111	7003938	Sleeve, Automatic, #6 Sol. CU	50	100
GL-117	1162719	Sleeve, Automatic, 1/0 Str.CU	50	100
GL-406A	1159886	Sleeve, Automatic, 1/0-6/1 ACSR	50	100
CS73	7000541	Sleeve, Service, Bare, #2-#2, RED/RED	100	100
CS68	7000544	Sleeve, Service, Bare, #4-#4, ORANGE/ORANGE	100	100
CS78	3001888	Sleeve, Service, Bare, 1/0-1/0 Str, YELLOW/YELLOW	100	100
ICS73-1	7000531	Sleeve, Service, Insulated, #2-#2, RED/RED	100	100
ICS68-1	7000534	Sleeve, Service, Insulated, #4-#4, ORANGE/ORANGE	100	100
ICS78-1	7010322	Sleeve, Service, Insulated, 1/0-1/0 YELLOW/YELLOW	100	100
OH1/0-7AL	1200135	Sleeve, Tension, 1/0 str. ALUM	100	100
30010	1200151	Sleeve, TPX, Neutral, #2 Alum ACSR	100	100
30011	1200160	Sleeve, TPX, Neutral, #4 Str. Alum	100	100
HLB2	1159527	Stirrup, Plated, #2 CU Bail Closed	100	100
37-09180	1164401	Tape, Electrical, Vinyl 3/4 x 66'	100	300
6813	7000337	Washer, Square, 5/8" Bolt	250	250
4-SOLID-CW-SPOOL	7001812	WIRE #4 SOLID ANNEALED 40% CONDUCTIVITY CW GROUND (427 = 50#)	25	250
AZUSA-CL	470935	Wire, 123.3KCM, 4/3 str, Bare AAAC	100	1000
TW00011	7000941	WIRE,#4,AAC,BARE,SOLID,SD,TIE WIRE,25 LB SPOOLS (APPROX. 651 FT) CONVERSION: FEET YOU WANT DIVIDED BY 26.04 = POUNDS TO ORDER		25#
C207-0144	7004467	WIREHOLDER,SERVICE,MAST BRACKET,1-1/4" - 3",NYLON		25

KU Storm Trailer Material Listing

BESCO CATALOG #	IIN #	DESCRIPTION	QTY	Notes
88135	7000791	Anchor, Expanding, Bust 8"	6	12
7010141-ANCHOR	7010141	Anchor, Socket Drive, 12", 1" Tap	4	8
10'-LGE/KU-CROSSARM	7000102	Arm, Cross, Douglas Fir, 10'	25	10
8'-LGE/KU-CROSSARM	7000101	Arm, Cross, Douglas Fir, 8'	25	50
7000173-KU-ARRESTER	7000173	Arrester, Distribution, OH, 9kv,	1	25
SBS000303	7000303	Assembly, Bolt, SS, 1/2"x 2"	100	100
3105.6	7006552	BAND, POLE, 10,000#, 9"- 12" POLE DIAMETER, 4-WAY, 90 DEGREE	2	10
89621R10	7001963	BLADE, SOLID, 300AMP, FOR S&C CUTOUT, SPARE DISCONNECT, TYPE XS	16	16
8645 1/2	1156178	Bolt, Carriage, 1/2"x 5-1/2"	250	250
J8634-1/2	7000206	Bolt, Carriage, 3/8" x 4-1/2"	250	250
DABOLT5812	7006328	Bolt, Double Arming, 5/8" x 12"	25	100
DABOLT5814	7006329	Bolt, Double Arming, 5/8" x 14"	25	100
DABOLT5816	7000209	Bolt, Double Arming, 5/8" x 16"	25	50
DABOLT5818	7000210	Bolt, Double Arming, 5/8" x 18"	25	50
DABOLT5820	7000211	Bolt, Double Arming, 5/8" x 20"	25	50
DABOLT5822	7000212	Bolt, Double Arming, 5/8" x 22"	25	25
DABOLT5826	7000214	Bolt, Double Arming, 5/8" x 26"	25	25
DABOLT5828	7000215	Bolt, Double Arming, 5/8" x 28"	25	25
MB1207	7000249	BOLT, MACHINE, 1/2" X 7"	100	100
AF6030	7010444	Brace, Crossarm, 60"Span, 30"Drop	5	50
2045-E45-9-11	7000143	Brace, Crossarm, 72" x 36",	5	10
D-1040	7002177	BRACKET, AERIAL CABLE, ANGLE, C-TYPE, GALV.	1	5
APP-1340	472494	Bracket, Crossarm, Cutout/Arrester	10	50
G1MDA318ATB	7001703	BRACKET, SINGLE PHASE, FG, 18" CUTOUT/ARRESTER STYLE W/CAPTIVE BOLTS, LW, AND NUTS & KEYHOLE	8	48
BM-14	7002178	BRACKET, SPACER CABLE, TANGENT MESSENGER, 14" SPACING, GALVANIZED STEEL, FOR 1/4" - 5/8"	1	5
CLAM	1199519	Cable, OH, Triplex, #2, AAC, 7 Str.	500'	5000
OYSTER	1564260	Cable, OH, Triplex, #4, AAC, 7 Str.	500'	5000
MUREX	1565819	Cable, OH, Triplex, 1/0, AAC, 7 Str	250'	2500
ADS-88-N	1157901	CLAMP, DEADEND, #2-556.5 ACSR CONTOURED GROOVE - ANDERSON	20	40
SDE-125	1157960	CLAMP, DEADEND, ALUM., .62-1.125 266.8 - 1033.5 ACSR (2-BOLT)	25	50
HDC58R	7000887	Clamp, Ground Rod, Heavy Duty 5/8"	50	50
BC-2/0	7000591	Clamp, Hotline, 8-2/0 CU	50	100
MB-62	1158043	Clamp, Triplex, Secondary, Ferrous	25	25
7195	7002215	Clamp, Wedge, Service, #2-6 ACSR	25	500
7187	7005143	Clamp, Wedge, Service, 1/0-#4 ACSR,	25	500
7197	1200443	Clamp, Wedge, Service, 4/0-2/0 ACSR	25	500
337	7000911	Clevis, Extended, 3"	25	50
WR159	1200201	Connector, H-Tap, #2 - #6 ACSR #1	25	250
WR189	1199919	Connector, H-tap, 1/0-#2 - #2-#6 #2	25	500
WR179	1200219	Connector, H-Tap, 1/0-#3 - 1/0-#2	25	250
WR289	1200194	Connector, H-Tap, 1/0,2/0 -- #2-#6 #3	25	250
WR139	1200351	Connector, H-Tap, 2-4 ACSR - 8-14	25	25
WR379	1162835	Connector, H-Tap, 3/0,4/0 - #2-#6 #5	25	25
505-82	1200186	Connector, H-Tap, Comp, 3/0,4/0 #6	25	25
YHD-400	1199951	Connector, H-tap, Comp, 3/0,4/0	25	25
YHD-300	1199927	Connector, H-tap, Comp., #1-2/0- #4	25	25
1HPS	1200394	Connector, Splitbolt, Plated, CU	100	300
2B10PW	1200401	Connector, Tap, 2-bolt, #2-1/0	25	100
6-SD-CU-SPL	7000384	Copper, 6 Solid, Soft Drawn, Bare	25#	200
4A-3STR-COPPERWELD	1197501	Copperweld, 4A, 3Str, Bare, 30%	100	1000
6A-COPPERWELD-REEL	1197494	Copperweld, 6A, 3Str, Bare, 30%	100	1000
8427-16	1162151	Cover, Cold-Shrink, 250-400mcm	10	20
8428-18	1162160	Cover, Cold-Shrink, 500-800mcm 14"	10	20
C7	1162127	Cover, Tap, Compression, "D"	100	200
C710-112L	7001957	Cutout, Fused, 15KV, 100 Amp,	1	54
GD-115	1200060	Deadend, Automatic, #1 Sol, CU, 4A	50	50
GD-516	1199994	Deadend, Automatic, #1 Str, CU	50	50
GD-116	1200035	Deadend, Automatic, #1 Str, CU, 3A	50	50
GD-514	1199986	Deadend, Automatic, #2 Sol, CU	50	50
GD-114	1200178	Deadend, Automatic, #2 Sol, CU	50	50
27LD	1242960	Deadend, Automatic, #2 Str, CU	50	50
GD-4442A	1242978	Deadend, Automatic, #4 & #2 ACSR	50	50
GD-512	1199978	Deadend, Automatic, #4 Sol, CU, 8A	50	50
47FD	1200051	Deadend, Automatic, #4 Str, CU	50	50
47LD	1200001	Deadend, Automatic, #4 Str, CU, 6A	50	50
GD-511	1199960	Deadend, Automatic, #6 Sol, CU	50	50
GD-406A	1199935	Deadend, Automatic, 1/0 ACSR/AL.	50	50
GD-446A	1200027	Deadend, Automatic, 1/0 ACSR/ALUM	50	50
107LD	850127	Deadend, Automatic, 1/0 CU, 2A CW	50	50
107FD	1200043	Deadend, Automatic, 1/0 CU, 2A CW	50	50
5202	1243443	Deadend, Automatic, 12.5M Guy Wire	25	25
GD-1195A	1199719	Deadend, Automatic, 4/0, 3/0 Str.CU	25	25
5201	1158494	Deadend, Automatic, 8M/10M Guy Wire	25	25
ND-0120	1158651	DEADEND, COATED, .889-.945" (336 AERIAL CABLE)	10	20
ND-0125	7003757	DEADEND, COATED, 795MCM ALUM COMPRESS	10	20
EN58	7000905	Evenut, Oval, 5/8" Bolt	50	50
31100	1163751	Fuse, Link, 100amp, Type K, Fitall	25	100
FL3D10	7000715	Fuse, Link, 10A, Type D, Removable	25	50
31140	1163760	Fuse, Link, 140amp, Type K, Fitall	25	100
FL3D15	7000716	Fuse, Link, 15A, Type D, Removable	25	50
31200	1163778	Fuse, Link, 200amp, Type K, Fitall	25	50
31020	532460	Fuse, Link, 20amp, Type K, Fitall	25	25
31025	1163727	Fuse, Link, 25amp, Type K, Fitall	25	25
31040	1163735	Fuse, Link, 40amp, Type K, Fitall	25	50
31065	1163743	Fuse, Link, 65amp, Type K, Fitall	25	200
89521R10	7002154	FUSEHOLDER, 100 AMP, FOR S&C CUTOUT	16	32
89571R11	7001962	FUSEHOLDER, 200 AMP, FOR S&C CUTOUT 14.4KV, 110KV BIL, HEAVY DUTY, OUTDOOR PRIMARY	16	32
AWDE-4119	1158735	Grip, Deadend, AW Guy 12.5M AW	50	50
AWDE-4126	1218101	Grip, Deadend, AW Guy 20M AW	50	10
AWDE-4108	1158719	Grip, Deadend, AW Guy 4M AW	50	50
GA-5X	1158851	HOOK, GUY, 5/8" BOLT (REA)	50	50
GS21024CP	1163986	INSULATOR, GUY STRAIN, 24", FIBERGLASS, 21000#	5	20
HPI-15F	7001269	INSULATOR, PIN TYPE, 15KV, POLY, 1" PIN HOLE, SKY GRAY	18	180
INSULATOR-SPL-3-53-2	7001268	Insulator, Spool, 3" (Class 53-2)	25	50
RTL-15	7001274	Insulator, Spacer, Aerial Cable, 15kv, 3-phase, Ringless		14
401015-0215	7001280	Insulator, VeriLite, PDI-15, 15KV	15	90
3152	7000799	LINK, CONNECTING, 2 PIECE, 1/4"X2"X9-1/2", GALV ST	40	40
A7M-100-2NR	0510201	LUG, TERMINAL, BOLTED, ALUMINUM 336-795MCM AA, TIN PLATED, TWO 9/16" HOLES ON 1-3/4" CENTERS	8	16
TGP16-1B-8YPF	7000828	Marker, Guy, 8', w/One Clamp at	25	70
VP-1/2-GWM-BK8	7000913	Molding, Plastic GW, 1/2"x 8'	125	125
KVSU28	1161894	Oklip, 2-bolt, Universal	25	100
KVSU34	1161919	Oklip, 2-bolt, Universal	25	100
J207Z	1159078	Pin, Crossarm, 6-1/2", Nylon	25	25
J222Z	1159051	Pin, Crossarm, Short-Shank, NYLON	25	50
J203Z	7004088	Pin, Crossarm, Steel, 5-3/4" Nylon	25	100
AP8-6H	1159001	PIN, INSLR, ANGLE, 1"THREAD, 6"HIGH,WITH 5/8" X 7" MACHINE BOLT, 2" SQUARE WASHER, SQUARE NUT & LOCKNUT, GALVANIZED	10	30
7006359	7006359	PIN, POLE TOP, 20" NYLON	10	30
893	1218401	PIN, SHORT-SHANK, CROSSARM, 1-3/4" (3/4" SHANK, 6" MTG. HEIGHT)	25	25
S635	0376260	PROTECTOR, WILDLIFE, 4.75"X 9.00"	50	50
ANCHOR-ROD-B-D-8X58	1159194	Rod, Anchor, Bust 5/8 x 8' Twineye	5	15
ANCHOR-ROD-SC-D-7X34	475294	Rod, Anchor, Screw, 3/4" x 7',	5	10
615880	7000888	Rod, Ground, Copper 5/8"x 8' (UL)	5	50
J8784	1159243	Screw, Lag, Gimlet Point, 1/2 x 4"	250	25
6170000-2	7005833	Seal, Meter, Padlock, GREEN	1000	1000
ASH-55	7001094	Shackle, Anchor, 30000 LB, 2-3/4"	25	100
GL-116	7006654	Sleeve, Automatic, #1 Str, CU	50	300
GL-1140	7006668	Sleeve, Automatic, #2 Sol, CU	50	300
GL-115	7003941	Sleeve, Automatic, #2 Str, CU 4A CW	50	300
GL-112	7003939	Sleeve, Automatic, #4 Sol, CU,8A CW	50	300
GL-113	7003940	Sleeve, Automatic, #4 Str, CU,6A CW	50	300
GL-111	7003938	Sleeve, Automatic, #6 Sol, CU	50	300
GL-117	1162719	Sleeve, Automatic, 1/0 Str.CU	50	300
GL-406A	1159886	Sleeve, Automatic, 1/0-6/1 ACSR	50	300
GL-411	1159919	SLEEVE, AUTOMATIC, 336 18/1 ACSR	10	30
GL-120	7004109	Sleeve, Automatic, 4/0 Str, CU	50	50
GL-1385A	7003515	SLEEVE, AUTOMATIC, 795 AAC	10	30
CS73	7000541	Sleeve, Service, Bare, #2-#2, RED/RED	100	500
CS68	7000544	Sleeve, Service, Bare, #4-#4, ORANGE/ORANGE	100	500
CS78	3001888	Sleeve, Service, Bare, 1/0-1/0 Str, YELLOW/YELLOW	100	500
CS77	3001890	Sleeve, Service, Bare, 1/0Str-2Str, YELLOW/RED	100	500
CS76	3001885	Sleeve, Service, Bare, 1/0Str-4Str, YELLOW/ORANGE	100	500
CS72	7000542	Sleeve, Service, Bare, 2Str-4Str RED/ORANGE	100	500
ICS73-1	7000531	Sleeve, Service, Insulated, #2-#2, RED/RED	100	500
ICS72-1	7000535	Sleeve, Service, Insulated, #2-#4, RED/ORANGE	100	500
ICS68-1	7000534	Sleeve, Service, Insulated, #4-#4, ORANGE/ORANGE	100	500
ICS78-1	7010322	Sleeve, Service, Insulated, 1/0-1/0 YELLOW/YELLOW	100	500
ICS77-1	3001891	Sleeve, Service, Insulated, 1/0-2, YELLOW/RED	100	500
ICS76-1	3001889	Sleeve, Service, Insulated, 1/0-4- YELLOW/ORANGE	100	500
OH1/0-7AL	1200135	Sleeve, Tension, 1/0 str. ALUM	100	500
30010	1200151	Sleeve, TPX, Neutral, #2 Alum ACSR	100	500
30011	1200160	Sleeve, TPX, Neutral, #4 Str, Alum	100	500
GSS-24	1566778	SPREADER, SECONDARY CABLE, W/BAIL	10	20
J1672	7002254	Staple, 1-1/2", GALVANIZED	50	50
HLB2	1159527	Stirrup, Plated, #2 CU Bail Closed	100	100
M3D-96BC	7010217	SWITCH, DISCONNECT, UA, 15KV, 900A, 110KV BIL, 40KA MOMETARY, W/(4) 1/2" X 2"X 13TPI CAPTIVE BOLTS & TINNED PADS, BACK PLATE, W/(4) CARRIAGE BOLTS FOR CROSSARM MTG, POLYMER POST INSULATORS, 15" POST SPACING	1	9
TNT-4-40	1244794	Tap, Mid-Span, Neutral, 336.4 ACSR-	12	12
MST41-350-4/0	1162927	Tap, Mid-Span, Secondary Service	12	12
LC-833-XB	1157894	Tap, Parallel 336-795--8-2/0	25	100
37-08180	1164451	Tape, Electrical, Vinyl 1.5 x 66'	50	200
37-09180	1164401	Tape, Electrical, Vinyl 3/4 x 66'	100	200
GA-9821L	0484519	VISE-TAP, BOLTED 336-840 ACAR 3/0-397.5 ACSR TAP (2-BOLT)	25	50
GA-9843L	0484494	VISE-TAP, BOLTED 795-1/0, 4/0	25	50
6813	7000337	Washer, Square, 5/8" Bolt	250	750
4-SOLID-CW-SPOOL	7001812	WIRE #4 SOLID ANNEALED 40% CONDUCTIVITY CW GROUND (427 = 50#)	25	500
2-STR-SD-INS-CU-SPL	1199386	WIRE, #2, 7 STR, SOFT DRAWN CU, POLY INS, (25# = 107')	107	535
4-STR-SD-INS-CU-SPL	1199378	WIRE, #4, 7 STR, SOFT DRAWN CU, POLY INS., 25# (175')	175	875
6-SOL-SD-INS-CU-SPL	1199360	WIRE, #6 SOLID, SOFT DRAWN CU POLY INS, 25# (285')	285	2850
1197560	1197560	WIRE, #6, 7 STR, CU HARD DRAWN (309')	309	1500
1/0-STR-SD-INS-CU-RL	1199394	WIRE, 1/0, 7 STR, SOFT DRAWN CU POLY INS, 1000# (2700')	50	250
12.5M-GUY-500	1197435	WIRE, 12.5M, 7 STR, ALUMOWELD GUY/MESSENGER	500	1500
AZUSA-CL	470935	Wire, 123.3KCM, 4/3 str, Bare AAAC	100	5000
4/0-STR-SD-INS-CU-RL	1199401	WIRE, 4/0, 7 STR, SOFT DRAWN CU, POLY INS., 1397# (1397' RL)	50	250
8M-GUY	1197401	WIRE, 8M, 7 STR, ALUMOWELD GUY/MESSENGER	500	1500
TW00011	7000941	WIRE, TIE, 4 SOLID AAC SD, BARE	25	250
1197586	1197586	WIRE,#2,7STR,BARE CU,HD	125	1250
1197578	1197578	WIRE,#4,7STR,BARE CU,HD	200	2000
J0588Z	7004467	Wireholder, Mast, Nylon (K17)	25	200
J0893Z	1163378	Wireholder, Service, 3" (NYLON	25	200

Restaurant Set-up Process

Restaurants supplied from **Supply Chain/Logistics Emergency Response Procedures Manual (SCLERPM)**

1) Supply Chain assigned person will obtain a copy of appropriate Purchasing Card(s) for this Storm event from **Paul Tirey.**

2) Locate tab in the SCLERPM for appropriate Operation Center that food service is needed.

3) From "Operations Center specific Information" sheet find list of primary restaurants. These should be contacted first and most should have provided this service in the past.

4) If additional restaurants needed due to unavailability of primary sources due to storm outage.

   a) Contact the area operations center Administrative lead for suggestions.

   b) Google to search and enter "restaurants, (city), Kentucky." This should produce a list of restaurants in that area with phone numbers and addresses. (See **Restaurant Form** Tab for blank form)

5) The following procedure has been developed and should be used as a tool when setting up restaurants with Purchasing Card.

   a) Ask for Manager on duty. (Introduce yourself LGE or KU a part of LG&E and KU Services Company and record Managers name to be used in restaurant list spreadsheet).

   b) Ask if they are willing to assist LGE/KU during Storm Restoration efforts (next few days) by providing meals for our Employees and Contractors to be paid by Purchasing Card? If authorization form is requested, see **Hotel/Restaurant Purchasing Card Authorization Form** tab.

   c) If they reply yes, then inform them of the following:

      1) Once on the property, all persons eating should be Contractors of LGE or KU or LGE/KU employees. Contractors will typically be wearing identification bands and LGE/KU employees should be wearing company IDs.

      2) Normal menu food and drink **(non alcoholic)** items should be ordered/purchased. When finished eating please have customer print and sign their name on receipts and also note name of their company on receipts. Receipts will be needed for verification and should be kept by restaurant until end of the storm event.

3) Note: add a 15% gratuity to bill for waiter or waitress.

4) Request that the restaurant process the charges daily.

d) All receipts should be mailed to:

ATTN: Supply Chain
Purchasing Card Administrator
LGE and KU Services Company
PO Box 32020
Louisville, Kentucky 40232

e) Give Manager Purchasing Card information - (LGE or KU) whatever card is appropriate from card info received in step one, also leave your name and a phone number (office and/or cell) to call if they encounter any problems.

6) The following standard spreadsheet will be used to capture when restaurants have been set-up for contract and company crews. This spreadsheet will be maintained on the Supply Chain shared drive and the Supply Chain website:

Louisville					
Location	**Name**	**Address**	**Contact Managers**	**Telephone**	**Hours**
Central	Steak & Shake	3232 Bardstown Road	Dave	502-456-2670	24 hours
Central	Golden Corral	4032 Taylorsville Road	Scott	502-485-0004	11am – 9:00 pm
Central	Denny's	434 Eastern Pkwy	John	502-636-2538	24 hours
East	Hometown Buffett	1700 Alliant Ave (Blankenbaker)	Kim	502-267-7044	11am - 8:30 pm

Note: When restaurants are established, this information will be entered into the Resources on Demand (RoD) resource tracking system which can provide updates to Supply Chain and Operation Managers overseeing the storm restoration for the Bird Dogs with the restoration crews.

7) At the end of the Storm Event – Contact all restaurants on the set-up list, ask for Manager, and inform them of the cut-off time for accepting any additional request for meals covered by the LGE and/or KU Storm Purchasing Cards. At this time also remind them they need to send in the receipts for all charges as noted above in 5(d).

Emergency Individual "Storm" Purchasing Cards (Primarily Level I) Storm Purchasing Cards held by Team Leaders or Birddogs (cardholder) shall only be used in areas outside the heavy concentration restoration areas where Corporate Storm Process has not been activated. Individual Storm Purchasing Cards are intended to be used in sparsely / sporadic restoration areas. Collection of receipts and reconciling of statement will be the cardholder's responsibility. "Emergency Response Level I Storms" will be handled using the Individual "Storm" Purchasing Cards on an as needed basis with management responsibility controlled by Team Leaders or Birddogs."

Key Staging Information
Sites

Area	Facility	Address	Contact	Phone	Email
Louisville	Papa Johns Cardinal Stadium	2800 S. Floyd Street Louisville, KY 40209	[redacted]	[redacted]	
	Churchill Downs	700 Central Ave. Louisville, KY 40208	[redacted]	[redacted]	[redacted]
	LGE Riverport Property	7301 Distribution Dr. Louisville, KY 40258	[redacted]	[redacted]	[redacted]
	Kentucky Fair & Expo Center	937 Phillips Lane Louisville, KY 40209	[redacted]	[redacted]	[redacted]
	E.P. Tom Sawyer Park	3000 Freys Hill Rd. Louisville, KY 40241	[redacted]	[redacted]	[redacted]
	Metro Parks	Various Locations	[redacted]	[redacted]	
Carrolton	General Butler State Park	1608 US Highway 227 Carrollton, KY 41008	[redacted]	[redacted]	
	Dempsey's Realty	515 7th Street Carrolton, KY 41008		[redacted]	
	CBRE	252 W. Jay Louden Road Carrolton, KY 41008	[redacted]	[redacted]	
Lexington	Applebee's Park - Lexington Legends	207 Legends Ln. Lexington, KY 40505	[redacted]	[redacted]	[redacted]
	Kentucky Horse Park	4089 Iron Works Pkwy Lexington, KY 40511	[redacted]	[redacted]	[redacted]
	Rupp Arena	430 W. Vine St. Lexington, KY 40507	[redacted]	[redacted]	
	University of kentucky	1540 University Dr. Lexington, KY 40502	[redacted]	[redacted]	[redacted]
	Red Mile	1200 Red Mile Rd. Lexington, KY 40504	[redacted]	[redacted]	
Elizabethtown	Hardin County Industrial Development Foundation		[redacted]	[redacted]	[redacted]
	Potential - Fenced Parking lot by I-65	300 Steel Drive Elizabethtown, KY	[redacted]	[redacted]	
	Potential - Lot at Altec Factory	201 Altec Drive Elizabethtown, KY 42701	[redacted]	[redacted]	
Madisonville	Rental Facility	52 N. Franklin St Madisonville, KY 42431	[redacted]	[redacted]	
	Kruger International	200 Commerce Drive Madisonville, KY 42431			
	Hart Corporation	410 Autoliv Beltway Madisonville, KY 42431	[redacted]	[redacted]	
	Industrial Area	1000 Ford Island Road Madisonville, KY 42431	[redacted]	[redacted]	
Princeton	Peach Properties		[redacted]	[redacted]	
Richmond	NAI	101 Marsha Kay Drive Richmond, KY 40475	[redacted]	[redacted]	
	Diversified Realty Group	833-847 Eastern Bypass Richmond, KY 40475	[redacted]	[redacted]	

Key Staging Information
Sites

Area	Facility	Address	Contact	Phone	Email
Morganfield	EWM Service, LLC	2746 US Hwy 60 E. Morganfield, KY 42437	[redacted]	[redacted]	
VA	Norton Big Stone Gap	1941 Neeley Road Norton, Big Gap, VA	[redacted]	[redacted]	
Greenville	Muhlenberg County Agricultural and Convention Center	3705 State Route 1380 Powerdly, KY 42367	[redacted]	[redacted]	
Dawson Springs	CBRE	200 Industrial Park Blvd Dawson Springs, KY	[redacted]	[redacted]	
Barlow	Golightly Equipment	137 S. Fourth Street Barlow, KY	[redacted]	[redacted]	

Staging Areas Information
Suppliers

Company	Address	Contacts	Phone	Email/Website	
R&K	11600 Blankenbaker Access Louisville, KY 40299	Richard Fahringer Michael Fahringer	[redacted]		Vehicle Staging
Emergency Disaster Services (EDS)	1385 Pridemore Court Lexington, KY 40505	Jerry Lundergan, Owner Abigail (Jerry's daughter)			On-site food, lodging, sanitary facilities, laundry service, etc.
Catering Cajun of Georgia, Inc.	2409 Shallowford Road NE Marietta, GA 30066				On-site food, lodging, sanitary facilities, laundry service, etc.
Kelly and Company, 1st Responders, LLC	Rt. 2, Box 512 Norwood, MO 65717	Steve Kelly Anthony Kelly Timothy Kelly Office			On-site food, lodging, sanitary facilities, laundry service, etc.
Storm Services, LLC	272 Oak Hill Road Cairo, GA 39828	Tommy Hopkins Ann Hopkins Toll Free			Specializes in the design, construction, operation, & management of full base camp setups
International Management Assistance Corp.	15830 Foltz Parkway Cleveland, Ohio 44149-4745	David Levine			On-site food, lodging, sanitary facilities, laundry service, etc.
LG Fox, Inc.	1692 Jaggie Fox Way Lexington, KY. 40578	Charlie Waugh			Portable Generators
Cummings Crosspoint, LLC	9820 Bluegrass Pkwy. Louisville, KY 40299	Brian Leis			Portable Generators
Evans Construction Co	4807 Chenoweth Run Rd Louisville, KY 40299	Ann Evans			Janitorial Services/Light Maintenance
Rumpke	7501 Grade Lane Louisville, KY 40219				Port-A-Cans/Hand Washing Stations
Waste Mgmt	2673 Outer Loop Louisville, KY 40219				Port-A-Cans/Hand Washing Stations

EPRP Appendix 9 Work Planning Section

Work Planning

When Work Planning is activated, the **Resource Tracking** team will setup at the BOC in Training Room H located on the lower level. This team is responsible for tracking mutual assistance and other off-system crews while in-transit who have committed to assisting us. They make contact with the General Foreman to confirm crew counts, lodging requirements and estimated times of arrival, and they instruct the General Foreman on where to check-in once they arrive. They also enter crew level information into Resources on Demand (RoD) including estimated arrival times and lodging requirements. The Resource Tracking team then enters detailed team member information once rosters are received.

> The central phone number for Work Planning in Training Room H is **627-2046**. If it does not get answered or it is busy, the call will roll to the phones that are signed on (x3881, 3882, 3884, 3885, 3886, 3887, 3888 & 3889). To “sign on,” come off hook and hit #2 then hang up. That phone is then ready to accept calls. To “sign off,” come off hook and hit *2.
>
> If Resource Tracking shuts down for the night, the central number must be forwarded to someone’s cell phone until the day shift begins.
>
> The central email address for the Resource Tracking team is Storm.Resources@lge-ku.com
>
> This number and email address should be given to General Foremen as contact information while traveling. They must be manned and monitored at all times.

The **Resource Check-in** team is also activated as part of Work Planning. This team will co-locate with Safety at the location designated for safety training or “passporting” off-system crews as they arrive. The Resource Check-in team will validate each individual working on our system, will enter them into RoD if necessary and indicate their actual time of arrival.

If the check-in point does not have connectivity to the LG&E/KU network, a few personal WiFi devices are available and should be used by the Resource Check-in team(s). When you turn the device on, it will give you the network name and password. You will then need to connect your PC to this network. You will need power for prolonged use.

This job aid is a guide on how to track mutual assistance and other off-system resources, using Resources on Demand, that assist LG&E and/or KU during a significant power outage.

Access RoD

From the intranet home page, select **Applications**>**P-T**>**Resources on Demand**. You will automatically be logged into Resources on Demand.

Log Out

To log out of Resources on Demand (RoD), click on the **X** on the Internet Explorer window.

Resources View

Note: When entering information, all fields with an asterisk (*) are mandatory and must be filled in.

Manually Add New Team

1. From the main menu, select **Resources, Resources View**.

2. Click the icon to add a row at the end of the table.

3. Enter the following team information. All of the values, except where otherwise noted, are entered by the Resource Tracking team. Refer to the **Quick Reference Guide** for definition of fields.

Team Fields

*Team ID	Team Name	*Team Function	*Team Role	*Company Name	*Status	Use Roster	*System Type	*Operation Center	Crew Center	*Local Area
18										
DHEAOC400	DHE Management	Distribution	Line Workers	ELLIOTT	Active	☑	Off	LGE	LGE	LGE
DHEAOC402	Abbott, Mike	Distribution	Line Workers	ELLIOTT	Active	☑	Off	LGE	LGE	LGE
DHEAOC406	Davis, Tim	Distribution	Line Workers	ELLIOTT	Active	☑	Off	LGE	LGE	LGE
DHEAOC411	Burchett, Joe	Distribution	Line Workers	ELLIOTT	Active	☑	Off	LGE	LGE	LGE

- **Team Fields**: *Team ID, Team Name, *Team Type, *Team Function, *Team Role, *Company Name, *Status (to activate the team), Use Roster, *System Type, *Operating Center, Crew Center, *Local Area

  Note: Team ID is ten (10) characters long and must be unique. The naming convention is: 3 letter company code; 3 letter team type; 3 digit number (AEPMAU100, DHEMAC200, PKEOSC100, etc.).

  Company codes: PKE=Pike, DHE=Davis H Elliot, FIS=Fishel, GRV=Groves, HAL=Hall, HEN=Hendrix, UNI=United … others to be determined "on the fly;"
  Team types: MAU=Mutual Assistance Utility, MAC=Mutual Assistance Contractor, OSC=Off System Contractor;
  Numbers: Incremental numbering of your choosing to ensure unique team IDs.

  Note: Team Name is free-form text and is usually made up of the Company name and Foreman last name.

  Note: Use Roster – check this box once you have a roster and are ready to enter team member information, otherwise leave it unchecked and enter straw counts.

Team Leadership

*Team ID	Team Name	Team Lead	TL Cell Phone	Bird Dog	Bird Dog Phone	Bull Dog	Bull Dog Phone	General Foreman	General Foreman Phone
18									
DHEAOC400	DHE Management	Mekus, Mark	[redacted]					Mekus, Mark	[redacted]
DHEAOC402	Abbott, Mike	Abbott, Mike	[redacted]					Mekus, Mark	[redacted]
DHEAOC406	Davis, Tim	Davis, Tim	[redacted]					Mekus, Mark	[redacted]
DHEAOC411	Burchett, Joe	Burchett, Joe	[redacted]					Mekus, Mark	[redacted]

- **Team Leadership**: Team Lead, TL Cell Phone, General Foreman, General Foreman Phone

Straw Counts

*Team ID	Team Name	Bird Dog	Bull Dog	Customer Center Reps	Damage Assessors	Dispatcher	General Foreman	Line Worker	Management	Other
18		0	0	0	0	0	2	151	9	10
DHEAOC400	DHE Management	0	0	0	0	0	2	0	0	0
DHEAOC402	Abbott, Mike	0	0	0	0	0	0	79	1	0
DHEAOC406	Davis, Tim	0	0	0	0	0	0	4	0	0

Straw counts – enter number for Bird Dog, Bull Dog, Customer Center Reps, Damage Assessors, Dispatcher, **General Foreman, Line Worker,** Management, Other, PSRT Dispatch Lead, PSRT Field, PSRT Office, Safety, Security, **Substation, Transmission, Vegetation,** Total Members *(auto calculated)*

Note: Once the Use Roster checkbox is checked, all straw counts entered will be overridden by the information entered in to the Team Members screen, the counts will become automatically calculated.

Team Equipment

*Team ID	Team Name	Backhoe	Bucket Truck	Chipper	Digger Derrick	Dozer	Dump Truck	Mini Derrick	Other Equipment	Pickup	Service Truck	Total # Equipment
18		0	19	0	6	0	0	0	0	21	0	46
DHEAOC400	DHE Management	0	0	0	0	0	0	0	0	0	0	0
DHEAOC402	Abbott, Mike	0	0	0	0	0	0	0	0	0	0	0
DHEAOC406	Davis, Tim	0	0	0	0	0	0	0	0	0	0	0
DHEAOC411	Burchett, Joe	0	0	0	0	0	0	0	0	0	0	0

- **Team Equipment**: **If available, enter straw counts for** Backhoe, Bucket Truck, Chipper, Digger Derrick, Dozer, Dump Truck, Mini Derrick, Other Equipment, Pickup, Service Truck, Total # Equipment *(auto calculated)*

  Note: Once the Use Roster checkbox is checked, all straw counts entered will be overridden by the information entered in to the Team Members screen, the counts will become automatically calculated.

Other Information

*Team ID	Team Name	Work Planning Contact	Work Planning Phone	Departure Date Time	Estimated Time of Arrival	Actual Time of Arrival	Passport Site	Passport ETA	Passport ATA	Passport Status	Passport Date/Time	Roster Verified	Sta
18													
DHEAOC400	DHE Management	Paul Weis	[redacted]		11/17/2013 12:4	11/17/2013 14:0				☐		☐	
DHEAOC402	Abbott, Mike	Paul Weis	[redacted]		11/17/2013 12:4	11/17/2013 14:0				☐		☐	
DHEAOC406	Davis, Tim	Paul Weis	[redacted]		11/17/2013 12:4	11/17/2013 14:0				☐		☐	
DHEAOC411	Burchett, Joe	Paul Weis	[redacted]		11/17/2013 12:4	11/17/2013 14:0				☐		☐	

- **Team Departure / Arrival and Other Information**: Work Planning Contact, Work Planning Phone, Departure Date Time, Estimated Time of Arrival (**Note:** This field needed for Logistics.)

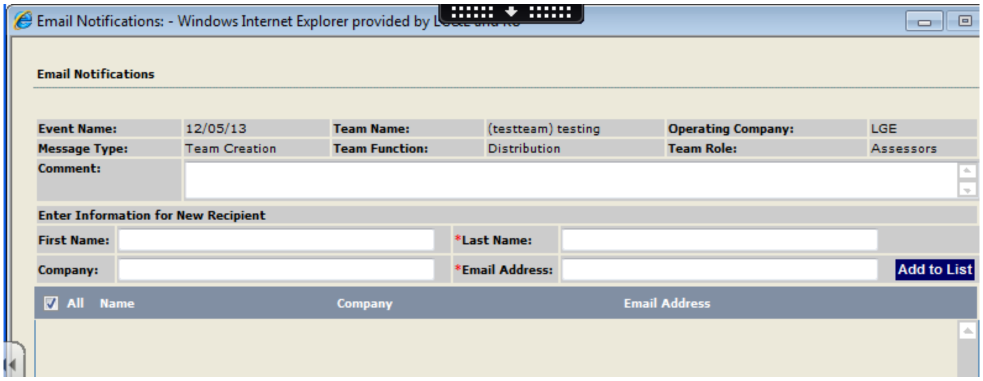
  The following fields are entered by the Resource Check-in team once the crews have been passported: Actual Time of Arrival, Passport Site, Passport Status, Roster Verified

- **Team Origin**: Home State, Home Utility, Home Office Contact, Home Office Phone #, Home Office e-mail

- **Team's Lodging and Logistic Requirements**: Requires Lodging, # of Singles, # of Doubles, # of Others, # of Females

4. Click **Save**.

5. Email Notification – when adding teams or changing locations of existing teams, an email pop-up box displays. This is meant to notify the Logistics team when teams move and need lodging at their new location. Add Comments if necessary to describe any particular situation and send the notice to Paul Tirey. First Name = Paul, Last Name = Tirey, Email Address = [redacted]

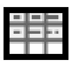


Team Member Info (Roster)

Add New Team Members

1. From the main menu, select **Resources**, **Resources View**.

2. Select a team by clicking on the **Team ID Hyperlink**. The Team Member Information screen opens.

3. Click the  icon to add a row at the end of the table.

4. Enter the following team information: *Last Name, *First Name, *Gender, Cell Phone, E-mail, Radio, Personnel ID, *Personnel Type, *Storm Role, Passport ID (entered by Resource Check-in), Crew ID, Team Lead, Crew Leader, Home State, Bed Type, Requires Lodging, Union, Comments, Original Team ID (*automatically populated)*, Equipment ID, Equipment Type, Equipment Description, Equipment Radio and Equipment Cell

*Last Name	*First Name	*Gender	Cell Phone	Radio	E-mail	Personnel ID	*Personnel Type	*Storm Role	Passport ID	Crew ID	Team Lead	Crew Leader	Home State	Bed Type	Requires Lodging
Davis	Tim	Male	[redacted]				Line Worker	Foreman			☑	☑	TN	Singles	☑
Corbett	Robert	Male					Line Worker	Journeyman			☐	☐	TN	Doubles	☑
Edds	Bret	Male					Line Worker	Apprentice			☐	☐	TN	Doubles	☑
Vangosen	Dick	Male					Line Worker	Journeyman			☐	☐	TN	Doubles	☑

Note: Much of the time, the information illustrated above is the most information provided for team members.

Note: Reference the **Quick Reference Guide** for definitions of Personnel Type and Storm Role.

5. Click **Save**.

Resource Tracking – screens and fields

The **Resource Tracking** team tracks Mutual Assistance and other off-system crews while they are in-transit to the check-in/passporting site. They will use the **Resources View** screen to capture company/crew level information in the following fields.

Field	Example Entry
• Team ID	PKEMAU100 *(company, team type, number)*
• Team Name	Pike – Joe Smith *(company, foreman name)*
• Team Type	Off System Contractor, Mutual Assistance Contractor, or Mutual Assistance Utility
• Team Function	Distribution
• Team Role	Line Workers
• Company Name	Pike
• Status	Active
• Use Roster	*Check if entering individual team members,* *Uncheck if entering straw counts for resources*
• System Type	Off
• Operation Center	LGE *(the work location they in which they will be helping)*
• Crew Center	LGE
• Local Area	LGE
• Team Lead	Joe Smith *(crew foreman)*
• TL Cell Phone	(502)555-1212
• General Foreman	David Cassidy *(general foreman for the company)*
• GF Phone	(502)555-1213
• BirdDog-Vegetation	straw counts, people – enter number for **Line Worker** if not using rosters *(enter other counts when applicable)*
• Backhoe-Service Truck	straw counts, equipment – enter counts for each equipment type known if not using rosters
• Work Planning Contact	MistyWhite *(your name here! ☺)*
• Work Planning Phone	(502) 627-2046 *(central number or your cell number)*
• Departure Date/Time	2/14/2014 14:00
• Estimated Time Arrival	2/14/2014 21:00
• Home State	Virginia
• Home Utility	AEP *(in this case, Pike normally works for AEP in VA)*
• Home Office Contact	*enter if known*
• Home Office Phone	*enter if known*
• Home Office Email	*enter if known*
• Hours Tracking	*enter start time equal to Departure Date/Time*
• Requires Lodging	*Check if they will require lodging <- usually yes*

If the **Resource Tracking** team has rosters, check the "Use Roster" checkbox and enter information in the **Team Member** screen.

Field	Example Entry
• Last Name	Smith
• First name	Joe
• Gender	Male
• Cell Phone	(502)555-1212
• Personnel Type	Line Workers *(pick the appropriate personnel type)*
• Storm Role	Journeyman *(pick the appropriate storm role)*
• Team Lead	*Check if he/she is the team lead/foreman*
• Home State	Virginia
• Requires Lodging	*Check if they will require lodging <- usually yes*
• Equipment ID	100 *(enter unique equipment ID)*
• Equipment Type	Bucket Truck *(pick the appropriate equipment type)*

Resource Check-In – screens and fields

The **Resource Check-In** team is co-located with the Safety Team at the passporting/check-in site. Once off-system resources have been "passported" (safety trained), they check-in by providing a form with pertinent information on it.

The following additional information is then added in the **Resources View** screen.

Field	Example Entry
• Actual Time of Arrival	2/14/2014 22:30

If the **Resource Tracking** team did not enter rosters, the **Resource Check-In** team must now check the "Use Roster" checkbox and enter information in the **Team Member** screen, including the Passport ID. If rosters are already loaded, then simply add the Passport ID.

Field	Example Entry
• Last Name	Smith
• First name	Joe
• Gender	Male
• Cell Phone	(502)555-1212
• Personnel Type	Line Workers *(pick the appropriate personnel type)*
• Storm Role	Journeyman *(pick the appropriate storm role)*
• **Passport ID**	**5739233** ***(obtained from the passport form submitted)***
• Team Lead	*Check if he/she is the team lead/foreman*
• Home State	Virginia
• Requires Lodging	*Check if they will require lodging <- usually yes*
• Equipment ID	100 *(enter unique equipment ID)*
• Equipment Type	Bucket Truck *(pick the appropriate equipment type)*

Other Helpful Tips

Managing Team Splits And Team Member Moves

Split an Existing Team by Creating a New Team

1. From the main menu, select **Resources, Resource View**.

2. Select the team to be split by clicking in the cell to the left of the Team ID.

3. Click **Manage Teams**.

4. In the left hand pane, view the team to be split. In the right hand pane, enter the following to create a new team: *Team ID, *Company Name, Team Name, *Team Type, Shift, *Team Function, *Team Role, *Operation Center, Team Home, *Local Area, *System Type.

5. Click **Save**.

6. Review team members to move from the left hand pane and assign to the right hand pane (new team).

7. Select team member by clicking in the cell to the left of the team member name.

8. Click the arrows to add/remove team members from one team to the other.

9. Click **Save**.

Move a Resource from an Existing Team to Another

1. From the main menu, select **Resources**, **Resources View**.

2. Select the team to move resources from by clicking in the cell to the left of the Team ID.

3. Click **Manage Teams**.

Note: The left pane is the source team that was selected. The right pane is the target team.
4. In the Team ID field on the right pane, type in the **Team ID** of the team to add the resource to and then tab out of Team ID field.

5. Select team member(s) from source team by highlighting the row of the team member(s).

Note: Team members are displayed at the bottom of source screen.
6. Click the arrow to move team member(s) to target team.

7. Click **Save and Return to Resource View**.

Resources View Bulk Operations

The following options are available in the **Resources View** main display grid after clicking the row header to select a team:
Note: Multiple teams can be selected by using the Ctrl button.

Change a Team's Local Area

1. Select **Change Local Area**.

2. Select **Operation Center:** and **Local Areas:** from the drop-down to change team's reporting staging center.

3. Enter **ETA Date & Time:** or select calendar icon.

4. Click **Update Local Areas** to save changes to team location.

5. Click **OK**.

Update Team Status

1. Select **Update Teams Status**.

2. Make a selection from the drop-down.

3. Click **Update Team Status**.

4. Click **OK**.

Update Team's ETA

1. Select **Update ETA**.

Note: Multiple teams can be selected to update their ETA by dragging cursor.
2. Enter ***ETA Date & Time:** or select calendar icon.

3. Click **Update ETA**.

4. Click **OK**.

Change Team ID

1. Select **Change Team ID**.

2. Select **Selected Team ID:** and enter **New Team ID:**. (**Note:** New Team ID must not exist already.)

3. Click **Update**.

4. Click **OK.**

Regional Mutual Assistance Groups

Midwest Mutual Assistance Group
Allete/Minnesota Power
Alliant Energy
Ameren
American Electric Power
American Transmission Co.
Aquila
Black Hills Energy
CenterPoint Energy
Duke Energy
Commonwealth Edison (an Exelon Company)
Empire District
Entergy
Indianapolis Power & Light
International Transmission Co.
Kansas City Power & Light
LG&E / KU Energy (a PPL, Inc. Company)
Madison Gas & Electric
MidAmerican Energy
Midwest Energy
Nebraska Public Power
Northern Indiana PSC
Northwestern PSC
Oklahoma Gas & Elec.
Omaha Public Power
Oncor Electric Delivery
Otter Tail Power
South Carolina Elec. & Gas
Texas New Mexico Power
Vectren Energy
WE Energy
Westar Energy
Wisconsin Public Service
XCEL Energy

Texas Mutual Assistance Group
American Electric Power
Austin Energy
Brownsville Public Utilities
Cap Rock Energy
CenterPoint Energy
City Public Service
Cleco
Entergy
Mississippi Power Co. (a Southern Company)
Oklahoma Gas & Electric
Oncor Electric Delivery
Texas New Mexico Power

North Atlantic Mutual Assistance Group
Central Hudson Gas & Electric
Consolidated Edison
Duquesne Light
Emera – (Bangor Hydro, Nova Scotia Power *)
Exelon – (BGE, PECO)
First Energy
Green Mountain Power
Hydro-One *
Hydro Quebec *
Iberdrola – (Central Maine Power, NYSEG)
National Grid (NY, NE, LIPA)
New Brunswick Power (Energie NB Power) *
New Hampshire Electric Cooperative
Northeast Utilities
Pepco Holdings, Inc. (PHI)
PPL Electric Utilities
Public Service Electric & Gas (PSE&G)
South Norwalk Electric & Water
UGI Utilities, Inc
United Illuminating
Unitil Corp

Wisconsin Utilities Association Mutual Assistance Group
Alliant Energy
Madison Gas & Elec. Co.
We Energies
Wisconsin Public Service Corporation
Xcel Energy Inc
American Transmission Company

Western Region Mutual Assistance Agreement
AltaLink L.P. *
Arizona Public Service Company
ATCO Electric *
Avista Corporation
BC Hydro *
Bonneville Power Administration
California Pacific Electric Company
Chelan County PUD No. 1
City of Mesa Utilities
Clark Public Utilities
El Paso Electric Company
ENMAX *
Eugene Water and Electric Board
Fortis Alberta, Fortis BC *
Hawaiian Electric Company
Idaho Power
Los Angeles Dept. of Water & Power (LADWP)
NorthWestern Energy
NV Energy
Pacific Gas & Electric Company
PacifiCorp
Portland General Electric
Public Service Company of New Mexico (PNM)
Puget Sound Energy
Sacramento Municipal Utility District
Salt River Project
Seattle City Light
Snohomish County PUD
Southern California Edison
Tucson Electric Power Company
Unisource Energy Services

Great Lakes Mutual Assistance Group
American Electric Power
Consumer's Energy
Dayton Power & Light (an AES company)
DTE Energy
Duke Energy
Duquesne Light Co.
LG&E/KU (a PPL, Inc. company)
ComEd (an Exelon company)
FirstEnergy
Indianapolis Power & Light (an AES company)
ITC Holdings
Northern Indiana Public Service Co. (a NiSource company)
Vectren Energy
We Energies

Southeastern Electric Exchange
American Electric Power
Baltimore Gas & Electric Co. (an Exelon Company)
CenterPoint Energy
Cleco
Commonwealth Edison (an Exelon Company)
Dayton Power & Light
Dominion
Duke Energy
Entergy Corporation
First Energy
Florida Power & Light Co.
Florida Public Utilities Company
LG&E / KU Energy (a PPL, Inc. Company)
Oklahoma Gas & Electric Co.
Oncor Electric Delivery
PECO Energy Company (an Exelon Company)
PHI, Inc.
PPL Electric Utilities
South Carolina Elec. & Gas Co.
Southern Company
Tampa Electric Co.
Texas – New Mexico Power

Produced by Edison Electric Institute's Project Support Group. Data Source: Regional Mutual Assistance Groups 2014.

3/2014

Last Revised 9/1/16

Company	Name	Office	Cell
American Electric Power (AEP)	Phil Lewis	[redacted]	
	Patrick Weyers		
Consumers Energy	Raymond Klavon		
	Tom Farr		
	Brenda Houtz		
	Kate Miller		
	Jim Anderson		
Dayton Power & Light	Don Gebele		
	Bruce Coppock		
	Kevin Hall		
DTE Energy Electric	Corey Cicerco		
	Rob Bellini		
	John Bueltel		
	Bob Almaguer		
Duke Energy	Marty Zearbaugh		
	Marc Arnold		
	Joan Sharpshair		
	Marty Wright (NC)		
Duquesne Light	Kathy Paras		
	Larry Wallace		
	Mike Peluso		
	Pat Conti		
ComEd	Steve Lusted		
	Robert Fournie		
	Tom McGowan		
	Ken Wagner		
	David Bunge		
	Stan Wilk		
FirstEnergy	John Huber		
	Randy Coleman		

Indianapolis Power & Light (IP&L)	Kevin Walker Dan Davenport	[redacted]
ITC Holdings	Rolland Scheels Mark Tollensdorf	
LG&E KU Energy	Morgan Pfeiffer Jamie Archer Robbie Trimble Steve Woodworth	
NIPSCO	David Holmes Ron Bates Alex Cervantes Scott Hanson	
Vectren (Southern Indiana Gas & Electric)	Brian Gatewood Mike Singer Chris Claybrooks	
We Energies	Jim Charboneau Chris Norton Glenn Peliska David Effertz John Nesbitt Dan Gruver Deb Casper Mike DiGiacomo	

Email
[redacted]
[redacted]
[redacted]
[redacted]
[redacted]
[redacted]
[redacted]
[redacted]

[redacted]

Southeastern Electric Exchange
MUTUAL ASSISTANCE CONTACT LIST - March, 2016

Latest Update: 3-15-16

Company	Order	Contact	Office Phone	Cell Phone	Email	Home Phone	Office Fax
S.E.E.	1	Jim Collins	[redacted]				
	2	Scott Smith					
	3	Amy Bekele					
AEP	1	Phil Lewis					
	2	Patrick Weyers					
BGE	1	Frank Tiburzi					
	2	Joe Picarelli					
	3	Jonathan Aguilera-Titus					
	4	David Olchowski					
	5	John Horner					
CenterPoint	1	Ed Scott					
	2	Thomas Klesel					
	3	Lee Bishop					
	4	Colby Gravatt					
	5	Bert Sausse					
Cleco	1	Floyd Pittman					
	2	James Lass					
	3	Andy Guillory					
ComEd	1	Kimberly Smith					
	2	Dawn Owens					
	3	Tom McGowan					
	4	Steve Lusted					
	5	Dave Bunge					
Dayton P&L	1	Bruce Coppock					
	2	Don Gebele					
	3	Kevin Hall					
	4	Steve Hesler					
Dominion	1	Shad Hedrick					
	2	Mike Evans					
	3	Dave Vanderbloemen					
Duke	1	Marty Wright					
Duke Carolinas	1	Donald Gower					
	2	Chester Ferguson					
	3	Rick Nicholson					
Duke Florida	1	Lou Mandese					
	2	Luis Ordaz					
	3	Jimmy Guzman					
Duke Midwest	1	Marty Zearbaugh					
	2	Joan Sharpshair					
	3	Marc Arnold					
Entergy	1	Mike Fricke					
	2	David Luthe					
	3	Billy Blaylock					
FirstEnergy	1	John Huber					
	2	Randy Coleman					
	3	Peter Manousos					
FPL	1	Tom Gwaltney					
	2	Iliana Rentz					
	3	Ed Devarona					
	4	Barry Wilkinson					
	5	Michael Willems					
FPUC	1	Warren DiNapoli					
	2	Lynwood Tanner					
	3	Buddy Shelley					
LGE-KU	1	Steve Woodowrth					
	2	Jamie Archer					
	3	Robby Trimble					
	4	Morgan Pfeiffer					
OGE	1	Rick Berg					
	2	Gary Rowlett					
	3	Robert Gottshall					
ONCOR	1	Mike Carter					
	2	Jeff Dossey					
	3	Rusty Evans					
PECO	1	William Kelbaugh					
	2	Koleen Dougherty					
	3	Eileen Mather					
	4	Phil Joel					
	5	Storm Rm/Asst Dir					
PPL	1	Mike Menges					
	2	Vince Cuce					
	3	Paul Ward					
PHI	1	Bryan Blazejak					
	2	J.B. Rogers					
	3	Andrew Sykes					
SCE&G	1	Doug Spires					
	2	Charles Moore					
	3	Bill Turner					
	4	Keller Kissam					
Tampa	1	Lee Collins					
	2	Rick Jackson					
	3	Regan Haines					
	4	Beth Young					
TNMP	1	Dan Nelson					
	2	Pauline Moore					
	3	Evans Spanos					
	4	Neal Walker					
MISS Power	1	David Simmons					
	2	Robert Boyd					
	3	Randall Pinkston					
	4	Steve Craig					
AL Power	1	Bobby Hawthorne					
	2	Steve Thompson					
	3	Corey Sweeney					
GA Power	1	Aaron Strickland					
	2	Hamilton Hardin					
	3	David Maske					
	4	Steve Lewis					
	5	Bo Braswell					
GULF Power	1	Paul Talley					
	2	Alan McDaniel					
	3	Charlene Damron					
	4	Andy McQuagge					

Municipal and Cooperative Mutual Assistance Contacts

COMPANY	NAME	Address	OFFICE	CELL	E-MAIL
Kentucky Association of Electrical Cooperatives, Inc.	David White, CLCP; Safety Instructor	[redacted]			
Owensboro Municipal Utilities	Tim Lyons, Director Engineering				
Clark Energy	Kim Moore, Operations Coordinator				
Nashville Electric Service	Dennis Boehms, VP Operations				

[redacted]

MIDWEST MUTUAL ASSISTANCE			
16-Sep			
COMPANY	NAME	OFFICE	PHONE EXT.
ALLIANT ENERGY- IPL			
200 First Street SE	Joe White	[redacted]	
Cedar Rapids, IA 52401-1409	Lacey Hogan	[redacted]	
800.255.4268	Josh Murray	[redacted]	
	Randy Bauer	[redacted]	
	NOTES: 24/7 Distribution Distpatch Center- IPL 800.526.3323 c	[redacted]	
ALLIANT ENERGY- WPL		[redacted]	
4902 Biltmore Ln.	Joe White	[redacted]	
Madison, WI 53718	Lacey Hogan	[redacted]	
800.255.4268	Mike Schmid	[redacted]	
	Ron Graber	[redacted]	
	NOTES: 24/7 Distribution Distpatch Center- WPL 800.551.1744	[redacted]	
AMERICAN TRANSMISSION		[redacted]	
N19W 23993 Ridgeview PK	System Operator- Pewaukee SOC	[redacted]	
Waukesha, WI 53187-0047	System Operator- Cottage Grove SOC	[redacted]	
866.899.3204	Thomas Betthauser	[redacted]	
Emergency Control Center 877.402.5228	NOTES: Nick Grossenbach Ph: 262.506.6770	[redacted]	
ITC MIDWEST		[redacted]	
27175 Energy Way	Rolland Scheels	[redacted]	
Novi, MI 48377	Mark Tollensdorf	[redacted]	
	Drew Schafer	[redacted]	
MADISON GAS & ELECTRIC COMPANY		[redacted]	
133 South Blair	Jim Lorenz	[redacted]	
Madison, WI 53703	Richard (Dick) Schwarz	[redacted]	
608.252.7111	Mitch Grundahl	[redacted]	
Fax: 608.252.1591		[redacted]	
MINNESOTA POWER- ALLETE		[redacted]	
3215 Arrowhead Rd.	John Muehlbauer, Supt Line	[redacted]	
Duluth, MN 55811	Tim Laeupple, Supt Line	[redacted]	
218.722.2641		[redacted]	
Fax # 218.720.2775		[redacted]	
NORTHWESTERN ENERGY		[redacted]	
600 Market	Jason Merkel	[redacted]	
Huron, SD 57350		[redacted]	
605.352.8411	Steve Arbach	[redacted]	
Fax # 605.353.7519		[redacted]	
OTTER TAIL POWER COMPANY		[redacted]	
215 S. Cascade	Dan Wynn	[redacted]	
Fergus Falls, MN 56538-0496		[redacted]	
218.73.8200		[redacted]	
Fax # 218.739.8200		[redacted]	
WISCONSIN PUBLIC SERVICE ORGANIZATION			

700 North Adams Street	Scott Phinney	[redacted]	
Green Bay, WI 54301	Rick Rohr	[redacted]	
800.743.6634	Nate Hall	[redacted]	
Fax # 920.433.1758	Craig Kahoun	[redacted]	
Emergency Control Center # 800.511.7720	Scott Petersen	[redacted]	
	Jeff DeGrave	[redacted]	
		[redacted]	
XCEL ENERGY- NORTHERN STATES POWER CO.- MINNESOTA		[redacted]	
414 Nicollet Mall	Todd Place	[redacted]	
Minneapolis, MN 55401-1923	Scott Hafner	[redacted]	
612.330.5500	Sean Walker	[redacted]	
Fax # 612.330.7699	Tony Wishard	[redacted]	
Emergency Control Center #612.321.7434	NOTES: The Xcel Energy Operating Companies are Northern State Power Co.		

MIDWEST MUTUAL ASSISTANCE

16-Sep

COMPANY	NAME	OFFICE	PHONE EXT.
AMEREN ILLINOIS			
6 Executive Drive	Riley Adams	[redacted]	
Collinsville, IL 62234	Marvin Morey	[redacted]	
		[redacted]	
AMEREN MISSOURI		[redacted]	
P.O. Box 66149	Dave Muntean	[redacted]	
St. Louis, MO 63166-6149	Vince Grelle	[redacted]	
800.552.7583	Mike Renieri	[redacted]	
Fax # 314.554.6454		[redacted]	
COMED COMPANY		[redacted]	
1700 Spencer Rd.	Kimberly Smith	[redacted]	
Joliet, IL 60433	Tom McGowan	[redacted]	
815.463.2950	Steve Lusted	[redacted]	
Emergency Control Center # 816.463.2996	David Bunge	[redacted]	
[redacted]	Ken Wagner	[redacted]	
	Stan Wilk	[redacted]	
	Debra Volling	[redacted]	
	Katie Doherty	[redacted]	
	Rebecca Sheperd	[redacted]	
	Jim Gute	[redacted]	
	Julia Ubaldo	[redacted]	
	Kelli McCurdy	[redacted]	
	NOTES: Also known as Commonwealth Edison	[redacted]	
MIDAMERICAN ENERGY COMPANY			

P.O. Box 657	Mark Weeks	[redacted]	
Des Moines, IA 50303-0657	Matt Mitchell	[redacted]	
515.252.6408	Jason Ewers	[redacted]	
Fax # 515.252.6403	Terry D. Smith	[redacted]	
NEBRASKA PUBLIC POWER DISTRICT		[redacted]	
P.O. Box 499	Robert G. Ausdemore	[redacted]	
Columbus, NE 68602-0499	Scott Walz	[redacted]	
800.379.1037	Brent Arens	[redacted]	
Fax # 402.644.3303	Joel Dagerman	[redacted]	
	NOTES: Include the following in emails- [redacted]	[redacted]	
NORTHERN INDIANA PUBLIC SERVICE COMPANY		[redacted]	
801 E. 86th Ave.	Scott Hanson	[redacted]	
Merrillville, IN 46410	Ronald Bates	[redacted]	
219.647.5089	Alex Cervantes	[redacted]	
Fax # 219.647.4777	David Holmes	[redacted]	
Emergency Control Center # 219.647.4846		[redacted]	
		[redacted]	
OMAHA PUBLIC POWER DISTRICT		[redacted]	
444 S. 16 St. Mall	Jerry McCaw	[redacted]	
Omaha, NE 68102	John Buckley	[redacted]	
402.636.2000	Ryan Mayberry	[redacted]	
	Amy Gurtis	[redacted]	
		[redacted]	
WE ENERGIES		[redacted]	
PO Box 2046	Jim Charboneau	[redacted]	
Milwaukee, WI 53201-2046	Glenn Peliska	[redacted]	
414.221.2345	Mike DiGiacomo	[redacted]	
Emergency Control Center # 262.542.1440	Dave Effertz	[redacted]	
	John Nesbitt	[redacted]	
	Deb Casper	[redacted]	
	Dan Gruver	[redacted]	
	Chris Norton	[redacted]	

MIDWEST MUTUAL ASSISTANCE

16-Sep

COMPANY	NAME	OFFICE	PHONE EXT.
BLACK HILL ENERGY			
105 S. Victoria	Larry Grammon	[redacted]	
Pueblo, CO 81003	Kevin Warmack	[redacted]	
800.694.8989			
	NOTES: Formerly WestPlains Energy- Colorado/Formerly Aquila Network- WPC		
DUKE ENERGY			

139 East 4th Street	Marty Zearbaugh	[redacted]	
Cincinnati, OH 46502	Marc Arnold	[redacted]	
	Joan Sharpshair	[redacted]	
	NOTES: Formerly Cinergy	[redacted]	
LG & E AND KU ENERGY LLC		[redacted]	
820 West Broadway	Morgan Pfeiffer	[redacted]	
Louisville, KY 40202	Jamie Archer	[redacted]	
502.627.3401	Steve Woodworth	[redacted]	
	Robby Trimble	[redacted]	
INDIANAPOLIS POWER AND LIGHT COMPANY		[redacted]	
1230 West Morris St	Kevin Walker	[redacted]	
Indianapolis, IN 46221-1744	Dan Davenport	[redacted]	
317.261.8189	Dave Rohlman	[redacted]	
Fax # 317.630.5709		[redacted]	
KCP&L		[redacted]	
P.O. Box 418679	Carol Baxter	[redacted]	
Kansas City, MO 64141-9679	Randy Watson	[redacted]	
816.556.2200	Chris Kurtz	[redacted]	
816.654.1287	NOTES: Acquired Aquila Networks, St.Joe Light & Power, Aquila	[redacted]	
MIDWEST ENERGY		[redacted]	
1330 Canterbury Road	Dale Giebler	[redacted]	
Hays, KS 67601	Fred Taylor	[redacted]	
800.222.3121		[redacted]	
Fax # 785.625.1487		[redacted]	
VECTREN ENERGY DELIVERY OF INDIANA		[redacted]	
1 N. Main Street	Chris Claybrooks	[redacted]	
Evansville, IN 47702-0209	Brian Gatewood	[redacted]	
812.491.4000	Mike Singer	[redacted]	
Fax # 812.464.4715	NOTES: Previously Southern Indiana Gas & Electric Company	[redacted]	
		[redacted]	
		[redacted]	
WESTAR ENERGY		[redacted]	
P.O. Box 889	Bryan Nowlin	[redacted]	
Topeka, KS 66601	Natalie Rolfe	[redacted]	
785.575.6300	Sandy Zordel	[redacted]	
Fax # 316.299.7520	NOTES: Previously DBA KPL and KGE	[redacted]	
XCEL ENERGY- PUBLIC SERVICE COMPANY OF COLORADO		[redacted]	
1800 Larimer Street	Jay W. Smith	[redacted]	
Denver, CO 80202	Allen Kiggins	[redacted]	
303.571.3927	Teresa Maestas	[redacted]	
Fax # 303.571.3991		[redacted]	
MIDWEST MUTUAL ASSISTANCE			
16-Sep			

COMPANY	NAME	OFFICE	PHONE EXT.
AMERICAN ELECTRIC POWER			
1 Riverside Plaza	Phil Lewis	[redacted]	
Columbus, OH 43215			
614.716.1000	Patrick Weyers		
EMPIRE DISTRICT ELECTRIC COMPANY			
P.O. Box 127	Tina Gaines		
Joplin, MO 64802-0127	Sam McGarrah		
417.625.5100	Jeff Westfall		
Fax # 417.625.5165			
ENTERGY			
P.O. Box 1640	Mike Fricke		
Jackson, MS 39215	David Luthe		
601.985.2750	Billy Blaylock		
Fax # 601.985.2366			
Emergency Control Center # 504.374.4461	NOTES: Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, Entergy Texas		
OG & E ELECTRIC SERVICE			
P.O. Box 321	Rick Berg	[redacted]	
Oklahoma City, OK 73101-0321	Gary Rowlett		
405.553.3000	Robert Gottshall		
Fax # 405.553.3760			
Emergency Control Center # 405.553.8109			

MIDWEST MUTUAL ASSISTANCE

16-Sep

COMPANY	NAME	OFFICE	PHONE EXT.
CENTERPOINT ENERGY			
P.O. Box 1700	Edward Scott	[redacted]	
Houston, TX 77251	Thomas Klesel		
713.207.1111	Lee Bishop		
Emergency Control Center # 713.207.9849	Colby Gravatt		
	NOTES: Formerly Reliant Energy HL & P		
TEXAS-NEW MEXICO POWER COMPANY			
1479 FM 407	Dan Nelson	[redacted]	[redacted]
Lewisvile, TX 75077	Pauline Moore		
972.317.5542, X407	Evans Spanos		
Fax # 972-318-0138	Neal Walker		
ONCOR ELECTRIC DELIVERY			
1616 Woodall Rodgers Fwy, Ste. 7B-006	Mike Carter	[redacted]	
Dallas, TX 75202	Rusty Evans		
	Jeff Dossey		

XCEL ENERGY- SOUTHWESTERN PUBLIC SERVICE			
600 South Tyler	Joey Zahn	[redacted]	
Amarillo, TX 79118	Julie Dillard		
806.378.2919	Brad Baldridge		
Fax # 806.378.2995			

FAX	CELL	HOME	PAGER
[redacted]			
[redacted]			
	[redacted]		
[redacted]			
[redacted]			
	[redacted]		
[redacted]			
[redacted]			

[redacted]

[redacted]

FAX	CELL	HOME	PAGER
	[redacted]		
	[redacted]		
	[redacted]		

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

FAX	CELL	HOME	PAGER

[redacted]

[redacted]			
[redacted]			
	[redacted]		
	[redacted]		
[redacted]			
[redacted]			
[redacted]			
[redacted]			

FAX	CELL	HOME	PAGER
[redacted]			
[redacted]			
[redacted]			
	[redacted]		

FAX	CELL	HOME	PAGER
[redacted]			
[redacted]			
[redacted]			

[redacted]			

[redacted]

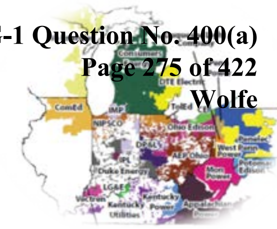
[redacted]

[redacted]

[redacted]

[redacted]

[redacted]



Great Lakes Mutual Assistance Group
Governing Principles

Introduction

The Great Lakes Mutual Assistance group (GLMA) is a consortium of large investor owned electric utility companies pulled together to effectively and collaboratively share electric restoration resources as needed to respond to significant outage events within the Midwest/Great Lakes region of the United States. The group first convened March 2005 with thirteen members. Since its initial meeting, the GLMA has met at least annually to discuss and establish guiding principles, share best practices, and assess and respond to related industry issues.

Mission

GLMA's primary mission is to facilitate safe, effective, and coordinated regional emergency assistance efforts among member companies and other regional mutual assistance groups (RMAGs).

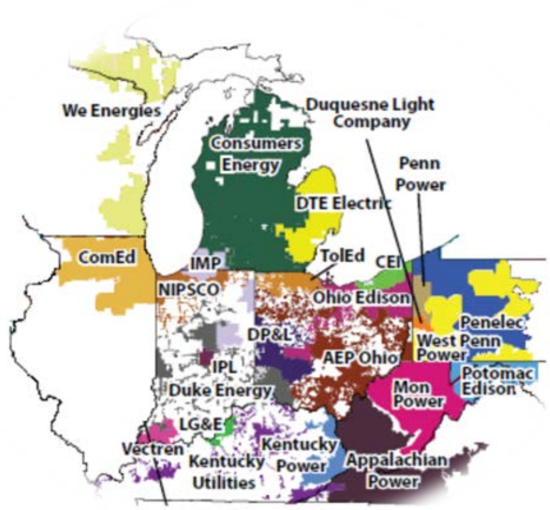
Membership

1. Membership (Member Company) in GLMA shall be defined at:
    a. An Operating Company level, where only one Operating Company under a Holding Company maintains membership in GLMA; or
    b. A Holding Company level.
2. Participation in GLMA shall be limited to sixteen (16) Member Companies as defined in 1 above.
3. To be considered for membership in GLMA, the Operating or Holding Company:
    a. Must be investor owned;
    b. Must have an electric service area that is within the footprint of GLMA's established membership territory;
    c. Must sign or have signed the Edison Electric Institute (EEI) *Governing Principles Covering Emergency Assistance Arrangements Between EEI Member Companies*;
    d. Must present Company information and membership justification to member utilities at a scheduled GLMA meeting; and
    e. Must be elected unanimously by existing members.
4. The GLMA is currently comprised of the following members:
    a. AES Corporation
        i. Dayton Power & Light (DP&L)
        ii. Indianapolis Power and Light (IP&L)
    b. American Electric Power (AEP)
        i. AEP Ohio
        ii. Appalachian Power
        iii. Indiana Michigan Power
        iv. Kentucky Power
    c. Consumers Energy
    d. DTE Energy

e. Duke Energy Corporation
    i. Duke Energy Indiana
    ii. Duke Energy Kentucky
    iii. Duke Energy Ohio
f. Duquesne Light Company (DLC)
g. Exelon Corporation
    i. Commonwealth Edison (ComEd)
h. First Energy Corp (FE)
    i. Cleveland Electric Illuminating Company
    ii. Monogahela Power
    iii. Ohio Edison
    iv. Penelec
    v. Pennsylvania Power Company
    vi. Potomac Edison
    vii. Toledo Edison
    viii. West Penn Power
i. ITC Holdings (ITC)
j. Pennsylvania Power and Light (PPL) Corporation
    i. LG&E and KU Energy LLC (LKE)
k. Northern Indiana Public Service Company (NIPSCO)
l. Vectren Corporation
    i. Vectren Energy Delivery of Indiana - South
m. We Energies

Membership Territory

The GLMA membership territory is defined to include the geographical service areas of approved operating companies with service territory located within a 300 mile radius of Lima, Ohio. Proposed changes to this footprint must be submitted to the GLMA governing body, and be voted on by members in accordance with rule 5 under the Organization and Governance section of these governing principles.



Organization and Governance

1. The GLMA group shall be governed under the following structure (Governing Body):
    a. Chair (1) –
        i. Responsible for providing guidance and direction on GLMA governing principles, serving as a mentor and subject matter expert for the group, scheduling and developing agenda topics for periodic GLMA meetings, designating special working groups and committees, and keeping members abreast of industry related issues and governance status.
        ii. Responsible for serving as the primary GLMA representative on the EEI Mutual Assistance / Emergency Preparedness Executive Committee, National Mutual Assistance Resource Team, and with other regional mutual assistance or industry mutual assistance working groups.
    b. Vice-Chair (1) –
        i. Responsible for assisting the Chair, leading special working groups or committees, developing agenda items for periodic meetings, working with host utilities on meeting logistics, and serving as a mentor and subject matter expert for the group.
        ii. Responsible for serving as the secondary GLMA representative on the EEI Mutual Assistance Executive Committee, National Mutual Assistance Resource Team, and with other regional mutual assistance or industry mutual assistance working groups.
    c. Secretary (1) – Responsible for documenting and distributing meeting minutes utilizing a standard format, assisting with periodic meeting preparations and agenda development, and assisting other GLMA governance positions as needed.
    d. Secretary-in-Waiting (1) – Responsible for assisting all Governing Roles, and serving as a backup to the Secretary position.
2. The four Governing Roles shall serve a one (1) year term.
3. No member company shall hold more than one Governing Role concurrently.
4. All Governing Roles shall be filled according to the following:
    a. The Secretary-in-Waiting position shall be filled, during the annual Spring Meeting or when vacated prematurely, through a nomination and silent election process.
    b. The Secretary position shall be filled by the individual holding the Secretary-in-Waiting position, by rotating them into the role at the annual Spring Meeting or when the Secretary is vacated prematurely.
    c. The Vice-Chair position shall be filled by the individual holding the Secretary position, by rotating them into the role at the annual Spring Meeting or when the Vice-Chair is vacated prematurely.
    d. The Chair position shall be filled by the individual holding the Vice-Chair position, by rotating them into the role at the annual Spring Meeting or when the Chair position is vacated prematurely.
    e. Nominations for Governing Roles shall only be considered if submitted by a Member Company to all other Member Companies verbally during a planned meeting or via email.

No individual should be nominated for a Governing Role unless he or she has agreed to assume the role if elected for the position.

f. Silent elections for Governing Roles shall be conducted in one of two ways:
    i. If a vacant Governing Role is to be filled during a planned GLMA meeting, candidates will be presented to member companies by the Chair or their designee. Member companies shall exercise their vote for their preferred candidate by "show of hand" when the candidate's name is presented, with all candidates for the Governing Role not in attendance.
    ii. If a vacant Governing Role is to be filled outside of a planned GLMA meeting, candidates shall be presented to member companies via email by the Chair or their designee. Member companies shall exercise their vote via email to the GLMA Secretary or their designee, as agreed upon by the member companies.
    iii. Member Companies will be afforded **one vote** per Governing Role.
    iv. Vacant Governing Roles will be offered to the nominated candidate who receives the majority of votes.

5. Policies and procedures associated specifically with the GLMA shall be voted on by Member Companies. Each Member Company shall be afforded one vote per decision item.
    a. Unanimous votes shall be required for the following items:
        i. New members
        ii. Membership Boundaries
        iii. Governing Principles
    b. Majority votes shall be required for the following items:
        i. Governing Roles
        ii. Meeting Locations
        iii. Procedural Changes
6. Member Holding Companies with multiple Operating Companies may designate a separate representative(s)/participant for each Operating Company during GLMA meetings and joint mobilization conference calls. However, Member Holding Companies are limited to a single vote for any voting activities.
7. All GLMA members shall periodically and, as necessary, identify their Home RMAG by Operating Company to enable GLMA to conform with and effectively execute EEI's National Response Event (NRE) procedures for national level resource mobilization events.

Meetings

1. GLMA members shall meet at least annually, in the spring, to review GLMA activities, discuss open items and new business, and assess industry issues and their impacts on the GLMA. During the annual meeting or as needed, Member Companies can elect to conduct more frequent meetings.
2. Meetings shall be rotated between Member Companies.
3. The member company hosting a meeting shall be responsible for:
    a. Scheduling the dates and times for the meeting;

   b. Coordinating lodging arrangements (i.e. reserving a block of rooms for a set period) for overnight members;
   c. Providing meals, as necessary; and
   d. Providing meeting rooms and associated resources (projectors, laptop, etc…).

4. Non-member companies (including vendors) will be allowed to participate in a GLMA meeting if invited by a Member Company and agreed to by all other Member Companies.
5. Non-member companies (including vendors) shall not be allowed to participate in GLMA business decisions, including any voting activities.
6. GLMA activities and statistical information shall be updated and distributed quarterly by the GLMA Secretary or their designee, and shall be presented at each GLMA meeting by the GLMA Chair. This information shall include:
   a. Number of calls;
   b. Number of internal requests;
   c. Number of resources moved internally; and
   d. Number of resources moved externally.

Mutual Aid Calls

1. Call Representation
   a. All Member Companies are expected to provide a primary and backup representative with contact information for mutual aid conference calls.
   b. Operating companies may be represented individually on joint mobilization calls.
   c. All Member Companies are expected to provide a representative on all requested calls. The Governing Body shall have authority to address any Member Company that doesn't consistently participate on joint mobilization calls.
   d. Member Company representatives shall have their company's authority to request, accept or release resources during a mutual assistance call.
2. Call Organization and Format
   a. All calls will follow a standardized call/spreadsheet agenda.
   b. Member Companies will share facilitation of mutual aid calls, with every effort being made to avoid having an impacted company host the call.
   c. Non-member companies or organizations shall not be permitted on GLMA calls without authorization or invitation from a GLMA member company. If a non-member is invited to participate in a call, the responsible member company shall announce the company or organization invited during the roll call process.
   d. At the beginning of each call, the call host shall request all non-members to identify themselves prior to proceeding with the call agenda.
   e. All Member Companies shall endeavor to mute their lines when not talking.
   f. Members understand that conversations between member utilities during Joint Mobilization Conference Calls are confidential and proprietary. Therefore, with the exception of general deployment data/information, members agree not to share or release

any information shared between member utilities during Joint Mobilization Conference Calls unless mutually agreed.

Resource Requests

1. Utilities needing assistance/resources shall initiate the mutual aid process by notifying the designated GLMA administrative representative or their backup and requesting that a mutual aid conference call be scheduled.
2. The designated administrative representative shall send out an electronic meeting notice/email with the following;:
    a. Call number
    b. Call date and time
    c. Requesting utility
    d. Situation report
    e. Preliminary resource needs
3. During the mutual aid call, the requesting Company shall be responsible for communicating the following for responding utilities:
    a. Working conditions
    b. Contact information
    c. Reporting location
    d. Labor restrictions
    e. Crew size and composition
    f. Specialty equipment needs
4. In the event a requesting utility's resource needs cannot be satisfied by GLMA members, the utility may seek assistance from an adjacent RMAG in which they are also a member. If the requesting GLMA member is not a member of an adjacent RMAG, they may request the GLMA Chair to submit a request for their needed resource to an adjacent RMAG, from GLMA.

Provision of Assistance

1. The GLMA Secretary shall be responsible for developing, maintaining, and routinely communicating a list of first wave resource levels for member companies.
2. When releasing contractors for assistance, every effort should be made to release them to companies where existing contracts are in place.
3. Member Companies providing assistance/releasing resources should provide released personnel and contractors all necessary contact information from the requesting Company.
4. Member Companies providing assistance or releasing resources should provide or coordinate provision of resource rosters to the requesting Company.
5. Prior to securing GLMA resources without execution of a GLMA joint mobilization call, the requesting Member Company should send out an email to all other Member Companies to ensure a GLMA joint mobilization call is not needed. A joint mobilization call should be scheduled should any Member Company express a potential need or issue.

6. Prior to releasing resources outside of the GLMA, an email should be sent out to Member Companies to ensure there are no needs or issues with releasing resources outside of the GLMA. A joint mobilization call should be scheduled should any Member Company express a potential need or issue.

National Response Efforts

Member Companies shall adhere to the Edison Electric Institute's *National Response Event Structure and Principles Covering Emergency Assistance Arrangements between Edison Electric Institute Members Companies* when resource needs dictate that a national response effort be declared.

Best Practices Surveys

Member Company surveys shall only be shared with participating Member Companies.

Approved: 3/26/2014

Revisions:

- *9/30/2014 - added new territory map and associated language.*

EDISON ELECTRIC INSTITUTE RESTORE POWER

SUGGESTED GOVERNING PRINCIPLES COVERING EMERGENCY ASSISTANCE ARRANGEMENTS BETWEEN EDISON ELECTRIC INSTITUTE MEMBER COMPANIES

Electric companies have occasion to call upon other companies for emergency assistance in the form of personnel or equipment to aid in maintaining or restoring electric utility service when such service has been disrupted by acts of the elements, equipment malfunctions, accidents, sabotage or any other occurrences where the parties deem emergency assistance to be necessary or advisable. While it is acknowledged that a company is not under any obligation to furnish such emergency assistance, experience indicates that companies are willing to furnish such assistance when personnel or equipment are available.

In the absence of a continuing formal contract between a company requesting emergency assistance ("Requesting Company") and a company willing to furnish such assistance ("Responding Company"), the following principles are suggested as the basis for a contract governing emergency assistance to be established at the time such assistance is requested:

1. The emergency assistance period shall commence when personnel and/or equipment expenses are initially incurred by the Responding Company in response to the Requesting Company's needs. (This would include any request for the Responding Company to prepare its employees and/or equipment for transport to the Requesting Company's location but to await further instructions before departing). The emergency assistance period shall terminate when such employees and/or equipment have returned to the Responding Company, and shall include any mandated DOT rest time resulting from the assistance provided and reasonable time required to prepare the equipment for return to normal activities (e.g. cleaning off trucks, restocking minor materials, etc.).

2. To the extent possible, the companies should reach a mutual understanding and agreement in advance on the anticipated length – in general – of the emergency assistance period. For extended assistance periods, the companies should agree on the process for replacing or providing extra rest for the Responding Company's employees. It is understood and agreed that if; in the Responding Company's judgment such action becomes necessary the decision to terminate the assistance and recall employees, contractors, and equipment lies solely with the Responding Company. The Requesting Company will take the necessary action to return such employees, contractors, and equipment promptly.

3. Employees of Responding Company shall at all times during the emergency assistance period continue to be employees of Responding Company and shall not be deemed employees of Requesting Company for any purpose. Responding Company shall be an independent Contractor of Requesting Company and wages, hours and other terms and conditions of employment of Responding Company shall remain applicable to its employees during the emergency assistance period.

4. Responding Company shall make available at least one supervisor in addition to crew foremen. All instructions for work to be done by Responding Company's crews shall be given by Requesting Company to Responding Company's supervisor(s); or, when

Responding Company's crews are to work in widely separate areas, to such of Responding Company's foremen as may be designated for the purpose by Responding Company's supervisor(s).

5. Unless otherwise agreed by the companies, Requesting Company shall be responsible for supplying and/or coordinating support functions such as lodging, meals, materials, etc. As an exception to this, the Responding Company shall normally be responsible for arranging lodging and meals en route to the Receiving Company and for the return trip home. The cost for these in transit expenses will be covered by the requesting company.

6. Responding Company's safety rules shall apply to all work done by their employees. Unless mutually agreed otherwise, the Requesting Company's switching and tagging rules should be followed to ensure consistent and safe operation. Any questions or concerns arising about any safety rules and/or procedures should be brought to the proper level of management for prompt resolution between management of the Requesting and Responding Companies.

7. All time sheets and work records pertaining to Responding Company's employees furnishing emergency assistance shall be kept by Responding Company.

8. Requesting Company shall indicate to Responding Company the type and size of trucks and other equipment desired as well as the number of job function of employees requested but the extent to which Responding Company makes available such equipment and employees shall be at Responding Company's sole discretion.

9. Requesting Company shall reimburse Responding Company for all costs and expenses incurred by Responding Company as a result of furnishing emergency assistance. Responding Company shall furnish documentation of expenses to Requesting Company. Such costs and expenses shall include, but not be limited to, the following:

   a. Employees' wages and salaries for paid time spent in Requesting Company's service area and paid time during travel to and from such service area, plus Responding Company's standard payable additives to cover all employee benefits and allowances for vacation, sick leave and holiday pay and social and retirement benefits, all payroll taxes, workmen's compensation, employer's liability insurance and other contingencies and benefits imposed by applicable law or regulation.

   b. Employee travel and living expenses (meals, lodging and reasonable incidentals).

   c. Replacement cost of materials and supplies expended or furnished.

   d. Repair or replacement cost of equipment damaged or lost.

   e. Charges, at rates internally used by Responding Company, for the use of transportation equipment and other equipment requested.

f. Administrative and general costs, which are properly allocable to the emergency assistance to the extent such costs, are not chargeable pursuant to the foregoing subsections.

10. Requesting Company shall pay all costs and expenses of Responding Company within sixty days after receiving an invoice therefor.

11. Requesting Company shall indemnify, hold harmless and defend the Responding Company from and against any and all liability for loss, damage, cost or expense which Responding Company may incur by reason of bodily injury, including death, to any person or persons or by reason of damage to or destruction of any property, including the loss of use thereof, which result from furnishing emergency assistance and whether or not due in whole or in part to any act, omission, or negligence of Responding Company except to the extent that such death or injury to person, or damage to property, is caused by the willful or wanton misconduct and / or gross negligence of the Responding Company. Where payments are made by the Responding Company under a workmen's compensation or disability benefits law or any similar law for bodily injury or death resulting from furnishing emergency assistance, Requesting Company shall reimburse the Responding Company for such payments, except to the extent that such bodily injury or death is caused by the willful or wanton misconduct and / or gross negligence of the Responding Company..

12. In the event any claim or demand is made or suit or action is filed against Responding Company alleging liability for which Requesting Company shall indemnify and hold harmless Responding Company under paragraph (11) above, Responding Company shall promptly notify Requesting Company thereof, and Requesting Company, at its sole cost and expense, shall settle, compromise or defend the same in such manner as it in its sole discretion deems necessary or prudent. Responding Company shall cooperate with Requesting Company's reasonable efforts to investigate, defend and settle the claim or lawsuit.

13 Non-affected companies should consider the release of contractors during restoration activities. The non-affected company shall supply the requesting companies with contact information of the contactors (this may be simply supplying the contractors name). The contractors will negotiate directly with requesting companies.

Last update September 2005

- Section 11 and 12 updated

Edison Electric Institute
Mutual Assistance Agreement

Edison Electric Institute ("EEI") member companies have established and implemented an effective system whereby member companies may receive and provide assistance in the form of personnel and equipment to aid in restoring and/or maintaining electric utility service when such service has been disrupted by acts of the elements, equipment malfunctions, accidents, sabotage, or any other occurrence for which emergency assistance is deemed to be necessary or advisable ("Emergency Assistance"). This Mutual Assistance Agreement sets forth the terms and conditions to which the undersigned EEI member company ("Participating Company") agrees to be bound on all occasions that it requests and receives ("Requesting Company") or provides ("Responding Company") Emergency Assistance from or to another Participating Company who has also signed the EEI Mutual Assistance Agreement; provided, however, that if a Requesting Company and one or more Responding Companies are parties to another mutual assistance agreement at the time of the Emergency Assistance is requested, such other mutual assistance agreement shall govern the Emergency Assistance among those Participating Companies.

In consideration of the foregoing, the Participating Company hereby agrees as follows:

(1) When providing Emergency Assistance to or receiving Emergency Assistance from another Participating Company, the Participating Company will adhere to the written principles developed by EEI members to govern Emergency Assistance arrangements among member companies ("EEI Principles"), that are in effect as of the date of a specific request for Emergency Assistance, unless otherwise agreed to in writing by each Participating Company.

(2) With respect to each Emergency Assistance event, Requesting Companies agree that they will reimburse Responding Companies for all costs and expenses incurred by Responding Companies in providing Emergency Assistance as provided under the EEI Principles, unless otherwise agreed to in writing by each Participating Company; provided, however, that Responding Companies must maintain auditable records in a manner consistent with the EEI Principles.

(3) During each Emergency Assistance event, the conduct of the Requesting Companies and the Responding Companies shall be subject to the liability and indemnification provisions set forth in the EEI Principles.

(4) A Participating Company may withdraw from this Agreement at any time. In such an event, the company should provide written notice to EEI's Director of Security of Transmission and Distribution Operations.

(5) EEI's Director of Security of Transmission and Distribution Operations shall maintain a list of each Participating Company which shall be posted on the RestorePower web site at www.restorepower.com. However, a Participating Company may request a copy of the signed Mutual Assistance Agreement of another Participating Company prior to providing or receiving Emergency Assistance.

____
Company Name

____
Signature

Officer Name:
Title:
Date:

EDISON ELECTRIC INSTITUTE RESTORE POWER

SUGGESTED GOVERNING PRINCIPLES COVERING EMERGENCY ASSISTANCE ARRANGEMENTS BETWEEN EDISON ELECTRIC INSTITUTE MEMBER COMPANIES

Electric companies have occasion to call upon other companies for emergency assistance in the form of personnel or equipment to aid in maintaining or restoring electric utility service when such service has been disrupted by acts of the elements, equipment malfunctions, accidents, sabotage or any other occurrences where the parties deem emergency assistance to be necessary or advisable. While it is acknowledged that a company is not under any obligation to furnish such emergency assistance, experience indicates that companies are willing to furnish such assistance when personnel or equipment are available.

In the absence of a continuing formal contract between a company requesting emergency assistance ("Requesting Company") and a company willing to furnish such assistance ("Responding Company"), the following principles are suggested as the basis for a contract governing emergency assistance to be established at the time such assistance is requested:

1. The emergency assistance period shall commence when personnel and/or equipment expenses are initially incurred by the Responding Company in response to the Requesting Company's needs. (This would include any request for the Responding Company to prepare its employees and/or equipment for transport to the Requesting Company's location but to await further instructions before departing). The emergency assistance period shall terminate when such employees and/or equipment have returned to the Responding Company, and shall include any mandated DOT rest time resulting from the assistance provided and reasonable time required to prepare the equipment for return to normal activities (e.g. cleaning off trucks, restocking minor materials, etc.).

2. To the extent possible, the companies should reach a mutual understanding and agreement in advance on the anticipated length – in general – of the emergency assistance period. For extended assistance periods, the companies should agree on the process for replacing or providing extra rest for the Responding Company's employees. It is understood and agreed that if; in the Responding Company's judgment such action becomes necessary the decision to terminate the assistance and recall employees, contractors, and equipment lies solely with the Responding Company. The Requesting Company will take the necessary action to return such employees, contractors, and equipment promptly.

3. Employees of Responding Company shall at all times during the emergency assistance period continue to be employees of Responding Company and shall not be deemed employees of Requesting Company for any purpose. Responding Company shall be an independent Contractor of Requesting Company and wages, hours and other terms and conditions of employment of Responding Company shall remain applicable to its employees during the emergency assistance period.

4. Responding Company shall make available at least one supervisor in addition to crew foremen. All instructions for work to be done by Responding Company's crews shall be given by Requesting Company to Responding Company's supervisor(s); or, when

Responding Company's crews are to work in widely separate areas, to such of Responding Company's foremen as may be designated for the purpose by Responding Company's supervisor(s).

5. Unless otherwise agreed by the companies, Requesting Company shall be responsible for supplying and/or coordinating support functions such as lodging, meals, materials, etc. As an exception to this, the Responding Company shall normally be responsible for arranging lodging and meals en route to the Receiving Company and for the return trip home. The cost for these in transit expenses will be covered by the requesting company.

6. Responding Company's safety rules shall apply to all work done by their employees. Unless mutually agreed otherwise, the Requesting Company's switching and tagging rules should be followed to ensure consistent and safe operation. Any questions or concerns arising about any safety rules and/or procedures should be brought to the proper level of management for prompt resolution between management of the Requesting and Responding Companies.

7. All time sheets and work records pertaining to Responding Company's employees furnishing emergency assistance shall be kept by Responding Company.

8. Requesting Company shall indicate to Responding Company the type and size of trucks and other equipment desired as well as the number of job function of employees requested but the extent to which Responding Company makes available such equipment and employees shall be at Responding Company's sole discretion.

9. Requesting Company shall reimburse Responding Company for all costs and expenses incurred by Responding Company as a result of furnishing emergency assistance. Responding Company shall furnish documentation of expenses to Requesting Company. Such costs and expenses shall include, but not be limited to, the following:

   a. Employees' wages and salaries for paid time spent in Requesting Company's service area and paid time during travel to and from such service area, plus Responding Company's standard payable additives to cover all employee benefits and allowances for vacation, sick leave and holiday pay and social and retirement benefits, all payroll taxes, workmen's compensation, employer's liability insurance and other contingencies and benefits imposed by applicable law or regulation.

   b. Employee travel and living expenses (meals, lodging and reasonable incidentals).

   c. Replacement cost of materials and supplies expended or furnished.

   d. Repair or replacement cost of equipment damaged or lost.

   e. Charges, at rates internally used by Responding Company, for the use of transportation equipment and other equipment requested.

f. Administrative and general costs, which are properly allocable to the emergency assistance to the extent such costs, are not chargeable pursuant to the foregoing subsections.

10. Requesting Company shall pay all costs and expenses of Responding Company within sixty days after receiving an invoice therefor.

11. Requesting Company shall indemnify, hold harmless and defend the Responding Company from and against any and all liability for loss, damage, cost or expense which Responding Company may incur by reason of bodily injury, including death, to any person or persons or by reason of damage to or destruction of any property, including the loss of use thereof, which result from furnishing emergency assistance and whether or not due in whole or in part to any act, omission, or negligence of Responding Company except to the extent that such death or injury to person, or damage to property, is caused by the willful or wanton misconduct and / or gross negligence of the Responding Company. Where payments are made by the Responding Company under a workmen's compensation or disability benefits law or any similar law for bodily injury or death resulting from furnishing emergency assistance, Requesting Company shall reimburse the Responding Company for such payments, except to the extent that such bodily injury or death is caused by the willful or wanton misconduct and / or gross negligence of the Responding Company..

12. In the event any claim or demand is made or suit or action is filed against Responding Company alleging liability for which Requesting Company shall indemnify and hold harmless Responding Company under paragraph (11) above, Responding Company shall promptly notify Requesting Company thereof, and Requesting Company, at its sole cost and expense, shall settle, compromise or defend the same in such manner as it in its sole discretion deems necessary or prudent. Responding Company shall cooperate with Requesting Company's reasonable efforts to investigate, defend and settle the claim or lawsuit.

13 Non-affected companies should consider the release of contractors during restoration activities. The non-affected company shall supply the requesting companies with contact information of the contactors (this may be simply supplying the contractors name). The contractors will negotiate directly with requesting companies.

Last update September 2005

- Section 11 and 12 updated

Southeastern Electric Exchange

Mutual Assistance Procedures and Guidelines

February 2012

As directed by the Board of Directors of Southeastern Electric Exchange, the Mutual Assistance Committee has developed and accepted the following procedures to provide and request assistance to aid in restoring electric service when it has been disrupted and cannot be restored in a safe and timely manner by the affected company or companies alone. In approaching this task, committee members recognized the significant differences between work performed under normal circumstances and emergency restoration, as well as the fact that each member will at some time both require and supply emergency assistance. Therefore, members have reached understanding and agreement to adhere to the procedures and guidelines that follow without the necessity of formal contractual arrangements.

The Mutual Assistance Committee shall have responsibility for maintenance and revision of the *Southeastern Electric Exchange Mutual Assistance Procedures and Guidelines*. Final acceptance of this document, as well as any future modifications, must be approved by ¾ of the appointed and serving members of the S.E.E. Mutual Assistance Committee, each operating member company having one (1) vote.

Section I

Understanding Among Members Regarding Mutual Assistance

1. Members of Southeastern Electric Exchange understand and agree:

1.1 That members will work together to minimize risk to all parties. Responding Companies will provide assistance (personnel and equipment) on a not-for-profit basis, and Requesting Companies will reimburse Responding Companies for all expenses incurred in providing the assistance. [1]

1.2 To adhere to and operate in accordance with the procedures contained in this document (the *Southeastern Electric Exchange Mutual Assistance Procedures and Guidelines*).

1.3 That should there be any conflict in procedures and guidelines contained in the *S.E.E. Mutual Assistance Procedures and Guidelines* and other regional or national mutual assistance agreements, guidelines, principles, or procedures, S.E.E. members will adhere to the procedures approved by the S.E.E. Mutual Assistance Committee when assisting or requesting assistance from fellow members through the Joint Mobilization Conference Call Procedure outlined in this document.

---

1. In this document the terms Responding Company and Requesting Company refers to both the company and its employees.

Section II
General Guidelines / Responsibilities

2. Personnel Safety

2.1 Whether providing or receiving assistance, personnel safety will be the preeminent objective and responsibility of all participants.

2.2 The Requesting Company agrees to make every effort to avoid moving Responding Company personnel into harms way during the initial, first-wave mobilization.

2.3 Responding Company will follow its own safety rules, except as noted in paragraphs 2.6 and 2.7 below.

2.4 Responding Company is responsible for following its own personal protective grounding practices.

2.5 Responding Company will immediately report any and all accidents to Requesting Company (both incidence and injury).

2.6 Switching procedures will be handled as the Requesting Company designates, provided that the procedures do not violate the safety rules of the Responding Company.

2.7 Requesting Company will provide information on their switching and tagging rules. Requesting Company switching/blocking tags will be used.

2.8 Security personnel requirements shall be discussed and mutually agreed upon by the Requesting and Responding Companies prior to deployment of armed security personnel.

2.9 Any deployment of “Security Personnel” – armed or otherwise – must comply with Federal, State, and Local regulations.

3. Maintenance of Contact Roster

3.1 In order to facilitate efficient communication and response, S.E.E. member utilities will share the following information:

- The names, contact numbers (work phone, home phone, cellular phone, and pager), and e-mail addresses for three (3) individuals authorized to participate in Joint Mobilization Conference Calls.
- If available, the telephone number for the 24-hour operations / dispatch center for the member company.
- If available, a satellite telephone number for the 24-hour storm or operations / dispatch center.
- If available, a corporate storm / emergency center 24-hour telephone number, if different from the 24-hour operations / dispatch telephone number.

3.2 The Southeastern Electric Exchange office will be responsible for maintaining and updating the Member Company Contact Roster at least every three months.

4. Code of Conduct

4.1 Whether providing or receiving assistance, all personnel will be expected to conduct themselves in a professional and responsible manner.

5. Communication With Contractors

5.1 Members understand the need for clear communication with contractors working on their systems and are encouraged to explain the joint mobilization process discussed in this document.

6. Definition of Emergency Assistance Period

6.1 Members agree that the emergency assistance period shall commence when personnel and/or equipment expenses are initially incurred by the Responding Company in response to the Requesting Company's needs. This includes any request for the Responding Company to prepare its employees and/or equipment for travel to the Requesting Company's location but to await further instructions before departing. This preparation time should begin when normal work activities for Responding Company stop and preparations dedicated to supporting the off system effort begin. Except as noted in paragraph 6.3, the emergency assistance period shall terminate when such employees and/or equipment have returned to their point of origin and after a reasonable time required preparing the equipment for return to normal activities (e.g. cleaning trucks, restocking minor materials, etc.).

6.2 The length of stay by Responding Company personnel will be mutually agreed to by both companies. Generally, this period should not exceed 14 consecutive days, including travel time to the work area and return to the point of origin. When mutual assistance assignments go beyond this time frame, S.E.E. members agree that Responding Company personnel will usually be changed out (rotated) rather than take extended reset periods (days off). Responding and Requesting companies may agree upon exceptions to this procedure.

6.3 It is understood and agreed that if Responding Company's or its Holding Company's system is threatened during any time after it has mobilized to provide mutual assistance, any part or all of the Responding Company's native and contract workforce may be recalled. In these instances:

- It is understood and agreed that the decision to terminate assistance and recall employees lies solely with the Responding Company.
- If recall of Responding Company's workforce becomes necessary, the Requesting Company will be responsible for all expenses incurred by Responding Company until the Responding Company returns home and vehicles are cleaned and stocked for normal work activities.
- If Responding Company's workforce is recalled to another of the Responding Company's locations other than their original point of origin, the Requesting Company will be responsible for travel costs to the alternate location <u>not to exceed</u> that which would have been incurred had the workforce returned to their original point of origin.

Section III

The Joint Mobilization Conference Call Procedure

7. Purpose and Rationale for Joint Mobilization Call Procedures

7.1 The following procedures are intended to enhance and in no way hamper the mobilization goals of member companies during emergencies.

7.2 Because response time is critical in emergency situations, the Joint Mobilization Conference Call provides a mechanism that allows members to quickly request assistance and identify the number and status of all available regional resources.

7.3 The conference call format should:

- Provide members with the opportunity to understand the entire scope of the emergency situation, including the number of companies expecting to be impacted and the potential damage to each.
- Allow members to discuss and evaluate weather forecasts from different sources.
- Result in the most efficient, effective and equitable allocation of available resources while mitigating the financial risk associated with early mobilization of resources.

8. Agreement / Understanding – Joint Mobilization Procedures

8.1 Members agree to adhere to the procedures contained in this section to request, identify and mobilize emergency mutual assistance resources. The understood exception being when an event impacts a single member utility and the impacted utility anticipates a short restoration time requiring assistance from only neighboring (adjacent) utilities. In this instance, the impacted member may contact neighboring utilities directly to arrange assistance. However, because emergency events tend to expand and impact more than one utility over time, members are encouraged to use the Joint Mobilization Conference Call procedures described below for <u>all</u> mutual assistance requests.

8.2 Members understand and agree that participation on Joint Mobilization Conference Calls is restricted to employees of member companies of Southeastern Electric Exchange, unless otherwise agreed by members of the Mutual Assistance Committee.

8.3 Members understand that conversations between member utilities during Joint Mobilization Conference Calls may be confidential and proprietary. Therefore, with the exception of general deployment data / information, members agree not to share or release any information shared between member utilities during Joint Mobilization Conference Calls unless mutually agreed.

9. Initiation of the Joint Mobilization Conference Call

9.1 Typically, the member that expects to be impacted first by an event will initiate the conference call.

9.2 Members agree to initiate a conference call anytime they experience or are threatened by an event so significant that they anticipate needing resources beyond the capabilities of their neighboring (adjacent) utilities to restore their system.

9.3 Procedure for initiating the conference call:

- During normal business hours, the initiating member will notify any S.E.E. staff member (phone number 404-233-1188) that they wish to hold a conference call for storm response, give the staff member the toll-free conference call number, date, and time for the call (specifying time zone). S.E.E. will contact all members via e-mail, providing conference call information and confirm all members' participation. After every call, S.E.E. will send out an e-mail providing a summary of the conference call discussion.
- After normal working hours and on weekends, members initiate the call by contacting the Executive Director of S.E.E., at home or on his cell phone. The Director will contact members as described above. If the S.E.E. Director cannot be reached, the initiating member will use the S.E.E. Mutual Assistance Contact Roster to contact members directly.

10. Responsibilities of Company Initiating Conference Call

10.1 The company initiating the conference call will designate an individual to serve as moderator for the conference call. The moderator will:

- Call the roll of member companies.
- Present the weather forecast for his / her company service territory. At their discretion, the initiating company may have a weather consultant present the current forecast.
- Ask other members for input regarding the weather forecast / predictions.
- Present an estimate of predicted impact / damages and when these are expected to occur. If the event is large enough to impact more than one member's service territory, the moderator will ask other members for their projected damage assessments.
- Present an estimate of resources needed. If the event is large enough to impact more than one member's service territory, the moderator will ask other members for their projected resource needs.
- By roll call, ask all non-impacted members to state the numbers of resources available to assist once their territories are no longer threatened.
- When appropriate, the moderator will lead discussion of staging areas to be used by assisting companies; transportation concerns, such as evacuation orders, fuel availability, DOT exemptions, etc.; and, the availability of non-member resources that may be available to assist impacted members.
- Keep the call moving and minimize the length of the call as much as possible.
- If requested, notify non-S.E.E. members via the EEI Restore Power list serve.
- Set the date and time for future conference calls.

11. Responsibilities of Non-Initiating Members Participating In Conference Calls

11.1 Members agree not to release or dispatch ANY resources (contract or native) unless committed to and confirmed by a Requesting Company. It is understood that Responding Companies' territories must be free from significant threat before resources can be committed and dispatched.

11.2 On the first Joint Mobilization Conference Call, non-threatened / non-impacted members will be prepared to specify the numbers of their employee and contractor distribution line, transmission line, vegetation management, and damage assessment personnel available to assist impacted companies, including an estimate of when these resources can be dispatched. If Requesting Companies identify needs in other areas (such as IT, safety, etc.), assisting members will be given time (usually 24 hours) to identify available resources in these additional areas.

11.3 To enhance safety and flexibility, upon request non-threatened / non-impacted members will be prepared to identify staging areas available in their territories.

11.4 Upon request non-threatened / non-impacted members will assist with DOT exemptions for crews traveling through their service territories.

12. Resource Allocation and Mobilization

12.1 When more than one company has requested emergency assistance, all members understand and agree that it is the responsibility of the Requesting Companies to agree upon the allocation of available first wave and subsequent member company resources.

12.2 Members agree that, in general, resources will be allocated on the basis of severity of need, based on:

- Predicted impact – percentage / degree of system loss and estimated time customers will have been without power.
- Storm timing – which company will be first impacted.
- Travel time.
- Availability of other non-S.E.E. member controlled resources.
- The intent will be to allocate available resources to meet all member company needs in the most efficient and equitable manner possible.

12.3 Members agree that final dispatch of committed resources is to be coordinated directly between the Requesting Company and the Responding Company (or its contractor(s), where applicable).

13. Responsibilities of S.E.E. Coordinator

13.1 The Southeastern Electric Exchange coordinator, (usually the Executive or Assistant Director), will be responsible for notifying members of Joint Mobilization Conference Calls in accordance with paragraph 9.3.

13.2 The Southeastern Electric Exchange coordinator will be responsible for producing and distributing conference call summary notes including the S.E.E. Resource Summary spreadsheet after each conference call.

13.3 When more than one company has requested emergency assistance, the Southeastern Electric Exchange coordinator will serve as moderator of conference calls between impacted companies on which Requesting Companies will agree upon the allocation of available first wave S.E.E. resources.

Section IV

Requesting Company Responsibilities

14. Requesting Company – Responsibilities Prior to Mobilization

14.1 To the extent possible, the Requesting Company is expected to clearly communicate the degree of devastation and working conditions Responding Company personnel should expect to encounter upon arrival at the emergency restoration work area.

14.2 The Requesting Company is expected to inform the Responding Company if their requirements for the maintenance of receipts differ from the procedures stated in paragraph 19.5.

14.3 To facilitate communications, the Requesting Company may opt to provide a single point of contact (Coordinator) to interact with the Responding Company.

14.4 The Requesting Company will provide the Responding Company with the name and contact information for their "company contact" as required on the *RESPONDING COMPANY INITIAL INFORMATION SHEET* before Responding Company personnel leave their point of origin.

14.5 Requesting Company will coordinate with their state DOT officials concerning emergency exemptions and any other transportation issues that will facilitate the Responding Company's trip to and from the Requesting Company.

14.6 The Requesting Company is encouraged to communicate general guidelines with Responding Companies. Items covered may include labor contractual issues, safety issues, contact personnel, vehicle fueling arrangements, typical standard construction, meal and lodging arrangements, and other items that will be of benefit to the responding personnel and their supervision.

15. Requesting Company – Responsibilities During Emergency Assistance Period

15.1 The Requesting Company will establish expectations for work, including start time and duration.

15.2 The Requesting Company will provide materials unless specifically noted otherwise.

15.3 When necessary, the Requesting Company will provide a guide with communications capability, portable radios or cellular telephones to assist responding team leaders.

15.4 The Requesting Company will authorize Responding Company to use cellular phones as a method of communication. Where cellular service is unavailable, it is understood that satellite phones may be used until such time that cellular service is restored in the Requesting Company's area.

15.5 The Requesting Company will provide vehicle security for parking areas unless specifically agreed otherwise.

15.6 With the exception of food and lodging during travel to and from the final work site, the Requesting Company will handle all food, lodging and incidental support needed by Responding Company unless both companies agree for Responding Company to handle these logistics.

15.7 Requesting and Responding companies should agree on the provision of laundry services.

15.8 Requesting Company will make and communicate provisions for Responding Company personnel to make personal long distance telephone calls during the emergency response period. For example, the Requesting Company may authorize the Responding Company to purchase pre-paid long distance calling cards for responding crew members or authorize the use of company or employee owned cellular phones for an agreed upon maximum number of minutes. As a general rule, Requesting Company agrees to allow and reimburse a maximum of 10-minutes personal long distance telephone charges per employee per day. Any personal cellular phone charges or pre-paid calling card expenses shall be included in the supporting documentation on the company's preliminary invoice, subject to paragraph 19.5.

15.9 Requesting Company understands that the Responding Company will not incur hotel-related expenses other than lodging, unless agreed to by the Requesting Company prior to their occurrence. For example, phone calls made from rooms, room service, in-room movies, mini bar usage, etc. should not be incurred.

16. Requesting Company - Procedures for Releasing Responding Companies

16.1 During emergencies impacting more than one member company simultaneously, each Requesting Company will develop and send the S.E.E. coordinator a proposed "Release Schedule" 48-hours before releasing any contract or utility (members & non-member) crews. This release schedule will include: Names of utilities and contractors to be released, the numbers and specialty (distribution line, transmission line, vegetation, etc.) of workers from each utility and / or contractor being released, the on-site contact or the coordinator of the crews being released, and the date and approximate time the crews expect to be released.

16.2 During emergencies when Responding Company contract and / or utility resources are already deployed and working to provide restoration help to one member company and another member company (or companies) is impacted by another emergency, or, in the case of hurricanes, a second landfall of the storm, the company that obtained help first agrees to:

- NOT retain personnel solely to perform maintenance, street lighting work, or clean up type work and will aggressively work to release personnel.
- Immediately prepare a release schedule which includes details listed in paragraph 16.1 above, including projected release dates.
- Provide realistic estimated restoration times and release dates to the SEE coordinator for dissemination to the second Requesting Company (or companies). Since this could mean the difference in going days away or waiting on resources closer that may become available, it is essential that release dates be as accurate as possible. **Note: Should the emergency situation described above develop before a Responding Company personnel arrive at the initial restoration area, these resources will be reallocated to Requesting Companies in accordance with the provisions of Section 12 and paragraph 17.3 of these procedures and guidelines.**

16.3 In the emergency situation described in paragraph 16.2 above, the initial and secondarily impacted companies agree to:

- Immediately hold an "impacted companies" conference call to negotiate reallocation of the resources on the release schedule developed by the first impacted company as well as any other resources not already committed.

- Regarding personnel released by the first impacted company, secondary Requesting Companies will contact the resources (companies) allocated to them to determine if those persons will agree to re-deploy or be changed out (rotated) in accordance with paragraph 6.2.

16.4 In all emergency situations, the Requesting Company will make every effort to notify each Responding Company's mutual assistance contact 24-hours in advance of the anticipated final release of their utility personnel.

17. Requesting Company – Responsibility for Reimbursement of Expenses And Indemnification of Responding Company

17.1 Members understand and agree that the provision of emergency mutual assistance is a not-for-profit endeavor for Responding Companies. Therefore, the Requesting Company will reimburse all costs and expenses incurred by the Responding Company in the provision of the emergency assistance for the entire emergency assistance period as defined in paragraph 6 above.

17.2 If Responding Company resources are released after mobilization but before being utilized, the Requesting Company will reimburse Responding Company for all incurred preparation and travel expenses including reasonable time required to prepare the equipment for return to normal activities after returning to their point of origin.

17.3 During emergencies impacting more than one member, Responding Company resources may be re-assigned either: en route to the Requesting Company; at an initial staging area before reaching the Requesting Company; or at the Responding Company's final staging area. Additionally, resources may be assigned to assist a second Requesting Company after completing work for the initial Requesting Company. ***Note:*** In any of these instances, unless otherwise mutually agreed, the utility that receives the re-assigned Responding Company resources will be responsible for all Responding Company costs <u>from the time of re-assignment.</u>

17.4 Requesting Company will reimburse members for expenses incurred in the provision and management of interim staging areas (i.e. labor and miscellaneous expenses provided by the host utility to operate the staging area, but not including any Responding Company crew costs). In emergencies involving more than one Requesting Company, staging costs will be shared by Requesting Companies on a prorated basis based on the resources committed to each entering (logged into) the staging site.

17.5 Provided proper supporting documentation is included, the Requesting Company will pay all (preliminary and final) invoice(s) from Responding Company within 60 calendar days after receipt of invoice(s).

17.6 Requesting Company shall indemnify and hold Responding Company harmless from and against any and all liability for loss, damage, cost or expense which Responding Company may incur by reason of bodily injury, including death, to any person or persons or by reason of damage to or destruction of any property, including the loss of use thereof, which result from furnishing emergency assistance and whether or not due in whole or in part to any act, omission, or negligence of Responding Company except to the extent that such death or injury to person, or damage to property, is caused by the willful or wanton misconduct and/or gross negligence of the Responding Company. Where payments are made by Responding Company under a worker's compensation or disability benefits law or any similar law for bodily injury or death resulting from furnishing emergency assistance, Requesting Company shall reimburse the Responding Company for such payments, except to the extent that such bodily injury or death is caused by the willful or wanton misconduct and/or gross negligence of the Responding Company.

17.7 In the event any claim or demand is made or suit or action is filed against Responding Company alleging liability for which Requesting Company shall indemnify and hold harmless Responding Company under paragraph (17.6) above, Responding Company shall promptly notify Requesting Company thereof, and Requesting Company, at its sole cost and expense, shall settle, compromise or defend the same in such manner as it in its sole discretion deems necessary or prudent.

Section V

Responding Company – Procedures / Responsibilities

18. Responding Company – Responsibilities Prior to Mobilization

18.1 To the extent possible, the Responding Company is expected to clearly communicate the degree of devastation and working conditions that their responding employees should expect to encounter upon arrival at the emergency restoration work area.

18.2 To facilitate communications, the Responding Company may opt to provide a single point of contact (Coordinator) to interact with the Requesting Company.

18.3 Responding Company will complete and forward the *RESPONDING COMPANY INITIAL INFORMATION SHEET* before departing their home location.

18.4 If requested, Responding Company will provide a copy of completed *PERSONNEL LISTING FORM* as soon as the information becomes available.

18.5 Responding Company's telecommunications personnel shall contact Requesting Company's telecommunications personnel and local FCC authorities to make any temporary telecommunications arrangements.

18.6 Prior to traveling, Responding Company will reach agreement with the Requesting Company regarding the provisions for Responding Company personnel to make personal long distance telephone calls during the emergency response period as described in paragraph 15.8 above. This agreement should preclude any telephone charges from any lodging facility by the Responding Company personnel, except in case of emergency local 911 calls.

18.7 Responding Company agrees not to load extra emergency stock on trucks unless specifically requested by the Requesting Company.

18.8 When Responding Company's available contractor resources have been allocated to a Requesting Company through the Joint Mobilization Conference Call procedures, the Responding Company will:

- Provide Requesting Company with contact information for their on-site contractors.
- Alert their contractors that their assistance has been requested and that they will be contacted by the Requesting Company.
- Give their contractors the Requesting Company contact information.
- Encourage their contractors to respond to the S.E.E. member's request for help with all contract crews being released from the Responding Company's work site.

19. Responding Company – Responsibilities During Emergency Assistance Period

19.1 Responding Company will handle all communication needs within their teams. This could include acquiring additional communications equipment, such as portable repeaters, to ensure continuous communication capabilities.

19.2 The Responding Company will be responsible for performing normal maintenance on their vehicles and equipment during the emergency assistance period and this work will be covered in their standard hourly/daily rates.

19.3 Responding Company will maintain daily records of time and expenses for personnel and equipment. This documentation will be provided with their preliminary invoice.

19.4 When the Requesting Company has provided specific guidance in advance that differs from that in paragraph 19.5, the Responding Company will maintain and furnish the requested documentation of expenses with their preliminary invoice.

19.5 Unless otherwise agreed prior to mobilization, members agree that Responding companies will maintain and furnish upon request receipts for all individual expenses / purchases made during the emergency assistance period in accordance with the IRS requirements in effect at the time assistance is requested.

20. Responding Company – Responsibilities End Of Emergency Assistance Period

20.1 Responding Company should submit their "preliminary invoice" to Requesting Company within 60 calendar days from date released by the Requesting Company. Responding Company will provide supporting documentation at the time the preliminary invoice is mailed. Requesting Utility should receive final invoice within 90 calendar days from invoice date of preliminary invoice. An *S.E.E. INVOICE COVER SHEET* shall be included with the Responding Company's billing package.

20.2 Responding Companies agree to maintain auditable records of billed expenses for emergency mutual assistance sufficient to satisfy the legal / statutory requirements and obligations incumbent upon the Requesting Company.

Attachments:

Attachment I – Joint Mobilization Conference Call Outline
Attachment II – Responding Company Initial Information Sheet
Attachment III – Emergency Assistance Personnel Listing Form
Attachment IV – S.E.E. Invoice Cover Sheet

Southeastern Electric Exchange

Mutual Assistance Procedures and Guidelines

February 2012

As directed by the Board of Directors of Southeastern Electric Exchange, the Mutual Assistance Committee has developed and accepted the following procedures to provide and request assistance to aid in restoring electric service when it has been disrupted and cannot be restored in a safe and timely manner by the affected company or companies alone. In approaching this task, committee members recognized the significant differences between work performed under normal circumstances and emergency restoration, as well as the fact that each member will at some time both require and supply emergency assistance. Therefore, members have reached understanding and agreement to adhere to the procedures and guidelines that follow without the necessity of formal contractual arrangements.

The Mutual Assistance Committee shall have responsibility for maintenance and revision of the *Southeastern Electric Exchange Mutual Assistance Procedures and Guidelines*. Final acceptance of this document, as well as any future modifications, must be approved by ¾ of the appointed and serving members of the S.E.E. Mutual Assistance Committee, each operating member company having one (1) vote.

Section I

Understanding Among Members Regarding Mutual Assistance

1. Members of Southeastern Electric Exchange understand and agree:

1.1 That members will work together to minimize risk to all parties. Responding Companies will provide assistance (personnel and equipment) on a not-for-profit basis, and Requesting Companies will reimburse Responding Companies for all expenses incurred in providing the assistance. [1]

1.2 To adhere to and operate in accordance with the procedures contained in this document (the *Southeastern Electric Exchange Mutual Assistance Procedures and Guidelines*).

1.3 That should there be any conflict in procedures and guidelines contained in the *S.E.E. Mutual Assistance Procedures and Guidelines* and other regional or national mutual assistance agreements, guidelines, principles, or procedures, S.E.E. members will adhere to the procedures approved by the S.E.E. Mutual Assistance Committee when assisting or requesting assistance from fellow members through the Joint Mobilization Conference Call Procedure outlined in this document.

---

1. In this document the terms Responding Company and Requesting Company refers to both the company and its employees.

4. Code of Conduct

4.1 Whether providing or receiving assistance, all personnel will be expected to conduct themselves in a professional and responsible manner.

5. Communication With Contractors

5.1 Members understand the need for clear communication with contractors working on their systems and are encouraged to explain the joint mobilization process discussed in this document.

6. Definition of Emergency Assistance Period

6.1 Members agree that the emergency assistance period shall commence when personnel and/or equipment expenses are initially incurred by the Responding Company in response to the Requesting Company's needs. This includes any request for the Responding Company to prepare its employees and/or equipment for travel to the Requesting Company's location but to await further instructions before departing. This preparation time should begin when normal work activities for Responding Company stop and preparations dedicated to supporting the off system effort begin. Except as noted in paragraph 6.3, the emergency assistance period shall terminate when such employees and/or equipment have returned to their point of origin and after a reasonable time required preparing the equipment for return to normal activities (e.g. cleaning trucks, restocking minor materials, etc.).

6.2 The length of stay by Responding Company personnel will be mutually agreed to by both companies. Generally, this period should not exceed 14 consecutive days, including travel time to the work area and return to the point of origin. When mutual assistance assignments go beyond this time frame, S.E.E. members agree that Responding Company personnel will usually be changed out (rotated) rather than take extended reset periods (days off). Responding and Requesting companies may agree upon exceptions to this procedure.

6.3 It is understood and agreed that if Responding Company's or its Holding Company's system is threatened during any time after it has mobilized to provide mutual assistance, any part or all of the Responding Company's native and contract workforce may be recalled. In these instances:

- It is understood and agreed that the decision to terminate assistance and recall employees lies solely with the Responding Company.
- If recall of Responding Company's workforce becomes necessary, the Requesting Company will be responsible for all expenses incurred by Responding Company until the Responding Company returns home and vehicles are cleaned and stocked for normal work activities.
- If Responding Company's workforce is recalled to another of the Responding Company's locations other than their original point of origin, the Requesting Company will be responsible for travel costs to the alternate location not to exceed that which would have been incurred had the workforce returned to their original point of origin.

9. Initiation of the Joint Mobilization Conference Call

9.1 Typically, the member that expects to be impacted first by an event will initiate the conference call.

9.2 Members agree to initiate a conference call anytime they experience or are threatened by an event so significant that they anticipate needing resources beyond the capabilities of their neighboring (adjacent) utilities to restore their system.

9.3 Procedure for initiating the conference call:

- During normal business hours, the initiating member will notify any S.E.E. staff member (phone number 404-233-1188) that they wish to hold a conference call for storm response, give the staff member the toll-free conference call number, date, and time for the call (specifying time zone). S.E.E. will contact all members via e-mail, providing conference call information and confirm all members' participation. After every call, S.E.E. will send out an e-mail providing a summary of the conference call discussion.
- After normal working hours and on weekends, members initiate the call by contacting the Executive Director of S.E.E., at home or on his cell phone. The Director will contact members as described above. If the S.E.E. Director cannot be reached, the initiating member will use the S.E.E. Mutual Assistance Contact Roster to contact members directly.

10. Responsibilities of Company Initiating Conference Call

10.1 The company initiating the conference call will designate an individual to serve as moderator for the conference call. The moderator will:

- Call the roll of member companies.
- Present the weather forecast for his / her company service territory. At their discretion, the initiating company may have a weather consultant present the current forecast.
- Ask other members for input regarding the weather forecast / predictions.
- Present an estimate of predicted impact / damages and when these are expected to occur. If the event is large enough to impact more than one member's service territory, the moderator will ask other members for their projected damage assessments.
- Present an estimate of resources needed. If the event is large enough to impact more than one member's service territory, the moderator will ask other members for their projected resource needs.
- By roll call, ask all non-impacted members to state the numbers of resources available to assist once their territories are no longer threatened.
- When appropriate, the moderator will lead discussion of staging areas to be used by assisting companies; transportation concerns, such as evacuation orders, fuel availability, DOT exemptions, etc.; and, the availability of non-member resources that may be available to assist impacted members.
- Keep the call moving and minimize the length of the call as much as possible.
- If requested, notify non-S.E.E. members via the EEI Restore Power list serve.
- Set the date and time for future conference calls.

13.3 When more than one company has requested emergency assistance, the Southeastern Electric Exchange coordinator will serve as moderator of conference calls between impacted companies on which Requesting Companies will agree upon the allocation of available first wave S.E.E. resources.

Section IV

Requesting Company Responsibilities

14. Requesting Company – Responsibilities Prior to Mobilization

14.1 To the extent possible, the Requesting Company is expected to clearly communicate the degree of devastation and working conditions Responding Company personnel should expect to encounter upon arrival at the emergency restoration work area.

14.2 The Requesting Company is expected to inform the Responding Company if their requirements for the maintenance of receipts differ from the procedures stated in paragraph 19.5.

14.3 To facilitate communications, the Requesting Company may opt to provide a single point of contact (Coordinator) to interact with the Responding Company.

14.4 The Requesting Company will provide the Responding Company with the name and contact information for their "company contact" as required on the *RESPONDING COMPANY INITIAL INFORMATION SHEET* before Responding Company personnel leave their point of origin.

14.5 Requesting Company will coordinate with their state DOT officials concerning emergency exemptions and any other transportation issues that will facilitate the Responding Company's trip to and from the Requesting Company.

14.6 The Requesting Company is encouraged to communicate general guidelines with Responding Companies. Items covered may include labor contractual issues, safety issues, contact personnel, vehicle fueling arrangements, typical standard construction, meal and lodging arrangements, and other items that will be of benefit to the responding personnel and their supervision.

15. Requesting Company – Responsibilities During Emergency Assistance Period

15.1 The Requesting Company will establish expectations for work, including start time and duration.

15.2 The Requesting Company will provide materials unless specifically noted otherwise.

15.3 When necessary, the Requesting Company will provide a guide with communications capability, portable radios or cellular telephones to assist responding team leaders.

15.4 The Requesting Company will authorize Responding Company to use cellular phones as a method of communication. Where cellular service is unavailable, it is understood that satellite phones may be used until such time that cellular service is restored in the Requesting Company's area.

15.5 The Requesting Company will provide vehicle security for parking areas unless specifically agreed otherwise.

16.3 In the emergency situation described in paragraph 16.2 above, the initial and secondarily impacted companies agree to:

- Immediately hold an "impacted companies" conference call to negotiate reallocation of the resources on the release schedule developed by the first impacted company as well as any other resources not already committed.

- Regarding personnel released by the first impacted company, secondary Requesting Companies will contact the resources (companies) allocated to them to determine if those persons will agree to re-deploy or be changed out (rotated) in accordance with paragraph 6.2.

16.4 In all emergency situations, the Requesting Company will make every effort to notify each Responding Company's mutual assistance contact 24-hours in advance of the anticipated final release of their utility personnel.

17. Requesting Company – Responsibility for Reimbursement of Expenses And Indemnification of Responding Company

17.1 Members understand and agree that the provision of emergency mutual assistance is a not-for-profit endeavor for Responding Companies. Therefore, the Requesting Company will reimburse all costs and expenses incurred by the Responding Company in the provision of the emergency assistance for the entire emergency assistance period as defined in paragraph 6 above.

17.2 If Responding Company resources are released after mobilization but before being utilized, the Requesting Company will reimburse Responding Company for all incurred preparation and travel expenses including reasonable time required to prepare the equipment for return to normal activities after returning to their point of origin.

17.3 During emergencies impacting more than one member, Responding Company resources may be re-assigned either: en route to the Requesting Company; at an initial staging area before reaching the Requesting Company; or at the Responding Company's final staging area. Additionally, resources may be assigned to assist a second Requesting Company after completing work for the initial Requesting Company. ***Note:*** In any of these instances, unless otherwise mutually agreed, the utility that receives the re-assigned Responding Company resources will be responsible for all Responding Company costs from the time of re-assignment.

17.4 Requesting Company will reimburse members for expenses incurred in the provision and management of interim staging areas (i.e. labor and miscellaneous expenses provided by the host utility to operate the staging area, but not including any Responding Company crew costs). In emergencies involving more than one Requesting Company, staging costs will be shared by Requesting Companies on a prorated basis based on the resources committed to each entering (logged into) the staging site.

17.5 Provided proper supporting documentation is included, the Requesting Company will pay all (preliminary and final) invoice(s) from Responding Company within 60 calendar days after receipt of invoice(s).

18.7 Responding Company agrees not to load extra emergency stock on trucks unless specifically requested by the Requesting Company.

18.8 When Responding Company's available contractor resources have been allocated to a Requesting Company through the Joint Mobilization Conference Call procedures, the Responding Company will:

- Provide Requesting Company with contact information for their on-site contractors.
- Alert their contractors that their assistance has been requested and that they will be contacted by the Requesting Company.
- Give their contractors the Requesting Company contact information.
- Encourage their contractors to respond to the S.E.E. member's request for help with all contract crews being released from the Responding Company's work site.

19. Responding Company – Responsibilities During Emergency Assistance Period

19.1 Responding Company will handle all communication needs within their teams. This could include acquiring additional communications equipment, such as portable repeaters, to ensure continuous communication capabilities.

19.2 The Responding Company will be responsible for performing normal maintenance on their vehicles and equipment during the emergency assistance period and this work will be covered in their standard hourly/daily rates.

19.3 Responding Company will maintain daily records of time and expenses for personnel and equipment. This documentation will be provided with their preliminary invoice.

19.4 When the Requesting Company has provided specific guidance in advance that differs from that in paragraph 19.5, the Responding Company will maintain and furnish the requested documentation of expenses with their preliminary invoice.

19.5 Unless otherwise agreed prior to mobilization, members agree that Responding companies will maintain and furnish upon request receipts for all individual expenses / purchases made during the emergency assistance period in accordance with the IRS requirements in effect at the time assistance is requested.

20. Responding Company – Responsibilities End Of Emergency Assistance Period

20.1 Responding Company should submit their "preliminary invoice" to Requesting Company within 60 calendar days from date released by the Requesting Company. Responding Company will provide supporting documentation at the time the preliminary invoice is mailed. Requesting Utility should receive final invoice within 90 calendar days from invoice date of preliminary invoice. An *S.E.E. INVOICE COVER SHEET* shall be included with the Responding Company's billing package.

20.2 Responding Companies agree to maintain auditable records of billed expenses for emergency mutual assistance sufficient to satisfy the legal / statutory requirements and obligations incumbent upon the Requesting Company.

Statement of Understanding And Endorsement

The member companies of Southeastern Electric Exchange understand that they will have occasion to either provide or receive assistance in the form of personnel and equipment to aid in restoring electric service when it has been disrupted and cannot be restored in a safe and timely manner by the affected company or companies without assistance. For this reason, the Board of Directors of Southeastern Electric Exchange instructs and authorizes the Mutual Assistance Committee to develop and maintain operating procedures and guidelines to insure the most effective and efficient response by the entire membership when emergency assistance is requested by one or more member companies. Final acceptance of the *Southeastern Electric Exchange Mutual Assistance Procedures and Guidelines*, as well as any future modifications, must be approved by ¾ of the appointed and serving members of the S.E.E. Mutual Assistance Committee, each operating member company having one (1) vote.

Further, as an officer of the Southeastern Electric Exchange member company noted below, the undersigned hereby endorses the following principles and agreements on behalf of his / her member company:

1. Whether providing or receiving assistance, personnel safety will be the preeminent objective and responsibility of all participants.

2. Member companies agree to adhere to and operate in accordance with the procedures contained in the *Southeastern Electric Exchange Mutual Assistance Procedures and Guidelines*.

3. Whether providing or receiving assistance, members will work together to minimize risk to all parties. In accordance with S.E.E. procedures, responding companies will provide assistance (personnel and equipment) on a not-for-profit basis, and requesting companies will reimburse responding companies for all expenses incurred in providing the assistance. In keeping with this principle, S.E.E. members agree to abide by the indemnification provisions contained in the *Southeastern Electric Exchange Mutual Assistance Operating Procedures and Guidelines.*

E.ON US
Company Name

Paul Gregory Thomas
Officer Signature

Paul Gregory Thomas
Name of Company Officer

2/11/09
Date

JO
D.G.

STOLL
KEENON
OGDEN
PLLC

2000 PNC PLAZA
500 WEST JEFFERSON STREET
LOUISVILLE, KY 40202-2828
MAIN: (502) 333-6000
FAX: (502) 333-6099

KENDRICK R. RIGGS
[redacted]

October 21, 2013

VIA ELECTRONIC FILING

Joel Peck
Clerk, Virginia State Corporation Commission
Document Control Center
[redacted]

RE: ***Joint Application of Kentucky Utilities Company d/b/a Old Dominion Power Company, Louisville Gas and Electric Company, LG&E and KU Services Company, LG&E and KU Energy LLC, LG&E and KU Capital LLC, PPL Corporation, PPL Electric Utilities Corporation, and PPL Services Corporation for Authority to Engage in Affiliate Transactions and to Enter Into Utility Services Agreements, Pursuant to Chapter 4 of Title 56 of the Code of Virginia, § 56-76 et seq.***
Case No. PUE-2011-00095

Dear Mr. Peck:

Pursuant to ordering paragraph (7) of this Commission's Order Granting Authority dated November 14, 2011, attached please find and accept for filing Kentucky Utilities Company d/b/a Old Dominion Power Company's Utility Services Agreement (Mutual Assistance / Emergency Assistance Agreement) in the above-referenced case.

Should you have any questions, please do not hesitate to contact me.

Yours very truly,

Kendrick R. Riggs

Kendrick R. Riggs

KRR:ec
Attachment

cc: Raymond L. Doggett Jr., Associate General Counsel
Susan D. Larsen, Director, Division of Utility Accounting & Finance
William F. Stephens, Director, Division of Energy Regulation
C. Meade Browder, Senior Assistant Attorney General

UTILITY SERVICES AGREEMENT

This Utility Services Agreement (this "Agreement") is entered into as of the 21st day of October, 2013, by and between Kentucky Utilities Company ("KU/ODP"), a public utility organized under Virginia and Kentucky law and doing business in Virginia as Old Dominion Power Company, and PPL Electric Utilities Corporation ("PPL Electric"), a public utility organized under Pennsylvania law.

WHEREAS, KU/ODP is an indirect subsidiary of PPL Corporation;

WHEREAS, PPL Electric is a direct, wholly owned subsidiary of PPL Corporation;

WHEREAS, KU/ODP and PPL Electric are utility companies that provide electric service within their respective service territories;

WHEREAS, KU/ODP and PPL Electric may receive from and provide assistance to each other in the form of personnel, equipment, and services to aid in restoring and/or maintaining electric utility service when such service has been disrupted by the elements, equipment malfunctions, accidents, sabotage, or any other occurrence for which emergency assistance is deemed to be necessary or advisable ("Emergency Assistance"); and

WHEREAS, KU/ODP and PPL Electric believe that it is in the public interest and the interests of each company to provide for such an arrangement.

NOW, THEREFORE, in consideration of the mutual covenants contained herein and other valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto, intending to be legally bound, hereby agree as follows:

1. GOODS AND SERVICES. From time to time during the term of this Agreement, KU/ODP and PPL Electric may supply Emergency Assistance to one another. Such Emergency Assistance will be provided only (a) upon request, (b) when the requesting party ("Requesting Company") believes in good faith that the transaction will benefit the Requesting Company and its native-load customers, and (c) the responding party ("Responding Company") believes in good faith that the Emergency Assistance can be provided without material detriment to the Responding Company and its native-load customers.

2. COMPENSATION AND ALLOCATION.

A. The Emergency Assistance period shall commence when personnel and/or equipment expenses are initially incurred by the Responding Company in response to the Requesting Company's needs. The Emergency Assistance period shall terminate when such employees and/or equipment have returned to the Responding Company.

B. The Requesting Company shall reimburse the Responding Company for all costs and expenses incurred by the Responding Company as a result of furnishing Emergency Assistance. The Responding Company shall furnish documentation of expenses to the Requesting Company. Such costs and expenses shall include, but not be limited to, the following:

(i) Employees' wages and salaries for paid time spent in the Requesting Company's service area and paid time during travel to and from such service area, plus the Responding Company's standard payable additives to cover all employee benefits and allowances for vacation, sick leave and holiday pay and social retirement benefits, all payroll taxes, workers' compensation, employer's liability insurance and other contingencies and benefits imposed by applicable law or regulation.

(ii) Employee travel and living expenses (meals, lodging and reasonable incidentals).

(iii) Replacement cost of materials and supplies expended or furnished.

(iv) Repair or replacement cost of equipment damaged or lost.

(v) Charges, at rates internally used by the Responding Company, for the use of transportation equipment and other equipment requested.

(vi) Administrative and general costs, which are properly allocable to the Emergency Assistance, to the extent such cost are not chargeable to the foregoing subsections.

3. TERMINATION AND MODIFICATION. Either party to this Agreement may terminate this Agreement by providing 60 days written notice of such termination to the other party.

This Agreement is subject to termination or modification at any time to the extent its performance may conflict with any rule, regulation or order of the Federal Energy Regulatory Commission adopted before or after the making of this Agreement. This Agreement shall be subject to the approval of any state commission or other state regulatory body whose approval is, by the laws of said state, a legal prerequisite to the execution and delivery or the performance of this Agreement.

The authorization for this Agreement shall expire at the conclusion of five years beginning on the date this Agreement is given final approval by the Virginia State Corporation Commission and the Pennsylvania Public Utility Commission, whichever occurs later, unless the respective Commissions extend their authorizations.

4. BILLING AND PAYMENT. Payment for services provided by either party to this Agreement shall be by making remittance of the amount billed or by making appropriate accounting entries on the books of KU/ODP and PPL Electric. Billing will be made after the work is completed and all actual costs have been accumulated with remittance due within 30 days of billing. Any amount remaining unpaid after 30 days following receipt of the bill shall bear interest thereon from the date of the bill at annual rate of A1/P1 30-day Commercial Paper.

5. INDEMNIFICATION. The Requesting Company shall indemnify, hold harmless and defend the Responding Company from and against any and all liability for loss, damage, cost or expense which the Responding Company may incur by reason of bodily injury, including death, to any person or persons or by reason of damage to or destruction of any property, including the loss of use thereof, which result from furnishing Emergency Assistance and whether or not due in whole or in part to any act, omission or negligence of the Responding Company except to the extent that such death or injury to person, or damage to property, is caused by the willful or wanton misconduct and/or gross negligence of the Responding Company. Where payments are made by the Responding Company under a workers' compensation or disability benefits law or any similar law for bodily injury or death resulting from furnishing Emergency Assistance, the Requesting Company shall reimburse the Responding Company for such payments, except to the extent that such bodily injury or death is caused by the willful or wanton misconduct and/or gross negligence of the Responding Company.

6. NOTICE OF INDEMNIFICATION. In the event any claim or demand is made or suit or action is filed against the Responding Company alleging liability for which the Requesting Company shall indemnify and hold harmless the Responding Company under Section 5 above, the Responding Company shall promptly notify the Requesting Company thereof, and the Requesting Company, at its sole cost and expense, shall settle, compromise or defend the same in such manner as it in its sole discretion deems necessary or prudent. The Responding Company shall cooperate with the Requesting Company's reasonable efforts to investigate, defend and settle the claim or lawsuit.

7. NOTICE. Where written notice is required by this Agreement, all notices, consents, certificates, or other communications hereunder shall be in writing and shall be deemed given when mailed by United States registered or certified mail, postage prepaid, return receipt requested, addressed as follows:

A. To KU/ODP:
One Quality Street
Lexington, Kentucky 40507
Attn: Corporate Secretary

B. To PPL Electric:
2 North 9th Street
Allentown, Pennsylvania 18101
Attn: Gallus F. Wukitsch III

8. GOVERNING LAW. This Agreement shall be governed by and construed in accordance with the laws of the Commonwealth of Kentucky, without regard to its conflict of laws provisions.

9. MODIFICATION. No amendment, change, or modification of this Agreement shall be valid, unless made in writing and signed by the parties hereto.

10. ENTIRE AGREEMENT. This Agreement constitutes the entire understanding and agreement of the parties with respect to its subject matter, and effective upon the execution of this Agreement by the respective parties hereof and thereto, any and all prior agreements, understandings, or representations with respect to this subject matter are hereby terminated and canceled in their entirety and are of no further force and effect.

11. WAIVER. No waiver by either party hereto of a breach of any provision of this Agreement shall constitute a waiver of any preceding or succeeding breach of the same or any other provision hereof.

12. ASSIGNMENT. This Agreement shall inure to the benefit and shall be binding upon the parties and their respective successors and assigns. No assignment of this Agreement or either party's rights, interests, or obligations hereunder may be made without the other party's consent, which shall not be unreasonably withheld, delayed, or conditioned.

13. SEVERABILITY. If any provision or provisions of this Agreement shall be held by a court of competent jurisdiction to be invalid, illegal, or unenforceable, the validity, legality, and enforceability of the remaining provisions shall in no way be affected or impaired thereby.

IN WITNESS WHEREOF, the parties have caused this Agreement to be duly executed as of this 21st day of October, 2013.

Kentucky Utilities Company

By: Paul Gregory Thomas
Name: Paul Gregory Thomas
Title: Vice President, Energy Delivery – Distribution Operations

PPL Electric Utilities Corporation

By: David J. Boneberger
Name: David J. Boneberger
Title: Vice President – Distribution Operations

July 2, 2013

LGE & KU Energy LLC
Attn: John Wolf-Director Distribution Operations
[redacted]

Dear Mr. Wolf:

Enclosed for your review is a fully executed Mutual Aid Agreement between LGE/KU and OMU. I would like to take this opportunity to thank you and your staff for assisting OMU in the development of this agreement. Please let me know if you ever need assistance.

Sincerely,

Tim Lyons

Tim Lyons
Director of Engineering & Operations
Owensboro Municipal Utilities
[redacted]

LG&E KU Services
Owensboro Municipal Utilities
Mutual Aid Agreement

On occasion, LG&E and KU Services (LKE) and Owensboro Municipal Utilities (OMU) shall need to call upon each other for emergency assistance in the form of personnel or equipment to aid in maintaining or restoring electric utility service when such service has been disrupted by acts of the elements, equipment malfunctions, accidents, sabotage or any other occurrences where the parties deem emergency assistance to be necessary or advisable. While it is acknowledged that LKE and OMU are not under any obligation to furnish such emergency assistance, experience indicates that both Companies are willing to furnish such assistance when personnel or equipment are available.

The following principles are agreed to as the basis for a contract governing emergency assistance between the company requesting emergency assistance ("Requesting Company") and the company willing to furnish such assistance ("Responding Company"), when such assistance is requested between LKE and OMU:

1. The emergency assistance period shall commence when personnel and/or equipment expenses are initially incurred by the Responding Company in response to the Requesting Company's needs. (This would include any request for the Responding Company to prepare its employees and/or equipment for transport to the Requesting Company's location but to await further instructions before departing). The emergency assistance period shall terminate when such employees and/or equipment have returned to the Responding Company, and shall include any mandated DOT rest time resulting from the assistance provided and reasonable time required to prepare the equipment for return to normal activities (e.g. cleaning off trucks, restocking minor materials, etc.).
2. To the extent possible, LKE and OMU should reach a mutual understanding and agreement in advance on the anticipated length – in general – of the emergency assistance period. For extended assistance periods, LKE and OMU should agree on the process for replacing or providing extra rest for the Responding Company's employees. It is understood and agreed that if; in the Responding Company's judgment such action becomes necessary the decision to terminate the assistance and recall employees, contractors, and equipment lies solely with the Responding Company. The Requesting Company will take the necessary action to return such employees, contractors, and equipment promptly.
3. Employees of Responding Company shall at all times during the emergency assistance period continue to be employees of Responding Company and shall not be deemed employees of Requesting Company for any purpose. Responding Company shall be an independent Contractor of Requesting Company and wages, hours and other terms and conditions of employment of Responding Company shall remain applicable to its employees during the emergency assistance period.
4. Responding Company shall make available at least one supervisor in addition to crew foremen. All instructions for work to be done by Responding Company's crews shall be given by Requesting Company to Responding Company's supervisor(s); or, when Responding Company's crews are to work in widely separate areas, to such of Responding

Company's foremen as may be designated for the purpose by Responding Company's supervisor(s).

5. Unless otherwise agreed by LKE and OMU, the Requesting Company shall be responsible for supplying and/or coordinating support functions such as lodging, meals, materials, etc. As an exception to this, the Responding Company shall normally be responsible for arranging lodging and meals en route to the Receiving Company and for the return trip home. The cost for these in transit expenses will be covered by the Requesting Company.
6. Responding Company's safety rules shall apply to all work done by their employees. Unless mutually agreed otherwise, the Requesting Company's switching and tagging rules should be followed to ensure consistent and safe operation. Any questions or concerns arising about any safety rules and/or procedures should be brought to the proper level of management for prompt resolution between management of the Requesting and Responding Companies.
7. All time sheets and work records pertaining to Responding Company's employees furnishing emergency assistance shall be kept by Responding Company.
8. Requesting Company shall indicate to Responding Company the type and size of trucks and other equipment desired as well as the number of job function of employees requested but the extent to which Responding Company makes available such equipment and employees shall be at Responding Company's sole discretion. . Responding Company shall provide a copy to Requesting Company of an employee roster, equipment roster of billable material, and emergency contact information for those persons who will be providing assistance to Requesting Company.
9. Requesting Company shall reimburse Responding Company for all costs and expenses incurred by Responding Company as a result of furnishing emergency assistance. Responding Company shall furnish documentation of expenses to Requesting Company. Such costs and expenses shall include, but not be limited to, the following:
   a. Employees' wages and salaries for paid time spent in Requesting Company's service area and paid time during travel to and from such service area, plus Responding Company's standard payable additives to cover all employee benefits and allowances for vacation, sick leave and holiday pay and social and retirement benefits, all payroll taxes, workmen's compensation, employer's liability insurance and other contingencies and benefits imposed by applicable law or regulation.
   b. Employee travel and living expenses (meals, lodging and reasonable incidentals).
   c. Replacement cost of materials and supplies expended or furnished.
   d. Repair or replacement cost of equipment damaged or lost.
   e. Charges, at rates internally used by Responding Company, for the use of transportation equipment and other equipment requested.
   f. Administrative and general costs, which are properly allocable to the emergency assistance to the extent such costs, are not chargeable pursuant to the foregoing subsections.
10. Requesting Company shall pay all costs and expenses of Responding Company within sixty days after receiving an invoice therefor.
11. Requesting Company shall indemnify, hold harmless and defend the Responding Company from and against any and all liability for loss, damage, cost or expense which Responding Company may incur by reason of bodily injury, including death, to any person or persons or by reason of damage to or destruction of any property, including the loss of use thereof, which result from furnishing emergency assistance and whether or not due in whole or in part

to any act, omission, or negligence of Responding Company except to the extent that such death or injury to person, or damage to property, is caused by the willful or wanton misconduct and / or gross negligence of the Responding Company. Where payments are made by the Responding Company under a workmen's compensation or disability benefits law or any similar law for bodily injury or death resulting from furnishing emergency assistance, Requesting Company shall reimburse the Responding Company for such payments, except to the extent that such bodily injury or death is caused by the willful or wanton misconduct and / or gross negligence of the Responding Company.

12. In the event any claim or demand is made or suit or action is filed against Responding Company alleging liability for which Requesting Company shall indemnify and hold harmless Responding Company under paragraph (11) above, Responding Company shall promptly notify Requesting Company thereof, and Requesting Company, at its sole cost and expense, shall settle, compromise or defend the same in such manner as it in its sole discretion deems necessary or prudent. Responding Company shall cooperate with Requesting Company's reasonable efforts to investigate, defend and settle the claim or lawsuit.
13. LKE and OMU should consider the release of contractors during restoration activities. The Responding Company shall supply the Requesting Company with contact information of the contactors (this may be simply supplying the contractors name). The contractors will negotiate directly with Requesting Company.
14. Either party may withdraw from this agreement at any time by providing written notice to the other party. Such notice shall not affect any obligations which may have been incurred hereunder prior to the effective date of such notice or which may arise out of events occurring prior to that date. No Requesting Company may withdraw from this agreement while it is receiving assistance pursuant to the terms of this agreement.

John K. Wolfe
Director Dist. Ops. & System Restoration
LG&E KU Services

Date: 6/04/13

T. P. Naulty
Terry Naulty
General Manager & CEO
Owensboro Municipal Utilities

Date: 6/19/13

LG&E KU
PPL companies

OMU

Edison Electric Institute

National Response Event Playbook

September 2014

Table of Contents

Table of Figures

Table of Tables

I. Ownership and Updates

National Response Executive Committee (NREC) Chair is responsible for ensuring that this National Response Event (NRE) Playbook is maintained current and updated with any changes during his/her tenure. This playbook will be reviewed at least annually prior to June 1st in preparation for an annual drill and the hurricane season.* Following log provides the history of the changes to the playbook.

Date of Change	Authorized by	Section(s) changed	Reason:
April 25, 2014	NREC After Action	Various	Updated Draft based on feedback from March 2014 Table Top Exercise
July 30, 2014	NREC After Action	Various	Updated Draft based on feedback from May 2014 Functional Exercise
September 11, 2014	NREC After Action	Various	Updated Draft based on feedback from August 2014 Functional Exercise

* Though this playbook is all hazards, the most likely hazard that will cause an NRE is a hurricane.

II. Scope

This playbook applies to any event for which the NRE process is activated, irrespective of the specific hazard. The NRE is activated by the CEOs (or designated officers) of requesting Edison Electric Institute (EEI) member utilities when multiple Regional Mutual Assistance Groups (RMAGs) cannot adequately support the resource requirements of the requesting utilities. The Playbook should be used by all NRE participants as a reference guide during the event and should be tested in table top and functional exercises annually. Updates to the playbook should be based on lessons learned from the after action review following actual events or exercises.

By definition, a National Response Event is an electric utility event that:

- The event is expected to or has impacted two or more RMAGs; or
- The resource requirements are greater than what the impacted RMAGs can offer; or
- There are multiple events that create a resource constraint or competition between RMAGs.

Once the NRE is activated, all of the available resources (line workers, tree trimmers, damage assessors, logistical support, etc.) are allocated at the national level across individual companies and RMAGs based on transparent and objective criteria.

A National Response Event will also require coordination of the Federal, State and Local response.

III. National Response Event Structure, Roles and Responsibilities

A. Structure

National Response Executive Committee (NREC)
The NREC is responsible to the Edison Electric Institute ("EEI") Board of Directors. The NREC will provide executive leadership to develop procedures and processes covering Emergency Assistance arrangements between Participating Companies to respond to an NRE. The NREC will also review and validate a request to activate an NRE, and resolve any issues stemming from the resource allocation process.

The EEI Board of Directors will designate one Participating Company executive from each RMAG to serve as primary members of the NREC, as well as two additional executives from each RMAG (except for the Wisconsin RMAG, which shall have one primary member) to serve as first and second alternates, respectively. The EEI Board of Directors shall also, at its discretion, designate up to two additional 'at large' executives to serve as primary members of the NREC. Members of the NREC shall be executive level, have operations and emergency assistance experience, and possess the ability to communicate at all levels of management. No one Participating Company, or parent thereof, may have multiple members on the NREC.

The leadership of the NREC shall consist of a Chair, a Vice Chair, and a Second Vice Chair. The NREC shall annually elect a Second Vice Chair from its membership at its first meeting of each year. At that time, the Vice Chair will assume the role of Chair, the Second Vice Chair will assume the role of Vice Chair, and the newly elected Second Vice Chair shall become Second Vice Chair. All leadership roles will last one year. The three officers will rotate on a yearly cycle. Other NREC members will rotate on a three year cycle and be replaced sequentially; with the primary member rolling off, the first alternate becoming primary, the second alternate becoming the first alternate and the new second alternates designated by the EEI Board of Directors. The two 'at large' NREC members shall serve one-year terms and be replaced on an annual basis.

National Mutual Assistance Resource Team (NMART)
During an NRE, the NMART is responsible for collecting information regarding the scope of actual or forecasted damage, determining available and requested resources and allocating the available resources in a safe, efficient, transparent and equitable manner.

The NMART consists of the officers of the EEI Mutual Assistance/Emergency Preparedness Committee (EEI MA/EP) and one representative from each RMAG. The EEI MA/EP Co-Chairs, Vice Chair, Secretary and Secretary in Waiting will serve as the same roles in the NMART.

Edison Electric Institute
EEI serves as the industry liaison to EEI Member Company Chief Executive Officers ("CEOs"), senior government officials, federal agencies, and national organizations representing state and local interests. At the request of an EEI Member, EEI may also serve as an industry liaison to state regulatory agencies. During an NRE, EEI convenes periodic conference calls with the EEI Member Company CEOs and senior governmental officials. EEI will also serve as the investor-owned electric utility industry's primary national information resource. EEI will provide a broad, national perspective on the event through media and public

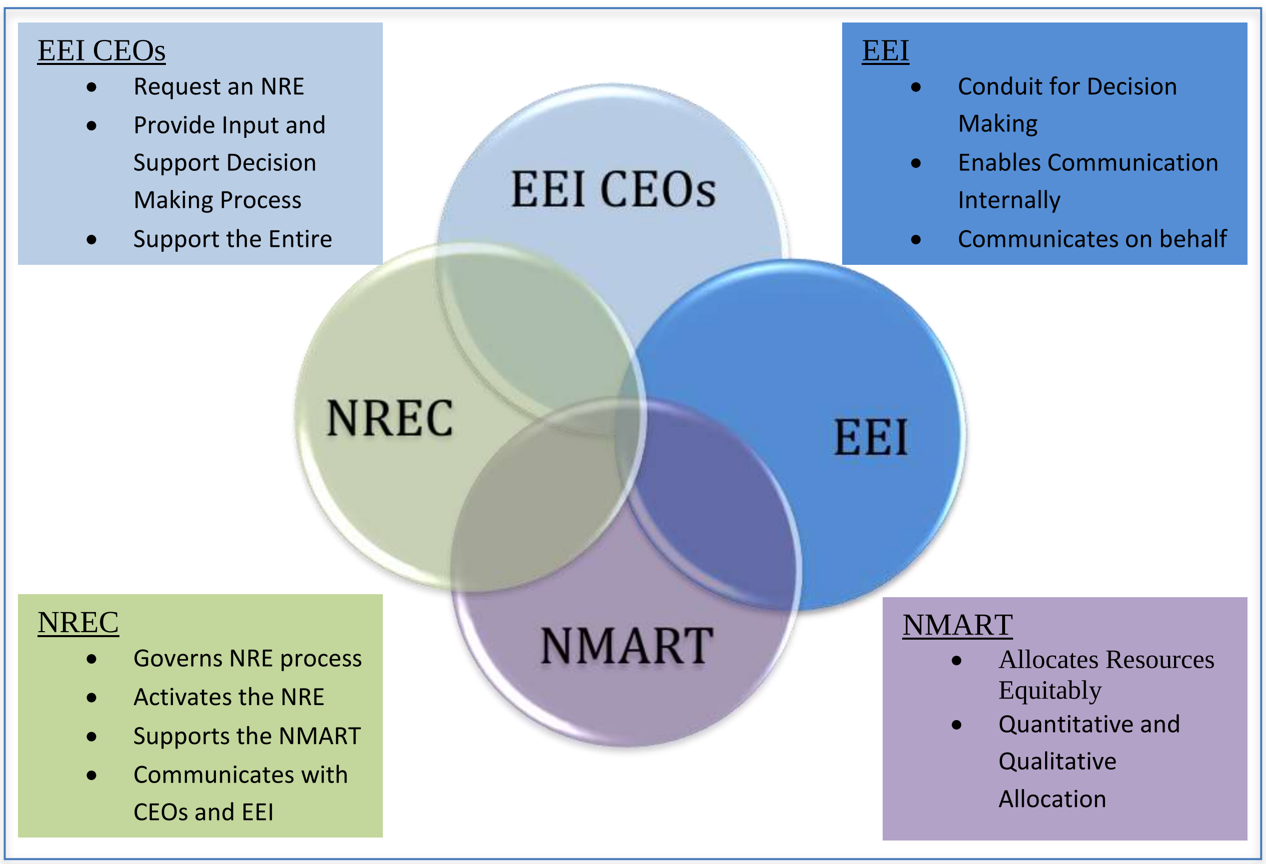
relations activities, national stakeholder outreach, including relevant Federal agencies, social media support, and industry-wide communication and coordination to relevant stakeholders.

EEI is not a member of the NREC, but will work closely with the NREC and may participate in NREC and NMART activities as appropriate to carry out its functions. EEI will also perform the role of the EEI NRE Liaison, filling two roles: communication liaison officer to the NREC and operations liaison officer to the NREC.

EEI Chief Executive Officers

The EEI Chief Executive Officers or their designees are the primary stakeholder for the National Response Event. Individually, they may request that the NRE be activated. Working through the EEI Policy Committee on Reliability and Business Continuity (PC – RBC), they support fellow CEOs and the NREC in the NRE appeals process. Working through the EEI PC – RBC, they receive daily updates on the NRE.

Figure 1 NRE Roles and Responsibilities



B. NRE Roles and Responsibilities

In addition to NREC, NMART, EEI and EEI CEOs all of which are described in Section III A above, the following are the key roles/groups responsible for executing the NRE resource allocation process:

EEI CEOs and Member Companies

EEI CEOs (or designees)

All EEI member CEOs or their designees are eligible to request an NRE. The EEI CEOs are responsible for:

- Individually can request an NRE
- Collectively support the NRE process by providing counsel through EEI, the EEI Policy Committee on Reliability and Business Continuity and the NREC.

Requesting Companies
Requesting companies are those companies that are either under a threat of a major event or have been impacted and are looking for mutual assistance resources.

Responding Companies
Responding companies are those companies that have not been affected by the event itself and/or are in position to provide resources to assist in the restoration effort at other utility companies.

NREC

NREC Chair
At the beginning of the first NREC meeting each year, the NREC First Vice Chair is elevated to the NREC Chair. The NREC chair shall lead the NREC throughout the NRE unless the NREC Chair's company is impacted by the event or there is some other potential conflict that would require the NREC First Vice Chair, Second Vice Chair or other NREC member to assume the role of the NREC Chair. The NREC Chair is responsible for:

- Work with the requesting CEO, the Policy Committee on Reliability and Business Continuity Co-Chairs and EEI and managing the activation of the NRE
- Developing situational awareness including contacting the NREC members
- Responsible for the weather forecast and safety message for each conference call
- Managing the NRE process from request to demobilization
- Interacting with CEOs
- Notifying the NMART of activation
- Managing appeals
- Coordinating with EEI
- Transferring responsibility to the Vice-Chair if Chair's own company is impacted
- Co-locate with EEI in the event of an NRE

NREC Vice Chair (s)
At the beginning of the first NREC meeting each year, as the NREC First Vice Chair is elevated to the NREC Chair, and the NREC Second Vice Chair is elevated to First Vice Chair. The incoming Second Vice Chair would then be elected by the NREC. The NREC First or Second Vice Chair may assume or assist with the NREC Chair's responsibilities.
The NREC Vice Chairs are responsible for:

- Supporting the NREC Chair
- Back filling the NREC Chair in his/her absence or if conflict of interest arises
- Co-locating with EEI in the event of a NRE.

NREC Members

The NREC members are typically executive representatives from each of the RMAGs. The NREC members include 3 executive members from 6 of 7 RMAGS (Southeastern Electric Exchange, Texas, North Atlantic, Midwest, Western, Great Lakes), 1 representative from the Wisconsin RMAG and 2 at-large members. The NREC members are responsible for:

- Supporting the NREC Chair and Vice-chair
- Providing counsel during the activation and appeals process
- Supporting their RMAG and RMAG member companies throughout the NRE process

NMART

NMART Co-Chair(s)

The two NMART Co-chairs are the EEI Mutual Assistance Emergency Preparedness (MA/EP) Executive Committee Co-Chairs. The Co-Chairs serve a two year term with one Co-Chair completing their term each year at the Annual EEI Mutual Assistance Emergency Preparedness (MA/EP) Executive Committee Spring Meeting. At that meeting, a new Secretary-in-Waiting is elected by the EEI Operating Companies present. The NMART Co-chairs are responsible for:

- Managing the resource allocation process
- Interacting with the NREC and EEI providing information and counsel
- Travelling to EEI or the NREC co-location site
- Potentially acting as the NMART liaison to the NREC

NMART Vice-Chair

The NMART Vice Chair is the EEI Mutual Assistance Emergency Preparedness (MA/EP) Executive Committee Vice Chair. The Vice Chair serves a one year term, completing the term each year at the Annual EEI Mutual Assistance Emergency Preparedness (MA/EP) Executive Committee Spring Meeting, at which time the Vice Chair is elevated to one of the Co-Chair positions. The NMART vice-chair acts as a backup and resource to the NMART Co-Chairs.

NMART Secretary

The NMART Secretary serves a one year term, completing the term each year at the Annual EEI Mutual Assistance Emergency Preparedness (MA/EP) Executive Committee Spring Meeting, at which time the Secretary is elevated to Vice Chair. The NMART Secretary is responsible for:

- Documenting all aspects of the NMART process
- Supporting the NMART Co-chairs
- Consolidating all the inputs from templates into the Resource Allocation Tool
- Managing the resource allocation tool
- Populating the dashboards in support of the NMART and NREC.

NMART Secretary-in-Waiting

The NMART Secretary in Waiting is elected annually by the EEI operating companies present. The NMART Secretary-in-Waiting is responsible for:

- Documenting all aspects of the NMART process
- Supporting the NMART Co-chairs
- Consolidating all the inputs from templates into the Resource Allocation Tool
- Managing the resource allocation tool
- Populating the dashboards in support of the NMART and NREC.

NMART Liaison to the NREC
At the time of the event, NMART will assign at least one member of the NMART's officers (NMART Co-Chairs, Vice Chair, or Secretary) to serve as a liaison to NREC. The NMART Liaison is responsible for:

- Maintaining a deep understanding of the NMART process and allocation decisions
- Co-locate with the NREC Chair during the event
- Be responsible for providing updates and information on allocation decisions to the NREC and the EEI Liaison

NMART Analytic Team
The Analytic Team is an ad hoc group made up of various members of the NMART team possibly including one of the co-chairs, the analyst, possibly the secretary and some members of the RMAGs. The Analytic Team will consist of at the minimum three members during an event; however, the number and makeup of the team members may change depending on the size of the event, specific companies affected by the event and stage of the restoration. The NMART Analytic Team is responsible for:

- Looking at the formula outputs, subjective factors and use experience to make the first recommendations on resource allocations to requesting companies.
- Ensuring that the allocations are logical and assist in answering questions by the NREC.
- Managing the resource allocation tool
- Supporting the NMART process
- Collecting data from the RMAGs

Regional Mutual Assistance Groups (RMAGs)
The RMAGs are governed by their own by-laws and participate willingly in the NRE process. They appoint their own RMAG leadership to represent the RMAGS on an annual basis. Their role as part of the NRE includes:

- Facilitating the data gathering from the utilities
- Participating in the process of matching the mutual assistance resources that were assigned to that RMAG to those requesting companies that have designated it as the "Home" RMAG
- RMAGs are not conducting any re-allocations of the resources during an NRE
- Declaring a "Home RMAG" annually

EEI[†]

EEI Crisis Management Officer
The EEI Crisis Management Officer is defined in the EEI Crisis Management Plan. The officer is responsible for:

- Receiving a request for activation from an EEI CEO
- Notifying the NREC Chair
- Supporting the activation process by communicating with the NREC Chair and the impacted CEO
- Convening calls for the NREC

[†] All EEI Crisis Operations or Crisis Communication positions are defined in the relevant EEI response plans. Their roles in the NRE are in addition to the responsibilities that are listed in the EEI plans.

EEI Operations Liaison

The EEI Operations Liaison is responsible for:

- Interacting with the NREC and the NMART to support operational needs of the industry
- Participates in all conference calls
- Communicating these needs to Federal and national governmental officials
- Maintaining operational situational awareness for EEI

EEI Communications Liaison

The EEI Communication Liaison is responsible for:

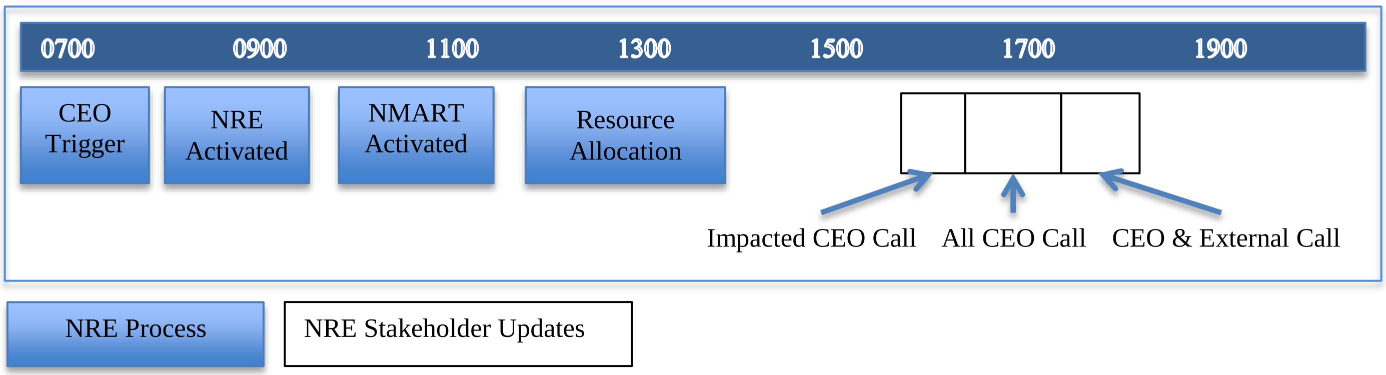
- Interacting with the NREC and the NMART to support communication needs of the industry, specifically the NRE
- Communicating these needs to external stakeholders
- Working with the NREC to ensure that NRE communications are accurate

IV. National Response Event Process and Functions

A. Overview

The NRE resource allocation process can be executed within the same business day if a NRE is declared before noon Eastern Standard Time. If the NRE is declared after noon or on the weekend, the process will be executed within the subsequent day. Below is the target timeline for daily NRE activities:

Figure 2 First Day Example Timeline - Early Activation



In the event that a NRE is requested after noon on the first day, there will be a modified structure to the activities, calls and deliverables for the first and second day. Whenever possible and where it will make a difference in the deployment of resources, the Resource Allocation process shall happen on the same day as the activation.

Figure 3 First Two Days Example Timeline - Late Activation

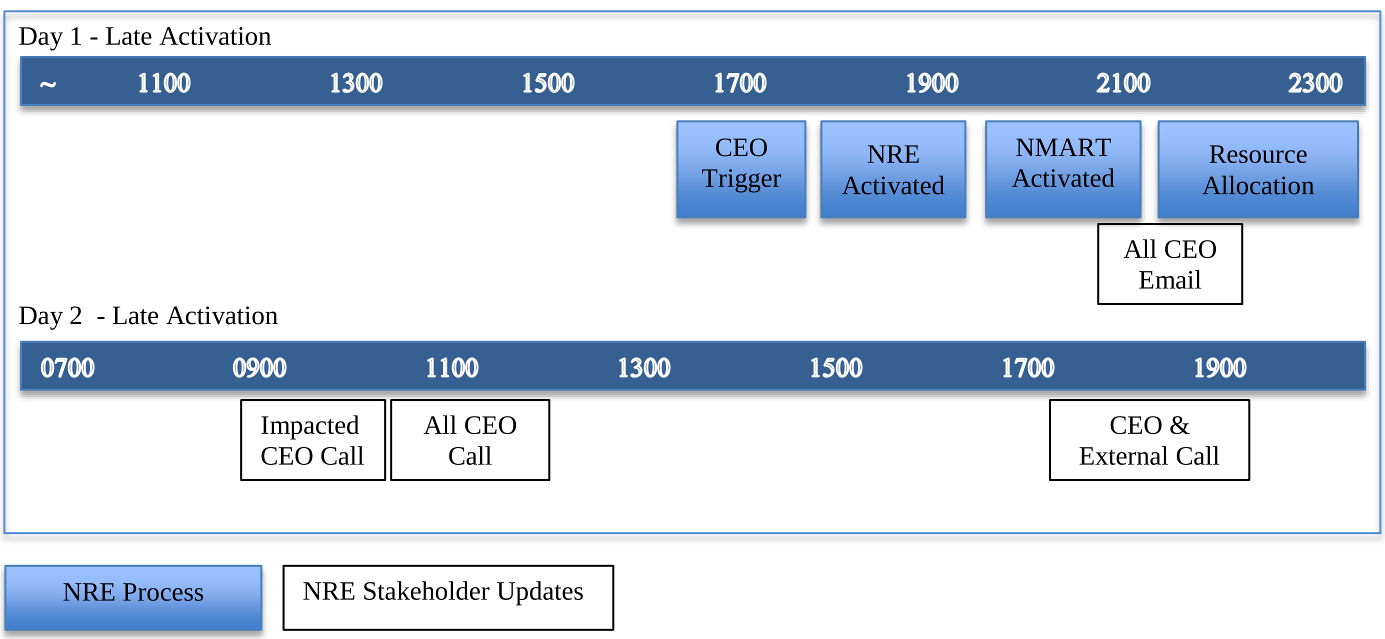


Figure 4 Every Day Following Activation Timeline

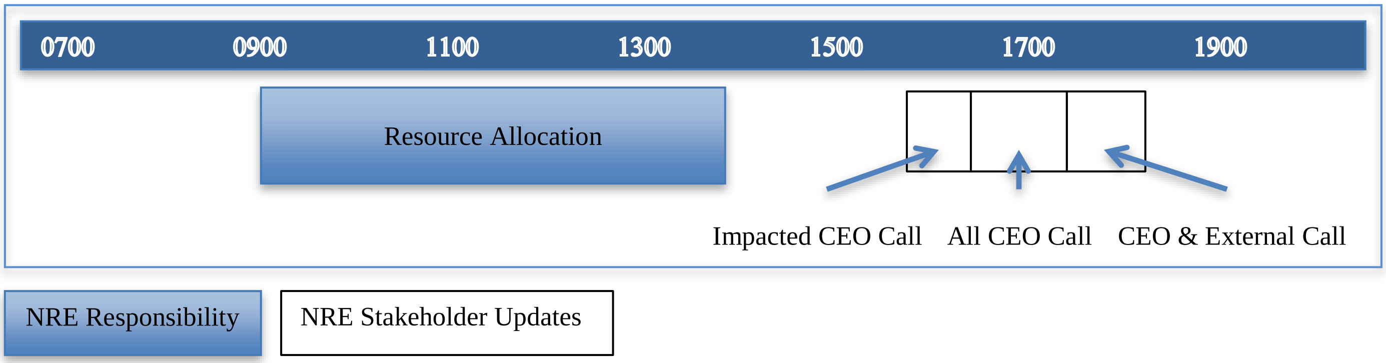


Table 1 Example Timing of Daily Calls and Deliverables

Ideal Timing (Eastern Time)	Activity/Deliverable
09:00	NMART Call to request resource and factor data from utilities
12:00	Utilities submit resource requests, factors and resource offers
13:00	Run initial allocation based on quantitative formula
14:00	Finalize allocation including qualitative factors ▪ Provide allocation information to NREC ▪ Provide matching spreadsheets to the RMAGs
14:30	NREC Convenes Conference Call to Review Allocation Info
15:00	Complete matching of resources by RMAGs
15:30	Impacted EEI CEOs Call (no government officials)
16:30	All EEI CEOs Call (no government officials)
17:15	EEI CEOs and Federal Government Officials Call

B. Activation and Mobilization

Any utility CEO or his/her designee can request NRE to be activated. The primary path for requesting the NRE activation involves a CEO or their designee contacting EEI to request activation of an NRE:

- A requesting CEO (or a designee) contacts EEI President or designee to discuss the need for an NRE activation.
- EEI then hosts a call with the requesting CEO, the NREC Chair and the CEO Policy Committee on Reliability and Business Continuity Co-Chairs to discuss the CEO's request.
- The NREC Chair then makes a decision.
- The NREC Chair will either:

  1. Decide to activate the NRE
  2. Decide not to activate the NRE
  3. Wait 6 hours and reconsider the decision

National Response Event Activation Criteria

The request for activating the NRE should meet the following criteria regarding the actual/forecasted event:

- The event is expected to or has impacted two or more RMAGs; or
- The resource requirements are greater than what the impacted RMAGs can offer; or
- There are multiple events that create a resource constraint or competition between RMAGs.

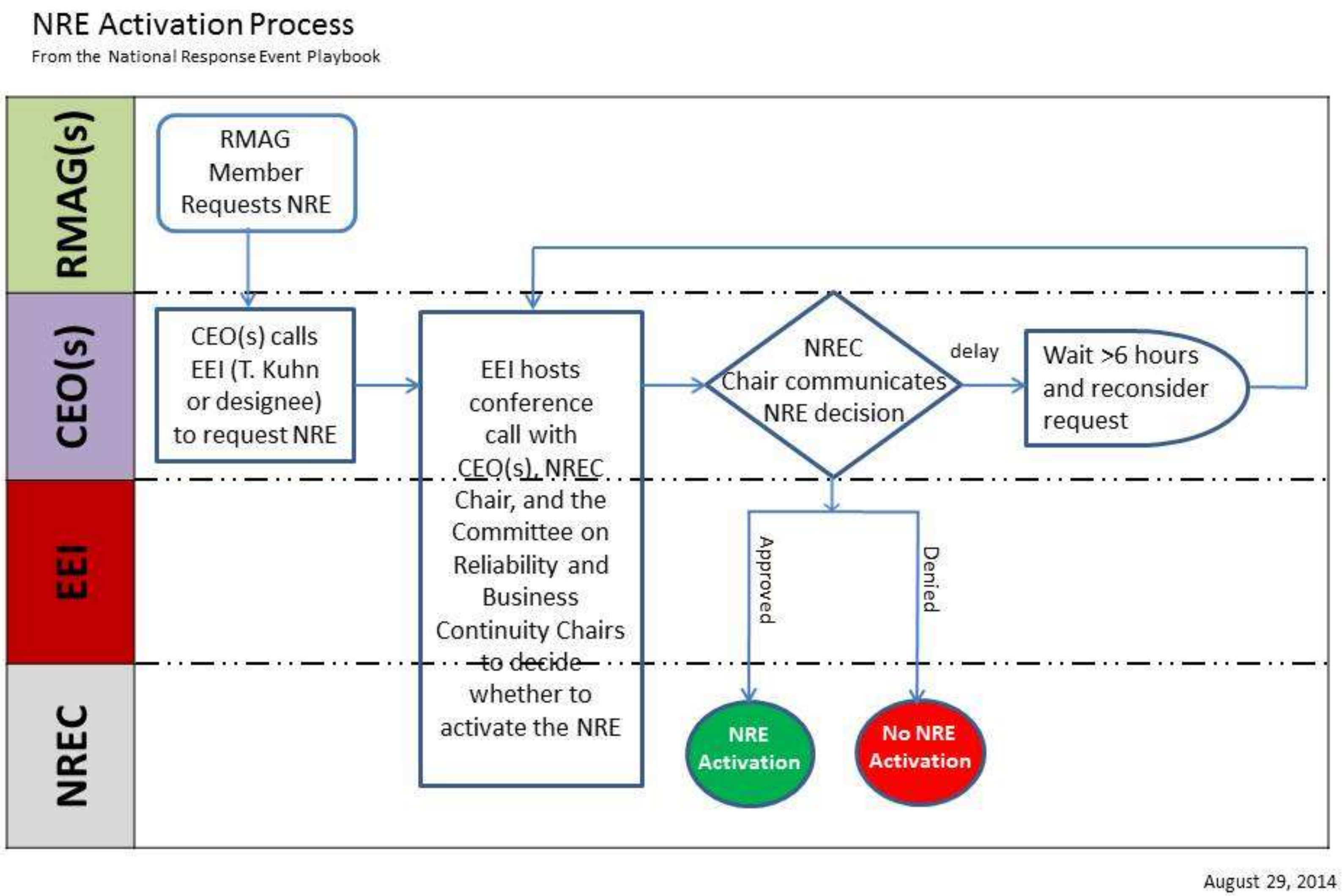
National Response Event Activation Steps

When the decision to activate NRE is made, the NREC Chair will:

1. Call the NREC Vice Chair and Second Vice Chair to inform them that NRE was activated;
2. Contact the EEI MA/EP Co-Chairs to activate the NMART;
3. Set up the initial conference call with the NREC leadership, EEI Operations Officer and the EEI MA/EP Co-Chairs (this call should take place within 2 hours of the activation);
4. Determine the daily NRE call schedule (typically an hour before the CEO briefings start). (SEE timeline Section IV, A Table 1)

The contact information for all the key NRE roles is provided in the Appendix B and the sample agenda for the initial NRE call and subsequent daily calls is included in the Appendix A of this playbook.

Figure 5 NRE Activation Process Map



C. Resource Allocation Methodology

National Response Event Resource Allocation Guiding Principles

Voluntary Participation: Utility participation will remain voluntary and will not undermine a utility's ability to retain local control of respective operations while benefiting from outside support.

Full and Reciprocal Participation: Utilities requesting mutual assistance during a NRE will offer assistance in future events proportional to their size and abilities, recognizing that great geographical separation may limit opportunities to share in all but the most catastrophic events. There will be a standing offer that each company will set and which will be available for support unless the company is threatened.

Resource Transparency: Requesting companies will disclose all available resources, including their own personnel, full time sustaining contractors, parent/sister company resources and any other resources secured in the reported mutual assistance resource counts.

Coordinate Release of Resources: Companies agree not to release or dispatch any resources unless committed to and the need confirmed by the requesting member company. It is understood that the responding member company's territories must be free from significant threat before resources (company and contractor) can be committed and dispatched.

Situational Awareness: Requesting companies will communicate to responding companies' personnel regarding the degree of devastation in the emergency restoration work area and expected work conditions. Requesting companies will communicate general guidelines with responding companies, such as labor contractual issues, safety issues, contract personnel, vehicle fueling arrangements, typical standard construction, meal and lodging arrangements, etc.

National Response Event Resource Allocation Guidelines

Since NRE events involve a large number of companies, the allocation process will adhere to the following guidelines that are critical to success for all utilities:

- Home RMAG declaration
  - Each Member Company with multiple OpCos in multiple RMAGs will declare a "Home RMAG" and make requests and/or provide information through their "Home RMAG" only.
  - The "Home RMAGs" are declared annually and are listed in Appendix B

- Resource Transparency:
  - Each operating company will work with their respective Home RMAG to prepopulate company resources (including internal and contractor) on the property;
  - Each company (responding/requesting) will complete required information sheets and submit in a timely manner;
  - Utilities will report accurate and total numbers of resources secured to support restoration (including all company and off-system resources, contractors and internal resources);
  - Utilities will report the most accurate and current customer outage information available – projected or actual; and,
  - All participants in the NRE process will have access to information used in the allocation process resulting allocations.

- Equitable Allocation
  - Any parent company will retain full control of all of its operating company resources throughout an NRE and will be able to deploy them among its operating companies as needed;
  - The allocation methodology will include a quantitative or formulaic solution that will be further refined by qualitative factors:
    - Formula will be simple and transparent, and
    - Refinement approach will be documented and consistent;
  - Actual outages carry a higher priority than projected outages;
  - Pre-staging will be limited to the first wave of support, unless the NMART and NREC believe that the forecasted threat requires mobilization of larger number of resources;
  - Reallocations of resources during the event will focus on redistributing those resources that have been released from the utility they were supporting.
    - Reallocation of resources that have been committed but may not yet be engaged in the physical restoration will be kept to a minimum during an event, and
    - Reallocation of resources actively engaged in restoration will be extremely rare and a measure of last resort to correct a critical resource deficiency. Any reallocation will be a subject to the agreement by the utilities affected by the decision.
- Continuous Improvement
  - Documentation must be maintained at a level to provide sufficient insight for after-action review (AAR); and,
  - The allocation tool will serve as a repository for manpower requests and allocations.

The resource allocation methodology consists of three key components: (1) allocation formula; (2) refinement based on other emerging circumstances; and (3) matching of resources to the specific company needs.

Resource Allocation Formula

The resource allocation formulas will be different for pre and post impact. Pre-impact allocations are limited and challenged by weather forecast error, damage model error and degree to which mutual assistance crews can be placed on productive assignments on day one of restoration. These challenges do not exist post-impact allowing a more rigorous quantitative allocation methodology. For mixed events, where some utilities have active restoration efforts and others remain under threat, both pre and post impact methods will have to coexist under the direction of the NMART with oversight from the NREC.

Pre-event Formula

Prior to the hazard striking a service territory and causing damage – "pre-event", the resources will be allocated to each requesting utilities, through the RMAGs, proportional to their request for resources. It is expected that at this stage only the initial wave of the resources will be mobilized and that a large number of utilities will be holding resources, which will become available once the weather system has dissipated. It is probable that all requests will not be met; however, the pre-event allocation contemplates providing enough assistance to reinforce utility response to those threatened during impact and quickly deliver significant support to areas actually impacted under the outage formula.

Outage Formula

The post-event resource allocation formula is based on the extent of damage and the impact of damage on electric customers. The two variables that are used in the formula are:

1. Customers out – portion of customer outages experienced by one utility as percent of the total customers out reported by all companies requesting resources.
2. Cases of Trouble – portion of the cases of trouble (locations) experienced by one utility as the percent of total cases of trouble reported by all companies requesting resources.

The current formula is based on the weighted average of the percentages associated with these two variables, where the customers out of power are weighted 60% and portion of the trouble weighted at 40%.

Given the allocation approach, the resources will be allocated based on available resources, rather than the number of resources requested by a utility. The requested number will only serve as the upper limit of the allocation. In situations where a company requested fewer resources than what its fair share is, the extra resources will be re-distributed to other utilities with open requests.

It is important to note that the exact number ultimately received by a utility may be slightly different from the fair allocation depending on the size and type of the resource contingents made available by providing utilities and contractors. For example, if the smallest block of resources is 80 full time equivalents (FTEs), the company that was allocated 100 FTEs through the process may end up with 80 FTEs.

Dealing with a Multiple Storm Event

If there is a second event, while the industry is already mobilized under the NRE, the following processes will be used:

1. Reconvene the NMART to assess the current allocation of resources with respect to both events;
2. Execute the allocation process, using the allocation tool and refinement approach to determine fair allocation based on the new damage factors and pre-staging needs;
3. Request impacted companies from the initial event(s) to begin developing a release plan;
4. Deploy available or redeploy released resources; and,
5. Consider reallocation of resources physically engaged in restoration if necessary (last resort).

If a utility that is responding to the initial event is threatened by or affected by the secondary event, it may recall its resources. This recall will be reflected in the updated numbers during the allocation process described in step 2 above.

Refinement Approach

In order to ensure efficiency of the allocation process, NMART will consider refinements to the calculated allocation numbers by evaluating qualitative factors. While difficult to incorporate into a formula, these additional factors need to be considered in the final allocation of available resources to ensure that the industry response to a NRE best reflects the needs of all customers served by utilities and any consideration of national interest. Some qualitative factors that will be considered include, but not limited to:

- Type of damage – after a thorough damage assessment, consider factors such as wires down, poles broken, flooding issues, etc.
- Significant events/societal impacts – consider impacts to major transportation hubs, critical infrastructure, national security facilities, major societal events, elections, etc.

- Estimated Time of Restoration (ETR) – Review impacted companies' ETRs to ensure reasonableness.
- % of customers out – Determine whether any company is disproportionately affected by the event where majority or entire customer base is affected by the outage. .
- Ratio of customers out per restoration FTE – ensure that the coverage of customer outages by restoration resources is reasonable across utilities;
- Ratio of cases of trouble per FTE – ensure that the impacted companies are provided comparable coverage of cases of trouble by restoration resources;
- Ability of requesting company to receive and effectively deploy incoming resources;
- Travel route – consider situations where a responding company may be able to support restoration at another affected utility in route, if the assigned requesting utility was catastrophically impacted by the event and may not be able to begin restoration immediately (e.g., major areas are still flooded, etc.); and
- Ability of a utility to restore an area in a timely manner that had major destruction.

If refinement factors are used to adjust the calculated share, the reasoning for such use will be documented appropriately.

At least one member of the NREC will participate on the NMART resource allocation review call to gain an understanding of the allocation decisions and provide any necessary input. He/she will work closely with the NMART Liaison and raise any potential concerns around the allocation decisions during the call. These concerns should be limited only to any departures from the pre-agreed upon resource allocation process. In addition, the NMART Liaison will actively participate in the entire resource allocation process and will be able to explain the allocations to the NREC and EEI Liaisons, alert NREC of any potential issues, or request NREC input on key allocation decisions in case of an impasse.

Resource Matching

The NMART, after reviewing the data supplied by the RMAGs from both the requesting and responding companies, and after considering any mitigating factors during the refinement step, will determine the appropriate number of each category of workers to be allocated to the RMAGs. The NMART will then allocate the specific groups of resources from each responding company to the home RMAGs of the requesting companies to ensure the most efficient and effective assignments based on the distance to travel and needs. Each Home RMAG will then work with the companies to match the assisting resources to their specific needs.

In general, the resources will be matched in a manner that will limit the overall travel time and meet the logistical and other needs of the requesting companies. Factors that will be considered when matching requests with available resources include, but are not limited to:

- The type of resources needed (e.g., distribution line, transmission line, damage assessors, vegetation crews, material, etc.);
- The qualifications of the workers (e.g., hot-stick qualified, glove-hand qualified, secondary qualified, de-energized work, etc.);
- The type of equipment needed (e.g., bucket trucks, digger-derrick trucks, backyard equipment, off-road equipment, etc.);
- The level of support provided by the responding company (e.g., travel team complete with management, logistic support, vehicle mechanics, etc., or stand-alone resources without support);

- Contractor resources or utility company resources;
- The estimated time of arrival at the reporting locations;
- The availability of material, lodging, fuel, and other logistical needs at the reporting location;
- Contractual agreements between responding contractors and the requesting utility (e.g., liability insurance, terms and conditions, etc.); and,
- Internal resource transfers between operating companies and regions.

Once the NMART team agrees on allocation of available resources to the RMAGs, the NMART Secretary will send a report in spreadsheet format to each requesting RMAG. The spreadsheet will provide the specific information on how many of each type of resources were allocated to requesting companies and which responding companies resources have been assigned to that specific RMAG. Each RMAG will match assigned resources to specific companies according to the numbers of resources that each company received through the NMART allocation process. RMAGs will then complete the worksheet by indicating what requesting company received which specific group of resources. Once all resources have been assigned, the RMAG will return the completed worksheet to the NMART. The NMART will consolidate the allocations across NRE participants and make the summary report available to all member companies, the NREC, and EEI.

Redeployment of Resources

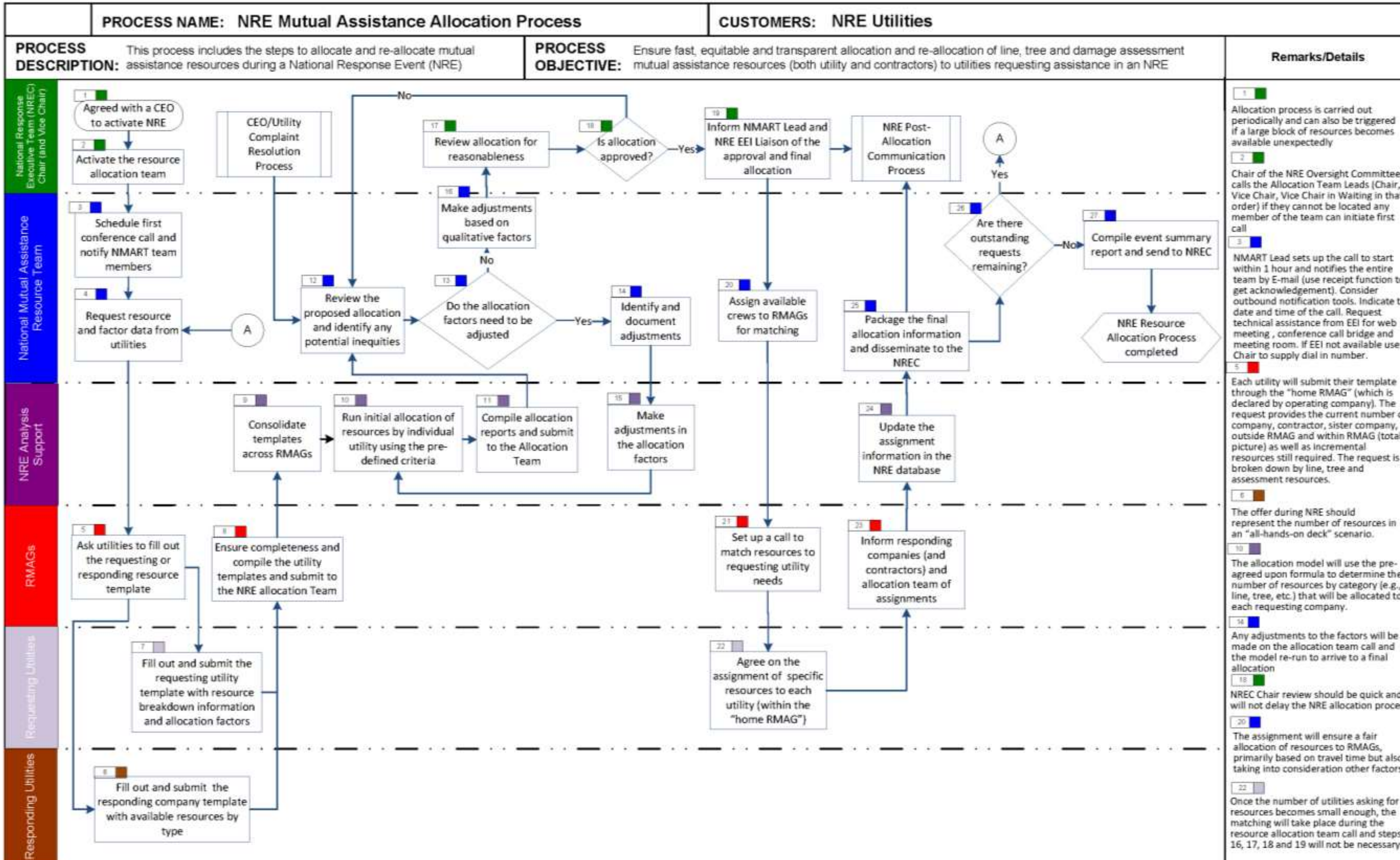
During an event, as impacted companies complete their restorations, they will release the off-system resources and make them available to assist other companies that have open requests. When this does occur, the NRE will use the following process:

- Impacted utility releasing the off-system resources (IOU or contractor) will contact the home utility where the resources work day-today to request authorization to place the resources back into the NRE allocation pool.
- Upon authorization from the home utility, the impacted utility will submit the information about the resources being released to their home RMAG, providing the same information as any other responding utility.
- The released resources will be assigned to another requesting utility in the subsequent resource allocation decision.

D. National Response Event Resource Allocation Process Map

The detailed process map provides a graphical representation of the key activities and steps required to complete the allocation of mutual assistance resources to requesting companies during a NRE. The map includes the comments (to the right of the process diagram) that provide more detailed descriptions of each process step. The key roles are listed on the left hand side and are aligned with the process steps that those roles are responsible for performing. The actual process map is provided below.

Figure 6 NRE Overall Process Map



23-01 NRE Mutual Assistance Activation Process v0-07 2013-04-17 .vsd Rev. 1.07-19-02

E. National Response Event Resource Allocation Process Information Requirements

In order to ensure transparent allocation process, participating companies are expected to provide specific information that will ensure equitable allocation of resources. The following information must be provided by the participating companies using the pre-defined templates.

Requesting Company Information Requirements

The requesting companies will provide three categories of information: (1) damage information (projected or actual) as expressed by the factors for allocation; (2) number of (non-native) resources currently secured; and (3) outstanding resource request. Below is the description of each of these categories, including the list of specific pieces of information.

Damage Factors

The key factors that describe the amount of damage projected or experienced by a requesting utility include:

- Total customers served (may be pre-populated) – based on the total meters served across the service territory. Does not include outdoor lighting;
- Number of customer outages – best estimate of the number of customers who are without power at a point of time. This number will come from the outage management system (OMS);
- Number of cases of trouble on distribution system – defined as the number of devices that are predicted by the OMS to be out of service;
- Number of cases of trouble on transmission system – defined as the number of locations that require physical repair in order to return to normal service;
- Projected customer outages – prior to the event, utilities that have predictive models, will provide their estimates of the number of customer outages that they expect based on the most current forecast;
- Projected cases of trouble – prior to the event, utilities that have predictive models, will provide their estimates of the number of cases of trouble that they expect based on the most current forecast; and,
- Other factors to consider – such as outages to facilities that may have regional or national impact, such as transportation hubs, large sporting events (e.g., Super Bowl, Olympics, etc.)

Current Resources Secured (expressed in FTEs)

The requesting companies are expected to provide the count of all of the resources by type that they have been able to secure at the time of the request. These resource numbers include:

- Native Resources – these are the company resources and sustaining contractors. Understanding that these numbers constantly change, the utilities will be asked to provide an estimate twice a year and those numbers will then be used during the event which include:
  - Distribution Line
  - Transmission Line
  - Tree Trimming
  - Damage Assessors
  - Network Mechanics
  - Service Mechanics
  - Underground Splicers
  - Logistics Support personnel

- Other

- Non-Native Resources – this number will include any parent/sister company resources, contractor resources secured through other efforts, any resources assigned through RMAG process if that was activated in advance of a NRE and any mutual assistance resources already allocated through the NRE process which includes:
  - Distribution Line
  - Transmission Line
  - Tree Trimming
  - Damage Assessor
  - Network Mechanics
  - Service Mechanics
  - Underground Splicers
  - Logistics Support personnel
  - Other

Requested Resources (Expressed in FTEs)

The requested resources are the numbers of resources that the a company is still looking for in order to complete its restoration. It represents the additional resources on top of those that have already been secured (under previous sections).

- Outstanding Resource Needs:
  - Distribution Line
  - Transmission Line
  - Tree Trimming
  - Damage Assessors
  - Network Mechanics
  - Service Mechanics
  - Underground Splicers
  - Logistics Support personnel
  - Other
- Maximum Travel Distance – indicates the number of days that the requesting utility is willing to pay for travel.
- Destination City
- Comments and special requests

Responding Company Information Requirements

The responding company will submit specific information on the resources they are able to provide to assist other utilities in the restoration effort. The numbers of resources will be provided in terms of FTEs. In order to support the transparency and fairness of the NRE, each company will define the standing offer in terms of the number of resources that it can provide depending on the level of mobilization in the first wave of support and in an “all-hands on deck” response. These numbers will be used to estimate the potential support that can be provided, while the exact numbers of available resources by type will be provided for each event. The specific event information will include:

- Line resources
  - Distribution line FTEs – include any overhead line personnel for all classifications, including servicemen, troublemen, etc.
    - Company resources
    - Contractor resources
  - Transmission line FTEs – include any overhead personnel for all classifications
    - Company resources
    - Contractor resources
- Tree trimming resources
- Network/Service/Underground resources
  - Company resources
  - Contractor resources
- Damage Assessment resources
  - Damage assessors (company)
  - Damage assessors (contract)
- Logistical support personnel
- Other resources
- Departure location – indicates the city and state from which the resources will start their travel
- Comments

<u>Companies That Have Met Outstanding Requests through NRE</u>

In order to help NMART and NREC maintain situational awareness, companies that have acquired off-system resources through NRE, but are no longer requesting additional resources (i.e., do not have any remaining outstanding requests), will be required to provide the following information using the requesting company template, for each subsequent NRE resource allocation period:

- # Customers out
- # Cases of Trouble
- Estimated Time of Restoration (ETR)
- # Non-Native Resources:
  - # Distribution Line
  - # Transmission Line
  - # Tree
  - # Damage Assessors
- # Native Resources that may become available after restoration:
  - # Distribution Line
  - # Transmission Line
  - # Tree
  - # Damage Assessors

This information will help provide valuable insight on potential resource releases at future time and provide full visibility into the allocations.

Information Maintenance and Version Control

In order to maintain accurate records of the allocation decisions, the Analytic Team will apply a standard naming convention for the Excel files generated throughout the resource allocation process. This standard will help maintain historical information and facilitate the tracking of the most current allocation decisions. The naming convention for the Excel files will use the following format:

File Naming Convention Formula
[Year] [Storm Name] [Date] [Time] [RMAG] [(Requesting, Responding, Allocation, Matching or NMART)]

Example of a file name: 2013 Sandy 1023 MAMA Requesting.xls

The data field definitions are:

- [Year] – 4 digit format (e.g., 2013);
- [Storm Name] – alphanumeric name of the storm (e.g., Sandy, MW Ice Storm 2010);
- [Date] –4 digit format with the month first and date second with a dash in between (e.g., May 9 would be 0509);
- [Time] – using military time (e.g., 1830);
- [Requesting, Responding, Allocation and Matching] – will indicate the type of data input contained in the file and will use the appropriate term in its entirety; and,
- [NMART] – Designation will be utilized only for the files containing the overall data spreadsheet maintained by the NMART. For NMART files, the type of data indication will not be used.
- The NMART Secretary shall be responsible for posting the NMART Dashboard to the NRE Workroom.

Allocation Process Documentation

NRE Analysis Support team will be responsible for generating and maintain the documentation related to the resource allocation process, including defining and ensuring version control of various documents, allocation decision output reports, and archiving information necessary to perform an appropriate after-action review (AAR). This documentation will be placed on the EEI NRE Workroom.

F. Demobilization/Deactivation

Once all of the outstanding resource requests have been met and each affected company has received the mutual assistance supported it needs, the NREC Chair will begin deactivation of the NRE process. After an NRE has been completed, any additional re-allocations of resources for that event will be conducted at the individual RMAG level.

As a part of the demobilization process, the NMART Secretary will compile all the key documentation related to the key allocation decisions made throughout the NRE and ensure that the latest version of the allocation model is archived on the NRE workroom. The EEI MA/EP Co-Chairs (NMART Co-Chairs) will then develop a summary report that describes the key decisions made and process participants.

Subsequent to each NRE, the NREC chair will schedule an after action review (AAR) with the key participants in the response effort. The purpose of this review will be to assess the response and identify any potential improvement opportunities. This review will be done in a half-day facilitated session and any actions that come out of it will be assigned to specific individuals for completion.

G. After Action Review and Process Improvement

Following an NRE or exercise, the NREC shall conduct an after action review of the NRE process and procedures to identify practices to sustain as well as any opportunities for improvement. The NREC, the NMART and EEI shall also meet to exercise the NRE Playbook at least once annually, prior to storm season, with timing coordinated to facilitate a report out at the Spring EEI CEO meeting. This exercise will provide an opportunity for sharing updates and any lessons learned, and any other pertinent business.

The NREC leadership has the responsibility to track these lessons learned and ensure that the lessons are addressed in a continuous improvement process.

V. National Response Event Communications

Timely, accurate and consistent communication throughout an NRE event is paramount. The process, roles and responsibilities designed to support the NRE effort ensure "one voice" communication with internal and external audiences.

A. NRE Communications Roles and Responsibilities

During a National Response Event (NRE) Edison Electric Institute (EEI) will serve as the investor-owned electric utility industry's primary national information resource. EEI will serve as the industry liaison to EEI member company CEOs, senior government officials, and federal and state regulatory agencies. EEI will also provide communication support to the National Response Executive Committee (NREC).

In this role, EEI will provide a broad, national perspective on the event through media and public relations activities and industry-wide communication and coordination to relevant stakeholders.

Similar to EEI's communication protocols during major storms, EEI's efforts during an NRE will not take the place of or interfere with individual utilities' efforts to communicate company-specific information to national or local reporters, elected officials, regulators, customers, and other stakeholders.

The following matrix outlines the communication steps and actions EEI will take before, during, and after a designated NRE.

B. Key NRE Stakeholders

Internal Stakeholders

EEI member company personnel

External Stakeholders

National media
National policymakers and elected officials
Federal Government partners
National organizations representing state officials (e.g., NCSL, NGA, NARUC, etc.)
Consumers

C. Overall NRE Communications Process

Prior to Event

Assuming there is advance notice of event, these activities will begin approximately 2-5 days before the beginning of the event. In the case of an event with no advance warning, these activities will commence as soon as an NRE is declared by the NREC (in this case, some Prior to Event actions will, by necessity, be combined with During Event actions).

Communication Need	Audience	EEI Action
Prepare the press, policymakers and elected officials, customers, and other stakeholders for a severe outage event. Focus on preparation and safety (for customers and crews), reinforce value of electricity, and the commitment of industry to restoring power safely and efficiently.	National Media Policymakers and Elected Officials Federal Government Partners Consumers	Distribute safety tips and restoration information and collaterals via social media channels and EEI web site. Online resources include: tips on how to prepare for power outages, an emergency outage kit, and safety tips for various types of outages scenarios including earthquakes, flash floods, hurricanes, tornadoes, wildfires, and winter storms. Additionally, EEI has resources information on cybersecurity available, as need.
Explain mutual assistance and power restoration process to the press, policymakers and elected officials, customers, and other stakeholders.	National Media Policymakers and Elected Officials Federal Government Partners Consumers	Distribute the background information on the industry mutual assistance program through the EEI web site, social media, and through media relations activities (see below).
Address undergrounding issues, as needed.	National Media Policymakers and Elected Officials Federal Government Partners	Provide the press, policymakers and elected officials, and other stakeholders with information on issues related to undergrounding including the EEI report, Out of Sight, Out of Mind 2012.
Update member companies with event information.	EEI Members	Recirculate EEI materials and lists of additional resources to EEI member companies. Provide member companies with pre-event talking points, template press releases, social media materials, and collaterals

		Provide EEI staff contact information to member companies. Set up daily "one voice" conference call with affected company communicators.
Conduct media relations outreach and education.	National Media	Provide pre-event briefings/updates and resources to the press explaining the how companies prepare for major outage events, the restoration process, and the industry's mutual assistance procedures. Make EEI leadership available to the press, as appropriate. Support company media relation efforts, as appropriate. Provide EEI staff contact information to press.
Activate EEI Storm Center.	Consumers EEI Members National Media Policymakers and Elected Officials Federal Government Partners	Replace EEI's home page with the EEI Storm Center/NRE Center. Visitors to www.eei.org will immediately see and have easy access to all of EEI storm/NRE resources.

Communication Need	Audience	EEI Action
Staff EEI Command Center.	EEI Members	Set up in-office and/or remote NRE/Storm command center. Deploy EEI staff and backups.
Provide industry-wide information on event to media and member companies.	National Media EEI Members Policymakers and Elected Officials Federal Government Partners	Develop and distribute event specific talking points with a focus on how mutual assistance works and the how the industry is meeting the event's challenges (daily by 11 AM or more frequently). Reinforce safety messages through social media and media relations. Promote EEI web site resources on preparation, emergency preparedness, mutual assistance and reliability.
Serve as information clearinghouse on event.	EEI Members Policymakers and Elected Officials Federal Government Partners	Collect and consolidate summary of outages and allocation process. Prepare external resource allocation summary report, including maps if appropriate, and key messages for external stakeholders and members. Monitor press and social media; distribute press clips and social media tracking report to member companies and external stakeholders; track company communication efforts and share lessons learned. Convene daily "one voice" conference call with member company communicators (7 PM).
Engage the public, the press, stakeholders including Federal agencies, groups representing state and local officials, Congress, Wall Street.	National Media EEI Members Policymakers and Elected Officials Federal Government Partners Consumers	Using social media and EEI web site provide national perspective on industry actions as well as updates, tips, safety messages. Develop and deliver an "opt-out" email summary of NRE process and key industry messages for external stakeholders. Conduct media relations activities, briefings, press releases, interviews, etc. as needed. Expand media outreach to the press in affected areas, if requested. Activate EEI liaisons for outreach to Federal agencies and other external stakeholders
Provide communication support to National Response Executive Committee	EEI Members National Media Policymakers and Elected Officials Federal	Serve as industry's communication lead upon declaration of NRE. Prepare and distribute external messages on mutual assistance allocation to press, stakeholders (including groups representing state and local officials, Congress, DOE, FERC, DHS, White House, DOT, Wall Street).

	Government Partners	

Post Event

Communication Need		**EEI Action**
Provide after action information.	National Media Policymakers and Elected Officials Federal Government Partners	Reinforce post-outage safety messages through web site and social media. Reinforce messages on how restoration process works, lessons learned to the press. Distribute information on industry system hardening and resiliency measures, as appropriate. Conduct post-event press briefing, as appropriate.
Report on final cumulative outage and response information.	EEI Members	Provide members with final outage matrix, put into historical context, if necessary.
Support members for post event regulatory hearings/proceedings.	EEI Members Policymakers and Elected Officials	Develop materials/talking points to help companies, as requested by companies.
Provide public/media relations support for members.	National Media (local if requested) EEI Members Consumers	Provide media relations support (op-eds, letters to the editor, local/regional media outreach, etc.) in support of individual companies, as requested by companies. Capture and compile human interest, success stories, social media, press clips to share with members and external stakeholders. Conduct post-event quantitative and qualitative public opinion research, if requested by member companies. Run "thank you" advertising, as appropriate, to highlight the extent of the restoration effort, the role of mutual assistance, and the overall value of electricity, if requested by companies.

D. NRE Key Message Development and Approval Process

"Canned" messages for the NRE are listed below. The approval process for external messaging/press releases that contain NRE-specific message will follow the procedure below. EEI's standard message approval process will apply to communications that do not specifically address the NRE or NREC actions. Draft media documents are vetted by the EEI Crisis Support Team's Communications Lead.

1. Drafts are sent to subject-matter expert from legislative/policy/legal/operations as appropriate
2. Drafts are vetted by NREC Chair
3. Drafts are reviewed by EEI Crisis Support Team's Communications Officer, Legal Officer, and Operations Officer.
4. Materials are sent to EEI's Crisis Support Team's Management Officer for final approval.

E. Checklists and Templates

Member company contacts are stored in Netforum in the "Senior Communication Executives" list. This list will be used for communicating directly with companies during an NRE.

Attached Checklists and Templates (see Appendix I)
Checklist: How to Activate the Storm Center
Checklist: Reporter's List Guide
Template: Be Prepared, Be Safe Generic Preparedness Message
Template: News Clips and Social Media Summary (Sample from Sandy – not included, see Workroom)
Template: NRE Industry Communicators Conf. Call Agenda
Template: NRE Talking Points-During-Event
Template: NRE Talking Points-Pre-Event
Template: Opt In Email Request for External Stakeholders
Template: Outage Matrix
Template: Outage Overview
Template: Press Release NRE Activated
Template: Press Release Pre-Storm
Template: Press-Media Advisory NRE Press Call
Template: Scheduled Tweets

F. Canned Messages

Why has the industry not moved to a national response for this event?

The investor-owned electric utility industry defines a National Response Event (NRE) as a natural or man-made event that is forecast to cause or that causes widespread power outages impacting a significant population or several regions across the U.S. and requires resources from multiple Regional Mutual Assistance Groups (RMAGs). It's important to understand an NRE designation is reserved only for the most significant events, such as a major storm, earthquake, an act of war, or other occurrence that results in widespread power outages.

Based on [weather forecasts/projections], this event does not appear to warrant a national response at this time. However, the industry's regionally based mutual assistance program [is/will be activated] to support companies in [region] that need restoration resources. The industry and individual companies continue to closely monitor this event, and thanks to enhancements made after Superstorm Sandy, we can quickly scale the restoration effort to a national level if necessary.

[Northeast specific if appropriate] In September 2013, the Mid-Atlantic Mutual Assistance (MAMA), New York Mutual Assistance Group (NYMAG), and the Northeast Mutual Assistance Group (NEMAG) finalized their merger into the North Atlantic Mutual Assistance Group (NAMA)—reducing the total number of RMAGs from nine to seven. This merger included 21 utilities across 13 states, 1 district, and 4 Canadian provinces. Merging these three smaller RMAGs into one larger RMAG allows more resources to be available to the participating utilities and increases the ability of the RMAG to provide more self-sustaining support for most local and regional outage events without having to reach out and coordinate across multiple RMAGs.

Why does the industry not pre-deploy all resources based on a forecast?

Restoring power after a major incident is a complex task that must be completed as safely and efficiently as possible. A speedy restoration process requires significant logistical expertise, along with skilled workers and specialized equipment. Electric utilities begin their preparation for weather-related events long before an event actually occurs, with organization-wide plans and drills that involve virtually all employees. When a major storm or natural disaster is expected, electric utilities begin their standard preparations to organize restoration workers, trucks, and equipment. Mutual assistance is an essential part of the electric utility industry's service restoration process and contingency planning. Electric utilities impacted by a major outage event are able to increase the size of their workforce by "borrowing" restoration workers from other utilities through the mutual assistance program.

An important part of these preparations is balancing the pre-deployment of resources with factors such as the weather forecast, damage potential, travel conditions, resource availability, and actual requests for assistance by utility companies. Individual companies have detailed restoration plans that address how they will restore service after major outages [direct to individual companies for specifics] that take into account the resources they have on hand, the potential threat, and the need for additional resources through the mutual assistance program. Because storms/events cannot be perfectly forecast, it isn't prudent to call up <u>all</u> resources far in advance of an event. However, our regionally based mutual assistance program [is/will be activated if conditions warrant] to provide restoration support to utilities, and thanks to enhancements made after Superstorm Sandy, we can quickly scale the restoration effort to a national level if necessary.

<u>Additional Reasons:</u>

- Early pre-deployment could cause resources to be misdirected if the event forecast changes/event isn't as serious as forecast

- Significant expenses may be incurred if resources are not needed (travel, lodging, logistics)
- Resources [Depending on the event/storm track] may be needed in other areas first. Because companies have a duty to restore their "native" customers first, it is not possible to move resources until the event/storm track is clearer.
- [Northeast specific] In September 2013, the Mid-Atlantic Mutual Assistance (MAMA), New York Mutual Assistance Group (NYMAG), and the Northeast Mutual Assistance Group (NEMAG) finalized their merger into the North Atlantic Mutual Assistance Group (NAMA)—reducing the total number of RMAGs from nine to seven. This merger included 21 utilities across 13 states, 1 district, and 4 Canadian provinces. Merging these three smaller RMAGs into one larger RMAG allows more resources to be available to the participating utilities and increases the ability of the RMAG to provide more self-sustaining support for most local and regional outage events without having to reach out and coordinate across multiple RMAGs.

How are union issues being addressed? Are non-union crews being turned away?

[Local facts if known] In the case of significant outage events, electric utilities request and accept assistance from any and all qualified workers. The reports of non-union crews being turned away during Sandy were found to be untrue. Utilities in the affected areas and union representatives welcomed assistance regardless of their union status. [Redirect to companies and union representatives if necessary.]

Issues with Crossing State Lines/Crews Being Blocked from Moving

A timely restoration effort requires a smooth transition of resources from other regions into the affected area, regardless of the state boundary. Utility service territories often extend beyond state boundaries and restoration work often involves multiple jurisdictions. Having flexibility to move resources to the outage location is the key to successfully completing a restoration. The electric utility industry's mutual assistance program ensures that all available emergency restoration resources (including contractors) will be pooled and allocated to participating utilities in a safe and efficient manner.

The industry's national response to [event] is successfully coordinating [Number] response workers from [# Companies/States/Region/Nationally] to assist throughout the affected areas. These workers are [arriving/on the road], and limiting utilities' ability to move restoration resources in the most efficient manner undermines this process. The total workforce, including workers from affected companies and those providing mutual assistance, is [Number].

Workforce Issues: Will the enhancements made to the industry's mutual assistance program get more workers to the outage in [AREA]?

The investor-owned electric utility industry's mutual assistance program now has the ability to coordinate the allocation of restoration workers on a regional and national scale, but it does not create a larger overall pool of qualified restoration workers. The industry is working on workforce development through the Center for Energy Workforce Development and with programs like Troops to Energy Jobs, but these efforts are designed to bring new workers into the industry over time.

The industry's response to [event] is successfully coordinating [Number] response workers from [# Companies/States/Region/Nationally] to assist throughout the affected areas. These workers are [arriving in the region/on the road/already at work]. The total workforce, including workers from affected companies and those providing mutual assistance, is [Number].

Hardening and Restoration: Will the enhancements made to the industry's mutual assistance program make the system stronger/prevent outages?

The electric utility industry's mutual assistance program is not designed to directly address infrastructure needs. These decisions are made by utilities and regulatory bodies that determine the most cost-effective measures to strengthen the grid and make it more resilient.

Will the enhancements to the mutual assistance program make the lights come on faster?

Due to the inherently unpredictable nature of disasters, the mutual assistance program cannot reduce the damage that may occur from severe outage events. Enhancements made to the process do scale up the industry's mutual assistance program to address national level outages and ensure that mutual assistance is safe and efficient.

Would undergrounding prevent outages?

The mutual assistance program is not designed to directly address infrastructure needs. However it is important to remember that some measures of reliability indicate that underground electric infrastructure has only a slightly better reliability performance than overhead electric systems, while other measures show a higher reliability factor for underground facilities. One explanation may be that many underground facilities are fed by overhead facilities that can become disabled during storms.

Repairs to underground facility outages are often more complex and time consuming, and such facilities are more costly to upgrade and replace. And, as recent experiences with Superstorm Sandy demonstrate, underground facilities are very vulnerable to flooding and water damage. Undergrounding also brings significant costs. Industry data show that costs for underground transmission and distribution construction costs can be between five to 10 times greater than for overhead.

Mutual Assistance Program Overview

The Edison Electric Institute's mutual assistance program is a voluntary partnership of investor-owned electric utilities across the country committed to helping restore power whenever and wherever assistance is needed. Created decades ago, the mutual assistance program provides a formal, yet flexible, process for utilities to request support from other utilities in parts of the country that have not been affected by major outage events. Municipal utilities and electric cooperatives also have their own mutual aid programs that provide restoration support to their participating utilities.

Mutual assistance is an essential part of the electric utility industry's service restoration process and contingency planning. Electric utilities impacted by a major outage event are able to increase the size of their workforce by "borrowing" restoration workers from other utilities. When called upon, a utility will send skilled restoration workers—both utility employees and contractors—along with specialized equipment to help with the restoration efforts of a fellow utility.

Partnerships in the mutual assistance program are based upon voluntary agreements among electric utilities within the same region. Most of these agreements are managed by seven Regional Mutual Assistance Groups (RMAGs) throughout the country. When a participating utility determines that it needs restoration assistance, it initiates a request through an RMAG. (Utilities in the western states coordinate responses directly with each other, rather than through an RMAG.)

RMAGs facilitate the process of identifying available restoration workers and help utilities coordinate the logistics and personnel involved in restoration efforts. For example, RMAGs can help utilities locate specialized skill sets, equipment, or materials, and can assist in identifying other types of resources that may be needed, including line workers, tree trimmers, damage assessors, and even call center support.

What enhancements were made to the mutual assistance program following Superstorm Sandy?

The investor-owned electric utility industry has developed a new framework to institutionalize the lessons learned and best practices from Sandy in order to optimize restoration efforts following events that impact a significant population or several regions across the U.S. and require resources from multiple Regional Mutual Assistance Groups (RMAGs). In the case of significant outage events, where an industry-wide response is needed, all available industry emergency restoration resources (including contractors) will be pooled and allocated to participating utilities to safely and efficiently meet restoration needs.

A committee of senior-level member company utility executives from all regions of the country governs this allocation process, with members drawn from utilities in each of the seven RMAGs. RMAGs will continue to facilitate the process of identifying available restoration workers and help utilities coordinate the logistics and personnel involved in restoration efforts.

One of the important lessons learned following Superstorm Sandy was that there were too many small RMAGs in the Northeast. In September 2013, the Mid-Atlantic Mutual Assistance (MAMA), New York Mutual Assistance Group (NYMAG), and the Northeast Mutual Assistance Group (NEMAG) finalized their merger into the North Atlantic Mutual Assistance Group (NAMA)—reducing the total number of RMAGs from nine to seven.

This merger included 21 utilities across 13 states, 1 district, and 4 Canadian provinces. Merging these three smaller RMAGs into one larger RMAG allows more resources to be available to the participating utilities and increase the ability of the RMAG to provide more self-sustaining support for most local and regional outage events without having to reach out and coordinate across multiple RMAGs.

The electric utility industry continues to collaborate and work with the federal government and the states to enhance and formalize industry-government partnerships developed during Superstorm Sandy. These efforts include:

- Improving communication and coordination by embedding senior industry officials with government response teams at the U.S. Department of Energy and coordinating with the Federal Emergency Management Agency.
- Streamlining transportation by developing information resources and tools to expedite the movement of resources across state lines in partnership with the U.S. Department of Transportation and state transportation agencies. Additionally, we have negotiated a new procedure for U.S. and Canadian border crossings with the Department of Homeland Security and the Canadian Border Services Agency to minimize delays and to ensure timely movement of mutual assistance crews across the international border.
- Engaging in an ongoing dialogue with the Department of Defense (DOD) to enhance logistical support, such as access to DOD property and facilities for pre-staging areas, exploring ways to enhance security and road access with the National Guard, and securing access to critical supplies and equipment from the Army Corps of Engineers.

How is the National Response Event Framework is Different from the Current Mutual Assistance Program?

The current mutual assistance program works well for regional events, but was not designed to be scalable for national events. After Superstorm Sandy, a storm of unprecedented size and scope, the investor-owned electric utility industry enhanced its mutual assistance program to improve how it responds to a natural or man-made event that is forecast to cause or that causes widespread power outages impacting a significant population or several regions across the U.S. and that requires resources from multiple RMAGs.

To meet the challenges of these major national events, a new National Response Event (NRE) framework was developed. When an NRE is activated, the investor-owned electric utility industry's mutual assistance efforts will be scaled to the national level and coordinated so industry restoration resources are allocated in a singular and seamless fashion.

All available emergency restoration resources (including contractors) will be pooled and allocated to participating utilities in a safe, efficient, and equitable manner. This process is overseen by a new National Response Executive Committee (NREC) comprised of senior-level member utility executives from all regions of the country.

During an NRE, the NREC will activate a National Mutual Assistance Resource Team (NMART) that will evaluate mutual assistance requests and assign available resources to affected utilities in coordination with the RMAGs. The Edison Electric Institute (EEI) will serve as the industry liaison to EEI member company CEOs, senior government officials, and federal and state regulatory agencies. EEI will also serve as the investor-owned electric utility industry's primary national information resource providing a broad, national perspective on the event.

The NRE framework allows EEI member utilities to efficiently coordinate and scale their restoration resources to create an industry-wide national response effort while retaining the current, successful, and geographically based RMAG mutual assistance process for events that do not require a national response.

Specifically how does the mutual assistance program allocate response resources during a National Response Event?

The national allocation of response resources uses a formula that takes into account the proportion of customer outages and the proportion of trouble spots relative to all requesting utilities. Additional qualitative refinements to the allocation may also be made based on geography, travel routes, type of damage, and other factors that can affect restoration. After the allocation, resource matching to individual utilities is conducted through the Regional Mutual Assistance Groups (RMAGs) based on local requirement. Reallocation of resources is also built into the process so restoration workers and equipment can be effectively redeployed throughout an event. The process is designed to make an efficient and equitable allocation based on need.

What are the specific numbers?

[EEI will release national numbers based on publicly available information and information from the NREC/NMART.]

Appendix A: Conference Call Agendas

Initial NRE Conference Call

The initial NRE call will take place within 2 hours of the NRE activation and will be initiated by the NREC Chair or in his/her absence by the Vice Chair or the Second Vice Chair.

Initial NRE Conference Call Participants

The participants in the initial call will include at the minimum the individuals (or their designees) serving the following NRE roles:

- NREC Chair
- NREC Vice Chair
- NMART Co-Chairs
- EEI NRE Operations Officer, Operations Liaison, Communications Liaison

NREC Chair may invite other members of the NREC. The names and contact information for each of the roles is provided in the Appendix B of this playbook.

Initial NRE Conference Call Agenda

Agenda Item	Responsible
1. Roll call	NREC Chair
2. Review the reason for NRE activation and background	NREC Chair
3. Provide status of mutual assistance activity ▪ Weather forecast ▪ Currently activated RMAGs ▪ Status of existing mutual assistance requests and any allocations that have been made within the RMAGs ▪ Cross-RMAG calls and assignments prior to NRE ▪ Contractor engagement	NREC Chair
4. Set the roster for NRE support in this event ▪ Determine availability of the key NRE team members to support this event ▪ Set the roster for the NRE support based on availability ▪ Agree on the date, roles and location (should be EEI HQ unless it is not accessible) for NRE co-location	NMART Co-Chairs
4. Update the team on the EEI activity ▪ Discuss any CEO calls that may have already taken place ▪ Understand the overall communication strategy key EEI messages related to the event	EEI Operations Officer, Operations Liaison, Communications Liaison
5. Set the objectives for the next 24 hours (until the next call) ▪ Set the specific timeline for the initial allocation ▪ Agree on the daily NRE conference call schedule	NREC Chair

Agenda Item	Responsible
▪ NRE communication objectives	
6. Discuss any unique issues (Chair's discretion) ▪ Significant safety issues (public and restoration worker) ▪ Peer Emergency Management community issues ▪ Media issues	NREC Chair
7. Summarize the next steps and schedule the next call	Chair

Initial NRE Conference Call Documentation

The NREC Chair will designate someone on the call to capture the notes from the conference call.

Daily NRE Conference Call

The timing of the daily NRE conference call will be determined in the initial call and can be adjusted as necessary by the NREC Chair. The objective of this call is to discuss any potential issues related to resource allocation in preparation for the CEO conference calls. Typically, these calls will take place right before CEO calls, which start at 3:30pm every day.

Daily NRE Conference Call Participants

The participants in the initial call will include at the minimum the individuals (or their designees) serving the following NRE roles:

- NREC Chair
- NREC Vice Chair
- NREC Members
- NMART Co-Chairs
- EEI NRE Liaison

Names and contact information for each of these roles is provided in the Appendix B of this playbook.

Daily NRE Conference Call Agenda

Agenda Item	Responsible
1. Roll call	NREC Chair
2. Provide an outage status and weather forecast update ▪ Number of outages that the participating companies have reported and restoration progress ▪ Weather forecast (short term – 1-2 days and long term – week)	NMART Co-Chairs
3. Review the current period allocations ▪ Review the allocation dashboard ▪ Discuss any outstanding requests ▪ Highlight any refinements/adjustments to initial allocations ▪ Pending releases of resources ▪ Contractor engagement	NREC Chair
4. Discuss any unique issues (Chair's discretion) ▪ Significant safety issues (public and restoration worker) ▪ Peer Emergency Management community issues	NREC Chair

Agenda Item	Responsible
▪ Media issues	
5. Prepare key talking points for the CEO calls ▪ Confirm key statistics	NMART Co-Chairs
6. Set the objectives for the next 24 hours (until the next call)	NREC Chair
7. Summarize the next steps	NREC Chair

Daily NRE Conference Call Documentation

The NREC Chair will designate someone on the call to capture the notes from the conference call.

PRE—ACTIVATION CALL

EEI CEO NREC PCRBC Call #0

3:30pm Eastern
(Impacted CEOs, PCRBC and NRE Chair (no government officials))
1-412-317-6060 (Ask for the EEI NRE call)

Call Purpose

- Gather information and input from CEOs from within the impacted areas
- Provide CEOs update on the NRE allocation process and share information communicated to or through the NREC
- Identify areas for potential federal government coordination or support

Agenda

1. Introduction & Roll Call (Tom Kuhn, or designee)
2. NREC Report (NREC Chair, or designee)
    a. Safety Message
    b. Weather Report
3. Requesting CEO(s) provide reason for NRE request
4. NREC Chair reviews criteria for NRE
5. RBC Co-Chairs provide counsel
6. Discussion and Decision
    a. Will NRE be triggered?
    b. Where will core team meet
7. Adjourn

EEI CEO NRE Call #1

3:30pm Eastern
(Impacted CEOs and NRE Team (no government officials))
1-412-317-6060 (Ask for the EEI NRE call)

Call Purpose

- Gather information and input from CEOs from within the impacted areas
- Provide CEOs update on the NRE allocation process and share information communicated to or through the NREC
- Identify areas for potential federal government coordination or support

Agenda

8. Introduction & Roll Call (Tom Kuhn, or designee)
9. NREC Report (NREC Chair, or designee)
   a. Safety Message
   b. Weather Report
10. CEO Input
11. Impacted Company CEOs, or designees
12. Areas of Needed Government Coordination
13. Adjourn

EEI CEO NRE Call #2

4:30pm Eastern
(All CEOs and NRE Team (no government officials))
412-717-9582 (Ask for the EEI NRE call)

Call Purpose

- Gather additional information and input from CEOs not operating within the impacted areas
- Provide all CEOs update on the NRE allocation process and share information communicated to or through the NREC
- Identify areas for potential federal government coordination or support

Agenda

14. Introduction & Roll Call (Tom Kuhn, or designee)
15. NREC Report (NREC Chair, or designee)
    a. Safety Message
    b. Weather Report
16. CEO Input
17. Impacted Company CEOs, or designee
18. Other CEOs, or designees
19. Areas of Needed Government Coordination
20. Adjourn

EEI CEO NRE Call #3

5:15pm Eastern
(All CEOs, NRE Team, Federal Government Officials)
412-717-9582 (Ask for the EEI NRE call)

Call Purpose

- Provide federal government partners information from within the impacted areas
- Provide federal government partners an update on the NRE allocation process and share information communicated to or through the NREC
- Discuss identified areas for potential federal government coordination or support

Agenda

1. Introduction & Roll Call (Tom Kuhn, or designee)
2. Federal Government Opening Remarks (Government / DOE Leadership)
3. NREC Report (NREC Chair, or designee)
    a. Safety Message
    b. Weather Report
4. CEO Input (CEOs, or designees)
5. Industry / Federal Government Discussion on Areas of Needed Government Coordination
6. Adjourn

NMART Call Agenda

In order to ensure efficiency of the discussion during the NMART call, the following standing agenda will be used.

NMART Conference Call Agenda

Agenda Item	Responsible
1. Roll call	NMART Co-Chair
2. Confirm in-person participation and location – If either the chair or vice chair do not have the capacity, for any reason, to organize the event and travel to Washington (or another designated location, appoint designees who will serve in those roles for this event	NMART Co-Chair
3. Weather report/system status (if needed)	NMART Vice Chair
4. Review NRE Template (if not available or incomplete instruct the team to gather the information) ▪ Review template for mistakes, omissions, or inconsistencies, including all requested and available resources – Verify that all requests have been reported through the home RMAG ▪ Utilize the allocation model to determine the formulaic allocation ▪ Refine the allocations based on other factors and capture the discussion around any adjustments to the initial allocations	NMART Co-Chair
5. Discuss non-line or line clearance (tree trimming) resource requests	NMART Co-Chair
6. Discuss any unique issues (Chair's discretion) – Significant safety issues (public and restoration worker) – Peer Emergency Management community issues – Media issues	NMART Co-Chair
7. Schedule the next call	NMART Co-Chair

Post NMART Conference Call Documentation

After each conference call, NMART members will capture the key decisions and outstanding items. The level of documentation will provide enough specificity to allow for after-action review and lessons learned effort. Following are two key activities:

1. Prepare Call Documentation (Secretary)
   - Completed allocation template
     - Resources already secured
     - Total resources requested
     - Total resources available
     - All other allocation criteria
     - Allocation (by utility)
   - Criteria used for Allocation
   - Outstanding issues
   - Next call time and date

2. Disseminate the documentation (Secretary)
   - All NMART team members (for distribution to all RMAG Executive Committee members)
   - EEI Liaison
   - NREC Chair

Appendix B: Membership and Contact Lists

- National Response Executive Committee (NREC)
- National Mutual Assistance Resource Allocation Tool (NMART)
- “Home” RMAG List

Edison Electric Institute
Power by Association

National Response Executive Committee (NREC)

CHAIR	Tom Kirkpatrick [redacted]
1st Vice-Chair	Bill Quinlan [redacted]
2nd Vice-Chair	Keith Hull [redacted]
EEI STAFF	Paul Frey [redacted]
	Gail Royster [redacted]

GREAT LAKES MUTUAL ASSISTANCE GROUP (GLMAG) – GREAT LAKES MA
PRIMARY – Tom Kirkpatrick [redacted]
1st Alternate – Steve Strah [redacted]
2nd Alternate – Daniel Malone [redacted]

MIDWEST MUTUAL ASSISTANCE GROUP (MMAG) – MIDWEST MA
PRIMARY – Melody Birmingham-Byrd [redacted]
1st Alternate – James Conway [redacted]
2nd Alternate – Bruce Akin [redacted]

NORTH ATLANTIC MUTUAL ASSISTANCE GROUP (NAMAG) – NORTH ATLANTIC MA
PRIMARY – Bill Quinlan [redacted]
1st Alternate – Dave Bonenberger [redacted]
2nd Alternate – John Donleavy [redacted]

SOUTHEASTERN ELECTRIC EXCHANGE (SEE) – SOUTHEASTERN ELECTRIC EXCHANGE
PRIMARY – Manny Miranda [redacted]
1st Alternate – Greg Grillo [redacted]
2nd Alternate – Danny Glover [redacted]

TEXAS MUTUAL ASSISTANCE GROUP (TXMAG) – TEXAS MA
PRIMARY – Keith Hull [redacted]
1st Alternate – David Baker [redacted]
2nd Alternate – Mike Mathews [redacted]

WESTERN REGION MUTUAL ASSISTANCE GROUP (WRMAG) – WESTERN REGION MA
PRIMARY – Barry Anderson [redacted]
1st Alternate – Doug Butler [redacted]
2nd Alternate – Dana Kracke [redacted]

WISCONSIN UTILITIES ASSOCIATION MUTUAL ASSISTANCE GROUP (WUA) – WISCONSIN UTILITIES ASSOC.
PRIMARY – Vern Gebhart [redacted]

AT-LARGE
PRIMARY – Carlos Torres [redacted]
PRIMARY – Mike Sullivan [redacted]

August 2014

1. At the time an NRE is declared, please make yourself available for the Chair and Vice Chair.
2. Please ensure the companies you represent in the NRE process understand the gravity of the situation and are responding appropriately.
3. Maintain communications with your CEO and others within your company keeping them aware of the situation, and providing any updates that would be beneficial.
4. Provide updates as needed to those companies you represent through your NRE team.
5. Provide feedback if there are process issues or third party concerns to the Chair and Vice Chair.
6. Support the NRE process with those whom may question as we work through the event.
7. If questions arise, please work through the NREC group to develop responses if unknown.
8. Support your peers who are battling the event.
9. Support the NMART and EEI Communication teams and their processes.
10. Remember to be engaged, you could be the one in the barrel the next time.

National Mutual Assistance Resource Team (NMART)

Executive Committee 2014

CO-CHAIRS Aaron Strickland [redacted]
VICE-CHAIR Rachel Sherrill [redacted]
SECRETARY Marty Wright [redacted]
SECRETARY IN WAITING Mike Zappone [redacted]
EEI STAFF Gail Royster [redacted]
Paul Frey [redacted]

Great Lakes Mutual Assistance Group (GLMAG) – Great Lakes MA
PRIMARY – Marty Zearbaugh [redacted]
SECONDARY – Brian Gatewo[redacted]

Midwest Mutual Assistance Group (MMAG) – Midwest MA
PRIMARY – Bryan Nowlin [redacted]
SECONDARY – Carol Baxter [redacted]

North Atlantic Mutual Assistance Group (NAMAG) – -North Atlantic MA
PRIMARY – Chuck Anna [redacted]
SECONDARY – Tom Murphy [redacted]

Southeastern Electric Exchange (SEE) – Southeastern Electric Exchange
AT LARGE – Jim Collins [redacted]
AT LARGE – Scott Smit[redacted]
PRIMARY – Michael Fricke [redacted]
SECONDARY – "Vacant"

Texas Mutual Assistance Group (TXMAG) – Texas MA
PRIMARY – Mike Carter [redacted]
SECONDARY – Jeffrey Dossey [redacted]

Western Region Mutual Assistance Group (WRMAG) – Western Region MA
PRIMARY – Don Daigler [redacted]
SECONDARY – Gary Nieborsky [redacted]

Wisconsin Utilities Association Mutual Assistance Group (WUAG) – Wisconsin Utilities Assoc.
PRIMARY – Don LuMaye [redacted]
SECONDARY – John Nesbitt [redacted]

August 2014

EEI T&D Officers with Operations Responsibilities

Kuhn, Thomas R.	President
Owens, David K.	Executive Vice President, Business Operations
Wolff, Brian L.	Executive Vice President, Public Policy & External Affairs
Comer, Edward H.	Vice President, General Counsel
Easton, John J.	Vice President, International Programs
Fama, James P.	Vice President, Energy Delivery
McCormack, Brian V.	Vice President, Political and External Affairs
McMahon, Jr., Richard F.	Vice President, Energy Supply and Finance
Miller, Mary D.	Chief Administrative Officer
Owens, Jim	Executive Director, Member Relations and Meeting Services
Schlenker, John S.	Chief Financial Officer and Treasurer
Shea, III, Quinlan J.	Vice President, Environment
Steckelberg, Kathryn A.	Vice President, Government Relations
Tempchin, Richard S.	Executive Director, Retail Energy Services

EEI Energy Delivery Group

NAME	TITLE	WORK	WORK CELL
Batz, Dave	Director, Cyber Security	[redacted]	[redacted]
Dworzak, David	Director, Reliability	[redacted]	[redacted]
Eisenbrey, Chris	Director, Business Continuity	[redacted]	[redacted]
Fama, Jim	Vice President	[redacted]	[redacted]
Franklin, Tawanna	Administrative Assistant	[redacted]	[redacted]
Frey, Paul	Manager, Distribution Operations	[redacted]	[redacted]
Gray, Mark	Manager, Transmission Operations	[redacted]	[redacted]
Hart, Jennifer	Administrative Assistant	[redacted]	[redacted]
Hatch, Maryann	Manager, Regulatory	[redacted]	[redacted]
Ingram, Tony	Sr. Director, Transmission Policy	[redacted]	[redacted]
Mastin, Judy	Manager, Operations	[redacted]	[redacted]
Onaran, Karen	Manager, Regulatory	[redacted]	[redacted]
Royster, Gail	Manager, Business Continuity	[redacted]	[redacted]
Seader, Melanie,	Senior Cyber and Infrastructure Security Analyst	[redacted]	[redacted]
Stone, Lauren	Administrative Assistant	[redacted]	[redacted]

Communications

NAME	TITLE	WORK	WORK CELL
Mealiea, Wally	Manager, Customer Research & Advertising	[redacted]	[redacted]
Ostermayer, Jeff	Manager, Media Relations	[redacted]	[redacted]
Voyda, Stephanie	Director, Communications	[redacted]	[redacted]
Ward, Richard	Manager, Communications	[redacted]	[redacted]
Wolff, Brian	Executive Vice President, Public Policy & External Affairs	[redacted]	[redacted]

Edison Electric Institute
Power By Association

CEO Policy Committee on Reliability and Business Continuity
August 2014

Rigby, Joe (co-chair)	Pepco Holdings, Inc.
Spence, William (co-chair)	PPL Corp.
Torgerson, Jim (co-chair)	UIL Holdings Corp.
Blue, Bob	Dominion
Borkowski, Maureen	Ameren Services
Bridge, Tracy	CenterPoint Energy
Crane, Christopher	Exelon Corp.
Donleavy, John	National Grid
Fehrman, William	MidAmerican
Fowke III, Benjamin	Xcel Energy
Greene, Kim	Southern Company
Greer, Jim	Oncor
Harris, Kimberly	Puget Sound Energy
Hutchens, David	UniSource
Jones, Charles	FirstEnergy
Kampling, Patricia	Alliant Energy
Koonce, Paul	Dominion
Lau, Constance	Hawaiian Electric Industries Inc.
Litzinger, Ron	Southern California Edison
McAvoy, John	Consolidated Edison
Morris, Scott	Avista Corp.
Olivier, Leon	Northeast Utilities
Piro, James	Portland General Electric
Powers, Bob	AEP
Procario, John	American Transmission Company
Ramil, John	TECO Energy
Riazzi, Richard	Duquesne Light
Ruelle, Mark	Westar Energy
Schiavoni, Mark	Arizona Public Service
Schrock, Charles	Integrys
Silagy, Eric	Florida Power & Light
Stanley, Jim	NIPSCO
Vincent-Collawn, Pat	PNM Resources
Walker, Kevin	Iberdrola USA
Welch, Joseph	ITC Holdings Corp.
West, Rod	Entergy
Williams, Geisha	Pacific Gas & Electric
Yates, Lloyd	Duke Energy

Home RMAG List

	Great Lakes MAG
SEE	American Electric Power
GLMAG	Consumer's Energy
GLMAG	Dayton Power & Light (an AES company)
GLMAG	DTE Energy
GLMAG	Duke Energy - Midwest
NAMAG	Duquesne Light Co.
GLMAG	LG&E/KU (a PPL, Inc. company)
GLMAG	ComEd (an Exelon company)
GLMAG	FE Cleveland Electric Illuminating Co.
GLMAG	FE Ohio Edison Company
GLMAG	FE The Toledo Edison Company
GLMAG	Indianapolis Power & Light
GLMAG	International Transmission Co.
GLMAG	Northern Indiana Public Service Co.
GLMAG	Vectren Energy
GLMAG	We Energies

	Midwest MAG
MMAG	Allete/Minnesota Power
MMAG	Alliant Energy - IPL
MMAG	Alliant Energy - WPL
MMAG	Ameren - Illinois
MMAG	Ameren - Missouri
SEE	American Electric Power
MMAG	American Transmission Co.
MMAG	Black Hills Energy
SEE	CenterPoint Energy
GLMAG	Duke Energy - Midwest
GLMAG	Commonwealth Edison (an Exelon Company)
MMAG	Empire District
SEE	Entergy
GLMAG	Indianapolis Power & Light
GLMAG	International Transmission Co.
MMAG	Kansas City Power & Light
GLMAG	LG&E / KU Energy (a PPL, Inc. Company)
MMAG	Madison Gas & Electric
MMAG	MidAmerican Energy
MMAG	Midwest Energy
MMAG	Nebraska Public Power
GLMAG	Northern Indiana PSC
MMAG	Northwestern PSC
SEE	Oklahoma Gas & Elec.
MMAG	Omaha Public Power
SEE	Oncor Electric Delivery
MMAG	Otter Tail Power
TXMAG	Texas New Mexico Power
GLMAG	Vectren Energy
GLMAG	WE Energy
MMAG	Westar Energy
MMAG	Wisconsin Public Service
MMAG	XCEL Energy - Minnesota
MMAG	XCEL Energy - Colorado
MMAG	XCEL Energy - Southwestern Public Service

	North Atlantic MAG
NAMAG	Central Hudson Gas & Electric
NAMAG	Con Ed (incl. Orange & Rockland)
NAMAG	Duquesne Light
NAMAG	Emera - (Bangor Hydro, Nova Scotia Power *)
SEE	Baltimore Gas & Electric Co. (an Exelon Company)
NAMAG	PECO Energy Company (an Exelon Company)

	North Atlantic MAG (cont'd)
NAMAG	FE Metropolitan Edison Company
NAMAG	FE Pennsylvania Electric Company
NAMAG	FE Pennsylvania Power Company
NAMAG	FE West Penn Power Company
NAMAG	Green Mountain Power
NAMAG	Hydro-One *
NAMAG	Hydro Quebec *
NAMAG	Iberdrola - (Central Maine Power, NYSEG)
NAMAG	Liberty Utilities
NAMAG	National Grid (NY, NE)
NAMAG	New Brunswick Power (Energie NB Power) *
NAMAG	New Hampshire Electric Cooperative
NAMAG	Northeast Utilities
SEE	Pepco Holdings, Inc. (PHI)
NAMAG	PPL Electric Utilities
NAMAG	Public Service Electric & Gas (PSE&G)
NAMAG	South Norwalk Electric & Water
NAMAG	UGI Utilities, Inc
NAMAG	United Illuminating
NAMAG	Unitil Corp

	Southeastern Electric Exchange
SEE	AEP Texas
SEE	AEP Appalachian Power Co.
SEE	AEP Indiana Michigan Power Co.
SEE	AEP Kentucky Power Co.
SEE	AEP Ohio Power Company
SEE	AEP Public Service of Oklahoma
SEE	AEP SW Electric Power Company
SEE	Baltimore Gas & Electric Co. (an Exelon Company)
SEE	CenterPoint Energy
SEE	Cleco
GLMAG	Commonwealth Edison (an Exelon Company)
GLMAG	Dayton Power & Light
SEE	Dominion
SEE	Duke Energy - Carolina
SEE	Duke Energy - Florida
GLMAG	Duke Energy - Midwest
SEE	Entergy Arkansas
SEE	Entergy Louisiana
SEE	Entergy Mississippi
SEE	Entergy Texas
NAMAG	FE Cleveland Electric Illuminating Co.
SEE	FE Jersey Central Power & Light Co.
NAMAG	FE Metropolitan Edison Company
SEE	FE Monongahela Power Company
NAMAG	FE Ohio Edison Company
NAMAG	FE Pennsylvania Electric Company
NAMAG	FE Pennsylvania Power Company
SEE	FE The Potomac Edison Company
NAMAG	FE The Toledo Edison Company
NAMAG	FE West Penn Power Company
SEE	Florida Power & Light Co.
SEE	Florida Public Utilities Company
GLMAG	LG&E / KU Energy (a PPL, Inc. Company)
SEE	Oklahoma Gas & Electric Co.
SEE	Oncor Electric Delivery
NAMAG	PECO Energy Company (an Exelon Company)
SEE	PHI Atlantic City Electric
SEE	PHI Delmarva Power & Light
SEE	PHI Potomac Electric Power Co.
NAMAG	PPL Electric Utilities
SEE	South Carolina Elec. & Gas Co.
SEE	SoCo Alabama Power Company

	Southeastern Electric Ex (cont'd)
SEE	SoCo Georgia Power Company
SEE	SoCo Gulf Power Company
SEE	SoCo Mississippi Power Company
SEE	Tampa Electric Co.
SEE	Texas - New Mexico Power

	Texas MAG
SEE	American Electric Power
TXMAG	Austin Energy
TXMAG	Brownsville Public Utilities
TXMAG	Sharyland Utilities
SEE	CenterPoint Energy
TXMAG	City Public Service
SEE	Cleco
SEE	Entergy
SEE	Mississippi Power Co. (a Southern Company)
SEE	Oklahoma Gas & Electric
SEE	Oncor Electric Delivery
SEE	Texas New Mexico Power

	Western Region MAG
WRMAG	AltaLink L.P. *
WRMAG	Arizona Public Service Company
WRMAG	ATCO Electric *
WRMAG	Avista Corporation
WRMAG	BC Hydro *
WRMAG	Bonneville Power Administration
WRMAG	Chelan County PUD No. 1
WRMAG	City of Mesa Utilities
WRMAG	Clark Public Utilities
WRMAG	El Paso Electric Company
WRMAG	ENMAX *
WRMAG	Eugene Water and Electric Board
WRMAG	Fortis Alberta, Fortis BC *
WRMAG	Hawaiian Electric Company
WRMAG	Idaho Power
WRMAG	Liberty Utilities, CA
WRMAG	Los Angeles Dept. of Water & Power (LADWP)
WRMAG	NorthWestern Energy
WRMAG	NV Energy
WRMAG	Pacific Gas & Electric Company
WRMAG	PacifiCorp
WRMAG	Portland General Electric
WRMAG	Public Service Company of New Mexico (PNM)
WRMAG	Puget Sound Energy
WRMAG	Rocky Mountain Power
WRMAG	Sacramento Municipal Utility District
WRMAG	Salt River Project
WRMAG	Seattle City Light
WRMAG	Snohomish County PUD
WRMAG	Southern California Edison
WRMAG	Tucson Electric Power Company
WRMAG	Unisource Energy Services

	Wisconsin Utilities Association
MMAG	Mutual Assistance Group
MMAG	Alliant Energy
MMAG	Madison Gas & Elec. Co.
GLMAG	We Energies
MMAG	Wisconsin Public Service Corporation
MMAG	Xcel Energy Inc
MMAG	American Transmission Company

Appendix C: Web Content/Document Repository

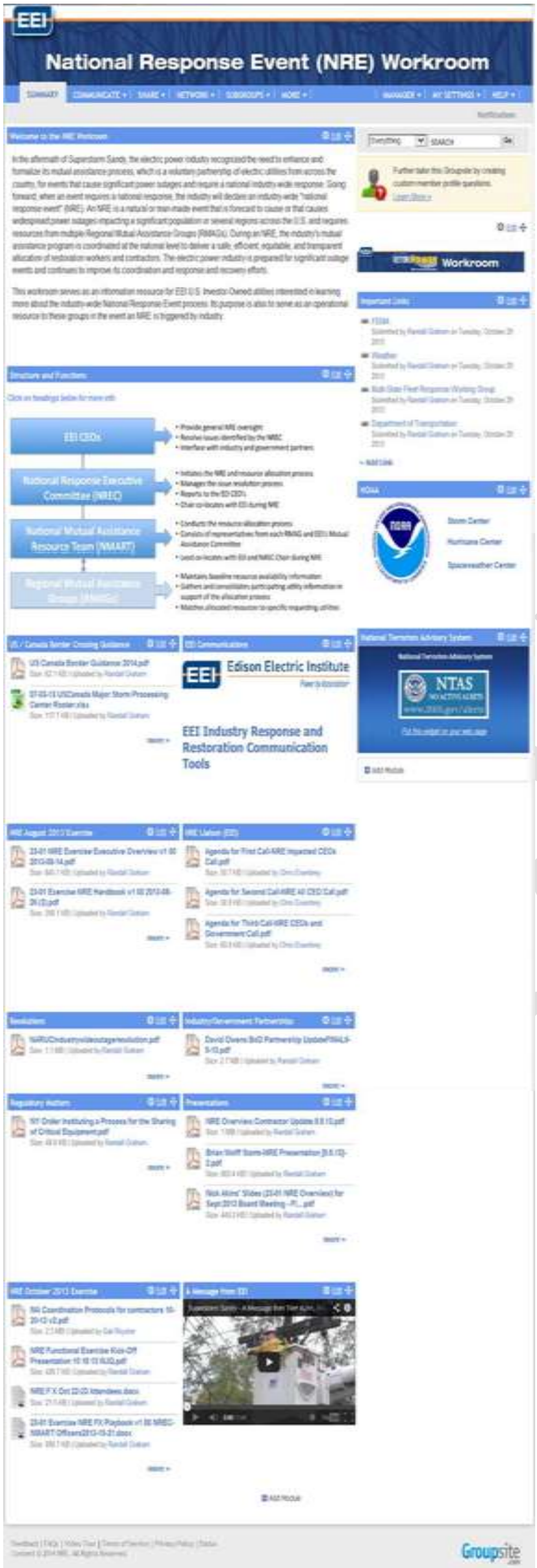
NRE Electronic Workroom

EEI's Issue Workrooms provide members an online forum to facilitate policy development, information exchange and networking. Members communicate and share ideas, participate in discussion forums, send email blasts, create file libraries, organize conference calls and keep track of important dates and upcoming events.

EEI utilizes the NRE Workroom as both a document and NMART tool repository as well as a communications means. EEI is able to limit access to documents and tools to those who need access; provide simultaneous access to documents and tools; and quickly change access as needs arise through the use of Groupsite.com.

To access the NRE Workroom, set your browser to "groupsite.com" and login. If you do not have access, contact your EEI representative.

Following is the opening page to the NRE Workroom.


EEI
National Response Event (NRE) Workroom
Workroom
Edison Electric Institute
EEI Industry Response and Restoration Communication Tools
NTAS
Groupsite

Documentation Retention

EEI General Policy is listed below. More detail is available if needed.

Edison Electric Institute
Power by Association

Edison Electric Institute
Records Retention Schedule

August 2013

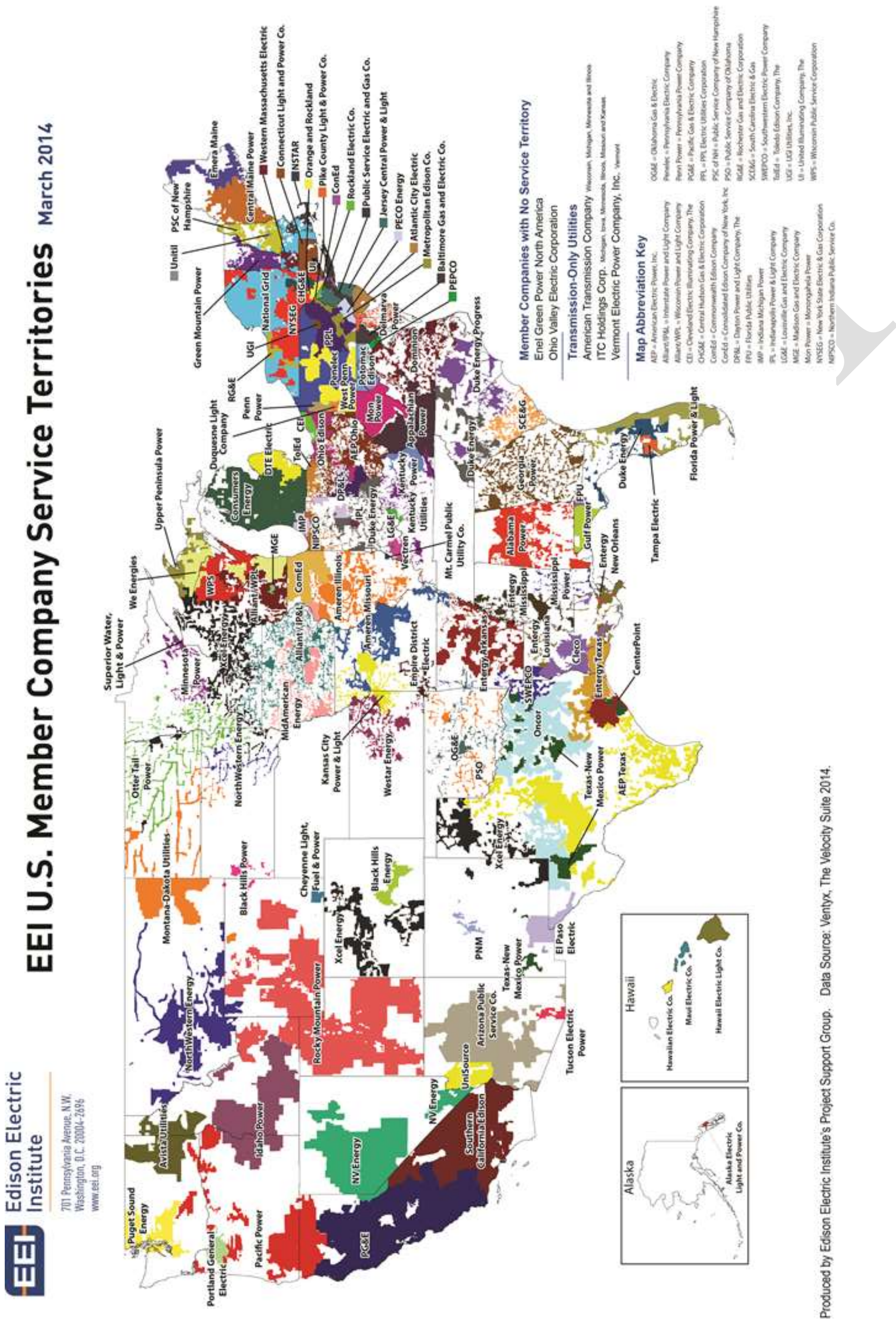
General Guidance

1. Most files, publications and materials only need to be kept while a matter is active.
2. Member information, financial information, contracts, purchasing and other business records, personnel files, meeting attendance and payment records are the responsibility of EEI's administrative groups. Legal and regulatory filings, testimony and EEI studies, reports and publications are the responsibility of each individual business group, governmental affairs and supporting groups.
3. Detailed guidance is included. It applies to both hard copy and electronic files.
4. If you have questions, please seek guidance from your supervisor or contact Ed Comer, x5615

These are the general guidelines. Specific guidelines for an NRE need to be developed. .

Appendix D: Key Maps

EEI U.S. Member Company Service Territory (March 2014)



EEI "Short Form" Mutual Assistance Agreement – Signed and Not Signed Companies – (May 2014)

EEI RESTORE POWER

Mutual Assistance Agreement - as of 5/2014

Signed

AES Corporation
Dayton Power and Light
Indianapolis Power & Light Company

ALLETE
Minnesota Power
Superior Water, Light and Power Company

Alliant Energy Corporation
Interstate Power and Light Company
Wisconsin Power and Light Company

Ameren Corporation
Ameren Illinois
Ameren Missouri

American Electric Power, Inc.
AEP Ohio
AEP Texas
Appalachian Power
Indiana Michigan Power
Kentucky Power
Public Service Company of Oklahoma
Southwestern Electric Power Company

American Transmission Company

Avista Corporation
Avista Utilities

Black Hills Corporation
Black Hills Energy
Black Hills Power
Cheyenne Light, Fuel & Power Company

CenterPoint Energy, Inc.

CH Energy Group, Inc.
Central Hudson Gas & Electric Corporation

Chesapeake Utilities Company
Florida Public Utilities Company

Cleco Corporation
Cleco Power LLC

CMS Energy Corporation
Consumers Energy

Consolidated Edison, Inc.
Consolidated Edison Company of New York, Inc.
Orange and Rockland Utilities, Inc.
Pike County Light & Power Company
Rockland Electric Company

Dominion

DTE Energy Company
Detroit Edison

Duke Energy

Duquesne Light Holdings, Inc.
Duquesne Light Company

Edison International
Southern California Edison Company

Empire District Electric Company, The

Energy Future Holdings
Oncor

Entergy Corporation
Entergy Arkansas, Inc.
Entergy Louisiana, Inc.
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.
Entergy Texas, Inc.

Exelon Corporation
Baltimore Gas and Electric Company
Commonwealth Edison Company
PECO Energy

FirstEnergy Corp.
The Cleveland Electric Illuminating Company
Jersey Central Power & Light Company
Metropolitan Edison Company
Monongahela Power
Ohio Edison Company
Pennsylvania Electric Company
Pennsylvania Power Company
Potomac Edison
The Toledo Edison Company
West Penn Power

Gaz Métro
Green Mountain Power

Great Plains Energy, Inc.
Kansas City Power & Light Company

Iberdrola USA
Central Maine Power Company
New York State Electric & Gas Corporation
Rochester Gas and Electric Corporation

Integrys Energy Group
Upper Peninsula Power Company
Wisconsin Public Service Corporation

ITC Holdings Corp.
ITC Great Plains
ITC Midwest
ITC Transmission
Michigan Electric Transmission Company, LLC (METC)

MGE Energy, Inc.
Madison Gas and Electric Company

MidAmerican Energy Holdings Company
MidAmerican Energy Company
PacifiCorp
Pacific Power
Rocky Mountain Power

National Grid

NextEra Energy, Inc.
Florida Power & Light Company

NiSource Inc.
Northern Indiana Public Service Co (NIPSCO)

Northeast Utilities
The Connecticut Light and Power Company
NSTAR
Public Service Company of New Hampshire
Western Massachusetts Electric Company

NorthWestern Energy

NV Energy

OGE Energy Corporation
OG&E Electric Services

Otter Tail Corporation
Otter Tail Power Company

Pepco Holdings, Inc.
Atlantic City Electric
Delmarva Power
Pepco

PG&E Corporation
Pacific Gas & Electric Company

Pinnacle West Capital Corporation
Arizona Public Service Company

PNM Resources, Inc.
PNM
Texas-New Mexico Power Company

Portland General Electric

PPL Corporation
Kentucky Utilities Company
Louisville Gas and Electric Company

Public Service Enterprise Group, Inc.
Public Service Electric and Gas Company
PSEG LI

Puget Energy, Inc.
Puget Sound Energy

SCANA Corporation
South Carolina Electric & Gas Company

Southern Company
Alabama Power Company
Georgia Power Company
Gulf Power Company
Mississippi Power Company

TECO Energy, Inc.
Tampa Electric Company

UGI Corporation
UGI Utilities, Inc.

EEI RESTORE POWER

Mutual Assistance Agreement - as of 5/2014

UIL Holdings Corporation
The United Illuminating Company

Unitil
Fitchburg Gas & Electric Light Company
Unitil Energy System, Inc.

Vectren Corporation
Vectren Energy Delivery-South

Westar Energy Inc.

Wisconsin Public Service
Upper Peninsula Power

Wisconsin Energy Corporation
We Energies

Xcel Energy Inc.

Not Signed

Alaska Electric Light and Power Company

El Paso Electric Company

Emera
Bangor Hydro Electric Company
Maine Public Service Company

Enel Green Power North America

Hawaiian Electric Industries
Hawaii Electric Light Company
Hawaiian Electric Company
Maui Electric Company, Ltd.

IDACORP, Inc.
Idaho Power Company

MDU Resources Group, Inc.
Montana-Dakota Utilities Co.

Mt. Carmel Public Utility Company

UNS Energy Corporation
Tucson Electric Power Company
UniSource Energy Services

Vermont Electric Power Company

On Mutual Assistance signing list as Previous Company name

Allegheny Energy Inc (merged with FirstEnergy)
Allegheny Power

***Central Vermont Public Service** (acquired by Gaz Metro and combined with and called Green Mountain Power)

Cinergy (acquired by Duke)

LG&E (PPL)

FPL Group (acquired by NextEra)

KeySpan Corp (National Grid)

Progress Energy Inc (Duke)

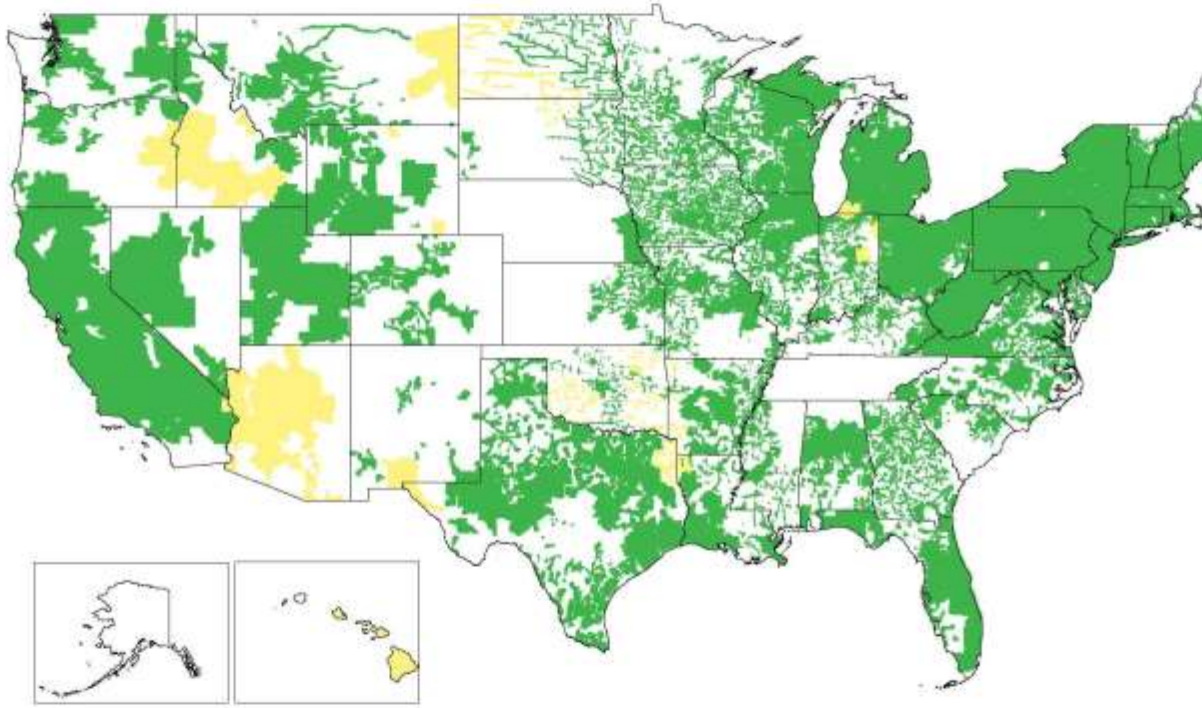
EEI RESTORE POWER
Resources for Restoration

EEI "Short Form" Mutual Assistance Agreement

Non-Signed Companies

Signing Companies
as of May, 2014

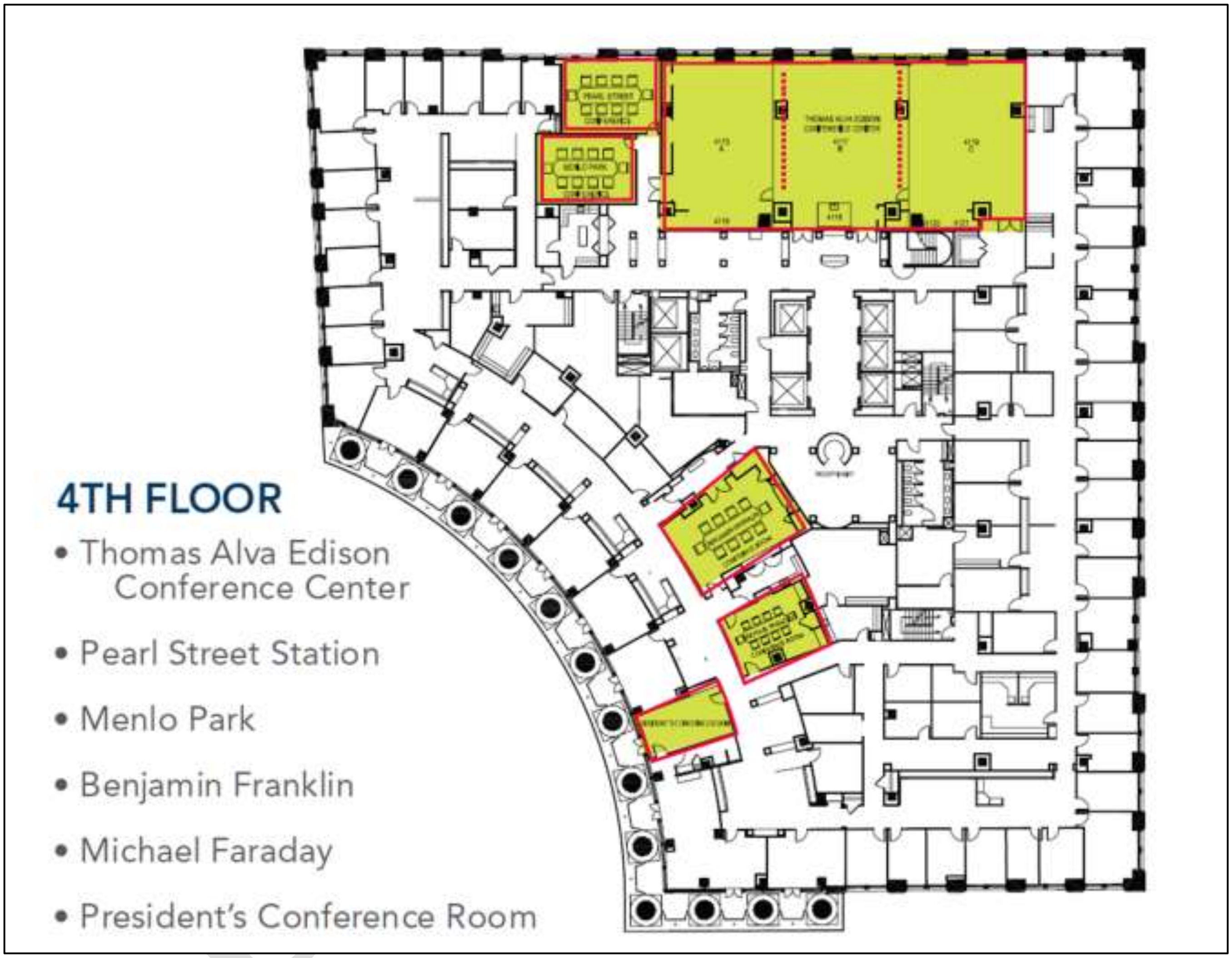
Allegheny Energy Inc
ALLETE d/b/a Minnesota Power
Ameren Corp
American Electric Power
ATC – American Transmission Company
Avista Corp
Baltimore Gas and Electric Company
Black Hills Energy
CenterPoint Energy Inc
Central Hudson Gas & Electric Corp
Central Maine Power Company (Iberdrola USA)
Cinergy Corp
Cleco Corp
CMS Energy Corp
Consolidated Edison Inc
Consolidated Edison Inc (Orange & Rockland Utilities)
Dayton Power & Light
Dominion
DTE Energy
Duke Energy Corp
Duquesne Light Holdings
LG&E (KU – LG&E Energy)
Empire District Electric Company
Entergy Corp
Exelon Corp (ComEd)
Exelon Corp (PECO)
First Energy Corp
Florida Public Utilities
FPL Group Inc
Great Plains Energy Inc (KCP&L)
Green Mountain Power (Central Vermont Public Service)
Hydro One
Indianapolis Power & Light Co
International Transmission Company
Interstate Power & Light (IPL) (Alliant Energy)
Kentucky Utilities Company (LGE – KU Energy)
KeySpan Corp
Madison Gas & Electric
MidAmerican Energy Company
Midwest Energy Inc
National Grid
Nebraska Public Power District
Northeast Utilities
Northern Indiana Public Service
NorthWestern Energy
NSTAR
NV Energy
NYSEG – New York State Electric & Gas (Iberdrola USA)
OGE Energy
Omaha Public Power District (OPPD)
ONCOR Electric Delivery Company LLC
Otter Tail Power Company
Pacific Power
Pepco Holdings Inc
PG&E
PNM Resources Inc
Portland General Electric
PPL Corp
Progress Energy Inc
Public Service Enterprise Group Inc
PSEG LI
Puget Sound Energy
Rochester Gas and Electric Corporation (Iberdrola USA)
Rocky Mountain Power (PacifiCorp)
South Carolina Electric & Gas
Southern California Edison
Southern Company (Alabama Power)
Southern Company (Georgia Power)
Southern Company (Gulf Power)
Southern Company (Mississippi Power)
Tampa Electric Company (TECO Energy Inc)
UGI Utilities
UIL Holdings Corp
Unitil
Upper Peninsula Power Company (UPPCO)
Vectren Corp
We Energies
Westar Energy
Wisconsin Power & Light (WPL) (Alliant Energy)
Wisconsin Public Service Corp
Xcel Energy



Produced by Edison Electric Institute's Project Support Group. Data Source: Ventyx, The Velocity Suite 2014.

EEI Facility and NRE Rooms

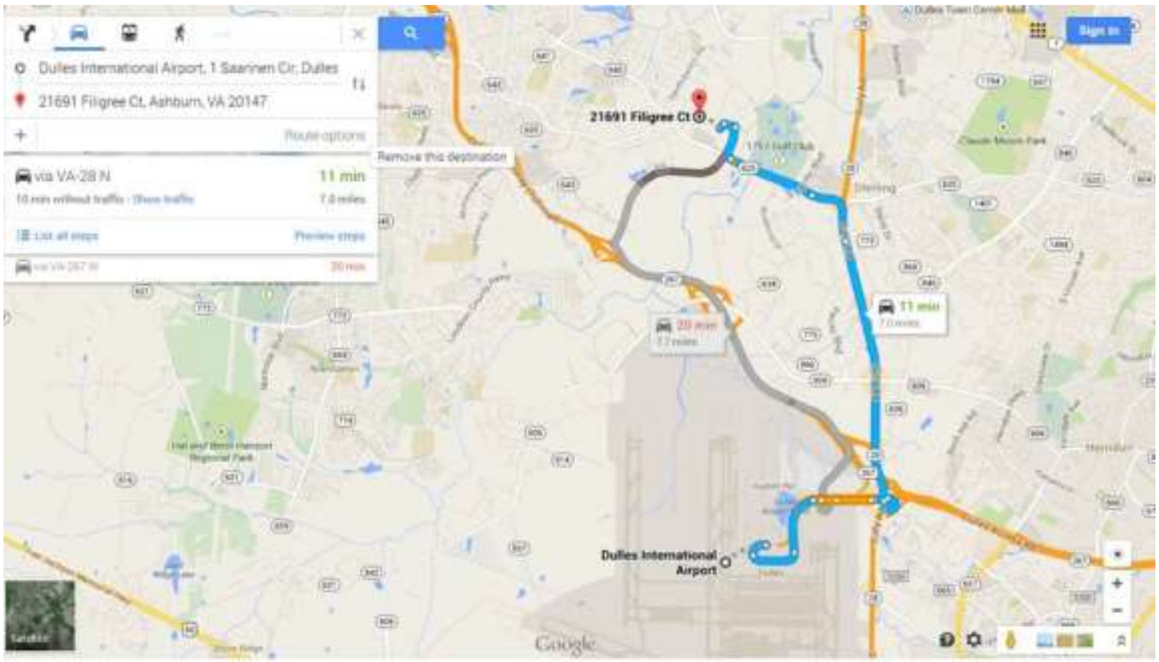
EEI Headquarters is Located at 701 Pennsylvania Ave, NW, Washington, DC 20004
The General Number is 202-508-5000



NREC will convene in the Edison Conference Room B
NMART will convene in the Edison Conference Room A
Menlo Park will be a breakout room
President's Conference Room is for use by EEI and will be used to host the CEO calls

NRE Alternate Facility Ashburn, VA

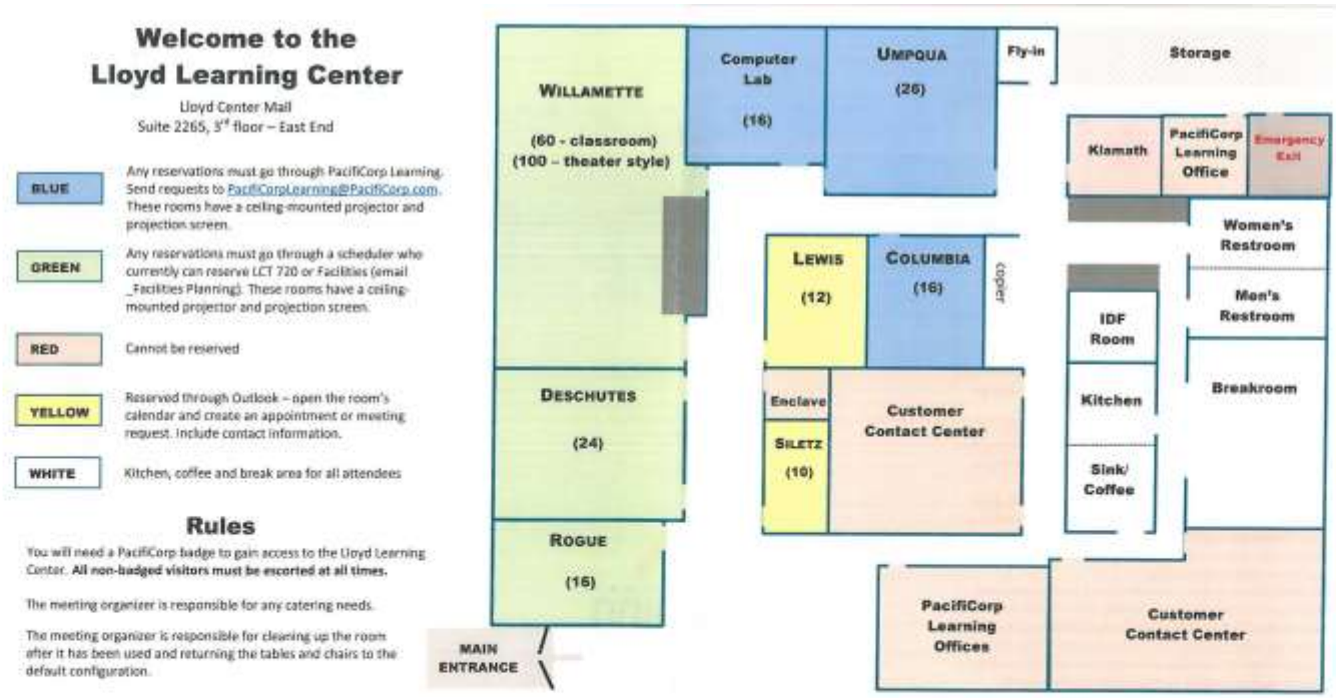
This facility which houses EEI's offsite servers, has a 500 square foot conference room outfitted with tables, 12 chairs, an air printer, multiple big screen televisions, white boards, and one land line conference capable phone.

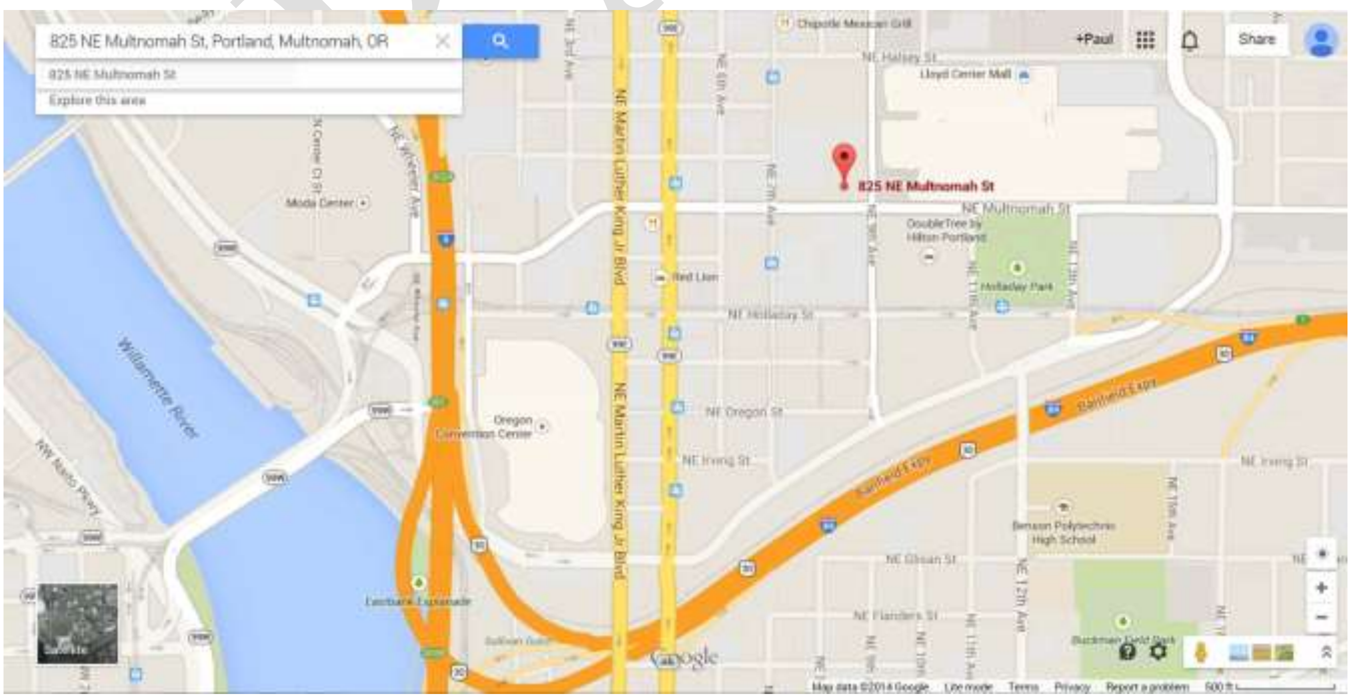


Location of EEI Alternate Facility in Ashburn, VA
Equinix DC4/IBX
21691 Filigree Court
Ashburn, VA 20147
approximately 15 minutes north of Dulles International Airport

NRE Alternate Facility NorthWest

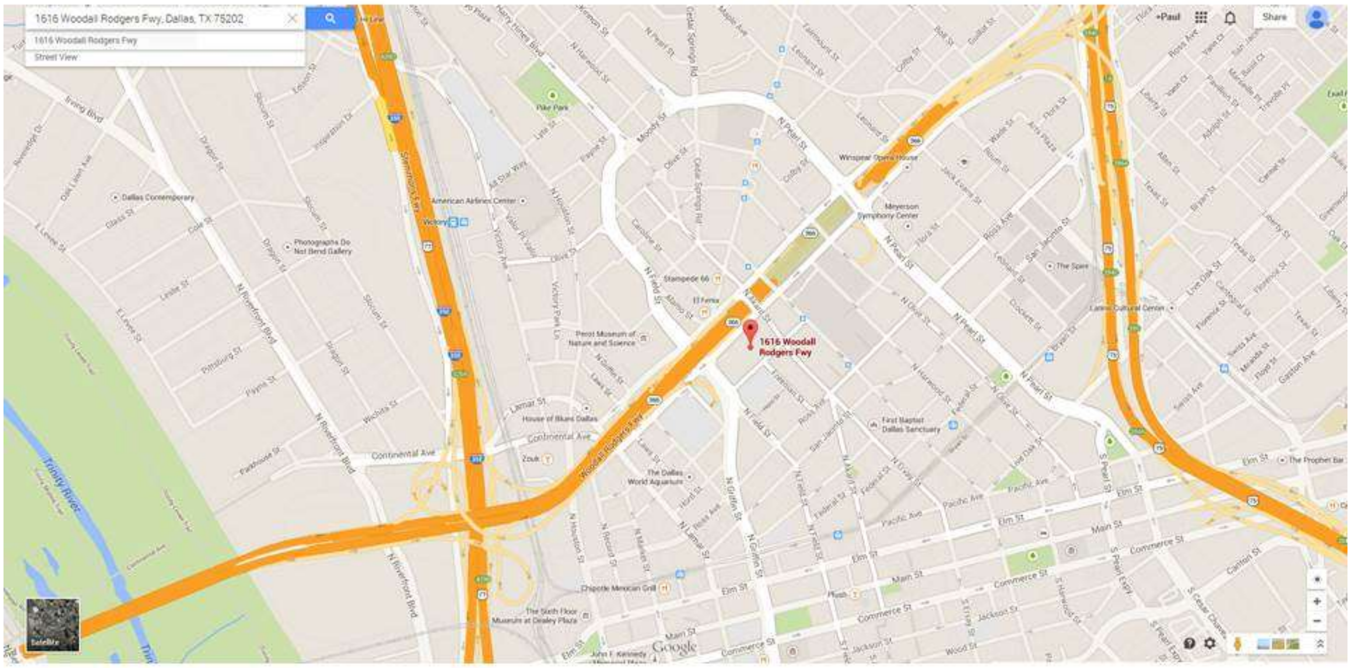
Pacificorp Learning Center
Lloyd Center Mall, Suite 2265, 3rd Floor – East End
825 NE Multnomah Street
Portland, OR 97232





NRE Alternate Facility SouthWest

Oncor System Emergency Center
Woodall Rodgers Building, 2nd Floor
1616 Woodall Rodgers FWY
Dallas, Tx 75202



Regional Mutual Assistance Groups – Map and NREC Members

EEI

National Response Executive Committee

List of National Response Executive Committee (NREC) Members – May 2014

Chair	Tom Kirkpatrick
First Vice-Chair	Bill Quinlan
Second Vice-Chair	Keith Hull

Great Lakes Mutual Assistance Group	Tom Kirkpatrick	American Electric Power	Primary Member
Great Lakes Mutual Assistance Group	Steve Strah	FirstEnergy	1st Alternate
Great Lakes Mutual Assistance Group	Daniel Malone	CMS Energy	2nd Alternate
Southeastern Electric Exchange	Manny Miranda	NextEra Energy Inc.	Primary Member
Southeastern Electric Exchange	Greg Grillo	Entergy	1st Alternate
Southeastern Electric Exchange	Danny Glover	Southern Company	2nd Alternate
Texas Mutual Assistance Group	Keith Hull	Oncor	Primary Member
Texas Mutual Assistance Group	David Baker	Centerpoint Energy, Inc.	1st Alternate
Texas Mutual Assistance Group	Mike Mathews	OGE	2nd Alternate
North Atlantic Mutual Assistance Group	Bill Quinlan	Northeast Utilities	Primary Member
North Atlantic Mutual Assistance Group	Dave Bonenberger	PPL Electric Utilities Corporation	1st Alternate
North Atlantic Mutual Assistance Group	John Donleavy	National Grid	2nd Alternate
Midwest Mutual Assistance Group	Melody Birmingham-Byrd	Duke Energy	Primary Member
Midwest Mutual Assistance Group	Jim Conway	Exelon Corporation	1st Alternate
Midwest Mutual Assistance Group	Bruce Akin	Westar Energy, Inc.	2nd Alternate
Western Region Mutual Assistance Group	Barry Anderson	Pacific Gas & Electric	Primary
Western Region Mutual Assistance Group	Doug Butler	PacifiCorp	1st Alternate
Western Region Mutual Assistance Group	Dana Kracke	Southern California Edison	2nd Alternate
Wisconsin Utilities Association Mutual Assistance Group	Vern Gebhart	Alliant Energy Corporation	Primary Member
At-Large	Carlos Torres	Consolidated Edison of New York, Inc.	Primary Member
At-Large	Mike Sullivan	Pepco	Primary Member

Below is an interactive link to the Regional Mutual Assistance Groups identifying each region along with each member company participating within that region. The link will require you to login to the NRE Workroom.

[RMAG 03 2014 CN.pdf]

Appendix E: EEI Mutual Assistance Agreement

July 30, 2014

Edison Electric Institute
Power By Association

Edison Electric Institute
Mutual Assistance Agreement

Edison Electric Institute ("EEI") member companies have established and implemented an effective system whereby member companies may receive and provide assistance in the form of personnel and equipment to aid in restoring and/or maintaining electric utility service when such service has been disrupted by acts of the elements, equipment malfunctions, accidents, sabotage, or any other occurrence for which emergency assistance is deemed to be necessary or advisable ("Emergency Assistance"). This Mutual Assistance Agreement sets forth the terms and conditions to which the undersigned EEI member company ("Participating Company") agrees to be bound on all occasions that it requests and receives ("Requesting Company") or provides ("Responding Company") Emergency Assistance from or to another Participating Company who has also signed the EEI Mutual Assistance Agreement; however, that if a Requesting Company and one or more Responding Companies are parties to another mutual assistance agreement at the time of the Emergency Assistance is requested, such other mutual assistance agreement shall govern the Emergency Assistance among those Participating Companies.

In consideration of the foregoing, the Participating Company hereby agrees as f follows:

(1) When providing Emergency Assistance to or receiving Emergency Assistance from another Participating Company, the Participating Company will adhere to the written principles Suggested Governing Principles Covering Emergency Assistance Arrangements Between Edison Electric Institute Member Companies adopted in September 2005 ("EEI Governing Principles"), that are in effect as of the date of a specific request for Emergency Assistance, unless otherwise agreed to in writing by each Participating Company.

(2) When a National Response Event ("NRE") is activated due to a natural or man-made event that is forecast to or causes widespread power outages, impacting a significant population or several regions across the United States, that requires resources from multiple Regional Mutual Assistance Group(s) ("RMAG" or "RMAGs"), the Participating Companies will operate in accordance with the current National Response Event Structure and Principles Covering Emergency Assistance Arrangement between Edison Electric Member Companies.

(3) In recognition of the confidential nature of the number of resources and allocation of those resources in an NRE event as well as the methodology used to allocate those resources, the Participating Companies agree to the confidentiality provisions set forth in the National Response Event Structure and Principles Covering Emergency Assistance Arrangements between Edison Electric Institute Member Companies.

(4) With respect to each Emergency Assistance event, Requesting Companies agree that they will reimburse Responding Companies for all costs and expenses incurred by Responding Companies in providing Emergency Assistance as provided under the EEI Principles, unless otherwise agreed to in writing by each Participating Company; provided, however, that Responding Companies must maintain auditable records in a manner consistent with the EEI Principles.

(5) During each Emergency Assistance event, the conduct of the Requesting Companies and the Responding Companies shall be subject to the liability and indemnification provisions set forth in the EEI Principles.

(6) A Participating Company may withdraw from this Agreement at any time. In such an event, the company should provide written notice to Vice President of Energy Delivery or his/her designee who shall maintain a list of each Mutual Assistance Agreement Participating Company Signatory which shall be posted in the EEI NRE Workroom http://nre.groupsite.com/main/summary. A Participating Company may request a copy of the signed Mutual Assistance Agreement of another Participating Company prior to providing or receiving Emergency Assistance.

____
Company Name

____
Signature

Officer Name:
Title:
Date:

Edison Electric Institute
Power By Association

SUGGESTED GOVERNING PRINCIPLES COVERING EMERGENCY ASSISTANCE ARRANGEMENTS BETWEEN EDISON ELECTRIC INSTITUTE MEMBER COMPANIES

Electric companies have occasion to call upon other companies for emergency assistance in the form of personnel or equipment to aid in maintaining or restoring electric utility service when such service has been disrupted by acts of the elements, equipment malfunctions, accidents, sabotage or any other occurrences where the parties deem emergency assistance to be necessary or advisable. While it is acknowledged that a company is not under any obligation to furnish such emergency assistance, experience indicates that companies are willing to furnish such assistance when personnel or equipment are available.

In the absence of a continuing formal contract between a company requesting emergency assistance ("Requesting Company") and a company willing to furnish such assistance ("Responding Company"), the following principles are suggested as the basis for a contract governing emergency assistance to be established at the time such assistance is requested:

1. The emergency assistance period shall commence when personnel and/or equipment expenses are initially incurred by the Responding Company in response to the Requesting Company’s needs. (This would include any request for the Responding Company to prepare its employees and/or equipment for transport to the Requesting Company’s location but to await further instructions before departing). The emergency assistance period shall terminate when such employees and/or equipment have returned to the Responding Company, and shall include any mandated DOT rest time resulting from the assistance provided and reasonable time required to prepare the equipment for return to normal activities (e.g. cleaning off trucks, restocking minor materials, etc.).

2. To the extent possible, the companies should reach a mutual understanding and agreement in advance on the anticipated length – in general – of the emergency assistance period. For extended assistance periods, the companies should agree on the process for replacing or providing extra rest for the Responding Company’s employees. It is understood and agreed that if; in the Responding Company’s judgment such action becomes necessary the decision to terminate the assistance and recall employees, contractors, and equipment lies solely with the Responding Company. The Requesting Company will take the necessary action to return such employees, contractors, and equipment promptly.

3. Employees of Responding Company shall at all times during the emergency assistance period continue to be employees of Responding Company and shall not be deemed employees of Requesting Company for any purpose. Responding Company shall be an independent Contractor of Requesting Company and wages, hours and other terms and conditions of employment of Responding Company shall remain applicable to its employees during the emergency assistance period.

4. Responding Company shall make available at least one supervisor in addition to crew foremen. All instructions for work to be done by Responding Company's crews shall be given by Requesting Company to Responding Company's supervisor(s); or, when Responding Company's crews are to work in widely separate areas, to such of Responding Company's foremen as may be designated for the purpose by Responding Company's supervisor(s).

5. Unless otherwise agreed by the companies, Requesting Company shall be responsible for supplying and/or coordinating support functions such as lodging, meals, materials, etc. As an exception to this, the Responding Company shall normally be responsible for arranging lodging and meals en route to the Receiving Company and for the return trip home. The cost for these in transit expenses will be covered by the requesting company.

6. Responding Company's safety rules shall apply to all work done by their employees. Unless mutually agreed otherwise, the Requesting Company's switching and tagging rules should be followed to ensure consistent and safe operation. Any questions or concerns arising about any safety rules and/or procedures should be brought to the proper level of management for prompt resolution between management of the Requesting and Responding Companies.

7. All time sheets and work records pertaining to Responding Company's employees furnishing emergency assistance shall be kept by Responding Company.

8. Requesting Company shall indicate to Responding Company the type and size of trucks and other equipment desired as well as the number of job function of employees requested but the extent to which Responding Company makes available such equipment and employees shall be at Responding Company's sole discretion.

9. Requesting Company shall reimburse Responding Company for all costs and expenses incurred by Responding Company as a result of furnishing emergency assistance. Responding Company shall furnish documentation of expenses to Requesting Company. Such costs and expenses shall include, but not be limited to, the following:

    a. Employees' wages and salaries for paid time spent in Requesting Company's service area and paid time during travel to and from such service area, plus Responding Company's standard payable additives to cover all employee benefits and allowances for vacation, sick leave and holiday pay and social and retirement benefits, all payroll taxes, workmen's compensation, employer's liability insurance and other contingencies and benefits imposed by applicable law or regulation.

    b. Employee travel and living expenses (meals, lodging and reasonable incidentals).

    c. Replacement cost of materials and supplies expended or furnished.

    d. Repair or replacement cost of equipment damaged or lost.

    e. Charges, at rates internally used by Responding Company, for the use of transportation equipment and other equipment requested.

    f. Administrative and general costs, which are properly allocable to the emergency assistance to the extent such costs, are not chargeable pursuant to the foregoing subsections.

10. Requesting Company shall pay all costs and expenses of Responding Company within sixty days after receiving an invoice therefor.

11. Requesting Company shall indemnify, hold harmless and defend the Responding Company from and against any and all liability for loss, damage, cost or expense which Responding Company may incur by reason of bodily injury, including death, to any person or persons or by reason of damage to or destruction of any property, including the loss of use thereof, which result from furnishing emergency assistance and whether or not due in whole or in part to any act, omission, or negligence of Responding Company except to the extent that such death or

injury to person, or damage to property, is caused by the willful or wanton misconduct and / or gross negligence of the Responding Company. Where payments are made by the Responding Company under a workmen's compensation or disability benefits law or any similar law for bodily injury or death resulting from furnishing emergency assistance, Requesting Company shall reimburse the Responding Company for such payments, except to the extent that such bodily injury or death is caused by the willful or wanton misconduct and / or gross negligence of the Responding Company..

12. In the event any claim or demand is made or suit or action is filed against Responding Company alleging liability for which Requesting Company shall indemnify and hold harmless Responding Company under paragraph (11) above, Responding Company shall promptly notify Requesting Company thereof, and Requesting Company, at its sole cost and expense, shall settle, compromise or defend the same in such manner as it in its sole discretion deems necessary or prudent. Responding Company shall cooperate with Requesting Company's reasonable efforts to investigate, defend and settle the claim or lawsuit.

13 Non-affected companies should consider the release of contractors during restoration activities. The non-affected company shall supply the requesting companies with contact information of the contactors (this may be simply supplying the contractors name). The contractors will negotiate directly with requesting companies.

Last update September 2005

- Section 11 and 12 updated

December 4, 2013

National Response Event Structure and Principles Covering Emergency Assistance Arrangements between Edison Electric Institute Member Companies

This document sets forth the structure and principles that Participating Companies agree to follow when engaged in Emergency Assistance activities during a National Response Event ("NRE"). An NRE is a natural or man-made event that is forecast to or causes widespread power outages, impacting a significant population or several regions across the United States that requires resources from multiple Regional Mutual Assistance Group(s) ("RMAG" or "RMAGs"). When an NRE is activated, all available emergency restoration resources (including contractors) will be pooled and allocated to Participating Companies in a safe, efficient, transparent and equitable manner.

Structure:

National Response Executive Committee ("NREC"). The NREC is responsible to the Edison Electric Institute ("EEI") Board of Directors. The NREC will provide executive leadership to develop procedures and processes covering Emergency Assistance arrangements between Participating Companies to respond to an NRE. The NREC will also review and validate a request to declare an NRE, and resolve any issues stemming from the resource allocation process.

The EEI Board of Directors will designate one Participating Company executive from each RMAG to serve as primary members of the NREC, as well as two additional executives from each RMAG (except for the Wisconsin RMAG, which shall have one primary member) to serve as first and second alternates, respectively. The EEI Board of Directors shall also, at their discretion, designate up to two additional 'at large' executives to serve as primary members of the NREC. Members of the NREC shall be executive level, have operations and emergency assistance experience and possess the ability to communicate at all levels of management. No one Participating Company, or parent thereof, may have multiple members on the NREC.

The leadership of the NREC shall consist of a Chair, a Vice Chair, and a Second Vice Chair. The NREC shall annually elect a Second Vice Chair from its membership at its first meeting of each year. At that time, the Vice Chair will assume the role of Chair, the Second Vice Chair will assume the role of Vice Chair, and the newly elected Second Vice Chair shall become Second Vice Chair. All leadership roles will last one year. The three officers will rotate on a yearly cycle. Other NREC members will rotate on a three year cycle and be replaced sequentially; with the primary member rolling off, the first alternate becoming primary, the second alternate becoming the first alternate and the new second alternates designated by the EEI Board of Directors. The two 'at large' NREC members shall serve one-year terms and be replaced on an annual basis.

National Mutual Assistance Resource Team ("NMART"). During an NRE, the NMART is responsible for collecting information regarding the scope of actual or forecasted damage, determining available and requested resources and allocating the available resources in a safe, efficient, transparent and equitable manner as prescribed by its policies and procedures.

The NMART consists of the officers of the EEI Mutual Assistance/Emergency Preparedness Committee ("EEI MA/EP") and one representative from each RMAG. The EEI MA/EP Chairs and Vice Chair and will serve as the NMART Chairs and Vice Chair, respectively.

Edison Electric Institute. EEI serves as the industry liaison to EEI Member Company Chief Executive Officers ("CEOs"), senior government officials, federal agencies, and national organizations representing state and local interests. At the request of an EEI Member, EEI may also serve as an industry liaison to state regulatory agencies. During an NRE, EEI convenes periodic conference calls with the EEI Member Company CEOs and senior governmental officials. EEI will also serve as the electric power industry's primary national information resource and spokesperson. EEI will provide a broad, national perspective on the event through media and public relations activities, national stakeholder outreach, including relevant Federal agencies, social media support, and industry-wide communication and coordination to relevant stakeholders. EEI is not a member of the NREC but will work closely with the NREC and may participate in NREC and NMART activities as appropriate to carry out its functions. As set forth below, EEI will maintain exclusive ownership and control of the NRE Resource Allocation Methodology, its related tools, and all data provided by Participating Companies to the NMART to carry out its functions.

NRE Principles:

Activating an NRE. A Participating Company CEO(s) or executive designee(s) may make a request to initiate the NRE process by directly contacting the President of EEI (or his designee), who would then host a conference call with the CEO(s) or executive designee(s), the NREC Chair, and the CEO Policy Committee on Reliability and Business Continuity Chairs to validate the request and either activate the NRE, delay the decision for 6 to 12 hours (time determined by NREC Chair), or not activate the NRE. The decision on whether or not to activate the NRE will be made on this decisional call. The request can occur before or after an event impacts a region or utility. Such requests shall be based upon a high probability forecast or actual damage and careful consideration of the resources requested. Once an NRE is activated, the NREC Chair shall activate the NMART and notify the NREC members that an NRE is activated.

Activities During an NRE. NREC Members should be available throughout the NRE. The NREC Chair or Vice Chair or their respective designee from the NREC should co-locate with the NMART Chairs or Vice Chair or their respective designee from the NMART and EEI.

The NMART shall collect the necessary information to make resource allocation decisions as prescribed by its policies and procedures. The NMART will inform the NREC Chair and EEI of all allocation decisions.

Upon activation, EEI shall develop, and communicate consistent messaging for all stakeholders concerning the NRE pursuant to the EEI Crisis Communications Plan. The NREC Chair and EEI will periodically update the EEI CEOs throughout the NRE.

During an NRE, specific issues from any Participating Company CEO or designee should be addressed directly to the NREC Chair. The NREC Chair shall involve the NREC or NMART, as necessary, in the disposition of such issues, including any modification to decisions made by the NMART. Any further review of the disposition of such issues may be directed to the EEI Board of Directors.

Post-NRE Activities and Coordination. Following an NRE or exercise, the NREC shall conduct a review of the NRE process and procedures to identify any opportunities for improvement. The NREC and the NMART shall also meet at least once a year during the Spring EEI CEO meeting to provide a forum for scheduling and execution of annual exercises and drills, sharing updates and any lessons learned, and any other pertinent business.

Resource Allocation Tool and Data Confidentiality:

Confidentiality of NRE activities, data and work products: During an NRE, Participating Companies may provide or receive confidential information regarding available and requested resources and the allocation thereof ("Confidential Information"). Each Participating Company agrees to hold all Confidential Information obtained from the NRE structure and process (including the NRE Resource Allocation Methodology and its related tools) in confidence, not use and not disclose the Confidential Information to anyone, including but not limited to any person, company, agency, commission, regulatory body, legal tribunal or court. Each Participating Company agrees to only share such Confidential Information with other Participating Companies and EEI.

In the event a Participating Company, any of its affiliates, or any representative of such Participating Party or any of its affiliates, is requested or required, pursuant to any applicable court order, administrative order, or official order by any government or any agency or department thereof, to disclose information obtained through the NRE structure and process, including the NRE Resource Allocation Methodology and its related tools, it will provide EEI, as representative of the Participating Companies, with prompt written notice of any such request or requirement unless prohibited by law or court order to do so and shall reasonably cooperate with EEI upon specific request to obtain such protective order or remedy. Participating Companies agree that if EEI and/or the Participating Company is not successful in precluding the requesting legal body from requiring the disclosure of the information, EEI and/or the Participating Company will only furnish that portion of the information or work product that is legally required and will exercise appropriate legal efforts to obtain reasonable assurances that confidential treatment will be accorded the information or work product.

The Participating Companies recognize the need to maintain the confidentiality of the Resource Allocation Methodology and its related tools and data. As such, each Participating Company assigns any right, title or interest in the Resource Allocation Methodology and its related tools and data to EEI to own and protect the confidentiality thereof. The Resource Allocation Methodology and its related tools and data will at all times be treated as Confidential Information as set forth above.

Amendments

Any changes or amendments to the NRE Structure and Principles must be approved by the NREC and communicated to the Participating Companies.

December 2013

Coordination with Public Power Utilities

In the event of an NRE, the DOE Emergency Response Team (ERT) will provide coordination calls between each of the electric sector representatives. These calls will include APPA, EEI, and NRECA.

EEI has reached out to APPA and NRECA to coordinate as much as possible in advance of an NRE. To that end, APPA has provided EEI with the following description of Public Power's Mutual Aid Network.

Understanding Public Power's Mutual Aid Network

Public power is a collection of more than 2,000 community-owned electric utilities, serving more than 47 million people or about 14 percent of the nation's electricity consumers. These utilities are operated by local governments to provide communities with reliable, responsive, not-for-profit electric service. Public power utilities are directly accountable to the people they serve through locally elected or appointed officials. While of the nation's largest cities – Los Angeles, San Antonio, Seattle and Orlando – operate publicly owned electric utilities in their communities, many public power electric utilities are small and serve 3,000 or fewer customers.

In the area of mutual aid and disaster management, public power utilities have developed mutual aid networks to ensure an expeditious and organized response for assistance. The networks are comprised of local utility-to-utility agreements, state associations, and joint action agencies. Each network has network coordinators that work together during large-scale disasters to facilitate the movement of crews and supplies from one region to the next. These networks have existed for many years and, since the late 1990's, the American Public Power Association (APPA) has acted as a conduit for the network coordinators during large-scale disasters.

APPA also works with the National Rural Electric Cooperative Association and Edison Electric Institute to coordinate public power's aid with cooperative and investor-owned utilities, respectively. Additionally, APPA keeps the Department of Energy, Federal Emergency Management Agency, and other federal partners abreast of recovery efforts for public power communities.

To learn more about public power's mutual aid network, please visit publicpower.org/MutualAid or email MutualAid@publicpower.org.

EEI has also reached out to NRECA and obtained the following information via their website.

NRECA

NRECA is the national service organization for more than 900 not-for-profit rural electric cooperatives and public power districts providing retail electric service to more than 42 million consumers in 47 states and whose retail sales account for approximately 12 percent of total electricity sales in the United States.

NRECA's members include consumer-owned local distribution systems — the vast majority — and 66 generation and transmission (G&T) cooperatives that supply wholesale power to their distribution cooperative owner-members. Distribution and G&T cooperatives share an obligation to serve their members by providing safe, reliable and affordable electric service.

AGA MUTUAL ASSISTANCE PROGRAM

The American Gas Association offers its members (utilities, transmission, and manufacturers/suppliers/service providers) a voluntary, no-fee mutual assistance program designed to suit the wide variation of needs of its member companies across the United States and Canada. The program is based on a coalition of AGA member companies, which agree to a set of baseline provisions that govern mutual assistance and agree to populate and maintain the AGA Mutual Assistance Database with company-specific emergency contact information, field capabilities and other key resources available for mutual assistance. The purpose of the AGA program is to supplement local, state and regional mutual assistance programs and is intended for those unprecedented man-made or natural disasters requiring the dedication of response/recovery/restoration resources outside the limits of existing mutual aid programs. The incorporation of the AGA Mutual Assistance Program into a company's emergency planning portfolio enhances advanced planning and effectuates response efforts in time of extenuating circumstances. Point of Contact: Mike Bellman, Email: [redacted] Below is AGA's URL if want more information. AGA held an Exercise in January 2014 and the overview and lessons learned is on their website too.

http://www.aga.org/Kc/OperationsEngineering/ngmarc/Pages/default.aspx

Appendix F: Background on a National Response Event

The purpose of the NRE Resource Allocation Process is to efficiently deliver an equitable and transparent allocation of restoration workers to EEI member companies ("utilities" or "companies") during a National Response Event. This process will be used for events in which an NRE is activated and will be used throughout the event until all resource requests have been met.

Case for action

In the aftermath of Superstorm Sandy, the electric utility industry developed the NRE process to enhance the existing mutual assistance process for national events because:

- Electric customers who have increasing expectations and electricity dependence need to see the mutual assistance process as efficient, transparent and equitable;
- Each individual utility or regional mutual assistance group (RMAG) plays a key role in successful response;
- The industry wants to demonstrate that it is prepared for significant events and committed to continuous improvement; and
- More efficient resource allocation would further improve public safety, accelerate restoration and reduce potential economic consequences.

Defining a National Response Event

A National Response Event is an electric utility event that:

- The event is expected to or has impacted two or more RMAGs; or
- The resource requirements are greater than what the impacted RMAGs can offer; or
- There are multiple events that create a resource constraint or competition between RMAGs.

Once the NRE is activated, all of the available resources (line workers, tree trimmers, damage assessors, logistical support, etc.) are allocated at the national level across individual companies and RMAGs based on transparent and objective criteria.

A National Response Event will also require coordination of the Federal, State and Local response.

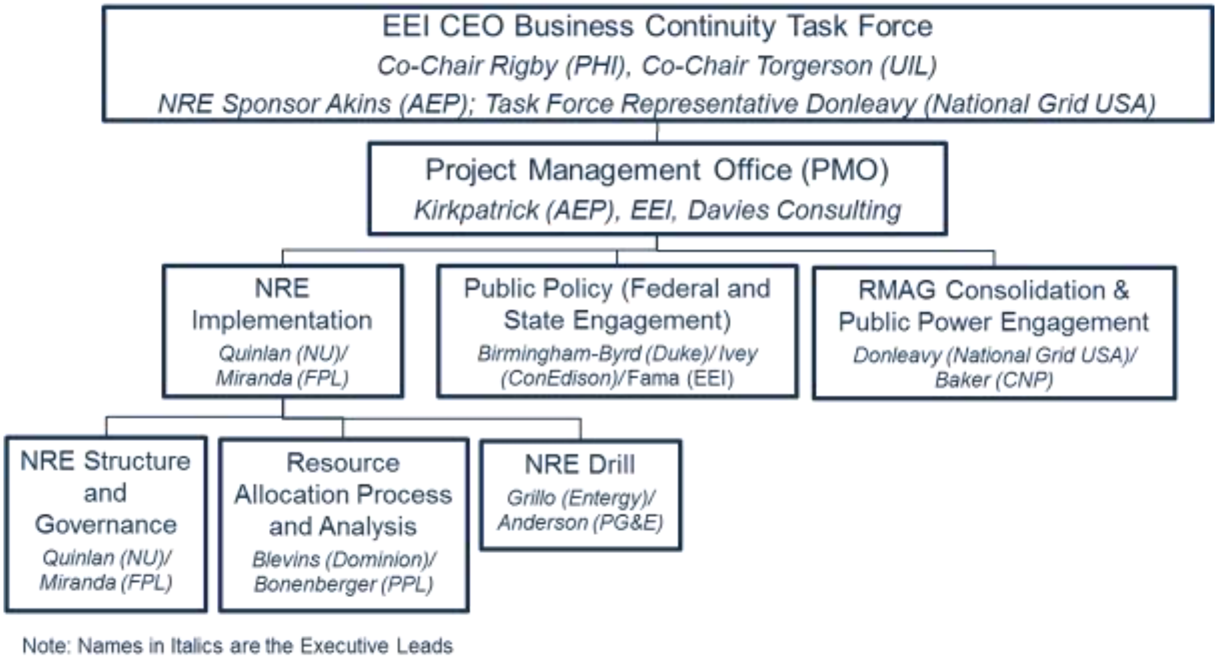
Project Management Office (PMO) efforts in 2013

In the aftermath of Superstorm Sandy under EEI's leadership, the industry undertook an effort to further enhance its mutual assistance process for large outage events. Throughout 2013, nearly 60 representatives from 36 utilities, supported by EEI staff and Davies Consulting, LLC, worked tirelessly to strengthen the industry's capability to respond to future outage events that impact multiple regions of the country.

The request for activating the NRE should meet the following criteria regarding the actual/forecasted event:

- The event is expected to or has impacted two or more RMAGs; or
- The resource requirements are greater than what the impacted RMAGs can offer; or
- There are multiple events that create a resource constraint or competition between RMAGs.

In order to make necessary progress in a relatively short period of time, the team created a project management office and project structure, which is described in the following chart:



The first phase of the NRE design was completed and presented to the EEI Board in June 2013, where the team obtained approval to continue with implementation. The initial implementation was completed in October 2013, after being tested through a set of one table top and two functional exercises.

The Executive Leads worked closely with the EEI Mutual Assistance Executive Team, representatives from most of the RMAGs and other executives. The list of contributors throughout includes individuals listed in Appendix B in alphabetical order of their utility names:

- Brad Oachs (ALLETE)
- Vern Gebhart & Tom Hess (Alliant Energy)
- Tom Kirkpatrick, Jim Nowak & Bob Powers (American Electric Power)
- David Baker (CenterPoint Energy)
- Tim Hayes & Charles Freni (CH Energy)
- Terrence Donnelly (ComEd)
- Craig Ivey, Carlos Torres & Tony Torphy (ConEd)
- Anthony Bunting (Cleco LLC)
- Rodney Blevins (Dominion)
- Melody Byrd-Birmingham, Marty Zearbaugh, & Marty Wright (Duke Energy)
- Patrick Conti & Tim Kuruce (Duquesne Light)
- Greg Grillo & Michael Fricke (Entergy)
- Randy Coleman, Mark Julian & Cheryl Scheeler (FirstEnergy)
- Kevin Walker (Iberdrola USA)
- Carol Baxter (KCP&L)
- Greg Thomas (LG&E & KU Energy)
- John Donleavy & Dave Way (National Grid USA)

- Manny Miranda (NextEra)
- Bill Quinlan & Mike Zappone (Northeast Utilities)
- Jim Reagan (NV Energy)
- Mike Mathews (OGE)
- Keith Hull, Mike Carter, & Jeffrey Dossey (Oncor)
- Debbie Guerra (PacifiCorp)
- Barry Anderson (PG&E)
- Dave Velazquez, Thomas Born & George Nelson (PHI)
- David Bonenberger (PPL)
- Booga Gilbertson (Puget Sound)
- Dana Kracke, Rachel Sherrill & Henry Martinez (SCE)
- Jim Collins (Southeastern Electric Exchange)
- Aaron Strickland, Danny Glover & Mark Crosswhite (Southern Co.)
- John Prete (UIL Holdings)
- Tom Murphy (Unitil)
- Brian Gatewood & Rich Schach (Vectren)
- Kevin Fletcher (We Energies)
- Bryan Nowlin (Westar Energy)
- Don LuMaye (WPS)

Appendix G: Frequently Asked Questions

Questions and Answers: Union Issues

Q. Are non-union crews being turned away?

A. [Local facts if known] In the case of significant outage events, electric utilities request and accept assistance from any and all qualified workers. The reports of non-union crews being turned away during Sandy were found to be untrue. Utilities in the affected areas and union representatives welcomed assistance regardless of their union status.

Questions and Answers: Cross State Lines/Blocking by Governors

Q. Why should workers be allowed to move across state lines? How do you respond to [Governor of State] who has called for crews to remain/not be allowed to cross state/not be allowed to leave?

A. A timely restoration effort requires a smooth transition of resources from other regions into the affected area, regardless of the state boundary. Utility service territories often extend beyond state boundaries and restoration work often involves multiple jurisdictions. Having flexibility to move resources to the outage location is the key to successfully completing a restoration. The electric utility industry's mutual assistance program ensures that all available emergency restoration resources (including contractors) will be pooled and allocated to participating utilities in a safe and efficient manner.

The investor-owned electric utility industry's national response to [event] is successfully coordinating [Number] response workers from [# Companies/States/Region/Nationally] to assist throughout the affected areas. These workers are [arriving/on the road], and limiting utilities' ability to move restoration resources in the most efficient manner undermines this process. The total workforce, including workers from affected companies and those providing mutual assistance, is [Number].

Questions and Answers: Workforce Issues

Q. Will the enhancements made to the industry's mutual assistance program get more workers to the outage in [AREA]?

A. The investor-owned electric utility industry's mutual assistance program now has the ability to coordinate the allocation of restoration workers on a regional and national scale, but it does not create a larger overall pool of qualified restoration workers. The industry is working on workforce development through the Center for Energy Workforce Development and with programs like Troops to Energy Jobs, but these efforts are designed to bring new workers into the industry over time.

The investor-owned electric utility industry's response to [event] is successfully coordinating [Number] response workers from [# Companies/States/Region/Nationally] to assist throughout the affected areas. These workers are [arriving in the region/on the road/already at work]. The total workforce, including workers from affected companies and those providing mutual assistance, is [Number].

Questions and Answers: Hardening and Restoration

Q. Will the enhancements made to the industry's mutual assistance program make the system stronger/prevent outages?

A. The electric utility industry's mutual assistance program is not designed to directly address infrastructure needs. These decisions are made by utilities and regulatory bodies that determine the most cost-effective measures to strengthen the grid and make it more resilient.

Q. Will the enhancements to the mutual assistance program make the lights come on faster?

A. Due to the inherently unpredictable nature of disasters, the mutual assistance program cannot reduce the damage that may occur from severe outage events. Enhancements made to the process do scale up the industry's mutual assistance program to address national level outages and ensure that mutual assistance is safe and efficient.

Q. Would undergrounding prevent outages?

A. The mutual assistance program is not designed to directly address infrastructure needs. However it is important to remember that some measures of reliability indicate that underground electric infrastructure has only a slightly better reliability performance than overhead electric systems, while other measures show a higher reliability factor for underground facilities. One explanation may be that many underground facilities are fed by overhead facilities which can become disabled during storms.

Repairs to underground facility outages are often more complex and time consuming and such facilities are more costly to upgrade and replace. And, as recent experiences with Superstorm Sandy demonstrate, underground facilities are very vulnerable to flooding and water damage.

Undergrounding also brings significant costs, industry data show that costs for underground transmission and distribution construction costs can be between five to 10 times greater than for overhead.

Questions and Answers: Mutual Assistance Process Specific

Q. What enhancements were made to the industry's mutual assistance program following Superstorm Sandy?

A. The investor-owned electric utility industry has developed a new framework to institutionalize the lessons learned and best practices from Sandy in order to optimize restoration efforts following events that impact a significant population or several regions across the U.S. and require resources from multiple Regional Mutual Assistance Groups (RMAGs). In the case of significant outage events, where an industry-wide response is needed, all available industry emergency restoration resources (including contractors) will be pooled and allocated to participating utilities to safely and efficiently meet restoration needs.

A committee of senior-level member company utility executives from all regions of the country governs this allocation process, with members drawn from utilities in each of the seven RMAGs. RMAGs will continue to facilitate the process of identifying available restoration workers and help utilities coordinate the logistics and personnel involved in restoration efforts.

One of the important lessons learned following Superstorm Sandy was that there were too many small RMAGs in the Northeast. In September 2013, the Mid-Atlantic Mutual Assistance (MAMA), New York Mutual Assistance Group (NYMAG), and the Northeast Mutual Assistance Group

(NEMAG) finalized their merger into the North Atlantic Mutual Assistance Group (NAMA)—reducing the total number of RMAGs from nine to seven.

This merger included 21 utilities across 13 states, 1 district, and 4 Canadian provinces. Merging these three smaller RMAGs into one larger RMAG allows more resources to be available to the participating utilities and increase the ability of the RMAG to provide more self-sustaining support for most local and regional outage events without having to reach out and coordinate across multiple RMAGs.

The electric utility industry continues to collaborate and work with the federal government and the states to enhance and formalize industry-government partnerships developed during Superstorm Sandy. These efforts include:

- Improving communication and coordination by embedding senior industry officials with government response teams at the U.S. Department of Energy and coordinating with the Federal Emergency Management Agency.

- Streamlining transportation by developing information resources and tools to expedite the movement of resources across state lines in partnership with the U.S. Department of Transportation and state transportation agencies. Additionally, we have negotiated a new procedure for U.S. and Canadian border crossings with the Department of Homeland Security and the Canadian Border Services Agency to minimize delays and to ensure timely movement of mutual assistance crews across the international border.

- Engaging in an ongoing dialogue with the Department of Defense (DOD) to enhance logistical support, such as access to DOD property and facilities for pre-staging areas, exploring ways to enhance security and road access with the National Guard, and securing access to critical supplies and equipment from the Army Corps of Engineers.

Q. Specifically how does the mutual assistance program allocate response resources?

A. The national allocation of response resources uses a formula that takes into account the proportion of customer outages and the proportion of trouble spots relative to all requesting utilities. Additional qualitative refinements to the allocation may also be made based on geography, travel routes, type of damage, and other factors that can affect restoration. After the allocation, resource matching to individual utilities is conducted through Regional Mutual Assistance Groups (RMAGs) based on local requirement. Reallocation of resources is also built into the process so restoration workers and equipment can be effectively redeployed throughout an event. The process is designed to make an efficient and equitable allocation based on need.

Q. What are the specific numbers?

A. [EEI will release national numbers based on information from the NREC/NMART.]

Appendix H: Glossary of Terms

Term	Definition
Analytic Team	Designated members of NMART Team (EEI MA Executive Committee) that will review allocations output and make preliminary RMAG assignments prior to NMART call.
Company resources	Resources that work on a utility property on a blue sky day at the time of the event, including contractors.
Continuous Improvement	Ongoing effort to review and improve the current business practices.
Contractor	Company that provides resources and equipment (line, tree, etc.) to an IOU through a contractual agreement.
Customer	Metered facility serving electricity to one residence, business or industry. Does not include outdoor lighting.
Customer Outage (sustained)	Sustained distribution outage longer than 5 minutes.
Damage Assessor	FTE that goes into the field and evaluates and records damage to an electrical system.
Full Time Equivalent (FTE)	Resources are counted as individual workers versus using the term of "Crew". Crew is defined in many different ways across the industry, so for consistency purposes, the mutual assistance discussions are based on FTE counts.
Investor Owned Utility (IOU)	Utility that is owned by investors. Does not include Co-Operatives, Municipal owned systems, etc.
Non-Native Resources	Resources that are not on a utility system on a daily basis. Non-Native includes sister company resources.
Off-system resources	Resources that are not working on a utility system on a daily basis (includes contractors & sister companies)
Reallocation	In the unlikely event that a utility has a larger share of the workforce and it is obvious, it may be asked to release some portion of workers and move them to another utility. This is a last resort effort.
Redeployment	Once a utility has made progress and cannot utilize all resources efficiently, they will begin a release of a portion (or all) outside resources to assist others.
Requesting company	Company that has been impacted with outages and is receiving resources from others.
Resource request (Pre-staging)	Resource requests for pre-staging should be the summation of resources acquired plus additional needs at this point in time. This should be a maximum number that you would take at this point in time.
Resource Request (Allocations)	Resource requests for allocations should be the maximum incremental number of resources that you would take at this point in time.
Responding company	Company that provides resources to assist in restoring power for an impacted company.
Cases of Trouble	One case of trouble representing a device that is damaged and in need of repair in order to restore the service to their customers.
Utility	Business entity that provides electrical service to customers.

Appendix I: Communications Checklists and Templates

Checklist -- How To Activate the Storm Center as the www.eei.org Home Page

Slide Show Images

Update images for use in the slide show at the top of the page.
Images are 600px x 360px.
The images in this folder will be shown in the slide show. Delete any images that should not be on the home page.
http://www.eei.org/SiteCollectionImages/Forms/Thumbnails.aspx?RootFolder=%2FSiteCollectionImages%2Fma%2Fslider

Edit Title

Edit page http://www.eei.org/Pages/ma.aspx to include the new Title.

Edit Storm Center Multimedia Page

Set up the multimedia gallery by editing the storm center page in the Mutual Assistance section under the Electric Reliability issue.
http://www.eei.org/issuesandpolicy/electricreliability/mutualassistance/Pages/default.aspx

Update Map of Affected States

When appropriate shade and update map.
Verify the companies' outage center links of affected states. If they need to change edit, this list:
http://www.eei.org/Lists/Company%20Storm%20Sites/AllItems.aspx
Shade affected states and post new image here: http://www.eei.org/SiteCollectionImages/ma/storm-map.jpg

Activate New Home Page

1. From the current home page select "Site Actions"
2. Select "Site Settings"
3. Under "Look and Feel" select "Welcome Page"
4. Change "default.aspx" to "ma.aspx"
5. Hit "OK"

Checklist -- Reporter's List Guide

All lists of reporters are located on Vocus under media contacts lists.

- Energy and Utilities List: 345 Energy and Utility reporters
  - Printed and organized by Outlet Name
- Master Media List: 287 Reporters Covering Multiple Topics
  - Printed and organized by Outlet Name

- National Media List: 865 Assignment Desk Reporters
  - On Vocus
- RMAG Assignment Desk Lists: on Vocus
  - Midwest RMAG: ND, SD, NE, KS, MO, CO
  - Western RMAG: MT, WY, NV, AZ, NM, ID, UT, CA, OR, WA
  - Texas RMAG: TX, OK, AR
  - Wisconsin RMAG: WI, MN, IA
  - Southeast RMAG: FL, GA, AL, LA, MS, SC, NC, VA
  - Great Lakes RMAG: TN, KY, IN, IL, MI, OH, WV
  - North Atlantic RMAG: MD, DE, PA, NJ, NY, MA, CT, VT, ME, RI, NH

Template -- Generic Preparedness Message

Be Prepared, Be Safe.

What you can do now:

- Read EEI's [Type of Event] safety tips.
- Develop an emergency plan that addresses any special medical needs you or your family members have. Call your local emergency management office to discuss necessary arrangements.
- Have your Emergency Outage Kit stocked and readily available.
- Know all evacuation routes.
- Pay attention to local weather reports on the radio, television, or Internet.
- Stock up on non-perishable food, water, medications, and any other necessities to avoid the need for travel during the storm. If called to evacuate, do so immediately.
- Learn what to do in case of a power outage.

If a severe storm does hit your area:

- Stay in a secure room and away from windows. Remain indoors.
- Monitor weather bulletins on a battery-powered radio.
- If your power goes out, report your outage immediately to your local electric company. Don't rely on your neighbors to report your outage.

Severe Weather and Reliability
In addition to customer safety, the electric power industry's top priority is to provide a reliable supply of on-demand power. Discover how the industry responds to outages caused by severe weather:

- Review the power restoration process.
- Learn about the industry's Mutual Assistance Network.

Don't forget to visit your local electric company's Web site for the latest updates and guidance on how to prepare for storms.

Template -- Email to CEOs about NRE Activation

Email to CEOs about NRE Activation

TO: EEI CEOs
CC: Communicators, External Affairs (State/Local Contacts), Mutual Assistance and Emergency Preparedness Committee, Business Continuity Task Force, and NREC/NRE/RMAG distribution lists.
FROM: Tom Kuhn/Crisis Management Officer
DATE: [DA/MO/YEAR]

As you know [NRE EVENT] is forecast to impact [REGION].

[SITUATIONAL ANALYSIS AS NEEDED].

Based on the [NRE EVENT FORECAST/EXISTING CONDITIONS/IMPACT OF NRE EVENT] and the recommendation of EEI CEO(s), the National Response Executive Committee (NREC has activated our National Response Event (NRE) framework.

An NRE is a natural or man-made event that is forecast to cause or that causes widespread power outages impacting a significant population or several regions across the U.S. and requires resources from multiple Regional Mutual Assistance Groups (RMAGs). During an NRE, our mutual assistance program is coordinated at the national level by the NREC and restoration resources are allocated by the National Mutual Assistance Resource Team (NMART) to deliver a safe, efficient, and equitable, allocation of restoration workers and contractors.

EEI has activated its crisis management plan to address this NRE.

Throughout the NRE, we will be hosting daily CEO calls to discuss events (timeline below) and the NREC chair will update CEOs on these calls.

<u>Timeline for CEO Calls</u>
3:30 PM EDT – CEOs directly affected by [NRE EVENT]
4:30 PM EDT - All CEOs
5:15 PM EDT - CEOs and Government/External partners

The predetermined call number is 1-412-717-9582 / ask for “EEI NRE Call”. Agendas are attached.

Our communication team will be preparing daily talking points on the NRE for internal and external audiences, a copy is attached.

We have also attached a roster of the NREC members and EEI staffing chart.

Template -- NRE Industry Communicators Conference Call Agenda

7 PM Eastern (Daily during NRE/Event)
Call-in Number: 1-800-882-3610
Guest Code: 4731734
Host Code: 0452833
<u>Agenda</u>

1. NRE/Event Status
    a. Event outage overview (total out, % restored, progress, unable to energize)
    b. Topline resource allocation and response summary (process update, total responding, resources allocated through NRE)
    c. Review of broader resource and restoration challenges and issues being addressed by EEI (as needed)
        i. Logistics/Transportation/Access/Lodging/Security/Equipment
        ii. Political issues
        iii. Federal actions
    d. CEO Conference Call Summary and Update
2. Company Restoration Status Review
    a. Input from companies on their restoration progress
    b. Successes
    c. Challenges
    d. Special considerations/issues
    e. Comparison to overall numbers
3. Daily Industry Message Update
    a. Review EEI industry messages/talking points
    b. Highlights from daily email/messaging/visual report
4. Company Messaging Review
    a. Input from companies on their messaging
    b. Share messaging examples
    c. Channels/Tactics that are working well
    d. Any unique/special messages
5. Communication Challenges/Successes
    a. Input from companies
    b. What's working well?
    c. What's not working?

Template -- NRE Talking Points (Pre-Event)

[NRE EVENT NAME]
Time, Date
Prepared By EEI Communications

Top Line
Utilities in the projected path of [NRE EVENT NAME] are prepared and if you live in the projected path you need to be prepared too.

Storm Update
The latest update from NOAA indicates that [NRE EVENT NAME] is a [EVENT DESCRIPTION] and may [EVENT IMACT TIMING].

The Edison Electric Institute (EEI), along with the investor-owned electric utility industry's Regional Mutual Assistance Groups (RMAGs) and the utilities in the projected path, continue to closely monitor the storm and its intensity and are taking steps now to prepare.

Utilities in the projected path are prepared to respond to any customer outages that may occur. If called upon, restoration crews are prepared to travel to impacted areas, and utilities remain in constant contact with their RMAG. Additionally, if conditions warrant, the industry is prepared to scale our mutual assistance efforts to the national level so industry restoration resources are allocated in a singular and seamless fashion.

Be Prepared. Be Safe.
If you live in the forecasted path of [EVENT DESCRIPTION], now is the time to prepare. Electric customers are encouraged to prepare for the possibility of sustained power outages by taking action before [NRE EVENT NAME]
makes landfall. For safety tips and updates visit the Edison Electric Institute website, www.eei.org, or your local utility's website.

[EVENT DESCRIPTION/WEATHER UPDATE] (Time, Date, Source)

-
-
-

Mutual Assistance Program
RMAGs continue to monitor **[NRE EVENT NAME]**. At this time, a National Response Event has not been activated, but the industry is closely monitoring the situation and will be ready to activate if conditions warrant. The investor-owned electric utility industry defines a National Response Event (NRE) as a natural or man-made event that is forecast to cause or that causes widespread power outages impacting a significant population or several regions across the U.S. and requires resources from multiple Regional Mutual Assistance Groups (RMAGs). It's important to understand an NRE designation is reserved only for the most significant events, such as a major storm, earthquake, an act of war, or other occurrence that results in widespread power outages.

Thoughts & Prayers Message
EEI and its member electric power companies understand that power outages of any duration are hugely disruptive to peoples' lives, which is why we are preparing now for **[NRE EVENT NAME]**. Through the electric power industry's Mutual Assistance Program, impacted member companies will be able to request restoration workers and respond to outages as safely and quickly as possible. In the event of outages, our industry is committed to working around the clock, to get every last customer's lights turned back on.

Template -- [NRE EVENT NAME]
Time, Date
Prepared By EEI Communications

Top Line
The damage left in the wake of [DAMAGE ASSESSMENT – states/customers impacted, outages]. Restoring power as safely and efficiently as possible is the electric power industry's number one priority. First responders, aid workers, and utility workers are the true unsung heroes.

Electric utility companies affected by [NRE EVENT NAME] have been working around-the-clock to assess the damage/restore power to millions of customers. Prior to [NRE EVENT NAME], utility companies mobilized thousands of storm response personnel and called upon extra workers and resources from all across the country through the industry's Mutual Assistance Network.

Mutual Assistance Overview
EEI's mutual assistance network—a voluntary partnership of investor-owned electric utilities from across the country—leverages the strength, skills, and resources of participating utilities to help restore power after an emergency situation. Through the network, affected electric utilities are able to "borrow" skilled restoration workers—both utility employees and contractors—along with specialized equipment from other utilities that participate in one or more of our seven Regional Mutual Assistance Groups (RMAGs). Municipal utilities and electric cooperatives also have their own mutual aid programs that provide restoration support to their participating utilities.

The current mutual assistance program works well for regional events, but was not designed to be scalable for national events.

NRE Activated
Due to the significant size and scope of [NRE EVENT NAME], the investor-owned electric utility industry activated [NRE EVENT NAME] a "national response event" (NRE) on [DATE]. During an NRE, our mutual assistance program is coordinated at the national level to deliver a safe, efficient, equitable allocation of restoration workers and contractors to participating utilities.

Storm Update
The latest update from NOAA indicates that [NRE EVENT NAME] is a [EVENT DESCRIPTION] and may [EVENT IMACT TIMING/DURATION].

Restoration Outage Overview
Customers impacted:
Percent of customers out in impacted states:
Impacted States/Customers Out:

Safety Message
Restoring power as safely and efficiently as possible is the electric power industry's number one priority. Customers need to be prepared for the possibility of extended outages due to the enormity of [NRE EVENT NAME]. Although our industry prepared for [NRE EVENT NAME] by pre-staging restoration workers and equipment near affected areas, [NRE EVENT NAME] damaged the electric system, blocked roads, and created hazardous working conditions for people in the area.

Restoration workers always put safety first, and we urge the public to be patient and to stay clear of fallen power lines and avoid standing water that could hide damaged electrical equipment or other dangerous objects.

For safety tips and updates visit the Edison Electric Institute website, www.eei.org, or your local utility's website.

Thoughts & Prayers Message
Our hearts and prayers go out to those affected by [NRE EVENT NAME]. We know that people without electricity face very real hardships. And we deeply appreciate their understanding and patience as utility crews go about their vital jobs of restoring power under extremely challenging and dangerous circumstances. Our entire industry will give it everything it has, working around the clock, to restore power as safely and efficiently as possible.

Industry-Government Coordination
Because of the severity of [NRE EVENT NAME], industry and government officials are closely coordinating to identify potential barriers and areas where federal and state governments would be able to assist during the response and restoration process.

Other Key Talking Points As Needed (See "Canned Messages")

Template -- Opt Out Email for External Stakeholders

As you know, [Storm Name] is [expected to / has impacted] several states. Due to the [severity / forecasted severity] of [Storm Name], The [Mutual Assistance Network / industry-wide National Response Event (NRE) process] has been activated, which allows the investor-owned electric utility industry to coordinate its storm restoration response to [Storm Name] at the national level [(only if NRE) in order to ensure industry restoration resources are seamlessly allocated in the most safe and efficient manner possible].

Through the duration of [Storm Name], EEI will be distributing daily news clips and summary reports reviewing the industry's restoration progress; the first summary report is attached. If you do not want to continue to receive these daily updates, please click on this link to opt-out of these reports.
[OPT OUT LINK]

Background
In the aftermath of Superstorm Sandy, the investor-owned electric utility industry recognized the value of enhancing and formalizing the mutual assistance process for events that require a national, industry-wide response. For outage events that require a national response, the investor-owned electric utility industry will activate an industry-wide "national response event" (NRE). An NRE is a natural or man-made event that is forecast to cause or that causes widespread power outages impacting a significant population or several regions across the U.S. and requires resources from multiple Regional Mutual Assistance Groups (RMAGs). Municipal utilities and electric cooperatives also have their own mutual aid programs that provide restoration support to their participating utilities.

[Storm/Event]
Updated Briefing Points
[Time, Date]
Prepared By EEI Communications

Restoration Outage Overview

- Customers impacted: 0 (Sandy: 10 million; Irene: 7 million; Derecho: 5 million)
- Current outages: 0 (EEI – Time, Date)
- Total restored: 0 (EEI – Time, Date)
- Percent restored:
- Outages restored last 24 hours
- Percent restored that could be energized: TBD
- Customers unable to energize: [Total]; [MC 1]; [MC 2]; [MC 3]
- Current outages/peak outages: [State 1]: [CO/PO]; [State 2]: [CO/PO]; [State 3]: [CO/PO]
- Estimated Economic Damage: $ (Citation)
- Restoration Update: An army of [Number] ([Number] utility companies)—from as far away as [Canada], [California] & [Hawaii]
- Death Toll: [Number] in [Number] states; [State 1]: [Number]; [State 1]: [Number] (Citation)

Daily Outage Breakdown

Days	Date	Outages	Percent Restored
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			

Template – Press Release Pre-Storm

Edison Electric Institute
Power by Association

News

701 Pennsylvania Ave., N.W. | Washington, D.C. 20004-2696 | 202.508.5000 | Fax: 202.508.5759 | news@eei.org | www.eei.org

FOR IMMEDIATE RELEASE
TEMPLATE **FOR INFORMATION CONTACT:**
[EEI MEDIA RELATIONS CONTACT, PHONE #]

EEI, Electric Utility Industry Prepare for [NRE EVENT NAME]

Washington, DC (Day, Date) – With [NRE EVENT NAME] expected to impact [STATES/LOCATIONS], the electric utilities companies in the forecasted path are taking steps now to prepare. [NRE EVENT NAME] [EVENT DESCRIPTION/EXPECTED IMPACTS]. Electricity customers are encouraged to prepare for the possibility of sustained power outages by taking action before [NRE EVENT NAME] [EVENT DESCRIPTION/EXPECTED IMPACTS].

"With [NRE EVENT NAME] predicted to strike as early as [DAY/DATE], we urge customers to put safety first and be ready should severe weather reach their areas," said EEI President Tom Kuhn. "EEI and its member electric utility companies understand that power outages of any duration are hugely disruptive to peoples' lives, which is why we are preparing now for [NRE EVENT NAME]."

No pre-deployment: *Electric utility companies in the region are initiating their storm response plans. And, the investor-owned electric utility industry's Regional Mutual Assistance Program is ready to provide restoration support by calling upon extra workers and resources from all across the country in order to restore service as safely and efficiently as possible."*

Pre-deployment: *Through the investor-owned electric utility industry's Regional Mutual Assistance Program, many of our member companies have already begun the process of pre-mobilizing thousands of storm and field personnel, and calling upon extra workers and resources from all across the country to assist if the power goes out in order to restore service as safely and efficiently as possible."*

STORM CENTER NOT ACTIVATED: *On the EEI web site utility customers can find safety tips and information about how electric service is restored. EEI also encourages utility customers to follow EEI's social media sites on Twitter and Facebook.*

STORM CENTER ACTIVATED: *On the EEI Storm Center site, utility customers can find safety tips, links to customers' own electric company's outage centers, real-time information and updates on storm preparation and restoration progress. EEI also encourages utility customers to follow EEI's social media sites Twitter and Facebook.*

###

The Edison Electric Institute (EEI) is the association that represents all U.S. investor-owned electric companies. Our members provide electricity for 220 million Americans, operate in all 50 states and the District of Columbia, and directly employ more than 500,000 workers. EEI has 70 international electric companies as Affiliate Members, and 250 industry suppliers and related organizations as Associate Members.

Template – Press Release NRE Activated

Edison Electric Institute
Power by Association

News

701 Pennsylvania Ave., N.W. | Washington, D.C. 20004-2696 | 202.508.5000 | Fax: 202.508.5759 | news@eei.org | www.eei.org

TEMPLATE

FOR IMMEDIATE RELEASE
FOR INFORMATION CONTACT:
[EEI MEDIA RELATIONS CONTACT, PHONE #]

Investor-owned Electric Utility Industry Activates Industry-Wide National Response to [NRE EVENT NAME]

WASHINGTON, DC ([Day], [Date]) — The investor-owned electric power industry today activated its industry-wide national response event plan to mobilize a major restoration effort to address the significant outages that are expected from/that occurred as a result of [NRE EVENT NAME].

Due to the size and severity of [NRE EVENT NAME], the electric power industry has designated [NRE EVENT NAME] an industry-wide 'national response event' (NRE). "During an NRE, our member companies' mutual assistance program is coordinated at the national level to deliver a safe and efficient allocation of restoration workers and contractors, said EEI President Tom Kuhn." "By coordinating the industry's response in this fashion, we can increase public safety, accelerate the industry's response, and minimize economic consequences for consumers and the nation."

In the aftermath of Superstorm Sandy, EEI member companies recognized the need to enhance its mutual assistance program—which is a voluntary partnership of investor-owned electric utilities from across the country—for events that cause significant power outages and require a national industry response. NRE declarations are reserved for the most significant outage events, such as a major storm like [NRE EVENT NAME], earthquakes, an act of war, or other occurrence that results in widespread power outages.

Under the industry's NRE framework, mutual assistance is overseen by a new National Response Executive Committee (NREC), comprised of senior-level member utility executives from all regions of the country. The NREC has activated a National Mutual Assistance Resource Team (NMART) that will evaluate mutual assistance requests and assign available resources to participating utilities through the industry's established mutual assistance program. This allows investor-owned electric utilities to efficiently coordinate and scale their restoration resources to create a coordinated, national response for major events.

EEI continues to update its Storm Center site with safety tips, links to customers' own electricity providers' outage centers, real-time information, and updates on storm preparation and restoration progress. More information about storm restoration can also be found at EEI's social media sites on Twitter and Facebook.

###

The Edison Electric Institute (EEI) is the association that represents all U.S. investor-owned electric companies. Our members provide electricity for 220 million Americans, operate in all 50 states and the District of Columbia, and directly employ more than 500,000 workers. EEI has 70 international electric companies as Affiliate Members, and 250 industry suppliers and related organizations as Associate Members.

Template -- Scheduled Tweets:

Visit the EEI Storm Center at http://www.eei.org for safety tips and updates on storm preparation and restoration progress. #StormName

What is mutual assistance and how does it work when a storm like #StormName strikes? Find out here: http://ow.ly/eOFwn

Should #StormName cause outages, your electric company will take the following steps to get your power back on: http://ow.ly/eOH23

All you need to know about preparing for and staying safe during a power outage: http://ow.ly/eOJbO #StormName

Keep track of the electric power industry's response to #StormName by checking out our Storm Center at http://eei.org .

As #StormName hits, remember safety comes first for crews and customers. Check out http://eei.org for tips for you and your family.

Our members will work tirelessly to get power back on in the wake of #StormName. Here's how restoration works: http://ow.ly/eQNgt

Mutual assistance network is activated & thousands from across the country are already restoring power. More at http://eei.org . #StormName

What is mutual assistance and how does it work? Find out here: http://ow.ly/eRmZU #StormName

Millions are without power due to #StormName. Learn the steps your electric company takes to restore power: http://goo.gl/HHZgl

Restoring power is a multi-step process, and safety always comes first. Learn how power gets restored: http://ow.ly/eT5tu #StormName

Mutual assistance going strong to restore power quickly. Want to know how it works? Read about it here: http://ow.ly/eTEAz #StormName

Stay safe during a power outage by following these tips: http://ow.ly/eUhS7 #StormName

Tens of thousands are working to restore power. Get the latest #StormName recovery updates from our Storm Center at http://www.eei.org .

Utility workers from all across America are rushing to areas affected by #StormName to restore power. http://www.eei.org

National Response Event Check List for TTX, FX, Activation

Task	Owner	Conference Room	Due Date	Completed
Logistics				
• Reserve TAE Conference Rooms				
• Room Set-up: Conference (i.e. 12 people conference style)				
• After hour facilities notification and HVAC system				
• Food/Beverage				
Materials				
• Tent Cards/Badges				
• NRE Handbook (playbook)				
• Paper/pens				
A/V & Materials				
• Power strips to accommodate 6 attendees				
• Projector /screen				
• Laptop				
• WiFi – Access (username/password)				
• Flip Charts – Markers				
• Internet Access Cable				
Telephone / Printers				
• Polycon phone				
• Meridan handset phone (labelled w/number)				
• Printers - WiFi				
Correspondence				
• Save the date/Mark your calendar				
• Exercise announcement Hotel Information RSVP to "Oper. Assistant"				
• Reminder notices				
• Handbook distribution				
• Talking points – NREC Chair				
• Talking points – Crisis Management Officer				
• Talking points – Oper. Officer				
• Talking points – Comms. Officer				

Points of Contacts

Information Technology

Phones, Webinar Webinar (i.e., Live Meeting)	Lead IT Customer Support (Eddie Jreidini) Office: [redacted] Email:
Printers	Manager, Operation /IT Customer Support (Jeanny Ho) Office: [redacted] Email:

Internal Service Center

Facilities processes and procedures After hour/weekend access to 701 Penn HVAC After hour/ reserve conference room and logistics set up Catering (food/beverage)	Dir. Internal Services (Jennifer McKinney) Office: [redacted] Cell: Email:

Member Services

NetForum Database List Servers	Assoc. Management System Coordinator (Lee Hutchinson) Office: [redacted] Email:

Energy Delivery

Research hotel accommodations and disseminate information	Administrative Manager (Judy Mastin) Office: [redacted] Mobile: Email:

The **Edison Electric Institute** (EEI) is the association that represents all U.S. investor-owned electric companies. Our members provide electricity for 220 million Americans, operate in all 50 states and the District of Columbia, and directly employ more than 500,000 workers.

With $90 billion in annual capital expenditures, the electric power industry is responsible for millions of additional jobs. Reliable, affordable, and sustainable electricity powers the economy and enhances the lives of all Americans.

EEI has 70 international electric companies as Affiliate Members, and 270 industry suppliers and related organizations as Associate Members.

Organized in 1933, EEI provides public policy leadership, strategic business intelligence, and essential conferences and forums.

For more information, visit our Web site at www.eei.org.

Edison Electric Institute

701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
202.508.5000
www.eei.org

EPRP Appendix 10 EPRP Contact Lists

Emergency Preparedness and Restoration Plan Contact List

EPRP Reference	Name/Organization	Incident Command Section	Storm Role	Office	Mobile	Home	Reporting Location/ Operations Center

Emergency Preparedness and Restoration Plan Contact List

EPRP Reference	Name/Organization	Incident Command Section	Storm Role	Office	Mobile	Home	Reporting Location/ Operations Center
7.1	Atkins, Ryan	Customer Experience	Major Account Representatives	[redacted]			BOC
7.1	Bruner, Cheryl	Customer Experience	Customer Experience Section Chief				BOC
7.1	TBD	Customer Experience	Major Account Representatives				1 Quality
7.1	French, David	Customer Experience	Major Account Representatives				BOC
7.1	Howard, Joe	Customer Experience	Major Account Representatives				1 Quality
7.1	Jeffers, Kevin	Customer Experience	Major Account Representatives				1 Quality
7.1	LaFollette, Donna	Customer Experience	Municipal Customer Lead				LG&EB
7.1	Lane, Chuck	Customer Experience	Major Account Representatives				DANOC
7.1	Leist, Debbie	Customer Experience	Customer Experience Section Chief				BOC
7.1	Lynch, Michelle	Customer Experience	Major Account Representatives				LG&EB

Emergency Preparedness and Restoration Plan Contact List

EPRP Reference	Name/Organization	Incident Command Section	Storm Role	Office	Mobile	Home	Reporting Location/ Operations Center
7.1	Mehanna, Charles	Customer Experience	Major Account Representatives	[redacted]	[redacted]	[redacted]	1 Quality
7.1	Melton, Tim	Customer Experience	Critical Customer Director	[redacted]	[redacted]	[redacted]	BOC
7.1	Prince, Lawrence	Customer Experience	Major Account Representatives	[redacted]	[redacted]	[redacted]	LG&EB
7.1	Stethen, Julie	Customer Experience	Ombudsman Team Lead	[redacted]	[redacted]	[redacted]	BOC
7.1	Weis, Paul	Customer Experience	Critical Customer Director	[redacted]	[redacted]	[redacted]	LG&EB
7.1	Ward, David	Customer Experience	Major Account Representatives	[redacted]	[redacted]	[redacted]	1 Quality
7.1	Warren, Curtis	Customer Experience	Major Account Representatives	[redacted]	[redacted]	[redacted]	1 Quality
7.1	White, Mark	Customer Experience	Major Account Representatives	[redacted]	[redacted]	[redacted]	LG&EB
7.2	Crawford, Diaz	Customer Experience	Residential CC Team Leads	[redacted]	[redacted]	[redacted]	BOC
7.2	Daniel, David	Customer Experience	Call Center Director	[redacted]	[redacted]	[redacted]	BOC
7.2	Haley, Brian	Customer Experience	Residential CC Team Leads	[redacted]	[redacted]	[redacted]	EAROC
7.2	Lepp, Darius	Customer Experience	Call Center Director	[redacted]	[redacted]	[redacted]	BOC
7.2	Pfisterer, Jean Ann	Customer Experience	Call Center Director	[redacted]	[redacted]	[redacted]	BOC
7.2	Rausch, Diane	Customer Experience	Residential CC Team Leads	[redacted]	[redacted]	[redacted]	BOC
7.2	Stone, Brian	Customer Experience	Residential CC Team Leads	[redacted]	[redacted]	[redacted]	MORCC
7.2	Robinson, John	Customer Experience	Residential CC Team Leads	[redacted]	[redacted]	[redacted]	PINOC
7.2	Weathers, Andita	Customer Experience	Residential CC Team Leads	[redacted]	[redacted]	[redacted]	BOC
7.3	Bennett, Jackie	Customer Experience	Business Office Managers	[redacted]	[redacted]	[redacted]	SOMCC
7.3	Coleman, Jan Rose	Customer Experience	Business Office Director	[redacted]	[redacted]	[redacted]	BOC
7.3	Goldsmith, Carla	Customer Experience	Business Office Managers	[redacted]	[redacted]	[redacted]	ELIOC
7.3	Jones, Alex	Customer Experience	Business CC Team Leads	[redacted]	[redacted]	[redacted]	BOC
7.3	Long, Darlene	Customer Experience	Business Office Managers	[redacted]	[redacted]	[redacted]	EAROC
7.3	Mercer, Debbie	Customer Experience	Business Office Managers	[redacted]	[redacted]	[redacted]	GRECC
7.3	Thomas, Gus	Customer Experience	Business Office Managers	[redacted]	[redacted]	[redacted]	wincc
7.3	Raglin, Shana	Customer Experience	Business Office Managers	[redacted]	[redacted]	[redacted]	1 Quality
7.3	Thompson, Christy	Customer Experience	Business Office Director	[redacted]	[redacted]	[redacted]	BOC
7.3	Winkler, Devinn	Customer Experience	Business CC Team Leads	[redacted]	[redacted]	[redacted]	1 Quality
7.4	Alexander, Keith	Customer Experience	Emergency Preparedness and Response Manager	[redacted]	[redacted]	[redacted]	BOC
7.4	Atkins, Ryan	Customer Experience	Major Account Representatives	[redacted]	[redacted]	[redacted]	BOC
7.4	TBD	Customer Experience	Major Account Representatives	[redacted]	[redacted]	[redacted]	1 Quality
7.4	French, David	Customer Experience	Major Account Representatives	[redacted]	[redacted]	[redacted]	BOC
7.4	Howard, Joe	Customer Experience	Major Account Representatives	[redacted]	[redacted]	[redacted]	1 Quality
7.4	Jeffers, Kevin	Customer Experience	Major Account Representatives	[redacted]	[redacted]	[redacted]	1 Quality
7.4	Lane, Chuck	Customer Experience	Major Account Representatives	[redacted]	[redacted]	[redacted]	DANOC
7.4	Lynch, Michelle	Customer Experience	Major Account Representatives	[redacted]	[redacted]	[redacted]	LG&EB
7.4	Mehanna, Charles	Customer Experience	Major Account Representatives	[redacted]	[redacted]	[redacted]	1 Quality
7.4	Prince, Lawrence	Customer Experience	Major Account Representatives	[redacted]	[redacted]	[redacted]	LG&EB
7.4	Ward, David	Customer Experience	Major Account Representatives	[redacted]	[redacted]	[redacted]	1 Quality
7.4	Warren, Curtis	Customer Experience	Major Account Representatives	[redacted]	[redacted]	[redacted]	1 Quality
7.4	White, Mark	Customer Experience	Major Account Representatives	[redacted]	[redacted]	[redacted]	LG&EB

IC Department	Operation Center	Team
Executive	1 Quality	Command Staff
Customer Experience	AOC	PSRT
Operations	BOC	Damage Assessment
Work Planning	DANOC	DCC
Logistics	EAROC	Safety
	ELIOC	Resource Planning
	EOC	Operating Services
	Forestry	Resource Management (OP Ctrs)
	GRECC	Critical Customer
	KU	Call Center
	LEXOC	Business Office
	LG&EB	Emergency Management Outreach
	LONOC	
	MAYOC	
	MORCC	
	NOROC	
	PINOC	
	Quality	
	RICOC	
	SCM-EAR	
	SCM-LEX	
	SCM-PIN	
	SHEOC	
	SOMCC	
	SSC	
	TCC	
	WINCC	

Storm Role	Company/Entity
	LG&E-KU
	LG&E
	KU

Equipment	Type	Make	Proposed Activity Name	Task	Task Description
Transformers	Distribution	All	Quarterly Inspection	Bushing oil level inspection.	Perform a visual inspection to check the oil level.
				Perform functional test.	Monitor fan operation and listen for abnormal noise.
				Perform visual inspection.	Check bushings for contamination and damaged insulation.
				Perform visual inspection.	Perform a visual inspection of the transformer, LTC, bushings, gaskets, valves, piping and welds for oil leaks and check oil levels.
				Perform visual inspection.	Perform visual inspection of temperature indicators, and compare readings with other indicators at the station. Record and trend results.
				Perform visual inspection.	Check for obstructions and valve positions.
				Record LTC counter readings.	Check and record LTC counter reading.Record position indicator present position, high and low.
				Perform visual inspection.	Inspect control cabinet
				Record demand.	Record Load Demand Meter Readings
				Perform visual inspection.	Inspect Primary Fuses
				Perform visual inspection.	Check nitrogen system regulator
			In service Diagnostic Maintenance	Perform Dissolved Gas Analysis (LTC)	Sample oil in the LTC compartment for DGA and Mini-Screen. Send to system lab for analysis. Lab will record and trend results. If results are above a specified limit or abnormal gas ratios, investigate and recondition as required.
				Perform Dissolved Gas Analysis (Main)	Sample oil in main tank for DGA and Mini-Screen. Send to system lab for analysis. Lab will record and trend results. If results are above a specified limit or abnormal gas ratios, investigate and recondition as required.
				Perform functional test.	Prove the operation of the LTC manual/automatic control loop and ensure regulatory voltage tolerances are maintained.
				Perform infrared scan.	See Infrared Inspection Plan and Guidelines. Check on temperature differential between main tank and LTC compartment. Look for temperature inconsistencies in radiators.
			Out of Service Diagnostic Maintenance	Insulation Power Factor Test	Perform power factor test in conjunction with maintenance of associated transformer. Record and trend results for age exploration. Review results with respect to determining the effectiveness of this test.
				Perform insulation resistance test.	Perform watts loss Doble test in conjunction with transformer power factor tests. Record and trend results.
				Perform Excitation Test	Perform winding excitation test in conjunction with maintenance of associated transformer. Record and trend results for age exploration. Review results with respect to determining the effectiveness of this test.
			LTC Overhaul	Perform functional test.	Perform a functional test of tap changer in conjunction with preventative maintenance of associated apparatus. Listen for abnormal operation. Record and trend results.
				Perform functional test.	Verify temperature alarms with cooling equipment operation, in conjunction with LTC maintenance.
				Perform visual inspection.	Inspect current boxes for leaks or loose connections
				Perform internal inspection.	Inspect and adjust operating mechanism and assess condition of stationary and arcing contacts. Filter tap changer oil. Inspect and clean load tap changer compartment.
				Check fault pressure relay	Check Fault Pressure Relay
				Check nitrogen system	Check nitrogen system regulator & alarms
				Test fuses.	Perform air flow test on S&C Power fuses if applicable.
			Transformer Maintenance	Perform internal inspection.	Filter and condition oil. Visually inspect internal components and connections for abnormalities and tightness.

Equipment	Type	Make	Proposed Activity Name	Task	Task Description
Breakers	Distribution	Oil <= 60 gallon	Quarterly Inspection	Perform visual inspection.	Check breaker for mechanical integrity.
				Perform visual inspection.	Check breaker for oil leaks and gauge for clarity.
				Perform visual inspection	Check for expected indication and condition of monitoring lights.
				Record and verify operations.	Record counter reading. Record number of fault operations. Record relay targets.
				Perform visual inspection.	Check primary drops from disconnects
				Perform visual inspection.	Check physical grounds on all breakers
				Perform visual inspection.	Check all breakers monitor light in cont. house & swgrs
				Record circuit loading.	Record circuit loading for each phase.
			Annual In service Diagnostic Maintenance	Perform infrared scan.	See Infrared Inspection Plan and Guidelines for details.
				Insulating oil visual inspection.	Sample and visually inspect oil. If excessive moisture is present, investigate source of moisture and perform field dielectric test or send sample to lab for complete oil quality testing. If dielectric strength is < 22KV, recondition or replace oil as required. If oil is excessively dark (light cannot be seen through the oil), send sample to lab for oil quality testing, investigate fault duty on breaker and recondition or replace oil as required. Track and trend results for age exploration.
			Functional Test	Trip and close circuit breaker.	Manually operate relay to trip breaker. Allow reclosing relay to perform reclosing function if applicable. Perform test on breakers that can be bypassed or transferred internal to the station without dropping load.
			Out of Service Diagnostic Maintenance	Lubricate mechanism.	Perform a visual inspection of the mechanism lubrication points, assess condition of lubricant and relubricate. Record and trend results for age exploration.
				Perform timing test.	Perform test in conjunction with maintenance of associated breaker. Adjust mechanism as necessary. Record and trend results for age exploration.
				Perform contact resistance test.	Perform test in conjunction with other tests. If the load path resistance differential measurement is greater than 25% or the actual resistance is greater than specified micro-ohms investigate the cause. Record and trend results for age exploration.
				Perform visual inspection.	Check control cabinet components as per manufacturer
				Trip and close circuit breaker.	Verify trip and close operation of breaker (SCADA)
				Insulating oil quality and dielectric test	Sample and analyze oil quality (field dielectric test). If dielectric strength is <22 kV, recondition or replace oil as required.
			Breaker Overhaul	Inspect interrupter assembly.	Perform overhaul and check adjustment of interrupter assemblies. Record and trend results for age exploration.
				Perform timing test.	Perform test in conjunction with maintenance of associated breaker. Adjust mechanism as necessary. Record and trend results for age exploration.
				Insulating oil quality.	Obtain samples from each tank for lab DGA and oil quality analysis. Filter oil and correct deficiencies. Sample and analyze oil quality (field dielectric test). If dielectric strength is < 22KV, recondition or replace oil as required.
				Perform contact resistance test.	Perform test in conjunction with other tests. If the load path resistance differential measurement is greater than 25% or the actual resistance is greater than specified micro-ohms investigate the cause. Record and trend results for age exploration.
				Inspect and adjust operating mechanism and assess condition of stationary and arcing contacts.	Perform overhaul and check adjustment of mechanism and drive linkages, assess condition of stationary and arcing contacts. Record and trend results for age exploration.
				Inspect solid dielectric.	Perform visual inspection of solid dielectric in conjunction with an overhaul of associated breaker. Record and trend for age exploration.
				Trip and close circuit breaker.	Verify trip and close operation of breaker (SCADA)

Equipment	Type	Make	Proposed Activity Name	Task	Task Description
Breakers	Distribution	Oil > 60 gallon	Quarterly Inspection	Perform visual inspection.	Check breaker for mechanical integrity.
				Perform visual inspection.	Check breaker for oil leaks and gauge for clarity.
				Perform visual inspection	Check gauge for expected indication and condition. Record for age exploration.
				Record and verify operations.	Record counter reading. Record number of fault operations. Record relay targets.
				Perform visual inspection.	Check primary drops from disconnects
				Perform visual inspection.	Check physical grounds on all breakers
				Perform visual inspection.	Check all breakers monitor light in cont. house & swgrs
				Record circuit loading.	Record circuit loading for each phase.
			Annual In service Diagnostic Maintenance	Perform infrared scan.	See Infrared Inspection Plan and Guidelines
			Functional Test	Trip and close circuit breaker.	Manually operate relay to trip breaker. Allow reclosing relay to perform reclosing function if applicable. Perform test on breakers that can be bypassed or transferred internal to the station without dropping load.
			Out of Service Diagnostic Maintenance	Lubricate mechanism.	Perform a visual inspection of the mechanism lubrication points, assess condition of lubricant and relubricate. Record and trend results for age exploration.
				Perform power factor test.	Perform power factor test in conjunction with maintenance of associated breaker. Record and trend results for age exploration. Review results with respect to determining the effectiveness of this test.
				Perform time/travel test.	Perform test in conjunction with maintenance of associated breaker. Adjust mechanism as necessary. Record and trend results for age exploration.
				Perform contact resistance test.	Perform test in conjunction with other tests. If the load path resistance differential measurement is greater than 25% or the actual resistance is greater than specified micro-ohms investigate the cause. Record and trend results for age exploration.
				Perform visual inspection.	Check control cabinet components as per manufacturer
				Trip and close circuit breaker.	Verify trip and close operation of breaker (SCADA)
				Insulating oil quality and dielectric test	Sample and analyze oil quality (field dielectric test). If dielectric strength is <22 kV, recondition or replace oil as required.
			Breaker Overhaul	Inspect interrupter assembly.	Perform overhaul and check adjustment of interrupter assemblies. Record and trend results for age exploration.
				Perform time/travel test.	Perform test in conjunction with maintenance of associated breaker. Adjust mechanism as necessary. Record and trend results for age exploration.
				Insulating oil quality.	Obtain samples from each tank for lab DGA and oil quality analysis. Filter oil and correct deficiencies. Sample and analyze oil quality (field dielectric test). If dielectric strength is < 22KV, recondition or replace oil as required.
				Perform contact resistance test.	Perform test in conjunction with other tests. If the load path resistance differential measurement is greater than 25% or the actual resistance is greater than specified micro-ohms investigate the cause. Record and trend results for age exploration.
				Perform power factor test.	Perform power factor test in conjunction with maintenance of associated breaker. Record and trend results for age exploration. Review results with respect to determining the effectiveness of this test.
				Inspect/adjust operating mechanism and assess condition of contacts.	Perform overhaul and check adjustment of mechanism and drive linkages, assess condition of stationary and arcing contacts. Record and trend results for age exploration.
				Trip and close circuit breaker.	Verify trip and close operation of breaker (SCADA)
				Inspect solid dielectric.	Perform visual inspection of solid dielectric in conjunction with an overhaul of associated breaker. Record and trend for age exploration.

Equipment	Type	Make	Proposed Activity Name	Task	Task Description
Breakers	Distribution	Free Standing Vacuum	Quarterly Inspection	Perform visual inspection.	Check breaker for mechanical integrity.
				Perform visual inspection.	Check breaker and bushings for contamination and damaged insulation.
				Record and verify operations.	Record counter reading. Record number of fault operations. Record relay targets.
				Check heaters.	Assure that all heaters are functional.
				Perform visual inspection.	Check physical grounds on all breakers
				Perform visual inspection.	Check primary drops from disconnects
				Perform visual inspection.	Check all breakers monitor light in cont. house & swgrs
				Record circuit loading.	Record circuit loading for each phase.
			Annual In service	Perform infrared scan.	See Infrared Inspection Plan and Guidelines for details.
			Functional Test	Trip and close circuit breaker.	Manually operate relay to trip breaker. Allow reclosing relay to perform reclosing function if applicable. Perform test on breakers that can be bypassed or transferred internal to the station without dropping load.
			Breaker Overhaul/Out of Service Diagnostic	Inspect and adjust operating mechanism and assess condition of contacts.	Perform overhaul and check adjustment of mechanism and drive linkages, assess condition of contacts. Record and trend results for age exploration.
				Lubricate mechanism.	Perform a visual inspection of lubrication points, assess condition of lubricant and relubricate. Record and trend results for age exploration.
				Perform hipot test.	Perform Hipot test in conjunction with maintenance of associated breaker. Record and trend results for age exploration.
				Perform contact resistance test.	Perform contact resistance test in conjunction with other tests. If resistance phase differential measurement is greater than 25% or actual resistance greater than specified micro-ohms investigate cause. Record and trend results for age exploration.
				Perform timing test.	Perform test in conjunction with maintenance of associated breaker. Adjust mechanism as necessary. Record and trend results for age exploration.
				Check manufacturers specs	Check all manufacturers specs as described in the instruction manual.

Equipment	Type	Make	Proposed Activity Name	Task	Task Description
Breakers	Distribution	Free Standing SF6	Quarterly Inspection	Perform visual inspection.	Check breaker for mechanical integrity.
				Perform visual inspection.	Check breaker and bushings for contamination and damaged insulation.
				Record and verify operations.	Record counter reading. Record number of fault operations. Record relay targets.
				Perform visual inspection.	Check physical grounds on all breakers
				Perform visual inspection.	Check primary drops from disconnects
				Perform visual inspection.	Check all breakers monitor light in cont. house & swgrs
				Record circuit loading.	Record circuit loading for each phase.
			Annual In service Diagnostic Maintenance	Perform infrared scan.	See Infrared Inspection Plan and Guidelines for details.
			Functional Test	Trip and close circuit breaker.	Manually operate relay to trip breaker. Allow reclosing relay to perform reclosing function if applicable. Perform test on breakers that can be bypassed or transferred internal to the station without dropping load.
			Breaker Overhaul	Inspect and adjust operating mechanism and assess condition of contacts.	Perform overhaul and check adjustment of mechanism and drive linkages, assess condition of contacts. Record and trend results for age exploration.
				Perform hipot test.	Perform Hipot test in conjunction with maintenance of associated breaker. Record and trend results for age exploration.
				Perform contact resistance test.	Perform contact resistance test in conjunction with other tests. If resistance phase differential measurement is greater than 25% or actual resistance greater than specified micro-ohms investigate cause. Record and trend results for age exploration.
				Perform timing test.	Perform test in conjunction with maintenance of associated breaker. Adjust mechanism as necessary. Record and trend results for age exploration.
			Out of Service Diagnostic Maintenance	Lubricate mechanism.	Perform a visual inspection of lubrication points, assess condition of lubricant and relubricate. Record and trend results for age exploration.
				Perform contact resistance test.	Perform contact resistance test in conjunction with other tests. If the load path resistance phase differential measurement is greater than 25% or actual resistance is greater than specified micro-ohms investigate cause
				Perform hipot test.	Perform Hipot test in conjunction with maintenance of associated breaker. Record and trend results for age exploration.
				Perform timing test.	Perform test in conjunction with maintenance of associated breaker. Adjust mechanism as necessary. Record and trend results for age exploration.
				Check manufacturers specs	Check all manufacturers specs as described in the instruction manual.

Equipment	Type	Make	Proposed Activity Name	Task	Task Description
Breakers	Distribution	Air Magnetic	Quarterly Inspection	Perform visual inspection.	Check breaker for mechanical integrity.
				Record and verify operations.	Record counter reading. Record number of fault operations. Record relay targets.
				Record circuit loading.	Record circuit loading for each phase.
				Perform visual inspection.	Visually inspect control cab. & mech. (heaters, oil, etc.)
				Perform visual inspection.	Check all breakers monitor light in cont. house & swgrs
			Semi-Annual Inspection	Test cubicle heaters and thermostats.	Perform current test on heater system. Record current readings and compare to initial in-service readings.
			Annual In service Diagnostic Maintenance	Perform infrared scan.	See Infrared Inspection Plan and Guidelines for details.
			Functional Test	Trip and close circuit breaker	Manually operate relay to trip breaker. Allow reclosing relay to perform reclosing function if applicable. Perform test on breakers that can be bypassed or transferred internal to the station without dropping load.
			Overhaul/Out of Service Diagnostic Maintenance	Perform Hipot test.	Perform Hipot test in conjunction with maintenance of associated breaker. Record and trend results for age exploration.
				Perform contact resistance test.	Perform test in conjunction with maintenance of associated breaker.
				Perform timing test	Perform test in conjunction with overhaul of associated breaker. Adjust mechanism as necessary. Record and trend results for age exploration.
				Perform visual inspection	Perform visual inspection in conjunction with maintenance of associated breaker. Clean or replace as necessary.
				Inspect primary disconnects	Perform visual inspection in conjunction with maintenance of associated breaker. Lubricate, adjust or replace as necessary.
				Lubricate operating mechanism.	Perform visual inspection of the mechanism lubrication points, assess the condition of lubricant and relubricate. Record and trend results for age exploration.

Equipment	Type	Make	Proposed Activity Name	Task	Task Description
Breakers	Distribution	Vacuum,SF6 (Switch Gear)	Quarterly Inspection	Perform visual inspection.	As part of station general inspection check breaker for mechanical integrity.
				Perform visual inspection.	As part of station general inspection, check breaker and bushings for contamination and damaged insulation. Trend the results for age exploration.
				Record and verify operations.	Record counter reading. Record number of fault operations. Record relay targets.
				Perform visual inspection.	Check physical grounds on all breakers
				Perform visual inspection.	Check primary drops from disconnects
				Perform visual inspection.	Check all breakers monitor light in cont. house & swgrs
			Semi-Annual Inspection	Test mechanism heaters and thermostats.	As part of station general inspection, check breaker cabinet for proper heater operation. Trend the results for age exploration.
			Annual In service Diagnostic Maintenance	Perform infrared scan.	See Infrared Inspection Plan and Guidelines for details.
			Functional Test	Trip and close circuit breaker.	Manually operate relay to trip breaker. Allow reclosing relay to perform reclosing function if applicable. Perform test on breakers that can be bypassed or transferred internal to the station without dropping load.
			Out of Service Diagnostic Maintenance/Overhaul	Lubricate mechanism.	Perform a visual inspection of lubrication points, assess condition of lubricant and relubricate. Record and trend results for age exploration.
				Perform contact resistance test.	Perform contact resistance test in conjunction with other tests. If the load path resistance phase differential measurement is greater than 25% or actual resistance is greater than specified micro-ohms investigate cause
				Perform hipot test.	Perform Hipot test in conjunction with maintenance of associated breaker. Record and trend results for age exploration.
				Perform timing test.	Perform test in conjunction with maintenance of associated breaker. Adjust mechanism as necessary. Record and trend results for age exploration.
				Check manufacturers specs	Check all manufacturers specs as described in the instruction manual.
				Inspect and adjust operating mechanism and assess condition of contacts.	Perform overhaul and check adjustment of mechanism and drive linkages, assess condition of contacts. Record and trend results for age exploration.

Equipment	Type	Make	Proposed Activity Name	Task	Task Description
Disconnects	Manual - Single, Ganged	Substation	Quarterly Inspection	Perform visual inspection.	Perform visual inspection of disconnects and insulators with associated apparatus
			Annual In service Diagnostic Maintenance	Perform infrared scan.	Scan disconnects and insulators with associated apparatus. See Infrared Inspection Plan and Guidelines for details.
			Out of Service Field Maintenance	If switching is required observe operation, report all problems, repair/replace.	Perform visual inspection of the mechanism lubrication points, assess condition of the lubricant and relubricate if necessary. Record trend results for age exploration.
		Other (Non Substation)	Out of Service Field Maintenance	If switching is required observe operation, report all problems, repair/replace.	Perform visual inspection of the mechanism lubrication points, assess condition of the lubricant and relubricate if necessary. Record trend results for age exploration.

Equipment	Type	Make	Proposed Activity Name	Task	Task Description
Disconnects	MOD/MOS		Quarterly Inspection	Perform visual inspection.	Perform visual inspection of disconnect(s) and insulator(s) with associated apparatus
			Annual In service Diagnostic Maintenance	Perform infrared scan.	Scan disconnects and insulators with associated apparatus. See Infrared Inspection Plan and Guidelines for details.
			Out of Service Field Maintenance	Perform functional test.	Perform test in conjunction with maintenance of associated apparatus.
				If switching is required observe operation, report all problems, repair/replace.	Perform visual inspection of the mechanism lubrication points, assess condition of the lubricant and relubricate if necessary. Record trend results for age exploration.

Equipment	Type	Make	Proposed Activity Name	Task	Task Description
Surge Arresters	All		Quarterly Inspection	Perform visual inspection.	Perform visual inspection of Surge Arresters with associated apparatus
			Annual In service Diagnostic Maintenance	Perform infrared scan.	Scan surge arresters with associated apparatus. See Infrared Inspection Plan and Guidelines for details.
			Out of Service Diagnostic Maintenance	Perform insulation resistance test.	Perform watts loss Doble test in conjunction with transformer power factor tests. Record and trend results.

Equipment	Type	Make	Proposed Activity Name	Task	Task Description
Relays	Electro-mechanical		Bench Test	Bench test relay.	Calibrate to within 50% of the maximum acceptable tolerance if found to be beyond the desired setting. Record as found for age exploration.
			Functional Test	Perform functional test	Move the contacts/spin disk to verify they are free of mechanical binding and verify targets and alarms. Perform this test in conjunction with functional test of associated apparatus.
	Solid State		Bench Test	Bench test relay.	Calibrate to within 50% of the maximum acceptable tolerance if found to be beyond the desired setting. Record as found for age exploration.
			Functional Test	Perform functional test	Move the contacts/spin disk to verify they are free of mechanical binding and verify targets and alarms. Perform this test in conjunction with functional test of associated apparatus.
	Microprocessor		Monitor alarms.	Monitor alarms.	At the occurrence of an alarm investigate the cause.

Equipment	Type	Make	Proposed Activity Name	Task	Task Description
Station Current Transformer	All		Quarterly Inspection	Perform visual inspection.	Perform visual inspection of current transformers as part of general station inspection
			Annual In service Diagnostic Maintenance	Perform infrared scan.	Scan current transformers. See Infrared Inspection Plan and Guidelines for details.

Equipment	Type	Make	Proposed Activity Name	Task	Task Description
Station Potential Voltage Transformer	All		Quarterly Inspection	Perform visual inspection.	Check column for contamination and damaged insulation.
				Perform visual inspection.	Check PT for oil leaks and gauge for clarity.
			Annual In service Diagnostic Maintenance	Measure secondary voltage of PT	Compare measured readings between phases, if difference > 10% (secondary) investigate the cause. Record and trend results for age exploration.
				Perform infrared scan.	Scan potential transformers. See Infrared Inspection Plan and Guidelines for details.

Equipment	Type	Make	Proposed Activity Name	Task	Task Description
Metal Clad Bus			Quarterly Inspection	Perform visual inspection.	Perform visual inspection enclosed bus with associated apparatus
			Annual In service Diagnostic Maintenance	Test cubicle and bus duct heaters and thermostats.	Perform current test on heater system. Record current readings and compare to initial in-service readings.
				Perform infrared scan.	Scan metal clad bus with associated apparatus. See Infrared Inspection Plan and Guidelines for details.

Equipment	Type	Make	Proposed Activity Name	Task	Task Description
Air Insulated Bus	All	All	Quarterly Inspection	Perform visual inspection.	Perform visual inspection of air insulated bus with associated apparatus
			Annual In service Diagnostic Maintenance	Perform infrared scan.	Scan air insulated bus with associated apparatus. See Infrared Inspection Plan and Guidelines for details.

Equipment	Type	Make	Proposed Activity Name	Task	Task Description
Meters (Non Billing)	watt/var/xducers	All	bench test	Check calibration	compare readings to calibrated standard, adjust to within 2% of standard.
Meters (Non Billing)	ammeters	All	Quarterly Inspection	Perform visual inspection	as part of quarterly inspection, compare between phases, if for 12KV > 100 amps between phases or other voltages > 50 amps between phases investigate the cause.
Meters (Revenue or interchange energy/vars)	watthour/varhour	All	bench test	Check calibration	compare readings to calibrated standard, adjust to within 2% of standard.
Meters (Non Billing)	voltmeters/xducers	All	Annual In service Diagnostic Maintenance	Check calibration	Compare readings to calibrated standard, if difference > 2% (secondary) investigate the cause.

Equipment	Type	Make	Proposed Activity Name	Task	Task Description
Voltage Regulators	Distribution	All	Quarterly Inspection	Perform visual inspection.	Perform visual inspection of bushings, gaskets, valves, piping and welds for oil leaks, as part of general station inspection. Also check bushings for contamination and damaged insulation.
				Record operations	Check and record counter reading. Record position indicator present position, high and low.
				Perform visual inspection.	Inspect control cabinet
			In service Diagnostic Maintenance	Perform functional test.	Prove the operation of the LTC manual/automatic control loop and ensure regulatory voltage tolerances are maintained.
				Perform infrared scan.	See Infrared Inspection Plan and Guidelines for details.
				Insulating oil visual inspection.	Sample and visually inspect oil. If excessive moisture is present, investigate source of moisture and perform field dielectric test or send sample to lab for complete oil quality testing. If dielectric strength is < 22KV, recondition or replace oil as required. If oil is excessively dark (light cannot be seen through the oil), send sample to lab for oil quality testing, investigate fault duty on breaker and recondition or replace oil as required. Track and trend results for age exploration.
			Regulator Overhaul	Perform functional test.	Perform a functional test of the regulator control in conjunction with preventative maintenance of associated apparatus. Listen for abnormal operation. Record and trend results.
				Perform internal inspection.	Inspect and adjust operating mechanism and assess condition of stationary and arcing contacts. Filter or change oil.

Equipment	Type	Make	Proposed Activity Name	Task	Task Description
Reclosers	Distribution	Oil-Hydraulic	Quarterly Inspection	Record and verify operations during inspections.	Check and record counter reading, fault operations, targets
				Perform visual inspection.	Check for oil leaks and overall condition.
				Perform visual inspection	Check gauge for expected indication and condition.
			In service Diagnostic Maintenance	Perform infrared scan.	See Infrared Inspection Plan and Guidelines for details.
			Functional Test	Trip and close recloser if electronic control	Reclosers that can be bypassed or transferred internal to the station without dropping load.
			Recloser Overhaul	Recloser Overhaul	Perform overhaul, trip test, hi pot, filter oil and adjust per manufacturers specs. Record and trend results for age exploration.

Equipment	Type	Make	Proposed Activity Name	Task	Task Description
Reclosers	Distribution	Vacuum	Quarterly Inspection	Record and verify operations during inspections.	Check and record counter reading, fault operations, targets
				Perform visual inspection.	Check for oil leaks and overall condition.
				Perform visual inspection	Check gauge for expected indication and condition.
			In service Diagnostic Maintenance	Perform infrared scan.	See Infrared Inspection Plan and Guidelines for details.
			Functional Test	Trip and close recloser if electronic control	Reclosers that have not operated in previous 9 months, and can be bypassed or transferred internal to the station without dropping load.
			Recloser Overhaul	Recloser Overhaul	Perform overhaul, trip test, hi pot, filter oil and adjust per manufacturers specs. Record and trend results for age exploration.

Equipment	Type	Make	Proposed Activity Name	Task	Task Description
Station Batteries	All	All	Weekly, monthly or quarterly Inspection	Perform visual inspection.	Check for battery charger operation, proper voltage, electrolyte level, and condition of connections.
			Diagnostic Maintenance	Perform detailed inspection	Test intercall and intracell resistances. Check specific gravity, voltage, and temperature of each cell. Perform visual check of electrolyte levels and general conditions. Check main DC bus voltage. Record and trend results. Refer to Battery Maintenance document for further details.

AOP

Electric APPROVED OPERATING POLICIES

Policy
URD Cable Failure Repair/Replacement Decision for Direct Buried Systems

Subject
URD Failure Repair and Replacement Plan

OM&I Number
EAOP-SI-002

Effective Date
November 17, 2016

SECTION 1 –PURPOSE

1.1 This policy describes a practical, reliability centered, repair/replacement decision policy for direct buried, URD (underground residential distribution) systems. This decision policy is designed to increase cable replacement activity in response to an increase in the frequency of URD section (span) failure, and to an increase in the frequency of URD circuit outages caused by cable failure.

SECTION 2 – SCOPE

2.1 This policy defines the repair or replacement decision in response to cable failures on direct buried URD systems. Cable failures typically require a local repair unless failure frequency recommends replacement of the section (span), as defined below.

SECTION 3 – FAILURE REPAIR DECISION

3.1 Cable fault location, excavation, and local repair is the "default" response to a cable failure event on a direct buried URD circuit.

Failure repair on a direct buried cable section requires the location, excavation, removal, and repair (splicing) of the faulted area.

Care should be taken when pinpointing the location of the cable fault using high voltage DC testing and capacitive discharge (thumper) equipment to produce an audible confirmation of the fault location. Minimize the potential for further cable damage by reducing "thumper" testing time by approximating the cable fault location using Time Domain Reflectometry (TDR) and then using the lowest discharge voltage necessary to produce an audible "thump."

SECTION 4 – FAILED SECTION REPLACEMENT DECISION

4.1 Following a cable failure on a direct buried URD cable, schedule replacement of the failed section, in lieu of repair, if any of the following apply,

If the current cable failure event is the:

- 3rd failure in the same section
- 2nd failure in the same section within 1 year of the 1st failure
- 2nd failure on the same URD circuit half-loop within the recent rolling year
- 3rd failure on the same URD circuit half-loop within the recent rolling 2 years.

SECTION 5 - SCHEDULING

5.1 Operations Engineers will prioritize and schedule the required repair or replacement activity as quickly as possible and return the affected loop circuit to its normal configuration to minimize the risk of a lengthy outage during a subsequent failure on the loop.

Replacement may be scheduled in lieu of repair, under certain circumstances, at the Operations Engineers discretion.

SECTION 6 – DECISION SUPPORT

6.1 Operations Engineers will maintain a database to track cables failures, repairs, and replacements.

Operations Engineers will consult the failure database to determine if the criteria is met for section replacement in lieu of local repair.

Operations Engineers will provide monthly reports detailing failure repair and section replacement backlogs and schedules.

The database will contain sufficient cable failure and replacement information to support ongoing failure and replacement budgetary projections and to assist with the development, planning, justification, and prioritization of aging URD cable infrastructure strategies.

LG&E KU
PPL companies

AOP

Electric APPROVED OPERATING POLICIES

Policy
INSPECTION, MAINTENANCE, AND LOAD MONITORING REQUIREMENTS FOR DOWNTOWN LOUISVILLE SECONDARY NETWORK

Subject
Inspection Of Systems

OM&I Number
EAOP-SI-001

Effective Date
Jan 01, 2007

SECTION 1 –PURPOSE

1.1 This policy describes operating, maintenance, and inspection requirements for the LG&E-KU low voltage secondary network system in downtown Louisville, Kentucky. Inspection, maintenance, and load monitoring is intended to ensure public safety, minimize the potential for public property damage resulting from delivery system failures, provide safe access and working conditions for operating and maintenance personnel, and to provide reliable electric service.

SECTION 2 – SCOPE

2.1 This policy addresses routine facility inspection, preventive maintenance, and load monitoring requirements applicable to the LG&E-KU low voltage secondary network facilities and equipment. Generally, LG&E-KU facilities will include vaults, manholes, transformers, network protectors, cables, ventilating equipment, and associated hardware.

SECTION 3 – REFERENCES

3.1 Kentucky Administrative Regulations, Title 807 KAR 5:006, Section 25, Inspection of Systems.

3.2 Kentucky Occupational Safety and Health Act (KOSHA).

3.3 LG&E-KU Health & Safety Manual, Latest edition.

3.4 EOM&I IS-002, Regulatory Inspection Requirements for the Downtown Louisville Secondary Network.

SECTION 4 –RESPONSIBILITIES

4.1 The Asset Management Electric System Codes and Standards shall have responsibility for the requirements of this Policy. Revisions to this policy shall be reviewed and approved by the Directors of Asset Management and Distribution Operations.

4.2 Auburndale Operations Center shall have responsibility for execution of this policy. Execution of this policy shall include inspecting network vaults and manholes; cleaning and ventilating network vaults; operating trip tests; inspecting, cleaning, and maintaining network protectors; and monitoring network loads.

SECTION 5 –DISCUSSION

5.1 Regulatory Accountability

5.1.1 In accordance with 807 KAR 5:006, Section 25 (4) (b) 3, each utility shall inspect, at intervals not to exceed six months, “underground network transformers and network protectors in vaults located in

Denise Simon	C. David Gray	William M. Maynard
Dir. Asset Management	Dir. Distribution Operations	Dir. Distribution Reliability

buildings or under sidewalks, for leaks, condition of case, connections, temperature and overloading".

SECTION 6 – POLICY

6.1 Inspect Network Vaults and Equipment

6.1.1 Visually inspect the vault enclosure and vault structural equipment including, ceilings, walls, and floors; interior doors; entrance hatches, frames, and ladders; drip pans, shields, and drains; ventilating blowers and duct; drains and dry wells; and cable and equipment mounting hardware. Inspect locking provisions and ensure access security.

6.1.2 Visually inspect vault electrical equipment including, network transformers and protectors; cable bus; transformer, protector, and service conductors; conductor connections; fuse boxes; vault lighting and wiring; and load monitoring equipment. Inspect the transformer case for dielectric coolant leaks. Read, record and reset oil temperature gauges and peaking demand load monitoring equipment.

6.1.3 Vault and vault equipment inspections shall be performed semi-annually.

6.2 Inspect Network Manholes and Equipment

6.2.1 Visually inspect manhole and hardware including, ceilings, walls, and floors; entrance throats; manhole ring and cover; duct openings; dry wells; and equipment mounting hardware.

6.2.2 Visually inspect manhole electrical equipment including, primary, secondary, street lighting, and service cables; communication cables; private and foreign utility conductors; electrolysis cables; grounding and bonding wires; primary cable splices and terminations; secondary and service cable splices, junctions, and terminations; grounding and bonding wire connections; and switching equipment.

6.2.3 Network manhole inspections shall be performed bi-annually. Assign manholes to two annual groups. Inspect each group on alternate calendar years.

6.3 Clean Network Vaults

6.3.1 Remove debris from network vaults and associated equipment to minimize vault fire potential, to minimize equipment surface corrosion and rust, to reduce dust type protector cleaning, and to provide a safe and dry workplace.

6.3.2 Dust off network transformers and network protector cases.

6.3.3 Remove and discard debris from catch pans, ventilating grates, drains and dry wells, and vault floors.

6.3.4 Vault cleaning shall be performed semi-annually.

6.4 Inspect Flood Prone Network Vaults

6.4.1 Inspect vault equipment and pump water from vaults during and/or following heavy rains.

6.4.2 Publish and maintain a list of vaults that retain water during heavy rain.

6.5 Ventilate Network Vaults

6.5.1 Operate and maintain forced air ventilation in summer peaking vaults.

a. Turn “on” blowers during Spring, prior to summer load increase.
b. Turn “off” blowers during Fall, following summer load decline.

6.5.2 Clean, lubricate, and winterize blower fans, duct, and vents following summer service.

6.5.3 Publish and maintain a list of vaults that contain ventilating equipment.

6.6 Feeder Trip Test

6.6.1 Network protector trip and close operations shall be tested prior to annual load periods, to verify successful and proper operation.

6.6.2 Test trips shall be performed annually during the Spring season while network loads are at seasonal minimums.

a. Individual circuits may be exempted from a scheduled test trip if all network protectors operated successfully during the 6 month period immediately preceding the scheduled test trip. The test trip record must reflect the date of the successful operation.

6.6.3 Each network circuit shall be tripped open, one circuit at a time. Load Dispatch will “OPEN” and “CLOSE” the circuit breaker to perform the test.

a. Following each circuit interruption, verify that the affected protectors "OPENED" upon loss of circuit voltage. Load Dispatch will note that the circuit potential light goes out if all protectors successfully tripped open.
b. Following circuit restoration, verify that affected network protectors "CLOSED."

6.7 Preventive Maintenance - Inspect, Clean, and Adjust Network Protectors

6.7.1 Inspect, clean, and adjust network protectors (WHILE ENERGIZED) to ensure safe and reliable operation. Refer to detailed, step-by-step instructions for each protector type.

a. Visually inspect condition of enclosures, mounting hardware, and external terminations.
b. Visually inspect condition of internal components, including breaker assembly, fuses, links, barriers, relays, control wiring for evidence of broken, loose, and overheated parts.
c. Clean and dust external covers and internal components.
d. Lubricate and adjust moving parts.
e. Clean and lubricate relay mechanism and contacts.

6.7.2 Dust Cover Type and No Cover Type Protectors

a. Perform routine inspection, cleaning, and adjustments, annually.

6.7.3 Submersible Type Protectors

a. Perform routine inspection, cleaning, and adjustments, annually.

6.8 Field Testing – Network Protector

6.8.1 Perform electrical and mechanical field operating tests on network protectors and relays immediately following a protector mis-operation or protector maintenance work. Mis-operations include failures to trip or close during normal operation or during Feeder Trip Tests, as defined in Section 6.6.

a. Refer to detailed, step-by-step instructions provided by the manufacturer for each protector and relay type.
b. Check electrical and mechanical operation using a network simulation test kit.
c. Re-calibrate or exchange relay.

6.9 Monitor Network Load

6.9.1 Vault Load Peak Demand

a. Monitor totalized peaking summer and winter demands on network transformers and protectors.
b. An AD-6 maximum demand, current type meter and associated current transformers shall be installed in each network vault. The AD-6 meter will be configured to totalize the coincident demand of all transformers in the vault.
c. Read, reset, and record AD-6 meters during the Spring and Fall seasons to capture the maximum demand during the preceding Winter and Summer seasons, respectively.

6.9.2 Vault Load Indicating Tests and Thermal Imaging Tests

a. Monitor phase loads and operating temperature on network vault buss, network protector leads, transformer secondary leads, service leads and street main ties to identify imbalance conditions and poor cable connections.
b. Vault load indicating tests and thermal imaging tests shall be conducted annually during the Summer season.

6.9.3 Secondary and Service Load Indicating Tests

a. Monitor summer season loads on network secondary street mains and services and vault supply main and services to support load flow analysis on the secondary network grid.
b. Monitor secondary street main continuity detect open circuit cables.
c. Summer season load tests shall be conducted bi-annually. Schedule secondary and service load tests on alternating calendar years during June, July, or August.
d. Street main continuity tests shall be conducted and recorded bi-annually during bi-annual regulatory manhole inspections.

6.10 Network Transformer High Voltage Compartment Insulating Compound Test

Cable insulating compounds in high voltage cable terminating compartments shall be dielectric tested to detect the presence of moisture on five year intervals.

6.11 Work Schedules

The activities defined in sections 6.1 through 6.10 above shall be performed coincidentally to optimize technician productivity and to minimize travel time. The requirements of this AOP are sufficient to meet the regulatory inspection requirements as defined in EOM&I-SI-002, "Regulatory Inspection Requirements for Downtown Louisville Secondary Network."

6.12 Network Protector Corrective Maintenance

Network protector corrective maintenance, including repair, rebuild, and decommissioning shall be individually determined by the network engineer and operating team leader using preventive maintenance histories, operating performance, and test trip results.

SECTION 7 - SAFETY

7.1 All applicable provisions of the Company safety manual shall be observed.

7.2 Cleaning and maintenance of network protectors involve working on energized equipment with exposed and unshielded components.

SECTION 8 – ENVIRONMENTAL

8.1 The downtown network system contains several environmentally regulated materials and compounds.

8.1.1 Network protectors manufactured prior to 1990 utilized asbestos-containing materials in arc-extinguishing assemblies, non-metallic structural members, and insulating barrier boards.

8.1.2 Network cable bus conductors and connections manufactured and installed prior to the early -1980's utilize asbestos fire proofing tapes.

8.1.3 Network transformers contain insulating fluids, such as, mineral oil, high fire point mineral oil, silicon fluid, and various cable compounds. Network transformers may contain traces of Polychlorinated Biphenols (PCB).

8.1.4 Paper Insulated Lead Covered (PILC) primary and secondary cables and associated cable splices are insulated with medium and high viscosity oils and petroleum based compounds contained within an overall lead jacket.

8.2 Special measures are required when disturbing and/or disposing asbestos-containing materials. Contact the Environmental Affairs Department prior to handling and disposing of asbestos materials.

8.3 Fluid release from network transformers in network vaults shall be immediately contained and reported promptly to the Transformer Services Department for cleanup.

8.3.1 Transformers labeled as containing PCB fluids or not having a label specifically stating that the fluid is non-PCB, shall be handled as if containing PCB fluids.

8.3.2 Fluid releases and disposal shall be reported to the Environmental Affairs Department.

8.4 Materials containing lead may require special disposal considerations. Contact the Environmental Affairs for disposal recommendations and assistance.

SECTION 9 – TRAINING AND QUALIFICATIONS

9.1 Employees performing cleaning, inspection, testing, and rebuilding must be qualified by training and/or experience.

SECTION 10 –EQUIPMENT

10.1 Network testing equipment and recording instruments

10.1.1 Network protector electrical test kit.
10.1.2 Electronic relay interface devices.
10.1.3 Voltmeter.
10.1.4 Ammeter.
10.1.5 Recording voltmeter.
10.1.6 Recording ammeters.
10.1.7 Thermometer (ambient air).

10.1.8 Thermal imaging camera.

SECTION 11 – RECORD KEEPING

11.1 Vault, manhole, and miscellaneous equipment inspection and maintenance records provided in Sections 6.1 through 6.5 shall be retained by the Auburndale Operations Center for a minimum of five years.

11.2 Network protector trip tests, preventive maintenance, field tests provided in Section 6.6 through 6.8 and primary termination compound dielectric tests provided in Section 6.10 shall be retained by the Auburndale Operations Center for the life of the equipment asset.

11.3 Load monitoring records provided under Section 6.9 shall be retained by Asset Management - System Analysis and Planning group.

LG&E KU PPL companies

OM&I

Operation, Maintenance, and Inspection

KENTUCKY REGULATORY INSPECTION
ELECTRIC DISTRIBUTION SUBSTATIONS AND LINES

Subject
Distribution System Inspection

OM&I Number
EOM&I-SI-001

Effective Date
March 7, 2013

SECTION 1 – PURPOSE

This policy documents the inspection requirements for electric distribution substations, distribution lines and equipment and meters at Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU). The inspection program is intended to identify, where possible, problems or potential problems that could have an adverse effect on safety, customer service and/or the orderly and efficient operation of the electric distribution system. It is structured to assure that assets are properly inspected, apparent deficiencies identified and documented, and records retained to ensure compliance with requirements of the Kentucky Public Service Commission (KYPSC) and company procedures. This document is to be filed with the KYPSC per regulation KRS Chapter 278 and 807 KAR Chapter 5 Section 26 - Inspection of Systems.

SECTION 2 – SCOPE

2.1 This policy details the requirements for a periodic, ground based inspection program for electric distribution substations and electric distribution facilities operating at voltages less than 69,000 volts up to the point of service, including overhead and underground electric lines, equipment, utility owned (leased) lighting and meters. It does not cover the inspection of underground network transformers and network protectors in vaults addressed in EOM&I-SI-002: Regulatory Inspection Downtown Louisville Secondary Network Vaults, current revision.

2.2 The objectives of the distribution system inspection program are to:

2.2.1 Enhance public safety and the safety of LG&E and KU employees and contractors by periodically inspecting all distribution substations, electric lines, structures and equipment for recognizable damage, defects and/or unsafe conditions.

2.2.2 Improve system reliability, where possible, by identifying defective and/or damaged structures or equipment and other operating conditions which could result in outages or failures.

2.2.3 Provide documentation of inspections, deficiencies found and corrective actions taken.

2.2.4 Maintain compliance with the KYPSC Regulations and the National Electrical Safety Code (NESC) regarding distribution inspections.

Denise Simon	John Wolfe	Nelson Maynard
Denise Simon Director Distribution Operations	John Wolfe Director Distribution Operations	Nelson Maynard Director Electric Reliability
Beth McFarland	Steve Woodworth	Michael T. Leake
Beth McFarland Director Asset Management	Steve Woodworth Director Revenue Collection	Michael Leake Manager Electrical Eng. & Planning

SECTION 3 – REFERENCES

3.1 Kentucky Revised Statutes Chapter 278

3.2 Kentucky Administrative Regulations, Title 807 KAR 5:006, Section 26, Inspection of Systems.

3.3 Kentucky Occupational Safety and Health Act (KOSHA).

3.4 LG&E Energy's Health & Safety Manual, Latest edition.

3.5 National Electrical Safety Code, Latest edition.

SECTION 4 – RESPONSIBILITIES

4.1 Asset Management's Electric System Codes and Standards section shall have responsibility for revising and communicating the requirements of this Policy. Revisions to this policy shall be reviewed and approved by the Directors of Asset Management, Distribution Operations and Metering.

4.2 At LG&E, regulatory inspections for overhead and underground lines and associated equipment operating at less than 69,000 volts and the associated record keeping is centralized at Auburndale Operations Center in Louisville, Kentucky.

4.3 At KU, regulatory inspections for overhead and underground lines and associated equipment operating at less than 69,000 volts and the associated record keeping are performed by the individual operations centers. Specifically, these centers are located in Lexington, Richmond, Danville, Shelbyville, Elizabethtown, Maysville, Pineville, London and Earlington.

4.4 At LG&E and KU, regulatory inspections for meters and associated record keeping are performed by Meter Reading and stored electronically in the system(s) of record.

4.5 Regulatory inspections for distribution substations and the associated record keeping are performed by the individual Substation centers. Specifically, these centers are located in Louisville, Lexington, Danville, Pineville, and Earlington.

4.6 Records shall be stored electronically and/or filed in the appropriate substation, metering or operations center offices and kept for the time prescribed in Section 11 – Record Keeping. All records and associated documents must be kept in a manner which allows them to be easily accessed for KYPSC audits.

SECTION 5 – DISCUSSION

5.1 This policy and the KYPSC regulations impose minimum standards for frequency, content of inspections and record requirements. Nothing in this document shall be construed as limiting more frequent and/or more rigorous inspections and/or more stringent record requirements at the discretion of the individual operations center.

5.2 Inspection methods, timing of inspections and labor resource (utility personnel/contractor) utilized to complete regulatory inspections may vary by center provided they meet the minimum requirements contained in this document.

SECTION 6 – POLICY

6.1 Inspection Frequency for Substations, Distribution Lines, Equipment, and Meters.

The requirements of regulation KY KYPSC 807 KAR 5:006 Section 26 - Inspection of Systems impose the following minimum requirements for inspection frequency for substations, distribution lines, equipment, and meters.

6.1.1 At intervals not to exceed two years:

a) Electric lines, equipment, and meters operating at a voltage less than 69,000 volts.

6.1.2 At intervals not to exceed one year:

a) Distribution substations with primary voltage of less than 69,000 volts.

6.1.3 At intervals not to exceed six months:

a) Distribution substations with primary voltage 69,000 volts or greater.

6.1.4 Upon receipt of any report of a potentially hazardous condition all portions of the system which are the subject of the report shall be inspected as soon as practicable.

6.2 Intent of Inspections

6.2.1 Inspections will be completed by utility personnel or contractors qualified to perform field inspections.

6.2.2 The intent of the regulatory inspection is not to perform a detailed technical assessment of every line or structure or to open and inspect every piece of equipment unless a problem is otherwise apparent. The intent is to visually inspect the system looking for apparent unsafe conditions, while identifying, where possible, damaged and/or defective equipment and other operating conditions that may affect system reliability or safety. A listing of items commonly checked during inspections can be found in the Appendix of this document.

6.2.3 Distribution Lines and Equipment

6.2.3.1 The inspection of overhead and underground lines and equipment will consist of a ground (foot, vehicle) based visual inspection. The most effective method to achieve this requirement for each portion of line will be determined by the operating center based on the characteristics of the line being inspected. Aerial inspections shall not be used as the basis for compliance.

6.2.3.2 Distribution lines and equipment placed on foreign owned structures will be inspected to the same extent as facilities on the utility's own structures. It is not the responsibility of the utility to inspect foreign owned structures, lines or equipment. However, defects or structural deficiencies with foreign owned structures and attachments identified during routine inspections will be reported to the facility owner whenever such deficiencies could have a detrimental impact on safety or operation of the utility's lines and equipment. Any such deficiencies shall be documented in the same manner as deficiencies on the utility's own structures and tracked in the same manner until all deficiencies have been corrected.

6.2.3.3 It is not the responsibility of the utility to inspect foreign owned lines and equipment located on utility owned structures. However, such deficiencies identified during routine inspections will be reported to the facility owner whenever such deficiencies could have a detrimental impact on safety or operation of the utility's lines and equipment. Any such deficiencies shall be documented in the same manner as deficiencies on the utility's structures and tracked in the same manner until all deficiencies have been corrected.

6.2.3.4 Damage or unsafe conditions on customer-owned wiring or equipment at the utility/customer interface point identified during the course of normal utility inspections shall be documented and reported to the customer, and where necessary the appropriate Authority Having Jurisdiction (AHJ).

6.2.3.5 Utility owned (leased) lighting equipment mounted on overhead distribution line structures and underground fed leased lighting structures will be inspected as part of routine system inspections.

6.2.4 Electric Meters.

The inspection of manually-read meters and walk-by AMR meters will consist of a visual inspection by meter readers during the course of routine meter reading.

6.2.5 Distribution Substations.

The inspection of substations will consist primarily of a field visit to each substation site and a visual inspection of the substation facilities and equipment.

6.3 Patrol along Roads, Cross Country or in Easements

6.3.1 Visual inspections of distribution lines and equipment may be accomplished by patrolling lines from vehicles when distribution facilities are located adjacent to and in reasonable proximity to roadways. Patrolling lines from vehicles is also permitted in off road easements where vehicle access is available. Facilities located in easements on private property where vehicle access is either not available or not practical due to the nature of the line, must be inspected on foot.

6.3.2 Every reasonable attempt should be made to inspect each structure or piece of equipment from its immediate vicinity. If inaccessible, inspection with binoculars is permitted. If access cannot be gained to at least perform a visual inspection, the area or line must be noted on the inspection print and provisions made to inspect at another time. At a minimum, the intent is to visually inspect every structure, line, and piece of equipment each inspection cycle.

SECTION 7 - SAFETY

7.1 Personnel performing the duties related to system inspection shall perform the necessary tasks in a safe manner and in compliance with company and departmental Safety Manuals, procedures and policies using the required Personal Protective Equipment (PPE). Special attention will be directed to the hazards related to terrain, insects, snakes, other animals, and plants as well as vehicular hazards.

SECTION 8 – ENVIRONMENTAL

8.1 Oil filled equipment found to be passively leaking will be noted as part of the inspection process. Equipment found to be actively leaking requires immediate notification of the appropriate responsible department(s) so that compliance with utility oil spill response procedures can be assured.

SECTION 9 – TRAINING AND QUALIFICATIONS

9.1 All inspectors must be knowledgeable of company Safety Manual, safety policies and procedures and have a working knowledge of the NESC as it applies to the facilities being inspected. Distribution line inspectors shall have complete familiarity with the construction and operation of distribution lines, equipment and structures as well as a working knowledge of company construction standards. Meter readers shall have complete familiarity and working knowledge of meter reading and meter inspection requirements. Substation inspectors shall have complete familiarity and working knowledge of substation facilities and equipment.

SECTION 10 – EQUIPMENT

10.1 Inspectors shall be equipped with and qualified in the use of all personal protective equipment (PPE) appropriate for the work and facilities being inspected.

10.2 Inspectors shall carry a cellular phone and/or a company radio at all times while performing inspection work suitable for contacting the appropriate emergency response personnel in the event of an emergency or appropriate company personnel in the event an active oil leak or potentially dangerous condition is found during the course of inspection.

SECTION 11 – RECORD KEEPING

11.1 Records of Inspection – Distribution Lines and Equipment

11.1.1 Distribution line inspections must be performed from inspection records which identify every primary line segment, such as a circuit map, facility map, or electronic mobile mapping technology. Secondary voltage lines and services and leased lighting facilities need not be shown on these records. However, they must be inspected.

11.1.2 Each inspection record must contain the inspector's name and the completion date of the inspection, if inspected in whole on the completion date. If multiple days are required to complete the inspection, each portion inspected will be noted with each line segment being coded by respective date inspected and inspector's name. In addition, an overall completion date for the entire record is required when the inspection is complete.

11.1.3 Deficiencies found during inspections are to be identified by a unique number so that a cross-reference can be established between the inspection record and the deficiency repair order or work request. These records are the tangible basis from which the KYPSC will audit. Keeping records in this manner allows the KYPSC to verify that a facility was inspected, to relate the inspection to deficiencies found, to track the deficiency to a repair order, work request, database or work management system entry and to determine the disposition of work to correct the deficiency.

11.1.4 The inspection and deficiency records will be filed in the appropriate operations center offices and kept for six years. All records and associated documents must be kept in a manner which allows them to be easily accessed for KYPSC audits.

11.2 Records of Inspection – Meter

11.2.1 Meter inspections will be performed using electronic devices that allow for identification of each meter, location, date and time, inspector's name, and deficiency if applicable.

11.2.2 The inspection and deficiency records will be stored electronically or filed in the appropriate metering offices and kept for a minimum of six years. All records and associated documents must be kept in a manner which allows them to be easily accessed for KYPSC audits.

11.3 Records of Inspection – Substations

11.3.1 Substation inspections will document substation name, location, date, inspector's name, and deficiency if applicable.

11.3.2 The inspection and deficiency records shall be filed in the appropriate substation center offices and kept for four years. All records and associated documents must be kept in a manner which allows them to be easily accessed for KYPSC audits.

11.4 Documentation and Tracking of Deficiencies Found – Distribution Lines

11.4.1 When the inspector identifies a deficiency, a sequential or otherwise unique number is to be marked on the inspection record for that location. All pertinent information about the deficiency is to be recorded on a deficiency report form which contains the corresponding number placed on the inspection record, including a description of the problem, the exact location (house number or distance from a known highway intersection, etc.), the pole or coordinate number (if available) and any other pertinent information.

11.4.2 Where deficiency form is to also serve as the final repair record, information must be added to the deficiency form once work is completed which at a minimum includes, the completion date, repair crew information and a description of the corrective actions taken to address the deficiency. Upon completion of the work, the original deficiency form must be filed with the inspection record or retained in another manner such that the status and/or disposition of the corrective work can be tracked from the original inspection record.

11.4.3 Where the deficiency form information is to be transferred to a different work request document, work management system or database to manage the deficiency correction, all appropriate information from the deficiency form is transferred to the work request document or entered into the electronic record. Unless stored in a database that can be queried for the original deficiency form number recorded on the inspection record, each form or data entry must also have a unique identifier assigned that can be tracked to the original deficiency form number. The new work request or data tracking number will be recorded on the original inspection print and/or recorded on the deficiency form where the deficiency form is to be retained separate of the inspection record. At all times continuity must be maintained between the inspection record, deficiency form and any other form or electronic entry used to manage corrective work. Upon completion of work to correct the deficiency, the form or record must be updated with information which at a minimum includes, the completion date, repair crew information and a description of the corrective actions taken to address the deficiency.

11.4.4 When a defect, deficiency, or other condition is found that poses an imminent hazard to safety or customer service, the inspector must immediately notify (by phone or radio) the appropriate department for corrective action. If the condition represents a present safety hazard to customers or the public in general, such as a live wire down, the inspector must guard the area until maintenance crews arrive to make the area safe.

11.5 Documentation and Tracking of Deficiencies Found – Electric Meter

11.5.1 Meter deficiencies found will be recorded and identified to the specific meter with a repair order, description of the deficiency, location of meter, and any other pertinent information. The completion date, repair crew information, and appropriate remarks will be added once the work is complete. All records will be maintained by Meter Reading and stored electronically in the system(s) of record.

11.6 Documentation and Tracking of Deficiencies Found - Substations

11.6.1 Substation deficiencies found will be recorded and identified to the specific substation with a corrective work order, description of the deficiency, location, and any other pertinent information. The completion date, repair crew information, and appropriate remarks will be added once the work is complete. All records will be maintained electronically in the substation work management system.

Appendix – Guidelines for Inspection

A.1.0 Guidelines for Overhead Inspection (conditions to be reported)

A.1.1 Structures

a) All Supporting Structures – General
- ✓ Excessive lean or bowing
- ✓ External damage (vehicles, vandals, etc.)
- ✓ Insufficient clearance from curbs, roads, etc.
- ✓ Physical damage protection/marking (if required)
- ✓ Climbing hazards (including excessive vines and vegetation)
- ✓ Unauthorized foreign attachments (basketball goals, customer wiring/lighting, security cameras, etc.)
- ✓ Presence of any permanent climbing steps or other platforms providing climbing access (at least eight feet above ground level)
- ✓ Equipment and equipment supports are not readily climbable (hardware does not facilitate climbing – eight feet between footholds and handholds starting at not more than six feet above ground)
- ✓ Presence of fences, trees, sheds that would facilitate climbing by members of the public or encourage climbing by children
- ✓ Insufficient or improper grounding
- ✓ Lack of foundation integrity
- ✓ Proper signage when required
- ✓ Objectionable graffiti

b) Wood Poles
- ✓ Externally visible physical damage (external decay, woodpecker holes, excessive checking, damage by fire, vehicle contact, etc.)
- ✓ Ground line deficiencies.
  Wood poles with obvious ground line deficiencies must be sounded from ground line to six feet. If significant external decay is suspected at or just below the ground line, it may become necessary to remove soil from around the base of the pole, where practical, to determine the extent of decay. Poles with decay, infestation, or cracks, sufficient to jeopardize safety or service restoration shall be turned in for replacement or repair. If a pole is sufficiently defective to be a safety hazard to a person climbing the pole or to the public in general, a danger pole tag must be applied to the pole and special attention given to replacing the pole. In areas where poles appear solid, a reasonable attempt to sound a representative sample (approximately 10%) should be made. Exception: Wood pole structures supporting lines crossing limited access highways or railroads must be sounded each inspection cycle.

c) Steel Poles, Guy Beams and Lattice Towers
- ✓ Excessive corrosion or rust affecting structural integrity
- ✓ Missing, loose, damaged foundation bolts and nuts
- ✓ Loose or missing bracing

d) Concrete Poles
- ✓ Spalling
- ✓ Excessive cracking, voids, holes, etc.

A.1.2 Overhead Equipment
- ✓ Broken or damaged
- ✓ Oil leaks
- ✓ Structurally damaging rust (does not include minor surface rusting)
- ✓ Bulged
- ✓ Overheating (discolored terminals or melted insulation)
- ✓ Flashed or broken bushings or terminals

- ✓ Not bolted securely to structure
- ✓ Excessive lean
- ✓ Blown fuses
- ✓ Blown lightning arresters
- ✓ Cutouts and switches not properly terminated and fully closed
- ✓ Ground mounted equipment controls not locked and otherwise secure

A.1.3 Conductor Supports

a) Crossarms
- ✓ Broken, split, twisted, burned, or rotten
- ✓ If steel, excessive (structural) corrosion
- ✓ Not securely bolted to structure
- ✓ Braces not installed and in good working order

b) Miscellaneous Support Brackets, and Hardware
- ✓ Flashed or broken
- ✓ Broken spacer cable brackets or bands
- ✓ Not securely bolted to structure
- ✓ Loose or missing hardware

c) Insulators
- ✓ Cracks, chips and signs of flashing/tracking
- ✓ Excessive dirt, soot or other possible contamination
- ✓ Improper insulator attachment (suspension insulators are properly attached to pole, crossarm or other support, pin insulators are properly seated on pin or secured to support arm, pole, etc.)
- ✓ Conductor improperly secured to insulators (conductor floating)

A.1.4 Anchors and Guys
- ✓ Inadequate for loads or slack guying
- ✓ Improper insulation (insulate or grounded)
- ✓ Improper positioned guy insulators (insulated guys)
- ✓ Guy guards not installed (one per anchor)
- ✓ Anchor rod/eyes and guy-wire not sufficiently above grade to minimize the possibility of guy-wire or guy grip deterioration
- ✓ Anchor pulling out (excessive rod length)
- ✓ Guy wire strands, grips, and/or automatic guy deadends damaged, corroded, or broken
- ✓ Improperly insulated, grounded or guarded guys
- ✓ Guying hardware (guy hooks and eyebolt assemblies) are deteriorated or improperly secured)
- ✓ Insufficient clearances (distance between guy wires and curbs, sidewalks, paths, roads, etc. is not satisfactory)
- ✓ Push poles (improperly connected and structurally sound)
- ✓ Third party guying or lack of proper guying (obvious problems affecting pole loading/leaning/buckling)

A.1.5 Primary and Secondary Conductors and Conductor Hardware
- ✓ Improper clearances (at structure, throughout span, adjacent to other structures, or over ground)
- ✓ Defective conductors, splices, or connections (burns, broken strands or evidence of overloading such as discoloration or melted insulation)
- ✓ Improperly secured to insulators or deadend assemblies
- ✓ Foreign objects (trees, balloons, shoes, etc.)
- ✓ Vegetation (growing into or rubbing against conductors)
- ✓ Illegal services or unmetered load
- ✓ De-energized and/or abandoned lines not properly grounded
- ✓ Apparent easement violations (pools, buildings, private structures, etc.)

A.1.6 Services
- ✓ Low over roads, driveways or parking areas
- ✓ Improperly attached at house and pole
- ✓ Improper clearance over deck, garages and other structures

- ✓ Vegetation (limbs not clear from laying or rubbing on service to cause service integrity problems)
- ✓ Conduit damage (Overhead or UG)

A.1.7 Overhead Lighting

- ✓ Broken or loose mounting arms or fixtures
- ✓ Damaged or broken lighting fixtures

A.2.0 Guidelines for Underground Inspection (conditions to be reported)

A.2.1 Area around Equipment

- ✓ Improper clearances (to buildings, roads, fences, etc.)
- ✓ Traffic barriers (if required) not in place or not in satisfactory condition
- ✓ Vegetation (not trimmed to permit opening of cabinet and provide room for switching / maintenance)
- ✓ Dumping/Storage (materials or debris stored in front of or against the equipment)
- ✓ Ground erosion exposing energized cables
- ✓ Fences around open air installation on ground not secure, locked, and properly signed
- ✓ Danger and warning signs not properly applied
- ✓ Penta-head bolt not in subgrade grating

A.2.2 Pad/Foundation

- ✓ Not properly leveled
- ✓ Ground erosion compromising pad stability
- ✓ Damaged (cracked, broken, etc.)

A.2.3 Cabinet/Enclosure/Tank

- ✓ Improper alignment on pad (gaps between cabinet and pad)
- ✓ Holes (screw holes, bolt holes, rust holes, etc.)
- ✓ Mechanical damage due to rust
- ✓ Leaks or swollen areas
- ✓ Door/hood hinges damaged
- ✓ Cabinet doors/hood not properly aligned (no excessive gaps or spaces to permit access to the inside with wires, rods, etc.)
- ✓ Cabinet not properly secured (pentahead bolt and company lock not in place)
- ✓ Proper signage not applied (“Warning” meeting specifications of ANSI Z535, and “No Obstructions/Planting” signs not in place)
- ✓ Paint is not in satisfactory condition to prevent excessive corrosion
- ✓ Objectionable graffiti
- ✓ Lifting hardware has been removed
- ✓ Signs of excessive heating

A.2.4 Miscellaneous

- ✓ Loose or missing lids or covers (splice box lid, pedestal covers, etc.)
- ✓ Terminations show signs of tracking, excessive heating or otherwise damaged.
- ✓ Secondary buswork (open air) not properly insulated with no obvious signs of excessive heating

A.2.5 Underground Fed Lighting Poles and Fixtures

- ✓ Physical damage to pole
- ✓ Severely leaning poles
- ✓ Missing, loose, damaged foundation bolts and nuts
- ✓ Missing hand hole covers/exposed wiring
- ✓ Unauthorized attachments
- ✓ Damaged or missing fixtures, globes, etc.

A.3.0 Meters (conditions to be reported)

- ✓ Properly secured (missing seal, lock, cover)
- ✓ Broken glass
- ✓ Damaged meter, meter base, metering cabinets
- ✓ Vegetation (obstructions)

A.4.0 Substations (specific conditions on the following, including all status indicators, gauges, and metering if applicable, will be checked and deficiencies reported)

- ✓ Drive and Approach
- ✓ Fence and Gates, Substation Security
- ✓ Warning Signs, Danger Signs and Barriers
- ✓ Structures
- ✓ Annunciator Systems
- ✓ Disconnects and Motor Operated Disconnects
- ✓ Station Grounds
- ✓ Transformers, Tap Changers and Regulators
- ✓ Circuit Breakers and Reclosers
- ✓ Capacitor and Capacitor Protective and Switching Equipment
- ✓ Control House
- ✓ Switchgear
- ✓ Station Yard
- ✓ Metering
- ✓ Spill Prevention Control and Counter Measure
- ✓ Fire Protection System

OM&I

Electric Operation, Maintenance, And Inspection Plan

Policy
REGULATORY INSPECTION DOWNTOWN LOUISVILLE SECONDARY NETWORK VAULTS

Subject
Inspection Of Systems

OM&I Number
EOM&I-SI-002

Effective Date
Jan 01, 2007

SECTION 1 –PURPOSE

1.1 This policy describes inspection requirements for the LG&E-KU low voltage secondary network distribution system in downtown Louisville, Kentucky mandated by the Kentucky Public Service Commission. Regulatory inspections are intended to assure safe and adequate operation of its facilities.

SECTION 2 – SCOPE

2.1 This policy defines the regulatory inspection of underground network transformers and network protectors in vaults located within buildings and under sidewalks of the secondary network distribution system.

SECTION 3 – REFERENCES

3.1 Kentucky Administrative Regulations, Title 807 KAR 5:006, Section 25, Inspection of Systems.

3.2 Kentucky Occupational Safety and Health Act (KOSHA).

3.2 LG&E-KU Health & Safety Manual, Latest edition.

SECTION 4 –RESPONSIBILITIES

4.1 The Asset Management Electric System Codes and Standards section shall have responsibility for the requirements of this Policy. Revisions to this policy shall be reviewed and approved by the Directors of Asset Management and Distribution Operations.

4.2 Auburndale Service Center shall have the responsibility for the execution of this policy. Execution of this policy shall include regulatory vault and vault equipment inspection and load monitoring.

SECTION 5 –DISCUSSION

5.1 Regulatory Accountability

5.1.1 In accordance with 807 KAR 5:006, Section 25 (4) (b) 3, each utility shall inspect, at intervals not to exceed six months, “underground network transformers and network protectors in vaults located in buildings or under sidewalks, for leaks, condition of case, connections, temperature and overloading”.

Dir. Asset Management	Dir. Distribution Operations	Dir. Distribution Reliability

SECTION 6 – POLICY

6.1 Inspect Network Vault and Equipment

6.1.1 Visually inspect vault sidewalk surface areas for pedestrian safety including access and ventilation gratings and access hatchways. Inspect locking provisions and insure access security.

6.1.2 Visually inspect vault electrical equipment including network transformers and protectors; cable bus; transformer, protector, and service conductors; conductor connections; and load monitoring equipment. Inspect the transformer case for dielectric coolant leaks. Read, record and reset oil temperature gauges and peaking demand load monitoring equipment.

6.1.3 Vault and vault equipment inspections shall be performed semi-annually.

6.2 Monitor Network Loads

6.2.1 Vault Load Peak Demand

a. Monitor totalized peaking summer and winter demands on network transformers and protectors.
b. An AD-6 maximum demand, current type meter and associated current transformers shall be installed in each network vault. The AD-6 meter will be configured to totalize the coincident demand of all transformers in the vault.
c. Read, reset, and record AD-6 meters during the Spring and Fall seasons to capture the maximum demand during the preceding Winter and Summer seasons, respectively.

SECTION 7 - SAFETY

7.1 All applicable provisions of the Company safety manual shall be observed.

7.2 Inspecting vault electrical equipment involves working around energized equipment with exposed and unshielded components.

SECTION 8 – ENVIRONMENTAL

8.1 The downtown network system contains several environmentally regulated materials and compounds.

8.1.1 Network protectors manufactured prior to 1990 utilized asbestos-containing materials in arc-extinguishing assemblies, non-metallic structural members, and insulating barrier boards.

8.1.2 Network cable bus conductors and connections manufactured and installed prior to the early -1980's utilize asbestos fire proofing tapes.

8.1.3 Network transformers contain insulating fluids, such as, mineral oil, high fire point mineral oil, silicon fluid, and various cable compounds. Network transformers may contain traces of Polychlorinated Biphenols (PCB).

8.1.4 Paper Insulated Lead Covered (PILC) primary and secondary cables and associated cable splices are insulated with medium and high viscosity oils and petroleum based compounds contained within an overall lead jacket.

8.2 Fluid release from network transformers in vaults shall be immediately contained and reported promptly to the Transformer Services Department for cleanup.

8.2.1 Transformers labeled as containing PCB fluids or not having a label specifically stating that the fluid is non-PCB, shall be handled as if containing PCB fluids.

8.2.2 Fluid releases and disposal shall be reported to the Environmental Affairs Department.

SECTION 9 – TRAINING AND QUALIFICATIONS

9.1 Employees performing inspections and load tests must be qualified by training and/or experience.

SECTION 10 –EQUIPMENT

10.1 Network testing equipment and recording instruments required for inspection and load monitoring.

10.1.1 Ammeter.
10.1.2 Thermometer (ambient air).
10.1.3 Temperature tester.

SECTION 11 – RECORD KEEPING

11.1 Records shall be kept to document inspections, deficiencies, and corrective action.

11.2 Maintenance records shall be retained by Distribution Operations Center.

11.3 Load monitoring records shall be provided to and retained by Asset Management's System Analysis and Planning group.

11.4 Inspection and maintenance resulting from activities in section 6.1 and 6.2 shall be retained for a minimum of five years and be available for inspection by KyPSC.

11.5 Equipment maintenance records shall be retained for the life of the equipment asset.

LG&E KU	OM&I ELECTRIC OPERATING, MAINTENANCE, AND INSPECTION PLAN		Distribution Operations
Subject: **VOLTAGE SURVEY**	OM&I Number: **EOM&I - VS - 001**	Effective Date: 3/25/2002	
Policy: **VOLTAGE SURVEY REQUIREMENTS FOR CENTER OF DISTRIBUTIONS AND REPRESENTATIVE POINTS**			

SECTION 1 –PURPOSE

1.1 This procedure describes the requirements for voltage surveys and records on LG&E Energy Corp.'s facilities.

SECTION 2 – SCOPE

2.1 This procedure is applicable to all LG&E Energy Corp.'s facilities subject to voltage survey, per Kentucky Administrative Regulations. Generally, LG&E Energy Corp.'s facilities shall include all substations, line regulators, and distribution circuits.

SECTION 3 – REFERENCES

3.1 Kentucky Administrative Regulations, Title 807 KAR 5:041, Section 7, Voltage Surveys and Records.

3.2 Kentucky Administrative Regulations, Title 807 KAR 5:041, Section 13, Testing Equipment and Standards.

3.3 LG&E Energy's Health & Safety manual, Latest edition.

SECTION 4 –RESPONSIBILITIES

4.1 The Asset Management's Operating Policy and Standards section shall have responsibility for revising the requirements of this Policy. Revisions to this policy shall be reviewed and approved by the Directors of Asset Management and Distribution Operations.

4.2 The Substation Construction and Maintenance and/or Auburndale Trouble & Power Quality departments shall be responsible for conducting and coordinating the voltage survey at Substations and line regulators.

4.3 The Asset Management's System Analysis and Planning section shall have the responsibility for determining the number and location of the representative points that are surveyed for low voltage. If engineering judgment is used rather than network analysis software, the Operating Centers shall have responsibility for determining the number and locations of the representative points.

4.4 The Auburndale Trouble & Power Quality department (LG&E) or Operations Centers (KU) shall be responsible for conducting and coordinating the voltage survey for representative points; i.e., low voltage.

Dir., Distribution Operations	Dir., Distribution Operations	Dir., Distribution Operations
Dir., Asset Management	Manager, Operating Policy	

4.5 The Auburndale Trouble & Power Quality department, Operating Centers, or Trouble department (Lexington only) shall be responsible for conducting voltage surveys for high voltage.

SECTION 5 –DISCUSSION

5.1 Regulatory Accountability

In accordance with 807 KAR 5:041, Section 7, “each utility shall make a sufficient number of voltage surveys to indicate the service furnished from each center of distribution”. In addition, each utility shall keep at least one portable indicating voltmeter or recording or graphic voltmeter in continuous service at some representative point on its system. Finally, records of voltage surveys taken within the last three years shall be available for inspection by the utility’s customers and Public Service Commission’s staff.

In accordance with 807 KAR 5:041, Section 13 (9), “all working indicating instruments shall be checked against master indicating instruments at least once in each six (6) months”. In addition, “a calibration record shall be maintained for each instrument showing all pertinent data and name of person performing tests”.

SECTION 6 – POLICY

6.1 Voltage Surveys at Centers of Distribution

6.1.1 Definitions

a. Centers of Distribution - All substations and line regulators located on LG&E Energy Corp.’s system.
b. SCADA Equipped substations – Substations that have SCADA functionality.
c. Non-SCADA Equipped substations – Substations that do <u>not</u> have SCADA functionality.
d. Voltage survey – A recording of voltage that is conducted for a specific period of time.
e. Indicating voltages – An instantaneous voltage reading.

6.1.2 Recording Voltage

a. Voltage at SCADA equipped substations shall be recorded using SCADA equipment.
1. Voltage information shall be stored in the SCADA database.
2. Voltage information shall be available from either the system or database administrator.
b. Voltage at non-SCADA equipped substations and line regulators shall be recorded using handheld voltmeters.

6.1.3 Monitoring Interval

a. At SCADA equipped substations, voltage shall be continuously monitored. In addition, alarms shall be generated if the voltage is found to be outside of the acceptable range.
b. At non-SCADA equipped substations, voltage surveys shall consist of an indicating test on potential signal used to regulate bus voltage. These indicating tests shall be conducted as a part of routine substation inspections.
c. At line regulators, voltage surveys shall consist of an indicating test and be conducted on an annual basis.

6.1.4 Conducting and Coordination of Voltage Survey

a. For substations, the Substation Construction and Maintenance and Auburndale Trouble & Power Quality departments shall be responsible for conducting and coordinating the voltage survey.
b. For line regulators, the Substation Construction and Maintenance or Auburndale Trouble & Power Quality departments shall be responsible for conducting and coordinating the voltage survey.

1. For Louisville Gas & Electric Company, the Auburndale Trouble & Power Quality department shall be responsible for conducting and coordinating the voltage survey.

2. For Kentucky Utilities, the Substation Construction and Maintenance department shall be responsible for conducting and coordinating the voltage survey.

6.2 Voltage Surveys at Representative Points

6.2.1 Definitions

a. Representative points – Circuit points on LG&E Energy Corp.'s system that are suspected of having low voltages.
b. Voltage survey – A continuous recording of voltage that is conducted for a specific period of time

6.2.2 Recording Voltage

a. Voltage at representative points shall be recorded using portable recording voltmeters.
b. For low voltage, the number and location of the representative points shall be determined by the Asset Management's System Analysis and Planning section and/or Operations Center. This determination shall be based upon network analysis tools and/or engineering judgment.

1. If network analysis tools are used, the System Analysis and Planning section shall be responsible for determining the number and location of the representative points.
2. If engineering judgment is used, the Operations Centers shall be responsible for determining the number and location of the representative points. When engineering judgment is used, the following minimum information shall be recorded: 1) Survey Year, 2) Type of Survey, i.e., Representative Point, 3) Operations Center, 4) Substation, 5) Circuit number, 6) Date Reviewed, 7) Name of the person who performed the review, 8) Whether a survey is required, and 9) Reason for not requiring a survey. Shown below is an example spreadsheet that contains the minimum required information.

2001 Representative Point Voltage Survey Record - Elizbethtown Operations Center

Substation	Circuit No.	Date Reviewed	Reviewed By	Survey Required	Reason (if survey is not required)
Example No. 1					
Ashby Trail No. 1	1201	6/28/2001	P. Just	No	Circuit not worst case on substation
	1202	6/28/2001	P. Just	No	Circuit not worst case on substation
	1203	6/28/2001	P. Just	No	Circuit not worst case on substation
	1204	6/28/2001	P. Just	No	Worst case on substation, analysis shows no low voltage, analysis on file
Example No. 2					
Ashby Trail No. 2	1205	6/28/2001	P. Just	No	Circuit not worst case on substation
	1206	6/28/2001	P. Just	Yes	Survey results and analysis on file
	1207	6/28/2001	P. Just	No	Analysis showed no low voltage
Example No. 3					
Bishop Trail No. 1	1217	6/28/2001	P. Just	No	Circuit not worst case on substation
	1218	6/28/2001	P. Just	No	Line regulators on circuit, analysis shows no low voltage
	1219	6/28/2001	P. Just	No	Worst case on substation, analysis shows no low voltage, analysis on file
	1220	6/28/2001	P. Just	No	Circuit not worst case on substation

3. Voltage surveys shall be conducted during heavy loading conditions.

c. For high voltage, voltage surveys shall be conducted on an as needed basis as determined by customer complaints. The duration of the voltage survey shall be determined by the Auburndale Trouble & Power Quality department, Operating Centers, or Trouble department (Lexington only).

6.2.3 Monitoring Interval

Typically, voltage surveys shall be conducted for seven (7) days.

6.2.4 Conducting and Coordination of Voltage Survey

The Auburndale Trouble & Power Quality department or Operations Centers shall be responsible for conducting and coordinating the voltage survey.

a. For Louisville Gas & Electric Company, the Auburndale Trouble & Power Quality department shall be responsible for conducting and coordinating the voltage survey.
b. For Kentucky Utilities, each Operations Center shall responsible for conducting and coordinating the voltage survey for its service territory.

6.3 Remedial Measures

6.3.1 Results of the voltage survey shall be forwarded to the appropriate operations or support personnel; e.g., Asset Management's System Analysis and Planning section.

6.3.2 Remedial action shall be taken to keep voltage levels within standard nominal voltage range(s).

SECTION 7 - SAFETY

7.1 All applicable provisions of the LG&E Safety & Health manual shall be observed.

SECTION 8 – ENVIRONMENTAL

8.1 Not applicable to this procedure.

SECTION 9 – TRAINING AND QUALIFICATIONS

9.1 Employee Qualifications

Employees performing voltage surveys must be qualified by training and/or experience.

SECTION 10 –EQUIPMENT

10.1 Calibration

10.1.1 Graphic recording voltmeters that are rotated shall be checked with a working standard indicating voltmeter when it is placed in operation or when it is removed.

10.1.2 Indicating voltmeters shall be calibrated twice a year.

10.1.3 A calibration record shall be maintained for each voltmeter showing all pertinent data and the name of person that performed the tests.

SECTION 11 – RECORD KEEPING

11.1 Original records for voltage survey at substations and line regulators shall be kept as follows:

11.1.1 For Louisville Gas & Electric Company, the Auburndale Trouble & Power Quality department shall keep the records.

11.1.2 For Kentucky Utilities, the Substation Construction and Maintenance department shall keep the records.

11.2 Original records for voltage survey at "representative points" shall be kept as follows:

11.2.1 For Louisville Gas & Electric Company, the Auburndale Trouble & Power Quality department shall keep the records.

11.2.2 For Kentucky Utilities, each operations center shall keep the records for its service territory.

11.3 Original records shall be kept for a minimum of three years and be available for inspection by LG&E Energy Corp.'s customers and KYPSC.

11.4 If charts are used, the following information shall be recorded on each chart:

- Beginning time
- Date of registration
- Time the chart was removed
- The point where the voltage was taken
- Results of the check with the indicating voltmeter

2015 - 2019

LG&E AND KU ENERGY

Specifications for Condition Based Wood Distribution Pole Inspection and Remedial Retreatment

Distribution Operations – Asset Management
Updated December 12, 2014

Table of Contents

Specifications for Condition Based Wood Distribution Pole
Inspection and Remedial Retreatment

1. GENERAL

1.1. Scope

This specification covers the inspection and supplemental treatment of wood poles on the LG&E AND KU ENERGY distribution system. Not all LG&E AND KU ENERGY poles with distribution facilities are to be inspected under this program. Each pole that is to be inspected will be assigned a basic level of inspection with no mandatory supplemental treatment specified. The base inspection requirement will vary by pole and will be based on specific characteristics of the pole, including the pole's function, age, original treatment, ownership, treatment history, etc. The identification of any damage, defects or decay found during the base Level of Inspection will trigger progressively increasing detailed Levels Of Inspection and, where necessary, pole treatment. The requirements for the basic inspection levels are detailed in Section 7– Levels of Inspection. Inspections are to be completed consistent with Section 8 – Inspection Requirements.

The Levels of Inspection are progressive in the detail of inspection and include all of the requirements of all proceeding Levels of Inspection. Levels of Inspection, in progressive order are:

- Asset Data Inspection
- Visual Inspection
- Sound and Bore Inspection
- Full Excavation Inspection

1.2. General Requirements For Inspection

1.2.1. Poles Not Inspected

All Transmission and Foreign owned poles will not receive any level of Inspection unless otherwise specified by the Company. No poles composed of materials other than wood are to be inspected.

1.2.2. Poles 14 Years Old or Less

All Company owned wood Distribution Poles less than14 years old as well as all poles 15 years or older that have received a supplement treatment within the last 5 years will be Visually Inspected. Visual Inspections include all of the requirements of an Asset Data Inspection where asset data is either verified, if provided, or gathered if not. Each pole shall receive a full Visual Inspection for obvious signs of decay, damage, defects and/or safety hazards. No further work is to be done unless the Visual Inspection provides supportable justification, in the judgment of the Inspector that a more detailed Level of Inspection is warranted. See Section 8.4 – Visual Inspection for the full requirements of this inspection requirement.

1.2.3. Poles 15 Years Old or Greater

Poles 15 years old or greater which have not received a supplemental treatment in the last 5 years are to receive a Full Excavation Inspection. Full Excavation Inspections include all of the requirements of Asset Data, Visual and Sound and Bore Inspections.

Treatment, if any, will be performed only when warranted in the judgment of the Inspector and consistent with this specification and will be based on the actual physical condition of the pole. Treatment requirements are documented in Section 10 – Pole Treatment.

1.3. Key Definitions

1.3.1. General Definitions

ANSI 05.1	American National Standards Institute Standard (ANSI) 05.1: Wood Poles – Specifications and Dimensions, latest revision.
Company	LG&E AND KU ENERGY owned operating companies including Kentucky Utilities (KU), Louisville Gas and Electric Company (LG&E) and Old Dominion Power (ODP).
Company Pole	A pole owned by the Company regardless of whether there are any Company owned facilities on the pole.
Contractor	Firm awarded a formal contract to perform a condition based wood pole inspection and remedial retreatment program on distribution poles on behalf of LG&E AND KU ENERGY Companies as described in this specification.
Foreign Pole	A pole owned by any other party on which the Company has attached conductors, equipment or facilities.
Level of Inspection	Baseline inspection requirements for a pole within a given Pole Classification. Work actually completed may be more or less than the baseline requirement depending on the pole's physical characteristics, its location, condition or past history.
NESC	ANSI/IEEE C2: National Electrical Safety Code, latest revision.
Pole Classification	Classification of the pole determined by pole ownership and the nature of the conductors, equipment and other facilities placed on the pole. See Section 6.2 – Pole Classifications for specific definitions.

1.3.2. Pole Definitions

Priority Pole	A pole that in the judgment of the Contractor is in need of immediate replacement. In general includes poles with an average shell of one inch or less OR less than fifty percent (50%) of its original circumference or poles that otherwise present an imminent potential for failure. Priority poles will be reported to the Company's representative within 24 hours or immediately if extremely hazardous.
Reject Pole	Any pole designated by the Contractor which, upon inspection, is found deteriorated below a minimum of two-thirds of the ANSI defined strength. Reject Poles will be further classified as a Reject Replacement or as a Restorable Pole based on the actual physical condition of the pole and the actual loading on the pole.
Reject Replacement	A Reject Pole that has been classified as a Reject that is not suitable for restoration.
Report Pole	A pole which is determined by Contractor, in Contractor's reasonable opinion, to be inaccessible.

Restoration Pole	A Rejected Pole that, after inspection, meets the criteria for pole restoration. All poles found to be restorable will be externally groundline treated and internally treated if necessary. Fumigant Treatment will not be applied until after the pole has been restored.
RP1 Pole	This category would be your industry standard reject pole, but depending on the circumstance would need to be replaced during a six month period, after the inspection has been documented. This pole would probably be on the low end of remaining strength (closer to 35%) relating to the RP2 definition. This pole could be leaning badly or bowed badly due to hardware (maybe a dead end pole) or terrain. This pole is close to a priority pole, but still falls into the reject category. This pole may have termites that continue to destroy (eat) the wood at a fast pace – even carpenter ants with visual sawdust at the base of the pole. This pole could have lightning damage or a bad split where the top is in jeopardy, insulators hanging off cross arms, animals living in the top (squirrels, etc.), many large woodpecker holes close together, etc.
RP2 Pole	This category would be your industry standard reject pole. This pole probably has remaining strength < 67% and > 35% due to many types of decay or mechanical damage. This pole could be rejected for a split top that runs down through the hardware, where you can see through the split. This type of pole should be replaced during a one year period, after the inspection has been documented. This pole probably does not have any significant (heavy) hardware. This could be a junction pole where the wires help its support.
RP3 Pole	This category would be your industry standard reject that just falls into the reject category. This pole would be on the higher end of remaining strength (closer to 67%). There are no special circumstances with this pole otherwise it would fall into the RP1 or RP2 definitions. This pole would need to be replaced within a two year period, after the inspection has been documented. This pole could very likely have a problem above, otherwise it would fall into the Reinforcable category.

1.3.3. Inspection Definitions (in order of increasing inspection requirements)

Asset Inspection	Poles where the only inspection requirements are to verify and/or gather asset data and perform a casual inspection to identify any obvious damage, defects or safety hazards.
Visual Inspection	Poles that are Asset Inspected and are subjected to a detailed Visual Inspection at and above ground. Includes a visual inspection of equipment, supports, and ancillary equipment such as guys and anchors, push braces, etc. for obvious damage, defects or safety issues.
Sound And Bore Inspection	Poles that are Asset and Visually inspected that are sounded with a hammer from groundline to highest reach and bored with one or more inspection holes to facilitate the detection and extent of internal decay.
Full Excavation Inspection	Poles that are fully inspected including an Asset, Visual and Sound and Bored inspections where the pole is completely excavated to a minimum of 18” below groundline to facilitate a complete assessment of below ground decay and remaining strength. Includes cleaning and

chipping decay and gathering physically information on the extent of decay and the poles physical condition. All Full Excavation poles will be externally treated unless the pole is to be a Reject Replacement or Priority Pole.

1.3.4. Treatment Definitions

External Treatment	A Company approved, Contractor provided EPA registered below ground preservative treatment and wrap applied to the pole's exterior at and below grade when designated by the Company or when groundline decay is detected during inspection. All Full Excavation poles will be Externally Treated as part of the Full Excavation Inspection.
Fumigant Treatment	Application of a Company approved, Contractor provided EPA registered non-liquid fumigant placed internally in a pole where internal decay is detected during inspection or as otherwise directed by the Company or this specification.
Internal Treatment	Application of Company approved, Contractor provided EPA registered insecticide and preservative solution applied internally to a pole under pressure to any chambers and internal decay voids that constitute a size of 1/2" or larger detected during inspection.

1.3.5. Pole Strength Definitions

ANSI Strength	Baseline strength of a pole by pole type, height and class as determined from ANSI C05.1 dimensions.
Effective Circumference	Calculated usable circumference based on actual pole circumference as reduced for damage, defects and decay.
Load Calculations	Strength calculations used to determine either the Remaining Strength of a pole based on a pole's actual conditions or to determine Required Strength based on actual pole loading under appropriate NESC criteria.
Remaining Strength	Percentage of pole strength remaining as a function of the Effective Circumference. Expressed as a percentage of the ANSI C05.1 minimum strength for a given pole type, height and class.
Required Strength	Pole strength required for the actual loads impressed on a pole under the required NESC Loading District and Grade of Construction.

2. CONTRACTOR REQUIREMENTS

2.1. General Requirements

The Contractor shall furnish all supervision, labor, tools, equipment, PPE, report forms, transportation and material necessary for the inspection and treatment of poles identified by LG&E AND KU ENERGY, hereafter referred to as the Company. Company will furnish copies of this specification and physical or electronic maps showing locations of poles which are the subjects for inspection and/or treatment under this specification.

2.2. Contractor Documentation

The Contractor is required to demonstrate a minimum acceptable level of experience, as determined by the Company, in the inspection, remedial retreatment and reporting requirements consistent with this specification. Years of service in utility field service work other than pole inspection and/or treatment will not count toward this requirement. The Contractor must have documented policies conforming to EPA, OSHA, DOT along with all Federal and Kentucky State Pesticide & Contract regulations. These policies must include, at a minimum:

- Safety Manual
- Hazard Mitigation Plan
- Pesticide Training Manual and test
- Standards for safe storage of preservatives on vehicles
- Operating policies for Contractor's personnel to handle preservatives and procedures for spill containment and disposing of empty containers used for pole treatment
- OSHA regulations involving personal protective equipment
- MSDS Sheets for all chemicals and preservatives utilized

2.3. Contractor Safety & Ethics

2.3.1. Safety

Safe Work Practices are an absolute condition of this contract and contractors are expected to meet or exceed all Company safety guidelines and requirements. Without limiting the foregoing, Contractor agrees to strictly abide by and observe all standards of the Occupational Safety & Health Administration (OSHA) which are applicable to the work being performed. Any unsafe conditions or work practices found by the Contractor during the performance of this Contract will be reported to the Company.

Contractor shall hold Job Briefings daily or when work area changes.

Some areas may require contractor to call BUD (Before You Dig) for location of underground utilities. Contractor will be responsible for call and any expense as of result of underground locating.

Contractor shall be provided with Company’s Contractor Safety Policy and Health and Safety Manual (electronically) and all other Company approved policies and rules applicable to the scope of work, and shall meet the requirements therein as a minimum standard.

"Prior to any work starting a Hazard Analysis and Hazard Mitigation plan must be submitted and approved by the Company.

Contractor is required to have or develop a written safety program and work rules that equal or exceed the requirements of Company’s program and are compliant with applicable laws and regulations. The program plan will include training necessary to prepare or certify Contractor employees coming to work at Company. Additionally, the plan will contain provisions to maintain documentation of training, certifications, etc. required by Contractor employees to perform the work described. This documentation shall be available to Company upon request.

The plan shall include procedures to follow in the event of an injury, incident, or close call involving one of its employees working on Company facilities. Incidents shall be reported immediately to the Company. Incidents and hours of work shall be submitted in the Contractor Data Base monthly. The plan shall be submitted to Company prior to the start of this agreement. Contractor will be expected to participate in Company’s Safety Meetings when requested and to share pertinent information when requested.

No employee of the Contractor will be allowed to perform work on behalf of the Company until the employee has been certified in general safety awareness (Passport) program for contractors. . All training shall be entered into the Contractor Data Base and employees provided with a "Passport" card by the contractor prior to beginning work. "Passport" is an instructional general safety training session designed to orient new contractors to the Company's safety environment, rules, and culture. Contractor will have someone certified at an available "Train the trainer" session to provide their employees "Passport" training annually or use an approved 3rd party trainer at their expense.

Contractor shall furnish Personal Protective Equipment including but not limited to high voltage rubber gloves and sleeves and Flame Retardant clothing for anyone repairing a pole ground wire.

Contractor's employees will be subject to random safety audits and passport verification.

2.3.2. Ethics

Contractor will be provided with Company's Contractor Code of Conduct and shall meet the requirements therein as a minimum standard. Contractor shall at all times be solely responsible for complying with all applicable laws and regulations governing the work to be performed or any other rules and regulations that may be issued by the Company during the term of this Contract. Contractor shall abide by all federal, state, and local labor laws.

2.4. Insurance

The Contractor shall maintain throughout the term of this Agreement, in full force and effect, in amounts reasonably satisfactory to Company and otherwise in compliance with applicable law, the following insurance coverages:

- Workers' compensation
- Commercial general liability (including public liability, personal injury, property damage and contractual liability)
- Automobile liability, naming Owner as an additional insured.

Prior to the commencement of the Work, Contractor shall furnish Company with the necessary documentation evidencing said coverages. Notwithstanding any language to the contrary, any insurance coverage provided by Contractor shall not cover the Company for any negligent acts or omissions of the Company, its employees or agents.

3. CONTRACTOR QUALIFICATIONS

3.1. General Qualifications

All pole inspection and treatment must be performed by professional in-service groundline pole inspection and treatment specialists. Foreman and/or other lead people must demonstrate they have received formal training in inspecting and treatment of in-service wood poles and demonstrate they have a minimum of 3 years' experience as a pole inspector. The acceptability of experience and training will be determined by the Company.

The Company reserves the right to ask for evidence of previous experience and training in the form of training material, letters of reference and test results. Foreman or other lead people must also possess a Kentucky and Virginia State Pesticide License. All personnel are subject to approval by the Company before awarding the contract or at any time thereafter.

Failure to maintain adequately trained inspectors will result in payment being withheld by the Company in the area being inspected. Company will require that at least one employee be on a job site at all times who is able to speak English clearly wherever contact with customers or the public is possible. Direct contact with Contractor's field Foremen or other lead people by cell phone must be available during normal business hours.

3.2. Vehicles and Personal Attire

All vehicles must have a professional appearance and be clearly marked with the Contractor's identification. Vehicles will also be marked to indicate that crews are Contractors of LG&E AND KU ENERGY companies (LG&E, KU and ODP). Clothing will identify everyone on the work site as employees of the Contractor. Care will be taken to ensure everyone on a job site maintains a suitable appearance during the performance of work.

3.3. Supervision

Supervision of pole inspection and treating shall be performed using full-time supervisors located within the area with at least five (5) years of field experience in in-service pole inspection and treatment. Supervision must be present in the field every other week for a minimum of one half day for each crew working for the Company. Supervisors will be required to possess a valid Kentucky State Pesticide License and hold the position of Supervisor in the State of Kentucky and/or a Virginia State Pesticide License for work in Virginia.

Personnel not specifically qualified to inspect and treat in-service poles as outlined above shall not be transferred to work as pole inspectors from other contractual work.

4. WORKMANSHIP AND QUALITY CONTROL

4.1. Workmanship

All work shall be performed in a workmanlike manner and shall be in accordance with this specification and all applicable Federal and State regulations. The Contractor shall at all times exercise care to prevent injury to any persons and to prevent damage to Company facilities or to property during performance of the work.

The Company considers work not in accordance with this specification or work not in accordance with State or Federal regulations, or unskilled or careless work to be sufficient reason to order the Contractor to stop work. Work will not be allowed to resume until deficiencies are corrected to the satisfaction of the Company. Further, the Company reserves the right to require the Contractor to replace any worker before work is allowed to continue. If not satisfied, the Company will consider this to be just cause for termination of the Contract.

4.2. Damages

Any damages, real or personal, off the right of way arising directly from the performance of the work specified herein, or any damages on the right of way as a result of negligent operations, shall be settled promptly by the Contractor.

4.3. Quality Inspections

A quality control inspection shall be performed for each time period of not less than one week's work but not to exceed two weeks' previous work. The quality control will be conducted with the Contractor's Supervisor and Company's representative when available. The quality control inspection shall consist of the complete re-inspection of those poles selected by the Company's representative to compare the pole's condition and results shown on the pole report with those existing in the field. The re-inspection shall include, but shall not be limited to, the re-excavation and retreatment and re-wrapping of those poles that were inspected below groundline.

Contractor's cost of said re-treatments shall be borne by the Contractor. At least 3 poles will be selected for each quality control audit. Poles will be selected at random by the Company's representative. Company shall be issued a copy of the quality control field report.

4.4. Discrepancies and Corrective Action

Any serious errors will be brought to the attention of the Company. Corrective action, satisfactory to the Owner, must be taken by the Contractor to remedy the situation before the next quality control check. The corrective action may include, but not be limited to reworking each pole back to the previous quality control check point at no cost to the Company.

5. REQUIREMENTS FOR PRESERVATIVE APPLICATIONS

5.1. General Restrictions and Requirements

All preservatives and insecticides must be approved for use by the Company prior to any work being performed. Only preservatives registered by the Environmental Protection Agency (EPA) and the appropriate State Department of Agriculture for the intended use will be considered for approval by the Company.

MSDS sheets for all chemicals, preservatives and insecticides will be provided to the Company before use.

All preservatives shall be handled and applied in a manner that will prevent damage to vegetation and property. No preservatives shall be applied by the Contractor where a pole is readily identifiable as:

- Located on any school, preschool, day care or other child care facility
- Located in a vegetable garden
- Within ten (10) feet of a stream or standing water body
- Within (50) fifty feet of a private well.
- Located within active livestock or animal pastures or containment area unless additional precautions are taken to prevent access

Any container in which a preservative is stored shall be securely locked or bolted to vehicles on the right of way and kept locked when left unattended. Empty preservative containers shall be removed from the right of way and kept in a locked compartment until disposal. Disposal of preservatives and their containers shall be in accordance with the rules and regulations of all appropriate Federal and State agencies.

5.2. Pesticide Licensing and Reporting Requirements

The Contractor shall be a certified commercial pesticide business for the preservative application set forth under this Contract, and shall have each crew supervised by a full time Supervisor who is licensed and certified by the State where the work is performed. The Contractor shall be responsible for the accurate recording and submitting of all pesticide usage forms required by the various pesticide regulatory agencies and for meeting all applicable Federal and State rules and regulations.

The Contractor is required to have in his possession copies of the preservative labels and MSDS sheets for all the preservatives being used. The labels shall list the preservative composition, description, directions for use, precautionary statements, warnings, environmental hazards, practical treatments, storage and disposal instructions and any other relevant information about the preservatives used.

Upon request, the MSDS and labels will be shown to anyone desiring this information. Properly completed shipping papers will also be carried on each vehicle which is transporting pesticides.

5.3. Spill Prevention

Incidental releases of preservative shall be immediately cleaned up in a manner consistent with label requirements, Federal and State regulations, and relevant environmental procedures.

The Contractor shall provide each crew with a spill kit containing sufficient materials for cleaning up and neutralizing potential spills of liquid preservatives. The spill kit shall consist of, but shall not be limited to the following materials:

- Absorption material (such as sawdust or oil dry)
- Baking soda or laundry detergent
- Ammonia (undiluted)
- Trash bags for disposal of waste
- Any other item deemed necessary by the Contractor

5.4. Proper Equipment

The Contractor shall provide each crew with the following EPA required equipment:

- Goggles
- Sleeves
- Non permeable gloves and aprons
- Hard hats
- Change of clothing

The Contractor shall provide a truck that has covers and locks adequate to satisfy federal and state DOT regulations in which to store and transport the preservatives. No chemicals or preservatives will be left unattended at any time unless securely locked in a manner to prevent unauthorized access.

5.5. Pesticide Training

Each pole inspector or foreman shall be required to pass a pesticide training program which addresses biology of wood destroying insects and fungi, the proper and safe handling, storage, disposal and transport of pesticides, product labels and material safety data sheets, emergency procedures for pesticide spills, etc. The Contractor's Pesticide Training Program is to be in addition to state requirements for applicator licensing.

5.6. Hazard Communication and Safety Program

The Contractor shall provide to its employees a hazard communication program which addresses the purpose of using pesticides, material safety data sheets and product labels, protective safety equipment and clothing and product information. A safety manual and program is to be provided and utilized by the Contractor and its employees.

6. CLASSIFICATION OF POLES

6.1. General

The base level of inspection specified for wood distribution poles will be dependent on Pole's Classification as modified by factors including pole ownership, age, location, original treatment, previous remedial treatment, etc. Wood poles will be first classified in an order dependent on ownership and the type of facilities supported on or attached to the pole. Standard Classifications are defined below in Section 6.2.

All LG&E AND KU ENERGY poles that meet more than one classification will be classified by the higher classification (top to bottom). For example, a pole that supports both transmission and distribution conductors will be classified as a transmission pole unless it is not a Company owned pole (Foreign Pole). A Company owned Service Pole that has a street light will be classified as a Service Pole.

Foreign poles will only be classified as a Foreign Pole and all Foreign Poles will be treated the same unless otherwise directed by the Company. The Contractor is responsible for becoming familiar with common LG&E AND KU ENERGY transmission and distribution standards and ownership standards in order to differentiate the various Company Pole Classifications as defined below.

6.2. Pole Classifications

6.2.1. Non-LG&E AND KU ENERGY Pole Classifications

Foreign Pole	A pole used for conductor support, guying, secondary or service drops owned by any party other than the Company.

6.2.2. LG&E AND KU ENERGY Pole Classifications

Transmission Pole	A Company owned pole supporting any circuit conductors of 69kV nominal phase to phase or above as determined by common construction standards.
Distribution Pole	A Company owned pole supporting any distribution primary conductors defined as greater than 480V and less than or equal to 34.5kV nominal phase to phase as determined by common construction standards.
Guy Pole (Transmission Or Distribution)	A Company owned pole utilized in whole or in part for guying a Transmission or Distribution Pole.
Secondary Pole	A Company owned pole utilized to support secondary conductors defined as 480V nominal phase to phase or less not classified as a Service Pole or Street Light Pole as determined by common construction standards.
Service Pole	A Company owned pole used exclusively for the purpose of supporting service drops of 480V nominal phase to phase or less.
Light Pole	A Company owned pole used exclusively for the purpose of supporting overhead street lighting, including the attachment of secondary conductors used exclusive for providing service for overhead lighting.

7. LEVELS OF INSPECTION

Only Company owned wood poles are covered under the requirements of this specification. Non-wood distribution structures, transmission poles and transmission guy poles are not covered under this inspection requirement. No Foreign poles are to be inspected. The desired Level of Inspection specified for each pole will be determined by the Pole's Classification as defined in Section 6.

The Inspection Level is the desired level of inspection to be performed. The pole's location, the ability to access, physical impediments around the pole (poles in concrete, etc.), the pole's current condition or past history of decay may result in a higher or lower level of Inspection than directed in the table below.

Table 7-1 Wood Pole Inspection Criteria

Pole Classification	Pole Category	Inspection Level
Foreign Poles Transmission Poles Transmission Guy Poles	All	None
Distribution Poles Distribution Guy Poles Secondary Pole Service Pole Street Light Pole	14 years old or less 15 years and older that have been retreated within the last 5 years	Visual Inspection
	15 years and older that have not been retreated within the last 5 years	Full Excavation Inspection

8. INSPECTION REQUIREMENTS

8.1. General

The requirements of this specification were developed to provide for a "condition based" inspection program. The basic target Inspection level for any pole is based on the Pole's Classification as defined in Section 7. Based on the results of the initial inspection, the Contractor can, for just cause proceed with progressively higher levels of inspection and potentially Treatment when justified.

8.2. Preparation For All Inspection and Treatment Options

Before any work is started, all precautions shall be taken to insure that the work can be completed safely and no pole failure will occur during the work.

When work is to be done in close proximity to a home or in an enclosed area in the rear of a home, the property owner should be notified that the pole is to be inspected. Brush will be removed from around the pole to the extent necessary to allow for proper inspection and/or excavation. If the property owner denies access for any reason, the denial will be indicated in the inspection data the pole will be considered a "Report Pole".

Contractor will not inspect or perform work on poles inaccessible by acts of God or by any causes beyond the control of the Contractor. Any pole that cannot be inspected safely will not be inspected. Reason for the lack of inspection indicated in the inspection data. There will be no charge associated with inaccessible poles.

8.3. Asset Inspection

Every pole designated for inspection shall receive at a minimum, an Asset Inspection before any other work is done. An Asset Inspection includes recording (if missing) or verifying (if provided) pole asset information including (at a minimum):

- Pole ownership
- Pole identification number (if provided or tagged)
- GPS coordinate and/or location
- Pole height and class
- Manufacturer
- Manufacture date
- Pole species
- Original pole treatment
- Date of last remedial treatment (if applicable)

Other data collection or work may be incorporated into Asset Inspections when directed or approved by the Company. Inaccessible poles will be noted as such and will not be visually inspected. Reason for the lack of inspection will be noted in the remarks column of the pole report. There will be no charge associated with inaccessible poles.

When decay or insect damage is suspected or detected or for other reasons within the Contractor's discretion, Company owned poles designated for only an Asset Inspection will proceed to a full Visual Inspection where warranted.

8.4. Visual Inspection

Visual Inspections include all of the requirements of an Asset Inspection.

A Visual Inspection is made from groundline to the top of the pole and includes a visual inspection of all equipment and supports including ancillary equipment such as guys and anchors, push braces, etc. The inspector shall document the condition of the pole and shall record any of the following:

- Structural defects due to top rot, woodpeckers, lightning, compression wood, mechanical damage, excessive checking, bowing or leaning, etc.
- Obvious groundline decay and/or insect damage.
- Broken or damaged equipment
- Obvious clearance violations on the pole such as clearances to communications conductors, etc.
- Obvious clearance violations in any span adjacent to the inspected pole to ground, swimming pools, other structures, trees, buildings, etc.
- Unapproved non-utility attachments (basketball goals, private lighting, etc.).
  Note: Communications attachments, street and traffic signs and controls and banners from public or quasi-public agencies are considered approved attachments for the purpose of this item.

Prods, bars or picks shall not be used to determine the extent of external decay. Sounding may be used to further assess the condition of the pole.

If the inspector can determine without further inspection that the pole is not suitable to remain in service it shall be visually rejected and the Contractor shall bill the Company for a "Visual Inspection". Imminent hazards shall be reported to the Company immediately.

When decay or insect damage is suspected or detected or for other reasons within the Contractor's discretion, Company owned poles designated for only a Visual Inspection will proceed to a Sound and Bore Inspection or Full Excavation Inspection and where appropriate, Treatment.

8.5. Sound and Bore

Sound and Bore Inspections include all of the requirements of an Asset and Visual Inspection.

Poles shall be sounded with a hammer from the lowest accessible point to as high as an inspector can reach in order to locate exterior decay or interior pockets of decay. Hammer marks should be visible to indicate that the area was sounded.

Inspector shall bore the pole at least once to detect interior pockets or decay using a 3/8" bit. Bore holes should be made in the line of lead unless the inspector determines boring at other locations may provide better identification of decay. Bore hole shall be located near the groundline and should be drilled at a 45 degree downward angle to a depth of the center line of the pole in the line of the pole. Only sharp bits are to be used for boring and special attention shall be paid to the nature and characteristics of the shavings. A shell thickness indicator shall be used to detect the extent of any interior decay. If decay is present, the pole shall be bored a sufficient number of times to determine location and extent of decay. Detail on the type, size and location of pockets and decay will be noted on the report.

If heart rot or enclosed decay pockets are evident in a pole, a minimum of five (5) borings will be taken to determine the size and extent of decay.

Bored holes shall be plugged with tight-fitting 7/16" diameter treated wood dowels.

If the inspector can determine without further inspection that the pole is not suitable to remain in service it shall be rejected and the Contractor shall bill the Company for a "Sound and Bore Inspection". Imminent hazards shall be reported to the Company immediately.

When groundline decay, insect damage, internal decay pockets or internal decay is suspected or detected or for other reasons within the Contractor's discretion, Company owned poles designated for only a Sound and Bore Inspection will proceed to a Full Excavation Inspection and where appropriate, Treatment.

8.6. Partial Excavation

Occasionally, Partial Excavation may be necessary for the following but not limited to reasons:

- In pavement or concrete
- With underground power risers (unless approved by the Company)

Partial Excavation inspections include all of the requirements of an Asset, Visual and a Sound and Bore Inspection.

Where excavation is not possible the reason will be noted in the report and the Contractor will bill the pole as a "Sound and Bore" Inspection.

If no surface decay is suspected and the borings indicate no internal decay or pockets, no further action is required. The partial excavation will be back-filled and the soil reasonably compacted.

If the inspector can determine without further inspection that the pole is not suitable to remain in service it shall be rejected and the Contractor shall bill the Company for a "Partial Excavation" inspection. Imminent hazards shall be reported to the Company immediately.

8.7. Full Excavation

Full Excavation inspections include all of the requirements of an Asset, Visual Inspection and a Sound and Bore Inspection. All Full Excavation Poles with be externally groundline treated.

8.7.1. Excavation

All poles that have not been rejected on the basis of the above ground Visual and Sound and Bore Inspection shall be excavated to a depth of 18" below groundline. Exceptions include poles:

- In pavement or concrete

- In vegetable gardens
- With underground power risers (unless approved by the Company)

Where excavation is not possible the reason will be noted in the report and the Contractor will bill the pole as a "Sound and Bore" Inspection.

The excavation will be approximately 10" from the pole at ground level and taper to 4" from the pole at the 18" depth. For excavation in lawns, sod grass areas or gardens, care will be taken to keep surrounding area as clean as possible. The sod around pole shall be carefully cut and neatly stacked. Poles installed on slopes shall be excavated to a minimum depth of 18" on the down slope side and 18" on the high side. Tarpaulins or ground cloths shall be used whenever possible to minimize the possibility of any property damage and to aide in the tracking of excavated holes. (Exceptions should be rare, and would include situations where the slope is to steep or the ground surface to uneven to allow for effective use).

8.7.2. Chipping

Significant loose and decayed wood is to be removed from 18" below groundline to 6" above groundline. A quality chipping tool will be used for this procedure to obtain a smooth, clean removal of wood. External decay pockets will be shaved or chipped to remove decay from pole. It is essential that exterior decay be removed from the hole and surrounding ground and disposed of properly. Care should be taken not to remove good wood as this will increase the potential for decay and will reduce the strength of the pole. The pole will be scraped using a check scraper to remove dirt from the treatment zone.

8.7.3. Damaged Ground Wires

Contractor shall use extra care to avoid damaging or cutting pole grounds. Ground wires broken by the Contractor shall be repaired by the Contractor at no charge to the Company. The Contractor shall repair broken ground wires using proper PPE and workers qualified to safely reconnect the ground in a method acceptable to the Company.

8.8. Digital Collection for Rejected Poles

All rejected poles shall have two photos. The unit shall consist of two digital images of each reject pole. One image of the pole number and one image of the top of the pole where all material/equipment would be captured in the image.

8.9. Pole Identification Number

If an inspected pole does not have an identification number, contractor shall attach pole number.

9. EVALUATION

9.1. Obvious Rejects

Poles obviously unsuitable to remain in service will be classified as a Reject Replacement Pole or a Priority Pole. If excavation was performed, soil will be carefully returned to the hole and lightly tamped. No further work will be done. The pole will be properly tagged as a Reject Replacement Pole or a Priority Pole in accordance with Section 12 – Pole Marking. Priority Poles will be reported to the Company's designated utility contact within 24 hours and details on the pole's condition and reasons for classifying the pole as a Priority Pole will be provided at that time.

9.2. Effective Circumference

A qualified Inspector will measure the actual minimum circumference at or below groundline wherever the least sound wood is present. An Effective Circumference will be determined in the field by adjusting the actual circumference to account for external decay pockets and internal decay by the use of Company approved tables, calculators or handheld software.

9.3. Remaining Strength

The Effective Circumference in conjunction with Company approved tables, calculators or handheld software will be used to determine the effective Remaining Strength as a percentage of specified ANSI Strength (ANSI 05.1, current revision) for the pole type, height and class. Remaining Strength will be calculated as a percentage of ANSI 05.1 strength and the percentage recorded.

Poles with Remaining Strength greater than or equal to 67% will be treated in accordance with Section 10 - Pole Treatment.

Poles with Remaining Strength of more than 35% but less than 67% will be subjected to a Load Calculation to determine if the Remaining Strength is adequate for the actual loads impressed on the pole under NESC loading requirements.

9.4. Load Calculation

A Load Calculation will be performed on any poles with Remaining Strength greater 35% but less than 67% (2/3) of the ANSI Strength that is in otherwise suitable condition to remain in service. The Load Calculation will be used to determine if the pole's Remaining Strength meets or exceeds the Required Strength as determined by the appropriate NESC loading requirements. Required Strength will be determined based on the following requirements:

9.4.1. Loading District

Unless otherwise directed by the Company, the following NESC loading criteria will be used to determine Required Strength.

- Kentucky: NESC Medium Loading
- Virginia: NESC Heavy Loading

Where any portion of the structure or facilities supported by the structure exceeds sixty feet (60') above ground NESC High Wind and Heavy Ice criteria will also be considered.

9.4.2. Grade of Construction

NESC Loading Criteria	**Application**
Grade B	Crossings of Limited Access highways, railroad tracks, navigable waterways requiring waterway crossing permits Lower voltage circuits placed above or crossing circuits of 8.7kV phase to ground or higher Crossings of any lines where the crossed line must meet Grade B criteria whether crossed on a common structure or not.
Grade C at Crossings	Any other poles not required to meet Grade B construction

Poles where the Remaining Strength exceeds the Required Strength which are otherwise in acceptable condition to remain in service will be treated in accordance with the requirements in Section 10 - Pole Treatment.

9.5. Reject Poles

Poles below minimum Required Strength and poles unsuitable to remain in service in their present condition shall be classified as a Reject Pole, and so marked in the field and reported. Poles classified as a Reject Pole will be further classified as either a Reject Replacement or as a Reinforcable Pole based on the criteria below. The pole will be tagged with the appropriate tag in accordance with Section 12 – Pole Marking.

9.5.1. Reinforcement Candidates

Poles with a minimum shell equal to or greater than 2 inches will be considered a Candidate for Reinforcement and evaluated under Section 9.6.

9.5.2. Reject Replacement

The following poles will be classified as Reject Replacements. No treatment will be applied and any excavation will be carefully filled and lightly tamped back in place. Pole will be recorded as a Reject Replacement or Priority Pole.

- Poles with a shell thickness less than 2” will be rejected.
- Poles with a minimum shell of 1 inch or 50% of original circumference or less will be designated a "Priority Pole". Priority Poles will be reported to the Company’s designated utility contact within 24 hours and details on the pole’s condition and reasons for classifying the pole as a Priority Pole provided at that time.

9.6. Reinforcable Candidates

When the initial inspection or loading analysis results in the rejection of a pole, and the pole is otherwise serviceable the pole shall be marked for replacement or reinforcement. The following inspections shall be performed to determine if the pole is a viable candidate for reinforcement.

The pole shall be sounded thoroughly concentrating on the zone fifteen inches (15”) to 5 feet above groundline.

To be considered a Candidate for Reinforcement, the pole must meet <u>both</u> of the following requirements.

1. A minimum of two 3/8-inch diameter borings shall be made at 5 feet above groundline, to determine the average shell thickness at this level. The first boring shall be made perpendicular to the line of lead. A second boring shall be made opposite (180 degrees) the first boring, whenever possible. Additional borings should be made, as necessary, to determine the average shell thickness. If the average is less than the required four inches, the pole should be checked at 6 feet to determine if the required shell thickness exists at 6 feet. If the average shell thickness at either 5 feet or 6 feet above the groundline is four inches the pole is a candidate for reinforcement provided all other requirements are met.

2. A minimum of two 3/8-inch diameter borings shall be made at 15 inches above groundline, to determine the average shell thickness at this level. The first boring shall be made perpendicular to the line of lead. A second boring shall be made opposite (180 degrees) the first boring, whenever possible. Additional borings shall be made, as necessary. If the average shell

thickness, at 15 inches, is two inches or greater, the pole is a candidate for reinforcement. Poles with less than two inches of average shell, at 15 inches above groundline, can be reinforced if they have an average shell thickness of two inches or greater at 26 inches and the requirements and all other requirements are met.

If the pole fails to meet either of these requirements, the pole will be classified as a Reject Replacement. The pole will be marked with a reject tag and any excavation will be carefully filled in.

If the pole meets both of the minimum shell thickness requirements, the pole will be treated under the requirements of Section 10 - Pole Treatment except no fumigant will be applied. If it was necessary to go to 26 inches or 6 feet to obtain the required shell thickness, a notation will be made in the pole record.

All inspection holes shall be plugged with 7/16" diameter treated wood dowels.

10. **POLE TREATMENT**

10.1. Treatment Schedule

Poles will be treated according to the following schedule.

10.1.1. Poles With Internal Decay Pockets of 1/2" Or Greater

The following poles will be Internally Treated:

- All poles with internal decay pockets will be treated with an Internal Treatment, a Fumigant Treatment and an External Treatment where possible unless the pole is to be a Reject Replacement. This includes all poles classified as Reinforcement Candidates.

10.1.2. Poles With Internal Decay

The following poles with be Fumigated:

- All poles with internal decay but no decay pockets will be Fumigated and Externally Treated where possible unless the pole is to be a Reject Replacement.

  Note: Poles which are to be classified as Reinforcement Candidates will not be fumigated until after the pole is reinforced.

- All poles which are designated or progress to the Full Excavation requirements but can't be fully excavated due to risers or obstructions (such as poles in concrete) will be treated with a Fumigant Treatment even when no internal decay is detected.

- All poles which are designated or progress to the Full Excavation requirements that cannot be excavated (Except Section 5.1, in concrete, etc.)

10.1.3. Groundline Decay

The following poles will be Externally Treated:

- All fully excavated poles shall be treated in accordance with External Treatment regardless of the presence of decay unless the pole is to be a Reject Replacement.

10.1.4. Previously Treated Poles

Poles designated for any level of inspection that have been inspected and treated within the last 5 years will receive only a visual inspection.

All other poles that have been previously treated will receive a full excavate and treat inspection consistent with the requirements of Section 8 – Inspection Requirements. If Kraft paper is removed to facilitate inspection, then it should be reapplied when the inspection is complete. Where external or internal decay is detected or has been reestablished, treatment will be performed consistent with the requirements of Section 10 - Pole Treatment with the following exception:

Any pole previously treated with Internal or Fumigant treatment will be retreated in the same manner as the previous treatment cycle regardless of whether internal decay has been reestablished. Groundline treatment will be reapplied only if groundline decay is detected and/or has been reestablished.

10.2. Application of External Groundline Treatment

All poles which are excavated and serviceable or Reinforcable are to be groundline treated. Only a Company approved, EPA registered External Treatment will be used.

10.2.1. Application

Preservative paste shall be applied to the pole a minimum of 1/16" thick or to the minimum requirements specified by the manufacturer. Treatment will extend from 18" below groundline to 2" above groundline unless otherwise directed by the Company. Unapproved materials will not be accepted by Company. All restorable candidates will be externally treated.

All exposed pockets and checks will be liberally treated using a brush or trowel. Where obstructions occur such as fences, curbs, and walls, the preservative shall be applied in excessive amounts next to the obstruction to insure complete coverage.

10.2.2. Wrapping of External Treatment

A poly backed Kraft paper is to be applied over the wood preservative. The moisture barrier shall cover the preservative at 18" depth and extend 2" above the top of the treatment zone, for a total of 22" wide. It shall be of sufficient length to go around the pole with a minimum overlap of approximately 4" and shall be stapled to the pole at the top and side seams of the barrier. The mil thickness of the moisture barrier shall not be less than 4 mils thick.

Pasture wrap shall also be used in areas of livestock; it will be stapled to top of the moisture barrier to act as an additional protective barrier.

10.3. Application of Fumigant Treatment

Fumigant shall be applied as specified under Section 10.1. Only a Company approved, non-liquid (vial based or granular) EPA registered Fumigant will be used.

10.3.1. Application

Poles will be bored with 7/8" slanting downward holes to a minimum of 10" depth according to the following schedule. Proper protective equipment will be utilized to apply the fumigant. Following treatment all holes will be plugged using a tight fitting 15/16 x 3" treated wood dowel or composite plastic plug.

Pole Circumference	Number of Holes Drilled
30" to 35"	3 holes spaced 120 degrees apart and 6" to 8" higher than the previously bored hole.
36" to 49"	4 holes spaced 90 degrees apart and 6" to 8" higher than the previously bored hole.
50" to 59"	5 holes spaced 72 degrees apart and 6" to 8" higher than the previously bored hole.
60" & larger	6 holes spaced 60 degrees apart and 6" to 8" higher than the previously bored hole.

The number of treatment holes will be recorded in the pole record.

10.4. Application of Internal Treatment

Internal Treatment shall be applied as specified under Section 10.1. Only a Company approved, EPA registered Internal Treatment will be used.

10.4.1. Application

Poles containing decay pockets of 1/2" or larger shall be treated by pumping the preservative into the cavity under pressure through a series of 3/8" diameter holes. The solution will be applied at a minimum pressure of 40 psi or per manufacturer's recommendations. Beginning with the lowest hole, pump the preservative into the cavity until the material flows out of the next highest hole. This hole is then plugged and additional preservative is pumped into the cavity until the cavity is filled or a maximum of one gallon is used. Sufficient holes will be bored and preservative used to assure coverage of decayed area. All holes will be plugged with 7/16" treated wood dowels. If wood destroying insects are encountered in the pole, sound the pole to locate top of the insect gallery and drill enough holes to thoroughly treat wood and flood the galleries.

11. SITE RESTORATION

11.1. Damaged Ground Wires

Ground wires and risers will be carefully inspected after work is complete and before backfilling. Ground wires broken by the Contractor shall be repaired by the Contractor at no charge to the Company. The Contractor shall repair broken ground wires using workers qualified to safely reconnect the ground in a method acceptable to the Company.

11.2. Backfilling

After excavation and/or treatment, all poles will be solidly back-filled. The first half of excavation will be back-filled and tamped completely around the pole; the second half back-filled and tamped completely around the pole. The excess earth should be banked up to a maximum of 3" above normal ground level to allow for settlement. In grass areas the sod shall be carefully placed around the pole. Rocks or stones should not be laid against the pole except where they serve to key the pole or where no other fill is available. Extreme care should be taken not to tear the moisture barrier while back-filling.

11.3. Clean-up

No debris, loose dirt, wood shavings, etc., shall be left in the pole area. Private property turf, including that between curb and sidewalk, bushes, and plants, and shrubbery are to be replaced with care. If any preservative is spilled on the ground, it shall be cleaned up immediately. All containers shall be disposed of according to approved environmental practices.

12. **POLE MARKING**

12.1. Tagging (See Attachment 1)

All tagging will be approved or specified by the Company before use. All pole tags to be installed at or above 7 feet from the ground line.

All rejected poles are to have one reject tag placed on them at approximately 7 feet from groundline. In addition to the reject tag, red flagging, or spray paint, to be furnished by the Contractor if directed by the Company, will be applied to help in the identification of priority or rejected poles.

Poles rejected but capable of being restored are to be properly marked with an appropriate reject tag.

The Contractor's inspector will make a notation on the pole inspection and treating report as to whether the pole can or cannot be restored. If the pole has other damage of any kind, it will be noted in the remarks column.

Priority poles are to have two reject tags at approximately 7' from groundline.

13. **Data Requirements**

Company desires to conduct a comprehensive pole inspection and maintenance program. The data to be collected will include pole attributes, pole condition and treatment and may include additional information if requested or specified by the Company. Data will be submitted electronically in a format suitable for viewing, searching and reporting. On-line or proprietary data formats must be exportable to other formats acceptable to the Company Access, Excel, etc. and suitable to be migrated into other Company asset information systems.

The Contractor will be required to demonstrate a successful history in completing similar inspection and treatment projects in electronic format. The Contractor will include, as part of the prices set forth in the Contract, all required hardware, software, setup services, field services, data processing, project management, data deliverables and customer support necessary to fulfill the outlined project requirements.

The Company will work with the Contractor to provide pole facility data and attributes in a mutually agreeable format to facilitate the completion of the inspection work. The Company will provide, where available geospatial and attribute data prior to beginning inspection work. Omissions and errors in Company provided attribute data will be gathered and/or corrected by the Contractor as part of the inspection work.

13.1. Data Deliverables

Attribute inspection and treatment data, including digital photos of pole rejects, shall be provided to the Company electronically in a timely basis. The data must provide information that can be used to reconcile billings as well as to allow timely decisions on pole repair, replacement or maintenance activities. The method of delivering electronic data (email, CD, online) will be approved by the Company.

13.2. Archiving

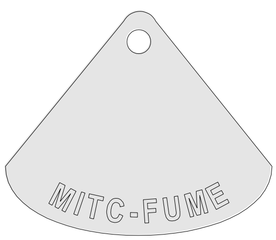
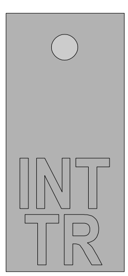
Contractor will archive the pole condition and attribute data for 12 months after the year in which the inspection is performed.

14. **INVOICING**

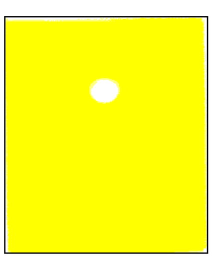
14.1. Billing

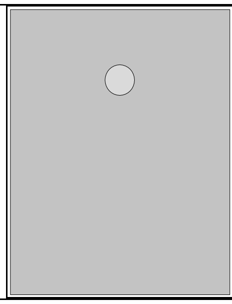
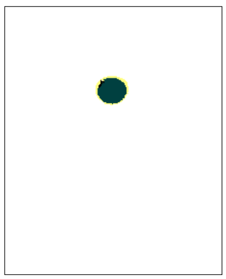
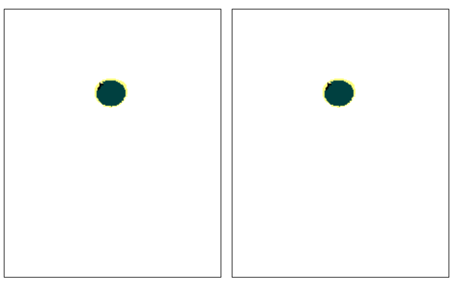
Contractor shall furnish Company with required deliverables in electronic format in no more than two week work increments. Billings will be itemized for all charges and submitted either electronically or through the mail, from pole inspection reports.

Attachment 1- INSPECTION AND TREATMENT TAGS

	This tag is an example of a contractor's tag. This oval tag is to be used whenever any inspection involves more than the requirements of an Asset Inspection but less than a Full Excavate (and Treatment) Inspection. This will include "Visual Inspection", "Sound and Bore" or "Partial Excavate Inspections. The tag should incorporate the contractors name and the year the work is performed.
	This tag is an example of a contractor's tag used when a Full Excavate Inspection has been done. This round tag represents an inspection via a full 18" dig and treatment with an approved preservative paste. The tag should incorporate the contractors name and year the work is performed.
	The fumigant tag is used whenever a fumigant is applied to a pole. This tag will be used in conjunction with one of the above tags depending on the type of inspection performed. The tag will identify the type of fumigant used.
	The Internal Treat tag is used whenever Internal Treatment is injected into the pole. This tag will be used in conjunction with one or more of the above tags depending on the type of inspection performed.

REJECT TAGS

	**One yellow** reject tag is used to denote that the pole is a **Reinforcable Reject.**

<table>
<tr><td></td><td rowspan="3">One white (or silver) tag is used to denote a Replacement Pole (non-Reinforcable Reject).</td></tr>
<tr><td>OR</td></tr>
<tr><td></td></tr>
<tr><td></td><td rowspan="3">Red With Crossed Out Arrow or Two White Square tags are used to denote a Danger or Priority Pole that is a Priority Replacement Pole (non-Reinforcable). The direction of the arrow is to be aligned to indicate the general location of the major defect.</td></tr>
<tr><td>OR</td></tr>
<tr><td></td></tr>
</table>

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 401

Responding Witness: John K. Wolfe

Q-401. Regarding the 2-year distribution capital investment shown in the table on page 46 of the Testimony of Paul W. Thompson, provide the following:

a. For LG&E historic annual investments for each category over the past 5 years (2012-2016).

A-401.

a. Historical results (in Millions):

	2012	**2013**	**2014**	**2015**	**2016**
Distribution Automation	0	0	0	0	0
Transformer Contingency	0	0	0	0	0
New Business	16	20	23	26	27
Repair and Replace	26	31	32	40	41
All Other	13	14	13	16	12
Total	**55**	**65**	**68**	**82**	**80**

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 402

Responding Witness: Lonnie E. Bellar

Q-402. Regarding section 4.1.2 of Exhibit PWT-2 provide the total work estimate developed by Environmental Consultants, Inc. regarding vegetation management.

A-402. Environmental Consultants, Inc. identified $56.3 million dollars of vegetation work on the LG&E and KU transmission system.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information Dated January 11, 2017

Question No. 403

Responding Witness: Lonnie E. Bellar

Q-403. Regarding section 4.1.3 of Exhibit PWT-2 provide detailed annual information regarding the 5-year line sectionalizing program including line segments identified for improvement and sectionalization solutions and related costs, as well as expected SAIDI improvement related to each installation.

A-403. Based on historical outages, the Company expects a reduction to SAIDI through reduced restoration times in the future, however the Company did not project SAIDI improvement by installation.

See attached.

Project	Bud Description	Code	Line Position	2017	2018	2019	2020	2021
150846	REL-Madisonville Loop-P&C	SWITCH	Green River to Earlington North 69 kV line	$0	$0	$0	$0	$0
151744	REL-Campbellsville 605 Switch	SWITCH-AUTO	Lebanon to Taylor County 69 kV line	$243,625	$0	$0	$0	$0
151811	REL-Rockwell Motor-Auto	SWITCH-AUTO	Loudon Avenue to Winchester 69 kV	$200,000	$0	$0	$0	$0
151816	REL-Paris 819-615 Motor-Auto	SWITCH-AUTO	Millersburg (604) to Paris (634) 69 kV	$0	$200,000	$0	$0	$0
152123	REL-Harmony Landing Auto	SWITCH-AUTO	Harrods Creek to Harmony Landing 69 kV line	$0	$200,728	$0	$0	$0
152134	REL-Radcliff Motor-Auto	SWITCH-AUTO	Rogersville to Vine Grove 69 kV	$200,080	$0	$0	$0	$0
152135	REL-GE Lamp 615 Motor-Auto	SWITCH-AUTO	American Avenue to Higby Mill to Parkers Mill 69 kV line	$200,080	$0	$0	$0	$0
152136	REL-Esserville Motor-Auto	SWITCH-AUTO	Bond to Dorchester 69 kV line	$200,080	$0	$0	$0	$0
152138	REL-Irvine Motor-Auto	SWITCH-AUTO	Beattyville to West Irvine 69 kV line	$200,080	$0	$0	$0	$0
152139	REL-Hughes Lane 660-615 Auto	SWITCH-AUTO	Lexington Plant to Paris 69 kV line	$200,080	$0	$0	$0	$0
152140	REL-Etown 4 811-615 Motor-Auto	SWITCH-AUTO	Elizabethtown to Hodgenville EKPC 69 kV interconnection	$0	$198,717	$0	$0	$0
152142	REL-Morehead W 406-605 Auto	SWITCH-AUTO	Rodburn to Farmers 69 kV line	$0	$198,717	$0	$0	$0
152143	REL-Corbin 1 844-605 Auto	SWITCH-AUTO	Farley to Sweet Hollow 69 kV line	$0	$198,717	$0	$0	$0
152144	REL-Lemons Mill Motor-Auto	SWITCH-AUTO	Adams to Haefling 69 kV line	$0	$198,717	$0	$0	$0
152146	REL-Mt Sterling 737-615 Auto	SWITCH-AUTO	Spencer Road to Clark County 69 kV line	$0	$198,717	$0	$0	$0
144364	REL-Parkers Mill 604 Brkr Adds	BREAKER	Lexington Plant to Pisgah 69 kV line	$0	$0	$0	$0	$0
144632	REL-Cawood 604 Brkr Addition	BREAKER	Pocket to Catrons Creek to Rocky Branch 69 kV line	$750,000	$0	$0	$0	$0
144634	REL-FMC 604 Brkr Addition	BREAKER	Lansdowne 614 to Loudon Avenue 614 69 kV line	$850,000	$0	$0	$0	$0
144636	REL-Stanford 604 Brkr Add	BREAKER	Boyle County to Lancaster 69 kV line	$750,000	$0	$0	$0	$0
144637	REL-Camargo 604 Brkr Add	BREAKER	Spencer Road to Clark County 69 kV line	$750,000	$0	$0	$0	$0
148370	REL-Hoover 604 Breaker Add	BREAKER	Adams to Haefling 69 kV line	$750,000	$0	$0	$0	$0
148371	REL-Earlington 604 Brkr Add	BREAKER	Green River to River Queen to Walker 69 kV line	$750,000	$0	$0	$0	$0
150845	REL-Madisonville Loop-Subs	SWITCH	Green River to Earlington North 69 kV line	$0	$0	$0	$0	$0
151745	REL-Warsaw 615 Switch Motor	SWITCH-MOTOR OPERATED	Warsaw to Owen County EKPC 69 kV interconnection	$243,625	$0	$0	$0	$0
151746	REL-Hodgenville Switch Motor	SWITCH-MOTOR OPERATED	Elizabethtown to Hodgenville EKPC 69 kV interconnection	$0	$246,563	$0	$0	$0
151814	REL-Stanford 848-635	SWITCH	Boyle County to Lancaster 69 kV line	$146,128	$0	$0	$0	$0
151815	REL-Somerset N 92-605 Motor	SWITCH-MOTOR OPERATED	Elihu to Somerset North 69 kV 96-634	$146,128	$0	$0	$0	$0
152108	REL-Centerfield 604 Brkr Add	BREAKER	Middletown to Trimble County Switching 138 kV line to Centerfield 138/69 kV tran	$0	$850,000	$0	$0	$0
152109	REL-Smyrna 604 Brkr Add	BREAKER	Fairmount to Mud Lane 69 kV line	$0	$850,000	$0	$0	$0
152118	REL-Shannon Run Brkr Rpl	BREAKER	Tyrone to Higby Mill 69 kV line	$0	$0	$850,000	$0	$0
152119	REL-Lagrange East 604 Brkr Add	BREAKER	Eminence to Centerfield 69 kV line	$0	$0	$850,000	$0	$0
152120	REL-Munfordville Brkr Add	BREAKER	Barren County EKPC to Bonnieville EKPC 69 kV line	$0	$0	$850,000	$0	$0
131374	REL WEDONIA 138KV SWITCH	SWITCH	Rodburn to Kenton 138 kV line	$0	$481,262	$0	$0	$0
134200	REL JFRSNTWN 138 SWTCH	SWITCH	Watterson to Middletown 138 kV line	$0	$0	$0	$707,910	$0
137739	REL ONTON 69KV SWITCH	SWITCH	Corydon to Calhoun 69 kV line	$0	$275,953	$0	$0	$0
137740	REL POOLE 69KV SWITCH	SWITCH	Corydon to Calhoun 69 kV line	$0	$275,953	$0	$0	$0
144061	REL TUNNELL HILL SWITCH	SWITCH	Corydon to Calhoun 69 kV line	$0	$0	$0	$0	$0
144062	REL KEOKEE SWITCH	SWITCH	Pocket to Imboden 69 kV	$0	$590,126	$0	$0	$0
144975	REL CLAYS MILL MOS	SWITCH	Higby Mill 724 to Brown North 734 138 kV line	$0	$0	$0	$759,584	$0
147480	REL Esserville Switch	SWITCH	Bond to Dorchester 69 kV line	$0	$0	$0	$0	$0
147481	REL Kenton Switch 91-6	SWITCH	Kenton to Murphysville EKPC 69 kV interconnection	$0	$340,815	$0	$0	$0
147482	REL Campbellsburg Switch	SWITCH	Carrollton to Eminence 69 kV	$340,819	$0	$0	$0	$0
147486	REL Dwina Switch	SWITCH	Dorchester to St Paul 69 kV line	$0	$346,146	$0	$0	$0
147487	REL Harlan 557 Tap Switch	SWITCH	Harlan Y to Evarts to Pocket 69 kV	$346,146	$0	$0	$0	$0
147488	REL Osaka East Switch	SWITCH	Lynch to Imboden 69 kV line	$0	$0	$493,153	$0	$0
147489	REL Rogers Gap Switch	SWITCH	Scott County to Delaplain 69 kV line	$0	$0	$346,146	$0	$0
147490	REL Airline Road Switch	SWITCH	Corydon to Green River Steel 69 kV line	$0	$346,146	$0	$0	$0
147491	REL Versailles West Switch	SWITCH	East Frankfort to Tyrone 69 kV line	$0	$542,477	$0	$0	$0
147492	REL Dycusburg Switch	SWITCH	Princeton 3-654 to Crittenden County 189-604 69 kV line	$0	$346,146	$0	$0	$0
147493	REL Hamblin Tap Switch	SWITCH	Pocket to Catrons Creek to Rocky Branch 69 kV line	$0	$346,146	$0	$0	$0
147494	REL Paint Lick Switch	SWITCH-MOTOR OPERATED	Lake Reba to Okonite 69 kV line	$0	$0	$360,857	$0	$0
147495	REL Belt Line Switch	SWITCH	Lexington Plant to Haefling 69 kV line	$0	$0	$360,857	$0	$0
147496	REL McKee Road Switch	SWITCH	Elihu to Somerset North 69 kV 96-624	$0	$0	$360,857	$0	$0
147497	REL Bailey Creek Switch	SWITCH	Evarts to Arnold 69 kV	$0	$0	$360,857	$0	$0

147498 REL Bardstown Ind Switch	SWITCH	Bardstown to East Bardstown EKPC 69 kV interconnection	$0	$0	$360,857	$0	$0
147499 REL Four Mile Switch	SWITCH	Pineville 192-624 to Rocky Branch 225-604 69 kV line	$0	$0	$495,857	$0	$0
147500 REL Owingsville Switch	SWITCH	Foreign EKPC Goddard to Hope 69 kV	$0	$0	$360,857	$0	$0
147501 REL Echols Switch	SWITCH	Ohio County to Indian Hill 69 kV line	$0	$0	$360,857	$0	$0
147502 REL Bens Branch Switch	SWITCH	Imboden to Dorchester 69 kV line	$0	$0	$360,857	$0	$0
147503 REL Nelson Switch	SWITCH	Green River to Indian Hill 69 kV line	$0	$0	$360,857	$0	$0
147504 REL Madisonville North Switch	SWITCH	Nebo 228-644 to Earlington North 202-614 69 kV line	$0	$0	$0	$381,235	$0
147505 REL Kuttawa Switch	SWITCH	Princeton 3-654 to Crittenden County 189-604 69 kV line	$0	$0	$0	$381,516	$0
147506 REL Woodlawn Switch	SWITCH	Bardstown to Hodgenville EKPC 69 kV interconnection	$0	$0	$0	$381,516	$0
147507 REL Vine Grove Switch	SWITCH	Rogersville to Vine Grove 69 kV	$0	$0	$0	$381,516	$0
147508 REL Corbin East Switch	SWITCH	Farley to Sweet Hollow 69 kV line	$0	$0	$0	$381,516	$0
147509 REL Taylorsville Switch	SWITCH	Finchville to Bardstown 69 kV	$0	$0	$0	$381,516	$0
147510 REL Wise Tap Switch	SWITCH	Bond to Dorchester 69 kV line	$0	$0	$0	$381,516	$0
147511 REL Manitou Switch	SWITCH	Nebo 228-634 to Earlington North 202-604 69 kV line	$0	$0	$0	$381,516	$0
147512 REL Nicholasville Switch	SWITCH	Higby Mill to Trim Master tap 69 kV line	$0	$0	$0	$381,516	$0
147513 REL Camp Breckenridge Switch	SWITCH	Morganfield to Nebo 69 kV	$0	$0	$0	$381,516	$0
147515 REL Lebanon W31 Switch	SWITCH	Lebanon to Taylor County 69 kV line	$0	$0	$0	$0	$420,175
147516 REL Paris City Switch	SWITCH-MOTOR OPERATED	Millersburg (644) to Paris (624) 69 kV	$0	$0	$0	$0	$420,175
147517 REL Benham Switch	SWITCH	Lynch to Arnold 69 kV line	$0	$0	$0	$0	$420,175
147518 REL Somerset South Switch	SWITCH	Somerset EKPC to Russell County EKPC 69 kV interconnections	$0	$0	$0	$0	$420,175
147519 REL Green River W86 Switch	SWITCH	Taylor County to Green County EKPC 69 kV interconnection	$0	$0	$0	$0	$420,175
147520 REL Bear Branch Switch	SWITCH	Imboden to Dorchester 69 kV line	$0	$0	$0	$0	$420,175
147521 REL Spindletop 823 Switch	SWITCH	Adams to Haefling 69 kV line	$0	$0	$0	$0	$538,675
147522 REL Fies City Switch	SWITCH	Green River to Earlington North 69 kV line	$0	$0	$0	$0	$420,175
147523 REL Morehead West Switch	SWITCH	Rodburn to Farmers 69 kV line	$0	$0	$0	$0	$420,175
147534 REL Radcliff Switch	SWITCH	Rogersville to Vine Grove 69 kV	$0	$0	$0	$0	$0
147565 REL Haley MOS	SWITCH	Loudon Avenue to Winchester 69 kV	$450,000	$0	$0	$0	$0
147592 REL Motor Op Switches KU 2019	SWITCH-MOTOR OPERATED	Undetermined	$0	$0	$1,506,612	$0	$0
147593 REL Motor Op Switches KU 2020	SWITCH-MOTOR OPERATED	Undetermined	$0	$0	$0	$1,768,425	$0
147594 REL Motor Op Switches KU 2021	SWITCH-MOTOR OPERATED	Undetermined	$0	$0	$0	$0	$1,796,760
148388 REL Hughes Lane MOS	SWITCH	Lexington Plant to Paris 69 kV line	$0	$0	$0	$0	$0
150844 REL Madisonville Loop MOS	SWITCH	Nebo 228-644 to Earlington North 202-614 69 kV line	$0	$0	$0	$0	$0
151792 REL Radcliff MOS	SWITCH-AUTO	Rogersville to Vine Grove 69 kV	$97,813	$0	$0	$0	$0
151793 REL Esserville MOS	SWITCH-AUTO	Bond to Dorchester 69 kV line	$97,946	$0	$0	$0	$0
151794 REL Elizabethtown Tap MOS	SWITCH-MOTOR OPERATED	Elizabethtown to Elizabethtown (2) 69 kV	$585,621	$0	$0	$0	$0
151796 REL Joyland 69kV MOS	SWITCH-MOTOR OPERATED	Lexington Plant to Paris 69 kV line	$97,851	$0	$0	$0	$0
151797 REL Campbellsville Ind MOS	SWITCH-AUTO	Lebanon to Taylor County 69 kV line	$73,472	$0	$0	$0	$0
151798 REL Harlan 557 MOS	SWITCH-MOTOR OPERATED	Harlan Y to Evarts to Pocket 69 kV	$97,851	$0	$0	$0	$0
151799 REL Somerset 3 MOS	SWITCH-MOTOR OPERATED	Elihu to Somerset North 69 kV 96-624	$390,564	$0	$0	$0	$0
151800 REL Elizabethtown 4 MOS	SWITCH-AUTO	Elizabethtown to Hodgenville EKPC 69 kV interconnection	$0	$493,778	$0	$0	$0
151801 REL Dayhoit Tap MOS	SWITCH-MOTOR OPERATED	Harlan Y to Rocky Branch 69 kV line	$0	$98,931	$0	$0	$0
151802 REL Dayhoit Tap LFI	SWITCH-MOTOR OPERATED	Harlan Y to Rocky Branch 69 kV line	$0	$24,757	$0	$0	$0
151803 REL Corydon-Calhoun LFI	SWITCH-MOTOR OPERATED	Corydon to Calhoun 69 kV line	$0	$9,891	$0	$0	$0
151804 REL Morehead West MOS	SWITCH-AUTO	Rodburn to Farmers 69 kV line	$0	$74,252	$0	$0	$0
151805 REL Calhoun MOS	SWITCH-MOTOR OPERATED	Earlington North to Green River Steel 69 kV line	$0	$247,295	$0	$0	$0
151806 REL Caron MOS	SWITCH-AUTO	London to Sweet Hollow	$0	$98,958	$0	$0	$0
151807 REL Corbin 2 795-625 MOS	SWITCH-MOTOR OPERATED	Farley to Sweet Hollow 69 kV line	$0	$74,468	$0	$0	$0
151808 REL Corbin 1 844-605 MOS	SWITCH-AUTO	Farley to Sweet Hollow 69 kV line	$0	$74,468	$0	$0	$0
151810 REL Ashland MOS	SWITCH-MOTOR OPERATED	Race Street to UK Medical Center 69 kV line	$0	$98,958	$0	$0	$0
151812 REL Lemons Mill MOS	SWITCH-AUTO	Adams to Haefling 69 kV line	$0	$444,770	$0	$0	$0
151813 REL Mt Sterling MOS	SWITCH-AUTO	Spencer Road to Clark County 69 kV line	$0	$247,298	$0	$0	$0
153030 REL Line Mod-In Line Breakers	BREAKER	Undetermined	$250,000	$0	$0	$0	$0
153068 REL Lebanon S Motor Add	SWITCH-MOTOR OPERATED	Lebanon to Taylor County 69 kV line	$100,196	$0	$0	$0	$0
153073 REL Cynthiana S MOS 569-605	SWITCH-MOTOR OPERATED	Millersburg to Renaker EKPC 69 kV interconnection	$75,000	$0	$0	$0	$0
153076 REL Girdler MOS Add	SWITCH-AUTO	Bimble to London 69 kV	$0	$100,000	$0	$0	$0

153080	REL Newtown MOS Add	SWITCH-AUTO	Adams to Cynthiana Switching 69 kV line	$0	$0	$100,000	$0	$0
153081	REL Waitsboro MOS Add	SWITCH-AUTO	Somerset EKPC to Russell County EKPC 69 kV interconnections	$0	$0	$100,000	$0	$0
			Total	$9,583,185	$9,319,870	$8,839,481	$7,050,798	$5,696,835

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 404

Responding Witness: Lonnie E. Bellar

Q-404. Regarding Table 5 of Exhibit PWT-2 provide annual 5-year historic data for each of the listed categories (from 2012-2016).

A-404.

LG&E Reliability (MM USD)	**2012**	**2013**	**2014**	**2015**	**2016**
Switch Maintenance	0.0	0.0	0.0	0.0	0.0
Line Sectionalizing	0.0	0.0	0.0	0.0	0.0

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 405

Responding Witness: Lonnie E. Bellar

Q-405. Regarding Table 6 of Exhibit PWT-2 provide annual 5-year historic data for each of the listed categories (from 2012-2016).

A-405.

LG&E System Integrity and Modernization (MM USD)	**2012**	**2013**	**2014**	**2015**	**2016**
Replace Defective Line Equipment	3.8	4.1	3.3	7.7	5.8
Replace Line Switches	0.0	0.0	0.0	0.0	0.0
Replace Overhead Lines	0.0	0.0	0.0	0.0	0.0
Improve P&C Systems	0.1	0.3	0.8	0.9	0.8
Replace Circuit Breakers	0.6	2.6	0.2	2.3	2.9
Replace Underground Lines	0.0	0.0	0.0	0.0	0.0
Replace Subs Insulators	0.0	0.0	0.0	0.0	0.4
Corrosion Protection	0.0	0.0	0.0	0.0	0.0
Replace Substation Line Arresters	0.1	0.0	0.0	0.0	0.0
Replace Coupling Capacitors	0.0	0.0	0.0	0.0	0.1
Total LG&E System Integrity and Modernization	**4.6**	**7.0**	**4.3**	**10.9**	**10.0**

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 406

Responding Witness: Lonnie E. Bellar

Q-406. Regarding Line Sectionalizing Program Cost table at the bottom of page 27 of Exhibit PWT-2 provide annual 5-year historic data (from 2012-2016).

A-406.

LG&E Line Sectionalizing Program Cost (MM USD)	**2012**	**2013**	**2014**	**2015**	**2016**
Install Auto Line Sectionalizing	0.0	0.0	0.0	0.0	0.0

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 407

Responding Witness: Lonnie E. Bellar

Q-407. Regarding Table 7 of Exhibit PWT-2 provide annual 5-year historic data for each of the listed categories (from 2012-2016).

A-407. The Company did not track this information in 2012 for these categories, nor did it track insulators in 2013. The table below provides the available data for both LG&E and KU.

	2013	2014	2015	2016
Cross Arms	33	175	136	116
Insulators	0	246	90	120
Poles	487	315	572	654

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 408

Responding Witness: Lonnie E. Bellar

Q-408. Regarding Overhead Line Replacement Program Cost table at the top of page 33 of Exhibit PWT-2 provide annual 5-year historic data (from 2012-2016).

A-408.

LG&E Overhead Line Replacement Program Cost (MM USD)	**2012**	**2013**	**2014**	**2015**	**2016**
Replace Overhead Lines	0.0	0.0	0.0	0.0	0.0

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 409

Responding Witness: Lonnie E. Bellar

Q-409. Regarding Table 8 of Exhibit PWT-2 provide annual 5-year historic data for each of the listed categories (from 2012-2016).

A-409.

LG&E Total Protection & Controls Program Cost (MM USD)	**2012**	**2013**	**2014**	**2015**	**2016**
Replace Control Houses	0.0	0.0	0.0	0.0	0.0
Replace Relay Panels	0.1	0.2	0.8	0.9	0.6
Replace RTUs	0.0	0.0	0.0	0.0	0.0
Replace PLCs	0.0	0.0	0.0	0.0	0.0
Install DFRs	0.0	0.0	0.0	0.0	0.0
Replace Battery sets	0.0	0.1	0.0	0.0	0.2
Total Protection & Controls	**0.1**	**0.3**	**0.8**	**0.9**	**0.8**

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information Dated January 11, 2017

Question No. 410

Responding Witness: Lonnie E. Bellar

Q-410. Regarding Breaker Replacement Program Cost table at the top of page 41 of Exhibit PWT-2 provide annual 5-year historic data (from 2012-2016).

A-410.

LG&E Breaker Replacement Program Cost (MM USD)	**2012**	**2013**	**2014**	**2015**	**2016**
Replace Circuit Breakers	0.6	2.6	0.2	2.3	2.9

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 411

Responding Witness: Lonnie E. Bellar

Q-411. Regarding Underground Line Replacement Program Cost table at the top of page 44 of Exhibit PWT-2 provide annual 5-year historic data (from 2012-2016).

A-411.

LG&E Underground Line Replacement Cost (MM USD)	**2012**	**2013**	**2014**	**2015**	**2016**
Replace Underground Lines	0.0	0.0	0.0	0.0	0.0

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information Dated January 11, 2017

Question No. 412

Responding Witness: Lonnie E. Bellar

Q-412. Regarding Switch Replacement Program Cost table at the top of page 45 of Exhibit PWT-2 provide annual 5-year historic data (from 2012-2016).

A-412.

LG&E Switch Replacement Program Cost (MM USD)	**2012**	**2013**	**2014**	**2015**	**2016**
Replace Line Switches	0.0	0.0	0.0	0.0	0.0

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 413

Responding Witness: Lonnie E. Bellar

Q-413. Regarding Substation Insulator Replacement Program Cost table at the bottom of page 45 of Exhibit PWT-2 provide annual 5-year historic data (from 2012-2016).

A-413.

LG&E Substation Insulator Replacement Program Cost (MM USD)	**2012**	**2013**	**2014**	**2015**	**2016**
Replace Subs Insulators	0.0	0.0	0.0	0.0	0.4

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 414

Responding Witness: Lonnie E. Bellar

Q-414. Regarding Substation Arrester Replacement Program Cost table at the bottom of page 47 of Exhibit PWT-2 provide annual 5-year historic data (from 2012-2016).

A-414.

LG&E Substation Arrester Program Cost (MM USD)	**2012**	**2013**	**2014**	**2015**	**2016**
Replace Substation Line Arresters	0.1	0.0	0.0	0.0	0.0

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 415

Responding Witness: Lonnie E. Bellar

Q-415. Regarding Coupling Capacitor Replacement Program Cost table on page 48 of Exhibit PWT-2 provide annual 5-year historic data (from 2012-2016).

A-415.

LG&E Coupling Capacitor Replacement Cost (MM USD)	**2012**	**2013**	**2014**	**2015**	**2016**
Replace Coupling Capacitors	0.0	0.0	0.0	0.0	0.1

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 416

Responding Witness: John K. Wolfe

Q-416. Regarding the discussion of Investment selection methodology in Section 3 of Exhibit PWT-5, provide:

a. The detailed results of the DA evaluation against existing portfolio of system reliability and resiliency capital programs.

b. Data from this evaluation in electronic format, preferably Excel.

A-416.

a. The reference to the discussion on page 41 of the Testimony of Paul W. Thompson is specific to the use of AIS to evaluate the benefits of DA with respect to other reliability and resiliency programs. DA was first incorporated into AIS along with other system improvement projects in the 2016 Business Plan (developed 1 Qtr. 2015). The original DA program scope, timing, investment and valuation against other reliability and resiliency programs have evolved since that time but analysis continues to show DA is the most cost effective program to obtain the desired improvements in reliability. See the response to Question No. 399(a)

b. See the response to Question No. 399(a).

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 417

Responding Witness: John K. Wolfe

Q-417. Regarding Table 3 of Exhibit PWT-5 provide annual 5-year historic data for each of the listed categories (from 2012-2016).

A-417. The Distribution Automation program was initiated in 2016. There were no Distribution Automation program investments prior to 2016.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 418

Responding Witness: John K. Wolfe

Q-418. Regarding the telecommunications consultant engagement discussed in section 5.1.3 of Exhibit PWT-5 provide all written reports, findings and conclusions.

A-418. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

Power System Engineering, Inc.

PPL companies

LKS Solution Alternatives

Update from 10/19/16:

Added CVR Counts Updates and
Adjusted the FTE Cost Allocations

Distribution Automation and AMI Communications Medium Study

FULL-SERVICE CONSULTANTS

www.powersystem.org

Power System Engineering, Inc.

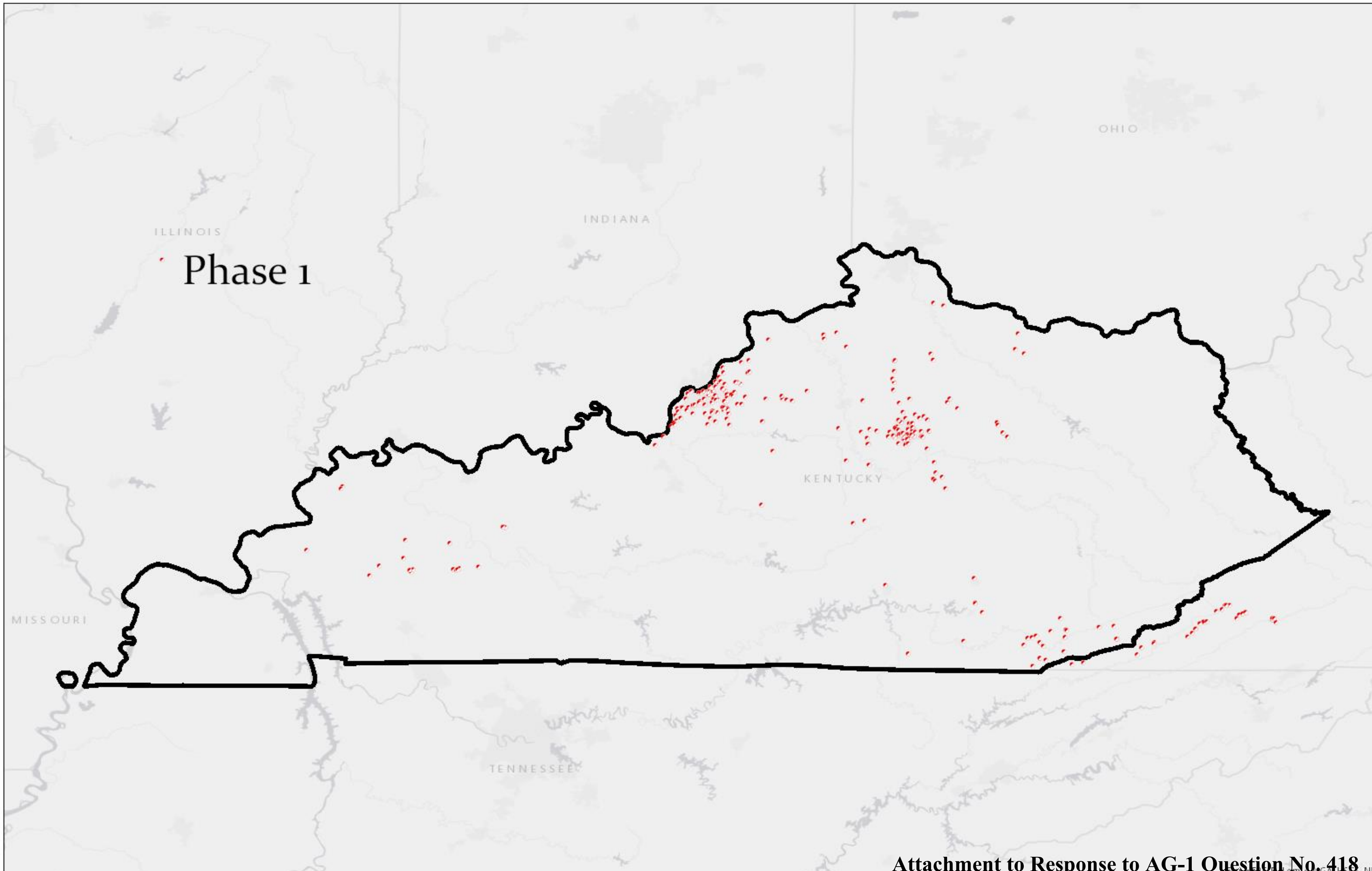
November 7, 2016

LKS Current State Summary

- Current FLISR DA Locations
  - 294 Installed Locations Planned for Phase 1 communications
  - 14 additional reclosers with comm service already – Not included in Pricing
  - 1597 Total Points Being Deployed - All are reclosers
- AMI Collectors
  - Used in Lexington and Louisville for an L&G pilot program
  - Private and cellular backhaul
    - Assume substation locations could be DA backhaul locations
  - Additional 154 Collectors to be added for a statewide system over the next 3 years
    - 106 Collectors requiring Backhaul Communications
- CVR Program Requiring Communications
  - Up to 619 Feeders in Program Identified
  - Capacitor Banks in the feeders – 3 Each Feeder
  - LTC's in subs – Some subs without adequate communications backhaul today
  - AMI bellwether meters will provide end of line voltage monitoring

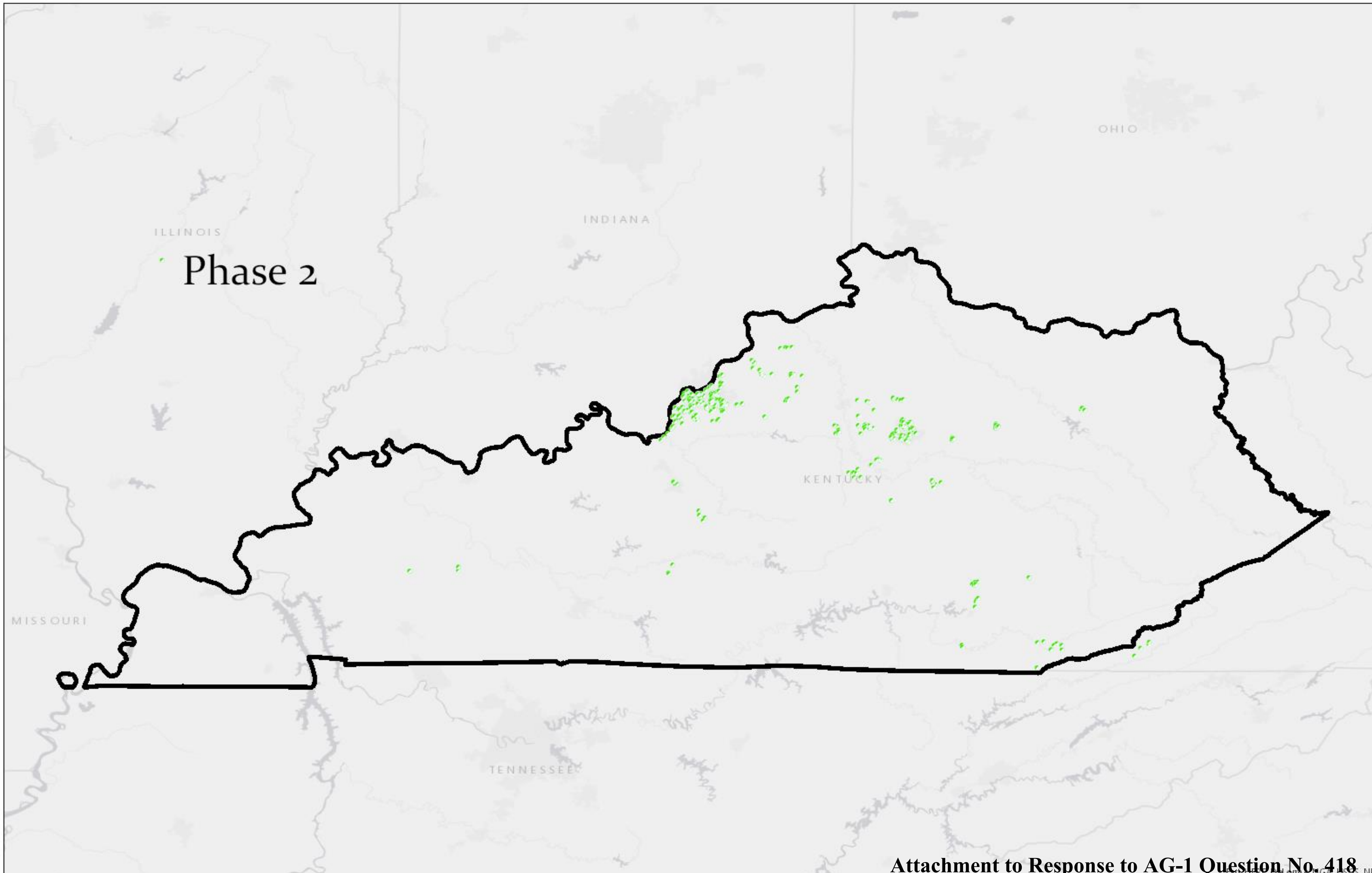
FLISR DA Locations

Phase 1 Build (294 Locations – Reclosers in Place)



Attachment to Response to AG-1 Question No. 418
Page 4 of 147
Wolfe

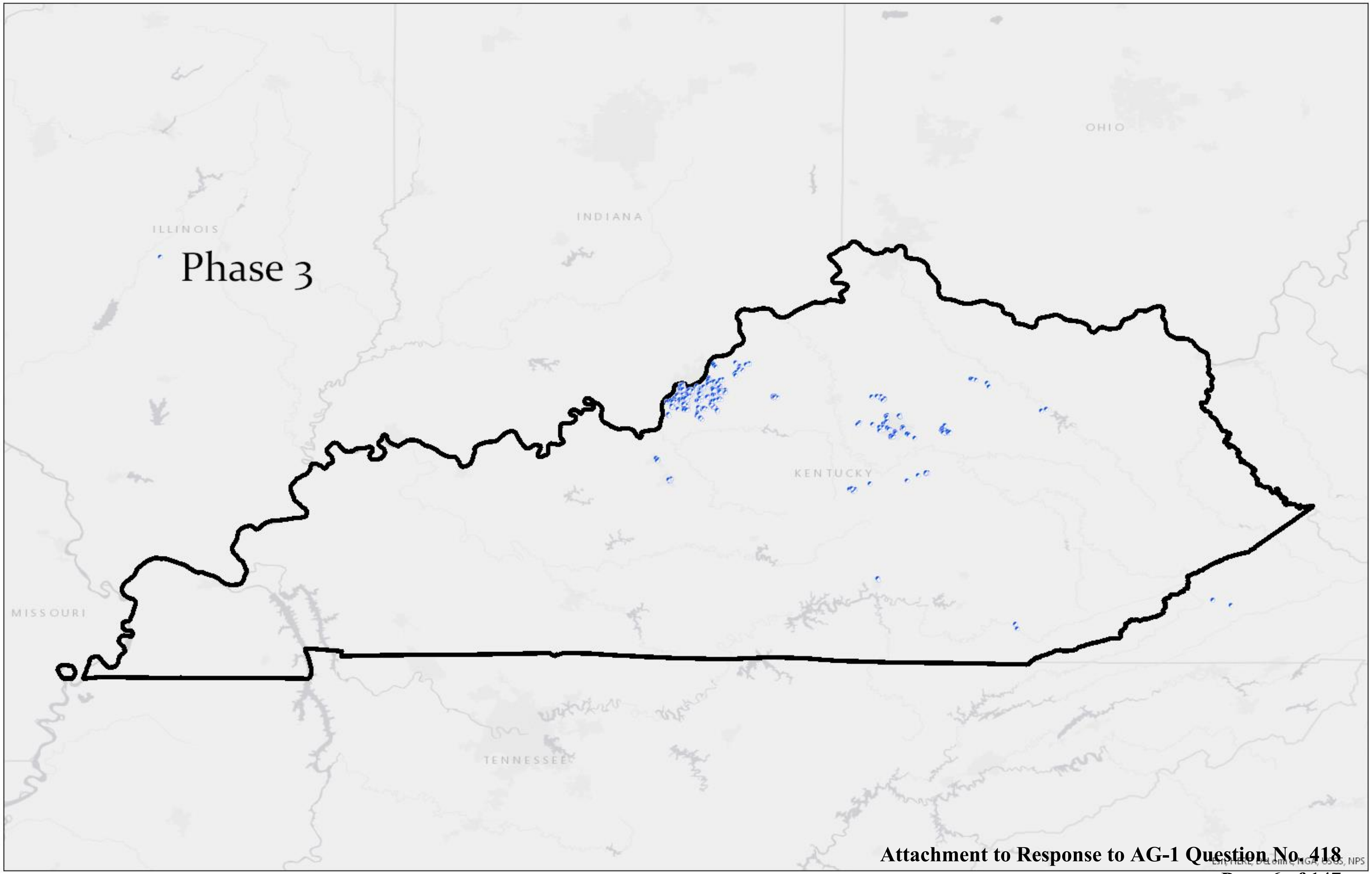
Phase 2 Build (420 Locations)



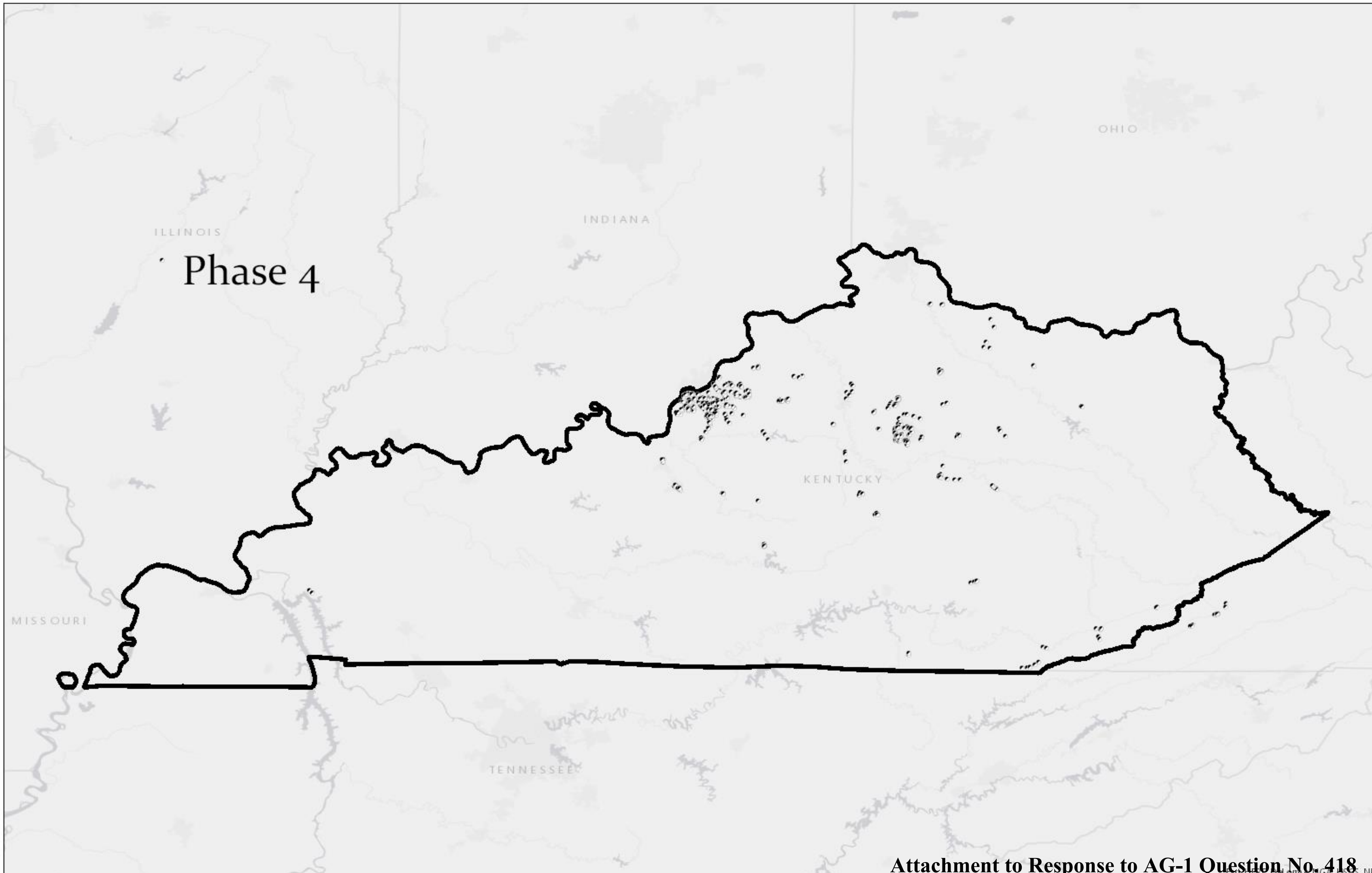
Attachment to Response to AG-1 Question No. 418
Page 5 of 147
[redacted] Wolfe

Power System Engineering, Inc.

Phase 3 Build (381 Locations)



Phase 4 Build (502 Locations)



Attachment to Response to AG-1 Question No. 418

[redacted] Wolfe

Power System Engineering, Inc.

Total Buildout Requirements for DA Locations

- 1,597 total FLISR DA locations identified and geo-located
- FLISR DA Roadmap Counts for Cost Estimates
  - IDA – 2017 + Master locations (if Applicable)
  - Remaining Phase 1 Remotes – 2018
  - Phase 2 Remotes – 2019
  - Phase 3 Remotes – 2020
  - Phase 4 Remotes – 2021

AMI Collectors Needing Communications

106 AMI Locations out of 153 Needed Comms

PSE located AMI collectors based on:

- Not in Substations (Feeders or Raw Land)
- In Substations without adequate communications
  - Leased 4-wire
  - MAS
  - Narrowband radio

[redacted]

CONFIDENTIAL INFORMATION REDACTED

Power System Engineering, Inc.

CVR Locations Needing Communications

PPL companies

CVR Circuits Provided 10/21/16

[redacted]

CONFIDENTIAL INFORMATION REDACTED

CVR Circuits Needing Communications

[redacted]

CONFIDENTIAL INFORMATION REDACTED

Solution Alternatives Assumptions

Power System Engineering, Inc.

Backhaul Requirements - Devices

- 1,597 total geo-located FLISR DA reclosers
  - Located in Feeders
- 106 geo-located AMI Collectors
  - Located in Feeders and at Substations with inadequate backhaul communications today
- 1,953 CVR capacitors and substation LTC's
  - Feeders and subs geo-located
  - 3 capacitors per feeder circuit (1,857 capacitors)
  - 96 substations require communications for the LTC's

FLISR Bandwidth Assumptions

- Using Suggested Report-by-Exception from Last Meeting:
  - DNP3 Class 0-3 Integrity Polls every 15 Minutes
  - Report-by-Exception Events
  - 5 Events per day (worst case)
  - 5 Control Commands per day

Inputs:	Ethernet		Seconds Between Polls	Times Per Day	Bytes Per Day
Integrity Poll Request Length	81	Bytes	900	96	7776
Integrity Poll Response Length	253	Bytes	900	96	24288
Integrity Poll TCP Acknowledge	60	Bytes	900	96	5760
Report By Exception Events	1000	Bytes	17280	5	5000
SCADA Confirm	80	Bytes	17280	5	400
Event TCP Acknowledge	60	Bytes	17280	5	300
Control Select	80	Bytes	17280	5	400
Control Confirm	81	Bytes	17280	5	405
Control Write	80	Bytes	17280	5	400
Control Confirm	81	Bytes	17280	5	405
Control TCP Acknowledge	60	Bytes	17280	5	300
				Total Bytes Per day	45434
				MegaBytes Per day	0.05
				MegaBytes Per Month (assuming 30 day month)	1.36

Attachment to Response to AG-1 Question No. 418

Wolfe

AMI Bandwidth Assumptions

- L&G Assumptions:
  - 200 Bytes of data per Meter
  - 10,000 Meters per Collector
  - 15 Minute Intervals (worst case)
  - 1% Bellwether Meters

PSE Recommended Scan Rates for AMI (AMS) Collectors					
Inputs:	Ethernet		Seconds Between Polls	Times Per Day	Bytes Per Day
Bytes Per Meter	414	Bytes			
Meters Per Collector	10000	Bytes			
15 Minute Meter Reads			14440	6	
Total Bytes Per Reads	7038000	Bytes	14400	6	42228000
Reads TCP Acknowledge/meter	60	Bytes			
Total Meter TCP Acknowledges	600000	Bytes	14400	6	3600000
Bell Weather Responses X 100 Meters	4420	Bytes	300	288	1272960
Bell Weather TCP Confirms X 100	6000	Bytes	300	288	1728000
Individual Meter Read Poll	102	Bytes	17280	5	510
Individual Meter Read Response	44.2	Bytes	17280	5	221
Individual Meter Read TCP Response	60	Bytes	17280	5	300
Meter/Module Firmware Updates 1/Year	50000	Bytes/Meter	3100	27.9	1393548
				Total Bytes Per day	50223539
				MegaBytes Per day	50.22
				MegaBytes Per Month (assuming 30 days/month)	1506.71
				GB/Mo	1.51

Attachment 10 to Response to AG-1 Question No. 418
Page 17 of 147
Wolfe

CVR Bandwidth Assumptions

- PSE Assumptions:
  - DNP3 Class 0-3 Integrity Polls every 5 Minutes
  - 5 Voltage Adjustment Control Commands per day
  - Operational 24/7/365

Inputs:	Ethernet		Seconds Between Polls	Times Per Day	Bytes Per Day
Integrity Poll Request Length	81	Bytes	300	288	23328
Integrity Poll Response Length	253	Bytes	300	288	72864
Integrity Poll TCP Acknowledge	60	Bytes	300	288	17280
Control Select	80	Bytes	17280	5	400
Control Confirm	81	Bytes	17280	5	405
Control Write	80	Bytes	17280	5	400
Control Confirm	81	Bytes	17280	5	405
Control TCP Acknowledge	60	Bytes	17280	5	300
				Total Bytes Per day	115382
				MegaBytes Per day	0.12
				MegaBytes Per Month (assuming 30 day month)	3.46

Solution Alternatives Attributes Review

Attachment to Response to AG-1 Question No. 418
Page 19 of 147
[redacted] Wolfe

Reviewed Attributes Definitions & Terminology

- Cost – Budgetary Costs relative to the other solutions
- Availability – How well is the telecommunications channel available for use.
  - Measure -Yes or No
- Latency – Round trip delay for enquiry / response
  - Measure – Less latency indicates higher quality
  - Latency Jitter – Variance in time round trip delay for enquiry / response
    - Measure – Less indicates higher quality
- Quality of Service (QoS) / priority – Capable of being prioritized
  - Measure –Supported or Not Supported
- Bandwidth – Maximum data rate of the channel available for use
  - Measure –Large, Medium, Narrow
  - In the case of leased services, while available bandwidth is large, there is a cost for using it. Analysis is based on costed service plans
- Security – Cybersecurity capability relative to other solutions
- Protocol Support – Ability to support desired device protocol
  - Measure -Yes or No

Solutions Alternatives Reviewed

- Leased LTE Cellular Service Through a Major Cellular Provider
- 700 MHz Private WiMAX Radio System
- Hybrid of Leased LTE Cellular and Private WiMAX
- Private LTE Network through AT&T/Nokia Partnership
- Capitalized Leased Cellular using Conxx Solution

Power System Engineering, Inc.

Cost Model Requirements

- Design Costs
- Network Management System
- PSE Assumed Periodic Maintenance:
  - Field Personnel visit each location every 2 years
    - Antenna sweeps
    - Battery maintenance and replacement
    - Physical maintenance and clean up
    - Visual Inspection
    - Record data and take pictures
  - 1.0 FTE – Engineering and IT support
    - PSE assumed 2.0 FTE for engineering support of the private LTE solution due to the complexity of maintaining a LTE network.

Leased Cellular Service

Leased Cell Data Service

- Leased M2M plan from major cellular provider
- LKS to purchase and install cellular modems in reclosers, AMI collectors and CVR capacitors and LTC's control cabinets
- Solution costs included external antennas and cables to help in signal acquisition
- Many vendors currently producing quality devices
  - Features range from basic to advanced
  - GE MDS, Cal Amp, Cisco, Sierra Wireless, etc.

Basic Cell Modem

Hardened Cell Modem with Router and Other Functionality

- PSE used this Modem for Pricing

Leased Cellular Attributes Review

10 Year Costs

AT&T Recently Provided Costs

[redacted]

[redacted]

Typical Plan Approach:		
Devices	1600	FLISR
Monthly Usage/Device	[redacted]	[redacted]
Monthly Fee/Device	$ [redacted]	
Monthly Pooled Data	[redacted]	[redacted]
Total Monthly Fees	$ [redacted]	[redacted]

Confidential Information Redacted

Verizon Provided Pooled Costs

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]

Confidential Information

Redacted

CapEx Budgetary Costs For Cellular

Estimated Site-Based Installed Capital Costs per Site

Cal Amp End Modem at End-Point		
Cellular Modem Radio	$	800
Line, Antenna, Surge Suppression	$	500
Third-party Installation	$	750
Total	**$**	**2,050**

Installed in Control Cabinet

Power System Engineering, Inc.

Budgetary Costs For Cellular – AMI and CVR Included

Data Inputs	
Remote Installed Costs	$ 2,050
Maintenance Percentage of Hardware Installed Cost	2.0%
SIM Card Cost	$ -
Maintenance Hours Per Year per FTE (90%)	1,872
Days Per Year FTE Working	234
Fully Loaded Cost Per FTE/hour (Comm or Ops Field Person)	$ 85.00
FTE Cost Per Year for Field Maintenance	$ 159,120.00
Field Locations Visited per day per FTE Employee	2
Periodic Maintenance Locations per year per FTE Employee	468
Visit All Locations Within this Many Years	2
Engineering (IT Department) Fully Loaded Costs per Hour	$ 100.00
Engineering FTE Required Per Year for Ongoing Support	1.00

	YEAR				YEAR				YEAR			
	0	1	2	3	4	5	6	7	8	9	10	Total
CapEx Initial Investment												
FLISR Remotes Installed - By Phase (30 IDA)		30	264	420	381	502						1,597
AMI (AMS) Collectors by Year		36	35	35								106
CVR Locations By Year		391	391	391	390	390						1,953
FLISR Remote Locations Modem Installed Costs		$61,500	$541,200	$861,000	$781,050	$1,029,100	$0	$0	$0	$0	$0	$ 3,273,850
AMI (AMS) Model Collectors Installed Costs		$73,800	$71,750	$71,750	$0	$0	$0	$0	$0	$0	$0	$ 217,300
CVR Remote Modem Installed Costs		$801,550	$801,550	$801,550	$799,500	$799,500	$0	$0	$0	$0	$0	$ 4,003,650
Network Management System	$0	$50,000										$ 50,000
System Design	$0	$40,000										$ 40,000
Total CapEx Costs	$0	$1,026,850	$1,414,500	$1,734,300	$1,580,550	$1,828,600	$0	$0	$0	$0	$0	$7,584,800
OpEx Costs (Excluding Initial Capital Investments)	[redacted]											
[redacted]												$ [redacted]
Maintenance Materials		$0	$19,737	$48,027	$82,713	$114,324	$150,896	$150,896	$150,896	$150,896	$150,896	$ 1,019,281
Remote Site Visited Each Year		0	229	574	997	1,382	1,828	1,828	1,828	1,828	1,828	12,321
FTE Needed for Field Work (Comm or OPS)			0.49	1.23	2.13	2.95	3.91	3.91	3.91	3.91	3.91	
Field Maintenance Labor Costs Per Year for Remote Locations			$ 77,690	$ 194,990	$ 338,810	$ 469,880	$ 621,520	$ 621,520	$ 621,520	$ 621,520	$ 621,520	$ 4,188,970
IT Engineering Labor Costs Per Year		$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 1,872,000
Total OpEx Costs		$204,648	$325,164	$497,703	$695,136	$879,610	$1,068,268	$1,068,268	$1,068,268	$1,068,268	$1,068,268	$7,943,600
Total System Costs	[redacted]	$1,231,498	$1,739,664	$2,232,003	$2,275,686	$2,708,210	$1,068,268	$1,068,268	$1,068,268	$1,068,268	$1,068,268	$15,528,400

Total CapEx Costs over 10 Year Period	**$7,585,000**
Total OpEx Costs over 10 Year Period	**$7,944,000**
Rounded 10 Year Total Cost	**$15,528,000**
Cost Per End Point over 10 Year Period	**$4,247**

Confidential Information Redacted

Attachment to Response to AG-1 Question No. 418
Page 31 of 147
[redacted] Wolfe

Leased LTE Cellular Attributes Review

Availability

Availability – Public LTE Networks - Pros

- All LTE network operators have central monitoring and dispatch for their networks
- A dedicated staff monitors degradation and outages 24/7/365. Dispatch criteria differs, but substantial outages are typically addressed quickly.
- LTE operators have trained maintenance and repair staff available to address outages.
- As the site density increases, a single site outage has less impact on overall network availability, especially during non-peak traffic.
- Network availability has steadily improved, especially with the largest nationwide carriers.

Availability – Public LTE Networks - Cons

- Unknown Coverage for all locations. Utility does not control coverage capability.
- LTE networks have grown large, and staffing has likely not increased in proportion. Therefore, response time appears to be increasing. However, the increased site density has allowed this without noticeable outage times (nearby site can cover while staff are dispatched)
- The risk which is most concerning with a public LTE network is a large, widespread outage typically due to a natural events such as weather. Deliberate damage (sabotage) is also a concern, but events have been rare.
- In the case of a natural disaster, sites may be unavailable for extended periods of time.
- The most likely risks are extended power outages due to damaged power distribution lines, physical damage to the building from flooding, or damage to the antenna system from high winds or ice storms.

Leased LTE Cellular Attributes Review

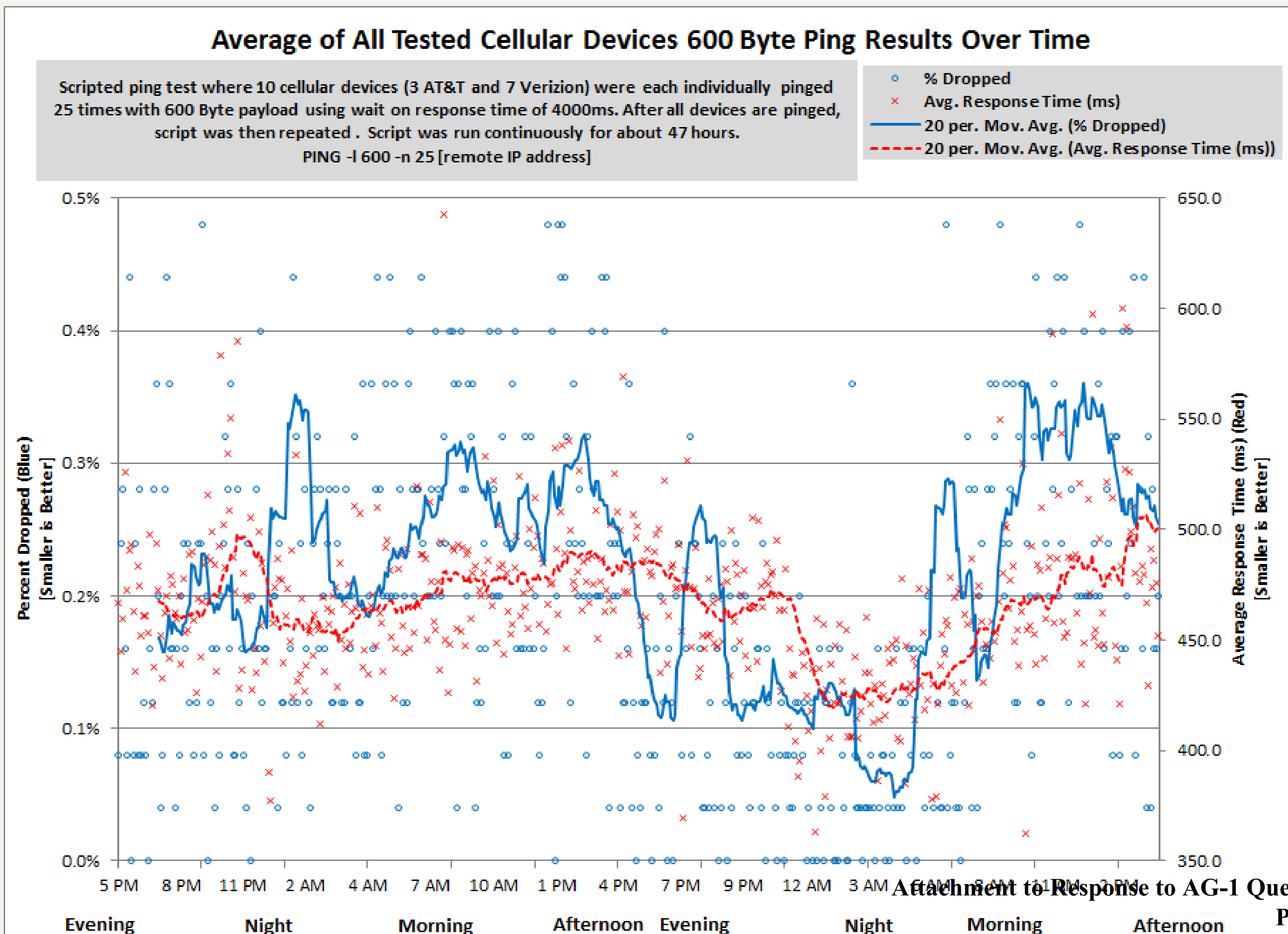
Latency

Latency – Public LTE networks

- A public LTE network is shared with many users. The traffic tends to ebb & flow during certain times of the day, thus the latency fluctuates based on users.
- The utility does not control the latency of a public cellular network.
- PSE has conducted lab experiments and studies in the past to measure latency at various times through several 24-hour periods (see example on next slide).

Cellular Latency by Time of Day

- Cellular latency can vary from 100ms to > 600ms
- Acceptable for DNP, but not for IEC-61850 GOOSE or SMV



Attachment to Response to AG-1 Question No. 418
Page 37 of 147
Wolfe

Leased LTE Cellular Attributes Review

Quality of Service (QoS)/Prioritization

Leased Cellular Quality of Service (QoS)/Latency

- Public networks cannot guarantee any given level of service. Many subscribers are competing for a finite amount of bandwidth and will have the same priority by law.
- Public networks suffer degradation during periods of high traffic. Events such as emergencies (car wrecks, fires, etc.) have been known to cause network blockage ranging form several minutes to several hours.
- Natural disasters such as weather, earthquake, etc. can cause outages and degradation for hours, days, or even longer in severe cases.

Leased LTE Cellular Attributes Review

Bandwidth Availability

Leased Cellular Bandwidth

- Bandwidth was defined previously as "Maximum data rate of the channel available for use"
- In the case of public LTE networks, bandwidth is considered "High" (~38Mbps 5MHz channel), but it is shared with many users.
- Our definition of leased cellular bandwidth is tied to the data plans chosen in the cost sections:
  - FLISR Reclosers and CVR Locations = 5 MB/Month Plan (<1 kbps per device)
    - Limited by using unsolicited report by exception
  - AMI Collectors = 2 GB/Month Plan (400 kbps per device)
- Extra bandwidth is available, but it comes at a monthly service cost penalty
  - Pooled data will help limit penalty
  - Note: Careful review of unnecessary SCADA traffic will need to be enforced to stay within data plans

Leased LTE Cellular Attributes Review

Cybersecurity

Security – Public Networks

- Since devices on a public network are visible to a wide area, there is more exposure to third-party "hacker" threats than private networks
  - End-to-end secure encryption is highly recommended for both private and public networks
- While it is possible to secure assets connected to a public network, more diligence is often required to ensure nothing is left exposed.
- See the Protocol Review of Security recommendations for all communications solutions alternatives

Leased LTE Cellular Attributes Review

Protocol Support

Protocol Support

At this time, subscriber units are available that will support all protocols expected to be required by a utility.

There is no clear advantage to one communications solution over another with respect to protocol at this time.

Full Spectrum 700 MHz Private Radio Network

Power System Engineering, Inc.

Full Spectrum “FullMax” Point-to-Multipoint

- Full Spectrum is a smaller company located in Silicon Valley focused on WiMAX communications for electrical utilities in the lower, privately-owned frequency bands
  - Most WiMAX products are at 2.4 or 5.8 GHz spectrum
  - 3 bits/hertz payload capacity
- Full Spectrum has been in business for about 10 years
  - Venture capital company
  - Soon to listed on the NASDAQ with a $15 M IPO
  - Has had some recent big wins at 700 MHz
    - Great River Energy in MN is one

LG&E KU
PPL companies

Full Spectrum Point-to-Multipoint

Basic Configuration:

- 700 MHz Upper A Block
- Use WiMAX sub-carriers (AMC) to create 4 logical sub-channels across 2 MHz
- Symmetrical TDD configuration
  - 4 Sectored towers can use same spectrum at all towers
  - 1.4 Mbps/Sector/Tower
  - 5.6 Mbps per Tower
  - TDD provides predictable latency
    - Some latency and speed compromises

Full Spectrum Point-to-Multipoint

Capacity Considerations:

- FullMAX uses adaptive modulation to maximize capacity on a per link / per direction basis
- Weakest link does not "drag down" all other links in the same sector
- Modulation / coding scheme determined by signal quality (CINR) for downlink and uplink
- Dynamic adaptation to accommodate fading
- TDD configuration allows for flexible use of bandwidth (symbols)
  - Symmetrical - equal downlink : uplink
  - Asymmetrical - higher capacity in downlink
  - Reverse asymmetrical - higher capacity in uplink (typical for utility applications, e.g. AMI backhaul)

Power System Engineering, Inc.

Access Spectrum 700 MHz Information

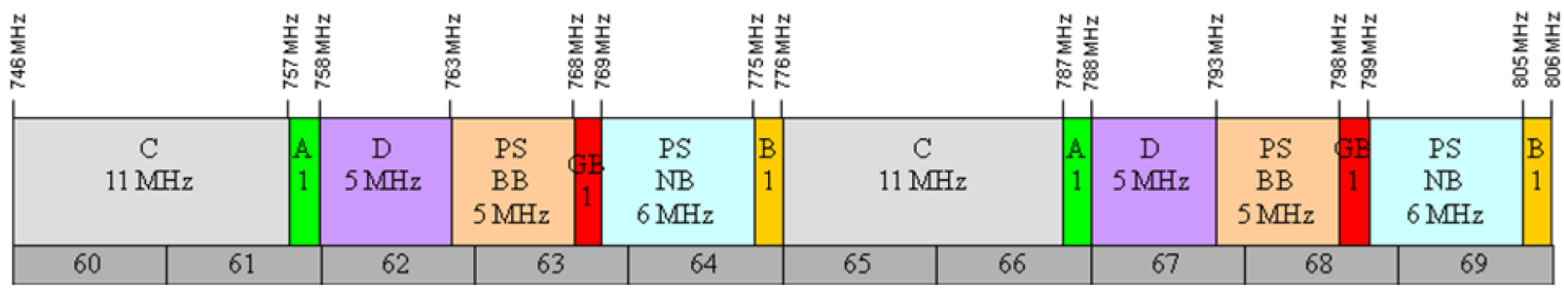
THE UPPER 700 MHZ A BLOCK

Block Size and License Areas

- The Upper 700 MHz A Block is a 1 MHz paired (2 MHz total) block of spectrum licensed by the FCC in 52 geographic areas called Major Economic Areas (MEAs).

Spectrum Location

- The Upper 700 MHz A Block is located between the Upper 700 MHz C and D Blocks.



- Access Spectrum owns the 700 MHz A1 Block
- Can be purchased for private use as a 2 MHz pair for $0.75 per MHz/population

Attachment to Response to AG-1 Question No. 418
Page 50 of 147
Wolfe

Typical 700 MHz Site Density

[redacted]

CONFIDENTIAL INFORMATION REDACTED

700 MHz WiMAX Attributes Review

10 Year Costs

Private Full Spectrum – Cost Assumptions

- Fiber to every site not connected to LKS backbone today
  - 74 miles of fiber at $25k/mile
- Three new 150' towers will be required
  - $80k/tower
  - Outside, environmentally-controlled cabinet used at towers
- LKS can purchase the spectrum only in the counties used and not the whole state of KY

Private Full Spectrum Network – Costs

Full Spectrum Remote End-Point		
Full Spectrum Radio	$	1,000
Line, Antenna, Surge Suppression	$	500
Third-party Installation	$	750
Total	**$**	**2,250**

Installed in Recloser Control Cabinet

700 MHz Frequency Purchase		
Cost Per MHz/Population	$	0.75
MHz of Spectrum		2.00
Population		5,358,037
Price of Spectrum	**$**	**8,037,056**

Private Full Spectrum Build Costs

	Count	Price	Extended Price
Antenna	4	$ 300	$ 1,200
Coax	800	$ 8.00	$ 6,400
Connectors	8	$ 50	$ 400
Cabinet with Power System	1	$ 4,000	$ 4,000
Master Radios	4	$ 12,000	$ 48,000
Installation	1	$ 10,000	$ 10,000
		Total	**$ 70,000**

Attachment to Response to AG-1 Question No. 418
Page 54 of 147
Wolfe

Private Full Spectrum Costs – Includes AMI and CVR

Input Data	
150' Tower Cost Per Tower	$ 80,000
Full Spectrum 4 Sector Tower Site Equipment Cost Per Site	$ 70,000
Remote Location Installed Costs	$ 2,250
Maintenance Percentage of Hardware Installed Cost	1.0%
SIM Card Cost	$ -
Fiber Cost Per Mile	$ 25,000.00
Maintenance Hours Per Year per FTE (90%)	1,872
Days Per Year FTE Working	234
Fully Loaded Cost Per FTE/hour (Comm or Ops Field Person)	$ 85.00
FTE Cost Per Year for Field Maintenance	$ 159,120.00
Field Locations Visited per day per FTE Employee	2
Periodic Maintenance Locations per year per FTE Employee	468
Visit All Locations Within this Many Years	2
Engineering (IT Department) Fully Loaded Costs per Hour	$ 100.00
Engineering FTE Required Per Year for Ongoing Support	1.00

	YEAR				YEAR				YEAR			
	0	1	2	3	4	5	6	7	8	9	10	Total
CapEx Initial Investment												
FLISR Remotes Installed - By Phase (30 IDA)		30	264	420	381	502						1,597
AMI (AMS) Collectors by Year		36	35	35								106
CVR Locations By Year		391	391	391	390	390						1,953
Tower Site Full Spectrum Installations		15	15	10								40
Tower Build Counts		1	1	1								3
Fiber Miles Built	25	25	24									49
FLISR Remote Locations Modem Installed Costs		$67,500	$594,000	$945,000	$857,250	$1,129,500	$0	$0	$0	$0	$0	$ 3,593,250
AMI (AMS) Modem Collectors Installed Costs		$81,000	$78,750	$78,750	$0	$0	$0	$0	$0	$0	$0	$ 238,500
CVR Remote Modem Installed Costs		$879,750	$879,750	$879,750	$877,500	$877,500	$0	$0	$0	$0	$0	$ 4,394,250
Access Spectrum 700 MHz Purchase	8,037,056											$ 8,037,056
Network Management System	50,000											$ 50,000
Tower Site Builds	0	80,000	80,000	80,000	0	0	0	0	0	0	0	$ 240,000
Full Spectrum Tower Equipment Builds	0	1,050,000	1,050,000	700,000	0	0	0	0	0	0	0	$ 2,800,000
Fiber Backbone Extensions	625,000	625,000	610,000									$ 1,860,000
Design	75,000											$ 75,000
Total CapEx Costs	$8,787,056	$2,783,250	$3,292,500	$2,683,500	$1,734,750	$2,007,000	$0	$0	$0	$0	$0	$21,288,056
OpEx Costs (Excluding Initial Capital Investments)												
Maintenance Materials		$500	$21,283	$47,308	$73,343	$90,690	$110,760	$110,760	$110,760	$110,760	$110,760	$ 786,923
Remote Site Visited Each Year		0	236	589	1,017	1,402	1,848	1,848	1,848	1,848	1,848	12,483
FTE Needed for Field Work (Comm or OPS)			0.50	1.26	2.17	3.00	3.95	3.95	3.95	3.95	3.95	
Field Maintenance Labor Costs Per Year for Remote Locations			$ 80,240	$ 200,090	$ 345,610	$ 476,680	$ 628,320	$ 628,320	$ 628,320	$ 628,320	$ 628,320	$ 4,244,220
IT Engineering Labor Costs Per Year		$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 1,872,000
Total OpEx Costs		$187,700	$288,723	$434,598	$606,153	$754,570	$926,280	$926,280	$926,280	$926,280	$926,280	$6,903,143
Total System Costs	$8,787,056	$2,970,950	$3,581,223	$3,118,098	$2,340,903	$2,761,570	$926,280	$926,280	$926,280	$926,280	$926,280	$28,191,198

Total CapEx Costs over 10 Year Period	**$21,288,000**
Total OpEx Costs over 10 Year Period	**$6,903,000**
Rounded 10 Year Total Cost	**$28,191,000**
Cost Per End Point over 10 Year Period	**$7,711**

Attachment to Response to AG-1 Question No. 418
Page 55 of 147
[redacted] Wolfe

700 MHz WiMAX Attributes Review

Availability

Availability – Private (utility owned & managed) Networks

- By owning, operating, and maintaining their own private network dedicated to their needs, the utility can set their own service availability objectives.
- However, this comes at a cost. In order to approach the availability and time to restore of the large common carriers, the communications system must be carefully monitored and maintained.
- A department with trained staff in sufficient numbers to complete routine maintenance programs and address outages in a timely manner is required.
- The costs associated with this include salary, training, instruments, and vehicles. Typically, 24/7/365 coverage is required to match the common carrier service level.

Power System Engineering, Inc.

Availability – Private (utility owned & managed) Networks

- Large and mid-sized utilities often have a telecommunications or SCADA group in place already. This group could be expanded, cross-trained, and tasked with the operation and maintenance of the private network.
- The cost of providing this level of service is often prohibitive for small to mid-sized utilities.

700 MHz WiMAX Attributes Review

Latency

Latency of 700 MHz Private WiMAX System

- Very stable and predictable latency for this network once all end points installed on network.
  - Links use adaptive modulation to change the individual links during times of interference which can cause the overall latency to vary
- Uses Time Division Duplexing (TDD) to create time slots for each device on the network
- Eliminates collisions in point-to-multipoint radio system
  - At the expense of throughput

Private 700 MHz WiMAX Attributes Review

Quality of Service (QoS)/Prioritization

Quality of Service (QoS) Support

Most equipment used in private communication networks can be configured with levels of priority and QoS. Additionally, the utility devices will not be competing with traffic other than their own. This is a distinct advantage of private communication networks.

- The Full Spectrum WiMAX product has several levels of QoS to choose from as part of the configuration.

Private 700 MHz WiMAX Attributes Review

Bandwidth Availability

FullMax Point-to-Multipoint Speeds

Frame Capacity / Throughput for basic configuration:
The following table shows the projected raw data throughput for a single sector using 1/4 of the 2 MHz in a single sector.

FEC Code	Repetition	Modulation Coding Scheme	Downlink Frame (bytes)	Uplink Frame (bytes)	Downlink Throughput (kbps)	Uplink Throughput (kbps)	Aggregate Throughput (kbps)
0	2	QPSK 1/2	120	123	77	79	156
0	1	QPSK 1/2	240	246	154	157	311
1	1	QPSK 3/4	360	369	230	236	467
2	1	16 QAM 1/2	480	492	307	315	622
3	1	16 QAM 3/4	720	738	462	472	933
4	1	64 QAM 1/2	720	738	461	472	933
5	1	64 QAM 2/3	960	984	614	630	1244
6	1	64 QAM 3/4	1080	1107	691	708	1399

Private 700 MHz WiMAX Bandwidth

- Bandwidth was defined previously as "Maximum data rate of the channel available for use"
- The previous table reflects speeds capable in one master radio sector.
  - PSE's analysis assumed 16 QAM ¾ modulation would be available on average for the end points
  - Equates to 933 kbps of throughout
  - Can be allocated to more up or down link speeds
  - In Metro areas, assumes 1 AMI collector per master radio sector
  - In Metro areas, assumes no more than 100 FLISR or CVR sites per master radio sector
  - Metro areas would require 500-600 kbps of uplink bandwidth
- Sufficient bandwidth across the service territory

Private 700 MHz WiMAX Attributes Review

Cybersecurity

Security – Private 700 MHz WiMAX

- A private network is inherently more secure than a public network, since the owner controls who gets access.
- Stolen equipment and physical security is still a threat. Private networks are more secure, but still require attention to detail to prevent a security breach.
- Even private networks can be compromised by determined individuals.
- See the Protocol Review of Security recommendations for all communications solutions alternatives.

Private 700 MHz WiMAX Attributes Review

Protocol Support

Protocol Support

At this time, subscriber units are available that will support all protocols expected to be required by a utility.

There is no clear advantage to one communications solution over another with respect to protocol at this time.

Full Spectrum 700 MHz Hybrid Private Radio Network in High Density Areas & Cellular for Lower Density Area

"FullMax" Point-to-Multipoint in Urban Areas with Cellular in Rural Areas

- The density of the FLISR DA point locations is much greater in the Louisville & Lexington metropolitan areas
  - 77% located in Louisville and Lexington metropolitan areas
- PSE included equally dispersed 2600 CVR locations the same as the FLISR DA locations
  - 77% within Louisville and Lexington metropolitan areas
- AMI collector locations were mapped via Geo-located list
  - Some substations were "unknown" for comms – Included needing comms
- A 700 MHz FullMax Full Spectrum system could be deployed with a modest amount of sites that would cover a significant number of DA FLISR and CVR Locations
- The CAPEX cost associated with this would reduce the OPEX recurring cost of cellular data charges

Conceptual RF Propagation 700 MHz FullMax

[redacted]

Wolfe

Conceptual RF propagation 700 MHz FullMax

- RF Propagation Study Assumptions:
  - Use only six existing towers
  - Assumed antenna centerline near top of structure
  - Available tower loading and space is assumed; it would need to be verified prior to a detailed design
  - Remote antennas located 20' above ground level
  - Remote antenna is omnidirectional, mounted in an optimal location and antenna gain is sufficient to offset feedline losses and minor mounting obstruction losses
    - In other words, antenna gain, feed line losses, and any local obstruction losses are assumed to equal zero. This is a conservative approach to modelling.
  - Used 25 km geo-fencing ring around the tower locations for backhaul counts for FLISR and AMI Collectors

Power System Engineering, Inc.

700 MHz Site Density for Reclosers

[redacted]

700 MHz Density for AMI Collectors Requiring Communications

[redacted]

Power System Engineering, Inc.

700 MHz Density for CVR Locations

[redacted]

Hybrid WiMAX/Cellular Attributes Review

10-Year Costs

Hybrid 700 MHz and Cellular Costs

Full Spectrum Remote End-Point		
Full Spectrum Radio	$	1,000
Line, Antenna, Surge Suppression	$	500
Third-party Installation	$	750
Total	**$**	**2,250**

Cal Amp End Modem at End-Point		
Cellular Modem Radio	$	800
Line, Antenna, Surge Suppression	$	500
Third-party Installation	$	750
Total	**$**	**2,050**

700 MHz Frequency Purchase		
Cost Per MHz/Population	$	0.75
MHz of Spectrum		2.00
Population		2,075,971
Price of Spectrum	**$**	**3,113,957**

Private Full Spectrum Build Costs

	Count	Price		Extended Price	
Antenna	4	$	300	$	1,200
Coax	800	$	8.00	$	6,400
Connectors	8	$	50	$	400
Cabinet wit	1	$	4,000	$	4,000
Master Radi	4	$	12,000	$	48,000
Installation	1	$	10,000	$	10,000
			Total	**$**	**70,000**

Hybrid 700 MHz and Cellular Costs

Power System Engineering, Inc.

Confidential Information Redacted

Input Data		
Full Spectrum 4 Sector Tower Site Equipment Cost Per Site	$	70,000
Full Spectrum Remote Location Installed Cost Per Site	$	2,250
Cellular Remote Location Installed Cost Per Site	$	2,050
Maintenance Percentage of Hardware Installed Cost		1.5%
SIM Card Cost	$	-
Maintenance Hours Per Year per FTE (90%)		1,872
Days Per Year FTE Working		234
Fully Loaded Cost Per FTE/hour (Comm or Ops Field Person)	$	85.00
FTE Cost Per Year for Field Maintenance	$	159,120.00
Field Locations Visited per day per FTE Employee		2
Periodic Maintenance Locations per year per FTE Employee		468
Visit All Locations Within this Many Years		2
Engineering (IT Department) Fully Loaded Costs per Hour	$	100.00
Engineering FTE Required Per Year for Ongoing Support		1.00

	YEAR					YEAR				YEAR		
	0	1	2	3	4	5	6	7	8	9	10	Total
CapEx Costs for Full Spectrum												
FS - FLISR Remotes Installed - By Phase (30 IDA)		30	200	315	285	401						1,231
FS - AMI (AMS) Collectors by Year		6	5	5								16
FS - CVR Locations By Year		273	273	273	272	272						1,363
Tower Site Full Spectrum Installations		6	-	-								6
FS - FLISR Remote Locations Modem Installed Costs	$0	$67,500	$450,000	$708,750	$641,250	$902,250	$0	$0	$0	$0	$0	$ 2,769,750
FS - AMI (AMS) Modem Collectors Installed Costs	$0	$13,500	$11,250	$11,250	$0	$0	$0	$0	$0	$0	$0	$ 36,000
FS - CVR Remote Modem Installed Costs	$0	$614,250	$614,250	$614,250	$612,000	$612,000	$0	$0	$0	$0	$0	$ 3,066,750
Access Spectrum 700 MHz Purchase	$3,113,957											$ 3,113,957
Full Spectrum Tower Equipment Builds	0	420,000	0	0	0	0	0	0	0	0	0	$ 420,000
CapEx Costs for Cellular Modems												
Cell -FLISR Remotes Installed - By Phase (30 IDA)		30	34	105	96	102						367
Cell - AMI (AMS) Collectors by Year		30	30	30								90
Cell - CVR Locations By Year		118	118	118	118	118						590
Cell - FLISR Remote Locations Modem Installed Costs	$0	$61,500	$69,700	$215,250	$196,800	$209,100	$0	$0	$0	$0	$0	$ 752,350
Cell - AMI (AMS) Model Collectors Installed Costs	$0	$61,500	$61,500	$61,500	$0	$0	$0	$0	$0	$0	$0	$ 184,500
Cell - CVR Remote Modem Installed Costs	$0	$241,900	$241,900	$241,900	$241,900	$241,900	$0	$0	$0	$0	$0	$ 1,209,500
Overall System Costs												
Network Management System	$50,000											$ 50,000
Design	$100,000											$ 100,000
Total CapEx Costs	$3,263,957	$1,480,150	$1,448,600	$1,852,900	$1,691,950	$1,965,250	$0	$0	$0	$0	$0	$11,702,807
OpEx Costs (Excluding Initial Capital Investments)	[redacted]											
[redacted]												$ [redacted]
Maintenance Materials		$3,750	$25,952	$47,681	$75,475	$100,854	$130,333	$130,333	$130,333	$130,333	$130,333	$ 905,376
Remote Site Visited Each Year		0	247	577	1,000	1,385	1,832	1,832	1,832	1,832	1,832	12,365
FTE Needed for Field Work (Comm or OPS)			0.53	1.23	2.14	2.96	3.91	3.91	3.91	3.91	3.91	
Field Maintenance Labor Costs Per Year for Remote Locations			$ 83,810	$ 196,010	$ 339,830	$ 470,900	$ 622,710	$ 622,710	$ 622,710	$ 622,710	$ 622,710	$ 4,204,100
IT Engineering Labor Costs Per Year		$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200
Total OpEx Costs		$217,902	$350,962	$513,643	$690,393	$852,122	$1,033,411	$1,033,411	$1,033,411	$1,033,411	$1,033,411	$7,792,076
Total System Costs	$3,263,957	$1,698,052	$1,799,562	$2,366,543	$2,382,343	$2,817,372	$1,033,411	$1,033,411	$1,033,411	$1,033,411	$1,033,411	$19,494,883

Total CapEx Costs over 10 Year Period	**$11,703,000**
Total OpEx Costs over 10 Year Period	**$7,792,000**
Rounded 10 Year Total Cost	**$19,495,000**
Cost Per End Point over 10 Year Period	**$5,331**

Hybrid WiMAX/Cellular Attributes Review

Availability

Hybrid WiMAX/Cellular Availability

- 6 Private Sites focus on the bulk of the FLISR and CVR required communication assets
  - Limits the public availability issues to only remote areas
  - Better availability in Metro areas
  - Less network maintenance needs due to the limited number of WiMAX Towers
- Cellular LTE availability is the same in the rural areas

Hybrid WiMAX/Cellular Attributes Review

Latency

Latency of 700 MHz Private WiMAX System

- Very stable and predictable latency for this network once all end points installed on network.
  - Links use adaptive modulation to change the individual links during times of interference which can cause the overall latency to vary
- Uses Time Division Duplexing (TDD) to create time slots for each device on the network
- Eliminates collisions in point-to-multipoint radio system
  - At the expense of throughput

Latency – Public LTE Networks

- A public LTE network is shared with many users. The traffic tends to ebb & flow during certain times of the day, thus the latency fluctuates based on users.
- The utility does not control the latency of a public cellular network

Hybrid WiMAX/Cellular Attributes Review

Quality of Service (QoS)/Prioritization

Quality of Service (QoS) Support

Most equipment used in private communication networks can be configured with levels of priority and QoS. Additionally, the utility devices will not be competing with traffic other than their own. This is a distinct advantage of private communication networks.

- The Full Spectrum WiMAX product has several levels of QoS to choose from as part of the configuration.
- The cellular network will not have QoS support for the rural areas

Hybrid WiMAX/Cellular Attributes Review

Bandwidth Availability

Private WiMAX Bandwidth

- Bandwidth was defined previously as "Maximum data rate of the channel available for use"
- The previous table reflects speeds capable in one master radio sector.
  - PSE's analysis assumed 16 QAM ¾ modulation would be available on average for the end points
  - Equates to 933 kbps of throughout
  - Can be allocated to more up or down link speeds
  - In Metro areas assumes 1 AMI collector per master radio sector
  - In Metro areas assumes no more than 100 FLISR or CVR sites per master radio sector
  - Metro areas would require 500-600 kbps of uplink bandwidth

Leased Cellular Bandwidth

- Bandwidth was defined previously as "Maximum data rate of the channel available for use"
- In the case of public LTE networks, bandwidth is considered "High" (~38Mbps 5MHz channel), but it is shared with many users.
- Our definition of leased cellular bandwidth is tied to the data plans chosen in the cost sections:
  - FLISR Reclosers and CVR Locations = 5 MB/Month Plan (<1 kbps per device)
    - Limited by using unsolicited report by exception
  - AMI Collectors = 2 GB/Month Plan (400 kbps per device)
- Extra bandwidth is available, but it comes at a monthly service cost penalty
  - Pooled data will help limit penalty
  - Note: Careful review of unnecessary SCADA traffic will need to be enforced to stay within data plans

Private WiMAX Attributes Review

Cybersecurity

Security – Public vs Private Networks

- Since devices on a public network are visible to a wide area, there is more exposure to third-party "hacker" threats.
- A private network is inherently more secure, since the owner controls who gets access.
- Stolen equipment and physical security is still a threat.
- End-to-end secure encryption is highly recommended for both private and public networks.
- While it is possible to secure assets connected to a public network, more diligence is often required to ensure nothing is left exposed.
- Private networks are more secure, but still require attention to detail to prevent a security breach.
- Even private networks can compromised by determined individuals.
- This solution would be a little less secure than a 100% private network.
- See the Protocol Review of Security recommendations for all communications solutions alternatives.

Hybrid WiMAX/Cellular Attributes Review

Protocol Support

Protocol Support

At this time, subscriber units are available that will support all protocols expected to be required by a utility.

There is no clear advantage to one communications solution over another with respect to protocol at this time.

AT&T/Nokia Private LTE Cellular Network

Power System Engineering, Inc.

Nokia/AT&T Private Cellular Network

- Spectrum provided by AT&T
  - 2.3 GHz Spectrum
  - 5 MHz Paired Blocks with 1 MHz Guard Bands
  - 3 MHz Up and Down
  - 10 year lease at approximately $0.50/MHz/Population
- LTE network provided by Nokia
  - 3 to 6 Sector Sites
  - 15 km range using directional antennas
    - PSE used 10 km for overlap between sites
  - 11 Mbps/sector
  - Utility owns Network

Power System Engineering, Inc.

Typical LTE Site Density

[redacted]

Typical Pole-Mounted Small LTE Site

Typical Small LTE Site

Antennas and radios are mounted aloft and usually connected by fiber and DC power.

Pad-mounted support equipment in weatherproof cabinets (power & battery plant, networking support equipment)

Private LTE Attributes Review

10-Year Costs

Private LTE Network – Cost Assumptions

- Fiber to every site not connected to LKS backbone today
  - 130 miles of fiber at $25k/mile
- Approximately (59) 150’ towers will be required
  - $80k/tower
  - Outside, environmentally-controlled LTE cabinet used at towers
- Core switch will be $0.5 million
- LKS can lease only the counties used and not the whole state of KY

Private LTE Network – Costs

Nokia Modem at End-Point	
Cellular Modem Radio	$ 1,200
Line, Antenna, Surge Suppression	$ 500
Third-party Installation	$ 750
Total	**$ 2,450**

Installed in Control Cabinet

Frequency 10 Year Lease	
Cost Per MHz/Population	$ 0.50
MHz of Spectrum	6.00
Population	3,736,406
Price of Spectrum	**$ 11,209,218**

Private LTE Tower Site Build Costs

	Count	Price	Extended Price
Antenna	3	$ 300	$ 900
Fiber Cable	200	$ 0.60	$ 120
Fiber Connector	6	$ 10	$ 60
Cabinet with Battery and DC Power System	1	$ 15,000	$ 15,000
Base station	1	$ 30,000	$ 30,000
Installation	1	$ 50,000	$ 50,000
		Total	**$ 96,080**

Power System Engineering, Inc.

Private LTE Network – 10-Year Costs

Data Inputs	
150' Tower Cost Per Tower	$ 80,000
LTE Tower Site Equipment Cost Per Site	$ 96,080
Remote Location Installed Costs	$ 2,450
Maintenance Percentage of Hardware Installed Cost	1.5%
SIM Card Cost	$ -
Fiber Cost Per Mile	$ 25,000.00
Maintenance Hours Per Year per FTE (90%)	1,872
Days Per Year FTE Working	234
Fully Loaded Cost Per FTE/hour (Comm or Ops Field Person)	$ 85.00
FTE Cost Per Year for Field Maintenance	$ 159,120.00
Field Locations Visited per day per FTE Employee	2
Periodic Maintenance Locations per year per FTE Employee	468
Visit All Locations Within this Many Years	2
Engineering (IT Department) Fully Loaded Costs per Hour	$ 100.00
Engineering FTE Required Per Year for Ongoing Support	2.00

		YEAR				YEAR			YEAR			
	0	1	2	3	4	5	6	7	8	9	10	Total
CapEx Initial Investment												
Tower Site LTE Installations		30	30	19								79
FLISR Remotes Installed - By Phase (30 IDA)		30	264	420	381	502						1,597
CVR Locations Installed		391	391	391	390	390						1,953
AMI Collectors Installed		36	35	35								106
Tower Build Counts	20	20	19									59
Fiber Miles Built	20	80	30									130
Remote Locations Installed Costs		$1,119,650	$1,690,500	$2,072,700	$1,888,950	$2,185,400	$0	$0	$0	$0	$0	$8,957,200
AT&T Frequency Lease	11,209,218											$11,209,218
LTE Core Switch and NMS	500,000											$500,000
Tower Site Builds	1,600,000	1,600,000	1,520,000	0	0	0	0	0	0	0	0	$ 4,720,000
LTE Tower Equipment Builds	0	2,882,400	2,882,400	1,825,520	0	0	0	0	0	0	0	$ 7,590,320
Fiber Backbone Extensions	500,000	2,000,000	752,500									$ 3,252,500
Design	500,000											$500,000
Total CapEx Costs	$14,309,218	$7,602,050	$6,845,400	$3,898,220	$1,888,950	$2,185,400	$0	$0	$0	$0	$0	$36,729,238
OpEx Costs (Excluding Initial Capital Investments)												
Cellular Usage Costs/Month	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$ -
Maintenance		$22,500	$142,531	$233,699	$292,173	$320,507	$353,288	$353,288	$353,288	$353,288	$353,288	$ 2,777,848
Remote Site Visited Each Year			244	604	1,036	1,422	1,868	1,868	1,868	1,868	1,868	12,642
FTE Needed for Field Work (Comm or OPS)			0.52	1.29	2.21	3.04	3.99	3.99	3.99	3.99	3.99	
Field Maintenance Labor Costs Per Year for Remote Locations			$ 82,790	$ 205,190	$ 352,240	$ 483,310	$ 634,950	$ 634,950	$ 634,950	$ 634,950	$ 634,950	$ 4,298,280
IT Engineering Labor Costs Per Year		$ 374,400	$ 374,400	$ 374,400	$ 374,400	$ 374,400	$ 374,400	$ 374,400	$ 374,400	$ 374,400	$ 374,400	$ 3,744,000
Total OpEx Costs		$396,900	$599,721	$813,289	$1,018,813	$1,178,217	$1,362,638	$1,362,638	$1,362,638	$1,362,638	$1,362,638	$10,820,128
Total System Costs	$14,309,218	$7,998,950	$7,445,121	$4,711,509	$2,907,763	$3,363,617	$1,362,638	$1,362,638	$1,362,638	$1,362,638	$1,362,638	$47,549,366

Total CapEx Costs over 10 Year Period	**$36,729,000**
Total OpEx Costs over 10 Year Period	**$10,820,000**
Rounded 10 Year Total Cost	**$47,549,000**
Cost Per End Point over 10 Year Period	**$13,006**

Private LTE Network Attributes Review

Availability

Availability – Private LTE Networks

- By owning, operating and maintaining their own private network dedicated their needs, the utility can set their own service availability objectives.
  - However, it will be harder to build a private LTE network more robust than the public network.
- However, this comes at a cost. In order to approach the availability and time to restore of the large common carriers, the communications system must be carefully monitored and maintained
- A department with trained staff in sufficient numbers to complete routine maintenance programs and address outages in a timely manner is required.
- The costs associated with this include salary, training, instruments and vehicles. Typically, 24/7/365 coverage is required to match the common carrier service level.

Availability – Private LTE Networks

- Large and mid-sized utilities often have a telecommunications or SCADA group in place already. This group could be expanded, cross-trained, and tasked with the operation and maintenance of the private network.
- The cost of providing this level of service is often prohibitive for small to mid-sized utilities.
- A Private LTE network will require a large staff to maintain the system.
- Depending upon design, network resilience can be provided if sites overlap; service could be available from another site during a single site failure scenario.
- Allows the utility to be the "masters of their own destiny" with respect to prioritizing maintenance and restoration activities.
- The spectrum available for a private LTE network is leased. Lease terms unknown, but expected to be 10 years. [redacted]

Confidential Information Redacted

[redacted]

Power System Engineering, Inc.

Private LTE Network Attributes Review

Latency

Latency of Private LTE Network

- A private LTE network would be extremely robust in bandwidth capability. The utility would be hard pressed to push the bandwidth limits.
- Causes of latency issues include:
  - Propagation delay on the RF link (low if build correctly)
  - Propagation delay on the backhaul
  - Competing for bandwidth for other users
- This means the latency should be:
  - Low due to the lack of competing for the bandwidth
  - Probably better than any other solution alternative
  - Very stable and predictable

Power System Engineering, Inc.

Private LTE Network Attributes Review

Quality of Service (QoS)/Prioritization

Quality of Service (QoS) Support

- Most equipment used in private communication networks can be configured with levels of priority and QoS.
- Additionally, the utility devices will not be competing with traffic other than their own.
- This is a distinct advantage of private communication networks.
- QoS capability may not need to be used for this network.

Private LTE Network Attributes Review

Bandwidth Availability

Private LTE Network Bandwidth

- Bandwidth was defined previously as "Maximum data rate of the channel available for use"
- 33 Mbps per sector (assumed 3 sectors per tower)
- A private LTE network would have substantial capacity beyond what is required for DA, and could be used in support of other initiatives:
  - CVR
  - AMI
  - Mobile Workforce Management (MWM)
  - Small Sub SCADA, metering, and video surveillance
  - Many other applications

Private LTE Network Attributes Review

Cybersecurity

Security – Private LTE Network

- A private network is inherently more secure than a public network, since the owner controls who gets access.
- Stolen equipment and physical security is still a threat. Private networks are more secure, but still require attention to detail to prevent a security breach.
- Even private networks can compromised by determined individuals.
- See the Protocol Review of Security recommendations for all communications solutions alternatives.

Private LTE Network Attributes Review

Protocol Support

Protocol Support

At this time, subscriber units are available that will support all protocols expected to be required by a utility.

There is no clear advantage to one communications solution over another with respect to protocol at this time.

Power System Engineering, Inc.

Conxx/Nokia 10-Year Capitalized Cellular Service

Combined Nokia and Conxx

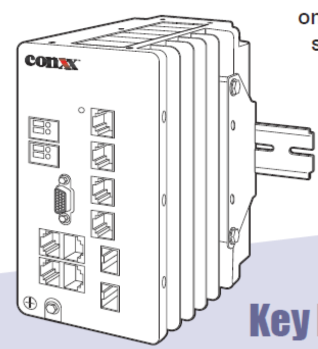
- Conxx – Third-party
- Uses Nokia 7705 router
- Uses universal SIM
  - AT&T and Verizon
- Provided quote for many options. PSE used lowest LTE quote for 300 MB per month for 10 years.
- 10-year hedge on cell costs.

conxx™

Global Grid Router

The Global Grid Router provides industry-leading IP/MPLS communications capabilities over a common carrier LTE network in a DIN rail-mountable compact form with temperature, electromagnetic, shock and vibration hardening.

The Global Grid Router is ideally suited for deployments in harsh and cramped environments, particularly smart grid distribution and field area automation or rolling rail vehicles' on-board applications. It is optimized for secure and reliable delivery of mission-critical applications for network operators in utilities, transportation, government and public safety.



Key Bundle Features

- 10 Year Globally Connected
- Ruggedized for vibration, shock, dust, splash & humidity
- Certified 3G/4G/LTE enterprise grade internal router and modem
- Software defined radio supports multiple carriers (Gobi)
- Built-in transient and reverse polarity voltage protection
- Out of Band modem and router management
- 9–36 DC voltage input range
- Integrated temperature sensors
- Active GPS support

Conxx Attributes Review

10-Year Costs

Budgetary Costs For Conxx CapEx Cellular

Estimated Site-Based Installed Capital Costs per Site

Global Grid Router (300 MB/Mo) (FLISR/CVR)		
Cabinet and 10 year 300 MB/Mo LTE Service	$	13,037
Line, Antenna, Surge Suppression	$	-
Third-party Installation	$	750
Total	**$**	**13,787**

Global Grid Router (2 GB/Mo) - AMI		
Cabinet and 10 year 2 GB/Mo LTE Service	$	14,693
Line, Antenna, Surge Suppression	$	-
Third-party Installation	$	750
Total	**$**	**15,443**

Global Grid Router Bill of Materials

- GGR Ruggedized Modem - Enterprise Class Mobile 3G / 4G LTE Multi-Band Router NO Wi-Fi
- GGR Ruggedized MPLS Router - Nokia SAR HC
- SAR HC 7705 SAM License
- 3G / 4G LTE 9 dBi Omni-Directional Fixed Mount Outdoor Fiberglass Antenna with mounting bracket
- Cable - Antenna cable 20-Ft
- Cable - GGR Serial Cable (Modem to Router)
- GGR Mounting Bracket
- Dual Power Supplies, 480W, 120-240VAC 1PH, 24-28VDC, 20-17.5A
- GGR NEMA 4 Enclosure
- GGR 10 Year Data SIM (LTE or 3G)
- DIN Rails and Lockable PIN Mounts
- GGR Out of Band Management Module
- GGR Modem Firmware
- GGR IP Addressing

Power System Engineering, Inc.

Budgetary Costs For Conxx CapEx Cellular

Input Data	
300 MB/Mo Remote Installed Costs	$ 13,787
10 GB/Mo Remote Installations	$ 15,443
Maintenance Percentage of Hardware Installed Cost	0.5%
SIM Card Cost	$ -
Maintenance Hours Per Year per FTE (90%)	1,872
Days Per Year FTE Working	234
Fully Loaded Cost Per FTE/hour (Comm or Ops Field Person)	$ 85.00
FTE Cost Per Year for Field Maintenance	$ 159,120.00
Field Locations Visited per day per FTE Employee	2
Periodic Maintenance Locations per year per FTE Employee	468
Visit All Locations Within this Many Years	2
Engineering (IT Department) Fully Loaded Costs per Hour	$ 100.00
Engineering FTE Required Per Year for Ongoing Support	1.00

	YEAR											
	0	1	2	3	4	5	6	7	8	9	10	Total
CapEx Initial Investment												
300 MB/Mo - FLISR Remotes Installed - By Phase (30 IDA)		30	264	420	381	502						1,597
300 MB/Mo - CVR Locations Installed		391	391	391	390	390						1,953
10 GB/Mo - AMI Collectors Installed		36	35	35								106
Remote Locations Installed Costs		$6,360,275	$9,570,990	$11,721,762	$10,629,777	$12,298,004	$0	$0	$0	$0	$0	$ 50,580,808
Network Management System	$50,000											$ 50,000
System Design	$20,000											$ 20,000
Total CapEx Costs	$70,000	$6,360,275	$9,570,990	$11,721,762	$10,629,777	$12,298,004	$0	$0	$0	$0	$0	$50,650,808
OpEx Costs (Excluding Initial Capital Investments)												
Cellular Usage Costs/Month -	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Maintenance Materials		$250	$32,051	$79,906	$138,515	$191,664	$253,154	$253,154	$253,154	$253,154	$253,154	$ 1,708,157
Remote Site Visited Each Year		0	229	574	997	1,382	1,828	1,828	1,828	1,828	1,828	12,321
FTE Needed for Field Work (Comm or OPS)			0.49	1.23	2.13	2.95	3.91	3.91	3.91	3.91	3.91	
Field Maintenance Labor Costs Per Year for Remote Locations			$ 77,690	$ 194,990	$ 338,810	$ 469,880	$ 621,520	$ 621,520	$ 621,520	$ 621,520	$ 621,520	$ 4,188,970
IT Engineering Labor Costs Per Year		$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 1,872,000
Total OpEx Costs		$187,450	$296,941	$462,096	$664,525	$848,744	$1,061,874	$1,061,874	$1,061,874	$1,061,874	$1,061,874	$7,769,127
Total System Costs	$70,000	$6,547,725	$9,867,931	$12,183,858	$11,294,302	$13,146,748	$1,061,874	$1,061,874	$1,061,874	$1,061,874	$1,061,874	$58,419,935

Total CapEx Costs over 10 Year Period	**$50,651,000**
Total OpEx Costs over 10 Year Period	**$7,769,000**
Rounded 10 Year Total Cost	**$58,420,000**
Cost Per End Point over 10 Year Period	**$15,979**

Attachment to Response to AG-1 Question No. 418
Page 120 of 147
[redacted] Wolfe

LG&E KU PPL companies

Capitalized Leased LTE Cellular Attributes Review

Availability

Availability – Public LTE networks - Pros

- All LTE network operators have central monitoring and dispatch for their networks
- A dedicated staff monitors degradation and outages 24/7/365. Dispatch criteria differs, but substantial outages are typically addressed quickly.
- LTE operators have trained maintenance and repair staff available to address outages.
- As the site density increases, a single site outage has less impact on overall network availability, especially during non peak traffic.
- Network availability has steadily improved, especially with the largest nationwide carriers.

Availability – Public LTE networks-Cons

- Unknown Coverage for all locations. Utility does not control coverage capability.
- LTE networks have grown large, and staffing has likely not increased in proportion. Therefore, response time appears to be increasing. However, the increased site density has allowed this without noticeable outage times (nearby site can cover while staff are dispatched)
- The risk which is most concerning with a public LTE network is a large, widespread outage typically due to a natural events such as weather. Deliberate damage (sabotage) is also a concern, but events have been rare.
- In the case of a natural disaster, sites may be unavailable for extended periods of time.
- The most likely risks are extended power outage due to damaged power distribution lines, physical damage to the building from flooding, or damage to the antenna system from high winds or ice storms.

Capitalized Leased LTE Cellular Attributes Review

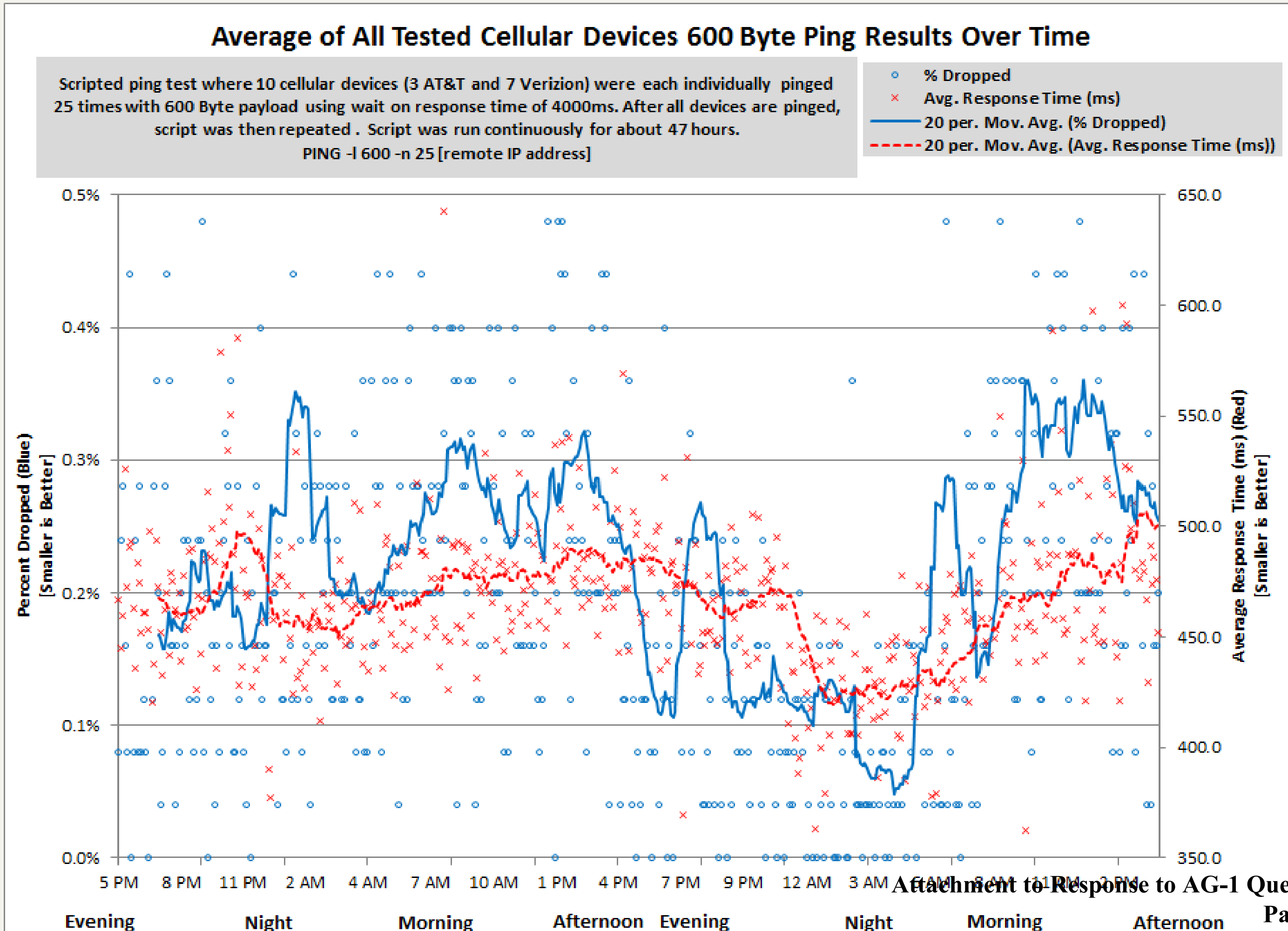
Latency

Latency – Public LTE networks

- A public LTE network is shared with many users. The traffic tends to ebb & flow during certain times of the day, thus the latency fluctuates based on users.
- The utility does not control the latency of a public cellular network.
- PSE has conducted lab experiments and studies in the past to measure latency at various times through several 24 hour periods (see example on next slide).

Cellular Latency by Time of Day

- Cellular latency can vary from 100ms to > 600ms
- Acceptable for DNP, but not for IEC-61850 GOOSE or SMV



Attachment to Response to AG-1 Question No. 418
Page 126 of 147
Wolfe

Capitalized Leased LTE Cellular Attributes Review

Quality of Service (QoS)/Prioritization

Leased Cellular Quality of Service (QoS)/Latency

- Public networks can not guarantee any given level of service. Many subscribers are competing for a finite amount of bandwidth and will have the same priority by law.
- Public networks suffer degradation during period of high traffic. Events such as emergencies (car wrecks, fires, etc.) have been known to cause network blockage ranging form several minutes to several hours
- Natural disasters such as weather, earthquake, etc. can cause outages and degradation for hours, days or even longer in severe cases.

Capitalized Leased LTE Cellular Attributes Review

Bandwidth Availability

Capitalized Leased Cellular Bandwidth

- Bandwidth was defined previously as "Maximum data rate of the channel available for use"
- In the case of public LTE networks, bandwidth is considered "High" (~38Mbps 5MHz channel), but it is shared with many users.
- Our definition of leased cellular bandwidth is tied to the data plans chosen in the cost sections:
  - FLISR Reclosers and CVR Locations = 300 MB/Month Plan (60 kbps per device)
    - Could use polling instead of RBE
  - AMI Collectors = 2 GB/Month Plan (400 kbps per device)
- Extra bandwidth is available, but it comes at a monthly service cost penalty.
  - Pooled data will help limit penalty
  - Note: Careful review of unnecessary SCADA traffic will need to be enforced to stay within data plans

Capitalized Leased LTE Cellular Attributes Review

Cybersecurity

Security – Public Networks

- Since devices on a public network are visible to a wide area, there is more exposure to third party “hacker” threats than private networks.
- End-to-end secure encryption is highly recommended for both private and public networks.
- While it is possible to secure assets connected to a public network, more diligence is often required to ensure nothing is left exposed.
- See the Protocol Review of Security recommendations for all communications solutions alternatives.

Capitalized Leased LTE Cellular Attributes Review

Protocol Support

Protocol Support

At this time, subscriber units are available that will support all protocols expected to be required by a utility.

There is no clear advantage to one communications solution over another with respect to protocol at this time.

Solution Alternatives Cost Summary

Power System Engineering, Inc.

Solution Alternatives 10-Year Cost Summary

Confidential Information Redacted

Cost Per Program	Total End Devices Needing Comms	Percentage of End Devices for Cost Allocations
FLISR DA	1597	43.7%
AMI Collectors	106	2.9%
CVR Program	1953	53.4%

Technology	Capital Costs ($1,000's)	Operational Costs ($1,000's)	Total Costs ($1,000's)	Cost per Device	Total Cost Allocation for FLISR ($1,000's)	Total Cost Allocation for AMI Collectors ($1,000's)	Total Cost Allocation for CVR ($1,000's)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
700 MHz Full Spectrum	$21,288	$6,903	$28,191	$7,711	$12,314	$817	$15,059
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ConXX - Capitalized Cellular	$50,651	$7,769	$58,420	$15,979	$25,519	$1,694	$31,207
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Using a Percentage Allocation based on Number of Remotes Installed in each Program

Attachment to Response to AG-1 Question No. 418
Page 136 of 147
[redacted] Wolfe

Power System Engineering, Inc.

Cellular Solution for FLISR DA Only

Data Inputs	
Remote Installed Costs	$ 2,050
Maintenance Percentage of Hardware Installed Cost	2.0%
SIM Card Cost	$ -
Maintenance Hours Per Year per FTE (90%)	1,872
Days Per Year FTE Working	234
Fully Loaded Cost Per FTE/hour (Comm or Ops Field Person)	$ 85.00
FTE Cost Per Year for Field Maintenance	$ 159,120.00
Field Locations Visited per day per FTE Employee	2
Periodic Maintenance Locations per year per FTE Employee	468
Visit All Locations Within this Many Years	2
Engineering (IT Department) Fully Loaded Costs per Hour	$ 100.00
Engineering (IT Department) FTE Required Per Year for Ongoing Support	1.00

Confidential Information Redacted

	YEAR				YEAR				YEAR			
	0	1	2	3	4	5	6	7	8	9	10	Total
CapEx Initial Investment												
FLISR Remotes Installed - By Phase (30 IDA)		30	264	420	381	502						1,597
FLISR Remote Locations Modem Installed Costs		$61,500	$541,200	$861,000	$781,050	$1,029,100	$0	$0	$0	$0	$0	$ 3,273,850
Network Management System		$50,000										$ 50,000
System Design		$40,000										$ 40,000
Total CapEx Costs	$0	$151,500	$541,200	$861,000	$781,050	$1,029,100	$0	$0	$0	$0	$0	$3,363,850
OpEx Costs (Excluding Initial Capital Investments)	[redacted]											
[redacted]												$ [redacted]
Maintenance Materials			$2,230	$13,054	$30,274	$45,895	$66,477	$66,477	$66,477	$66,477	$66,477	$ 423,838
Remote Site Visited Each Year for Maintenance		0	15	147	357	548	799	799	799	799	799	5,059
FTE Needed for Field Maintenance			0.03	0.31	0.76	1.17	1.71	1.71	1.71	1.71	1.71	
Non-IT Field Maintenance Labor Costs Per Year for Remote Locations			$ 5,100	$ 49,980	$ 121,380	$ 186,150	$ 271,490	$ 271,490	$ 271,490	$ 271,490	$ 271,490	$ 1,720,060
IT Engineering Labor Costs Per Year		$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 187,200	$ 1,872,000
Total OpEx Costs		$187,920	$201,601	$267,517	$365,491	$458,121	$564,294	$564,294	$564,294	$564,294	$564,294	$4,302,117
Total System Costs	$0	$339,420	$742,801	$1,128,517	$1,146,541	$1,487,221	$564,294	$564,294	$564,294	$564,294	$564,294	$7,665,967

Total CapEx Costs over 10 Year Period	**$3,364,000**
Total OpEx Costs over 10 Year Period	**$4,302,000**
Rounded 10 Year Total Cost	**$7,666,000**
Cost Per End Point over 10 Year Period	**$4,800**

FLISR DA Only Costs

This Program Absorbs the Engineering and Network Management System Costs plus IT FTE Engineer Costs and 1.71 FTE Field Maintenance

PPL companies

Cellular Solution for AMI (AMS) Only

Data Inputs	
Remote Installed Costs	$ 2,050
Maintenance Percentage of Hardware Installed Cost	2.0%
SIM Card Cost	$ -
Maintenance Hours Per Year per FTE (90%)	1,872
Days Per Year FTE Working	234
Fully Loaded Cost Per FTE/hour (Comm or Ops Field Person)	$ 85.00
FTE Cost Per Year for Field Maintenance	$ 159,120.00
Field Locations Visited per day per FTE Employee	2
Periodic Maintenance Locations per year per FTE Employee	468
Visit All Locations Within this Many Years	2
Engineering (IT Department) Fully Loaded Costs per Hour	$ 100.00
Engineering (IT Department) FTE Required Per Year for Ongoing Support	-

Confidential Information Redacted

	YEAR				YEAR				YEAR			
	0	1	2	3	4	5	6	7	8	9	10	Total
CapEx Initial Investment												
AMI (AMS) Collectors by Year		36	35	35								106
AMI (AMS) Model Collectors Installed Costs		$73,800	$71,750	$71,750	$0	$0	$0	$0	$0	$0	$0	$ 217,300
Network Management System		$0										$ -
System Design		$0										$ -
Total CapEx Costs	$0	$73,800	$71,750	$71,750	$0	$0	$0	$0	$0	$0	$0	$217,300
OpEx Costs (Excluding Initial Capital Investments)	[redacted]											
[redacted]												
Maintenance Materials			$1,476	$2,911	$4,346	$4,346	$4,346	$4,346	$4,346	$4,346	$4,346	$ 34,809
Remote Site Visited Each Year for Maintenance		0	18	36	53	53	53	53	53	53	53	425
FTE Needed for Field Maintenance			0.04	0.08	0.11	0.11	0.11	0.11	0.11	0.11	0.11	
Non-IT Field Maintenance Labor Costs Per Year for Remote Locations			$ 6,120	$ 12,070	$ 18,020	$ 18,020	$ 18,020	$ 18,020	$ 18,020	$ 18,020	$ 18,020	$ 144,330
IT Engineering Labor Costs Per Year		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total OpEx Costs		$7,344	$22,098	$36,641	$44,043	$44,043	$44,043	$44,043	$44,043	$44,043	$44,043	$374,384
Total System Costs	$0	$81,144	$93,848	$108,391	$44,043	$44,043	$44,043	$44,043	$44,043	$44,043	$44,043	$591,684

Total CapEx Costs over 10 Year Period	$217,000
Total OpEx Costs over 10 Year Period	$374,000
Rounded 10 Year Total Cost	$592,000
Cost Per End Point over 10 Year Period	$5,585

AMI (AMS) Only Costs
Minimal Maintenance FTE Allocation (0.11 FTE)

Cellular Solution for CVR Only

Confidential Information Redacted

Data Inputs	
Remote Installed Costs	$ 2,050
Maintenance Percentage of Hardware Installed Cost	2.0%
SIM Card Cost	$ -
Maintenance Hours Per Year per FTE (90%)	1,872
Days Per Year FTE Working	234
Fully Loaded Cost Per FTE/hour (Comm or Ops Field Person)	$ 85.00
FTE Cost Per Year for Field Maintenance	$ 159,120.00
Field Locations Visited per day per FTE Employee	2
Periodic Maintenance Locations per year per FTE Employee	468
Visit All Locations Within this Many Years	2
Engineering (IT Department) Fully Loaded Costs per Hour	$ 100.00
Engineering (IT Department) FTE Required Per Year for Ongoing Support	-

		YEAR				YEAR			YEAR			
	0	1	2	3	4	5	6	7	8	9	10	Total
CapEx Initial Investment												
CVR Locations By Year		391	391	391	390	390						1,953
CVR Remote Modem Installed Costs		$801,550	$801,550	$801,550	$799,500	$799,500	$0	$0	$0	$0	$0	$ 4,003,650
Network Management System		$0										$ -
System Design		$0										$ -
Total CapEx Costs	$0	$801,550	$801,550	$801,550	$799,500	$799,500	$0	$0	$0	$0	$0	$4,003,650
OpEx Costs (Excluding Initial Capital Investments)	[redacted]											
[redacted]												$ [redacted]
Maintenance Materials			$16,031	$32,062	$48,093	$64,083	$80,073	$80,073	$80,073	$80,073	$80,073	$ 560,634
Remote Site Visited Each Year for Maintenance		0	196	391	587	782	977	977	977	977	977	6,837
FTE Needed for Field Maintenance			0.42	0.84	1.25	1.67	2.09	2.09	2.09	2.09	2.09	
Non-IT Field Maintenance Labor Costs Per Year for Remote Locations			$ 66,470	$ 132,940	$ 199,410	$ 265,710	$ 332,010	$ 332,010	$ 332,010	$ 332,010	$ 332,010	$ 2,324,580
IT Engineering Labor Costs Per Year		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total OpEx Costs		$9,384	$101,465	$193,545	$285,602	$377,447	$459,932	$459,932	$459,932	$459,932	$459,932	$3,267,099
Total System Costs	$0	$810,934	$903,015	$995,095	$1,085,102	$1,176,947	$459,932	$459,932	$459,932	$459,932	$459,932	$7,270,749

Total CapEx Costs over 10 Year Period	**$4,004,000**
Total OpEx Costs over 10 Year Period	**$3,267,000**
Rounded 10 Year Total Cost	**$7,271,000**
Cost Per End Point over 10 Year Period	**$3,723**

CVR Only Costs

Maintenance FTE Allocation (2.1 FTE)

Difference Percentage Allocation and Full Allocation

Program	10 year Total Cost using Percentage Allocation ($1,000's)	10 year Total Cost using Detailed Allocation ($1,000's)
FLISR DA	$6,783	$7,666
AMI (AMS)	$450	$592
CVR	$8,295	$7,271

- FLISR pays for Engineer FTE, Design Costs and NMS using the Detailed Allocation Method

- The Detailed Allocation Method better Allocates the Cellular Usage Costs since the AMI Collectors require a higher Data Plan

Cost – Public Cellular (LTE) Network

- A public cellular (LTE) network solution would have the lowest CapEx, requiring only the endpoint radio devices, but would have a recurring network access fee OpEx cost.
- This solution has the lowest 10 year overall cost as well.
- Would require the least maintenance, but the service level is dictated by the carrier, with little influence from the utility.
- Difficult to predict future pricing of LTE data, but it has trended downward, and attractive rates are currently available.
- The lifespan of the endpoints purchased today is a concern, but it is expected to be 8 to 10 years before the carriers will discontinue service as technology evolves.
- If LKS feels the carrier would provide acceptable levels of service, PSE recommends this solution be considered, as it is the lowest cost.

Cost – Private WiMAX (Purchased Spectrum)

- The private WiMAX network based 700 MHz network ranked third in cost. This approach would have a CapEx build, with no monthly recurring fees other than maintenance labor.
- This solution provides adequate bandwidth with spectrum that is available for purchase rather than lease. However, the nature of 700 MHz radio propagation will require several sites to cover the low density of endpoints in more rural areas. This drives up the cost substantially to provide coverage over the entire service area.
- If the desire is to have a completely private network, PSE feels this is a viable approach.

Cost – Hybrid Private WiMAX and Public Cellular (LTE) Network

- Since the majority of the endpoints are located within a couple of urban areas, the private WiMAX solution could reach these with a relatively small number of base station sites. If the remaining rural or outlier sites were connected via a public cellular (LTE) network, the cost of a Hybrid, private-public solution becomes attractive.
- The cost of this solution is higher than an all public network solution, but somewhat less expensive than an all-private WiMAX solution. The utility would be able to control the QoS & restoration activities of the private WiMAX portion, while saving the costs of building multiple rural sites to serve only a few endpoints.
- PSE feels this approach presents a good tradeoff between cost and private vs. public networks.

Cost – Private LTE (Leased Spectrum)

- The Private LTE network solution was next highest cost.
- Covering the entire service area with this technology would be costly, with bandwidth capacity well in excess of current needs.
- The RF spectrum for this option is only available as a lease. It is not known if, or under what terms, the lease could be renewed after the initial 10 years period.
- PSE sees this not only as a significant cost, but also as a substantial risk. The entire life cycle of this system could be limited to the 10 year initial spectrum lease, which may not be financially viable.
- PSE does not recommend this solution due to the over capacity of the solutions, the complexity, the spectrum unknowns, and total costs.

Cost – Conxx All CapEx

- The Conxx all CapEx cellular solution is the most expensive.
- While this solution has a fixed CapEx with no recurring OpEx, it would have performance nearly identical to a month to month cellular (LTE) network solution.
- The cost is considered extremely high for the benefit of CapEx.
- PSE does not recommend this solution since the costs do not outweigh the benefits of capitalized cellular.

Attribute Table Summary

Evaluated Communications Technologies						
Evaluation Attributes	Cellular (4G/LTE)	Conxx Cellular CapEx	Private LTE	Private WiMAX	Hybrid (WiMAX/Cell)	
Availability	3	3	1	1	2	Substantial commitment to maintenance and restoration is required on Private Networks
Latency (predictable/consistent)	4	4	1	2	3	Latency of all platforms is expected to be acceptable. Latency of private networks will be more predictable and consistent (less jitter)
Security	3	3	1	1	2	All options can be made secure (end to end encryption) Private networks have less exposure to third party threats
Bandwidth	5	2	1	3	4	Public network has bandwidth, but it has a penalty for overage
Protocol support	1	1	1	1	1	All options support current protocols (DNP3 recommended)
QoS/prioritization	5	5	1	1	2	Public network QOS is typically not supported / guaranteed
Cost	1	5	4	3	2	

A lower number is considered better than the other solutions

All solutions reviewed meet the minimal technical requirements for LKS deployment

Thank you!

Power System Engineering, Inc.

Charles Plummer
Project Manager
[redacted]

Sarah Genschaw
Project Coordinator/Main Point of Contact
[redacted]

www.powersystem.org

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 419

Responding Witness: John K. Wolfe

Q-419. Regarding Table 5 of Exhibit PWT-5 identify transformers affected and detailed investment estimates for each identified transformer in the years of the N1DT contingency program.

A-419. Per Table 5 of Exhibit PWT-5 a total of $9,271k (2015-$2,632k; 2016-$6,639k expected) has been spent to date on the program. A description of the projects completed to date can be found in Section 5.2.3 of Exhibit PWT-5. Included in this amount are additional portable transformers, spare transformers and substation equipment to improve response time for outages in areas where the addition of permanent contingency capacity cannot be reasonably accommodated. Future investment shown in Table 5 of Exhibit PWT-5 will be continuously prioritized to maximize the benefit to the number of customers and transformers impacted. A detailed scope of work and estimate for each transformer listed has not been developed at this time. Estimates on the highest priority project(s) are completed annually and the project list is adjusted to integrate with other projects and programs. See Attachment in response to Question 396 (c) for the current project list of the N1DT contingency program.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 420

Responding Witness: John K. Wolfe

Q-420. Regarding Exhibit PWT-6 provide the estimated O&M expense vs Expected O&M savings for the each of the years 2017 through 2022.

A-420.

$000's	2017	2018	2019	2020	2021	2022
O&M Expense	440	1,362	1,470	1,336	1,371	42
O&M Savings	0	0	50	100	150	180

Note 1: Values shown are totals for LG&E and KU combined.

Note 2: The financial model referenced includes O&M expenses associated with the DMS over the depreciable life of the DMS asset which ends after 2021. The Companies believe this is the reasonable period for the analysis. Annual ongoing O&M expenses modeled beyond 2021 reflect communication costs associated with the SCADA connected reclosers. A financial scenario including escalated ongoing O&M DMS expenses as well as assumed DMS upgrade costs and timing through 2051 was completed. This scenario showed the "do nothing" alternative to be the lowest NPVRR of the alternatives evaluated. The Companies believe this is scenario is based on an unreasonable period for the analysis because of the uncertainties associated with the 30-year IT system assumptions. Recognizing the uncertainty of 30-year IT system related assumptions and noting reliability improvement is the primary objective of the DA program, completion of the DA program remains the recommended alternative based on the justification described in Exhibit PWT-5 of Mr. Thompson's testimony.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 421

Responding Witness: John K. Wolfe

Q-421. Regarding Exhibit PWT-7, page 1, provide background calculation for NPVRR's in electronic format, preferably Excel, with active cells.

A-421. See the response to PSC 1-54.

Att_KU_PSC_1-54_Exh_PWT-7_-_LGE_DA_Updated_2016_CEM.xlsx
Att_KU_PSC_1-54_Exh_PWT-7_-_KU_DA_Updated_2016_CEM.xlsx
Att_KU_PSC_1-54_Exh_PWT-7_-_DMS_-_Updated_2016_CEM.xlsx

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 422

Responding Witness: John K. Wolfe

Q-422. Regarding Exhibit PWT-7, page 2, provide:

a. Background calculation for all entries in electronic format, preferably Excel, with active cells.

b. A detailed explanation of all cost savings and assumptions used in deriving cost savings.

A-422.

a. The LGE DA CEM Model was filed December 8th, 2016.
http://psc.ky.gov/PSC_WebNet/ViewCaseFilings.aspx?case=2016-00370

Att_KU_PSC_1-54_Exh_PWT-7_-_LGE_DA_Updated_2016_CEM.xlsx

b. The cost savings are the O&M savings over the depreciable life of the installed assets. The O&M savings were developed by estimating the value of operational efficiency improvements such as the DMS system fault location predictions reducing the time required to locate faults, SCADA connected reclosers eliminating the need for some manual switching operations and SCADA connected reclosers permitting the remote application of caution cards.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 423

Responding Witness: John K. Wolfe

Q-423. Regarding Exhibit PWT-7, page 4, provide:

a. Background calculation for all entries in electronic format, preferably Excel, with active cells.

b. A detailed explanation of all cost savings and assumptions used in deriving cost savings.

A-423.

a. The DMS CEM Model was filed December 8th, 2016. Reference:

http://psc.ky.gov/PSC_WebNet/ViewCaseFilings.aspx?case=2016-00370

Att_KU_PSC_1-54_Exh_PWT-7_-_DMS_-_Updated_2016_CEM.xlsx

b. Cost savings were not included in the DMS CEM calculations.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 424

Responding Witness: Lonnie E. Bellar / John K. Wolfe

Q-424. Regarding Exhibit PWT-8, provide:

a. A detailed explanation of all projects.

b. Annual 5-year historic costs for each category from 2012 to 2016.

A-424.

a. For a detailed explanation of Automated Metering Systems refer to John P. Malloy testimony, pages 15-30.

For a detailed explanation of Distribution Automation refer to Paul W. Thompson testimony, Exhibit PWT-5, pages 24-25.

The Volt/Var Optimization "VVO" solution utilizes software and two-way communication with capacitor bank controls, load tap changers, and voltage regulator controls to provide real-time data, used to optimize voltage and power factor based on utility-selected parameters. Among the benefits of using VVO to achieve energy efficiency targets, it requires no change in customer behavior, requires no customer purchases or incentives, benefits all customer classes, and it reduces environmental impact.

For a detailed explanation of Control Houses refer to Paul W. Thompson testimony Exhibit PWT-2, page 34-36.

The Fiber/Telecom projects upgrade communications systems that are used to support substation devices that monitor and control the electric grid and automatically operate switching equipment in response to system conditions.

For a detailed explanation of Relay panels refer to Paul W. Thompson testimony Exhibit PWT-2 pages 36-37.

For a detailed explanation of RTU's refer to Paul W. Thompson testimony Exhibit PWT-2 pages 37-38.

For a detailed explanation of Switch – Auto refer to Paul W. Thompson testimony Exhibit PWT-2 pages 27-29.

For a detailed explanation of Switch: Motor Operated refer to Paul W. Thompson testimony Exhibit PWT-2 pages 27-29

b. See attached.

Smart Grid Investments
Historical
$000s

Project	2012	2013	2014	2015	2016
LG&E					
Distribution and Customer Services:					
Advanced Metering Systems					
Distribution Automation / DMS					
AMS Opt-in Program (DSM)				$ 1,196	$ 602
VOLT/VAR Optimization (DSM)					
VOLT/VAR Optimization Pilot (Non-DSM)					$ 205
Transmission:					
Control Houses	$ 1,439	$ 2,251	$ 732	$ (11)	$ -
Fiber/Telecom	$ -	$ -	$ -	$ -	$ -
Relay Panels	$ 91	$ 221	$ 816	$ 873	$ 567
RTU's	$ 9	$ 21	$ -	$ -	$ -
Switch - Auto					
Switch - Motor Operated	$ -	$ -	$ -	$ -	$ -
Total LG&E	$ 1,539	$ 2,493	$ 1,548	$ 2,058	$ 1,374

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 425

Responding Witness: John P. Malloy

Q-425. Regarding AMS benefits discussion beginning on page 24 of the Testimony of John P. Malloy, provide the following information regarding benefits related to enabling better localization and resolution of power outages:

a. All plans, software and communications planning documents related to providing AMS information to distribution and transmission operations.

b. A detailed explanation of how AMS information will be used to localize and resolve power outages including a description of information flow.

A-425.

a. The Company continues to define plans related to providing AMS information to distribution and transmission operations. See Appendix A-2 of Exhibit JPM-1 for an illustrative application architecture.

b. AMS meters are capable of sending power outage alerts to the Company in near-real time, enabling the Company to characterize more quickly outage locations and type. The outage alert would initiate at the electric meter, be communicated over the proposed infrastructure, be received by the AMS head-end software system, then be pushed to the proposed Meter Data Management System (MDMS) where it will then be reported to the Company's Outage Management System (OMS) to trigger response by Company personnel. The OMS system operates today based on customers calling or texting their outage in to the Company. As the Company receives multiple outage notifications it begins to hone in on the suspected outage source; this is where AMS information is expected to reduce crew time spent identifying outage locations.

.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 426

Responding Witness: John P. Malloy

Q-426. Regarding the Section 5.5 diagram at the top of page 13 of Exhibit JPM-1 provide the following information:

a. Detailed description of how information from customer services is transmitted to deployment operations including communication software from AMS to deployment operations to work orders or other field activities.

b. Detailed description of how information from the meter operations center is transmitted to deployment operations including communication software from AMS to deployment operations to work orders or other field activities.

c. Describe equipment, personnel, and facilities anticipated at the meter operations center.

A-426.

a. The diagram at the top of page 13 of Exhibit JPM-1 is meant to be illustrative. The Company continues to plan how information from customer services will be transmitted to deployment operations, but the Company anticipates frequent information exchange via file transfers and other electronic means.

b. The diagram at the top of page 13 of Exhibit JPM-1 is meant to be illustrative. The Company continues to plan how information from the meter operations center will be transmitted to deployment operations, but the Company anticipates frequent information exchange via file transfers and other electronic means.

c. The diagram at the top of page 13 of Exhibit JPM-1 is meant to be illustrative. See section 5.5.9 of Exhibit JPM-1 for a description of the metering operations center.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 427

Responding Witness: John P. Malloy

Q-427. Regarding discussion in Section 5.5.9 on page 20 of Exhibit JPM-1 describe how the proposed AMS system will communicate with ADA.

a. Will the AMS system being deployed communicate with the current planned distribution automation?

b. Explain how proposed AMS equipment is compatible with future ADA.

A-427.

a. The AMS system being deployed will communicate with planned distribution automation systems.

b. The proposed AMS communications infrastructure is capable of supporting multiple endpoint devices including, but not limited to, the currently proposed electric meters, gas indices, as well as load-control devices and a number of DA devices that could potentially be explored with future ADA.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 428

Responding Witness: John P. Malloy

Q-428. Regarding discussion in Section 5.7.2 of Exhibit JPM-1 describe how proposed AMS system will communicate with Volt/VAR optimization.

a. Describe the current a Volt/VAR optimization program or system and required AMS compatibility.

b. Describe future Volt/VAR optimization program or system and required AMS compatibility.

A-428.

a. The Companies will conduct a Volt/VAR Optimization pilot project in 2017 to gather data and evaluate the impacts to energy (kWh) and demand (kW) of a VVO system. The pilot project will be conducted at an LG&E substation on one transformer with two circuits. The pilot project will be conducted through the end of 2017.

b. The Companies may expand VVO to additional substations, and AMS data would be utilized as a data input. AMS data can provide approximately a 1% greater reduction in voltage, thus resulting in greater reductions in energy (kWh) and demand (kW) on the distribution circuit.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 429

Responding Witness: John P. Malloy

Q-429. Regarding discussion in Section 5.7.3 of Exhibit JPM-1 describe how proposed AMS system will communicate with FLISR.

a. Describe the current FLISR capability and required AMS compatibility.

b. Describe future FLISR capability and required AMS compatibility.

A-429. The Company does not currently have FLISR capability the AMS system has the capability to provide information for fault detection ability in the future.

a. Companies do not currently have FLISR capability.

b. FLISR is a module of the DMS software the Companies propose implementing as part of the DA Program. FLISR will identify the location of a fault and determine the optimal switching to safely isolate the fault and restore the most customers. Powerflow analysis is a prerequisite to performing FLISR. Data from AMS will be used by the DMS to assist in Powerflow analysis. If AMS data is not available, the Powerflow analysis is performed using load profiles.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 430

Responding Witness: John P. Malloy

Q-430. Regarding discussion in Section 5.7.3 of Exhibit JPM-1 describe how proposed AMS system will communicate with DERMS.

a. Describe the current DERMS and required AMS compatibility.

b. Describe future DERMS and required AMS compatibility.

A-430. The Company does not have a Distributed Energy Resource Management System.

a. Company does not currently utilize DERMS.

b. Company currently does not have plans to implement DERMS.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 431

Responding Witness: Lonnie E. Bellar

Q-431. Regarding the discussion on page 3 of the Testimony of Lonnie E. Bellar, provide detailed information regarding the customer service line ownership initiative.

A-431. Refer to Case Number 2012-0222, specifically Hermann Exhibit 1 – Gas Service Riser Replacement Program & Customer Service Ownership.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

**Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017**

Question No. 432

Responding Witness: Lonnie E. Bellar

Q-432. Regarding the discussion about the new gas pipeline in Bullitt County beginning on page 3 of the Testimony of Lonnie E. Bellar, provide the following information:

a. Maps showing the existing gas distribution system and the existing one-way feed.

b. Maps showing the proposed new gas pipeline.

c. Calculations showing the expected distribution pressures without the new pipeline and expected load growth.

d. Describe gas supplies to the affected customers both before and after the new pipeline.

A-432.

a. See the response to PSC 2-64(a).

b. See the response to PSC 2-64(a).

c. The gas supply for sections of Bullitt County including Mt. Washington, Shepherdsville, the Hwy 480 corridor, Clermont and Boston is supplied almost exclusively by an 8-inch diameter high pressure distribution pipeline (reducing to 6-inches near Clermont) originating from a gas regulation facility supplied by LG&E's Calvary gas transmission pipeline system in Mt. Washington effectively making the system a one-way, radial feed. The proposed pipeline will improve reliability for the customers supplied by this system by having a second geographically diverse gas supply to the system. Currently up to 9,500 customers could lose service if supply from the 8-inch high pressure distribution pipeline is lost due to third party damage or other reason. This project would provide a second supply to this area of the system mitigating the number of customers losing service. The high pressure distribution pipeline's available capacity has been almost fully utilized leading to the increased reliability concerns, as well as, limiting available capacity for growth in the area.

The high pressure distribution pipeline supplying gas to the system has a 275 psig maximum operating pressure (MAOP). Based upon the analysis of LG&E's gas system utilizing steady state gas system modeling software, Synergi Gas, completed in 2016 under design criteria without the new pipeline and without the expected load growth the high pressure distribution pipeline has a minimum pressure of approximately 93 psig occurring on the south end of the system in Boston. Normal growth that LG&E is required to serve by tariff over the next 2 years is expected to cause the high pressure distribution pipeline's minimum pressure to be below the system's design criteria.

d. Prior to constructing the proposed new pipeline the gas supply source for the affected customers is supplied almost exclusively by one source, the Mt. Washington high pressure regulator station. The Mt. Washington high pressure regulator station is supplied from a connection with the Calvary transmission pipeline in Mt. Washington.

After the proposed pipeline is constructed the gas system for the customers in this area will have a second supply from the Calvary gas transmission pipeline from an interconnection near the location where the Calvary gas transmission pipeline crosses Highway 480 and ending with an interconnection with the existing 8-inch high pressure distribution pipeline with an expected location between Hwy 480 and Hwy 245.

The proposed pipeline is expected to be completed in the Winter/Spring timeframe in 2019.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 433

Responding Witness: Lonnie E. Bellar

Q-433. Regarding the discussion on page 6 of the Testimony of Lonnie E. Bellar, provide detailed information regarding the advanced engine/compressor analyzer technology initiative.

A-433. LG&E utilizes the Windrock Model 6320/PA engine/compressor analyzer system to evaluate the performance and condition of gas compression equipment associated with underground gas storage system. The analyzer identifies poor fuel consumption factors, excessive exhaust factors, ignition system deficiencies, defective fuel injection valves, leaking intake/exhaust valves, defective piston rings, damaged bearings, damaged rod connecting pins, defective water and lube oil pumps, excessive vibration, and engine foundation damages on the engines driving gas compressors. The analyzer also identifies defective unloaders, excessive rod loadings, excessive cylinder liner wear, equipment pulsations, inadequate compressor rod reversals, loose compressor piston nuts, and excessive valve losses on gas compressors. The advanced analyzer system enables identification of engine/compressor performance issues and mechanical problems before costly damages occur and helps avoid unplanned outages impacting reliable gas supply from underground storage.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 434

Responding Witness: Lonnie E. Bellar

Q-434. Regarding the discussion on page 8 of the Testimony of Lonnie E. Bellar, provide detailed information regarding the Transmission Integrity Management Plan.

A-434. See the response to Question No. 252.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 435

Responding Witness: Lonnie E. Bellar

Q-435. Regarding the discussion on page 8 of the Testimony of Lonnie E. Bellar, provide detailed information regarding the Distribution Integrity Management Plan.

A-435. See the response to Question No. 250.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

**Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017**

Question No. 436

Responding Witness: Lonnie E. Bellar

Q-436. Regarding the discussion on page 18 of the Testimony of Lonnie E. Bellar, provide a detailed explanation, including anticipated annual work activities and associated costs, of why the first three years of the gas service line replacement program will cost $10 – 11 million annually and the last 12 years will cost approximately $4.5 – 7 million annually. Explanation should include the workplan and the rationale for front loading the program.

A-436. The accelerated rate of replacement in the first 3 years allows for a better transition of the current GLT Program contract work force and helps management of the resources for future work. It will also allow an opportunity to evaluate the project after this time frame to measure impact & success and if adjustments need to be made to the remaining program plan. The table below provides detail on work activity and costs. Note that the testimony stating spend in 2018-2020 would be $10-$11 million annually should be $9-$10 million annually.

PROGRAM PLANNED PRODUCTION				
Year	**Steel Services Per Year**	**County Loops Per Year**	**Curbed Services Per Year**	**Costs Per Year**
2018	3,375	333	1,467	$9,415
2019	3,394	333	1,467	$9,706
2020	3,412	333	1,467	$10,000
2021	2,024	--	--	$4,832
2022	2,041	--	--	$5,019
2023	2,058	--	--	$5,213
2024	2,074	--	--	$5,412
2025	2,091	--	--	$5,618
2026	2,106	--	--	$5,830
2027	2,122	--	--	$6,049

2028	2,137	--	--	$6,274
2029	2,151	--	--	$6,506
2030	2,165	--	--	$6,746
2031	2,179	--	--	$6,992
2032	2,193	--	--	$7,247
TOTALS	**35,521**	**1,000**	**4,400**	**$100,860**

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 437

Responding Witness: Lonnie E. Bellar

Q-437. Regarding the discussion on page 18 of the Testimony of Lonnie E. Bellar, provide a map of LG&E's gas transmission system and illustrate where the natural gas transmission pipeline segments being replaced are located as well as marked up to show the HCAs, Class 3 areas, Class 4 areas, and the MCAs.

A-437. See attached. The information in the attachment is confidential and is being provided under seal pursuant to a petition for confidential protection.

The entire attachment is Confidential and provided separately under seal.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information Dated January 11, 2017

Question No. 438

Responding Witness: Robert M. Conroy

Q-438. Regarding the discussion on page 35 of the Testimony of Robert M. Conroy, explain why LG&E is not seeking a CPCN for volt/var resources.

A-438. The Commission stated in its final order in Case No. 2012-00428, which was its most recent case concerning smart-grid standards, "With regard to CPCNs, the Commission finds it appropriate for jurisdictional electric utilities to obtain CPCNs for major AMR or AMI meter investments and distribution grid investments for DA, SCADA or volt/var resources."[7] LG&E does not believe its planned volt/VAR deployment is of sufficient scope to be "major" or otherwise require a CPCN; rather, it is an ordinary extension of its existing distribution system in the ordinary course of business that will not create wasteful duplication of plant, equipment, property, or facilities, or conflict with the existing certificates or service of other utilities, and will not involve sufficient capital outlay to materially affect the existing financial condition of LG&E.

[7] *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428, Order at 11 (Apr. 13, 2016).

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information Dated January 11, 2017

Question No. 439

Responding Witness: Robert M. Conroy / John P. Malloy

Q-439. Regarding the discussion on page 39 of the Testimony of Robert M. Conroy requesting a deviation from the quarterly meter reading requirement describe how LG&E proposes to make sure that meter reads from an AMS meter are properly assigned to the address of the customer. The description should include procedures in place to assure proper meter assignment as well as the process a customer would take if readings appear inappropriately assigned to an address.

A-439. While the mechanism by which meter reads are reported, over-the-air versus a manual read, is changing with the proposed AMS solution, the method by which the Company maintains customer records and assigned meters largely remains unchanged. Company's SAP Customer Care System (CCS) will remain the billing system so the process of assigning a meter read to an account will also remain.

Robust processes will be established and maintained to ensure meters are initially assigned to the proper address at the time of AMS meter installation. If a meter were to be removed and installed elsewhere, the AMS meters are capable of sending alerts when conditions indicating potential tampering has occurred. As a final level of security, meter numbers as well as current register readings are printed clearly on the face of the meter and the assigned meter is communicated to the customer each month on their bill. If a customer suspects readings are being inappropriately assigned to an address, they can follow existing procedures to request a meter re-read. Additionally, AMS will enable Company agents to ping and read meters in near real-time allowing them to tell customers what the current reading is and enabling immediate confirmation by the customer.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 440

Responding Witness: Lonnie E. Bellar / John K, Wolfe / Robert M. Conroy

Q-440. Regarding the response to PSC 1-12, provide the following:

a. Latest approved Integrated Resource Plan.

b. Latest 10-year plan for replacing key components in each power station.

c. Latest Transmission Expansion Plan.

d. Last 5 annual electric distribution plans.

e. Last 5 annual gas system plans.

A-440.

a. See the response to Question No. 296.

b. See attached.

c. See the response to Question No. 390.

d. For each of the last five years Electric Distribution Operations (EDO) has used the Asset Investment Strategy (AIS) decision-support model to compare the portfolio of diverse distribution capacity, resiliency and reliability projects to develop a five year Business Plan. The construction plan varies year to year based on load growth/reduction, changes in reliability needs and evolving programs to address system resiliency. See attached summaries for 2013-2017.

e. See attached.

Plant	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
MILL CREEK STATION	17,830,871	42,855,839	53,855,918	20,616,828	34,437,094	47,310,517	20,315,180	26,435,240	17,515,817	20,926,054
SIMPLE CYCLE		10,000								
TRIMBLE COUNTY STEAM	21,612,917	7,257,710	20,826,257	20,127,953	26,969,272	23,136,322	43,823,324	27,883,079	70,786,725	7,695,076
TRIMBLE COUNTY CTS	3,330,483	2,527,809	2,987,967	996,605	814,992	6,732,564	14,260,797	11,248,085	7,271,466	21,759,177
CANE RUN CCGT	910,860	52,434	43,500	38,840	55,541	56,706	57,872	59,037	60,202	61,367
TOTAL	43,685,132	52,703,792	77,713,643	41,780,227	62,276,899	77,236,110	78,457,173	65,625,441	95,634,210	50,441,674

Electric Distribution Operations Capital Business Plan
High Level Summary
Updated 8/26/16

EDO Budget Process

The Electric Distribution Operations (EDO) business plan consists of five strategic categories*: Connect New Customers, Enhance the Network, Maintain the Network, Repair the Network, and Miscellaneous*. Each category consists of identified projects and blanket projects.

Blanket projects cover anticipated annual routine work and equipment purchases where such work cannot be defined in advance. Work is typically driven by short cycle, high volume and often customer driven work requests and storm restoration. Blanket funding is trended from historical actual expenses, volumetric trends, and local economic indicators and is adjusted where necessary for known impacts such as system growth or increased equipment costs. Blanket projects include costs for connecting new customers, storm repairs, public works relocations, operation center driven reliability and enhancement work, and capital repairs or replacement of failed or damaged equipment.

Non-blanket projects are evaluated and prioritized in the Asset Investment Strategy (AIS) financial model and ranked using a benefit to cost methodology. Key components of the evaluation include capacity to serve, reliability and potential CAPEX/OPEX savings. Key strategic projects/programs such as the Pole Inspection and Treatment program (PITP), Aging Infrastructure (AI) programs, Reliability Initiatives, Capacity Enhancements and property are included in the model and may be classified as either non-discretionary or discretionary for evaluation purposes based on their strategic value. A technical review team of subject matter experts from various functional areas of EDO reviews and validates the project metrics for each project before projects are prioritized by AIS. The final plan is developed following reviews by EDO Directors and the VP, EDO and adjusted as necessary to address funding for key initiatives and strategies.

1. Connect New Customer Category

The Connect New Customer category largely consists of blanket projects spanning across the plan to cover the ongoing cost of extending electric facilities to serve new customers (or load). Equipment costs such as distribution poles, pad mount transformers and conductors also contribute to the cost for serving new customers (or load). Known major projects to serve new loads such as substation improvements or major circuit work for a single customer are identified separately, but do not occur in the plan every year. Funding for this category includes $67.7M in 2017, approximately a 3.5% ($2.3M) increase from the 2017 amount in the 2016 Business Plan ($65.3M). The variance is due in part to the addition of two large, unplanned LG&E network vault projects associated with the OMNI hotel ($902k), a new vault for the Homewood Suites ($250k) and an incremental need above the 2016 BP in 2017 to complete a substation transformer addition at Toyota South Substation ($300k).

There is an approximate 5% escalation for transformers across the plan. LG&E blanket escalation factors were assumed at 5% (accounting for growth and material/labor increases) and KU escalation assumed at 3% (accounting for growth and material/labor increases). The escalation factors are used in conjunction with historical spend trends, volumetric data, and local economic indicators as a means to forecasting future blanket needs. Major impacts and higher growth rates in the Louisville area have been realized which has been validated through economic data. LKE has seen a significant increase in New Business work requests from 2015 to 2016, especially in the LG&E area. KU as a whole has seen a slight increase in economic development which has been factored into the budget proposal. In total, New Business work requests have increased by 8% from 2015 to 2016 across LKE which is indicative of an increase is New Business activity.

Project Category/Code	2017 Proposed Plan	2018 Proposed Plan	2019 Proposed Plan	2020 Proposed Plan	2021 Proposed Plan
Connect New Customers					
New Business - Electric	50,852	53,695	56,380	58,538	60,784
New Business - Electric Major Projects	2,050	0	0	0	0
Purchase of Transformers	14,761	15,489	16,252	17,065	17,918
TOTAL Connect New Customers	**67,663**	**69,184**	**72,632**	**75,603**	**78,702**

2. Enhance the Network Category

The Enhance the Network category includes, blankets, major and minor system improvements required to serve growing load and to enhance the reliability, safety and/or durability of the system. Blanket funding for mandated work impacting existing facilities (such as blanket projects for relocations for public works and customer requested work pending reimbursements) is also included in this category. All enhancement work is further subdivided below into the categories of Enhancements to Meet Demand, Enhancements for Reliability, Mandated Relocations, and Customer Requested Projects.

Project Category/Code	2017 Proposed Plan	2018 Proposed Plan	2019 Proposed Plan	2020 Proposed Plan	2021 Proposed Plan
Enhance the Network					
Enhancements to Meet Demand	29,937	29,655	36,768	38,621	42,958
Enhancements for Reliability Improvements	23,864	38,484	35,687	34,666	35,019
Mandated Relocations (Public Works Improvements)	3,285	3,381	3,482	3,587	3,695
Customer Requested Projects	1,177	1,207	1,243	1,280	1,318
TOTAL Enhance the Network	**58,263**	**72,727**	**77,180**	**78,154**	**82,990**

<u>Enhancements to Meet Demand</u>

This category specifically addresses current loading issues or expected overloads, capacity additions for new load or contingency, expansion of SCADA, and other non-reliability system enhancements. This group of projects varies every year from the previously year's BP targets due to varying needs and priorities for capacity enhancements. A late addition to the plan in 2017 was necessary to serve an unplanned large new load (Corbin US Steel, $981k-2017) and increased funding for a Substation enhancement initiative (LG&E SMAC). Additional details of the Enhancements to Meet Demand subcategory are shown below.

Project Category/Code	2017 Proposed Plan	2018 Proposed Plan	2019 Proposed Plan	2020 Proposed Plan	2021 Proposed Plan
Total Enhancements to Meet Demand					
System Enhancement Blankets	2,347	2,405	2,466	2,540	2,616
Major Substation / Circuit Work Projects	19,567	19,466	24,015	25,794	27,055
N1DT Projects	7,245	7,506	10,000	10,000	13,000
Distribution Capacitors - LGE (For Transmission)	147	147	150	150	150
Distribution Capacitors - KU (For Transmission)	131	131	137	137	137
KU SCADA Expansion	499				
Total Enhancements to Meet Demand	**29,936**	**29,655**	**36,768**	**38,621**	**42,958**

- **System Enhancement Blankets**
  This item includes blanket funding at each distribution operations center to cover necessary, but currently undefined non-new business distribution system enhancements required each year. Funding is based on historical spend levels and starts at $2.3M in 2017 and is escalated approximately 3% across the plan.

- **Major Substation and Circuit Work Projects**
  Large, generally multiyear substation/circuit work projects are planned so that they can be completed in the year when the asset is forecasted to reach 95% - 100% of its "normal" seasonal operating limit including known or potential new loads. Also included are other enhancement projects that have demonstrated value. The forecasted load of large substation capacity enhancements projects is based on a 10-year non-coincidental substation load forecast which is updated annually and includes known new loads. Projects can also be placed in the plan when substations and circuits are at risk of exceeding their "emergency" operating limits under extreme weather events (such as the Polar Vortex of 2014 and Artic Blast of 2015) or where projects have substantial reliability benefits. The number of major new projects varies across the plan due to expected load growth (from the forecast) and/or expected system improvement benefits. Projects in the outer years of the plan may be adjusted forward or backward in future business plans based on actual load growth, funding

limits and the need to fund other more critical needs that develop in future years. This category also includes a late funding expansion for one major substation enhancement initiative to accelerate work on the Substation Monitoring and Control (SMAC) initiative. This project enhances the ability to control relays remotely at LG&E SCADA enabled stations reducing the OPEX costs associated with sending a Substation Operator to the station for manual operation. 2016 BP funding for SMAC of approximately $220k/year has been increased to $770k-2017, $1197k-2018 and $1410-2019 in an effort to accelerate completion of the program for LG&E in 3 years and recognize the associated operational savings. Another late addition to the plan was the second year of an approximately $1M project added to 2017 to complete a substation project at Corbin US steel due to unexpected new load growth.

A list of major projects through the first three years is shown below:

Project Name	2017	2018	2019	Project Name	2017	2018	2019
DSP American Ave Ckt 0008 Distribution Step Dow ns			185	DSP Oxford 2 Distribution			800
DSP American Ave Ckt 0008 Sw itchgear			105	DSP Oxford 2 Substation			960
DSP Black Branch Road Circuit 2477-Elizabethtow n Circuit 2462	353			DSP Paris 819-2 substation breaker addition	101		
DSP Buena Vista Upgrade		750	750	DSP Paris Circuit 805 circuit addition	225		
DSP Corbin Steel distribution	15			DSP Paynes Mill Road Substation- Distribution & Exit Feeders		359	
DSP Corbin US Steel Substation	966			DSP Paynes Mill Road Substation Project-Versailles	2101	2900	
DSP Delaplain 1 Ckt 0401 Distribution			120	DSP Pennington Gap Distribution			600
DSP Fariston 12KV Circuit Addition Project			123	DSP Pennington Gap Substation			1850
DSP Gene Substation (2018-2019)			2570	DSP Pepper Pike 138-12kV substation			2300
DSP Gene Substation Circuit Work (2018-2019)			380	DSP Radcliff South Circuit 2470 Re-conductor Project			147
DSP Georgetow n 12kV 2 Distribution			500	DSP Richmond North Substation Project	2200	1674	
DSP Georgetow n 12kV 2 Substation			2450	DSP Richmond North Substation Project Distribution		942	
DSP Hume Road Sub phase 2 distribution		1576		DSP Russell Corner Circuit Work (2017-2018)	701	400	
DSP Hume Road Substation Phase 2	2001	2301		DSP Russell Corner Substation Project (2017-2018)	3831	1820	
DSP IBM 1 Ckt 0057 Distribution			630	DSP Shelbyville North Breaker			75
DSP IBM 1 Ckt 0057 Substation Disconnects			29	DSP Shelbyville North Distribution			180
DSP Innovation Dr 2 Distribution Exit			341	DSP Simpsonville 1 Distribution			101
DSP Kenton to Wedonia Tie Circuit			273	DSP Simpsonville 1 Substation		751	750
DSP Law renceburg Substation Property Project	401			DSP St Paul 1 Ckt 0688 Breaker			81
DSP Law renceburg-Anderson County Substation Project			2000	DSP Viley 2 Distribution	600	600	
DSP Middlesboro 1 4kV 124-5 Distribution Conversion			100	DSP Viley 2 Substation	2210	1999	
DSP Middlesboro 1 4kV 124-5 Substation Conversion		700	300	DSP Wedonia circuit 965 reconductor			450
DSP Moorman 2.4KV to 7.2KV Conversion Project	118			DSP West Hickman transformer addition distribution	106		
DSP Mt. Sterling Substation Distribution			200	DSP West Hickman transformer addition year 2	1375		
DSP Mt. Sterling Substation Project			1226	DSP Wilson Dow ning 2 Substation Upgrade			1430
DSP Mt. Vernon Substation Project	1099	1101		SCM LGE MODIFY CANE RUN PLANT 14KV SUBSTATION	399		
DSP Mt. Vernon Substation Project Distribution		400		SCM RAP LGE SMAC PROJECT	771	1195	1410
DSP Oxford 1 Ckt 0471 Distribution			599	**Total Major Substation/Circuit**	**19572**	**19468**	**24019**

- **N-1 Distribution Transformers (N1DT):**
  The N1DT program was introduced in the 2014 BP to address substations that cannot be restored in the event of a transformer outage or failure during any portion of the year. During these outages some customers could experience outages greater than 24 hours until the equipment is replaced or a portable transformer is installed. Funding included $2.5M in the 2014 BP for work beginning in 2015 escalated across the plan and was expected to address an average of two projects over two years. Funding levels, scope and program length evolved over the 2015 and 2016 BP and this initiative is now a 15 year, $175M program.

  This initiative targets large, high impact substations in a priority rank order and includes substation/circuit upgrades, capacity additions and enhancements at critical substations for the purpose of adding contingency for substation transformer failures and outages. Targeted substations are stations where large numbers of customers or critical loads will be without service for extended periods of time during transformer failures/outages due to lack of contingency from area stations. This initiative is separate from capacity additions to serve existing customers although it also often addresses near term loading issues in addition to contingency. It also provides additional capacity necessary to support the long term goals of the Distribution Automation initiative. Projects are prioritized in a prioritization model using a benefit to cost methodology similar to AIS. Projects are evaluated on factors such as the number of transformers a project will remove from the N1DT list, load at risk, percent of year the load is at risk, customers served (by type), age of the power transformer, availability of property and other factors. The first two major projects, both at KU, will be completed in 2016 (Lakeshore and Innovation Drive).

Two recent revisions to the originally envisioned strategy for the program have been made. First, all new major capacity enhancements are now evaluated to also include a contingency provision for substation transformer failures. Where the incremental cost to gain contingency has high benefit/cost value and scores highly in the N1DT prioritization model, the incremental cost component for contingency can be funded with a reallocation of N1DT funding. This process has funded the contingency portion of three projects, Central City, West Hickman and Corbin US Steel.

The second revision to the program was the implementation of a project in 2016 to address reducing outage duration at more rural KU stations not currently targeted under this program. The N1DT Spares and Portables project, completes in 2017 and provides for two new, midsize portable transformers to be purchased and staged in Earlington and Pineville to better address transformer failures (Two KU's portables are currently shared and stationed in Lexington). The project also includes the purchase of additional spare transformers, and transformer components to speed restoration response in more rural KU areas. The project required additional funding in 2017 (above the $636k included in the original submission of the proposed 2017 BP) in the amount of $545k creating a variance to plan.

Planned spending on N1DT included in the proposed 2017 BP targets the projects listed below. However, projects actually addressed will likely change based on the potential to fund the incremental redundancy portion of capacity projects to achieve N1DT objectives at high benefit to cost ratio.

Start Year	First Year Project Name	2017	2018	2019	2020	2021
2017	N1DT Portables & Spares	1181				
2017	N1DT STR Highland Substation Property	700				
2017	N1DT STR Plainview Circuit Work	1110	2190			
2017	N1DT STR Plainview Substation Project	1600	3165			
2017	N1DT STR Stonewall 2 Distribution	314	486			
2017	N1DT STR Stonewall 2 Substation	1565	1665			
2017	N1DT STR West Hickman transformer addition year 2 - N1DT portion	775				
2019	N1DT STR Dixie Circuit Work			1200	300	
2019	N1DT STR Dixie Substation Project			3000	1000	
2019	N1DT STR Ashby Circuit Work			1200	800	
2019	N1DT STR Ashby Substation Project			3000	1000	
2019	N1DT STR Crestwood Area Property			800		
2019	N1DT STR Mud Lane/Smyrna Area Property			800		
2020	N1DT STR Mud Lane/Smyrna Area Circuit Work				600	1400
2020	N1DT STR Mud Lane/Smyrna Area Substation Project				2600	2952
2020	N1DT STR Crestwood Circuit Work				500	1000
2020	N1DT STR Crestwood Substation Project				2000	2000
2020	N1DT STR Mud Hikes Lane Area Property				1200	
2021	N1DT STR Breckenridge Circuit Work					300
2021	N1DT STR Breckenridge Substation Project					1500
2021	N1DT STR Ethel Circuit Work					300
2021	N1DT STR Ethel Substation Project					1200
2021	N1DT STR Kenwood Circuit Work					488
2021	N1DT STR Kenwood Substation Project					1500
2021	N1DT STR P&G Ckt 0066 Breaker					360
	Total N1DT By Year	7245	7506	10000	10000	13000

- **KU SCADA Expansion**
  Plans for a significant expansion of SCADA in KU substations first proposed in the 2014 BP at $5M/year has been deferred to allow for effective integration with the Distribution Automation initiative. In both the 2015 and 2016 BP's, $500k was retained in the first year to allow for the installation of cell enabled meters in non-SCADA KU substations to allow remote monitoring of substation transformer loads. This capability will allow better management of the distribution system under contingency and extreme whether events. Funding in both 2015 and 2016 was released when the promised cell enabled technology compatible with the current LG&E/KU AMI mesh type network and meter head end system did not come to market and funding is again requested in the 2017 BP because of its high value relative to cost. Currently, only 15% of KU Substations have SCADA whereas LG&E 12kV and 14kV substations are 100% SCADA equipped.

- **Distribution Capacitors**
  This program was added to the 2014 BP to provide for the new installation of distribution capacitors targeted to help improve the transmission system power factor. This work was funded in the past by Transmission but the budget was transferred to EDO in 2015 where it will be carried forward. Target areas for power factor improvement are prioritized by Transmission Planning and projects are scheduled to be online near midyear in time for summer peak when the need for power factor support is greatest. This program is also tied with annual inspections and repair and maintenance work on existing capacitors.

Enhancements for Reliability Improvements

This category addresses day to day reliability needs and select, high value Major Reliability initiatives and individual projects to address ongoing system reliability issues. It also includes funding for Distribution Automation (DA) and the implementation of a Distribution Management System (DMS) needed to make a step change improvement in reliability to address growing customer expectations for reliable service. Significant funding changes have been made to the Reliability portfolio in the proposed 2017 BP, including a rebalancing of programs that address ongoing reliability issues and an acceleration of the DA/DMS implementation plan from a 10 year implementation in the 2016 BP to 7 year implementation in the proposed 2017 BP. These changes, along with late additions to the plan have resulted in variances in Enhancements for Reliability when compared to the 2016 BP.

Project Category/Code	2017	2018	2019	2020	2021
Total Enhancements for Reliability					
Proposed 2017 BP	23,864	38,484	35,687	34,666	35,019
2016 BP Targets (includes 2016BP Rear Easement Hardening *)	18,841	26,518	26,652	27,639	28,330
Total Variance	5,024	11,966	9,035	7,027	6,689

*2016BP amounts 2017-2021 $17,789, $25,441, $25,548, $26,507, $27,169 before including $526k each for LG&E and KU from Rear Easement Hardening

Reactive Reliability Programs

In addition to blanket funding needed to address customer driven day to day reliability needs, the 2017 BP plans continues two major programs of strategic value, CEMI (Customers Experiencing Multiple Interruptions) and CIFI (Circuits Identified for Improvement) at both LG&E and KU. A new category, System Hardening has also been added to address high value reliability improvements on circuits not ranking high under CEMI or CIFI. This category includes funding previously falling under a category called Major Reliability Projects in the 2016 BP. A previous initiative in the 2016 BP targeting poor performing small conductor tap lines, named Rear Easement Hardening (+/- $1M/year) has been moved from the Aging Infrastructure category and the funding incorporated under System Hardening because the program's objectives were primarily reliability, and not age focused. Funding between CEMI, CIFI and now System Hardening has been rebalanced to maximize the benefits of the reliability portfolio due to declining benefits and increasing costs under the traditional CIFI program. This collection of Reliability initiatives in total was consistent with the 2016 BP targets before late additions to the plan although the mix within the individual programs has been changed.

Project Category/Code	2017 Proposed Plan	2018 Proposed Plan	2019 Proposed Plan	2020 Proposed Plan	2021 Proposed Plan
Ongoing Reliability Initiatives					
Reliability Improvements - Blanket	1,943	2,016	2,081	2,143	2,208
CEMI>5 Circuits - KU 24 Circuits 2016	825	846	867	888	911
CEMI>5 Circuits - LGE 14 Circuits 2016	425	436	447	458	469
CIFI (worst) Circuits - KU 2016	2,620	2,167	2,042	1,500	1,500
CIFI (worst) Circuits - LGE 2016	3,495	2,000	1,750	1,250	1,250
Enhanced Tap Line Coordination Program	1,000	1,000	1,000	1,000	1,000
System Hardening	4,306	4,770	5,500	6,427	7,031
Total Ongoing Reliability Initiatives	**14,614**	**13,235**	**13,687**	**13,666**	**14,369**

Reliability Improvement Blankets

The Reliability improvement blanket includes funding across the plan that is used to address upcoming reliability issues at the operations centers and unplanned small scale projects to target reliability improvement and/or safety and resiliency of the system. Blankets cover general distribution reliability improvements at the center level driven by customer complaints and abrupt downturns in reliability performance. The proposed 2017 BP plan is approximately $200k above the 2016 BP across the plan. Funding is escalated 3% across the plan.

- **CEMI>5**
  CEMI (Customers Experiencing Multiple Interruptions) is a reoccurring initiative to address circuits whose customers exceeded more than 7 outages in 2015 (CEMI is a one year look). The 2017 BP slightly increases spending under CEMI from the 2016 BP which included $600k for KU and $350k for LG&E. Similar to the CIFI program, total amounts vary by plan cycle based on the number of circuits impacted and by actual circuit performance across both utilities. Funding is escalated 2.5% across the plan.

  Two new sub-initiatives have been incorporated under CEMI in the 2017 BP. Funding has been included under the 2017 CEMI program to address Recurring Outage Devices (RODs) and to address unfused tap lines. RODs contribute significantly to CEMI customers and are protective devices that have operated frequently interrupting service to customers. Addressing these devices will have a favorable benefit on effectively reducing CEMI customers on the LGE/KU system. In addition, following a GIS query it was determined that 783 LG&E and 7,147 KU single or multi-phase taps do not have dedicated protective devices installed to sectionalize them in the event of a fault. Funding under CEMI will target the installation of 50 tap line fuses in LGE and 100 in KU. An effort will be made in 2017 to define the scope of a project to address all unfused taps in LGE/KU. Installation of tap line fuse provides excellent return on investment by reducing the risk of a larger outage with minimal cost. It also improves the safety of tap lines.

- **CIFI (worst performing) Circuits**
  This initiative covers reactive reliability improvement work on circuits that are prioritized based on each circuit's 5 year average SAIFI performance. CIFI circuit improvements include updating line protective coordination and targeted aging asset replacements where reliability is negatively impacted. Variances to the 2016 BP are a decrease for KU of $1,480k and a decrease for LG&E of $349k. This initiative has proven performance and value as seen by circuit SAIDI/SAIFI before/after metrics but future business plans will likely show reduced funding in this category to address diminishing returns for each dollar spent. Total amounts vary in each plan cycle by the number of circuits targeted and by actual circuit performance across both utilities.

  In addition, the proposed 2017 BP includes specific projects to be funded from the CIFI program budget. These projects include Dixie 1224 circuit addition, UPS Worldport Underground Cable Replacement and Sectionalization project for LGE and the Liberty tie circuit in Casey County, KY for KU. CIFI projects provide a clear value to the customer and company and were recommended by the 2017 AIS project evaluation team after ranking highly against other projects. Late additions to the plan included an incremental $800k to support an expanded scope for the UPS Worldport Underground Cable Replacement and Sectionalization project (above the $700k already incorporated under the proposed 2017 plan) and $1M/year across the plan to support increased Tap Line Coordination work (listed as a separate item).

- **System Hardening**
  The system hardening initiative focuses on rear easement hardening, conductor upgrades, and circuit relocations. Generally, rear easement hardening covers the rehabilitation or relocation of older, storm sensitive overhead lines in difficult to maintain rear easements where they have demonstrated poor reliability or storm performance. Aspects of this program include replacement of undersized and/or defective small wire, stronger and/or taller poles, selective undergrounding, storm guying, elimination of secondary, replacement of aged and defective equipment, and/or relocations of lines to less problematic areas. System hardening projects are prioritized based on AIS rankings. Project funding comes from the previous Major Reliability Projects (funding varied by year), Rear Easement Hardening (2016 BP +/- $1M) and funding targeted as CIFI improvements in previous plans.

- **Distribution Automation**
  Funding for this initiative has been accelerated from a 10 year implementation plan to a 7 year implementation plan resulting in the following variances to the 2016 BP.

Project Category/Code	2017	2018	2019	2020	2021
Total Distribution Automation					
Proposed 2017 BP	9,250	25,250	22,000	21,000	20,650
2016 BP Targets	5,804	14,070	13,750	13,750	13,750
Total Variance	(3,446)	(11,180)	(8,250)	(7,250)	(6,900)

DA (Distribution Automation) is the extension of intelligent control of the electrical power grid functions to the electric distribution level. Intelligent control of distribution equipment will provide near real-time information from the distribution system and allow for the remote control and automation of distribution line equipment. The proposed DA program will install electronic Distribution SCADA (Supervisory Control and Data Acquisition) connected reclosers to improve reliability by remote monitoring and control, segmentation of feeders, and “self-healing” of the distribution system. For customers, this means fewer outages and faster restoration times.

Previously a 10 year implementation plan in the 2016 BP, the proposed DA program is now a 7-year initiative beginning in 2016. The scope includes the implementation of a DSCADA (Distribution SCADA) system integrated with a DMS (Distribution Management System) and the installation of approximately 1,450 DSCADA connected electronic reclosers. This change in in the implementation plan is requested to achieve the next step change in Reliability (SAIDI SAIFI improvement) for Electric Distribution. This new initiative begins with the installation of SCADA controlled electronic reclosers which provide an immediate reliability benefit on select circuits beginning in 2017. The installation and turn-up of Distribution SCADA (DSCADA) and a Distribution Management System (DMS) allowing LG&E/KU to begin implementing FLISR (automatic Fault Location, Isolation, and Service Restoration) of field devices. Funding for this program varies across the years depending on the number of reclosers installed and circuits completed and available resources (both internal and external). Headcount to support this initiative is included in the WFP beginning in 2017. A communication study will be completed in 2016 prior to any new recloser installations (recloser install begins in 2017).

Public Works, Mandated Relocations and Customer Requested Projects
These categories cover alterations or relocation of distribution facilities to accommodate public works projects and provides funding for customer requested facility relocations prior to reimbursement by customers. This item is funded based on historical spend levels and includes a 3% escalation across the plan.

3. Maintain the Network Category

The Maintain the Network category includes capital blanket and project specific funding to maintain the condition of the system, replace failed or defective distribution and substation equipment, and specific projects to address aging infrastructure. Work specific to maintain, repair and replace distribution equipment is broken into the four main categories listed in the table below and covers distribution lines, substations, street lighting, distribution relocation work driven by transmission projects, and substation buildings and grounds. One new sub-category was added to the 2017 BP to address non-reimbursable pole replacement work that is expected to be driven by large fiber deployments under initiatives like Google, KYWired, and Fibertech. Transmission reliability and compliance work is also driving enhanced funding needs for unidentified projects and new/additional funding for defined distribution projects that did not appear in the 2016 BP.

Project Category/Code	2017 Proposed Plan	2018 Proposed Plan	2019 Proposed Plan	2020 Proposed Plan	2021 Proposed Plan
Maintain the Network					
Repair/Replace Defective Equipment (Incl. Substation Maint.)	34,224	34,392	38,793	37,096	37,529
Fiber Non-Reimbursable R/R Defective Equip	2,980	2,093	2,000	2,000	2,000
Aging Infrastructure - Distribution and Substation	15,577	15,923	16,285	14,620	15,003
Aging Infrastructure - Pole Inspection and Treatment Program	11,573	11,920	12,278	12,646	13,026
TOTAL Maintain the Network	**64,354**	**64,328**	**69,356**	**66,362**	**67,558**

<u>Maintain the Network - Repair/Replace Defective Equipment (Incl. Substation Maint)</u>

Repair/Replace Defective equipment consists of blankets and specific projects in seven categories covering defective or failed equipment in substations and on lines. Substation categories cover work to replaced failed equipment, address wildlife, lightning and code compliance issues, repair building and grounds and oil containment improvements/repairs. The Distribution Lines category of repair/replace includes blanket funds for reactive replacement of failed or defective overhead and underground equipment, cable, vaults and manholes, padmounted switchgear, distribution facility relocation work driven by increase in Transmission upgrades and compliance initiatives, and any major, identifiable repair/replace projects.

Project Category/Code	2017 Proposed Plan	2018 Proposed Plan	2019 Proposed Plan	2020 Proposed Plan	2021 Proposed Plan
Maintain the Network – Repair/Replace Defective Equipment					
Repair/Replace Defective Equipment - Substation Maintenance	3,098	3,122	3,904	3,280	3,362
Repair/Replace Defective Equipment - Substation Portable Transformer			2,255	308	
Repair/Replace Defective Equipment - Transmission Line Clearance	758	766	773	782	790
Repair/Replace Defective Equipment - Blankets	29,429	30,311	31,264	32,202	33,168
LEO Padmount Switchgear R/R	189	194	199	204	209
Repair/Replace Defective Equipment - Major Projects	550		398	320	
Distribution Crossing Relocations for NRP	200				
TOTAL *Repair/Replace Defective Equipment*	**34,224**	**34,393**	**38,793**	**37,096**	**37,529**

- **Repair and Replace Defective Equipment Blankets – Substation Maintenance**
  This grouping of projects covers the cost of reactive repair and replacement of defective substation equipment at each substation operations center. Specifically, these projects include the replacement of failed equipment that cannot be effectively repaired, wildlife protection at unprotected stations, upgrades for compliance (NESC, cooling fans, oil containment capital repairs), building and grounds repairs, and minor improvements to reduce future maintenance/repair (transformer oil filtration, addition of lightning protection). 2019 spending is escalated above the 2016 BP plan by three separate, specific substation repair projects (Pocket, Tom's Creek and St. Charles). Other years are essentially to the 2016 BP.

- **Purchase KU Portable Transformer**
  Funding for this project was in the 2016 BP for 2017 ($2.2M) and 2018 ($200k). The 2017/2018 project was to purchase a large portable transformer for the Lexington Operations area to support outage restoration and planned maintenance work on larger transformers. The purchase of an additional portable transformer (KU currently only has one large portable) for KU was seen as needed to minimize outage duration caused by larger substation transformer failures where quick restoration cannot be accomplished by a direct replacement with a spare transformer. Midyear 2016, funding for this project was reallocated to support the N1DT Spares and Portable Transformer project for contingency for the more rural KU areas. A need was still seen during the business planning cycle for a large new portable for the Lexington area and this project was resubmitted in AIS with purchase planned in 2019 and 2020.

- **Transmission Line Clearance**
  This blanket level funding is used to cover the cost of undefined distribution line relocations and upgrades during the year driven by Transmission pole replacements, relocations and compliance directed (NERC) clearance projects. Funding in the 2016 BP was approximately $300k split between KU and LG&E. A late addition to the plan added $450k to this category increasing funding to approximately $750k/year. The increase is necessary to address distribution work driven by increased transmission pole replacements and clearance work. This category is escalated approx. 1%/year across the plan.

- **Repair and Replace Defective Distribution Equipment Blankets - Lines**
  This blanket item covers the cost of repairing and replacing defective overhead and underground distribution line material and equipment at each operations center. Maintenance repairs and replacement of capacitors, poles, cable, vaults, and street lighting are included in this category. Funding is based on historical spend levels and is escalated at 3%/year across the plan.

- **Louisville Electric Operations Padmount Switchgear**
  This program replaces aged and defective, high risk padmounted switchgear in underground commercial and large residential areas that has been identified during system inspections. The program is necessary to address increasing failure rates on highly deteriorated equipment and to replace equipment that cannot be effectively maintained. This program covers approximately 10 padmount switchgear replacements per year.

- **Repair and Replace Defective Equipment Major Projects**
  This category covers major projects targeting defective distribution equipment not covered under other categories, including large planned transmission driven distribution upgrades and relocations. 2019 funding consists of two distribution projects in different KU Operations centers to remove portions of the same out of service line (Roundhill) that has become an operational concern ($238k). Two large planned transmission upgrades are also included. The 2017 Lexington Plant-Pisgah project was a late addition to the plan ($550k) and a planned relocation for transmission line in the Shelbyville Operations center in 2019 and 2020 ($160/$320k-2019/2020).

- **Distribution Crossing Relocations for NERC Rating Program (NRP)**
  This project was a late addition to the plan that involves distribution relocations or undergrounding for LG&E and KU to address transmission clearance conflicts at distribution crossings. The distribution work, where more cost effective than transmission improvements, could involve line relocation or placing the lines underground in the span where the conflict exists. This one time initiative is funded at $200k for 2017 to clear up previously identified conflicts.

Maintain the Network - Fiber Non-Reimbursable R/R Defective Equipment

This category is new to the 2017 BP and covers non-reimbursable distribution work associated with anticipated large fiber network buildouts by Google, KYWired, and Fibertech. Large fiber deployments include reimbursable and non-reimbursable distribution work. Reimbursable work is not budgeted as costs are recovered - work includes pole replacements for clearance or strength and other make ready work to allow new attachments. Non-reimbursable work includes corrections identified while assessing the system as part of the approval process for new attachments where the corrections are the responsibility of the utility. This includes the replacement of defective poles and pre-attachment overloaded poles as well as preexisting clearance violations. $2M is included across the plan for a potential Google deployment. $198k is included in the first two years of the plan for the KYwired deployment at KU ($170k/20k - 2017/2018) and $600k for LG&E/KU ($527/$73- 2017/2018). $275k is included in the plan in 2017 for the Fibertech deployment at LG&E.

Maintain the Network - Aging Infrastructure Distribution and Substation

EDO's Aging Infrastructure programs fall into three broad areas, LG&E's Downtown Network System, Substations Equipment and Distribution Cable Systems. Aging infrastructure initiatives are driven by available data by age, quantity in service, failure data, field experience, equipment specialty knowledge, and industry best practices. O&M considerations are cost to maintain, availability of spare parts, and environmental considerations. The age of the distribution system and increasing failure rates has necessitated beginning and/or consistently funding replacement and/or rehabilitation programs. These programs target critical distribution assets that are beyond their expected life expectancy in areas where they have resulted in declining reliability or unacceptable risk. Central downtown Louisville infrastructure in the Network area was originally built in the early 1900's and many of the manholes, duct, vaults and cable are approaching or exceeding 100 years old. In General, robust system expansion in the 1960's and 1970's has created substantially high groups of equipment and material, in particular underground cables with similar age and created the potential for very high failure rates in future years if not addressed incrementally. Critical substation equipment continues to age beyond expected life and is becoming less reliable while increasing the operational expenses necessary to maintain the equipment.

Funding is included in the plan to continue major strategic infrastructure enhancement programs addressing PILC Replacement, Legacy Substation Equipment, aging cable systems and other poor performing or high risk distribution facilities. For the 2017 BP, two new, and three expanded programs are funded. Four of the five changes address deterioration of the downtown network system infrastructure. Increased need and late additions to the plan drive variances in each year in several categories.

- LEO Downtown Network Vault Structural Repairs: +/- $900k in additional funding for existing program to address backlog of critical network vault structural repairs.
- LEO Manhole Structural Repairs: New +/- $213k item to address growing backlog of manhole structural issues found under the PILC program.
- PILC Cable Replacement: $500k incremental added to existing program to address increased need to replace duct as part of the PILC program.
- PILC Cable Replacement - Curb to Curb Paving: New $700k item to plan to address potentially high repaving costs driven by increased duct work under the PILC program due to changes to the Metro Louisville Asset Management program which now requires curb-curb paving.
- URD Cable Rejuvenation Program (KU & LG&E): $1.2M Incremental to accelerate the pace of URD cable rejuvenation to further reduce the rate of failure and potentially initiate a reduction in operating costs to address ongoing failures.

A description of major programs are listed below and are grouped by Network Systems, Substation Renewal and Cable Systems.

Network System Aging Infrastructure Programs

There are five separate network Aging Infrastructure initiatives in the plan for LG&E, including expanded funding for vault structural repairs and PILC and a new initiative targeting structural deficient manholes. One late addition to the plan was incremental funding to address new Metro Louisville Asset Management requirements that are likely to drive a significant increase in the cost to install duct in the Network by requiring curb-curb repaving for street cuts. Many of the cable systems, manholes and vaults in the network date to the early 1900's and are being found in increasingly poor condition.

Project Category/Code	2017 Proposed Plan	2018 Proposed Plan	2019 Proposed Plan	2020 Proposed Plan	2021 Proposed Plan
Aging Infrastructure – Network					
PILC Cable Replacement	6,866	7,056	7,253	6,957	7,165
PILC Cable Replacement - Curb to Curb Paving (new)	700	700	700	700	700
LEO Downtown Network Vault Structural Repairs (expanded)	1,200	1,230	1,261	1,292	1,325
LEO Manhole Structural Repairs (new)	213	218	224	229	235
Downtown Network Vent Type Protector Replacement	500	513	525	538	552
TOTAL Aging Infrastructure Network	**9,479**	**9,717**	**9,963**	**9,716**	**9,977**

- **Paper Insulated Lead Covered (PILC) Cable Replacement**
  This program continues work started in 2013 and involves the replacement of primary and secondary PILC cable in the downtown network to address increasing reliability and safety concerns. This $62M, 11 year program is scheduled to complete in 2023. Under this program approximately 7 miles of PILC cable is planned for replacement each year until program completion. Targeted cable is between 50 and 90+ years old and the program includes the cost for new duct

systems where existing duct systems are not adequate or usable which is increasingly being found to be the case. Program scope and funding has evolved, as follows:

- 2013: Initiated program at $2M for 20 years to fund cable replacement (escalated by 2.5% per year).
- 2014: BP included funding of $4M ($2M incremental escalated at 2.5% per year) to accelerate the program before adding an additional $2M ($6M total) to further accelerate the program and address higher than expected duct and manhole repairs and replacements. Shortening the program from 20 to 10 additional years is necessary because data does not exist to target the oldest cables first and some cable will be in excess of 100 years old by the time it is replaced.
- 2015 – Current: Continue funding at $6+M escalated level for 9 additional years with projected completion in 2023 (escalated by 3% per year). Significant levels of manhole and duct line structure deterioration encountered during the program has the potential to accelerate the program beyond the current 10 year replacement program. The program continues to validate and quantify remaining targeted assets.
- An additional $500k was added to the plan above 2016 BP targets to address increasing duct replacement costs.

- **PILC Cable Replacement - Curb to Curb Paving**
  This new item addresses changes implemented in 2016 under Metro Louisville's Asset Management requirements governing utility work in public rights of way in the downtown area. New requirements for work in public roadways will no longer allow for partial repaving for larger street cuts typically associated with duct line replacement work under the PILC replacement program. The majority of network cables reside in the street and new requirements require curb-curb paving as part of the street restoration process for open cuts. It is unknown at this time how rigorously the new requirements will be enforced. Increasingly, PILC cable replacement is requiring the installation of new duct because of the lack of spare, open duct or because the existing duct system has collapsed or deformed and will not allow existing cables to be removed or new cables to be installed. Under these conditions, streets must be cut and excavated and new duct installed. $700k in incremental funding was added to the 2017 BP to address expected incremental costs to the PILC program to stay on its current completion schedule in 2023.

- **Louisville Electric Downtown Network Vault Structural Repairs**
  This proactive program targets necessary repair and replacement of deteriorated vault structures including vault tops and ventilated openings (in sidewalks), steel ceiling header beams, and deteriorated brick and concrete walls in downtown Louisville Network vaults that have deteriorated as a result of age and deicing salts. The program originally targeted only vault top replacements; however, increasingly significant deficiencies are also being found in vault structural walls and supports requiring an increased cost for repair. Deteriorated vault structures, if not repaired, increase the risks to public safety, damage to high cost network transformers and equipment located in the vaults, and network service reliability. Funding has been increased in the 2017BP ($1.2M) over the 2016BP level ($283k) due to rapidly growing backlog of defective vaults. Deteriorated structural conditions are noted on periodic inspections and are reviewed by a structural engineering consulting firm to determine the type and priority of repair and replacement needed. Requested funding will typically allow the repair of 2-3 vault top replacements and 2-3 vault support structural repairs depending on the size of the vaults and the nature of the defects. There are currently 190 vaults in the downtown Louisville network.

- **Louisville Electric Downtown Network Manhole Structural**
  This new, proactive program targets necessary repair and replacement of a growing backlog of deteriorated manhole structures including cracked ceilings, sagging and caved-in brick and concrete walls, sinking floors, and corroded structural hardware as a result of years of settling soils from sewer and water main breaks, vibration from surface traffic, and deicing salts. Deteriorated manhole structures, if not repaired, increase the risk to public safety and network service reliability. This is a new project in the 2017 BP ($213k) in response to a growing list of deteriorated manholes found during PILC program work and through periodic inspections. Deteriorated manholes are reviewed by a structural engineering consulting firm to determine the type and priority of repair and replacement needed. Requested funding will typically allow the repair of 14 manholes at approximately $15k/manhole depending on varying conditions. There are currently more than 900 manholes in the downtown Louisville network area with many dating to the early 1900's.

- **DT Network Vent Type Protector Replacement**
  This program has been in the plan for several years and is funded to begin at $500k in 2017 with a growth of 2.5% across the plan. This program initiates the replacement of aged network protectors that are not submersible rated for below ground application in vaults subject to corrosion damage from sidewalk deicing agents and occasional flooding from

heavy rains and water main breaks. The program will address the most critical of these assets and further enhance the integrity of the downtown network in conjunction with other current or past network aging infrastructure programs (PILC, manhole lids, SCADA/AMI, vault/manhole repairs, etc.). Funding is consistent with the 2016 BP.

Substation Aging Infrastructure Programs

This collection of programs covers the annual replacement of aged, critical, maintenance intensive, unreliable substation equipment and/or equipment nearing obsolescence. These programs include equipment such as substation batteries, protective relays, 15kV and 34kV power circuit breakers, Remote Terminal Units, cap and pin insulators, Load Tap Changers (LTC), and regulator controls. In 2012, Substation Construction and Maintenance identified a "Top 5 List" for both LG&E and KU based on a combination of advanced age, chronic operational issues, quantity in service, field experience, and equipment specialty knowledge. O&M considerations are cost to maintain, availability of spare parts, and environmental considerations. The Substation Aging Infrastructure programs have been in past business plans but funding levels have varied in the individual initiatives due to capital funding constraints and as program initiatives are completed and new ones are identified. Funding needs vary somewhat each year as program initiatives are completed and new ones are identified. The group as a whole is relatively level to the 2016 BP except for Power Circuit Breakers where the 34kV breaker program completes in 2019 creating a positive variance.

Project Category/Code	2017 Proposed Plan	2018 Proposed Plan	2019 Proposed Plan	2020 Proposed Plan	2021 Proposed Plan
Aging Infrastructure – Substations					
Substation - Power Circuit Breakers	1,471	1,493	1,522	1,214	1,245
Substation - Batteries	209	214	220	224	229
Substation - Electromechanical Relays	146	150	153	157	161
Substation - Load Tap Changers and LTC Controllers	103	106	108	111	114
Substation - Remote Terminal Units	310	318	326	334	342
Substation - Cap and Pin Insulator Upgrade	157	161	165	169	173
Substation - ABB VHK MECH	50	51	53	54	55
TOTAL Aging Infrastructure Substations	**2,446**	**2,493**	**2,547**	**2,263**	**2,319**

Underground Cable System Aging Infrastructure Programs

The 2017 BP contains two primary initiatives to address aging, non-network underground cable systems. One initiative targets very old and/or poor performing substation exit cables on the LG&E system where most circuits exit the substation underground. The second initiative is a program to rejuvenate in place, early generation Underground Residential Cables (URD) at both LG&E and KU. A late addition to the plan added additional funding for URD Rejuvenation in the amount of $1.2M/year ($1M-LG&E, $200k-KU) in each year of the 2017 BP based on a demonstrated improvement in failure rates since program inception and because the additional funding could lead to a reduction in operational expenses associated with repairing ongoing cable failures.

Project Category/Code	2017 Proposed Plan	2018 Proposed Plan	2019 Proposed Plan	2020 Proposed Plan	2021 Proposed Plan
Aging Infrastructure – Cable Systems					
Underground Cable Replacement Substation Exits - LGE	1,051	1,077	1,104	1,132	1,160
URD Cable Rejuvenation Program - KU	524	532	540	349	358
URD Cable Rejuvenation Program - LGE	2,077	2,104	2,132	1,160	1,189
TOTAL Aging Cable Systems	**3,652**	**3,713**	**3,776**	**2,641**	**2,707**

- **Substation Underground Cable Exits (LG&E)**
  This program began with funding of $1M in 2015 with a growth of 2.5% across the plan, and funds the replacement of PILC and the poorest performing solid dielectric substation exit cables. Substation exit cables have significant reliability

implications because an entire circuit is lost until the location of the failure is identified. Targeted substation exits are between 40 and 90+ years old that have accrued multiple failed segments and have higher loading and customer impacts. This funding will provide funding for the replacement of 8-10 substation exits depending on the number and length of cable sections replaced. Funding is consistent with the 2016 BP.

- **Underground Cable Rejuvenation/Replacement (LG&E/KU)**
  This program first piloted in 2010 involves the life extension or replacement (where cables are not candidates for life extension) of direct buried primary underground residential distribution (URD) cable. This program addresses early generation URD cables that are typically 40-45 years old that have demonstrated poor reliability. These cables had a projected 30 year life expectancy when new. The purpose of this program is to extend the life of existing cables by more than 20 years by injecting dielectric fluid into the cable to restore the insulation strength to near new condition. The rejuvenation/replacement program is funded to levelize and/or slightly reduce cable failures and more expensive cable replacements. Sufficient performance data is now available and shows a correlation between the start of the cable rejuvenation/replacement program and a slight decrease in failure rates of vintage cables, however the cable systems as a whole continue to age. Past year's funding constraints did not allow the desired expansion of this program. Late in the planning cycle an incremental $1M for LG&E and $200k for KU was added to the plan to expand the program. An expansion of the program will result in contract rejuvenation crews being on site all, or the majority of the year. Having onsite contractors will enable the ability to repair and rejuvenate cable failures allowing failure repair to be capitalized. Without rejuvenation, cable repairs are expensed.

Maintain the Network - Pole Inspection and Treatment Program

This items continues the Pole Inspection and Treatment initiative which started in 2010 at $8.5M. This program is funded at $11.6M in 2017 with a growth of 3% across the plan. This program covers the capital cost to inspect and extend the life of wood poles though preservative retreatment and reinforcement and covers the cost of defective or overloaded pole replacements identified under this program. The program is intended to address approximately 8% of wood poles annually (+/- 13 year inspection cycle). Funding for 2017-2021 is consistent with the 2016 BP.

Rear Easement Hardening

Formally classified as an Aging Infrastructure initiative, funding for Rear Easement Hardening has been moved to the new System Hardening category under Enhancements for Reliability because the objectives of this program were driven more by Reliability than Aging Infrastructure.

4. Repair the Network Category

The Repair the Network category consists of two primary categories that cover the capital cost of damages by third parties, weather and non-weather related system repairs, and substation transformer repairs and rewinds. Storm related work is adjusted annually to 10 year averages. Other blanket items in this category are based on historical trends and volumetrics. As a category, variances to the 2016 BP of approximately $200k in 2017 and beyond are the result of an increase in storm related restoration costs.

Project Category/Code	2017 Proposed Plan	2018 Proposed Plan	2019 Proposed Plan	2020 Proposed Plan	2021 Proposed Plan
Repair the Network					
Storm Restoration	3,552	3,654	3,756	3,844	3,946
Non Weather System Restoration and Third Party Damages	9,705	9,990	10,289	10,598	10,916
TOTAL Repair the Network	**13,257**	**13,644**	**14,045**	**14,442**	**14,862**

Storm Restoration

- **Storm Restoration**
  This blanket item funds the capital portion of storm related repairs. Funding is based on a 10 year average cost adjusted by the consumer price index. The 2016 BP contained $3,292k in 2017 and this category is adjusted by the CPI index across the plan. The variance of approximately $200k is due to a change in the 10 year average cost of storm restoration.

Non Weather System Restoration and Third Party Damages

This category has three components shown below. 2016 BP funding for 2017 was $9,717 and 2017 BP amounts are consistent with the 2016 BP.

- **Third Party Damages**
  This blanket item covers the capital cost of unreimbursed repairs to utility facility caused by third parties. Funding is based on historical trends and volumetrics.

- **Non-Weather System Restoration**
  This blanket item covers the cost of routine, non-storm related service restoration at all operations centers. Funding is based on historical trends and volumetrics.

- **Substation Transformer Rewinds – (Combined LG&E/KU $2.5M-2017 escalated 3% across the plan)**
  This blanket item covers the cost of substation transformer repairs and the cost to rewind failed transformers for reuse. Funding is based on historical trends and volumetrics.

5. Miscellaneous Network Category

The Miscellaneous Network category consists of miscellaneous capital projects not directly associated with connecting new customers or enhancing, maintaining or repairing the network. The Miscellaneous category consists of projects to address special needs when necessary, but generally consists of three main categories, Tools and Equipment, Vehicles, and Equipment for Asset Management. An additional category was added this year to reflect special funding needs to explore options (including the expansion of the Transmission Control Center in Simpsonville, KY) to allow the implementation of a centralized Distribution Control Center. Significant variances to the 2016 BP across the plan include a reduction in vehicle purchases resulting from a change in strategy to leased vehicles instead of purchased vehicles which created a reduction of $5.8M in 2017 and varying levels of reductions across the remainder of the plan. The variance to expand the Simpsonville facility results in a variance of a $5M in both 2017 and 2018.

Project Category/Code	2017 Proposed Plan	2018 Proposed Plan	2019 Proposed Plan	2020 Proposed Plan	2021 Proposed Plan
Miscellaneous (Incl Servco)					
Tools & Equipment, Miscellaneous Items	695	714	734	722	741
Equipment Purchases for Asset Management	300	300	300	306	312
Simpsonville Facility Enhancement for DCC	5,000	5,000	0	0	0
Purchase of Vehicles/Garage Equipment	30	30	30	31	31
TOTAL Miscellaneous (Incl Servco)	**6,025**	**6,044**	**1,064**	**1,059**	**1,084**

- **Tools and Equipment**
  This item funds the capital portion of tool and equipment purchases at all operations centers within EDO. Funding is based on historical trends supplemented as necessary to fund large, costly equipment when needed. Funding in consistent with the 2016 BP.

- **Equipment Purchases for Asset Management**
  This item funds the capital purchase of computer hardware and associated equipment such as plotters, survey equipment, and GPS units to support both Gas and Electric Operations. Funding in consistent with the 2016 BP.

- **Simpsonville Facility Enhancement for DCC**
  This new item identifies funding needs for a facility expansion of the Transmission Control Center in Simpsonville, KY. Expansion is necessary to implement a centralized and expanded Distribution Control Center (DCC) for both KU and LG&E. Currently DCC functionality is split between two control centers, one for LG&E at the Broadway Office Complex in Louisville, KY and one for KU at Quality One in Lexington, KY. Centralized and expanded distribution dispatch is required to effectively implement Distribution Automation (DA) and a Distribution Management System (DMS). Funding of $5M is planned for both 2017 and 2018 to coincide with the rollout of the DMS system and is a variance to the 2016 BP.

- **Purchase of Vehicles and Equipment**
  This item funds the purchase of vehicles within EDO. The 2016 BP included significant funding to support the planned purchase of vehicles with funding varying from $5.8M in 2017 to as high as $10M in 2019 to support the purchase of Tier 1 and 2 vehicles. A change in strategy to leased vehicles led to significant reductions in this category.

Electric Distribution Operations Capital Business Plan
High Level Summary
Updated 7/30/2015

<u>Background</u>
The Electric Distribution Operations business plan consists of five strategic categories*: Connect New Customers, Enhance the Network, Maintain the Network, Repair the Network, and Miscellaneous*. Each category consists of identified projects and blanket projects.

Blanket projects cover anticipated annual routine work and equipment purchases where such work cannot be defined in advance. Work is typically driven by short cycle, high volume work requests. Blanket funding is trended from historical actual expenses, volumetric trends, and local economic indicators and is adjusted where necessary for known impacts such as system growth or increased equipment costs. Blanket projects include costs for connecting new customers, storm repairs, relocations, operation center driven reliability and enhancement work, and capital repairs or replacement of failed or damaged equipment.

Non-blanket projects are evaluated and prioritized in the Asset Investment Strategy (AIS) financial model and ranked using a benefit to cost methodology. Key components of the evaluation include capacity to serve, reliability, and potential CAPEX/OPEX savings. Key strategic projects/programs such as the Pole Inspection and Treatment program (PITP), Aging Infrastructure (AI) programs, Reliability Initiatives, and Capacity Enhancements are included in the model and may be classified as either non-discretionary or discretionary for evaluation purposes based on their strategic value. A technical review team of subject matter experts from various functional areas of EDO reviews and validates the project metrics for each project before projects are prioritized by AIS. The final plan is developed following reviews by EDO Directors and the VP, EDO and adjusted as necessary to address funding for key initiatives and strategies.

1. **<u>Connect New Customer Category – ($62.4M-2016, $65.3M-2017, $68M-2018, $71.4M-2019, $75.1-2020)</u>**
   The Connect New Customer category largely consists of blanket projects trended across the plan to cover the ongoing cost to extend electric facilities to serve new customers (or load) and the associated costs of equipment such as distribution poles, pole and padmount transformers, and conductor. Known major projects to serve new loads, such as substation improvements or major circuit work for a single customer are identified individually but do not occur in the plan every year. Funding for this category includes $64.38M in 2016, a slight reduction (1.5%) from the 2015 Business Plan (2015BP) ($65.358M). The variance is due to in part to the cancelation of two large new business related substation projects with planned expenditures in 2016 (Corning Danville, Delaplain) resulting from deferment or cancelation of expected customer load growth. This reduction was partially offset by one major new substation and circuit work project

expected to be required to serve new load in 2016 (Toyota South 4 - $3,300k: $2,700k 2016, $600k 2017). Excluding Major Projects, LG&E escalation assumed at 8% (5% growth and 3% material/labor increases) and KU escalation assumed at 3% (0% growth and 3% material/labor increases). Major impacts are lower growth rates in recent years offset by higher than inflationary costs for connecting new customers as they move to urban centers for employment (economic growth is offset by churn) particularly in the LG&E areas. New Business blankets are forecasted using historical actual expenses, volumetric trends, and local economic indicators and are verified against the system sales forecast for consistency. $2M of transformer purchases were later pulled into 2015.

2. Enhance the Network Category

The Enhance the Network category includes major and minor system improvements required to serve growing load and to enhance the reliability, safety and/or durability of the system. Blanket funding for mandated work impacting existing facilities (such as blanket projects for relocations for public works and customer requested work pending reimbursements) is also included in this category. All enhancement work is further subdivided below in the Categories of Enhancements to Meet Demand, Enhancements for Reliability, Mandated Relocations, and Customer Requested Projects.

Enhancements to Meet Demand specifically addresses current loading issues or expected overloads, capacity additions for contingency, expansion of SCADA, and other non-reliability system enhancements. Additionally, the 2016BP also requests incremental funding to address a regulatory driven mandate to reduce employee's arc flash exposure for work in the LG&E downtown secondary network. Further details of the Enhancements to Meet Demand subcategory are shown below:

- **System Enhancement Blankets – ($1.9M in 2016 and escalated 3% across the plan)**
  This item includes blanket funding at each distribution operations center to cover necessary, but currently undefined enhancements required each year. Funding is based on historical spend levels.

- **Major Substation and Circuit Work Projects –($6.676M-2016, $19.952M-2017, $18.902M-2018, $27.267-2019, $27.246M-2020)**
  Large, generally multiyear substation/circuit work projects are planned so that they can be completed in the year when the asset is forecasted to reach 95% - 100% of its "normal" operating limit including known or potential new loads. Also included are other enhancement projects that have demonstrated value. The forecasted load of capacity projects is based on a 10-year non-coincidental substation load forecast which is updated annually. Projects can also be placed in the plan when substations and circuits are at risk of exceeding their "emergency" operating limits under extreme weather events (such as the Polar Vortex of 2014 and Artic Blast of 2015) or where projects have substantial reliability benefits. The number of major new projects varies across the plan due to expected load

growth (from the forecast) and/or expected reliability benefits. Projects in the outer years of the plan may be adjusted forward or backward in future business plans based on actual load growth, funding limits and the need to fund other more critical needs that develop in the next several years. All major enhancement projects are summarized below:

Project and Funding ($000)	**2016**	**2017**	**2018**	**2019**	**2020**	
DSP Lexington Area Major Project Distribution	434					
DSP Lexington Area Major Project Substation	1866					
DSP Lebanon East Substation - 2nd Year	678					
DSP Lebanon East Distribution - 2nd Year	110					
DSP Manslick Circuit Work - 2nd Year	832					
DSP Manslick Substation Expansion	672					
DSP Shelbyville East Distribution 2nd Year	215					
DSP Shelbyville East Substation 2nd Year	768					
SCM LGE MODIFY CANE RUN PLANT 14KV SUBSTATION	615					
SCM RAP LGE SMAC PROJECT	185	190	194	199	204	
MAY Camargo-A.O. Smith Reconductor		152				Moved to 2017 from 2016
DSP Fariston 12KV Circuit Addition Project		120				Moved to 2017 from 2016
DSP Lemons Mill 1 Ckt 0441 Breaker		65				Moved to 2017 from 2016
DSP Paris 819-1 substation breaker addition		120				Moved to 2017 from 2016
DSP Paris 819-2 substation breaker addition		80				Moved to 2017 from 2016
DSP Paris Circuit 805 circuit addition		150				Moved to 2017 from 2016
DSP Paris Circuit 806 circuit addition		200				Moved to 2017 from 2016
DSP Sunoco CKT1732		50				Moved to 2017 from 2016
DSP Richmond North Substation Property	300					
DSP Richmond North Substation Project		2000	1500			
DSP Richmond North Substation Project Distribution		1180				
DSP Gene Substation		1906	2488			
DSP Gene Substation Circuit Work		344	344			
DSP Georgetown North Substation Property		500				

DSP Georgetown North Substation					2101
DSP Georgetown North Distribution					525
DSPNB Horse Cave Industrial Substation Property		500			
DSPNB Horse Cave Industrial Substation Project_Hart County		2000	1500		
DSPNB Horse Cave Industrial Distribution			600		
DSP Russell Corner Circuit Work (2016-2017)		514	514		
DSP Russell Corner Substation Project (2016-2017)		3541	1920		
DSP Simpsonville 1 Substation		600	600		
DSP Simpsonville 1 Distribution			100		
DSP Substation Property Mud Lane-Smyrna		800			
DSP Frankfort 34-69kV substation relocation		923	1230		
DSP Frankfort 34-69kV substation relocation distribution			51		
DSP Mt. Vernon Substation Project		718	718		
DSP Mt. Vernon Substation Distribution			103		
DSP Lawrenceburg Substation Property Project		400			
DSP Lawrenceburg-Anderson County Distribution Project					431
DSP Lawrenceburg-Anderson County Substation Project				2101	1576
DSP Wilson Downing 2 Substation Upgrade		1333	718		
DSP Wilson Downing 2 Substation Upgrade Distribution			308		
DSPNB Florida Tile Substation Transformer Expansion		1500			
DSP Tucker Station Circuit Work (2018-2019)			1500	1250	
DSP Tucker Station Substation Project (2018-2019)			3407	1643	
RIC Reconductor Ckt 2312		67			
DSP Black Branch Road Circuit 2477 Upgrade			488		
DSP American Ave Ckt 0008 Distribution Step Downs			168		
MAY Kenton to Wedonia tie circuit			268		
NOR St Charles Ckt 0760 Distribution			74		
DAN RECONDUCTOR CIRCUIT 154 STANFORD TO HUSTONVILLE			110	132	132
DSP Georgetown 12kV 2 Distribution				525	525

DSP Georgetown 12kV 2 Substation				2101	1576
DSP Hume Road Sub phase 2 distribution					
DSP Hume Road Substation Phase 2					1576
DSP Paynes Mill Road Substation Project-Versailles				2692	2154
DSP Paynes Mill Road Substation- Distribution & Exit Feeders					386
DSP Stonewall 2 Distribution				431	431
DSP Stonewall 2 Substation				1723	1131
DSP Lime Kiln Substation Circuit Work (Future 2019)				875	875
DSP Lime Kiln Substation Work (future 2019)				2946	1150
DSP Middlesboro 1 4kV 124-5 Distribution Conversion					88
DSP Middlesboro 1 4kV 124-5 Substation Conversion				798	195
DSP Middlesboro 2 4kV 780-1 Distribution Conversion					129
DSP Middlesboro 2 4kV 780-1 Substation Conversion				946	467
DSP London North Distribution Lines Project					592
DSP London North Substation Project				2154	1615
DSP Pennington Gap Distribution				513	513
DSP Pennington Gap Substation				2050	1538
DSP Versailles City 4KV to 12KV Distribution Conversion Project				323	
DSP Versailles City 4KV to 12KV Substation Conversion Project				1723	
DSP Viley 2 Distribution				431	431
DSP Viley 2 Substation				1723	1077
LEX Hume Road Distribution Project for Fiber Extension				130	
NOR Exeter Ckt 0743 Distribution				70	
DSP American Ave Ckt 0008 Distribution Switchgear				54	
DSP Radcliff South Circuit 2470 Re-conductor Project				65	
Russell Springs Substation Upgrade					1050
Buena Vista Substation Upgrade					1051
DSP Shelbyville North Breaker					83

DSP Shelbyville North Distribution					188
DSP Airline Road Substation Regulator Upgrade Project					226
DSP Bevier 34.5KV Coordination Project					55
DSP Black Branch Road_Etown Industrial Tie Circuit Project					1014
DSP Dawson Springs 12KV Substation Regulator Project					81
DSP Drakesboro 4KV Substation Regulator Project					71
DSP Innovation Dr 2 Distribution Exit Ckt					541
DSP Lemons Mill 1 Ckt 0440 Distribution					364
DSP Lemons Mill 1 Ckt 0441 Distribution					276
LON Denham Street - Circuit 531					99
NOR Ramsey 22kV Distribution Switches					66
PIN Calloway - Circuit 312					106
PIN Harlan Y - Circuit 4412					209
PIN Middlesboro - Circuit 0360 Upgrade					216
PIN Pineville - Circuit 303					91
PIN Shawnee Gas - Circuit 4402 Upgrade					245
PIN Stinking Creek - Circuit 0314 Upgrade					130
Total	6676	19951	18901	27598	27583

- **N-1 Distribution Transformers (N1DT):** The N1DT program was introduced in the 2014BP to address substations that cannot be restored in the event of a transformer outage or failure during any portion of the year. During these outages some customers could experience outages lasting 24-36 hours until the equipment is replaced or a portable transformer is installed. Funding included $2.5M beginning in 2015 escalated across the plan and was expected to address an average of two projects over two years. Funding in 2019 was later removed from the 2015BP to meet capital targets. While staying to plan in 2016, additional funding above target was originally requested in years 2017-2020 to complete projects of major concern, generally in the Louisville and Lexington area under an accelerated 11 year program. This would have required a funding increase to $10M in 2017 and $20M in years 2018–2020 to accelerate the N1DT program. Funding was then scaled back to complete this work over a 15 year period with funding in 2016 remaining at plan (less pull forward) and funding of 2017-$7M, 2018-2020-$10M.

This initiative includes substation/circuit upgrades, capacity additions and enhancements at critical substations for the purpose of adding contingency for substation transformer failures and outages. Targeted substations are stations where large numbers of customers or critical loads will be without service for extended periods of time during transformer failures/outages due to lack of contingency from area stations. This initiative is separate from capacity additions to serve existing customers although it also often addresses near term loading issues in addition to contingency. It also provides additional capacity necessary to support the long term goals of the Distribution Automation initiative. Projects are prioritized in a prioritization model using a benefit to cost methodology similar to AIS. Projects are evaluated on factors such as the number of transformers a project will remove from the N1DT list, load at risk, percent of year the load is at risk, customers served (by type), age of the power transformer, availability of property and other factors.

Projects initiated in 2015 that will complete in 2016 include a transformer addition (Lakeshore 3) and a transformer upgrade (Innovation Drive). One additional project planned for 2016 at Central City and Central City South for $745k was moved up for completion in 2015. The individual projects are identified belowof the summary of spending amounts. N1DT projects are dynamic and will be continually revised as other capacity enhancement change project priorities and as better engineering information becomes available.

- 2016 - 6 projects, $1.8M (Does not include 2 projects for $745k pulled into 2015 for Central City)
- 2017 - 6 projects, $7M ($4.4M incremental)
- 2018 - 8 projects, $10M ($7.3M incremental)
- 2019 - 6 projects, $10M ($10M incremental)
- 2020 - 8 projects, $10M

N1DT Projects:	2,017	2,017	2,018	2,019	2,020
N1DT STR Innovation Dr 2 Substation	397				
N1DT STR Lakeshore 2 Distribution	169				
N1DT STR Lakeshore 2 Substation	700				
N1DT STR Plainview Circuit Work	552	500	1,448		
N1DT STR Plainview Substation Project		3,000	1,000		
N1DT STR Viley 2 Distribution		350	450		
N1DT STR Viley 2 Substation		1,450	1,150		
N1DT STR Stonewall 2 Distribution - KU		200	600		
N1DT STR Stonewall 2 Substation - KU		1,500	1,150		
N1DT STR Mud Lane/Smyrna Area Circuit Work - LGE			1,202	798	

N1DT STR Mud Lane/Smyrna Area Substation - LGE			3,000	1,500	
N1DT STR Dixie Substation - LGE				3,000	1,000
N1DT STR Dixie Circuit Work - LGE				500	500
N1DT STR Lime Kiln Circuit Work - LGE				702	1,048
N1DT STR Lime Kiln Substation Work - LGE				3,500	2,000
N1DT STR Ethel Circuit Work - LGE					250
N1DT STR Ethel Substation Project- LGE					2,500
N1DT STR Kenwood Circuit Work - LGE					202
N1DT STR Kenwood Substation - LGE					2,500
Total N1DT Projects (From AIS)	**1,818**	**7,000**	**10,000**	**10,000**	**10,000**

- **KU SCADA Expansion, $500k-2016**
  First included in the 2014BP at a funding rate of $5M, the SCADA expansion was reduced to $500k across the plan in the 2015BP to install equipment for load monitoring and equipment monitoring and control at critical KU substations that currently lack any SCADA capabilities. Due to capital constraints, funding was later removed in years 2016-2019 with funding in 2015 retained to install cell enabled smart meters in non-SCADA stations to enable near real time monitoring of substation transformer loads. Approved funding for 2015 was later released when the vendor's rollout of their cell based technology was delayed. Funding was originally planned to be restored in years 2017-2020 to the $500k level but was later eliminated leaving only the 2016 funding in the plan. Currently, only 15% of KU Substations have SCADA whereas LG&E 12kV and 14kV substations are 100% SCADA equipped. Similar to the 2015BP, 2016 funding targets the installation of AMI meters in non-SCADA.

- **LG&E Downtown Network Arc Flash – Primary Switches and Secondary Links (New 2016) $2.2M-2016**
  In 2014, OSHA significantly revised standard 1910.269 which governs work performed by utility employees on distribution systems and for the first time implemented requirements for protecting employees from arc flash (previously covered by an exception in the NESC). The new regulation resulted in the need to install equipment on network transformer and protectors on the 480V network (216V network is unaffected and can be worked in normal PPE) to allow routine work on protectors without taking extraordinary measures. An arc flash in an energized protector is extremely hazardous due to high available fault currents (>200kA in some cases), and its box like configuration and close bus bar spacing. The secondary side of a protector (bus side) cannot be de-energized in most cases unless the connecting leads are disconnected, a time intensive process. Because the primary switch on a transformer is a non-load break switch,

the transformer cannot be de-energized unless the primary circuit is first de-energized. De-energizing the primary places the network in an N-1 condition which is avoided when possible to speed work and to ensure network reliability. Currently, protector work in most cases can't be performed under the new regulations even in a flash suit unless at least the transformer is de-energized. Heavy flash suits are impractical to work in for long periods of time in hot, dimly lit underground vaults. This initiative is to install primary side medium voltage switches on all 480V transformers and a small number of secondary disconnects on high exposure vaults by the end of 2016 to allow protector work to be performed in standard PPE. This will maintain the flexibility to perform work efficiently and will significantly improve worker safety. The program is expected to take two years to complete with $975k approved for 2015 and $2.2M in 2016 which targets the balance of 219-480V transformer/protectors.

Additional projects are designed to enhance the safety or integrity of the system, including:

- **Downtown Louisville Network Manhole Lid Replacement ($217k in 2016, pulled into 2015)** This program, started in 2013, enhances public safety in downtown Louisville by replacing conventional manhole lids with lids that are designed to remain in place in the event of a catastrophic cable failure or explosion in a manhole. The program is focused on manholes located in the downtown Louisville network area. The planned 2016 funding, which has been pulled into 2015 will complete the program
.
- **Lexington Area Manhole Lid Replacement ($52k in 2016, pulled into 2015)**
This program, started in 2013, enhances public safety in the central Lexington area by replacing conventional manhole lids with lids designed to remain in place in the event of a catastrophic cable failure or explosion in a manhole. This funding was to complete the planned deployment and funding was also pulled into 2015.

- **Distribution Capacitors (Combined LG&E/KU $278k 2016-2018, $287k 2019-2020)**
This program was added to the 2015 EDO BP to provide for the installation of distribution capacitors targeted for transmission system power factor improvement. This work had been funded in the past by Transmission but the budget was transferred to EDO in 2015.

Enhancements for Reliability Improvements are to address day to day reliability needs and select, high value Major Reliability Projects. The plans includes two major programs of strategic value, one of which is new in the 2016BP. The first program consists of two initiatives to enhance reliability of circuits that are historic poor performers. The second initiative requests incremental funding to implement a step changing proactive improvement in reliability by the staged implementation of Distribution Automation (Smart Grid).

- **Reliability Improvement Blankets - (combined KU-LG&E $2,102k in 2016, escalated by 3% through 2020).**
  The Reliability improvement blanket with funding across the plan is used to address upcoming reliability issues at the operations centers and unplanned small scale projects to target reliability improvement and/or safety and resiliency of the system. Blankets cover general distribution reliability improvements at the center level driven by customer complaints and abrupt downturns in reliability performance. The 2015BP included $2,190k in 2016 also escalated across the plan.

Initiatives targeting reactive work on historically poor performing circuits include CEMI (Customers Experiencing Multiple Interruptions) and CIFI (Circuits Identified for Improvement) and high value smaller reliability project work evaluated using the AIS financial model. Funding levels in the 2016BP were adjusted to reflect the current number of circuits in each category and escalated across the plan.

- **CIFI (worst performing) Circuits – (2016 $4M-KU, $3.75M-LGE escalated 2.5% across the plan)**
  (Previously CIFI Level 1, 2, & 3). This initiative covers reactive reliability improvement work on circuits whose 5 year average SAIFI performance exceeds the average circuit performance by more than one standard deviation. Previously segregated by standard deviation from the mean circuit performance (i.e. CIFI I - 4 standard deviations or more, CIFI II – 3 standard deviations, etc.), the three past initiatives have been combined into one project to allow more effective management. Combining funds of three sub-initiatives will simplify allocating funding across categories. Because circuits are always worked from the worst performers to the better performers no further benefit was seen for allocating by level. Circuits identified for improvement will be limited to those circuits that have not had past Reliability work completed. Variances to the 2015BP are an increase for KU of $1,010k and a decrease for LG&E of $2,490k. This initiative has proven performance and value as seen by circuit SAIDI/SAIFI before/after metrics but future business plans will likely begin to reduce funding in this category to address diminishing returns. Total amounts vary in each plan cycle by the number of circuits targeted (by standard deviation away from mean) and by actual circuit performance across both utilities.

- **CEMI>5 (2016 $600k-KU, $350k-LG&E escalated by 2.5% across the plan)**

  This initiative is a reoccurring initiative to address circuits whose customers exceeded more than 7 outages in 2014 (CEMI is a one year look). The 2015BP included $675k for KU and $400k for LG&E. Similar to the CIFI program, total amounts vary by plan cycle based on the number of circuit impacted and by actual circuit performance across both utilities.

- **Reliability Major Projects – $902k-2017, $132k-2019, $789k-2020**
  This category covers individual, high value reliability based projects not covered under CIFI or CEMI work.

- **Distribution Automation (Incremental 2016-$1.25M, 2017-$5.805M, 2018-$14.070M, 2019 & 2020-$13.75M)**

This new initiative to the plan is requested as incremental to the 2015BP beginning in 2016 (currently $117M spend over a 10 year planning window) to achieve the next step change in Reliability (SAIDI SAIFI improvement) for Electric Distribution. This new initiative begins with the installation of SCADA controlled electronic reclosers which have an immediate reliability benefit on select circuits beginning in 2016. Later years of the program transition into building additional contingency into the system and the installation and turn-up of a Distribution Management System (DMS) allowing FLISR (automatic **F**ault **L**ocation, **I**solation, and **S**ervice **R**estoration) of field devices. Funding for this program varies across the years depending on the type of work (Reclosers, Communication, Systems, Infrastructure to support Contingency) to be completed and available resources (both internal and external). Originally requested funding was set to complete full deployment in 7 years and has been scaled back to take 10 years for a full deployment.

Public Works, Mandated Relocations, and Customer Requested Projects **(2016-$4.301M escalated 3% across the plan)** covers alterations or relocation of distribution facilities to accommodate public works projects. It also provides funding for customer requested facility relocations prior to reimbursement by customers. This item is funded based on historical spend levels.

3. Maintain the Network Category

The Maintain the Network category includes capital blanket and project specific funding to maintain the condition of the system, replace failed or defective distribution and substation equipment, and specific projects to address aging infrastructure. Work specific to maintain, repair and replace distribution equipment covers distribution lines, substations, street lighting, distribution relocation work driven by transmission projects, and buildings and grounds.

- **Repair and Replace Defective Equipment Blanket: Lines - (2016 $28.482M escalated 3% across the plan)**
  This blanket item covers the cost of repairing and replacing defective distribution line material and equipment at each operations center. Maintenance and replacement of capacitors, poles, cable, vaults, and street lighting are included in this category. Funding is based on historical spend levels and is consistent with the 2015BP.

- **Repair and Replace Defective Equipment Blanket: Substation Maintenance (2016 $3.104M, escalated 2.5% across the plan)**
  This grouping of projects covers the cost of reactive repair and replacement of defective substation equipment at each operations center. Specifically, these projects include the replacement of failed equipment that cannot be effectively repaired, wildlife protection at unprotected stations, upgrades for compliance (NESC, cooling fans, oil containment capital repairs), building and grounds repairs, and minor improvements to reduce future maintenance/repair (transformer oil filtration, addition of lightning protection). Funding is up slightly from the 2015BP (2016 - $2,859k) primarily due to funding for the replacement of transformer fans.

- **Repair and Replace Defective Equipment Major Projects (2017-$220k)**
  This category covers major projects targeting defective equipment not covered under other categories. 2017 funding consists of two projects in different KU Operations to remove portions of the same out of service line (Roundhill) that has become an operational concern.

- **Purchase KU Portable Transformer – ($2.4M total, 2017-$2.2M, 2018-$200k)**
  Funding for this project was in the 2015BP for 2017 as has now been split across 2017 ($2.2M) and 2018 ($200k). The purchase of an additional portable transformer for KU is needed to minimize outage duration caused by substation transformer failures where quick restoration cannot be accomplished by a direct replacement with a spare transformer. The portable transformer is also needed to support maintenance work and an increasing work plan for substation transformer additions and replacements where transformers have to be removed from service as part of the construction process. The two KU portables are 19 and 62 years old and cannot be taken out of service for needed refurbishment due to the associated operational risk. The purchase of a large portable transformer for LG&E was completed in 2014.

- **Louisville Electric Operations Padmount Switchgear – ($185k 2016, escalated 2.5% across the plan)**
  This program replaces aged and defective, high risk padmounted switchgear in underground commercial and large residential areas that has been identified during system inspections. The program is necessary to address increasing failure rates on highly deteriorated equipment and to replace equipment that cannot be effectively maintained.

- **Transmission Line Clearance (LG&E/KU $460k-2016, $628k-2017, $315k-2018)**
  This funding is used to cover the cost of undefined distribution line relocations and upgrades during the year driven by Transmission pole replacements, relocations and compliance directed (NERC) clearance projects. The project is generally funded at $300k/year split between LG&E and KU. One large identified project is also included (Shelbyville East Circuit 2522, 2016-$160k, 2017-$320k).

4. <u>Repair and Replace Aging Infrastructure</u>

Aging infrastructure initiatives are based on available data by age, quantity in service, failure data, field experience, equipment specialty knowledge, and industry best practices. O&M considerations are cost to maintain, availability of spare parts, and environmental considerations. The age of the distribution system and increasing failure rates has necessitated beginning and/or consistently funding replacement and/or rehabilitation programs. These programs target critical distribution assets that are beyond their expected life expectancy in areas where they have resulted in declining reliability. Robust system expansion in the 1960's and 1970's has created substantially high groups of equipment and material with similar age and created the potential for very high failure rates in future years. Funding is included in the plan to continue major strategic infrastructure enhancement programs such as PILC Replacement, Pole Inspection and Treatment (PIPT), Legacy Substation Equipment and poor performing or high risk distribution facilities. An increase of approximately $1,400k is requested in 2016 compared to the 2015BP to reinstate several substation AI projects removed to meet reduction targets ($879k) and an additional $524k increase requested to fund additional cable rejuvenation work at LG&E across the plan. In years 2017, funding for small wire replacements is reduced by $700k compared to the 2015BP to better integrate this work with other reliability initiatives.

- **Pole Inspection and Treatment (LG&E/KU $11.2M, escalated 3% across the plan)**
  This program is funded at $10.9M in 2015 with a growth of 3% across the plan. This program covers the capital cost to extend the life of wood poles though preservative retreatment and reinforcement and covers the cost of defective or overloaded pole replacements identified under this program. The program is intended to address approximately 8% of wood poles annually (+/- 13 year inspection cycle). Funding for 2016-2020 is consistent with the 2015BP.

- **Paper Insulated Lead Covered (PILC) Cable Replacement (LG&E) – (2016-6.2M,escalated at 3% across the plan)**
  This program, started in 2013 involves the replacement of primary and secondary PILC cable in the downtown network to address increasing reliability and safety concerns. Targeted cable is between 50 and 90+ years old. Program scope and funding has evolved, as follows:
  - 2013: Initiated program at $2M for 20 years to fund cable replacement (escalated by 2.5% per year).
  - 2014: BP included funding of $4M ($2M incremental escalated at 2.5% per year) to accelerate the program before adding an additional $2M ($6M total) to further accelerate the program and address higher than expected duct and manhole repairs and replacements.
  - 2015 – current: Continue funding at $6M level for 9 additional years with projected completion in 2023 (escalated by 3% per year) due to significant levels of manhole and ductline structure deterioration encountered during the program and to accelerate the program from a 20 year to approximately a 10 year replacement program. Shortening the program to 10 years is necessary because data does not exist to target the oldest cables first and some cable will be in excess of 100 years old by the time it is replaced. Funding is consistent with the 2015BP.

- **Louisville Electric Downtown Network Vault Structural Repairs – (2016-$283k, escalated 2.5% across the plan)**

This program targets replacement of defective vault tops (in sidewalks) and ventilated openings on downtown Louisville Network vaults that have deteriorated as a result of age and deicing salts. Deteriorated vault tops if not repaired increase the risk to the public and to the high cost network transformers and equipment located in vaults. Funding is consistent with the 2015BP level. Requested funding will typically allow the repair of 2-3 vault tops depending on the size of the vaults. There are currently 190 vaults in downtown Louisville.

- **Substation Asset Replacements (LG&E/KU) (2016-$2.7M, 2017-$2.4M, 2018-$2.4M).**
  This collection of programs covers the annual replacement of aged critical, maintenance intensive, unreliable substation equipment and/or equipment nearing obsolescence. These programs include equipment such as substation batteries, relays, 15kV power circuit breakers, Remote Terminal Units, cap and pin insulators, Load Tap Changers (LTC), and LTC Controllers. In 2012, Substation Construction and Maintenance identified a "Top 5 List" for both LG&E and KU based on a combination of advanced age, chronic operational issues, quantity in service, field experience, and equipment specialty knowledge. O&M considerations are cost to maintain, availability of spare parts, and environmental considerations. The Substation Aging Infrastructure program has been in past business plans but funding has varied due to available capital funding. Funding needs vary somewhat each year as program initiatives are completed and new ones are identified. Funding in the 2015BP for this group is 2016-$1,815k, 2017-$2,479k, 2018-$2,541k. Variance of an increase of $879k in 2016 is due to the restoration of several projects removed from the 2015BP to meet reduction targets including some legacy RTU's, breakers (including 34kV), and Reinhausen LTC.

- **Substation Underground Cable Exits (LG&E) – ($1M-2016, escalated 2.5% across the plan)**
  This program began with funding of $1M in 2015 with a growth of 2.5% across the plan, and funds the replacement of PILC and the poorest performing solid dielectric substation exit cables. Substation exit cables have significant reliability implications because an entire circuit is lost until the location of the failure is identified. Targeted substation exits are between 40 and 90+ years old that have accrued multiple failed segments and have higher loading and customer impacts. Funding is consistent with the 2015BP.

- **Rear Easement Hardening (Combined LG&E/KU 2016-$1.7M, 2017 $1.1M-2017 escalated 3% across the balance of the plan)**
  This program covers the rehabilitation or relocation of older, storm sensitive overhead lines in difficult to maintain rear easements where they have demonstrated poor reliability or storm performance. Aspects of the program include replacement of undersized and/or defective small wire, stronger and/or taller poles, selective undergrounding, storm guying, elimination of secondary, replacement of aged and defective equipment, and/or relocation of lines to less problematic areas. Funding requested in 2016 is consistent with the

2015BP. Funding in the 2016BP is reduced beginning in 2017 to approximately $500k for each utility to better integrate with other reliability base initiatives resulting in a variance reduction of $700k beginning in 2017.

- **Underground Cable Rejuvenation/Replacement (LG&E/KU) – (2016: $316k-KU, $1,051k-LG&E, escalated 2.5% across plan)**
  This program first piloted in 2010 involves the life extension or replacement (where cables are not candidates for life extension) of direct buried primary underground residential distribution (URD) cable. This program addresses early generation URD cables that are typically 40-45 years old that have demonstrated poor reliability. These cables had a projected 30 year life expectancy when new. The purpose of this program is to extend the life of existing cables by injecting dielectric fluid into the cable to restore the insulation strength in order to levelize the rate of future reactive failure replacements. These projects were in the 2015BP for $316k-KU and $527k-LGE. A requested increase of $524k is planned for the LG&E portion ($1,051-2016 total) in 2016 and beyond. Sufficient performance data is now available and shows a correlation between the start of the cable rejuvenation/replacement program and a slight decrease in failure rates of this vintage cable.

- **DT Network Vent Type Protector Replacement (LG&E)**
  This program, funded to begin at $500k in 2017 with a growth of 2.5% across the plan, initiates the replacement of aged network protectors that are not submersible rated for below ground application in vaults subject to flooding. The program will address the most critical of these assets and further enhance the integrity of the downtown network in conjunction with other network aging infrastructure programs (PILC, manhole lids, SCADA, AMI, etc.). Funding is consistent with the 2015BP.

- **Miscellaneous Aging Infrastructure - (2018-$380k)**
  This category covers individually identified high value aging infrastructure projects not included elsewhere. This category includes one project in 2018 to rebuild a severely deteriorated distribution line that has become a reliability and maintenance problem (Richmond Pine Hill to Livingston Line).

5. <u>Repair the Network Category</u>

The repair the network category consists of four projects that cover the capital cost of damages by third parties, weather and non-weather related system repairs, and substation transformer repairs and rewinds. Storm related work is adjusted annually to 10 year averages. Other blanket items in this category are based on historical trends and volumetrics. As a category, variances to the 2015BP of approximately $330k in 2016 and beyond are the result of an increase in storm related restoration costs ($520k) partially offset by a reduction in Third Party Damages ($200k).

- **Third Party Damages – ($1.1M escalated 3% across the plan)**
  This blanket item covers the capital cost of unreimbursed repairs to utility facility caused by third parties. Funding is based on historical trends and volumetrics. The 2015BP contained $1,340k in 2016, escalated 3% across the plan resulting is a 2016BP reduction of approximately $200k (15%) across the plan.

- **Non-Weather System Restoration – ($8.3M-2016 escalated 3% across the plan)**
  This blanket item covers the cost of routine, non-storm related service restoration at all operations centers. Funding is based on historical trends and volumetrics. The 2015BP contained $8,294k in 2016, escalated 3% across the plan resulting in a minor 2016BP increase of approximately $10k across the plan.

- **Storm Restoration – (Combined LG&E/KU $3.2M-2016 escalated at CPI across the plan)**
  This blanket item funds the capital portion of storm related repairs. Funding is based on a 10 year average cost adjusted by the consumer price index. The 2015BP contained $2,696k in 2016, escalated 3% across the plan resulting in a 2016BP increase of approximately $520k (19%) across the plan. The variance is due to a change in the 10 year average resulting from a drop off of a relatively mild 2004 storm year from the rolling average and adding a higher 2014 year.

- **Substation Transformer Rewinds – (Combined LG&E/KU $2.5M-2016 escalated 3% across the plan)**
  This blanket item covers the cost of substation transformer repairs and the cost to rewind failed transformers for reuse. Funding is based on historical trends and volumetrics. The 2015BP contained $2,460k in 2016 and funding in the 2016BP is consistent with the 2015BP.

6. <u>Miscellaneous Network Category</u>

The Miscellaneous category consists of miscellaneous capital projects not directly associated with connecting new customers or enhancing, maintaining or repairing the network. The Miscellaneous category consists of projects to address special needs when necessary, but generally consists of three main items, Tools and Equipment, Vehicles, and Equipment for Asset Management. No special projects are identified in the 2016BP. Significant variances to the 2015BP in years 2016-2019 (approx. $5M-$9M) are the result of accelerated purchases of Tier 1 vehicles.

- **Tools and Equipment – ($662k-2016 escalated 2-3% across the plan)**

This item funds the capital portion of tool and equipment purchases at all operations centers within EDO. Funding is based on historical trends supplemented as necessary to fund large, costly equipment when needed. Funding in 2016-2018 includes a minor reduction of approximate $50k (7%) each year compared to the 2015BP.

- **Vehicles – ($6,584k-2016, $5,818k, $1,729k-2018, $10,376k-2019, $1,271k-2020)**
  This item funds the purchase of vehicles within EDO. The 2015BP included $3M 2016-2019. Accelerated spending was planned in all years for the purchase of Tier 1 and Tier 2 vehicles as they exited the lease program. Funding was later reduced to the expected purchase of only Tier 1 vehicles after the initial plan was developed.

- **Equipment Purchases for Asset Management – ($300k 2016-2018, with escalation in 2019-2020)**
  This item funds the capital purchase of computer hardware and associated equipment such as plotters, survey equipment, and GPS units to support both Gas and Electric Operations. Funding in the 2015BP was $280k 2016-2017 and $286k in 2018 with a minor variance of a $20k (7%) increase requested in the 2016BP.

Electric Distribution Operations Business Plan
Updated 7/21/2014

Background

The Electric Distribution Operations business plan consists of five strategic categories*: Connect New Customers, Enhance the Network, Maintain the Network, Repair the Network, and Miscellaneous*. Each category consists of identified projects and blanket projects.

Blanket projects cover anticipated annual routine work and equipment purchases where such work cannot be defined in advance. Work is typically driven by short cycle, high volume work requests. Blanket funding is trended from historical actual expenses, volumetric trends, and local economic indicators and is adjusted where necessary for known impacts such as system growth or increased equipment costs. Blanket projects include costs for connecting new customers, storm repairs, relocations, operation center driven reliability and enhancement work, and capital repairs or replacement of failed or damaged equipment.

Non-blanket projects are evaluated and prioritized in the Asset Investment Strategy (AIS) financial model and ranked using a benefit to cost methodology. Key components of the evaluation include capacity to serve, reliability, and potential CAPEX/OPEX savings. Key strategic projects/programs such as the Pole Inspection and Treatment program, Aging Infrastructure programs, Reliability Initiatives, and Capacity Enhancements are included in the model and may be classified as either non-discretionary or discretionary for evaluation purposes based on their strategic value. The final plan is developed following reviews by EDO Directors and the VP, EDO and adjusted as necessary to address funding for key initiative projects and strategies.

Connect New Customer Category

The Connect New Customer category largely consists of blanket projects trended across the plan to cover the ongoing cost to extend electric facilities to serve new customers (or load) and associated costs of equipment such as distribution pole and padmount transformers. Known major projects to serve new loads, such as substation improvements for a single customer, are identified individually but do not occur in the plan every year. Funding for this category includes $59.3M in 2015, approximately 9% over the 2014 forecast mainly due to two large New Business substation projects. Excluding Major Projects, and Department of Energy (DOE) impacts on distribution line transformers in 2015 and 2016, funding increases approximately 5% across the balance of the plan (2.7% labor/materials, 2.0% growth). Major impacts are lower growth rates in recent years offset by higher than inflationary costs for connecting new customers as they move to urban centers for employment (economic growth is offset by churn). Cost impacts of the DOE mandated minimum efficiency standards for distribution line transformers are seen in 2015 and 2016. Two major new business projects have been identified in 2015, completion of the Lexington Delaplain 2 Substation (Aichi Forge) project ($500K 2015), and Danville Corning Substation ($750K 2015, $2603K 2016). One major new business project has been identified to start in 2016 at Delaplain 3 Substation ($825K 2016, $925K 2017).

Enhance the Network Category

The Enhance the Network category includes major and minor system improvements required to serve growing load and to enhance the reliability, safety and/or durability of the system. Mandated work impacting existing facilities (such as blanket projects for relocations for public works and customer requested work pending reimbursements) are also included in this category. Funding is included for a new initiative beginning in 2015 to address "At Risk" substations. "At Risk" substations are substations where all customers cannot be restored from alternate sources in the event of a transformer failure or unplanned outage and some customers may experience outages lasting 24-36 hours.

Enhancements to Meet Demand address current loading issues or expected overloads. Blanket funding for distribution operation centers is included to cover expected enhancements during each year and is funded at approximately $1.5M in 2015 and escalated 2.7% across the plan. The need for large, generally multiyear substation/circuit work projects are identified based on loading forecasted annually in the 10-year non-coincidental substation load forecast. Projects are placed in the plan so they are completed in the year the facility is expected to reach 100% of its rated capacity. The number of major new projects increases across the plan due to expected load growth (from the forecast), the reoccurrence of need for projects deferred in 2012 and 2013 due to slower load growth (Central Baptist, Russell Corner, Manslick, Paynes Mill) and known new major load additions (VA Hospital (LG&E), UK/Central Lexington Area (KU)). All major enhancement projects are summarized below:

<u>2015 - 20 projects, $13.1M</u>

- 1 – Substation/circuit completion (Lyndon South)
- 3 - New substations (Manslick, Shelbyville East, Lexington Area Major Project: includes American Ave 2)
- 3 – Substation upgrades (Central City 4KV, Central City South, Lexington Area Major Project: includes GE Lamp, Picadome 1, American Ave 1)
- 2 – Substation breaker upgrades (East Stone Gap, Lockport)
- 11 – Distribution circuit upgrades (Fariston circuit 0217, Haefling circuit 0055, Innovation Dr. circuit 0593, Lexington Area Major Project Distribution, Newtown Distribution, Versailles City circuit 505, Re-conductor Circuit 2220, Re-conductor circuit 2109, Milford 0935 re-conductor, Lyndon South, Manslick)

<u>2016 - 14 projects, $12.9M</u>

- 3 – Complete substations (Lexington Area Major Project Substation American Ave 2, Shelbyville East, Manslick)
- 4 - New substations (Hume Rd Substation Phase 2, Redhouse Substation, Lebanon East, Russell Corner)
- 1 - Substation upgrade (Simpsonville 1)
- 5 - Distribution circuit upgrades (Central City System, Lexington Area Major Project Distribution, Shelbyville East Distribution, Manslick, Russell Corner)

- 1 - Property purchase for new substation Mud Lane/Smyrna Area

<u>2017 - 17 projects, $15.3M</u>

- 5 - Substation completions (Hume Rd Substation Phase 2, Redhouse, Simpsonville 1, Lebanon East, Russell Corner)
- 2 – New substations (Tucker Station, Gene)
- 9 - Distribution circuit work projects (Central City, Fariston Circuit 0217, Hume Rd Phase 2, Redhouse Substation Project and Distribution, Re-conductor circuit 2215, Re-conductor circuit 2312, Russell Corner, Tucker Station, Gene)
- 1 - Property purchase for new substation Watterson/Fairmount Area

<u>2018 - 20 projects, $22.5M</u>

- 2 – Substation completions (Tucker Station, Gene)
- 8 - New substations (Paynes Mill Road, Georgetown Substation, Horse Cave Industrial 3, Versailles West, Days Branch, Stonewall 2, Old Henry, Floyd)
- 3 - Substation upgrades (Simpsonville 2, Russell Springs, Crocket)
- 1 - Substation relocation (Frankfort 34-69kV)
- 6 - Distribution circuits (Georgetown Distribution, Stonewall 2 Distribution, Tucker Station, Gene, Old Henry, Crocket distribution)

<u>2019 - 34 projects, $28M</u>

- 1 - Relocation completion (Frankfort 34-69kV)
- 10 – Substation completions (Paynes Mill, Simpsonville 2, Russell Springs, Georgetown, Stonewall, Horse Cave Industrial 3, Versailles West 2, Days Branch 12kV, Old Henry, Floyd)
- 5 - New substations (Salt Lick, Middlesboro Area, Mt Vernon, Lime Kiln, Fegenbush)
- 14 - Distribution circuits (Russell Springs, Paynes Mill Distribution, Shelbyville North, Horse Cave Distribution, Versailles West Distribution, Days Branch Distribution, Georgetown, Stonewall 2, Old Henry, Floyd, Lime Kiln, Fegenbush, Frankfort relocation distribution, Rogers Gap)
- 4 - Distribution circuit upgrades (Ashland Ave circuit 0050, Ashland Ave circuit 0111, Oxford circuit 0471, Black Branch)

In addition to capacity enhancement projects necessary to the meet the demand of existing customers, other projects are targeted at enhancing non-load driven needs of the system. Three major projects included in the Enhancement to Meet Demand category address improving response to critical substation transformer failures or enhancing monitoring and control at substations. They include:

- **At Risk Substations**, $2.5M 2015-2019 with a 2.5% increase annually. This initiative includes substation/circuit upgrades, capacity additions and enhancements at high concern substations for the purpose of adding contingency for a substation transformer failure. Targeted substations are stations where large numbers of customers or critical loads will be without service for extended periods of time during transformer failures/outages due to lack of contingency from nearby stations. This initiative is separate from capacity additions to serve existing customers and was added as an incremental initiative in the 2014 BP. Funding will provide for completing two projects over two years. Projects identified for 2015-2016 include a transformer addition (Lakeshore 3) and a transformer upgrade (Innovation Drive).

- **KU spare transformers**, $1M each in 2017 and 2018. This funding will be used to increase the spare stock of KU transformers available for the replacement of failed units. Additional spares will be necessary to address the increasingly aging fleet of substation transformers in the KU areas.
- **KU SCADA Expansion**, $500K across the plan to install equipment for load monitoring and equipment monitoring and control at high value KU substations that currently lack any SCADA capabilities. Currently, only 29% of KU Substations have SCADA whereas LG&E 12kV and 14kV substations are 100% SCADA equipped. The 2014 BP included SCADA in 2018 at $5M. Funding was reduced and spread across the plan to be in line with the resources available to complete this core skill work.

Additional projects are designed to enhance the safety or integrity of the system, including:

- **Downtown Louisville Network Manhole Lid Replacement** ($865K 2015 and $212K in 2016). This program, started in 2013, enhances public safety in downtown Louisville by replacing conventional manhole lids with lids that are designed to remain in place in the event of a catastrophic cable failure or explosion in a manhole. The program is focused on manholes located in the downtown Louisville network area. This funding will complete the program in 2016.
- **Lexington Area Manhole Lid Replacement** ($98K in 2015 and $52K in 2016). This program, started in 2013, enhances public safety in the central Lexington area by replacing conventional manhole lids with lids designed to remain in place in the event of a catastrophic cable failure or explosion in a manhole. This funding will complete the program in 2016.

Enhancements for Reliability includes blanket funding across the plan to address upcoming reliability issues at the operations centers and unplanned small scale projects to target reliability improvement and/or safety and resiliency of the system. This blanket covers general distribution reliability improvements driven by customer complaint and abrupt downturn in reliability performance (KU-LG&E $2,131K in 2015, escalated by 2.7% through 2019).

Also included are ongoing programs to improve worst circuit performance through CEMI (Customers Experiencing Multiple Interruptions) and CIFI (Circuits Identified for Improvement) projects and high value smaller reliability project work evaluated using the AIS financial model. Funding levels in the 2014 BP were adjusted to reflect the current number of circuits in each category and escalated across the plan.

- **CIFI (worst) Circuits – Level 1:** Circuits whose 5 year average SAIFI performance exceeds the average circuit performance by > 4 standard deviations (KU $390K in 2015, escalated by 2.7% through 2019) (LG&E $1,170K in 2015, escalated by 2.7% through 2019).

- **CIFI (worst) Circuits – Level 2:** Circuits whose 5 year average SAIFI performance exceeds the average circuit performance by > 3 standard deviations (KU $650K in 2015, escalated by 2.7% through 2019) (LG&E $1,430K in 2015, escalated by 2.7% through 2019).
- **CIFI (worst) Circuits – Level 3:** Circuits whose 5 year average SAIFI performance exceeds the average circuit performance by > 2 standard deviations (KU $1,950K in 2015, escalated by 2.7% through 2019) (LG&E $3,640K in 2015, escalated by 2.7% through 2019).
- **CEMI>5:** Circuits whose customers exceeded more than 7 outages in 2013 (KU $675K in 2015, escalated by 2.7% through 2019) (LG&E $400K in 2015, escalated by 2.7% through 2019).

Maintain the Network Category

The Maintain the Network category includes capital blanket and project specific funding to maintain the condition of the system, replace failed or defective distribution and substation equipment and specific projects to address aging infrastructure. Work specific to maintain, repair and replace distribution equipment covers distribution lines, substations, street lighting, distribution relocation work driven by transmission projects, and buildings and grounds. Blanket funding for repair/replace blankets is $27.2M in 2015 and is escalated by 2.7% across the plan.

Repair and replace funding under Maintain the Network includes the following major projects:

- **Purchase KU Portable Transformer**, $2.4M in 2017. The purchase of additional portable transformer for KU is needed to minimize outage duration caused by substation transformer failures where quick restoration cannot be accomplished by a direct replacement with a spare transformer. The portable transformer is also needed to support maintenance work and an increasing work plan for substation transformer additions and replacements where transformers have to be removed from service as part of the construction process. The purchase of a large portable transformer for LG&E was completed in 2014.
- **Distribution Capacitors (LG&E/KU).** This new program, funded at $278K in 2015 through 2018 (increasing to $287K in 2019) provides for the installation of distribution capacitors targeted for transmission system power factor improvement. This work had been funded in the past by Transmission. Incremental Distribution Capital funding has been offset by the transfer of capital funding from Transmission.

New to the plan starting in 2015 is funding for two reoccurring projects to address known defective equipment and infrastructure identified through facility inspections.

- **Louisville Electric Operations Padmount Switchgear.** This program, funded at $180K in 2015 with a growth of 2.5% across the plan, is to replace aged and defective padmounted switchgear in underground commercial and large residential areas that has been identified during system inspections. The program is necessary to address increased failure rates on highly deteriorated equipment and to replace equipment that cannot be effectively maintained.
- **Louisville Electric Downtown Network Vault Structural Repairs.** This program, funded at $276K in 2015 with a growth of 2.5% across the plan, replaces defective vault tops (sidewalks) and

ventilated openings that have deteriorated as a result of age and deicing salts. Deteriorated vault tops are at risk of caving in from occasional vehicle loading.

Aging Infrastructure Initiatives:

Aging infrastructure initiatives are based on available data by age, quantity in service, failure data, field experience, equipment specialty knowledge, and industry best practices. O&M considerations are cost to maintain, availability of spare parts, and environmental considerations. The age of the distribution system and increasing failure rates has necessitated beginning and/or consistently funding replacement and/or rehabilitation programs. These programs target critical distribution assets that are beyond their expected life expectancy in areas where they have resulted in declining reliability. Robust system expansion in the 1960's and 1970's has created substantially high groups of equipment and material with similar age and created the potential for very high failure rates in future years. Key components of the program include:

- **Pole Inspection and Treatment (LG&E/KU).** This program is funded at $10.9M in 2015 with a growth of 3% across the plan. This program covers the capital cost to extend the life of wood poles though retreatment and reinforcement and covers the cost of defective or overloaded pole replacements identified under this program. The program is intended to address approximately 8% of wood poles annually (+/- 13 year inspection cycle).
- **Paper Insulated Lead Covered (PILC) Cable Replacement (LG&E).** This program, started in 2013 involves the replacement of primary and secondary PILC cable in the downtown network to address increasing reliability concerns. Targeted cable is between 50 and 90+ years old. Program scope and funding has evolved, as follows:
    - 2013 – Initiated program at $2M for 20 years to fund cable replacement (escalated by 2.5% per year).
    - 2014 – BP included funding of $4M (escalated at 2.5% per year) to accelerate the program before adding an additional $2M ($6M total) to further accelerate the program and address higher than expected duct and manhole repairs and replacements.
    - 2015-2019 – Continue funding at $6M level ($2M incremental over 2014 BP) for 9 additional years (escalated by 2.5% per year) due to significant levels of manhole and ductline structure deterioration encountered during the program and to move the program from a 20 year to a 10 year replacement program. Shortening the program to 10 years is necessary because data does not exist to target the oldest cables first and some cable will be in excess of 100 years old by the time it is replaced.
- **Substation Asset Replacements (LG&E/KU).** This collection of programs covers the annual replacement of critical, maintenance intensive, and/or unreliable substation equipment (substation batteries, relays, 15kV power circuit breakers, Remote Terminal Units, and Load Tap Changers). In 2012, Substation Construction and Maintenance identified a "Top 5 List" for both LG&E and KU based on a combination of advanced age, chronic operational issues, quantity in

service, field experience, and equipment specialty knowledge. O&M considerations were cost to maintain, availability of spare parts, and environmental considerations. The Substation Aging Infrastructure program has been in past business plans but funding has varied due to pressures on capital funding. The program is in the plan at $2.6M annually with a growth of 2.5% across the plan.

- **Substation Underground Cable Exits (LG&E).** This program, funded at $1M in 2015 with a growth of 2.5% across the plan, covers the replacement of PILC and poor performing solid dielectric substation exit cables. Targeted substation exits are between 40 and 90+ years old that have accrued multiple failed segments and have higher loading and customer impacts.
- **Rear Easement Hardening (LG&E/KU).** This program, funded at $1662K ($500K-LG&E, $1.162M-KU) in 2015 with a growth of 2.5% across the plan, covers the rehabilitation or relocation of older, storm sensitive overhead lines in difficult to maintain rear easements where they have demonstrated poor reliability or storm performance. Aspects of the program include replacement of undersized and/or defective small wire, stronger and/or taller poles, selective undergrounding, storm guying, and elimination of secondary, replacement of aged and defective equipment or relocation of lines to less problematic areas.
- **Underground Cable Rejuvenation/Replacement (LG&E/KU).** This program piloted since 2010 involves the life extension or replacement (where cables are not candidates for life extension) of direct buried primary underground residential distribution (URD) cable. This program addresses early generation URD cables that are 40-50 years old that have demonstrated poor reliability. These cables had a projected 30 year life expectancy when new. The purpose of this program is to extend the life of existing cables in order to levelize future reactive failure replacement costs. It is funded at $822K per year ($514K-LG&E, $308K-KU) with a growth of 2.5% across the plan.
- **DT Network Vent Type Protector Replacement (LG&E).** This program, funded at $500K in 2017 with a growth of 2.5% across the plan, initiates the replacement of aged network protectors that are not submersible rated for below ground application in vaults subject to flooding. The program will address the most critical of these assets and further enhance the integrity of the downtown network.
- **LEO WS1330 Cable Replacement.** This $274K project in 2015 is required to improve service reliability to Central High School, Taylor Elementary School, and Mount Lebanon Personal Care Center. Service reliability has declined due to multiple underground cable failures.
- **KU Substation Lightning Protection project** ($50K annually with a 2.5% increase across the plan). This program retrofits existing KU substations with lightning protection to improve reliability and reduce the potential for failure of high value substation equipment and transformers. All LG&E substations and new KU substations have lightning protection.
- **KU Substation Wildlife Protection project,** ($228K with a 2.5% increase across the plan) provides for the installation of wildlife protection at KU open air substations with exposed energized components. Outages caused by wildlife in substations are high impact events resulting in an outage for all customers and the potential to damage high value substation equipment and transformers.

Repair the Network Category

$11.9M in 2015 escalated across the plan. Repair the Network consist of blanket projects that address expected expenses associated with system restoration (storm and non-storm), repairs of third party damage, and substation power transformer repairs and rewinds.

Miscellaneous Network Category

Miscellaneous Network covers expenses for tooling, equipment and vehicles with funding of approximately $4M 2015-2017 and $6.5M in 2017-2019. This includes the multi-year EDO Tiered Capital Strategy for heavy duty, light duty, and yellow equipment.

Electric Distribution Operations Business Plan

Background

The Electric Distribution Operations business plan consists of five strategic categories: *Connect New Customers, Enhance the Network, Maintain the Network, Repair the Network, and Miscellaneous*. Each category consists of identified projects and blanket projects.

Blanket projects cover anticipated annual work and equipment purchases where such work cannot be defined in advance. Blanket funding is trended from historical actual expenses and adjusted where necessary for known impacts such as system growth or increased equipment costs. Blanket projects include costs for connecting new customers, storm repairs, operation center driven reliability and enhancement work, and capital repairs or replacement of failed equipment.

Non-blanket projects are evaluated and prioritized in the Asset Investment Strategy (AIS) financial model using a benefit to cost methodology. Key components of the evaluation include capacity to serve, reliability, and potential CAPEX/OPEX savings. Key strategic projects/programs such as the Pole Inspection and Treatment program, Aging Infrastructure programs, Reliability Initiatives, and Capacity Enhancements are included in the model and may be classified as either non-discretionary or discretionary for evaluation purposes based on their strategic value.

Connect New Customer Category

The Connect New Customer category largely consists of blanket projects trended across the plan to cover the ongoing cost to extend electric facilities to serve new customers (or load) and associated costs of equipment such as distribution pole and padmount transformers. Known major projects to serve new loads, such as substation improvements for a single customer, are identified individually but do not occur in the plan every year. Funding for this category includes $55.2M (2014) and increases approximately 5-8% across the plan (including the impact of specific projects). Major impacts are lower growth rates in recent years offset by higher than inflationary costs for connecting new customers as they move further from traditional urban centers and increasing costs for distribution transformers as a result of the DOE efficiency standards. One major new business project in 2015 is required to serve new University of Kentucky dormitory load.

Enhance the Network Category

The Enhance the Network category includes major and minor system improvements required to serve growing load, and to enhance the reliability, safety and/or durability of the system. Mandated work impacting existing facilities (such as blanket projects for relocations for public works and customer requested work pending reimbursements) are also included in this category.

Specifically, Enhancements to Meet Demand address current loading issues or expected overloads. Blanket funding for distribution operation centers is included to cover expected enhancements during each year. Large, generally multiyear substation/circuit projects are identified based on loading forecasted annually in the 10 year non-coincidental substation load forecast. Projects are planned for service in the year the facility is expected to reach 100% of its rated capacity. The number of major new projects increases across the plan due to expected load growth (from the forecast), the reoccurrence of need for projects deferred in 2012 and 2013 due to slower load growth (Central Baptist, Russell Corner, Manslick, Paynes Mill) and known new major load additions (VA Hospital, UK). Larger enhancement projects are summarized below:

<u>2014-3 projects, $7.3M</u>
1-completion (Hume Rd), 1-property acquisition (Central Baptist), 1-transformer addition (Lyndon South).

<u>2015-6 projects, $11.2M</u>
1-completion (Lyndon South), 2-new substations (Manslick , Paynes Mill), 2-transformer upgrades (Simpsonville #1, Atoka), 1-transformer addition (Stonewall), West High Street Substation upgrade ($1M - classified as new business).

<u>2016-6 projects, $10.2M</u>
5-completions (Manslick, Paynes Mill, Simpsonville, Atoka, Stonewall), 1-new substation (Lime Kiln).

<u>2017-10 projects, $15.1M</u>
1-completion (Lime Kiln), 5-new substations (Central Baptist, Lexington, Gene Street, Russell Corner, Shelbyville), 4-transformer upgrades (Owenton 4kV, Russell Springs, Shelby City, Simpsonville #2).

<u>2018-14 projects, $19.8M</u>
8-completions (Central Baptist, Lexington, Gene Street, Owenton, Russell Corner, Russell Springs, Shelbyville, Simpsonville #2), 3-substation upgrades (Crockett, Days Branch, Old Henry), 1-transformer addition (American Ave), 2-new substations (Floyd, Horse Cave area).

In addition to capacity enhancement projects necessary to the meet the demand of existing customers, other projects are targeted at enhancing non-load driven needs of the system. Three new projects (incremental to the 2012 Business Plan (BP)) included in the Enhancement to Meet Demand category address improving response to critical substation transformer failures. They include:

- **Purchase LG&E and KU Portable Transformers**, 2014-LGE $2.5M and 2017-KU $2.5M. The purchase of additional portable transformers is needed to minimize outage duration caused by substation transformer failures where quick restoration cannot be accomplished by a direct replacement with a spare transformer. These portable transformers are also needed to support maintenance work and an increasing work plan for substation transformer additions and replacements where transformers have to be removed from service as part of the construction process.
- **KU spare transformers**, $1M each in 2017 and 2018. This funding will be used to increase the spare stock of KU transformers available for the replacement of failed units. Additional spares

will be necessary to address the increasingly aging fleet of substation transformers in the KU areas.

- **At Risk Substations**, $2.5M 2015-2018 with a 3% increase annually. This project includes substation/circuit upgrades, capacity additions and enhancements at high concern substations for the purpose of adding contingency for a substation transformer failure. Targeted substations are stations where large numbers of customers or critical loads will be without service for extended periods of time during transformer failures/outages due to lack of contingency from nearby stations. This initiative is separate from capacity additions to serve existing customers. Funding will provide for one project per year. Targeted stations in the plan for contingency enhancements include Versailles 4 kV, Georgetown 4 kV, Watterson 12 kV, Highland 12 kV, and Harmony Landing (12kV).

Additional projects are designed to enhance the safety or integrity of the system, including:

- **Downtown Network Manhole Lid Replacement** ($1M 2014 and 2015 – this is $500k incremental to the 2012 BP plan to accelerate the existing program from a 5 year program to a 2.5 year program). This program started in 2013 and enhances public safety in high pedestrian areas and covers replacement of conventional manhole lids with lids that are designed to remain in place in the event of a catastrophic cable failure or explosion in a manhole.
- **KU Substation Lightning Protection project** ($50K annually with a 3% increase across the plan). This program retrofits existing KU substations with lightning protection to improve reliability and reduce the potential for failure of high value substation equipment and transformers. All LG&E substations and new KU substations have lightning protection. This program has been inconsistently funded in past years and is incremental to the 2012 BP.

Enhancements for Reliability include blanket funding to address upcoming reliability issues at the operations centers and defined projects to target reliability improvement and/or safety and resiliency of the system. Included are ongoing programs to improve worst circuit performance through CEMI (Customers Experiencing Multiple Interruptions) and CIFI (Circuits Identified for Improvement) projects and high value smaller project reliability work evaluated using the AIS financial model.

One project also included in the Enhancements for Reliability category is the installation of a system to gather load data in the downtown network.

- **Network Load Monitoring (LG&E) $750K (2014)** is incremental to the 2012 BP. This project is necessary to extend the benefits of the completion of the downtown network SCADA project scheduled for completion in 2013. This system will provide critical data necessary for electric system planning of the network under normal and contingency conditions.

The 2012 BP plan also specifically includes $5M in 2017 and 2018 to expand the KU SCADA system. Currently, only 29% of KU Substations have SCADA whereas LG&E 12kV and 14kV substations are 100% SCADA equipped.

<u>Maintain the Network Category</u>

The Maintain the Network category includes capital blanket and project specific funding to replace failed or defective distribution and substation equipment and specific projects to address aging infrastructure. Blanket funding is trended across the plan and key funding areas include distribution lines, substations, street lighting, network vault top replacement and buildings and grounds.

Specifically, aging infrastructure initiatives are based on available data on age, quantity in service, failure data, field experience, equipment specialty knowledge, and industry best practices. O&M considerations are cost to maintain, availability of spare parts, and environmental considerations. The significant aging of the distribution system has necessitated beginning and/or consistently funding replacement and/or rehabilitation programs. These programs target critical distribution assets nearing or beyond their expected life expectancy in areas where they have resulted in declining reliability. Robust system development in the 1960's and 1970's has created substantially high groups of equipment and material with similar age and created the potential for very high failure rates in future years. Key components of the program include:

- **Pole Inspection and Treatment (LG&E/KU).** This program is funded at $10.5M in 2014 with a growth of 3% across the plan. This program covers the capital cost to extend the life of wood poles though retreatment and reinforcement and covers the cost of defective or overloaded pole replacements. The program is intended to address approximately 8% of wood poles annually (+/- 13 year inspection cycle).
- **Paper Insulated Lead Covered (PILC) Cable Replacement (LG&E).** This program, started in 2013 ($2M) involves the replacement of primary and secondary PILC cable in the downtown network to address increasing reliability concerns. Targeted cable is between 50 and 90+ years old. PILC replacement is funded in the proposed 2013 BP at $4M each year with a growth of 3% across the plan. This includes $2M incremental annually to the 2012 BP to reduce the program from a 20 year to a 10 year replacement program. Shortening the program to 10 years is necessary because data does not exist to target the oldest cables first and some cable will be in excess of 100 years old by the time it is replaced.
- **Substation Asset Replacements (LG&E/KU).** This program covers the annual replacement of critical, maintenance intensive, and/or unreliable substation equipment (substation batteries, relays, 15kV power circuit breakers, Remote Terminal Units, and Load Tap Changers). In 2012, Substation Construction and Maintenance identified a "Top 5 List" for both LG&E and KU based on a combination of advanced age, chronic operational issues, quantity in service, field experience, and equipment specialty knowledge. O&M considerations were cost to maintain, availability of spare parts, and environmental considerations. The Substation Aging Infrastructure program has been in past business plans but has been cut or substantially reduced due to pressures in capital funding. The program is in the plan at approximately $3M annually with a growth of 3% across the plan.
- **Substation Underground Cable Exits (LG&E).** This program is funded at $1M in 2015 with a growth of 3% across the plan. This program covers the replacement of PILC and poor performing solid dielectric and underrated substation exit cables. Targeted substation exits are

between 40 and 90+ years old that have accrued multiple failed segments and have higher loading and customer impacts. The Substation Underground Cable Exits (LG&E) program has been in past business plans but has been cut due to pressures in capital funding.

- **Rear Easement Hardening (LG&E/KU).** This program covers the rehabilitation of older, storm sensitive overhead lines in difficult to maintain rear easements where they have demonstrated poor reliability or storm performance. Aspects of the program include replacement of undersized and/or defective small wire, stronger and/or taller poles, selective undergrounding, storm guying, elimination of secondary and replacement of aged and defective equipment. This program is incremental to the 2012 BP and is funded at $2M per year beginning in 2015 with a growth of 3% across the plan. The Rear Easement Hardening program has been in past business plans but has been cut due to pressures in capital funding.
- **Underground Cable Rejuvenation/Replacement (LG&E/KU).** This program piloted since 2010 involves the life extension or replacement (where cables are not candidates for life extension) of direct buried primary underground residential distribution (URD) cable. This program addresses early generation URD cables that are 40-50 years old that have demonstrated poor reliability. These cables had a projected 30 year life expectancy when new. The purpose of this program is to extend the life of existing cables to levelize future failure replacement costs. It is funded at $800k per year ($500k-LG&E, $300k-KU) with a growth of 3% across the plan.
- **DT Network Vent Type Protector Replacement (LG&E).** This program is in the plan in 2017/2018 and is intended to begin the incremental replacement of critical network protectors that are not submersible rated where they are installed below ground and subject to flooding. The program will be annually funded at $1M a year beginning in 2017 to address the most critical of these assets and further enhance the integrity of the downtown network.

Repair the Network Category

Repair the Network consist of blanket project that address expected expenses associated with system restoration (storm and non-storm), repairs of third party damage, and substation transformer repairs and rewinds.

Miscellaneous Network Category

Miscellaneous Network covers miscellaneous expense for tooling, equipment and vehicles (vehicles are funded at increased levels in 2015-2018 (2015, 2016 - $5M, 2017, 2018 – 10.5M).

						Cash Flow							Overloaded		
AIS Project	Start Year	Type	ProjectName	Description	Justification	2013	2014	2015	2016	2017	2018	2019	Peak Load	Normal Rating	Emergency Rating
2897	2013	Non-Discretionary	Downtown Network Automation (SCADA)	Design and install a network protector automation system for the Louisville Downtown Secondary Network distribution system. This system will permit real-time	Management commitment to fund network automation project.	2079	513						0.0	0.0	0.0
2892	2013	Non-Discretionary	DSP Flemingsburg Substation Upgrade	Year 2 of 2 year project. Peak normal service Winter load on Flemingsburg Sub was 114% of the 7MVA top nameplate. On the same size transformer, the Wedonia Sub	Project started in 2012.	910							8.6	8.4	9.5
2898	2013	Non-Discretionary	DSP Paris 12kV Substation Upgrade	Year 2 of 2 year project. The Paris system consists of two primary 12kV substations. The Detroit Harvester 22.4MVA substation experienced winter 2009 peak load of	Project started in 2012	820							17.8	16.8	19.0
2949	2013	Non-Discretionary	DSP Polo Club Blvd Distribution	Circuit construction required to accomodate DSP Polo Club Blvd Substation construction	This project is associated with the Polo Club Substation, which was started in	1430							0.0	0.0	0.0
2948	2013	Non-Discretionary	DSP Polo Club Blvd Substation	Year 2 of 2 year project. Construct new 22.4MVA substation with three breakers on new property purchased at 2975 Polo Club Boulevard. Construct substation to	This is year 2 of the project started in 2012	2547							15.0	14.0	16.8
2881	2013	Non-Discretionary	DSP Substation Property - Gene St. Mt. Washington	Purchase substation property for future use. We currently own a small parcel on Gene St. in Mt. Washington. The general consensus is it would be difficult to build	Substation property purchase for future capacity needs.	750							0.0	0.0	0.0
3686	2013	Non-Discretionary	Manhole Cover Replacement Program- LG&E - 2013	Retrofit approx 1000 existing manhole covers with vented, pressure relief type manhole covers on all downtown Louisville manholes containing secondary network	Improve public safety from catastrophic manhole explosions and lower risk of	700							0.0	0.0	0.0
2869	2013	Non-Discretionary	Pole Inspection and Treatment KU - 2013	An infrastucture improvement program to inspect and evaluate the condition of distribution wood poles on the KU system. The program inspects poles, assesses the	Corporate Asset Management Strategy to proactively evaluate, inspect, treat, and	6472							0.0	0.0	0.0
2870	2013	Non-Discretionary	Pole Inspection and Treatment LG&E - 2013	An infrastucture improvement program to inspect and evaluate the condition of distribution wood poles on the LG&E system. The program inspects poles, assesses	Corporate Asset Management Strategy to proactively evaluate, inspect, treat, and	3811							0.0	0.0	0.0
3701	2013	Non-Discretionary	SCM 2013 CENT-Purchase R O W for Access Road to	Purchase right of way to access the Buena Vista Substation from a dedicated road owned and maintained by Kentucky Utilities Company. Presently, access to the	ROW	141							0.0	0.0	0.0
3415	2013	Non-Discretionary	SCM 2013 CENT-REPL LEGACY LTC/REG CONTR	Purchase and Install New LTC and Regulator Controls. Remove and Retire Legacy Controls.	Ongoing project to replace legacy LTC and Regulator Controls with new style	55							0.0	0.0	0.0
3526	2013	Non-Discretionary	SCM 2013 EARL-REPL LEGACY LTC/REG CONTR	Purchase and Install New LTC and Regulator Controls. Remove and Retire Legacy Controls.	Ongoing project to replace legacy LTC and Regulator Controls with new style	55							0.0	0.0	0.0
2913	2013	Non-Discretionary	SCM 2013 LG&E LTC Oil Filter Units	We are requesting money to continue our succesful program of installing oil filtration systems on transformer LTC's. These devices have proven to significantly	We are requesting money to continue our succesful program of installing oil	53							0.0	0.0	0.0
3410	2013	Non-Discretionary	SCM 2013 LG&E Misc Dist Proj	Requesting funding for the miscellaneous capital expenses such as bushings, insulators, surge arresters, capacitors, etc. that are required throughout the year.	Failed units will require replacement to ensure continuity of service. Units which	105							0.0	0.0	0.0
3439	2013	Non-Discretionary	SCM 2013 PINE MISC CAPITAL PROJ	Requesting funding for the miscellaneous expenses such as bushings, insulators, arresters, etc that are required throughout the year.	Failed units will require replacements to ensure continuity of service. Units	145							0.0	0.0	0.0
2798	2013	Non-Discretionary	SCM 2013 PINE MISC NESC COMPLIANCE	Substation surveys have turned up many NESC compliance concerns such as fences too short and vertical electrical clearances not adequate. This miscellaneous project	requied to comply with NESC/PSC.	63							0.0	0.0	0.0
3438	2013	Non-Discretionary	SCM 2013 PINE REPLACE SUBSTATION BATTERIES	Replace defective wet cell batteries and battery chargers in distribution substations.	Reliable DC power is needed in order to properly operate automatic protection	28							0.0	0.0	0.0
3521	2013	Non-Discretionary	SCM 2013 PINE-REPL LEGACY LTC/REG CONTR	Purchase and Install New LTC and Regulator Controls. Remove and Retire Legacy Controls.	Ongoing project to replace legacy LTC and Regulator Controls with new style	55							0.0	0.0	0.0
3066	2013	Non-Discretionary	SCM CENT Misc Dist Capital Sub Project	Purchase and install material and equipment in various distribution substations as required to serve loads, upgrade equipment and replace failed facilities.	Replace failed equipment and facilities as encountered.	244							0.0	0.0	0.0
2935	2013	Non-Discretionary	SCM CENT Misc NESC Compliance	Substation checks have shown many NESC compliance issues. This includes fences too short and vertical electrical clearance issues. This project will enable us to	NESC issues must be addressed to meet PSC compliance (and NESC compliance)	68							0.0	0.0	0.0
3061	2013	Non-Discretionary	SCM CENT REPL BREAKERS	Replace approximately seven failed breakers per year in the Central substation area	Failed units will require replacement to ensure continuity of service	180							0.0	0.0	0.0
3064	2013	Non-Discretionary	SCM CENT REPL BUSHINGS	Replace approximately 27 failed and deteriorated bushings on substation transformers and breakers. This number has substantially increased from past years	Failed units will require replacement to ensure continuity of service	93							0.0	0.0	0.0
3065	2013	Non-Discretionary	SCM CENT REPL REGULATORS	Purchase regulators to replace approximately six failed units and maintain adequate stock	Failed units will require replacement to ensure continuity of service	74							0.0	0.0	0.0
3067	2013	Non-Discretionary	SCM CENT Replace Substation Batteries	Replace wet cell batteries and chargers due to age, defect, or failure.	Replacement due to age, defect, or failure. Failed units will require	42							0.0	0.0	0.0
2855	2013	Non-Discretionary	SCM EARL MISC DIST CAPITAL SUB PROJ	This project is to provide funding for various repairs and upgrades that arise throughout the year. Often, this work will be associated with an equipment failure or	Marked Non-Discretionary per Technical Review Team	200							0.0	0.0	0.0
2857	2013	Non-Discretionary	SCM EARL MISC NESC COMPLIANCE	A review of substations has revealed several deficiencies. Most deficiencies are perimeter fence height problems. There are some energized parts ground clearance	NESC COMPLIANCE RELATED	140							0.0	0.0	0.0
2971	2013	Non-Discretionary	SCM EARL REPLACE SUBSTATION BATTERIES	This project is to replace substation batteries and chargers at various locations. Several banks are deteriorated. Several chargers are becoming unreliable and should	Reliable DC power is needed in order to properly operate automatic protection	30							0.0	0.0	0.0
3695	2013	Non-Discretionary	SCM Earlington Replace Regulators	Purchase regulators to replace approximately six failed units and maintain adequate stock	Failed units will require replacement to ensure continuity of service	74							0.0	0.0	0.0
2918	2013	Non-Discretionary	SCM KU EARL Replace legacy 34KV breakers	Replace aging 34kv oil circuit breakers. Five units are 40-60 years old, and spare parts are becoming difficult to find. Replace 2 breakers per year until these 5 have	Replace aging 34kv oil circuit breakers. Five units are 40-60 years old, and spare	160							0.0	0.0	0.0
3437	2013	Non-Discretionary	SCM KU HZ Relay Replacement	Replace legacy, low reliability Westinghouse HZ Distance Relays, 6 per year. Transmission has a standard practice of replacing these relays whenever possible	Improved reliability and capability. Transmission has a standard practice of	60							0.0	0.0	0.0
3461	2013	Non-Discretionary	SCM KU Legacy RTU Replacements	The majority of KU Distribution Substations in or near the Lexington area have early 1980's vintage Leeds and Northrup remote terminal units. These legacy devices do	These legacy RTUs experience high failure rates, requiring labor intensive	268							0.0	0.0	0.0
2809	2013	Non-Discretionary	SCM KU PINE Replace legacy 34kv breakers	Replace aging 34kv oil circuit breakers. Several units were manufactured circa 1950, and spare parts are becoming difficult to find. Replace (2) breakers per year from	Replace aging 34kv oil circuit breakers. Several units were manufactured circa	160							0.0	0.0	0.0
2957	2013	Non-Discretionary	SCM LG&E Substation Building and Grounds	Request is for the funding of repairs/replacements on control house buildings, fire preventions systems and other general capital improvements to substation grounds	Request is for the funding of repairs/replacements on control house	70							0.0	0.0	0.0
3465	2013	Non-Discretionary	SCM LGE Legacy RTU Replacements	Several LG&E Distribution Substations have early 1980's vintage Landis and Systems Northwest remote terminal units. These legacy devices do not support serial or	These legacy units experience high failure rates, requiring labor intensive board	260							0.0	0.0	0.0
2804	2013	Non-Discretionary	SCM LGE Miscellaneous NESC Compliance Projects	Substation surveys have turned up many NESC compliance concerns such as fences too short and vertical electrical clearances not adequate. This miscellaneous project	Required for NESC and PSC compliance	75							0.0	0.0	0.0
2803	2013	Non-Discretionary	SCM LGE REPL TRANSF FIRE DETECTION SYSTEMS	A significant percentage of fire detection thermostats on these systems have experienced failures from an acknowledged design flaw. The inadvertent trip of a	Failed units will require replacement to ensure continuity of fire suppression	23							0.0	0.0	0.0
3509	2013	Non-Discretionary	SCM LGE Replace Legacy VRR's	LGE requests funding to replace legacy voltage regulating relays (VRR's) at a rate of (6) per year. The legacy units are not reliable and spare parts are very difficult to	LGE requests funding to replace legacy voltage regulating relays (VRR's) at a rate	40							0.0	0.0	0.0
2810	2013	Non-Discretionary	SCM LGE Replace Substation Batteries	Need to replace 5 Substation Battery systems per year due to age. Various Distribution Substations have batteries that are between 21 and 25 years old.	Failed units will require replacement to ensure continuity of service and proper	89							0.0	0.0	0.0
3532	2013	Non-Discretionary	SCM PINE RECLOSER REPL	The Pineville area has over 95 reclosers inside substations. Replace approximately two failed reclosers in substations in the Pineville area per year.	Must replace failed units	58							0.0	0.0	0.0
3709	2013	Non-Discretionary	SCM Pineville Replace Regulators	Purchase regulators to replace approximately six failed units and maintain adequate stock	Failed units will require replacement to ensure continuity of service	74							0.0	0.0	0.0
2866	2013	Non-Discretionary	UG Network PILC Primary Cable Replacement Program-	A proactive asset replacement program to replace aging and defective paper insulated lead covered (PILC) primary underground cables in the LG&E Downtown	Improve public safety from catastrophic manhole explosions and lower risk of	2000									
3685	2013	Non-Discretionary	UG Network PILC Secondary Cable Replacement Program-	A proactive asset replacement program to replace aged, deteriorating paper insulated lead covered (PILC), secondary underground cables in the LG&E Downtown	Improve public safety from catastrophic manhole explosions and lower risk of	2000							0.0	0.0	0.0
3678	2013	Discretionary	Belknap Vault	Replacing all network vault transformers with larger size transformers and intigrating a cooling system.		602							4.0	4.0	4.5
2890	2013	Discretionary	Black Mountain, Relocation FAA Ckt	Construct 7400' of 2/0 ASCR three phase space cable along the road to the FAA radar dome. New line woudl shorten the existing feed by approximately 2400'. The		226							0.0	0.0	0.0
3047	2013	Discretionary	Bromley Circuit 702 Removal	Remove 21,463 feet of 3 phase abandoned primary. Poles are rotten and several have fallen down. Safety/Liability issue.		125							0.0	0.0	0.0
3660	2013	Discretionary	California Reconductor	Reconductor approximately 32,000' of 4-2acsr 12 kv primary and neutral with 3-2/0 acsr 12kv primary. The existing conductor from Ivor Road to the city of California out		325							0.0	0.0	0.0
2867	2013	Discretionary	CEMI>5 Circuits - KU - 26 Circuits - 2013	Improve reliability on 26 KU circuits that have Customers Experiencing Multiple Interruptions (CEMI) of more than 8 outages in 2011. Budgetary project description		650							0.0	0.0	0.0

						Cash Flow							Overloaded		
AIS Project	Start Year	Type	ProjectName	Description	Justification	2013	2014	2015	2016	2017	2018	2019	Peak Load	Normal Rating	Emergency Rating
2868	2013	Discretionary	CEMI>5 Circuits - LGE - 43 Circuits - 2013	Improve reliability on 43 LGE circuits that have Customers Experiencing Multiple Interruptions (CEMI) of more than 8 outages in 2011. Budgetary project description		1075							0.0	0.0	0.0
3812	2013	Discretionary	CIFI (worst) Circuits - Level 1 KU - 5 Circuits - 2013	Improve reliability on five(5) Level 1 Circuits ID'd for Improvement (CIFI) at KU. Level 1 CIFI circuits have a long term (5 year) poor SAIFI performance record where the		650							0.0	0.0	0.0
3813	2013	Discretionary	CIFI (worst) Circuits - Level 1 LGE - 1 Circuit - 2013	Improve reliability on one(1) Level 1 Circuits ID'd for Improvement (CIFI) at LGE. Level 1 CIFI circuits have a long term (5 year) poor SAIFI performance record where		130							0.0	0.0	0.0
3818	2013	Discretionary	CIFI (worst) Circuits - Level 2 KU - 12 Circuits - 2013	Improve reliability on 12 Level 2 Circuits ID'd for Improvement (CIFI) at KU. Level 2 CIFI circuits have a long term (5 year) poor SAIFI performance record where the		1560							0.0	0.0	0.0
3819	2013	Discretionary	CIFI (worst) Circuits - Level 2 LGE - 1 Circuit - 2013	Improve reliability on one(1) Level 2 Circuits ID'd for Improvement (CIFI) at LGE. Level 2 CIFI circuits have a long term (5 year) poor SAIFI performance record where		130							0.0	0.0	0.0
3820	2013	Discretionary	CIFI (worst) Circuits - Level 3 KU - 28 Circuits - 2013	Improve reliability on 28 Level 3 Circuits ID'd for Improvement (CIFI) at KU. Level 3 CIFI circuits have a long term (5 year) poor SAIFI performance record where the		3640							0.0	0.0	0.0
3826	2013	Discretionary	CIFI (worst) Circuits - Level 3 LGE - 25 Circuits - 2013	Improve reliability on 25 Level 3 Circuits ID'd for Improvement (CIFI) at LGE. Level 3 CIFI circuits have a long term (5 year) poor SAIFI performance record where the		3250							0.0	0.0	0.0
2975	2013	Discretionary	Circuit 0254 relocation (Muddy Gap - Manchester)	To relocate 7000' of overhead three phase that travels though inaccesable territory. Project will dramatically improve restoration times for the area		280							0.0	0.0	0.0
2824	2013	Discretionary	Coordinate circuit #278, Corbin East Substation	Purchases and install 2 three phase reclosers, 2 single phase reclosers, three three phase cutout banks and fuse off all main line taps.		125							0.0	0.0	0.0
2899	2013	Discretionary	De-energized line removal - Manchester	LINES SHOULD BE REMOVED FOR PUBLIC SAFETY This project is to remove de-energized lines in Manchester, KY. The three phase lines run thought Clay County in		75							0.0	0.0	0.0
3720	2013	Discretionary	Downtown Network Vault Structural Repairs	Review and repair vault structural facilities that have deteriorated due to age, road salt, etc.		250							0.0	0.0	0.0
3021	2013	Discretionary	DSP Adams Ckt 0453 Recloser	Remove existing recloser and install new recloser(s) on Adams circuit 0453. The three 200 amp V4L reclosers near Paynes Depot Rd are currently out of service due		100							0.0	0.0	0.0
2850	2013	Discretionary	DSP Big Stone Gap 2 Breaker	Replace the 600 amp breaker with a 1200 amp breaker on Ckt 4702. See related distribution project. Big Stone Gap 2 breaker: 97% winter. Substation: $75,000.		75							12.6	13.0	13.0
2851	2013	Discretionary	DSP Big Stone Gap 2 Ckt 4702	Replace 100' 397ACSR with 795 AAC (first span beginning at the substation) while the substation disconnects are being replaced. See related substation project.		10							0.0	13.0	13.0
2952	2013	Discretionary	DSP Central City 4kV to 12kV Distribution Conversion	The purpose of this project is to convert the Central City 4KV distribution system to 12KV. The distribution system is fed from two dual voltage substations: Central City		240							0.0	0.0	0.0
3721	2013	Discretionary	DSP Central City Substation Conversion and Upgrade	The purpose of this project is to convert the two dual voltage substations to 12KV (Central City 4KV-5711 and Central City South 4KV- 4051 Substations). Both		255							0.0	0.0	0.0
3802	2013	Discretionary	DSP CENT-Replace Lancaster 2 Substation Transformer	The Danville Op Center has requested a project to replace the 3.75/5.25 MVA transformer in the Lancaster 2 Substation (#884-1) with a 10/14 MVA transformer.		1171							0.0	0.0	0.0
3681	2013	Discretionary	DSP Eddyville 12KV Substation Upgrade	Replace the 10.5 MVA transformer with a 14.0 MVA transformer due to customer load growth. the summer 2011 peak was 100% of the top rating. The summer of		480							11.1	10.5	12.6
3671	2013	Discretionary	DSP Elizabethtown 2- Bus Tie Breaker Project	The purpose of this project is install a bus tie breaker between the two base 12 transformers at Elizabethtown 2 Substation. The breaker is needed for planned and		125							0.0	0.0	0.0
3666	2013	Discretionary	DSP Elizabethtown 3-Circuit 2332 Tie Circuit Project	The purpose of this project is to develop a viable tie circuit between Elizabethtown 3 (809-2)and Elizabethtown Industrial (552-1)Substations. Replace 4400' of 2/0A with 3-		998							0.0	0.0	0.0
3462	2013	Discretionary	DSP Esserville Ckt 4614 Recloser	Install recloser on Esserville Ckt 4614 to improve the reliability. Distribution: $50,000.		50							0.0	13.0	13.0
3494	2013	Discretionary	DSP Hancock Highland Circuit Work	Circuit work required to establish new tie between Highland and Hancock Substations. Circuit will allow transfer of load from Highland Substation to Hancock		292							44.9	44.8	53.8
3718	2013	Discretionary	DSP Hartford 4KV Substation Conversion and Upgrade	The purpose of this project is to convert the Hartford 4KV substation transformer to 12KV and upgrade the substation to current standards. This project will solve voltage		105							0.0	0.0	0.0
3717	2013	Discretionary	DSP Hartford 4KV to 12KV Distribution Conversion	The purpose of this project is to convert the Hartford 4KV system to 12KV. Replace all straight 4KV rated distribution transformers, 3KV rated insulators and insulators		130							0.0	0.0	0.0
3676	2013	Discretionary	DSP Hartford 4KV to Beaver Dam North Tie Circuit Project	The purpose of this project is to complete a tie circuit from Hartford 4KV (Circuit 1911) to Beaver Dam North 12KV (Circuit 0919). This is the first step in a plan to		255							0.0	0.0	0.0
3457	2013	Discretionary	DSP High Bridge Distribution	Replace 4kV substation fuses with a new line recloser near the substation to provide full substation protection (due to inadequate space inside the substation). See		80							0.0	37.3	44.8
3455	2013	Discretionary	DSP High Bridge Substation	Increase the capacity of the substation regulators in order to fully utilize the substation capacity (2/2.3 MVA) and provide contingency support to the City of		150							37.0	37.3	44.8
3687	2013	Discretionary	DSP Liberty Substation Recloser Addition	Install electronic recloser, RTU and associated materials to feed and protect Liberty substation circuit 552. The Liberty substation has three 12kV distribution circuits,		120							0.0	0.0	0.0
2820	2013	Discretionary	DSP Manslick Circuit Work	Circuit work associated with Manslick Substation expansion (44.8 MVA transformer addition). See Manslick Substation expansion for detail.		748	748						0.0	0.0	0.0
2976	2013	Discretionary	DSP Manslick Substation Expansion	Add 1-44.8 MVA 138kV/13.09kV transformer, switchgear and complete associated circuit work at Manslick Substation. See attached business case document.		4203	639						44.9	44.8	53.7
3677	2013	Discretionary	DSP Norton East Ckt 4609	Replace 4900' 6C/4C neutral with 2/0A conductor along Kentucky Ave. The existing neutral conductor is a sub-standard size for the existing primary conductor (397		50							0.0	13.0	13.0
3503	2013	Discretionary	DSP Owenton Step Up Bank 2013	Synergee models show overload on 4/12 250KVA stepup bank off Owenton 0716. Scope of project is to confirm load with readings during peak and upgrade		20							1.0	0.9	10.2
2852	2013	Discretionary	DSP P&G Breaker	Replace an existing 600 amp breaker with a 1200 amp breaker on P&G Ckt 0066 plus upgrade various substation components (e.g. transfer bus). Ckt 0065 serves a		300							0.0	0.0	0.0
3004	2013	Discretionary	DSP Paris Circuit 805 Upgrade	Reconductor approximately 13000' of 266acsr with 397 acsr between the Paris 12kv substation and Bethlehem Road (circuit 805). The reconductor would increase the		330							0.0	0.0	0.0
3005	2013	Discretionary	DSP Paris Circuit 806 Tie Upgrade	Reconductor approximately 5100' of 266 acsr with 397 acsr between the Paris 12 kv substation and US highway 460 (circuit 806). The reconductor would increase the		132							0.0	0.0	0.0
3689	2013	Discretionary	DSP Pocket 34/4kV Substation	Aging Infrastructure Project: Remove and/or replace as necessary 34kV substation equipment (breakers/disconnects) and 4kV substation equipment (breaker,		260							16.8	16.8	19.0
2888	2013	Discretionary	DSP Richmond Industrial Breaker	Resubmittal of a 2012 project which was deferred. Install one 15kV 1200 amp breaker, remove one 15kV 600 amp breaker, circuit 343 on the Richmond Industrial		75							0.0	0.0	0.0
3775	2013	Discretionary	DSP Russell Corner Circuit Work (2013-2014)	The scope of this project is to build a new 138/13.09 kV, 10.5 MVA substation on currently owned property or a new site in Russell Corner, KY along US 42 or US 53.		500	250						0.0	0.0	0.0
2939	2013	Discretionary	DSP Russell Corner Substation Project (2013-	The scope of this project is to build a new 138/13.09 kV, 10.5 MVA substation on currently owned property or a new site in Russell Corner, KY along US 42 or US 53.		2000	1900						12.7	12.6	14.3
3517	2013	Discretionary	DSP SCM 2013 MANCHESTER SUBSTATION REBUILD	Replace transfer switch, add transfer switch, replace old pincap insulators, replace 50 year old OCB BB-0068 with VWE recloser and replace security fence.		170							0.0	0.0	0.0
3460	2013	Discretionary	DSP St Paul 1 Breaker	Install new breaker to divide the load on Ckt 0687. The installation of a breaker will permit the transfer bus to be de-energized and improve reliability. Substation:		75							0.0	16.8	19.0
3459	2013	Discretionary	DSP Trim Master Distribution	Install/replace/reconfigure underground and overhead exit circuits as necessary to fully utilize the Trim Master substation transformer capacity. See related substation		150							0.0	37.3	44.8
3458	2013	Discretionary	DSP Trim Master Substation	Purchase and upgrade (as necessary) the customer owned Trim Master substation (7.5 MVA). The Trim Master plant in Nicholasville, KY is scheduled to close their		300							37.0	37.3	44.8
2906	2013	Discretionary	DSP Versailles Substation Project	Install one 12/22.4 MVA 67/13.09kV LTC substation transformer, steel structures, main breaker, circuit breakers, and associated equipment on substation property		2100	2550						25.0	22.4	26.9
2834	2013	Discretionary	DSP Versailles West to Versailles Bypass- Circuit	The purpose of this distribution circuit project is to complete the tie circuit between Bypass 1 circuit 509 and the Versailles West 12KV circuit 513. This tie circuit supports		81							13.0	10.0	14.7
2901	2013	Discretionary	DSP Versailles-Alexander Circuit 500 Upgrade	The purpose of this project is to improve customer service and reliability by adding the third phase (B-Phase) to this extended two phase rural circuit. Install 10,000' of 1-		250							0.0	0.0	0.0
2943	2013	Discretionary	Evarts Relocation at Black Mountain	Relocate a section of Evarts circuit 4476 near Disney. This will bring the line from the mountain side to the shoulder of hwy. Where the line is currently located frequently		120							0.0	0.0	0.0

						Cash Flow							Overloaded		
AIS Project	Start Year	Type	ProjectName	Description	Justification	2013	2014	2015	2016	2017	2018	2019	Peak Load	Normal Rating	Emergency Rating
3610	2013	Discretionary	Fault Circuit Indicator UG Project	Install 100 FCI's on the the worst performing URD circuits.		33							0.0	0.0	0.0
3776	2013	Discretionary	Hamblin (Jonesville) circuit.	Three phase existing single phase route to provide a second feed into the town of Jonesville, the county seat for Lee County, VA This town has only one circuit feeding		250							0.0	0.0	0.0
2946	2013	Discretionary	Harlan, Relo 0413	relocate 2800' of circuit 0413. Relocation would remove portion of line that is inaccesable. Taller poles are needed to accomidate the 12 kV circuitry		215							0.0	0.0	0.0
2932	2013	Discretionary	Harrogate 395 Regulators	Install voltage regulators on Harrogate 395 to maintain voltage at SCC required levels when circuit is fed from Rose Hill Ckt 777. Total circuit distance when fed from Rose		75							0.0	0.0	0.0
2940	2013	Discretionary	HK1235	The HK-1235 reliability project will address reliability issues with the carline. The project will include replacing poles, brackets and reconductor of spacer cable and		766							0.0	0.0	0.0
2832	2013	Discretionary	HK1237	This project would address reliability complaints by bringing an additional underground 3-phase feed to create a tie between HL-1157. This project would also		451							0.0	0.0	0.0
3393	2013	Discretionary	INSTALL 5000 FEET OF 397 ACSR HWY 80 RUSSELL	INSTALL APPROXIMATELY 5,000 FEET OF 3-397 ACSR, 1-2/0 NEUTRAL ALONG KY HWY 80 TO SERVE COMMERCIAL AREA AT LAKEWAY DRIVE AND KY 80 IN RUSSELL		120							0.0	0.0	0.0
3754	2013	Discretionary	JODY JONES RELOCATION	LINE IS LOCATED AT UNACCESABLE LOCATION. PROJECT IS TO BUILD SECTION OF LINE ALONG HWY 1651 TO GET LINE OUT OF BAD LOCATION. POWER LINE GOES		65							0.0	0.0	0.0
3056	2013	Discretionary	Kenton to Wedonia tie circuit	Install approximately 5000' of 3-397acsr 12kv primary and 1-2/0 neurtal between the Kenton Substation circuit 923 and the Wedonia substation circuit 965. This		220							0.0	0.0	0.0
3806	2013	Discretionary	LEO Cable Rejuvenation	Cable rejuvenation restores the dielectric strength of in-service aged cable insulations to new cable dielectric strength levels and is warranted to provide 20		250							0.0	0.0	0.0
2829	2013	Discretionary	McKee Rd - Science Hill	SCIENCE HILL SUB TRANSFORMER IS CURRENTLY BEING WORKED ON BY ABB. WE CAN ONLY DO THIS CERTAIN TIMES OF THE YEAR DUE TO LOAD. IF THIS PROJECT		260							0.0	0.0	0.0
3063	2013	Discretionary	Milford Reconductor	Reconductor approximately 20,000' of 2-4acsr 7.2kv primary and neutral with 2-2acsr. This circuit, 935 out of the Sharon substation, is a radial feed to the town of		84							0.0	0.0	0.0
3917	2013	Discretionary	Rear Easement OH Hardening - KU - 2013 COPY	Initiate a project to replace defective, small capacity overhead conductor and related distribution line equipment in rear lot applications on the KU system. Targeted		1000									
3916	2013	Discretionary	Rear Easement OH Hardening LGE - 2013 COPY	Initiate a project to replace defective, small capacity overhead conductor and related distribution line equipment in rear lot applications on the LGE system. Targeted		1000									
2812	2013	Discretionary	RECONDUCTOR CIRCUIT #773 IN HARRODSBURG	REPLACE 10000 FEET OF 1/0ACSR WITH 397ACSR FROM SUB 404 TO 860-2 IN HARRODSBURG. THIS IS THE TIE FOR THREE SUBSTATIONS AND SERVES THE HITACHI		318							6.2	5.6	5.6
2807	2013	Discretionary	RECONDUCTOR CIRCUIT 154 STANFORD TO HUSTONVILLE	REPLACE 10000 FEET OF #1STR COPPER WITH 397 ACSR AND 2/0 ACSR NEUTRAL.		308							0.0	0.0	0.0
2941	2013	Discretionary	RECONDUCTOR CIRCUIT 2104	REPLACE 13000 FEET OF 3-2/0 ACSR WITH 397 ACSR AND 1-2/0 ACSR NEUTRAL.		400							5.3	6.3	6.3
3391	2013	Discretionary	RECONDUCTOR CIRCUIT 2215 IN LEBANON	REPLACE APPROXIMATELY 5,900 FEET OF 2/0 ACSR WITH 397 ACSR . THIS IS CIRCUIT 2215 WHICH TIES LEBANON SUB 788-2 TO LEBANON SUB 409-1. DUE TO THE		118							0.0	0.0	0.0
2938	2013	Discretionary	RE-CONDUCTOR DIXON FEEDER	Re-conductor approximately 6,000 ft., 3-phase, #2 ACSR Primary and Neutral with #2/0 ACSR on main feeder, circuit 1427, that has steel core deteriorating and causing		90							0.0	0.0	0.0
3392	2013	Discretionary	RECONDUCTOR PART OF CIRCUIT 2220, LEBANON	REPLACE APPROXIMATELY 3,000 FEET OF 266.8 ACSR WITH 397 ACSR IN CIRCUIT 2220. THIS IS THE HEAVILY LOADED INDUSTRAIL PARK CIRCUIT IN LEBANON AND		55							0.0	0.0	0.0
3062	2013	Discretionary	REMOVE ABANDON DEKOVEN LINE	Remove approximately 4.6 miles of abandon 69 KV transmission/distribution line, consisting of 39 Z-frames, 12 H-fixtures, and 2 running corners, and three 266 ACSR		80							0.0	0.0	0.0
3386	2013	Discretionary	REMOVE PERRYVILLE TO TEXAS LINE	REMOVE APPROXIMATELY 42,500 FEET OF OLD 33 KV LINE WHICH RUNS FROM PERRYVILLE TO TEXAS. THIS LINE HAS NOT BENN ENERGIZED FOR OVER 10 YEARS. IT		170							0.0	0.0	0.0
3384	2013	Discretionary	REMOVE ROUND HILL LINE	REMOVE APPROXIMATELY 35,000 FEET OF OLD 33 KV LINE.THIS LINE HAS NOT BEEN ENERGIZED IN 10 YEARS, IT HAS NO SERVICE TERRITORY ASSOCIATED WITH IT, AND		140							0.0	0.0	0.0
2934	2013	Discretionary	RIC Reconductor Ckt 2161	Circuit 2161 serves Pattie A Clay Hospital, Richmond Mall, Ky State Police, Madison County EMS and other hig profile customers along the EKU Bypass. The circuit is		89							0.0	0.0	0.0
2822	2013	Discretionary	RIC Remove Roundhill to Garrard County line	Remove 15,000 ft of 3-2/0A primary from Roundhill to the Garrard County line. The circuit is an old 34.5 KV line that was converted to distribution to serve as a tie		52							0.0	0.0	0.0
2823	2013	Discretionary	Rose Hill re-locate portion of Ckt 777	Re-locate portion of Ckt 777 from swamp created by highway relocation.		195							0.0	0.0	0.0
3420	2013	Discretionary	SCM 2013 CENT ADAMS 69/34KV AUTOTRANSF	Project to Replace Existing 34.5 KV Wood Pole Take Off Structure and Sectionalize 69/34.5 KV Transformer from 69 KV Line for increased line security at Adams #108		400							0.0	0.0	0.0
3703	2013	Discretionary	SCM 2013 CENT-Purchase and Install new Micro-	Purchase and Install new Micro-Processor Recloser for existing circuit 0718 at Hunters Bottom Substation. Hunters Bottom Circuit 0718 is presently a hydraulic		60							0.0	0.0	0.0
3069	2013	Discretionary	SCM 2013 CENT-SCHOLLS / VINE PROJECT	The purpose of this project is to provide an emergency replacement transformer for the Vine Street or Scholls 4 KV Substation. Vine Street and Scholls have a		470							0.0	0.0	0.0
2981	2013	Discretionary	SCM Fern Valley Substation Automatic Caution Card	The Substation Operating Group completes over 2,500 substation visits per year to apply cautions to Distribution Circuits. Fern Valley Substation has 22 distribution	The addition of SCADA control of reclosing in/out and ground relay in/out	180							0.0	0.0	0.0
3866	2013	Discretionary	SCM KU CENT Replace Legacy OCB's: Types FK, FKD, G, GC.	The KU system includes numerous legacy oil filled circuit breakers, typically installed in the 1940's or 1950's. These breakers require frequent maintenance intervals to		290									
3827	2013	Discretionary	SCM KU EARL Replace Legacy OCB's: Types FK, FKD, G, GC.	The KU system includes numerous legacy oil filled circuit breakers, typically installed in the 1940's or 1950's. These breakers require frequent maintenance intervals to	Both the KU and LG&E systems include numerous legacy oil filled circuit	150									
3821	2013	Discretionary	SCM KU PINE Replace Legacy OCB's: Types FK, FKD, G, GC.	The KU system includes numerous legacy oil filled circuit breakers, typically installed in the 1940's or 1950's. These breakers require frequent maintenance intervals to	Both the KU and LG&E systems include numerous legacy oil filled circuit	150									
3896	2013	Discretionary	SCM LGE BDD Diff Relay Replacement	The old BDD relays require upgrades. We have found the BDD relays older than 30 years to be out of tolerance. These relays are critical in the Transformer Differential		50							0.0	0.0	0.0
2914	2013	Discretionary	SCM LGE FPE Tapchanger Replacement - Reinhausen	LG&E has ten remaining FPE transformer LTC's in service throughout our distribution system. These have proven to be the most unreliable LTC's in our system. This is an		720							45.0	28.0	32.0
3811	2013	Discretionary	SCM LGE Replace Legacy 15KV Air-Magnetic Circuit	There are 18 McGraw Edison Air Magnetic style breakers in service at LG&E. Many of these units are over 40 years and are being operated at the limits of their design	Improve the reliability of HK Sec 1.	150							0.0	0.0	0.0
3836	2013	Discretionary	SCM LGE Replace Legacy Substation Oil Circuit	The LG&E system includes numerous legacy oil filled circuit breakers, typically installed in the 1940's or 1950's. These breakers require frequent maintenance	Both the KU and LG&E systems include numerous legacy oil filled circuit	290							0.0	0.0	0.0
3901	2013	Discretionary	SCM LGE Transformer Surge Arrester Replacement Project	Upgrade old style porcelain surge arresters to new metal oxide, silicon rubber type.	Pre 1976 surge protecters utilized Multigap Silicon Carbide blocks or Current	45							0.0	0.0	0.0
3785	2013	Discretionary	Stewart 1186 - Reliability Enhancements	Install 8 spans of 3-795AAC PRI W/195AAC NEU Install 9 spans of 4-123AAAC PRI/NEU Remove 5 spans of 3-1/0 AAC 12.47KV PRI Remove 12 spans of 3-#6 SDCU		45							0.0	0.0	0.0
2891	2013	Discretionary	Straight Creek, Relocate/Rebuild/Reconduct	Relocate/rebuild Straight Creek 12 kV Circuit 0317 from the sid eof the mountain to Hwy 66. The majority of the main line is away from customers and not accesable by		287							0.0	0.0	0.0
3070	2013	Discretionary	UG CABLE DETERIORATION	Project consists of replacing up to 21,800 feet of residential primary 12kv underground cable by directional boring. Recently discovered that a lot of the direct		125							0.0	0.0	0.0
3911	2013	Discretionary	UG Cable Replacement Substation Exits LG&E - 2013	A proactive asset replacement program to replace aged, poor performing underground substation exit cables on the LG&E distribution system. Medium		1000							0.0	0.0	0.0
3867	2013	Discretionary	URD Cable Repl/Rejuv Program KU - 2013	Proactive asset replacement program to replace or rejuvenate aged, poor performing underground cables on worst performing residential subdivision circuits		300							0.0	0.0	0.0
3872	2013	Discretionary	URD Cable Repl/Rejuv Program LG&E - 2013	Proactive asset replacement program to replace or rejuvenate aged, poor performing underground cables on worst performing residential subdivision circuits		1000							0.0	0.0	0.0
3052	2013	Discretionary	Wedonia Reconductor	Reconductor approximately 9700' of 4-CW 12 kv primary and 1-6C neutral out of the Wedonia substation, circuit 966, with 3-2/0 acsr and 1-2acsr. This line built in		160							0.0	0.0	0.0
2887	2013	Discretionary	Whitley City 0575 change voltage	Currently a portion of circuit 0575 is 7620V phase to ground, 13200V phase to phase. This is the only line in the KU system that is energize at this voltage. We should		140							0.0	0.0	0.0
3684	2014	Non-Discretionary	DSP Horse Cave Substation Property Project	The purpose of this project is to locate and purchase property suitable for a new substation near the Hart County Industrial Park. Commercial and industrial growth	Substation property purchase for future capacity needs.		400						0.0	0.0	0.0

						Cash Flow							Overloaded		
AIS Project	Start Year	Type	ProjectName	Description	Justification	2013	2014	2015	2016	2017	2018	2019	Peak Load	Normal Rating	Emergency Rating
3767	2014	Non-Discretionary	Pole Inspection and Treatment KU - 2013 - 2014	An infrastucture improvement program to inspect and evaluate the condition of distribution wood poles on the KU system. The program inspects poles, assesses the	Corporate Asset Management Strategy to proactively evaluate, inspect, treat, and		6666						0.0	0.0	0.0
3771	2014	Non-Discretionary	Pole Inspection and Treatment LG&E - 2013 -	An infrastucture improvement program to inspect and evaluate the condition of distribution wood poles on the LG&E system. The program inspects poles, assesses	Corporate Asset Management Strategy to proactively evaluate, inspect, treat, and		3925						0.0	0.0	0.0
3411	2014	Non-Discretionary	SCM 2013 LG&E Misc Dist Proj - 2014	Requesting funding for the miscellaneous capital expenses such as bushings, insulators, surge arresters, capacitors, etc. that are required throughout the year.	Failed units will require replacement to ensure continuity of service. Units which		108						0.0	0.0	0.0
3440	2014	Non-Discretionary	SCM 2013 PINE MISC CAPITAL PROJ - 2014	Requesting funding for the miscellaneous expenses such as bushings, insulators, arresters, etc that are required throughout the year.	Failed units will require replacements to ensure continuity of service. Units		149						0.0	0.0	0.0
3431	2014	Non-Discretionary	SCM 2013 PINE MISC NESC COMPLIANCE - 2014	Substation surveys have turned up many NESC compliance concerns such as fences too short and vertical electrical clearances not adequate. This miscellaneous project	requied to comply with NESC/PSC.		64						0.0	0.0	0.0
3444	2014	Non-Discretionary	SCM 2013 PINE REPLACE SUBSTATION BATTERIES -	Replace defective wet cell batteries and battery chargers in distribution substations.	Reliable DC power is needed in order to properly operate automatic protection		29						0.0	0.0	0.0
3534	2014	Non-Discretionary	SCM 2014 CENT Oil Filtration Additions	Purchase and installation of filtering system on high profile LTC's in our system.	Ability to filter oil in LTC's with high volume of operations per year. This will		50						0.0	0.0	0.0
3416	2014	Non-Discretionary	SCM 2014 CENT-REPL LEGACY LTC/REG CONTR	Purchase and Install New LTC and Regulator Controls. Remove and Retire Legacy Controls.	Ongoing project to replace legacy LTC and Regulator Controls with new style		56						0.0	0.0	0.0
3527	2014	Non-Discretionary	SCM 2014 EARL-REPL LEGACY LTC/REG CONTR	Purchase and Install New LTC and Regulator Controls. Remove and Retire Legacy Controls.	Ongoing project to replace legacy LTC and Regulator Controls with new style		56						0.0	0.0	0.0
3435	2014	Non-Discretionary	SCM 2014 PINE OIL FILTRATION ADDITIONS	Begin a LTC oil filtering program in 2014 that LG&E already has in place. By adding oil filtration to our LTCs that are difficult to get out of service, we decrease customer	Begin a LTC oil filtering program in 2014 that LG&E already has in place. by adding		50						0.0	0.0	0.0
3466	2014	Non-Discretionary	SCM 2014 PINE SUBSTN BUILDINGS & GNDS	This request is for the funding of capital improvements/replacements of station houses, roofs, yard, oil spill containment, driveways, and other general	This request is for the funding of capital improvements/replacements of station		40						0.0	0.0	0.0
3522	2014	Non-Discretionary	SCM 2014 PINE-REPL LEGACY LTC/REG CONTR	Purchase and Install New LTC and Regulator Controls. Remove and Retire Legacy Controls.	Ongoing project to replace legacy LTC and Regulator Controls with new style		56						0.0	0.0	0.0
3544	2014	Non-Discretionary	SCM CENT Misc Dist Capital Sub Project - 2014	Purchase and install material and equipment in various distribution substations as required to serve loads, upgrade equipment and replace failed facilities.	Replace failed equipment and facilities as encountered.		250						0.0	0.0	0.0
3548	2014	Non-Discretionary	SCM CENT Misc NESC Compliance - 2014	Substation checks have shown many NESC compliance issues. This includes fences too short and vertical electrical clearance issues. This project will enable us to	NESC issues must be addressed to meet PSC compliance (and NESC compliance)		70						0.0	0.0	0.0
3560	2014	Non-Discretionary	SCM CENT REPL BREAKERS - 2014	Replace approximately seven failed breakers per year in the Central substation area	Failed units will require replacement to ensure continuity of service		185						0.0	0.0	0.0
3564	2014	Non-Discretionary	SCM CENT REPL BUSHINGS - 2014	Replace approximately twelve failed and deteriorated bushings on substation transformers and breakers	Failed units will require replacement to ensure continuity of service		41						0.0	0.0	0.0
3568	2014	Non-Discretionary	SCM CENT REPL REGULATORS - 2014	Purchase regulators to replace approximately six failed units and maintain adequate stock	Failed units will require replacement to ensure continuity of service		76						0.0	0.0	0.0
3552	2014	Non-Discretionary	SCM CENT Replace Substation Batteries - 2014	Replace wet cell batteries and chargers due to age, defect, or failure.	Replacement due to age, defect, or failure. Failed units will require		43						0.0	0.0	0.0
3535	2014	Non-Discretionary	SCM CENT SUBSTATION BUILDING & GNDS	REPLACE/IMPROVE BUILDING AND GROUNDS IN LEXINGTON AND DANVILLE SUBSTATIONS	REPLACE/IMPROVE COMPANY ASSETS		40						0.0	0.0	0.0
3474	2014	Non-Discretionary	SCM EARL MISC DIST CAPITAL SUB PROJ - 2014	This project is to provide funding for various repairs and upgrades that arise throughout the year. Often, this work will be associated with an equipment failure or	Marked Non-Discretionary per Technical Review Team		205						0.0	0.0	0.0
3478	2014	Non-Discretionary	SCM EARL MISC NESC COMPLIANCE - 2014	A review of substations has revealed several deficiencies. Most deficiencies are perimeter fence height problems. There are some energized parts ground clearance	NESC COMPLIANCE RELATED		144						0.0	0.0	0.0
3482	2014	Non-Discretionary	SCM EARL REPLACE SUBSTATION BATTERIES -	This project is to replace substation batteries and chargers at various locations. Several banks are deteriorated. Several chargers are becoming unreliable and should	Reliable DC power is needed in order to properly operate automatic protection		31						0.0	0.0	0.0
3456	2014	Non-Discretionary	SCM EARL SUBSTN BUILDINGS & GROUNDS	Request is for the funding of repairs/replacements on control house buildings and other general capital improvements to substation grounds that arise annually.	Request is for the funding of repairs/replacements on control house		40						0.0	0.0	0.0
3639	2014	Non-Discretionary	SCM Earlington Recloser Replacement Program - 2014	There are over 40 oil filled electro-mechanical reclosers located in Earlington substations. Approximately half of these locations would greatly benefit from an	The oil filled electro-mechanical reclosers located in Earlington are aging and		114						0.0	0.0	0.0
3696	2014	Non-Discretionary	SCM Earlington Replace Regulators - 2014	Purchase regulators to replace approximately six failed units and maintain adequate stock	Failed units will require replacement to ensure continuity of service		76						0.0	0.0	0.0
3520	2014	Non-Discretionary	SCM KU CA DIFF Relay Replacement (2014 START)	Many legacy CA relays require replacement. Many have tested out of tolerance and have been replaced. These relays are critical in the Transformer Differential	These relays are critical in the Transformer Differential protection		60						0.0	0.0	0.0
3469	2014	Non-Discretionary	SCM KU CENTRAL Replace legacy 34KV breakers	Replace aging 34kv oil circuit breakers. Two units were manufactured in 1976 and 1978. Spare parts are becoming difficult to find. Replace 2 breakers per year until	Replace aging 34kv oil circuit breakers. Two units were manufactured in 1976		160						0.0	0.0	0.0
3588	2014	Non-Discretionary	SCM KU EARL Replace legacy 34KV breakers - 2014	Replace aging 34kv oil circuit breakers. Five units are 40-60 years old, and spare parts are becoming difficult to find. Replace 2 breakers per year until these 5 have	Replace aging 34kv oil circuit breakers. Five units are 40-60 years old, and spare		164						0.0	0.0	0.0
3627	2014	Non-Discretionary	SCM KU HZ Relay Replacement - 2014	Replace legacy, low reliability Westinghouse HZ Distance Relays, 6 per year. Transmission has a standard practice of replacing these relays whenever possible	Improved reliability and capability. Transmission has a standard practice of		62						0.0	0.0	0.0
3615	2014	Non-Discretionary	SCM KU Legacy RTU Replacements - 2014	The majority of KU Distribution Substations in or near the Lexington area have early 1980's vintage Leeds and Northrup remote terminal units. These legacy devices do	These legacy RTUs experience high failure rates, requiring labor intensive		275						0.0	0.0	0.0
3584	2014	Non-Discretionary	SCM KU PINE Replace legacy 34kv breakers - 2014	Replace aging 34kv oil circuit breakers. Several units were manufactured circa 1950, and spare parts are becoming difficult to find. Replace (2) breakers per year from	Replace aging 34kv oil circuit breakers. Several units were manufactured circa		164						0.0	0.0	0.0
3496	2014	Non-Discretionary	SCM KU Replace Legacy Vac Circuit Breakers: Types VIB	The KU system (Central, Pineville, and Earlington) contains numerous legacy GE Type VIB vacuum breakers from the 1970s. The mechanisms on these breakers have	The KU system (Central, Pineville, and Earlington) contains numerous legacy GE		250								
3398	2014	Non-Discretionary	SCM LG&E LTC Oil Filter Units - 2014	We are requesting money to continue our succesful program of installing oil filtration systems on transformer LTC's. These devices have proven to significantly	We are requesting money to continue our succesful program of installing oil		53						0.0	0.0	0.0
3406	2014	Non-Discretionary	SCM LG&E Substation Building and Grounds - 2014	Request is for the funding of repairs/replacements on control house buildings, fire preventions systems and other general capital improvements to substation grounds	Request is for the funding of repairs/replacements on control house		72						0.0	0.0	0.0
3619	2014	Non-Discretionary	SCM LGE Legacy RTU Replacements - 2014	Several LG&E Distribution Substations have early 1980's vintage Landis and Systems Northwest remote terminal units. These legacy devices do not support serial or	These legacy units experience high failure rates, requiring labor intensive board		267						0.0	0.0	0.0
3402	2014	Non-Discretionary	SCM LGE Miscellaneous NESC Compliance Projects - 2014	Substation surveys have turned up many NESC compliance concerns such as fences too short and vertical electrical clearances not adequate. This miscellaneous project	Required for NESC and PSC compliance		77						0.0	0.0	0.0
3504	2014	Non-Discretionary	SCM LGE Modify Cane Run Plant 14kv Substation	The Cane Run Coal Generation Plant is being shut down to meet EPA compliance; however, there are (3) 14kv circuits fed from the plant substation, and those circuits	Without the completion of this project, there are (3) 14kv circuits that will no		1200	1260					11.2	44.8	44.8
3598	2014	Non-Discretionary	SCM LGE REPL TRANSF FIRE DETECTION SYSTEMS - 2014	A significant percentage of fire detection thermostats on these systems have experienced failures from an acknowledged design flaw. The inadvertent trip of a	Failed units will require replacement to ensure continuity of fire suppression		24						0.0	0.0	0.0
3468	2014	Non-Discretionary	SCM LGE Replace 34KV Breakers	Replace aging 34kv oil circuit breakers. All four breakers were manufactured in 1960 and have outlived their expected service life. Spare parts are becoming difficult to	Replace aging 34kv oil circuit breakers. All four breakers were manufactured in 1960		160						0.0	0.0	0.0
3651	2014	Non-Discretionary	SCM LGE Replace Legacy VRR's - 2014	LGE requests funding to replace legacy voltage regulating relays (VRR's) at a rate of (6) per year. The legacy units are not reliable and spare parts are very difficult to	LGE requests funding to replace legacy voltage regulating relays (VRR's) at a rate		41						0.0	0.0	0.0
3602	2014	Non-Discretionary	SCM LGE Replace Substation Batteries - 2014	Need to replace 5 Substation Battery systems per year due to age. Various Distribution Substations have batteries that are between 21 and 25 years old.	Failed units will require replacement to ensure continuity of service and proper		91						0.0	0.0	0.0
3643	2014	Non-Discretionary	SCM PINE RECLOSER REPL - 2014	The Pineville area has over 95 reclosers inside substations. Replace approximately two failed reclosers in substations in the Pineville area per year.	Must replace failed units		59						0.0	0.0	0.0
3710	2014	Non-Discretionary	SCM Pineville Replace Regulators - 2014	Purchase regulators to replace approximately six failed units and maintain adequate stock	Failed units will require replacement to ensure continuity of service		76						0.0	0.0	0.0
3519	2014	Non-Discretionary	SCM Replace 15kV Steel Structure at WHAS Substation	The steel structure at WHAS Substation for TR3 and WH-1116 breaker is in very poor condition. It is 1950's vintage and has rusted extensively. The steel needs to be	The steel structure at WHAS Substation for TR3 and WH-1116 breaker is in very		220						0.0	0.0	0.0
3755	2014	Non-Discretionary	UG Network PILC Primary Cable Replacement Program-	A proactive asset replacement program to replace aging and defective paper insulated lead covered (PILC) primary underground cables in the LG&E Downtown	Improve public safety from catastrophic manhole explosions and lower risk of		2050						0.0	0.0	0.0
3759	2014	Non-Discretionary	UG Network PILC Secondary Cable Replacement Program-	A proactive asset replacement program to replace aged, deteriorating paper insulated lead covered (PILC), secondary underground cables in the LG&E Downtown	Improve public safety from catastrophic manhole explosions and lower risk of		2050						0.0	0.0	0.0
3722	2014	Discretionary	CEMI>5 Circuits - KU - 2013 - 2014	Improve reliability on 26 KU circuits that have Customers Experiencing Multiple Interruptions (CEMI) of more than 8 outages in 2011. Budgetary project description			666						0.0	0.0	0.0

						Cash Flow							Overloaded		
AIS Project	Start Year	Type	ProjectName	Description	Justification	2013	2014	2015	2016	2017	2018	2019	Peak Load	Normal Rating	Emergency Rating
3726	2014	Discretionary	CEMI>5 Circuits - LGE - 2013 - 2014	Improve reliability on 43 LGE circuits that have Customers Experiencing Multiple Interruptions (CEMI) of more than 8 outages in 2011. Budgetary project description			1102						0.0	0.0	0.0
3832	2014	Discretionary	CIFI (worst) Circuits - Level 1 KU - 5 Circuits - 2013 - 2014	Improve reliability on five(5) Level 1 Circuits ID'd for Improvement (CIFI) at KU. Level 1 CIFI circuits have a long term (5 year) poor SAIFI performance record where the			666						0.0	0.0	0.0
3841	2014	Discretionary	CIFI (worst) Circuits - Level 1 LGE - 1 Circuit - 2013 - 2014	Improve reliability on one(1) Level 1 Circuits ID'd for Improvement (CIFI) at LGE. Level 1 CIFI circuits have a long term (5 year) poor SAIFI performance record where			133						0.0	0.0	0.0
3845	2014	Discretionary	CIFI (worst) Circuits - Level 2 KU - 12 Circuits - 2013 - 2014	Improve reliability on 12 Level 2 Circuits ID'd for Improvement (CIFI) at KU. Level 2 CIFI circuits have a long term (5 year) poor SAIFI performance record where the			1599						0.0	0.0	0.0
3849	2014	Discretionary	CIFI (worst) Circuits - Level 2 LGE - 1 Circuit - 2013 - 2014	Improve reliability on one(1) Level 2 Circuits ID'd for Improvement (CIFI) at LGE. Level 2 CIFI circuits have a long term (5 year) poor SAIFI performance record where			133						0.0	0.0	0.0
3853	2014	Discretionary	CIFI (worst) Circuits - Level 3 KU - 28 Circuits - 2013 - 2014	Improve reliability on 28 Level 3 Circuits ID'd for Improvement (CIFI) at KU. Level 3 CIFI circuits have a long term (5 year) poor SAIFI performance record where the			3731						0.0	0.0	0.0
3857	2014	Discretionary	CIFI (worst) Circuits - Level 3 LGE - 25 Circuits - 2013 - 2014	Improve reliability on 25 Level 3 Circuits ID'd for Improvement (CIFI) at LGE. Level 3 CIFI circuits have a long term (5 year) poor SAIFI performance record where the			3331						0.0	0.0	0.0
2961	2014	Discretionary	DSP Bond 1 Breaker	Install a new circuit breaker in the Bond substation in order to divide the load on Bond 1 Ckt 0660. See related distribution project. Bond 1 Ckt 0660 breaker: 95%			75						13.0	13.0	13.1
2962	2014	Discretionary	DSP Bond 1 Distribution	Install 9,200' 397 ACSR or larger conductor from the substation to Apple St; additional distribution circuit provides reliability benefit. See related substation			650						0.0	0.0	0.0
3003	2014	Discretionary	DSP Camargo AO Smith Tie Circuit Upgrade	Reconductor 8000' of 266 with 397 ckt 605 between Carmargo and AO Smith for transfer of additional loads. Cost by Maysville Operations			140						0.0	0.0	0.0
2854	2014	Discretionary	DSP Central Baptist Area Distribution	Install circuit improvements (minimum three new circuits) as needed in order to provide adequate substation exit circuit capacity for the associated Central Baptist			400	400					0.0	0.0	0.0
2853	2014	Discretionary	DSP Central Baptist Area Substation	Install a new 20/37.3 MVA transformer, steel structures, main breaker, circuit breakers, and associated equipment on substation property yet to be identified.			1500	2300					16.4	16.3	21.6
2947	2014	Discretionary	DSP Elizabethtown Industrial-Breaker Addition Project	The purpose of this project is to develop a viable tie circuit between Elizabethtown 3 (809-2)and Elizabethtown Industrial (552-1)Substations. Install one 1200A breaker, 6			100						0.0	0.0	0.0
2950	2014	Discretionary	DSP Frankfort 34-69kV substation relocation	Funded 2012-2013 project, deferred after further review. There is a 34kV subtransmission line fed on each extremity by two 20MVA 34-69kV transformers,			250	1950					20.0	24.0	27.2
2965	2014	Discretionary	DSP Georgetown 4kV Ckt 0420	Install 350' conductor as necessary on Highland Ave or Montgomery Ave and convert a portion of the load on W. Clinton St from 4kV to 12kV in order to transfer load			60						3.8	3.6	3.9
3082	2014	Discretionary	DSP Lexington Downtown Electrical System Project	The purpose of this project is expand the downtown system due to system growth: Centre Pointe, new sports arena, The Lexington Distillery District, etc.			1000	1000					0.0	0.0	0.0
3511	2014	Discretionary	DSP Lime Kiln Substation Circuit Work	New substation. Install 44.8 MVA transformer and associated switchgear for five distribution circuits. This project is to address the potential load increase in the area			858	859					0.0	0.0	0.0
3510	2014	Discretionary	DSP Lime Kiln Substation Work	New substation. Install 44.8 MVA transformer and associated switchgear for five distribution circuits. This project is to address the potential load increase in the area			3000	1700					0.0	0.0	0.0
2882	2014	Discretionary	DSP Lyndon South Circuit Work (2014-2015)	This project is to add a 138/13.09 kV, 44.8 MVA transformer to the Lyndon South Substation. Both Lyndon and Lyndon South Substations are near their nameplate			1506	1506					0.0	0.0	0.0
2878	2014	Discretionary	DSP Lyndon South Substation Project (2014 - 2015)	This project is to add a 138/13.09 kV, 44.8 MVA transformer to the Lyndon South Substation. Both Lyndon and Lyndon South Substations are near their nameplate			3400	600					29.4	28.0	33.6
2905	2014	Discretionary	DSP Middlesboro Area Substation	The Middlesboro 1 4kV transformer peaked at 111% Winter 2011. The Middlesboro 2 4kV transformer peaked at 115% Winter 2009. Middlesboro 1 12kV 2 peaked at			800	900					14.0	14.0	16.8
3464	2014	Discretionary	DSP Newtown Ckt 0431	Install ABS as necessary to allow load transfer from Newtown to Oxford or Lemons Mill. Newtown transformer: 108% winter. Distribution $10,000. Project 134628.			10						15.1	16.8	19.0
2856	2014	Discretionary	DSP Oxford Circuit 0471	Replace 4,300' 2/0 ACSR with 397 ACSR on Oxford #1 Ckt 0471 and transfer load from Oxford #2 Ckt 0472 to Ckt 0471. This project will reduce the loading on Oxford			350						4.6	6.6	6.6
3454	2014	Discretionary	DSP Pennington Gap Distribution	Install circuit improvements as needed in order to provide adequate substation exit circuit capacity and tie circuits for the proposed new Pennington Gap substation. See			200	200					0.0	0.0	0.0
3452	2014	Discretionary	DSP Pennington Gap Substation	Install a new 10/14 MVA transformer, structures, breakers, and associated equipment on new substation property acquired in 2011. A 2012 load transfer is			700	900					16.8	16.8	19.0
2958	2014	Discretionary	DSP Russell Springs Substation Upgrade	The Russell Springs 10.5MVA transformer was loaded 117% of top nameplate in winter 2009. The Russell Springs substation feeds the town of Russell Springs with				300	750				12.6	12.6	14.3
3502	2014	Discretionary	DSP Shelbyville North Breaker 2014	Install a new circuit breaker in the Shelbyville North substation. Substation: $75,000. Related distribution project is to install 2,400' 795 AAC conductor from the			75								
3500	2014	Discretionary	DSP Shelbyville North Distribution 2014	Install 2,400' 795 AAC conductor from the Shelbyville North substation to Smithfield Rd (Ky 53) to create a new distribution circuit. The Op Center has reported voltage			170								
3029	2014	Discretionary	DSP Wilmore 4kV Regulators	Replace 3-100 kVA 4kV substation regulators in the Wilmore 4kV substation with 3-167 kVA units. Substation regulators = 98% summer (estimated after planned Op			90						2.8	2.9	3.2
3807	2014	Discretionary	LEO Cable Rejuvenation - 2014	Cable rejuvenation restores the dielectric strength of in-service aged cable insulations to new cable dielectric strength levels and is warranted to provide 20			256						0.0	0.0	0.0
3922	2014	Discretionary	Rear Easement OH Hardening - KU - 2013 COPY - 2014	Initiate a project to replace defective, small capacity overhead conductor and related distribution line equipment in rear lot applications on the KU system. Targeted			1025								
3918	2014	Discretionary	Rear Easement OH Hardening LGE - 2013 COPY - 2014	Initiate a project to replace defective, small capacity overhead conductor and related distribution line equipment in rear lot applications on the LGE system. Targeted			1025								
3868	2014	Discretionary	SCM KU CENT Replace Legacy OCB's: Types FK, FKD, G, GC. -	The KU system includes numerous legacy oil filled circuit breakers, typically installed in the 1940's or 1950's. These breakers require frequent maintenance intervals to			297								
3828	2014	Discretionary	SCM KU EARL Replace Legacy OCB's: Types FK, FKD, G, GC. -	The KU system includes numerous legacy oil filled circuit breakers, typically installed in the 1940's or 1950's. These breakers require frequent maintenance intervals to	Both the KU and LG&E systems include numerous legacy oil filled circuit		154								
3822	2014	Discretionary	SCM KU PINE Replace Legacy OCB's: Types FK, FKD, G, GC. -	The KU system includes numerous legacy oil filled circuit breakers, typically installed in the 1940's or 1950's. These breakers require frequent maintenance intervals to	Both the KU and LG&E systems include numerous legacy oil filled circuit		154								
3897	2014	Discretionary	SCM LGE BDD Diff Relay Replacement - 2014	The old BDD relays require upgrades. We have found the BDD relays older than 30 years to be out of tolerance. These relays are critical in the Transformer Differential			51						0.0	0.0	0.0
3623	2014	Discretionary	SCM LGE FPE Tapchanger Replacement - Reinhausen -	LG&E has ten remaining FPE transformer LTC's in service throughout our distribution system. These have proven to be the most unreliable LTC's in our system. This is an			738						45.0	28.0	32.0
3814	2014	Discretionary	SCM LGE Replace Legacy 15KV Air-Magnetic Circuit	There are 18 McGraw Edison Air Magnetic style breakers in service at LG&E. Many of these units are over 40 years and are being operated at the limits of their design	Improve the reliability of HK Sec 1.		154						0.0	0.0	0.0
3837	2014	Discretionary	SCM LGE Replace Legacy Substation Oil Circuit	The LG&E system includes numerous legacy oil filled circuit breakers, typically installed in the 1940's or 1950's. These breakers require frequent maintenance	Both the KU and LG&E systems include numerous legacy oil filled circuit		297						0.0	0.0	0.0
3902	2014	Discretionary	SCM LGE Transformer Surge Arrester Replacement Project	Upgrade old style porcelain surge arresters to new metal oxide, silicon rubber type.	Pre 1976 surge protecters utilized Multigap Silicon Carbide blocks or Current		46						0.0	0.0	0.0
3705	2014	Discretionary	UG CABLE DETERIORATION - 2014	Project consists of replacing up to 21,800 feet of residential primary 12kv underground cable by directional boring. Recently discovered that a lot of the direct			128						0.0	0.0	0.0
3912	2014	Discretionary	UG Cable Replacement Substation Exits LG&E - 2013 -	A proactive asset replacement program to replace aged, poor performing underground substation exit cables on the LG&E distribution system. Medium			1025						0.0	0.0	0.0
3883	2014	Discretionary	URD Cable Repl/Rejuv Program KU - 2013 - 2014	Proactive asset replacement program to replace or rejuvenate aged, poor performing underground cables on worst performing residential subdivision circuits			308						0.0	0.0	0.0
3887	2014	Discretionary	URD Cable Repl/Rejuv Program LG&E - 2013 - 2014	Proactive asset replacement program to replace or rejuvenate aged, poor performing underground cables on worst performing residential subdivision circuits			1025						0.0	0.0	0.0
3790	2015	Non-Discretionary	DSP Lawrenceburg Substation Property Project	The purpose of this project is to locate and purchase property suitable for a new substation in Lawrenceburg/Anderson County KY.	Substation property purchase for future capacity needs. Due to the large			400					0.0	0.0	0.0
2885	2015	Non-Discretionary	DSP Substation Property Mud Lane-Smyrna	Purchase of substation property for future substation in the Mud Lane-Smyrna area. Need year between 2016 and 2018.	Substation property purchase for future capacity needs.			769					0.0	0.0	0.0
3076	2015	Non-Discretionary	DSP Substation Property Watterson-Fairmount Area	Substation property purchase for future substation in the Watterson-Fairmount substation area. Need year between 2019 and 2022.	Substation property purchase for future capacity needs.				800				0.0	0.0	0.0

AIS Project	Start Year	Type	ProjectName	Description	Justification	Cash Flow 2013	2014	2015	2016	2017	2018	2019	Overloaded Peak Load	Normal Rating	Emergency Rating
3768	2015	Non-Discretionary	Pole Inspection and Treatment KU - 2013 - 2015	An infrastucture improvement program to inspect and evaluate the condition of distribution wood poles on the KU system. The program inspects poles, assesses the	Corporate Asset Management Strategy to proactively evaluate, inspect, treat, and			5047					0.0	0.0	0.0
3772	2015	Non-Discretionary	Pole Inspection and Treatment LG&E - 2013 -	An infrastucture improvement program to inspect and evaluate the condition of distribution wood poles on the LG&E system. The program inspects poles, assesses	Corporate Asset Management Strategy to proactively evaluate, inspect, treat, and			5861					0.0	0.0	0.0
3412	2015	Non-Discretionary	SCM 2013 LG&E Misc Dist Proj - 2015	Requesting funding for the miscellaneous capital expenses such as bushings, insulators, surge arresters, capacitors, etc. that are required throughout the year.	Failed units will require replacement to ensure continuity of service. Units which			110					0.0	0.0	0.0
3441	2015	Non-Discretionary	SCM 2013 PINE MISC CAPITAL PROJ - 2015	Requesting funding for the miscellaneous expenses such as bushings, insulators, arresters, etc that are required throughout the year.	Failed units will require replacements to ensure continuity of service. Units			152					0.0	0.0	0.0
3432	2015	Non-Discretionary	SCM 2013 PINE MISC NESC COMPLIANCE - 2015	Substation surveys have turned up many NESC compliance concerns such as fences too short and vertical electrical clearances not adequate. This miscellaneous project	requied to comply with NESC/PSC.			66					0.0	0.0	0.0
3445	2015	Non-Discretionary	SCM 2013 PINE REPLACE SUBSTATION BATTERIES -	Replace defective wet cell batteries and battery chargers in distribution substations.	Reliable DC power is needed in order to properly operate automatic protection			29					0.0	0.0	0.0
3536	2015	Non-Discretionary	SCM 2014 CENT Oil Filtration Additions - 2015	Purchase and installation of filtering system on high profile LTC's in our system.	Ability to filter oil in LTC's with high volume of operations per year. This will			51					0.0	0.0	0.0
3448	2015	Non-Discretionary	SCM 2014 PINE OIL FILTRATION ADDITIONS -	Begin a LTC oil filtering program in 2014 that LG&E already has in place. By adding oil filtration to our LTCs that are difficult to get out of service, we decrease customer	Begin a LTC oil filtering program in 2014 that LG&E already has in place. by adding			51					0.0	0.0	0.0
3490	2015	Non-Discretionary	SCM 2014 PINE SUBSTN BUILDINGS & GNDS - 2015	This request is for the funding of capital improvements/replacements of station houses, roofs, yard, oil spill containment, driveways, and other general	This request is for the funding of capital improvements/replacements of station			41					0.0	0.0	0.0
3417	2015	Non-Discretionary	SCM 2015 CENT-REPL LEGACY LTC/REG CONTR	Purchase and Install New LTC and Regulator Controls. Remove and Retire Legacy Controls.	Ongoing project to replace legacy LTC and Regulator Controls with new style			58					0.0	0.0	0.0
3528	2015	Non-Discretionary	SCM 2015 EARL-REPL LEGACY LTC/REG CONTR	Purchase and Install New LTC and Regulator Controls. Remove and Retire Legacy Controls.	Ongoing project to replace legacy LTC and Regulator Controls with new style			58					0.0	0.0	0.0
3523	2015	Non-Discretionary	SCM 2015 PINE-REPL LEGACY LTC/REG CONTR	Purchase and Install New LTC and Regulator Controls. Remove and Retire Legacy Controls.	Ongoing project to replace legacy LTC and Regulator Controls with new style			58					0.0	0.0	0.0
3545	2015	Non-Discretionary	SCM CENT Misc Dist Capital Sub Project - 2015	Purchase and install material and equipment in various distribution substations as required to serve loads, upgrade equipment and replace failed facilities.	Replace failed equipment and facilities as encountered.			256					0.0	0.0	0.0
3549	2015	Non-Discretionary	SCM CENT Misc NESC Compliance - 2015	Substation checks have shown many NESC compliance issues. This includes fences too short and vertical electrical clearance issues. This project will enable us to	NESC issues must be addressed to meet PSC compliance (and NESC compliance)			71					0.0	0.0	0.0
3561	2015	Non-Discretionary	SCM CENT REPL BREAKERS - 2015	Replace approximately seven failed breakers per year in the Central substation area	Failed units will require replacement to ensure continuity of service			189					0.0	0.0	0.0
3565	2015	Non-Discretionary	SCM CENT REPL BUSHINGS - 2015	Replace approximately twelve failed and deteriorated bushings on substation transformers and breakers	Failed units will require replacement to ensure continuity of service			42					0.0	0.0	0.0
3569	2015	Non-Discretionary	SCM CENT REPL REGULATORS - 2015	Purchase regulators to replace approximately six failed units and maintain adequate stock	Failed units will require replacement to ensure continuity of service			78					0.0	0.0	0.0
3553	2015	Non-Discretionary	SCM CENT Replace Substation Batteries - 2015	Replace wet cell batteries and chargers due to age, defect, or failure.	Replacement due to age, defect, or failure. Failed units will require			44					0.0	0.0	0.0
3556	2015	Non-Discretionary	SCM CENT SUBSTATION BUILDING & GNDS - 2015	REPLACE/IMPROVE BUILDING AND GROUNDS IN LEXINGTON AND DANVILLE SUBSTATIONS	REPLACE/IMPROVE COMPANY ASSETS			41					0.0	0.0	0.0
3475	2015	Non-Discretionary	SCM EARL MISC DIST CAPITAL SUB PROJ - 2015	This project is to provide funding for various repairs and upgrades that arise throughout the year. Often, this work will be associated with an equipment failure or	Marked Non-Discretionary per Technical Review Team			210					0.0	0.0	0.0
3479	2015	Non-Discretionary	SCM EARL MISC NESC COMPLIANCE - 2015	A review of substations has revealed several deficiencies. Most deficiencies are perimeter fence height problems. There are some energized parts ground clearance	NESC COMPLIANCE RELATED			147					0.0	0.0	0.0
3483	2015	Non-Discretionary	SCM EARL REPLACE SUBSTATION BATTERIES -	This project is to replace substation batteries and chargers at various locations. Several banks are deteriorated. Several chargers are becoming unreliable and should	Reliable DC power is needed in order to properly operate automatic protection			32					0.0	0.0	0.0
3486	2015	Non-Discretionary	SCM EARL SUBSTN BUILDINGS & GROUNDS -	Request is for the funding of repairs/replacements on control house buildings and other general capital improvements to substation grounds that arise annually.	Request is for the funding of repairs/replacements on control house			41					0.0	0.0	0.0
3697	2015	Non-Discretionary	SCM Earlington Replace Regulators - 2015	Purchase regulators to replace approximately six failed units and maintain adequate stock	Failed units will require replacement to ensure continuity of service			78					0.0	0.0	0.0
3606	2015	Non-Discretionary	SCM KU CA DIFF Relay Replacement (2014 START) -	Many legacy CA relays require replacement. Many have tested out of tolerance and have been replaced. These relays are critical in the Transformer Differential	These relays are critical in the Transformer Differential protection			62					0.0	0.0	0.0
3589	2015	Non-Discretionary	SCM KU EARL Replace legacy 34KV breakers - 2015	Replace aging 34kv oil circuit breakers. Five units are 40-60 years old, and spare parts are becoming difficult to find. Replace 2 breakers per year until these 5 have	Replace aging 34kv oil circuit breakers. Five units are 40-60 years old, and spare			168					0.0	0.0	0.0
3628	2015	Non-Discretionary	SCM KU HZ Relay Replacement - 2015	Replace legacy, low reliability Westinghouse HZ Distance Relays, 6 per year. Transmission has a standard practice of replacing these relays whenever possible	Improved reliability and capability. Transmission has a standard practice of			63					0.0	0.0	0.0
3616	2015	Non-Discretionary	SCM KU Legacy RTU Replacements - 2015	The majority of KU Distribution Substations in or near the Lexington area have early 1980's vintage Leeds and Northrup remote terminal units. These legacy devices do	These legacy RTUs experience high failure rates, requiring labor intensive			282					0.0	0.0	0.0
3585	2015	Non-Discretionary	SCM KU PINE Replace legacy 34kv breakers - 2015	Replace aging 34kv oil circuit breakers. Several units were manufactured circa 1950, and spare parts are becoming difficult to find. Replace (2) breakers per year from	Replace aging 34kv oil circuit breakers. Several units were manufactured circa			168					0.0	0.0	0.0
3655	2015	Non-Discretionary	SCM KU Replace Legacy Vac Circuit Breakers: Types VIB -	The KU system (Central, Pineville, and Earlington) contains numerous legacy GE Type VIB vacuum breakers from the 1970s. The mechanisms on these breakers have	The KU system (Central, Pineville, and Earlington) contains numerous legacy GE			256							
3399	2015	Non-Discretionary	SCM LG&E LTC Oil Filter Units - 2015	We are requesting money to continue our succesful program of installing oil filtration systems on transformer LTC's. These devices have proven to significantly	We are requesting money to continue our succesful program of installing oil			55					0.0	0.0	0.0
3407	2015	Non-Discretionary	SCM LG&E Substation Building and Grounds - 2015	Request is for the funding of repairs/replacements on control house buildings, fire preventions systems and other general capital improvements to substation grounds	Request is for the funding of repairs/replacements on control house			74					0.0	0.0	0.0
3592	2015	Non-Discretionary	SCM LGE Implement Direct Transfer Trip over SONET	The Direct Transfer Trip Circuits in LG&E have been moved off of the copper wire infrastructure. The remaining circuits that need to be moved will complete this	The copper system presently in use is less reliable and is not maintained. The fiber			100					0.0	0.0	0.0
3620	2015	Non-Discretionary	SCM LGE Legacy RTU Replacements - 2015	Several LG&E Distribution Substations have early 1980's vintage Landis and Systems Northwest remote terminal units. These legacy devices do not support serial or	These legacy units experience high failure rates, requiring labor intensive board			273					0.0	0.0	0.0
3403	2015	Non-Discretionary	SCM LGE Miscellaneous NESC Compliance Projects - 2015	Substation surveys have turned up many NESC compliance concerns such as fences too short and vertical electrical clearances not adequate. This miscellaneous project	Required for NESC and PSC compliance			79					0.0	0.0	0.0
3599	2015	Non-Discretionary	SCM LGE REPL TRANSF FIRE DETECTION SYSTEMS - 2015	A significant percentage of fire detection thermostats on these systems have experienced failures from an acknowledged design flaw. The inadvertent trip of a	Failed units will require replacement to ensure continuity of fire suppression			24					0.0	0.0	0.0
3652	2015	Non-Discretionary	SCM LGE Replace Legacy VRR's - 2015	LGE requests funding to replace legacy voltage regulating relays (VRR's) at a rate of (6) per year. The legacy units are not reliable and spare parts are very difficult to	LGE requests funding to replace legacy voltage regulating relays (VRR's) at a rate			42					0.0	0.0	0.0
3603	2015	Non-Discretionary	SCM LGE Replace Substation Batteries - 2015	Need to replace 5 Substation Battery systems per year due to age. Various Distribution Substations have batteries that are between 21 and 25 years old.	Failed units will require replacement to ensure continuity of service and proper			94					0.0	0.0	0.0
3644	2015	Non-Discretionary	SCM PINE RECLOSER REPL - 2015	The Pineville area has over 95 reclosers inside substations. Replace approximately two failed reclosers in substations in the Pineville area per year.	Must replace failed units			61					0.0	0.0	0.0
3711	2015	Non-Discretionary	SCM Pineville Replace Regulators - 2015	Purchase regulators to replace approximately six failed units and maintain adequate stock	Failed units will require replacement to ensure continuity of service			78					0.0	0.0	0.0
3756	2015	Non-Discretionary	UG Network PILC Primary Cable Replacement Program-	A proactive asset replacement program to replace aging and defective paper insulated lead covered (PILC) primary underground cables in the LG&E Downtown	Improve public safety from catastrophic manhole explosions and lower risk of			2101					0.0	0.0	0.0
3760	2015	Non-Discretionary	UG Network PILC Secondary Cable Replacement Program-	A proactive asset replacement program to replace aged, deteriorating paper insulated lead covered (PILC), secondary underground cables in the LG&E Downtown	Improve public safety from catastrophic manhole explosions and lower risk of			2101					0.0	0.0	0.0
3723	2015	Discretionary	CEMI>5 Circuits - KU - 2013 - 2015	Improve reliability on 26 KU circuits that have Customers Experiencing Multiple Interruptions (CEMI) of more than 8 outages in 2011. Budgetary project description				683					0.0	0.0	0.0
3727	2015	Discretionary	CEMI>5 Circuits - LGE - 2013 - 2015	Improve reliability on 43 LGE circuits that have Customers Experiencing Multiple Interruptions (CEMI) of more than 8 outages in 2011. Budgetary project description				1129					0.0	0.0	0.0
3833	2015	Discretionary	CIFI (worst) Circuits - Level 1 KU - 5 Circuits - 2013 - 2015	Improve reliability on five(5) Level 1 Circuits ID'd for Improvement (CIFI) at KU. Level 1 CIFI circuits have a long term (5 year) poor SAIFI performance record where the				683					0.0	0.0	0.0
3842	2015	Discretionary	CIFI (worst) Circuits - Level 1 LGE - 1 Circuit - 2013 - 2015	Improve reliability on one(1) Level 1 Circuits ID'd for Improvement (CIFI) at LGE. Level 1 CIFI circuits have a long term (5 year) poor SAIFI performance record where				137					0.0	0.0	0.0
3846	2015	Discretionary	CIFI (worst) Circuits - Level 2 KU - 12 Circuits - 2013 - 2015	Improve reliability on 12 Level 2 Circuits ID'd for Improvement (CIFI) at KU. Level 2 CIFI circuits have a long term (5 year) poor SAIFI performance record where the				1639					0.0	0.0	0.0

AIS Project	Start Year	Type	ProjectName	Description	Justification	Cash Flow 2013	2014	2015	2016	2017	2018	2019	Overloaded Peak Load	Normal Rating	Emergency Rating
3850	2015	Discretionary	CIFI (worst) Circuits - Level 2 LGE - 1 Circuit - 2013 - 2015	Improve reliability on one(1) Level 2 Circuits ID'd for Improvement (CIFI) at LGE. Level 2 CIFI circuits have a long term (5 year) poor SAIFI performance record where				137					0.0	0.0	0.0
3854	2015	Discretionary	CIFI (worst) Circuits - Level 3 KU - 28 Circuits - 2013 - 2015	Improve reliability on 28 Level 3 Circuits ID'd for Improvement (CIFI) at KU. Level 3 CIFI circuits have a long term (5 year) poor SAIFI performance record where the				3824					0.0	0.0	0.0
3858	2015	Discretionary	CIFI (worst) Circuits - Level 3 LGE - 25 Circuits - 2013 - 2015	Improve reliability on 25 Level 3 Circuits ID'd for Improvement (CIFI) at LGE. Level 3 CIFI circuits have a long term (5 year) poor SAIFI performance record where the				3415					0.0	0.0	0.0
3453	2015	Discretionary	DSP Atoka Substation 2015	Upgrade overloaded transformer with a 10/14 to cope with load growth.				267	533				5.0	4.7	5.6
3661	2015	Discretionary	DSP Central City System Circuit Upgrade Project	Replace small feeder circuit conductors with larger wire to fully utilize substation transformer capacities at Central City and Central City South. Circuit 1645: Replace				90					15.8	13.1	20.1
3659	2015	Discretionary	DSP Central City Tie Circuit Completion Project	Install 1-1200 amp AB switch, the associated poles, and equipment to complete a tie circuit between Central City 4KV and Muhlenberg Prison 12KV. Circuit #1648 (Central				75					0.0	0.0	0.0
3463	2015	Discretionary	DSP Delaplain 1 Ckt 0401	Reconductor 1,000' 2/0 ACSR with 397 ACSR from just outside the Delaplain substation to the Industrial Park. Delaplain 1 Ckt 0401 conductor: 92% summer.				80					6.1	6.6	6.7
3692	2015	Discretionary	DSP Delaplain 2 Transformer Addition	Install additional 22.4MVA 69-13.8kV Transformer at Delaplain Substation 609-2 when customer provides verified schedule. This odd-voltage substation serves one				1210	315				22.3	22.4	26.9
2907	2015	Discretionary	DSP Middlesboro Area Distribution	Distributuion circuit work required to utilize 12kV substation capacity addition. Includes conversion.				300					0.0	0.0	0.0
2910	2015	Discretionary	DSP Rineyville Circuit Upgrade Project	Reconductor 4500'of three phase 2/0 ACSR with 397 ACSR for a new circuit fed from Rineyville Substation to Burns Road. Project will be driven by new loads in the area.				451					6.6	6.6	6.6
3691	2015	Discretionary	DSP Scott St 2 4kV Distribution	Install 500' 795 AAC conductor as needed to create a new substation exit circuit and provide adequate circuit capacity for the associated Scott St 2 4kV substation					100				0.0	0.0	0.0
3690	2015	Discretionary	DSP Scott St 2 4kV Substation	Replace the 5/6.25 MVA transformer with a 7.5/10.5 MVA (or 10/14 MVA) 69-4kV transformer, install a new line breaker, plus perform associated substation upgrades				700	900				6.2	6.3	7.5
3436	2015	Discretionary	DSP Simpsonville 1 Substation 2015	Replace the 7.5/10.5 MVA transformer in the Simpsonville 1 substation with a 10/14 MVA transformer. Estimated Simpsonville 1 transformer loads (considering				500	200				11.1	10.5	12.6
2908	2015	Discretionary	DSP Somerset Area Substation	The Somerset area consists of two primary 12kV substations which were loaded as follows in the summer of 2007 (2008 was milder): 4kV subs: Somerset 1 6.25MVA -				800	900				14.3	14.0	16.8
3682	2015	Discretionary	DSP Spencer Chemical Substation Upgrade Project	Replace the 7.0MVA transformer with a 14.0 MVA transformer due to customer load growth. The summer of 2015 peak is projected to be 103%. Install 3-416KVA				470					7.2	7.0	8.4
2964	2015	Discretionary	DSP Stonewall 2 Distribution	Install circuit improvements (minimum three new circuits) as needed in order to provide adequate substation exit circuit capacity for the associated Stonewall 2				400	400				0.0	0.0	0.0
2963	2015	Discretionary	DSP Stonewall 2 Substation	Install a new 20/37.3 MVA transformer, steel structures, main breaker, circuit breakers, and associated equipment in the Stonewall substation. Load transfers will				2200	900				37.0	37.3	44.8
3078	2015	Discretionary	DSP Tucker Station Circuit Work (2015-2016)	This project is to build a new 138/13.09, 44.8 MVA substation along Tucker Station Road near Plantside Drive. This station will address potential overloads on				1500	1000				0.0	0.0	0.0
3077	2015	Discretionary	DSP Tucker Station Substation Project (2015-	This project is to build a new 138/13.09, 44.8 MVA substation along Tucker Station Road near Plantside Drive. This station will address potential overloads on				3100	1700				10.0	10.0	12.9
3081	2015	Discretionary	DSP Versailles 4KV Substation Upgrade	Replace the Versailles 6.25 MVA transformer with a 10 MVA transformer. The purpose of this project is to serve new developments resulting from infill and				750					5.8	6.3	6.3
3808	2015	Discretionary	LEO Cable Rejuvenation - 2015	Cable rejuvenation restores the dielectric strength of in-service aged cable insulations to new cable dielectric strength levels and is warranted to provide 20				263					0.0	0.0	0.0
3923	2015	Discretionary	Rear Easement OH Hardening - KU - 2013 COPY - 2015	Initiate a project to replace defective, small capacity overhead conductor and related distribution line equipment in rear lot applications on the KU system. Targeted				1051							
3919	2015	Discretionary	Rear Easement OH Hardening LGE - 2013 COPY - 2015	Initiate a project to replace defective, small capacity overhead conductor and related distribution line equipment in rear lot applications on the LGE system. Targeted				1051							
2825	2015	Discretionary	RIC Rebuild Pine Hill to Livingston Line	Replace 19,500 ft of 3-4CW and 1-6CU neutral with 3-2/0A primary and 1-2A neutral from the Pine Hill Substation to the town of Livingston. Replace defedtive poles,				380					0.0	0.0	0.0
2830	2015	Discretionary	RIC Reconductor Ckt 2312	Reconductor 1,900 ft of 3-2/0A primary with 3-397A primary on circuit 2312 from Old Boonesboro Road to US 25. Due to load growth in the area this conductor is						67			8.9	8.5	8.5
3869	2015	Discretionary	SCM KU CENT Replace Legacy OCB's: Types FK, FKD, G, GC. -	The KU system includes numerous legacy oil filled circuit breakers, typically installed in the 1940's or 1950's. These breakers require frequent maintenance intervals to				305							
3829	2015	Discretionary	SCM KU EARL Replace Legacy OCB's: Types FK, FKD, G, GC. -	The KU system includes numerous legacy oil filled circuit breakers, typically installed in the 1940's or 1950's. These breakers require frequent maintenance intervals to	Both the KU and LG&E systems include numerous legacy oil filled circuit			158							
3823	2015	Discretionary	SCM KU PINE Replace Legacy OCB's: Types FK, FKD, G, GC. -	The KU system includes numerous legacy oil filled circuit breakers, typically installed in the 1940's or 1950's. These breakers require frequent maintenance intervals to	Both the KU and LG&E systems include numerous legacy oil filled circuit			158							
3898	2015	Discretionary	SCM LGE BDD Diff Relay Replacement - 2015	The old BDD relays require upgrades. We have found the BDD relays older than 30 years to be out of tolerance. These relays are critical in the Transformer Differential				53					0.0	0.0	0.0
3624	2015	Discretionary	SCM LGE FPE Tapchanger Replacement - Reinhausen -	LG&E has ten remaining FPE transformer LTC's in service throughout our distribution system. These have proven to be the most unreliable LTC's in our system. This is an				756					45.0	28.0	32.0
3815	2015	Discretionary	SCM LGE Replace Legacy 15KV Air-Magnetic Circuit	There are 18 McGraw Edison Air Magnetic style breakers in service at LG&E. Many of these units are over 40 years and are being operated at the limits of their design	Improve the reliability of HK Sec 1.			158					0.0	0.0	0.0
3838	2015	Discretionary	SCM LGE Replace Legacy Substation Oil Circuit	The LG&E system includes numerous legacy oil filled circuit breakers, typically installed in the 1940's or 1950's. These breakers require frequent maintenance	Both the KU and LG&E systems include numerous legacy oil filled circuit			305					0.0	0.0	0.0
3903	2015	Discretionary	SCM LGE Transformer Surge Arrester Replacement Project	Upgrade old style porcelain surge arresters to new metal oxide, silicon rubber type.	Pre 1976 surge protecters utilized Multigap Silicon Carbide blocks or Current			47					0.0	0.0	0.0
3706	2015	Discretionary	UG CABLE DETERIORATION - 2015	Project consists of replacing up to 21,800 feet of residential primary 12kv underground cable by directional boring. Recently discovered that a lot of the direct				131					0.0	0.0	0.0
3913	2015	Discretionary	UG Cable Replacement Substation Exits LG&E - 2013 -	A proactive asset replacement program to replace aged, poor performing underground substation exit cables on the LG&E distribution system. Medium				1051					0.0	0.0	0.0
3884	2015	Discretionary	URD Cable Repl/Rejuv Program KU - 2013 - 2015	Proactive asset replacement program to replace or rejuvenate aged, poor performing underground cables on worst performing residential subdivision circuits				315					0.0	0.0	0.0
3888	2015	Discretionary	URD Cable Repl/Rejuv Program LG&E - 2013 - 2015	Proactive asset replacement program to replace or rejuvenate aged, poor performing underground cables on worst performing residential subdivision circuits				1051					0.0	0.0	0.0
3769	2016	Non-Discretionary	Pole Inspection and Treatment KU - 2013 - 2016	An infrastucture improvement program to inspect and evaluate the condition of distribution wood poles on the KU system. The program inspects poles, assesses the	Corporate Asset Management Strategy to proactively evaluate, inspect, treat, and				5199				0.0	0.0	0.0
3773	2016	Non-Discretionary	Pole Inspection and Treatment LG&E - 2013 -	An infrastucture improvement program to inspect and evaluate the condition of distribution wood poles on the LG&E system. The program inspects poles, assesses	Corporate Asset Management Strategy to proactively evaluate, inspect, treat, and				6037				0.0	0.0	0.0
3413	2016	Non-Discretionary	SCM 2013 LG&E Misc Dist Proj - 2016	Requesting funding for the miscellaneous capital expenses such as bushings, insulators, surge arresters, capacitors, etc. that are required throughout the year.	Failed units will require replacement to ensure continuity of service. Units which				113				0.0	0.0	0.0
3442	2016	Non-Discretionary	SCM 2013 PINE MISC CAPITAL PROJ - 2016	Requesting funding for the miscellaneous expenses such as bushings, insulators, arresters, etc that are required throughout the year.	Failed units will require replacements to ensure continuity of service. Units				156				0.0	0.0	0.0
3433	2016	Non-Discretionary	SCM 2013 PINE MISC NESC COMPLIANCE - 2016	Substation surveys have turned up many NESC compliance concerns such as fences too short and vertical electrical clearances not adequate. This miscellaneous project	requied to comply with NESC/PSC.				68				0.0	0.0	0.0
3446	2016	Non-Discretionary	SCM 2013 PINE REPLACE SUBSTATION BATTERIES -	Replace defective wet cell batteries and battery chargers in distribution substations.	Reliable DC power is needed in order to properly operate automatic protection				30				0.0	0.0	0.0
3537	2016	Non-Discretionary	SCM 2014 CENT Oil Filtration Additions - 2016	Purchase and installation of filtering system on high profile LTC's in our system.	Ability to filter oil in LTC's with high volume of operations per year. This will				53				0.0	0.0	0.0
3449	2016	Non-Discretionary	SCM 2014 PINE OIL FILTRATION ADDITIONS -	Begin a LTC oil filtering program in 2014 that LG&E already has in place. By adding oil filtration to our LTCs that are difficult to get out of service, we decrease customer	Begin a LTC oil filtering program in 2014 that LG&E already has in place. by adding				53				0.0	0.0	0.0
3491	2016	Non-Discretionary	SCM 2014 PINE SUBSTN BUILDINGS & GNDS - 2016	This request is for the funding of capital improvements/replacements of station houses, roofs, yard, oil spill containment, driveways, and other general	This request is for the funding of capital improvements/replacements of station				42				0.0	0.0	0.0
3418	2016	Non-Discretionary	SCM 2016 CENT-REPL LEGACY LTC/REG CONTR	Purchase and Install New LTC and Regulator Controls. Remove and Retire Legacy Controls.	Ongoing project to replace legacy LTC and Regulator Controls with new style				59				0.0	0.0	0.0

						Cash Flow							Overloaded		
AIS Project	Start Year	Type	ProjectName	Description	Justification	2013	2014	2015	2016	2017	2018	2019	Peak Load	Normal Rating	Emergency Rating
3529	2016	Non-Discretionary	SCM 2016 EARL-REPL LEGACY LTC/REG CONTR	Purchase and Install New LTC and Regulator Controls. Remove and Retire Legacy Controls.	Ongoing project to replace legacy LTC and Regulator Controls with new style				59				0.0	0.0	0.0
3524	2016	Non-Discretionary	SCM 2016 PINE-REPL LEGACY LTC/REG CONTR	Purchase and Install New LTC and Regulator Controls. Remove and Retire Legacy Controls.	Ongoing project to replace legacy LTC and Regulator Controls with new style				59				0.0	0.0	0.0
3546	2016	Non-Discretionary	SCM CENT Misc Dist Capital Sub Project - 2016	Purchase and install material and equipment in various distribution substations as required to serve loads, upgrade equipment and replace failed facilities.	Replace failed equipment and facilities as encountered.				263				0.0	0.0	0.0
3550	2016	Non-Discretionary	SCM CENT Misc NESC Compliance - 2016	Substation checks have shown many NESC compliance issues. This includes fences too short and vertical electrical clearance issues. This project will enable us to	NESC issues must be addressed to meet PSC compliance (and NESC compliance)				73				0.0	0.0	0.0
3562	2016	Non-Discretionary	SCM CENT REPL BREAKERS - 2016	Replace approximately seven failed breakers per year in the Central substation area	Failed units will require replacement to ensure continuity of service				194				0.0	0.0	0.0
3566	2016	Non-Discretionary	SCM CENT REPL BUSHINGS - 2016	Replace approximately twelve failed and deteriorated bushings on substation transformers and breakers	Failed units will require replacement to ensure continuity of service				43				0.0	0.0	0.0
3570	2016	Non-Discretionary	SCM CENT REPL REGULATORS - 2016	Purchase regulators to replace approximately six failed units and maintain adequate stock	Failed units will require replacement to ensure continuity of service				80				0.0	0.0	0.0
3554	2016	Non-Discretionary	SCM CENT Replace Substation Batteries - 2016	Replace wet cell batteries and chargers due to age, defect, or failure.	Replacement due to age, defect, or failure. Failed units will require				45				0.0	0.0	0.0
3557	2016	Non-Discretionary	SCM CENT SUBSTATION BUILDING & GNDS - 2016	REPLACE/IMPROVE BUILDING AND GROUNDS IN LEXINGTON AND DANVILLE SUBSTATIONS	REPLACE/IMPROVE COMPANY ASSETS				42				0.0	0.0	0.0
3476	2016	Non-Discretionary	SCM EARL MISC DIST CAPITAL SUB PROJ - 2016	This project is to provide funding for various repairs and upgrades that arise throughout the year. Often, this work will be associated with an equipment failure or	Marked Non-Discretionary per Technical Review Team				215				0.0	0.0	0.0
3480	2016	Non-Discretionary	SCM EARL MISC NESC COMPLIANCE - 2016	A review of substations has revealed several deficiencies. Most deficiencies are perimeter fence height problems. There are some energized parts ground clearance	NESC COMPLIANCE RELATED				151				0.0	0.0	0.0
3484	2016	Non-Discretionary	SCM EARL REPLACE SUBSTATION BATTERIES -	This project is to replace substation batteries and chargers at various locations. Several banks are deteriorated. Several chargers are becoming unreliable and should	Reliable DC power is needed in order to properly operate automatic protection				32				0.0	0.0	0.0
3487	2016	Non-Discretionary	SCM EARL SUBSTN BUILDINGS & GROUNDS -	Request is for the funding of repairs/replacements on control house buildings and other general capital improvements to substation grounds that arise annually.	Request is for the funding of repairs/replacements on control house				42				0.0	0.0	0.0
3641	2016	Non-Discretionary	SCM Earlington Recloser Replacement Program - 2016	There are over 40 oil filled electro-mechanical reclosers located in Earlington substations. Approximately half of these locations would greatly benefit from an	The oil filled electro-mechanical reclosers located in Earlington are aging and				120				0.0	0.0	0.0
3698	2016	Non-Discretionary	SCM Earlington Replace Regulators - 2016	Purchase regulators to replace approximately six failed units and maintain adequate stock	Failed units will require replacement to ensure continuity of service				80				0.0	0.0	0.0
3607	2016	Non-Discretionary	SCM KU CA DIFF Relay Replacement (2014 START) -	Many legacy CA relays require replacement. Many have tested out of tolerance and have been replaced. These relays are critical in the Transformer Differential	These relays are critical in the Transformer Differential protection				63				0.0	0.0	0.0
3590	2016	Non-Discretionary	SCM KU EARL Replace legacy 34KV breakers - 2016	Replace aging 34kv oil circuit breakers. Five units are 40-60 years old, and spare parts are becoming difficult to find. Replace 2 breakers per year until these 5 have	Replace aging 34kv oil circuit breakers. Five units are 40-60 years old, and spare				172				0.0	0.0	0.0
3629	2016	Non-Discretionary	SCM KU HZ Relay Replacement - 2016	Replace legacy, low reliability Westinghouse HZ Distance Relays, 6 per year. Transmission has a standard practice of replacing these relays whenever possible	Improved reliability and capability. Transmission has a standard practice of				65				0.0	0.0	0.0
3617	2016	Non-Discretionary	SCM KU Legacy RTU Replacements - 2016	The majority of KU Distribution Substations in or near the Lexington area have early 1980's vintage Leeds and Northrup remote terminal units. These legacy devices do	These legacy RTUs experience high failure rates, requiring labor intensive				289				0.0	0.0	0.0
3586	2016	Non-Discretionary	SCM KU PINE Replace legacy 34kv breakers - 2016	Replace aging 34kv oil circuit breakers. Several units were manufactured circa 1950, and spare parts are becoming difficult to find. Replace (2) breakers per year from	Replace aging 34kv oil circuit breakers. Several units were manufactured circa				172				0.0	0.0	0.0
3656	2016	Non-Discretionary	SCM KU Replace Legacy Vac Circuit Breakers: Types VIB -	The KU system (Central, Pineville, and Earlington) contains numerous legacy GE Type VIB vacuum breakers from the 1970s. The mechanisms on these breakers have	The KU system (Central, Pineville, and Earlington) contains numerous legacy GE				263						
3400	2016	Non-Discretionary	SCM LG&E LTC Oil Filter Units - 2016	We are requesting money to continue our succesful program of installing oil filtration systems on transformer LTC's. These devices have proven to significantly	We are requesting money to continue our succesful program of installing oil				56				0.0	0.0	0.0
3408	2016	Non-Discretionary	SCM LG&E Substation Building and Grounds - 2016	Request is for the funding of repairs/replacements on control house buildings, fire preventions systems and other general capital improvements to substation grounds	Request is for the funding of repairs/replacements on control house				75				0.0	0.0	0.0
3672	2016	Non-Discretionary	SCM LGE Implement Direct Transfer Trip over SONET -	The Direct Transfer Trip Circuits in LG&E have been moved off of the copper wire infrastructure. The remaining circuits that need to be moved will complete this	The copper system presently in use is less reliable and is not maintained. The fiber				103				0.0	0.0	0.0
3404	2016	Non-Discretionary	SCM LGE Miscellaneous NESC Compliance Projects - 2016	Substation surveys have turned up many NESC compliance concerns such as fences too short and vertical electrical clearances not adequate. This miscellaneous project	Required for NESC and PSC compliance				81				0.0	0.0	0.0
3600	2016	Non-Discretionary	SCM LGE REPL TRANSF FIRE DETECTION SYSTEMS - 2016	A significant percentage of fire detection thermostats on these systems have experienced failures from an acknowledged design flaw. The inadvertent trip of a	Failed units will require replacement to ensure continuity of fire suppression				25				0.0	0.0	0.0
3653	2016	Non-Discretionary	SCM LGE Replace Legacy VRR's - 2016	LGE requests funding to replace legacy voltage regulating relays (VRR's) at a rate of (6) per year. The legacy units are not reliable and spare parts are very difficult to	LGE requests funding to replace legacy voltage regulating relays (VRR's) at a rate				43				0.0	0.0	0.0
3604	2016	Non-Discretionary	SCM LGE Replace Substation Batteries - 2016	Need to replace 5 Substation Battery systems per year due to age. Various Distribution Substations have batteries that are between 21 and 25 years old.	Failed units will require replacement to ensure continuity of service and proper				96				0.0	0.0	0.0
3645	2016	Non-Discretionary	SCM PINE RECLOSER REPL - 2016	The Pineville area has over 95 reclosers inside substations. Replace approximately two failed reclosers in substations in the Pineville area per year.	Must replace failed units				62				0.0	0.0	0.0
3712	2016	Non-Discretionary	SCM Pineville Replace Regulators - 2016	Purchase regulators to replace approximately six failed units and maintain adequate stock	Failed units will require replacement to ensure continuity of service				80				0.0	0.0	0.0
3757	2016	Non-Discretionary	UG Network PILC Primary Cable Replacement Program-	A proactive asset replacement program to replace aging and defective paper insulated lead covered (PILC) primary underground cables in the LG&E Downtown	Improve public safety from catastrophic manhole explosions and lower risk of				2154				0.0	0.0	0.0
3761	2016	Non-Discretionary	UG Network PILC Secondary Cable Replacement Program-	A proactive asset replacement program to replace aged, deteriorating paper insulated lead covered (PILC), secondary underground cables in the LG&E Downtown	Improve public safety from catastrophic manhole explosions and lower risk of				2154				0.0	0.0	0.0
3724	2016	Discretionary	CEMI>5 Circuits - KU - 2013 - 2016	Improve reliability on 26 KU circuits that have Customers Experiencing Multiple Interruptions (CEMI) of more than 8 outages in 2011. Budgetary project description					700				0.0	0.0	0.0
3728	2016	Discretionary	CEMI>5 Circuits - LGE - 2013 - 2016	Improve reliability on 43 LGE circuits that have Customers Experiencing Multiple Interruptions (CEMI) of more than 8 outages in 2011. Budgetary project description					1158				0.0	0.0	0.0
3834	2016	Discretionary	CIFI (worst) Circuits - Level 1 KU - 5 Circuits - 2013 - 2016	Improve reliability on five(5) Level 1 Circuits ID'd for Improvement (CIFI) at KU. Level 1 CIFI circuits have a long term (5 year) poor SAIFI performance record where the					700				0.0	0.0	0.0
3843	2016	Discretionary	CIFI (worst) Circuits - Level 1 LGE - 1 Circuit - 2013 - 2016	Improve reliability on one(1) Level 1 Circuits ID'd for Improvement (CIFI) at LGE. Level 1 CIFI circuits have a long term (5 year) poor SAIFI performance record where					140				0.0	0.0	0.0
3847	2016	Discretionary	CIFI (worst) Circuits - Level 2 KU - 12 Circuits - 2013 - 2016	Improve reliability on 12 Level 2 Circuits ID'd for Improvement (CIFI) at KU. Level 2 CIFI circuits have a long term (5 year) poor SAIFI performance record where the					1680				0.0	0.0	0.0
3851	2016	Discretionary	CIFI (worst) Circuits - Level 2 LGE - 1 Circuit - 2013 - 2016	Improve reliability on one(1) Level 2 Circuits ID'd for Improvement (CIFI) at LGE. Level 2 CIFI circuits have a long term (5 year) poor SAIFI performance record where					140				0.0	0.0	0.0
3855	2016	Discretionary	CIFI (worst) Circuits - Level 3 KU - 28 Circuits - 2013 - 2016	Improve reliability on 28 Level 3 Circuits ID'd for Improvement (CIFI) at KU. Level 3 CIFI circuits have a long term (5 year) poor SAIFI performance record where the					3920				0.0	0.0	0.0
3859	2016	Discretionary	CIFI (worst) Circuits - Level 3 LGE - 25 Circuits - 2013 - 2016	Improve reliability on 25 Level 3 Circuits ID'd for Improvement (CIFI) at LGE. Level 3 CIFI circuits have a long term (5 year) poor SAIFI performance record where the					3500				0.0	0.0	0.0
3074	2016	Discretionary	DSP Floyd Circuit Work	Circuit work required for the expansion of Floyd Substation. A 44.8 MVA transformer will be added to Floyd Substation with completion in 2015.					480	480			0.0	0.0	0.0
3032	2016	Discretionary	DSP Floyd Substation Expansion	Floyd Substation serves the area surrounding and including the University of Louisville. The substation currently has one 44.8 MVA transformer. This project will					3260	850			45.1	44.8	53.7
2959	2016	Discretionary	DSP Russell Springs Distribution	Distribution circuit work required to accompany Russell Springs Substation Upgrade project.								100	0.0	0.0	0.0
2909	2016	Discretionary	DSP Somerset Area Distribution	Distribution circuit required to accomodate Somerset Area Substation project construction.					200				0.0	0.0	0.0
3809	2016	Discretionary	LEO Cable Rejuvenation - 2016	Cable rejuvenation restores the dielectric strength of in-service aged cable insulations to new cable dielectric strength levels and is warranted to provide 20					269				0.0	0.0	0.0
3924	2016	Discretionary	Rear Easement OH Hardening - KU - 2013 COPY - 2016	Initiate a project to replace defective, small capacity overhead conductor and related distribution line equipment in rear lot applications on the KU system. Targeted					1077						
3920	2016	Discretionary	Rear Easement OH Hardening LGE - 2013 COPY - 2016	Initiate a project to replace defective, small capacity overhead conductor and related distribution line equipment in rear lot applications on the LGE system. Targeted					1077						

AIS Project	Start Year	Type	ProjectName	Description	Justification	Cash Flow 2013	2014	2015	2016	2017	2018	2019	Overloaded Peak Load	Normal Rating	Emergency Rating
3870	2016	Discretionary	SCM KU CENT Replace Legacy OCB's: Types FK, FKD, G, GC. -	The KU system includes numerous legacy oil filled circuit breakers, typically installed in the 1940's or 1950's. These breakers require frequent maintenance intervals to					312						
3830	2016	Discretionary	SCM KU EARL Replace Legacy OCB's: Types FK, FKD, G, GC. -	The KU system includes numerous legacy oil filled circuit breakers, typically installed in the 1940's or 1950's. These breakers require frequent maintenance intervals to	Both the KU and LG&E systems include numerous legacy oil filled circuit				162						
3824	2016	Discretionary	SCM KU PINE Replace Legacy OCB's: Types FK, FKD, G, GC. -	The KU system includes numerous legacy oil filled circuit breakers, typically installed in the 1940's or 1950's. These breakers require frequent maintenance intervals to	Both the KU and LG&E systems include numerous legacy oil filled circuit				162						
3899	2016	Discretionary	SCM LGE BDD Diff Relay Replacement - 2016	The old BDD relays require upgrades. We have found the BDD relays older than 30 years to be out of tolerance. These relays are critical in the Transformer Differential					54				0.0	0.0	0.0
3625	2016	Discretionary	SCM LGE FPE Tapchanger Replacement - Reinhausen -	LG&E has ten remaining FPE transformer LTC's in service throughout our distribution system. These have proven to be the most unreliable LTC's in our system. This is an					775				45.0	28.0	32.0
3816	2016	Discretionary	SCM LGE Replace Legacy 15KV Air-Magnetic Circuit	There are 18 McGraw Edison Air Magnetic style breakers in service at LG&E. Many of these units are over 40 years and are being operated at the limits of their design	Improve the reliability of HK Sec 1.				162				0.0	0.0	0.0
3839	2016	Discretionary	SCM LGE Replace Legacy Substation Oil Circuit	The LG&E system includes numerous legacy oil filled circuit breakers, typically installed in the 1940's or 1950's. These breakers require frequent maintenance	Both the KU and LG&E systems include numerous legacy oil filled circuit				312				0.0	0.0	0.0
3904	2016	Discretionary	SCM LGE Transformer Surge Arrester Replacement Project	Upgrade old style porcelain surge arresters to new metal oxide, silicon rubber type.	Pre 1976 surge protecters utilized Multigap Silicon Carbide blocks or Current				48				0.0	0.0	0.0
3707	2016	Discretionary	UG CABLE DETERIORATION - 2016	Project consists of replacing up to 21,800 feet of residential primary 12kv underground cable by directional boring. Recently discovered that a lot of the direct					135				0.0	0.0	0.0
3914	2016	Discretionary	UG Cable Replacement Substation Exits LG&E - 2013 -	A proactive asset replacement program to replace aged, poor performing underground substation exit cables on the LG&E distribution system. Medium					1077				0.0	0.0	0.0
3885	2016	Discretionary	URD Cable Repl/Rejuv Program KU - 2013 - 2016	Proactive asset replacement program to replace or rejuvenate aged, poor performing underground cables on worst performing residential subdivision circuits					323				0.0	0.0	0.0
3889	2016	Discretionary	URD Cable Repl/Rejuv Program LG&E - 2013 - 2016	Proactive asset replacement program to replace or rejuvenate aged, poor performing underground cables on worst performing residential subdivision circuits					1077				0.0	0.0	0.0
2922	2017	Non-Discretionary	KU SCADA Expansion	Install SCADA at existing KU substations and new KU substations. This project will allow real time load monitoring, breaker loading, and outage status at distribution	This project was identified in the LTP as a priority for expanding the SCADA system					5000			0.0	0.0	0.0
3770	2017	Non-Discretionary	Pole Inspection and Treatment KU - 2013 - 2017	An infrastucture improvement program to inspect and evaluate the condition of distribution wood poles on the KU system. The program inspects poles, assesses the	Corporate Asset Management Strategy to proactively evaluate, inspect, treat, and					7144			0.0	0.0	0.0
3774	2017	Non-Discretionary	Pole Inspection and Treatment LG&E - 2013 -	An infrastucture improvement program to inspect and evaluate the condition of distribution wood poles on the LG&E system. The program inspects poles, assesses	Corporate Asset Management Strategy to proactively evaluate, inspect, treat, and					6188			0.0	0.0	0.0
3414	2017	Non-Discretionary	SCM 2013 LG&E Misc Dist Proj - 2017	Requesting funding for the miscellaneous capital expenses such as bushings, insulators, surge arresters, capacitors, etc. that are required throughout the year.	Failed units will require replacement to ensure continuity of service. Units which					116			0.0	0.0	0.0
3443	2017	Non-Discretionary	SCM 2013 PINE MISC CAPITAL PROJ - 2017	Requesting funding for the miscellaneous expenses such as bushings, insulators, arresters, etc that are required throughout the year.	Failed units will require replacements to ensure continuity of service. Units					160			0.0	0.0	0.0
3434	2017	Non-Discretionary	SCM 2013 PINE MISC NESC COMPLIANCE - 2017	Substation surveys have turned up many NESC compliance concerns such as fences too short and vertical electrical clearances not adequate. This miscellaneous project	requied to comply with NESC/PSC.					70			0.0	0.0	0.0
3447	2017	Non-Discretionary	SCM 2013 PINE REPLACE SUBSTATION BATTERIES -	Replace defective wet cell batteries and battery chargers in distribution substations.	Reliable DC power is needed in order to properly operate automatic protection					31			0.0	0.0	0.0
3538	2017	Non-Discretionary	SCM 2014 CENT Oil Filtration Additions - 2017	Purchase and installation of filtering system on high profile LTC's in our system.	Ability to filter oil in LTC's with high volume of operations per year. This will					54			0.0	0.0	0.0
3450	2017	Non-Discretionary	SCM 2014 PINE OIL FILTRATION ADDITIONS -	Begin a LTC oil filtering program in 2014 that LG&E already has in place. By adding oil filtration to our LTCs that are difficult to get out of service, we decrease customer	Begin a LTC oil filtering program in 2014 that LG&E already has in place. by adding					54			0.0	0.0	0.0
3492	2017	Non-Discretionary	SCM 2014 PINE SUBSTN BUILDINGS & GNDS - 2017	This request is for the funding of capital improvements/replacements of station houses, roofs, yard, oil spill containment, driveways, and other general	This request is for the funding of capital improvements/replacements of station					43			0.0	0.0	0.0
3419	2017	Non-Discretionary	SCM 2017 CENT-REPL LEGACY LTC/REG CONTR	Purchase and Install New LTC and Regulator Controls. Remove and Retire Legacy Controls.	Ongoing project to replace legacy LTC and Regulator Controls with new style					61			0.0	0.0	0.0
3530	2017	Non-Discretionary	SCM 2017 EARL-REPL LEGACY LTC/REG CONTR	Purchase and Install New LTC and Regulator Controls. Remove and Retire Legacy Controls.	Ongoing project to replace legacy LTC and Regulator Controls with new style					61			0.0	0.0	0.0
3525	2017	Non-Discretionary	SCM 2017 PINE-REPL LEGACY LTC/REG CONTR	Purchase and Install New LTC and Regulator Controls. Remove and Retire Legacy Controls.	Ongoing project to replace legacy LTC and Regulator Controls with new style					61			0.0	0.0	0.0
3547	2017	Non-Discretionary	SCM CENT Misc Dist Capital Sub Project - 2017	Purchase and install material and equipment in various distribution substations as required to serve loads, upgrade equipment and replace failed facilities.	Replace failed equipment and facilities as encountered.					269			0.0	0.0	0.0
3551	2017	Non-Discretionary	SCM CENT Misc NESC Compliance - 2017	Substation checks have shown many NESC compliance issues. This includes fences too short and vertical electrical clearance issues. This project will enable us to	NESC issues must be addressed to meet PSC compliance (and NESC compliance)					75			0.0	0.0	0.0
3563	2017	Non-Discretionary	SCM CENT REPL BREAKERS - 2017	Replace approximately seven failed breakers per year in the Central substation area	Failed units will require replacement to ensure continuity of service					199			0.0	0.0	0.0
3567	2017	Non-Discretionary	SCM CENT REPL BUSHINGS - 2017	Replace approximately twelve failed and deteriorated bushings on substation transformers and breakers	Failed units will require replacement to ensure continuity of service					44			0.0	0.0	0.0
3571	2017	Non-Discretionary	SCM CENT REPL REGULATORS - 2017	Purchase regulators to replace approximately six failed units and maintain adequate stock	Failed units will require replacement to ensure continuity of service					82			0.0	0.0	0.0
3555	2017	Non-Discretionary	SCM CENT Replace Substation Batteries - 2017	Replace wet cell batteries and chargers due to age, defect, or failure.	Replacement due to age, defect, or failure. Failed units will require					46			0.0	0.0	0.0
3558	2017	Non-Discretionary	SCM CENT SUBSTATION BUILDING & GNDS - 2017	REPLACE/IMPROVE BUILDING AND GROUNDS IN LEXINGTON AND DANVILLE SUBSTATIONS	REPLACE/IMPROVE COMPANY ASSETS					43			0.0	0.0	0.0
3477	2017	Non-Discretionary	SCM EARL MISC DIST CAPITAL SUB PROJ - 2017	This project is to provide funding for various repairs and upgrades that arise throughout the year. Often, this work will be associated with an equipment failure or	Marked Non-Discretionary per Technical Review Team					221			0.0	0.0	0.0
3481	2017	Non-Discretionary	SCM EARL MISC NESC COMPLIANCE - 2017	A review of substations has revealed several deficiencies. Most deficiencies are perimeter fence height problems. There are some energized parts ground clearance	NESC COMPLIANCE RELATED					155			0.0	0.0	0.0
3485	2017	Non-Discretionary	SCM EARL REPLACE SUBSTATION BATTERIES -	This project is to replace substation batteries and chargers at various locations. Several banks are deteriorated. Several chargers are becoming unreliable and should	Reliable DC power is needed in order to properly operate automatic protection					33			0.0	0.0	0.0
3488	2017	Non-Discretionary	SCM EARL SUBSTN BUILDINGS & GROUNDS -	Request is for the funding of repairs/replacements on control house buildings and other general capital improvements to substation grounds that arise annually.	Request is for the funding of repairs/replacements on control house					43			0.0	0.0	0.0
3642	2017	Non-Discretionary	SCM Earlington Recloser Replacement Program - 2017	There are over 40 oil filled electro-mechanical reclosers located in Earlington substations. Approximately half of these locations would greatly benefit from an	The oil filled electro-mechanical reclosers located in Earlington are aging and					123			0.0	0.0	0.0
3699	2017	Non-Discretionary	SCM Earlington Replace Regulators - 2017	Purchase regulators to replace approximately six failed units and maintain adequate stock	Failed units will require replacement to ensure continuity of service					82			0.0	0.0	0.0
3608	2017	Non-Discretionary	SCM KU CA DIFF Relay Replacement (2014 START) -	Many legacy CA relays require replacement. Many have tested out of tolerance and have been replaced. These relays are critical in the Transformer Differential	These relays are critical in the Transformer Differential protection					65			0.0	0.0	0.0
3591	2017	Non-Discretionary	SCM KU EARL Replace legacy 34KV breakers - 2017	Replace aging 34kv oil circuit breakers. Five units are 40-60 years old, and spare parts are becoming difficult to find. Replace 2 breakers per year until these 5 have	Replace aging 34kv oil circuit breakers. Five units are 40-60 years old, and spare					177			0.0	0.0	0.0
3630	2017	Non-Discretionary	SCM KU HZ Relay Replacement - 2017	Replace legacy, low reliability Westinghouse HZ Distance Relays, 6 per year. Transmission has a standard practice of replacing these relays whenever possible	Improved reliability and capability. Transmission has a standard practice of					66			0.0	0.0	0.0
3618	2017	Non-Discretionary	SCM KU Legacy RTU Replacements - 2017	The majority of KU Distribution Substations in or near the Lexington area have early 1980's vintage Leeds and Northrup remote terminal units. These legacy devices do	These legacy RTUs experience high failure rates, requiring labor intensive					296			0.0	0.0	0.0
3587	2017	Non-Discretionary	SCM KU PINE Replace legacy 34kv breakers - 2017	Replace aging 34kv oil circuit breakers. Several units were manufactured circa 1950, and spare parts are becoming difficult to find. Replace (2) breakers per year from	Replace aging 34kv oil circuit breakers. Several units were manufactured circa					177			0.0	0.0	0.0
3657	2017	Non-Discretionary	SCM KU Replace Legacy Vac Circuit Breakers: Types VIB -	The KU system (Central, Pineville, and Earlington) contains numerous legacy GE Type VIB vacuum breakers from the 1970s. The mechanisms on these breakers have	The KU system (Central, Pineville, and Earlington) contains numerous legacy GE					269					
3401	2017	Non-Discretionary	SCM LG&E LTC Oil Filter Units - 2017	We are requesting money to continue our succesful program of installing oil filtration systems on transformer LTC's. These devices have proven to significantly	We are requesting money to continue our succesful program of installing oil					57			0.0	0.0	0.0
3409	2017	Non-Discretionary	SCM LG&E Substation Building and Grounds - 2017	Request is for the funding of repairs/replacements on control house buildings, fire preventions systems and other general capital improvements to substation grounds	Request is for the funding of repairs/replacements on control house					77			0.0	0.0	0.0
3673	2017	Non-Discretionary	SCM LGE Implement Direct Transfer Trip over SONET -	The Direct Transfer Trip Circuits in LG&E have been moved off of the copper wire infrastructure. The remaining circuits that need to be moved will complete this	The copper system presently in use is less reliable and is not maintained. The fiber					105			0.0	0.0	0.0

						Cash Flow							Overloaded		
AIS Project	Start Year	Type	ProjectName	Description	Justification	2013	2014	2015	2016	2017	2018	2019	Peak Load	Normal Rating	Emergency Rating
3405	2017	Non-Discretionary	SCM LGE Miscellaneous NESC Compliance Projects - 2017	Substation surveys have turned up many NESC compliance concerns such as fences too short and vertical electrical clearances not adequate. This miscellaneous project	Required for NESC and PSC compliance					83			0.0	0.0	0.0
3601	2017	Non-Discretionary	SCM LGE REPL TRANSF FIRE DETECTION SYSTEMS - 2017	A significant percentage of fire detection thermostats on these systems have experienced failures from an acknowledged design flaw. The inadvertent trip of a	Failed units will require replacement to ensure continuity of fire suppression					25			0.0	0.0	0.0
3654	2017	Non-Discretionary	SCM LGE Replace Legacy VRR's - 2017	LGE requests funding to replace legacy voltage regulating relays (VRR's) at a rate of (6) per year. The legacy units are not reliable and spare parts are very difficult to	LGE requests funding to replace legacy voltage regulating relays (VRR's) at a rate					44			0.0	0.0	0.0
3605	2017	Non-Discretionary	SCM LGE Replace Substation Batteries - 2017	Need to replace 5 Substation Battery systems per year due to age. Various Distribution Substations have batteries that are between 21 and 25 years old.	Failed units will require replacement to ensure continuity of service and proper					98			0.0	0.0	0.0
3646	2017	Non-Discretionary	SCM PINE RECLOSER REPL - 2017	The Pineville area has over 95 reclosers inside substations. Replace approximately two failed reclosers in substations in the Pineville area per year.	Must replace failed units					64			0.0	0.0	0.0
3713	2017	Non-Discretionary	SCM Pineville Replace Regulators - 2017	Purchase regulators to replace approximately six failed units and maintain adequate stock	Failed units will require replacement to ensure continuity of service					82			0.0	0.0	0.0
3758	2017	Non-Discretionary	UG Network PILC Primary Cable Replacement Program-	A proactive asset replacement program to replace aging and defective paper insulated lead covered (PILC) primary underground cables in the LG&E Downtown	Improve public safety from catastrophic manhole explosions and lower risk of					2208			0.0	0.0	0.0
3762	2017	Non-Discretionary	UG Network PILC Secondary Cable Replacement Program-	A proactive asset replacement program to replace aged, deteriorating paper insulated lead covered (PILC), secondary underground cables in the LG&E Downtown	Improve public safety from catastrophic manhole explosions and lower risk of					2208			0.0	0.0	0.0
3725	2017	Discretionary	CEMI>5 Circuits - KU - 2013 - 2017	Improve reliability on 26 KU circuits that have Customers Experiencing Multiple Interruptions (CEMI) of more than 8 outages in 2011. Budgetary project description						717			0.0	0.0	0.0
3729	2017	Discretionary	CEMI>5 Circuits - LGE - 2013 - 2017	Improve reliability on 43 LGE circuits that have Customers Experiencing Multiple Interruptions (CEMI) of more than 8 outages in 2011. Budgetary project description						1187			0.0	0.0	0.0
3835	2017	Discretionary	CIFI (worst) Circuits - Level 1 KU - 5 Circuits - 2013 - 2017	Improve reliability on five(5) Level 1 Circuits ID'd for Improvement (CIFI) at KU. Level 1 CIFI circuits have a long term (5 year) poor SAIFI performance record where the						717			0.0	0.0	0.0
3844	2017	Discretionary	CIFI (worst) Circuits - Level 1 LGE - 1 Circuit - 2013 - 2017	Improve reliability on one(1) Level 1 Circuits ID'd for Improvement (CIFI) at LGE. Level 1 CIFI circuits have a long term (5 year) poor SAIFI performance record where						143			0.0	0.0	0.0
3848	2017	Discretionary	CIFI (worst) Circuits - Level 2 KU - 12 Circuits - 2013 - 2017	Improve reliability on 12 Level 2 Circuits ID'd for Improvement (CIFI) at KU. Level 2 CIFI circuits have a long term (5 year) poor SAIFI performance record where the						1722			0.0	0.0	0.0
3852	2017	Discretionary	CIFI (worst) Circuits - Level 2 LGE - 1 Circuit - 2013 - 2017	Improve reliability on one(1) Level 2 Circuits ID'd for Improvement (CIFI) at LGE. Level 2 CIFI circuits have a long term (5 year) poor SAIFI performance record where						143			0.0	0.0	0.0
3856	2017	Discretionary	CIFI (worst) Circuits - Level 3 KU - 28 Circuits - 2013 - 2017	Improve reliability on 28 Level 3 Circuits ID'd for Improvement (CIFI) at KU. Level 3 CIFI circuits have a long term (5 year) poor SAIFI performance record where the						4018			0.0	0.0	0.0
3860	2017	Discretionary	CIFI (worst) Circuits - Level 3 LGE - 25 Circuits - 2013 - 2017	Improve reliability on 25 Level 3 Circuits ID'd for Improvement (CIFI) at LGE. Level 3 CIFI circuits have a long term (5 year) poor SAIFI performance record where the						3587			0.0	0.0	0.0
3693	2017	Discretionary	DSP Pepper Pike Substation upgrade	The Pepper Pike substation has peaked recently at 112% during Winter. The 2011 Winter Peak load forecast projects 123% during winter 2014. The Pepper Pike						1500	1700		18.0	16.8	19.0
3810	2017	Discretionary	LEO Cable Rejuvenation - 2017	Cable rejuvenation restores the dielectric strength of in-service aged cable insulations to new cable dielectric strength levels and is warranted to provide 20						276			0.0	0.0	0.0
3925	2017	Discretionary	Rear Easement OH Hardening - KU - 2013 COPY - 2017	Initiate a project to replace defective, small capacity overhead conductor and related distribution line equipment in rear lot applications on the KU system. Targeted						1104					
3921	2017	Discretionary	Rear Easement OH Hardening LGE - 2013 COPY - 2017	Initiate a project to replace defective, small capacity overhead conductor and related distribution line equipment in rear lot applications on the LGE system. Targeted						1104					
3871	2017	Discretionary	SCM KU CENT Replace Legacy OCB's: Types FK, FKD, G, GC. -	The KU system includes numerous legacy oil filled circuit breakers, typically installed in the 1940's or 1950's. These breakers require frequent maintenance intervals to						320					
3831	2017	Discretionary	SCM KU EARL Replace Legacy OCB's: Types FK, FKD, G, GC. -	The KU system includes numerous legacy oil filled circuit breakers, typically installed in the 1940's or 1950's. These breakers require frequent maintenance intervals to	Both the KU and LG&E systems include numerous legacy oil filled circuit					166					
3825	2017	Discretionary	SCM KU PINE Replace Legacy OCB's: Types FK, FKD, G, GC. -	The KU system includes numerous legacy oil filled circuit breakers, typically installed in the 1940's or 1950's. These breakers require frequent maintenance intervals to	Both the KU and LG&E systems include numerous legacy oil filled circuit					166					
3900	2017	Discretionary	SCM LGE BDD Diff Relay Replacement - 2017	The old BDD relays require upgrades. We have found the BDD relays older than 30 years to be out of tolerance. These relays are critical in the Transformer Differential						55			0.0	0.0	0.0
3626	2017	Discretionary	SCM LGE FPE Tapchanger Replacement - Reinhausen -	LG&E has ten remaining FPE transformer LTC's in service throughout our distribution system. These have proven to be the most unreliable LTC's in our system. This is an						795			45.0	28.0	32.0
3817	2017	Discretionary	SCM LGE Replace Legacy 15KV Air-Magnetic Circuit	There are 18 McGraw Edison Air Magnetic style breakers in service at LG&E. Many of these units are over 40 years and are being operated at the limits of their design	Improve the reliability of HK Sec 1.					166			0.0	0.0	0.0
3840	2017	Discretionary	SCM LGE Replace Legacy Substation Oil Circuit	The LG&E system includes numerous legacy oil filled circuit breakers, typically installed in the 1940's or 1950's. These breakers require frequent maintenance	Both the KU and LG&E systems include numerous legacy oil filled circuit					320			0.0	0.0	0.0
3905	2017	Discretionary	SCM LGE Transformer Surge Arrester Replacement Project	Upgrade old style porcelain surge arresters to new metal oxide, silicon rubber type.	Pre 1976 surge protecters utilized Multigap Silicon Carbide blocks or Current					50			0.0	0.0	0.0
3708	2017	Discretionary	UG CABLE DETERIORATION - 2017	Project consists of replacing up to 21,800 feet of residential primary 12kv underground cable by directional boring. Recently discovered that a lot of the direct						138			0.0	0.0	0.0
3915	2017	Discretionary	UG Cable Replacement Substation Exits LG&E - 2013 -	A proactive asset replacement program to replace aged, poor performing underground substation exit cables on the LG&E distribution system. Medium						1104			0.0	0.0	0.0
3886	2017	Discretionary	URD Cable Repl/Rejuv Program KU - 2013 - 2017	Proactive asset replacement program to replace or rejuvenate aged, poor performing underground cables on worst performing residential subdivision circuits						331			0.0	0.0	0.0
3890	2017	Discretionary	URD Cable Repl/Rejuv Program LG&E - 2013 - 2017	Proactive asset replacement program to replace or rejuvenate aged, poor performing underground cables on worst performing residential subdivision circuits						1104			0.0	0.0	0.0

Louisville Gas and Electric

Gas System Planning
Ten-Year Gas Construction Plan

May 2007

Table of Contents

I. Crestwood-Eminence-Bedford High Pressure Distribution System

Gas System Overview
The Crestwood-Bedford high-pressure distribution system serves the Crestwood area, Smithfield, Campbellsburg, and Bedford. It is fed by the Elder Park, Bedford, and Crestwood city gate stations. The system serves a small number of large industrial and commercial customers, including Safety Kleen, Steel Technologies, Rosehill Greenhouses, and Hussey Copper.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Elder Park City Gate Station
- Crestwood City Gate Station
- Bedford City Gate Station

Maximum Allowable Operating Pressure
From Crestwood to Eminence, the Crestwood-Bedford high-pressure system has a maximum allowable operating pressure of 350 psig. From Eminence to Bedford, it has a maximum allowable operating pressure of 380 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure is located at the inlet to the **Pleasureville medium pressure regulator pit (47.61 psig).**

Regulator Operating Capacities
- Elder Park City Gate Station – **19.52%**
- Crestwood City Gate Station – **68.54%**
- Bedford City Gate Station – **61.9%**

Gas System Constraints
The system is composed primarily of 4-inch pipeline, limiting the system's capacity for expansion.

I. Crestwood-Eminence-Bedford High Pressure Distribution System (cont'd)

Recommended Gas System Reinforcements

Reinforcement 1
Connect the Ballardsville gas transmission line to the Crestwood-Bedford HP system with 5,900 feet of 8" steel gas transmission pipeline along Hwy 53 from Moody Lane to Hwy 22 (see Section III).

Minimum Gas System Pressure (-12°F)
- Inlet to Pleasureville **– 59.36 psig**

Regulator Operating Capacities
- Bedford City Gate Station **– 61.13%**

Recommended Timeline – 2010-2015

Reinforcement 2
Remove the Eminence high pressure regulator pit and replace with a full port motor operated ball valve at that location.

If the Eminence high pressure regulator pit was to fail, approximately 1,693 customers in the Eminence and New Castle areas would be lost. Installing a motor operated ball valve at the Eminence station could help prevent this loss of service. This ball valve could also be used to isolate either side of the Crestwood–Bedford line should a failure occur.

Minimum Gas System Pressure (-12°F)
- Inlet to Pleasureville **– 49.01 psig**

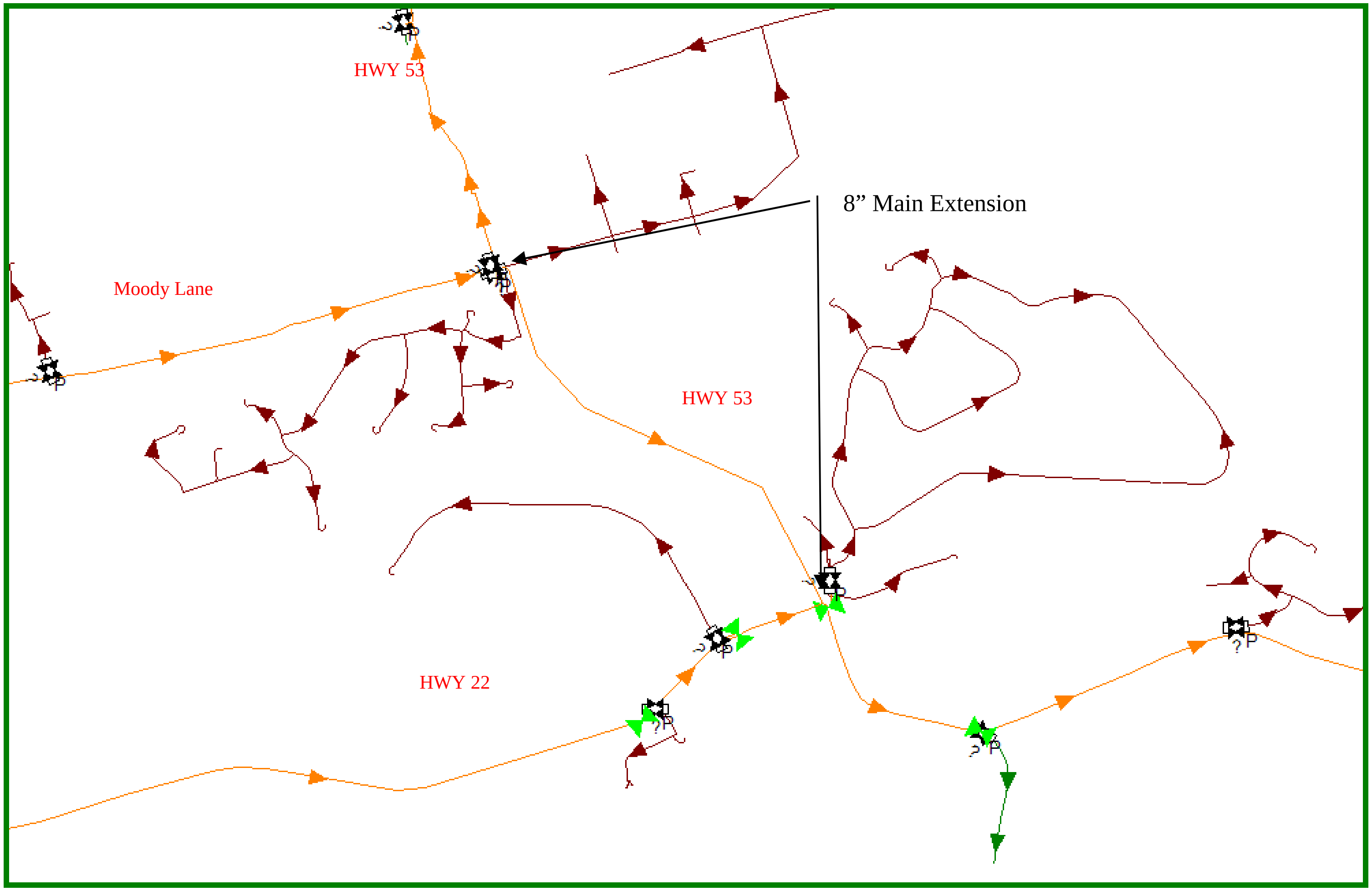
Regulator Operating Capacities
- Bedford City Gate Station **– 61.8%**
- Crestwood City Gate Station – **71.7%**

Recommended Timeline – 2008-2009

Reinforcement 3
- Install a new city gate station near L'Esprit Farms at the intersection of E Hwy 146 and Lake Jericho. This station will be fed from the Texas Gas Transmission pipeline.
- Extend approximately 4 miles of high pressure steel pipeline southwest along E Hwy 146 to connect with the Elder Park/Ballardsville Line.
- Extend approximately 5.4 miles of high pressure steel pipeline southeast along Hwy 153 (Lake Jericho to connect with Crestwood-Bedford HP line at Smithfield Rd).

Recommended Timeline – TBD

Crestwood-Eminence-Bedford High Pressure Gas System – Reinforcement 1



II. East End Gate Stations

Gas System Overview
The Elder Park City Gate Station is located on Elder Park Road just east of Highway 393 and serves from Elder Park to Zorn Avenue in Louisville. The Crestwood City Gate Station is located on Highway 22 west of Abbott Lane and serves the area from Lake Forest and Pee Wee Valley to Ballardsville and Eminence. The LaGrange City Gate Station is located on Highway 146 west of Button Lane and serves the City of LaGrange and the Crestwood/Buckner area north of I-71. These systems serve rural, residential, commercial, and small industrial customers.

Maximum Allowable Operating Pressure
The Elder Park system has a maximum allowable operating pressure of 400 psig. The Crestwood system has a maximum allowable operating pressure of 350 psig. East of the La Grange City Gate Station, the LaGrange system has a maximum allowable operating pressure of 100 psig. West of the LaGrange City Gate Station, the LaGrange system has a maximum allowable operating pressure of 200 psig.

Gas System Constraints
If any of these three gate stations was temporarily turned off (e.g., for maintenance or due to an accident), there would be insufficient pressure to serve the system that is fed by that gate station.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure on the Elder Park system is located at the inlet to the **Zorn Ave regulator station (162.70 psig).**

The predicted minimum gas system pressure on the Crestwood system is located at the inlet to the **Pleasureville regulator pit (47.60 psig)**.

The predicted minimum gas system pressure on the LaGrange system is located at **4705 Hwy 146 (64.66 psig)**.

Regulator Operating Capacities
- Elder Park City Gate Station – **19.52%**
- Crestwood City Gate Station – **73.70%**
- LaGrange City Gate Station – **7.53%**

Recommended Gas System Reinforcements

Recommended Gate Station Operating Conditions
- Operate the Elder Park City Gate Station at 350 psig
- Operate the Crestwood City Gate Station at 350 psig
- Operate the LaGrange City Gate Station at 90 psig

II. East End Gate Stations (cont'd)

Reinforcement 1
Connect the Elder Park system to the Crestwood system

- Connect the Elder Park line to the Crestwood line via Hwy 393 with approximately 4,770 feet of 8-inch pipeline.
- Connect the Elder Park line to the Crestwood line via Hwy 53 with approximately 5,900 feet of 8-inch pipeline

Minimum Gas System Pressure (-12°F)
- Zorn Inlet **– 293.56 psig**
- Pleasureville Inlet **– 129.26 psig**
- 4705 Hwy 146 **– 64.66 psig**

Regulator Operating Capacities
- Elder Park City Gate Station **– 22.09%**
- Crestwood City Gate Station **– 50.49%**
- LaGrange City Gate Station **– 7.53%**

Recommended Timeline – 2010-2015

Reinforcement 2
Connect the Elder Park system to the LaGrange system

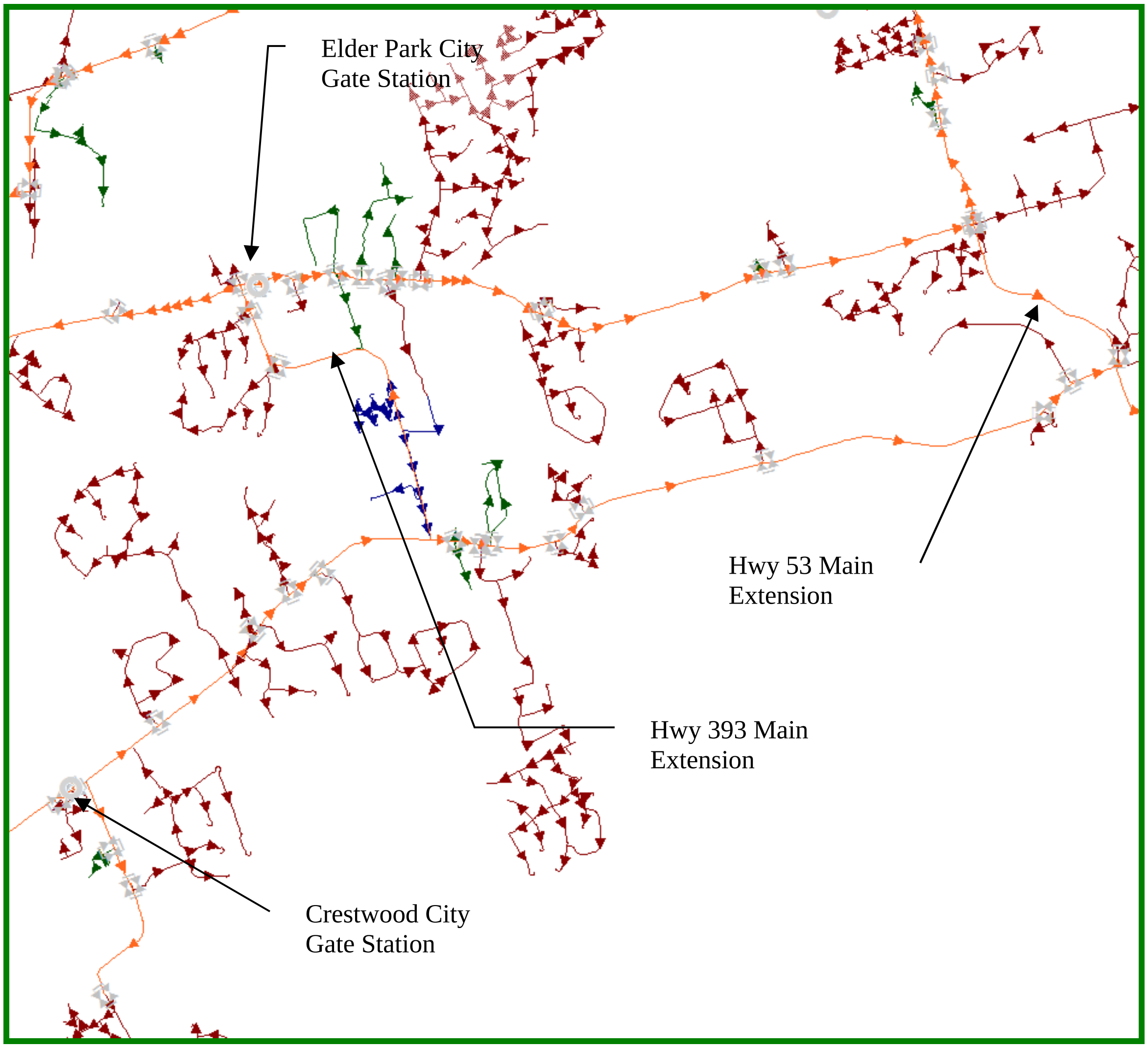
- Connect the Elder Park line to the LaGrange line via Hwy 393 with approximately 6,600 feet of 8-inch pipeline.
- Connect the Elder Park line to the LaGrange line via Hwy 146 and Fox Run Rd with approximately 4,300 feet of 8-inch pipeline.
- Install a new regulator facility at Hwy 393 and Hwy 146 to reduce the pressure from the new pipeline along Hwy 393 to 90 psig.
- Install a new regulator facility at the tie-in point on Fox Run Rd or at Hwy 146 and Quality Place to reduce the pressure from the new pipeline along Hwy 146 and Fox Run Rd to 90 psig.

Minimum Gas System Pressure (-12°F)
- Zorn Inlet **– 293.12 psig**
- Pleasureville Inlet **– 129.26 psig**
- 4705 Hwy 146 **– 70.71 psig**

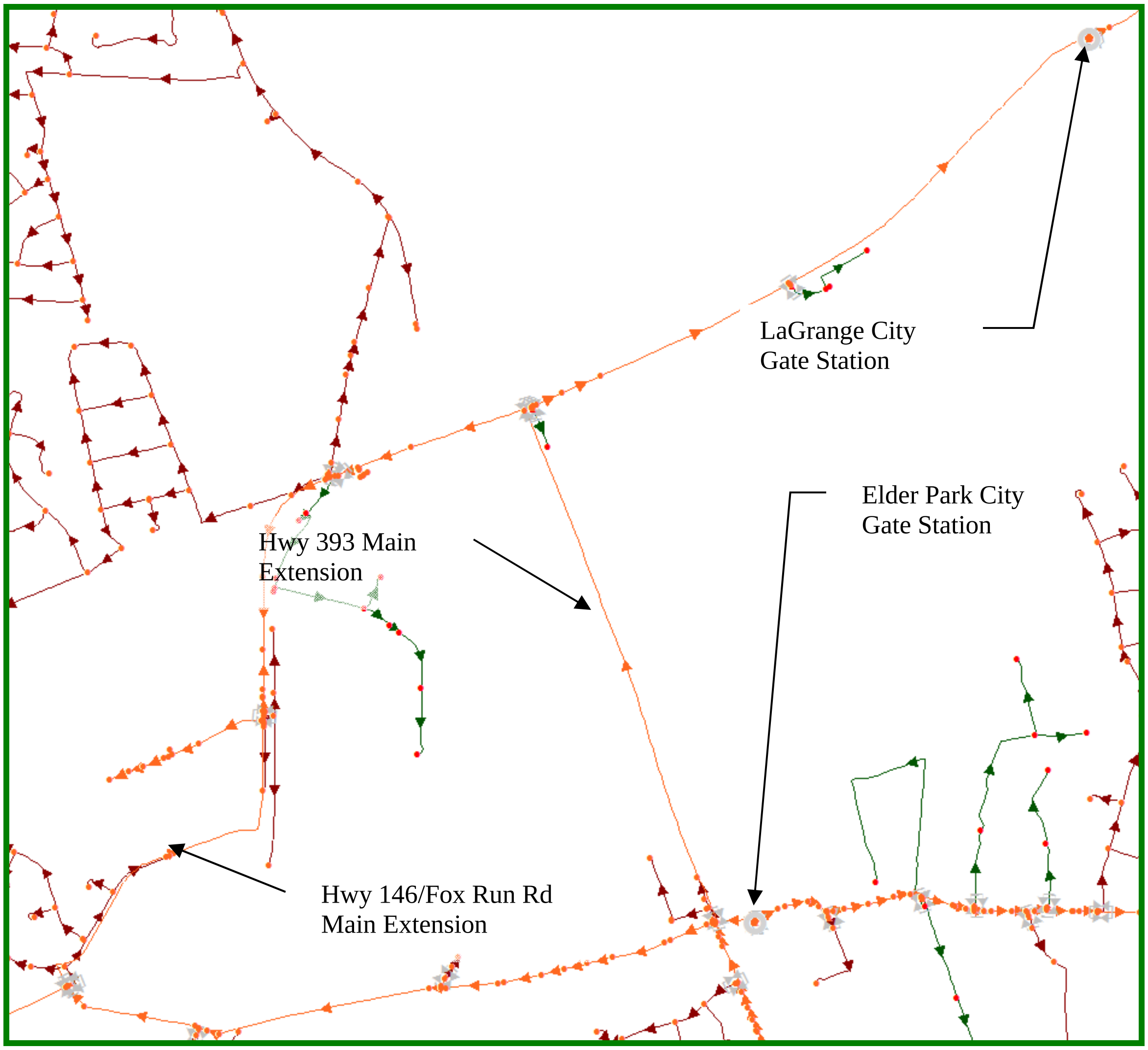
Regulator Operating Capacities
- Elder Park City Gate Station **– 23.95%**
- Crestwood City Gate Station **– 50.56%**
- LaGrange City Gate Station **– 2.77%**

Recommended Timeline – 2015 – 2020

East End Gate Stations – Reinforcement 1



East End Gate Stations – Reinforcement 2



III. Harrods Creek Project

Gas System Overview
The Harrods Creek system is a segment of a large medium pressure gas system which serves a portion of the Prospect area. This area is composed primarily of residential and commercial customers. It has continued to experience growth in the residential sectors with homes ranging from 4,000 to 5,000 sq. ft, including the Harrods Glen subdivision and a proposed Wolf Pen development.

Regulator Facilities
The regulator facility that supplies gas to the Harrods Creek area is as follows:

- The regulator pit at River Rd and Wolf Pen Branch Rd (U.S. Highway 42).

Maximum Allowable Operating Pressure (MAOP)
The Harrods Creek system has a maximum allowable operating pressure of 30 psig.

Model Results

Minimum Gas System Pressure (-12 ^{0}F)
The predicted minimum gas system pressure is located on **Wolf Dr** (**6.28 psig)**.

Regulator Operating Capacities
- River Rd and Wolf Pen Branch Rd (U.S. Highway 42) **– 63.18**%

Gas System Constraints
Gas system constraints are caused by the small diameter piping infrastructure within this area. Due to current and anticipated growth, it will be necessary to perform gas system reinforcement work.

Recommended Gas System Reinforcements

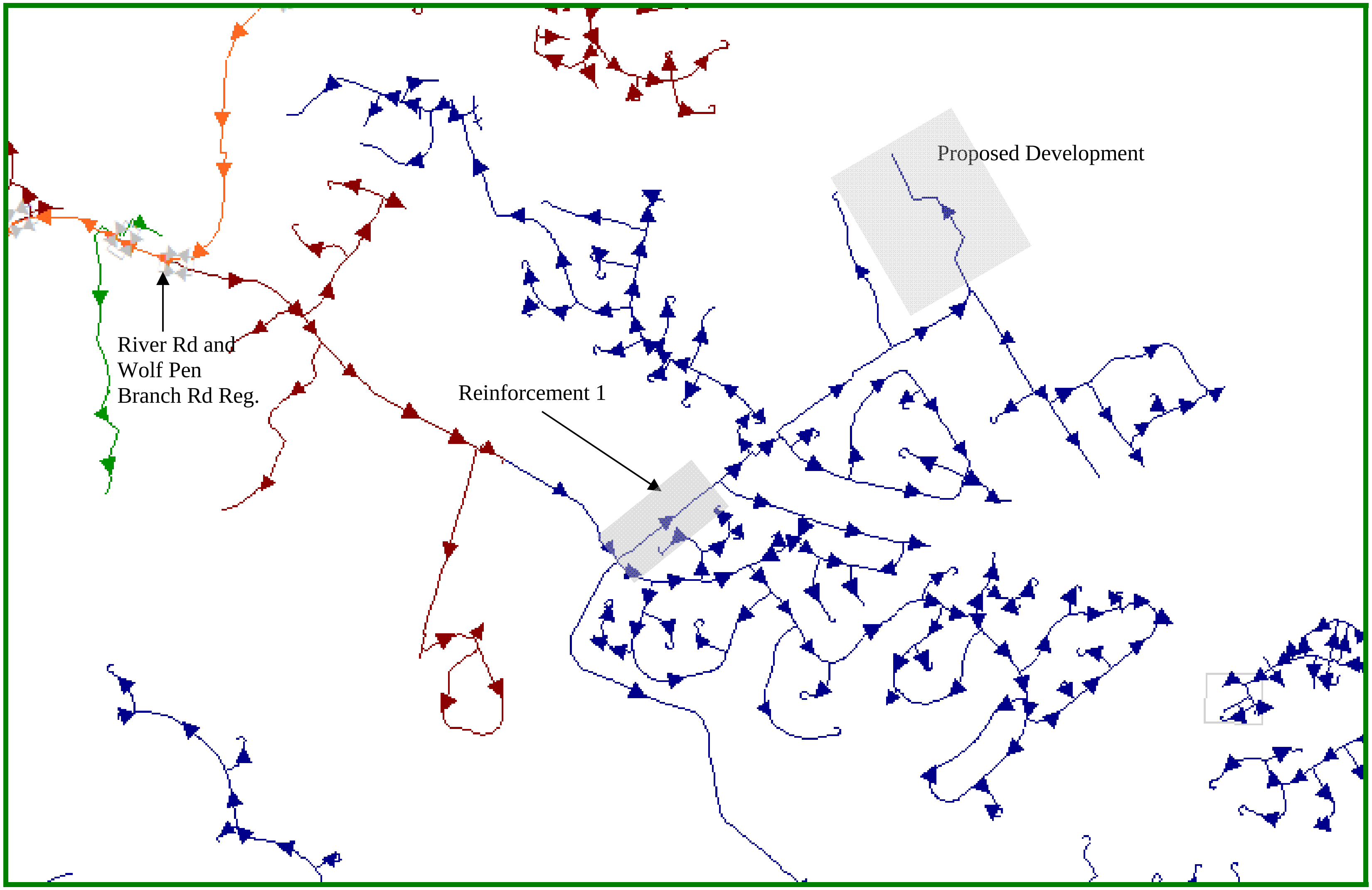
Reinforcement 1
Install approximately 1,293 ft of 6-inch medium pressure pipeline along Wolf Pen Branch Rd between Green Springs Dr and Springdale Rd.

Minimum gas system pressure (-12 ^{0}F)
- Wolf Dr **– 18.98 psig**
- Proposed subdivision (Fincastle Farm) **– 22.68 psig**
- Farm Spring Dr – **22.58 psig**

Regulator Operating Capacities
- River Rd and Wolf Pen Branch Rd (U.S. Highway 42) **– 63.18%**

Recommended Timeline – 2010-2012

Harrods Creek Project - Reinforcement 1



IV. LaGrange Medium Pressure Systems

Gas System Overview
The LaGrange Medium pressure systems are fed from the LaGrange and Elder Park City Gate Stations (see Section III). The system consists of several single-feed systems and one larger, multiple-feed system.

The Oldham County Economic Development Campus (OCEDA) is a 1000+ acre community that will contain office buildings, single and multifamily dwellings, a new school, and mixed use lands. Currently, gas infrastructure does not exist to support this development.

Maximum Allowable Operating Pressure
These subsystems have maximum allowable operating pressures of 10, 30, and 35 psig, as detailed below.

Model Results

Minimum Gas System Pressure (-12ºF)

Sub-System MAOP	Location	Pressure
10 psig systems	3501 Mattingly Road	**7.3 psig**
30 psig system	Fallen Wood Lane	**22.79 psig**
35 psig systems	Cedar Point Road and Hwy N 393	**28.5 psig**
	Cherrywood Place Section 3A-1	**-20.26 psig**

Regulator Operating Capacities:
35 psig Systems
- Regulator pit at New Cedar Point Rd and Hwy 146 – **42.89%**
- Regulator assembly at Commerce Pkwy and Button Court Ln – **4.53%**
- Regulator assembly at Springhouse Estates Section 1 – **100%**
- Regulator assembly at Hwy 146 and Fort Pickens Rd – **1.89%**
- Regulator assembly at Hoffman Ln & Parkview Manor – **35.79%**
- Regulator assembly at Crystal Dr & Grange Dr – **19.32%**
- Regulator pit at Granger Rd & Hwy 53 – **19.99%**
- Regulator assembly at Zhale Smith Rd & Hwy 53 – **2.45%**
- Regulator assembly at Cherry Creek Rd and Hwy 53 – **100%**
- Regulator pit at Glen Eagle Subdivision and Hwy 53 – **46%**
- Regulator assembly at Prestwick Dr & Hwy 53 – **49.40%**
- Medium pressure regulator assembly at Moody Ln & Hwy 53 – **24.30%**
- Regulator assembly at Deer Run Dr – **15.50%**
- Regulator pit at Elder Park Rd – **65.38%**

IV. LaGrange Medium Pressure Systems (cont'd)

30 psig systems
- Regulator pit at Woodlawn Ave and Lagrange Rd **– 6.93%**
- Lagrange medium pressure regulator pit **– 5.0%**
- Regulator pit at Hoffman Ln **– 35.79%**

10 psig systems
- Regulator pit at Hwy 146 **– 15.90%**
- Regulator pit at Hwy 393 & Hwy 146 **– 1.59%**
- Regulator pit at Kings Ln & Hwy 146 **– 2.95 %**
- Regulator assembly at Park Rd & Hwy 53 **– 1.97%**
- Regulator assembly at E. Moody Ln & Cal Ave **– 9.3%**
- Regulator assembly at Georgie Way and Moody Ln **– 5.72%**
- Regulator assembly at Hazelwood Dr & Elder Park Rd **– 20.36%**
- Regulator assembly at Sycamore Rd and Elder Park Rd **– 42.44%**

<u>Gas System Constraints</u>
Areas of low pressure are constrained by small diameter piping and single regulator stations feeding the systems.

<u>Gas System Reinforcements Planned for 2007</u>

Gas system reinforcements scheduled for completion in 2007 include:

- Replace 1/8" orifice plates at Cherry Creek Rd and Hwy 53 regulator assembly (35 psig system) with 3/8" orifice plates.
- Extend 4" PL main in Hwy 53 from existing 6" PL at Cherry Creek Rd to 4" CT at Gleneagles Way. Retire regulator pit at Hwy 53 & Glen Eagle Subdivision.
- The OCEDA Economic Development Campus is under construction. 3,500' of 4" PL has been extended in New Moody Ln from Baptist Hospital Northeast to the new Rawlings Group Office Campus.

Recommended Gas System Reinforcements:

<u>Reinforcement 1</u>
Replace 3/8" orifice plates at Springhouse Estates Section 1 regulator assembly (35 psig system) with 1/2" orifice plates.

Minimum Gas System Pressure (-12^{o}F)
- Majestic Woods Dr – **27.69 psig**

Regulator Operating Capacity
- Springhouse Estates Section 1 **– 48.9%**

Recommended Timeline – 2007

IV. LaGrange Medium Pressure Systems (cont'd)

Reinforcement 2

Extend gas mains and uprate LaGrange MP system as described in "An Analysis of the OCEDA Economic Development Campus" dated 7 November 2005 or latest version. As described in the report, this system will have an estimated new gas load of up to 387 MCFH. The proposed reinforcement project requires installing:

- 16,400 ft of 4 inch pipe
- 16,500 ft of 6 inch pipe
- An uprate of 10.8 miles of existing pipeline and 440 existing customers
- A new regulator facility at Moody Lane and North Fible Lane

Minimum gas system pressure (-12ºF):
- Peak Road near Hwy 53 – **32.79 psig**

Regulator Operating Capacities:
- Moody Ln and North Fible Ln – **11.8%**
- Granger Rd and Hwy 53 **– 47.6%**
- Elder Park Rd **– 59.3%**

Recommended Timeline – 2008-2012

Reinforcement 3

Extend gas mains and uprate Hwy 393 & Hwy 146 system as described in "An Analysis of Proposed Development at Buckner Crossings" dated 16 October 2006 or latest version. As described in the report, this system will have an estimated new gas load of up to 90MCFH. The proposed reinforcement requires installing:

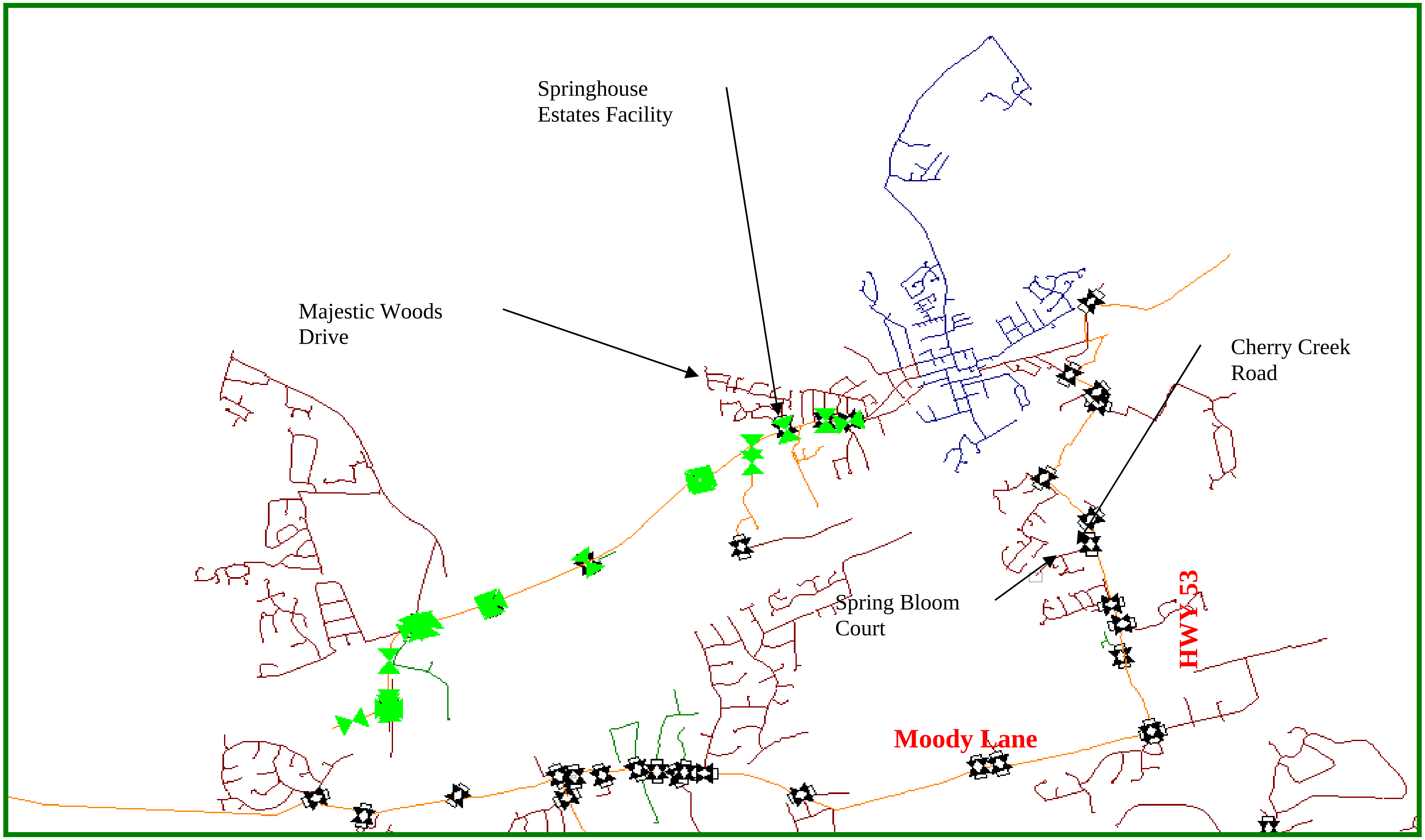
- 5,100 ft of 6-inch pipe
- 5,300 ft of 4-inch pipe
- 13,100 ft of 2-inch pipe
- Uprate 400 ft of existing pipeline and 5 existing customers
- Replace regulator facility at Commerce Pkwy & Button Court Ln
- Remove regulator facility at Hwy 393 & Hwy 146
- Install regulator facility at Hwy 393 & Commerce Pkwy

Minimum Gas System Pressure (-12°F)
- Northern Patio Home Circle **– 33.84 psig**

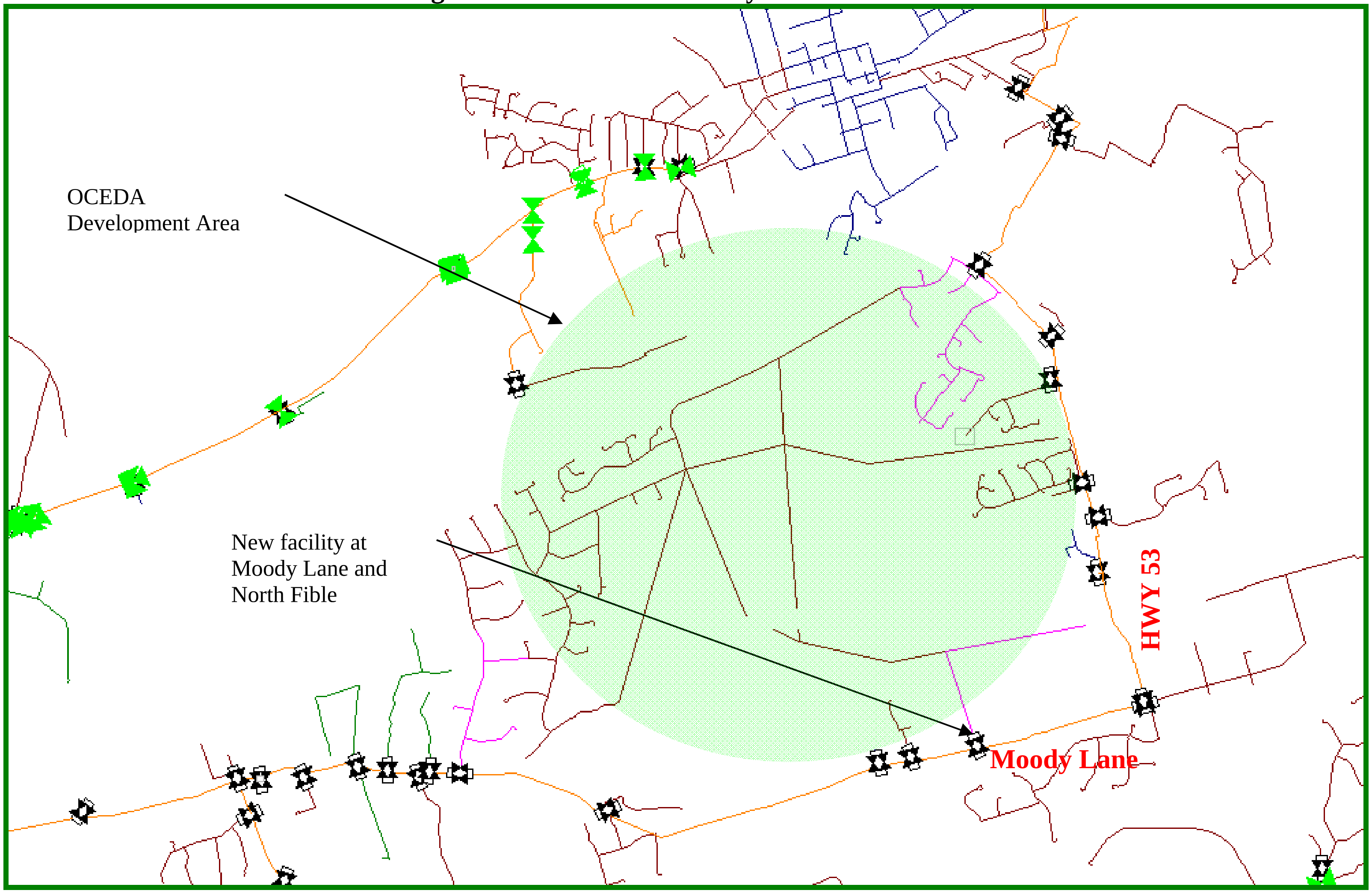
Regulator Operating Capacity
- Hwy 393 & Commerce Pkwy – **26.82%**
- Commerce Pkwy & Button Court Ln – **17.53%**

Recommended Timeline – TBD

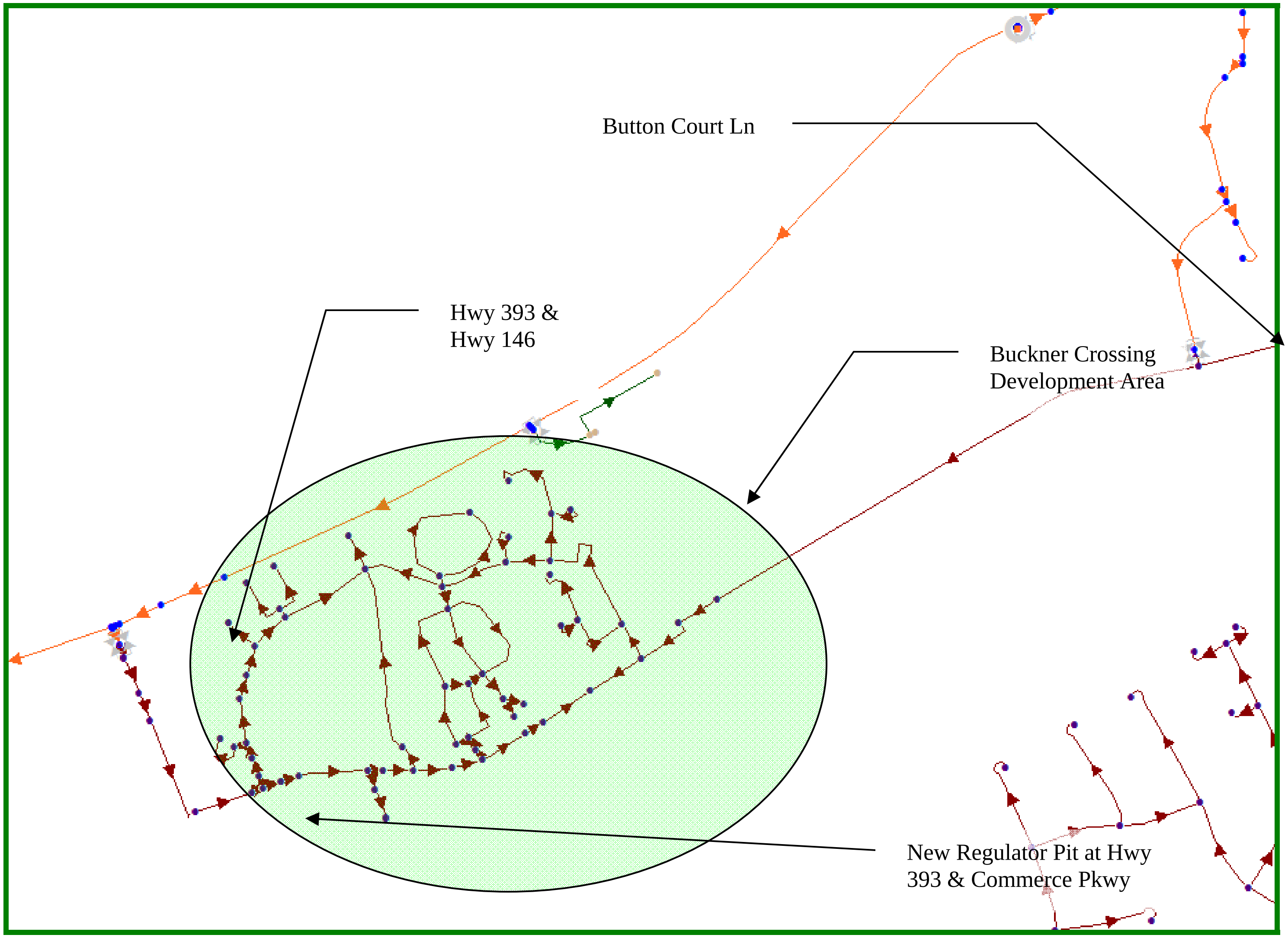
LaGrange Medium Pressure Gas System – Reinforcements 1



LaGrange Medium Pressure Gas System – Reinforcement 2



LaGrange Medium Pressure Gas System – Reinforcment 3



V. Middletown Medium Pressure System

Gas System Overview

The Middletown medium-pressure system will require reinforcement to continue to serve the Norton Commons development and the Old Brownsboro Crossing commercial park, which includes a professional medical center, office buildings, and retail/restaurants.

Gas System Reinforcement Completed in 2006

- Installed approximately 200 ft of 4-inch plastic main along Collins Lane across Chamberlain Lane.
- Installed approximately 430 ft of 4-inch plastic main near 7405 and 7314 Orchard Grass Blvd.
- Uprated 5,349 services and 72.2 miles of main from 30 psig to 50 psig. The uprate area is bordered by Hurstbourne Parkway on the west, Westport Road and LaGrange Road on the south, Crestwood on the east, and Norton Commons and existing infrastructure on the north.
- Closed the 8-inch valve at Hurstbourne Parkway and Brownsboro Road.
- Retired the Collins Lane and Electric Substation regulator pit.

Model Results

Minimum gas system pressure (-12 ^{0}F)

- 10928 Worthington Ln – **38.78 psig**

Regulator Operating Capacities

- Brownsboro Rd & Worthington – **14.13**%
- Westport Rd & Murphy Ln – **94.56**%

VI. Old Henry Road Development

Gas System Overview
The area around Old Henry Rd is served by the Middletown medium pressure system. With the addition of the Old Henry Road Business Park and realignment of Old Henry Rd, it will be necessary to perform reinforcement work on this gas system.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Regulator pit at English Station Way
- Regulator pit at Old Henry Rd and Terra Crossing Blvd (Old Henry MP)
- Regulator assembly at Conner Station Rd

Maximum Allowable Operating Pressure
The Middletown medium pressure system has a maximum allowable operating pressure of 50 psig.

Model Results

Minimum gas system pressure (-12°F)
The predicted minimum gas system pressure is located at **1601 Keever Ct (-47.56 psig).** Other low pressure locations are as follows:

Location	**-12ºF**	**-5ºF**	**0ºF**	**5ºF**
2725 Flat Rock Rd	**-45.02**	**-13.17**	7.47	16.10
1601 Keever Ct	**-47.56**	**-26.46**	4.59	14.41
420 Watch Hill Ln	**-43.88**	**-11.60**	7.62	16.17
Whispering Pines Cir	**-45.59**	**-23.59**	5.78	15.03

Note: The system cannot adequately serve the Polo Fields, Persimmon Ridge, and Fox Run under current conditions.

Regulator Operating Capacities
- English Station Way – **54.73**%
- Old Henry MP – **15.69**%
- Conner Station & Colt Run Rd – **6.07**%

Recommended Gas System Reinforcements

Reinforcement 1
Install 5,700 ft of 8-inch medium pressure pipe north along Old Henry Rd to tie into the 8-inch main at 9207 Ash Land Ct.

VI. Old Henry Road Development (cont'd)

Minimum gas system pressure (-12 ^{0}F)

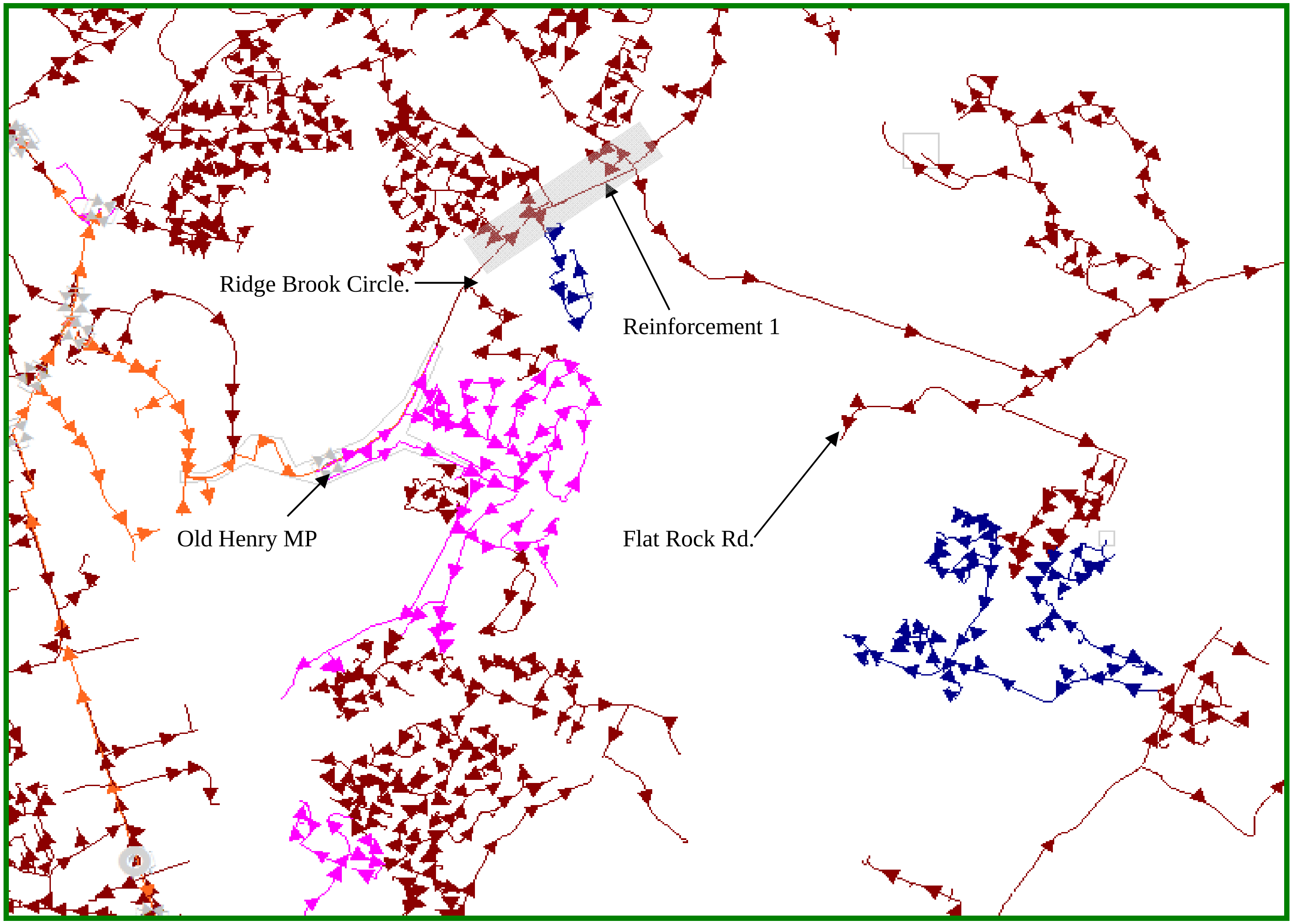
- Keever Ct **– 17.23psig**
- Flat Rock Rd. **– 24.60 psig**
- Whispering Pines Cir **– 23.85psig**
- Davenport Dr **– 23.64 psig**

Regulator Operating Capacities

- English Station Way **– 54.49**%
- Old Henry MP **– 31.79**%
- Conner Station & Colt Run Rd **– 5.37**%

Recommended Timeline – 2007

Old Henry Road Development – Reinforcement 1



VII. River Road Regulator Assemblies

Gas System Overview
Gas System Planning has identified eight regulator facilities on River Rd that could be removed to reduce the number of dead-end gas systems and reduce maintenance costs by removing unnecessary equipment. All regulators are fed by the Elder Park Line.

Gas System Reinforcement Anticipated in 2007
As part of the Farm Tap upgrade project, several medium pressure reinforcements will be made, resulting in the removal of two River Road Assemblies. The reinforcements are:

- Install 1,900 feet of 4-inch PL main in River Road from River Creek Dr up to Harrods Creek. Tie-in to regulator assembly at River Rd & Creekside Ct, uprate the River Creek Drive system from 10- 35 psig and remove the River Creek Dr regulator assembly. New main will allow eventual tie-in to Harrods Creek MP system and retirement of River Creek Dr regulator assembly.
- Install 2,200 feet of 4-inch PL main in River Road from 7009 River Rd to 7314 River Rd. Tie in to systems at River Rd & Private Dr, River Rd & Transylvania and River Rd & Mayfair Rd. Retire regulator assemblies at Private Dr and Mayfair Rd.

Regulator Facilities
The regulator facilities affected by this project are as follows:

- Regulator assemblies at Riverside Dr, River's Edge Rd, Knights of Columbus, Longview Ave, Woodside Rd, Juniper Beach Dr, and Creekside Ct
- Regulator pits at Blankenbaker Ln, Boxhill Ln, Glenview Ave, Lime Kiln Ln, Harbortown Rd, and River Creek Dr

Maximum Allowable Operating Pressure
The Elder Park Line has a maximum allowable operating pressure of 400 psig, but is typically operated at 250 psig.

The Longview Ave, Woodside Rd, and Creekside Dr systems have a maximum allowable operating pressure of 10 psig.

The Riverside Dr, Knights of Columbus, Boxhill Ln, and Lime Kiln Ln systems have a maximum allowable operating pressure of 20 psig.

The Blankenbaker Ln and Glenview Ave systems have a maximum allowable operating pressure of 30 psig.

The River's Edge Rd, Juniper Beach Dr, Harbortown Rd, and River Creek Dr systems have a maximum allowable operating pressure of 35 psig.

VII. River Road Regulator Assemblies (cont'd)

Recommended Gas System Reinforcements

Reinforcement 1

- Uprate River Rd & Creekside Dr medium pressure system from 10 psig to 35 psig.
- Install approximately 1,900 ft of 4-inch plastic gas main from 6301 River Road to 6421 River Road, connecting Creekside and River Creek systems.
- Remove the River Rd & Creekside Dr regulator assembly.

Minimum Gas System Pressure (-12°F)

- 5702 Captains Quarters Rd – **34.79 psig**

Regulator Operating Capacity

- River Rd & River Creek Dr – **44.71%**

Recommended Timeline – 2007

Reinforcement 2

- Install approximately 2,800 ft of 4-inch plastic gas main along River Rd to connect the River Rd & River Creek Dr and River Rd & Harbortown Rd systems.
- Install approximately 840 ft of 2-inch plastic gas main along Juniper Beach Rd to connect the River Rd & Juniper Beach Dr and River Rd & Harbortown Rd systems.
- Remove the River Rd & Juniper Beach Dr and Creekside Ct regulator assemblies and the River Rd & Harbortown Rd regulator pit.

Minimum Gas System Pressure

- 5702 Captains Quarters Rd – **34.78 psig**

Regulator Operating Capacity

- River Rd & River Creek Dr – **51.56%**

Recommended Timeline – 2008-2012

Reinforcement 3

- Uprate River Rd & Woodside Rd medium pressure system from 10 psig to 30 psig.
- Uprate River Rd & Lime Kiln Ln medium pressure system from 20 psig to 30 psig.
- Install approximately 850 ft of 4-inch plastic gas main along Arden Rd to connect Woodside Rd and Glenview Ave systems.
- Install approximately 1,200 ft of 4-inch plastic gas main along Lime Kiln Ln to connect Lime Kiln Ln and Glenview Ave systems.
- Remove the River Rd & Woodside Rd and River Rd & Lime Kiln Ln regulator assemblies.

VII. River Road Regulator Assemblies (cont'd)

Minimum Gas System Pressure (-12°F)
- Both ends of Blakely Ridge Rd – **16.65 psig**

Regulator Operating Capacity
- River Rd & Glenview Ave – **19.52%**

Recommended Timeline – 2008-2012

Reinforcement 4
- Uprate River Rd & Longview Ave medium pressure system from 10 psig to 20 psig.
- Install approximately 775 ft of 2-inch plastic gas main along Longview Ln to connect Longview Ave and Boxhill Ln systems.
- Remove the River Rd & Longview Ave regulator assembly

Minimum Gas System Pressure (-12°F)
- 4508 Longview Ln – **18.28 psig**

Regulator Operating Capacity
- River Rd & Boxhill Ln – **20.66%**

Recommended Timeline – 2008-2012

Reinforcement 5
- Uprate River Rd & Knights of Columbus medium pressure system from 20 psig to 35 psig.
- Install approximately 350 ft of 2-inch plastic gas main along River Rd to connect River's Edge Rd and Knights of Columbus systems.
- Remove the River Rd & Knights of Columbus regulator assembly.

Minimum Gas System Pressure (-12°F)
- Southeast end of the former Knights of Columbus system – **34.83 psig**

Regulator Operating Capacity
- River Rd & River's Edge Rd – **13.13%**

Recommended Timeline – 2008-2012

VII. River Road Regulator Assemblies (cont'd)

Reinforcement 6

- Uprate River Rd & Riverside Dr medium pressure system from 20 psig to 30 psig.
- Install approximately 250 ft of 2-inch plastic gas main along Riverside Dr to connect Riverside Dr and Blankenbaker Ln systems.
- Remove the River Rd & Riverside Dr regulator assembly.

Minimum Gas System Pressure (-12°F)

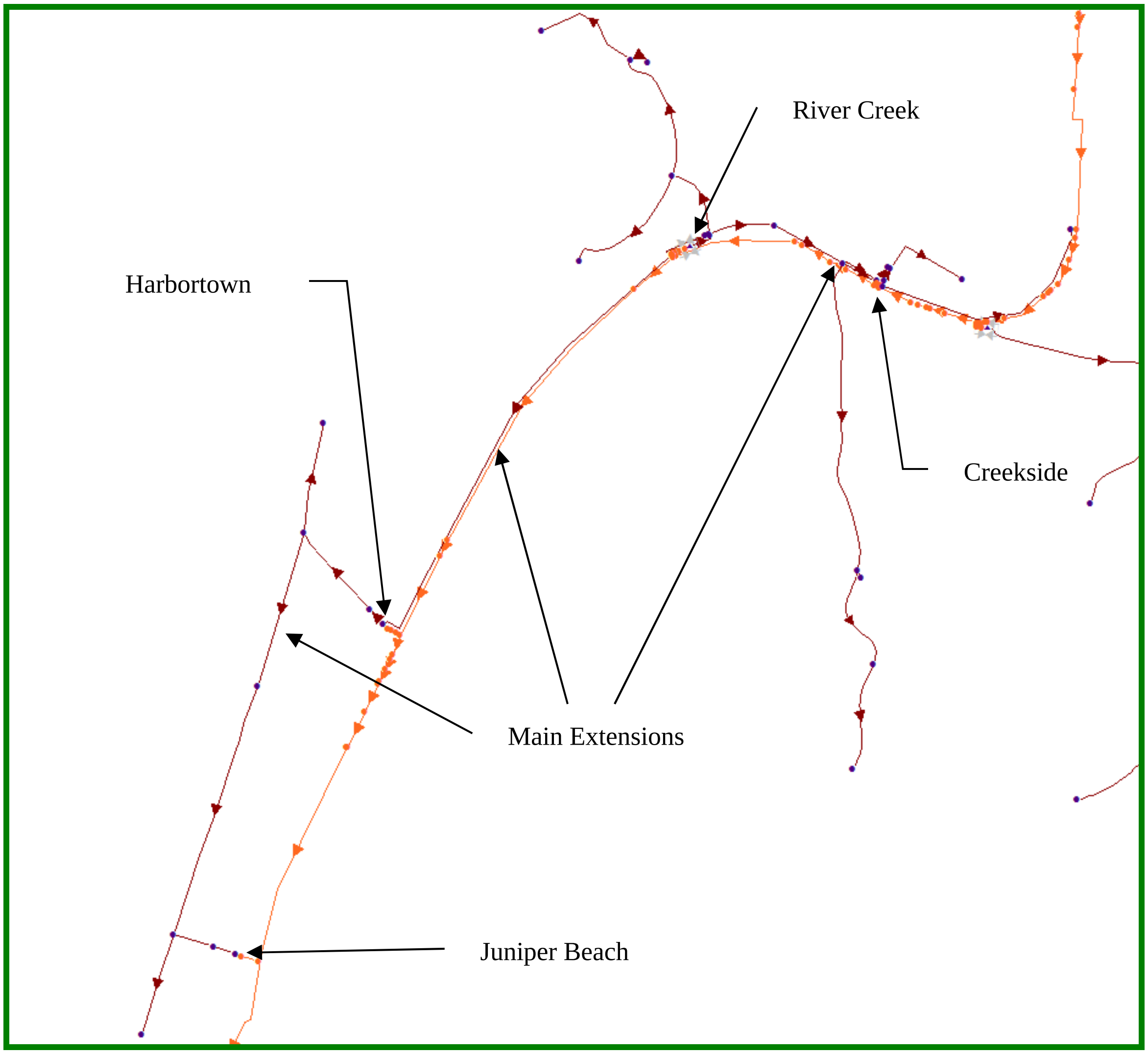
- 2630 Phoenix Hill Dr **– 17.65 psig**

Regulator Operating Capacity

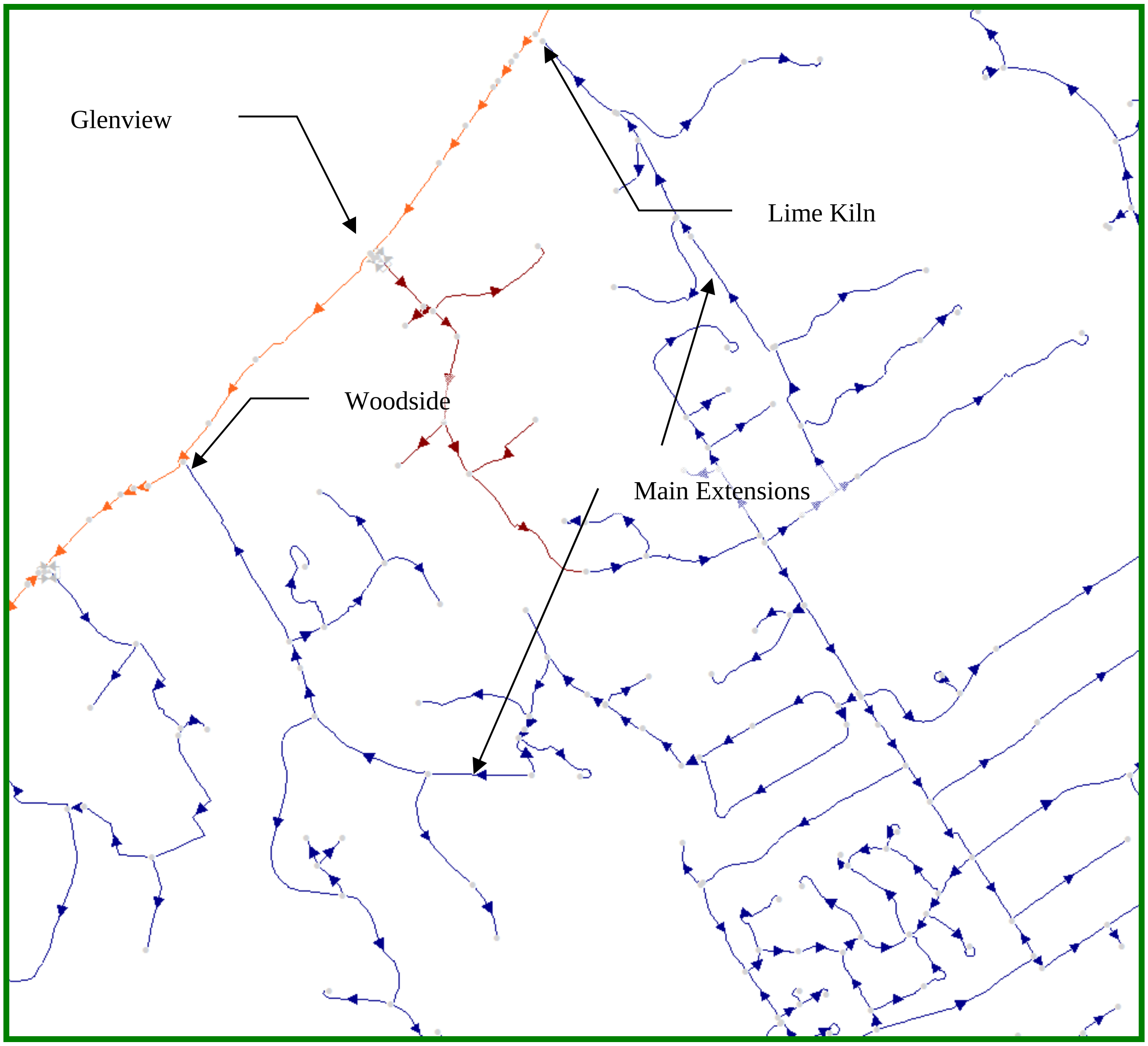
- Blankenbaker Ln & River Rd **– 20.67%**

Recommended Timeline – 2008-2012

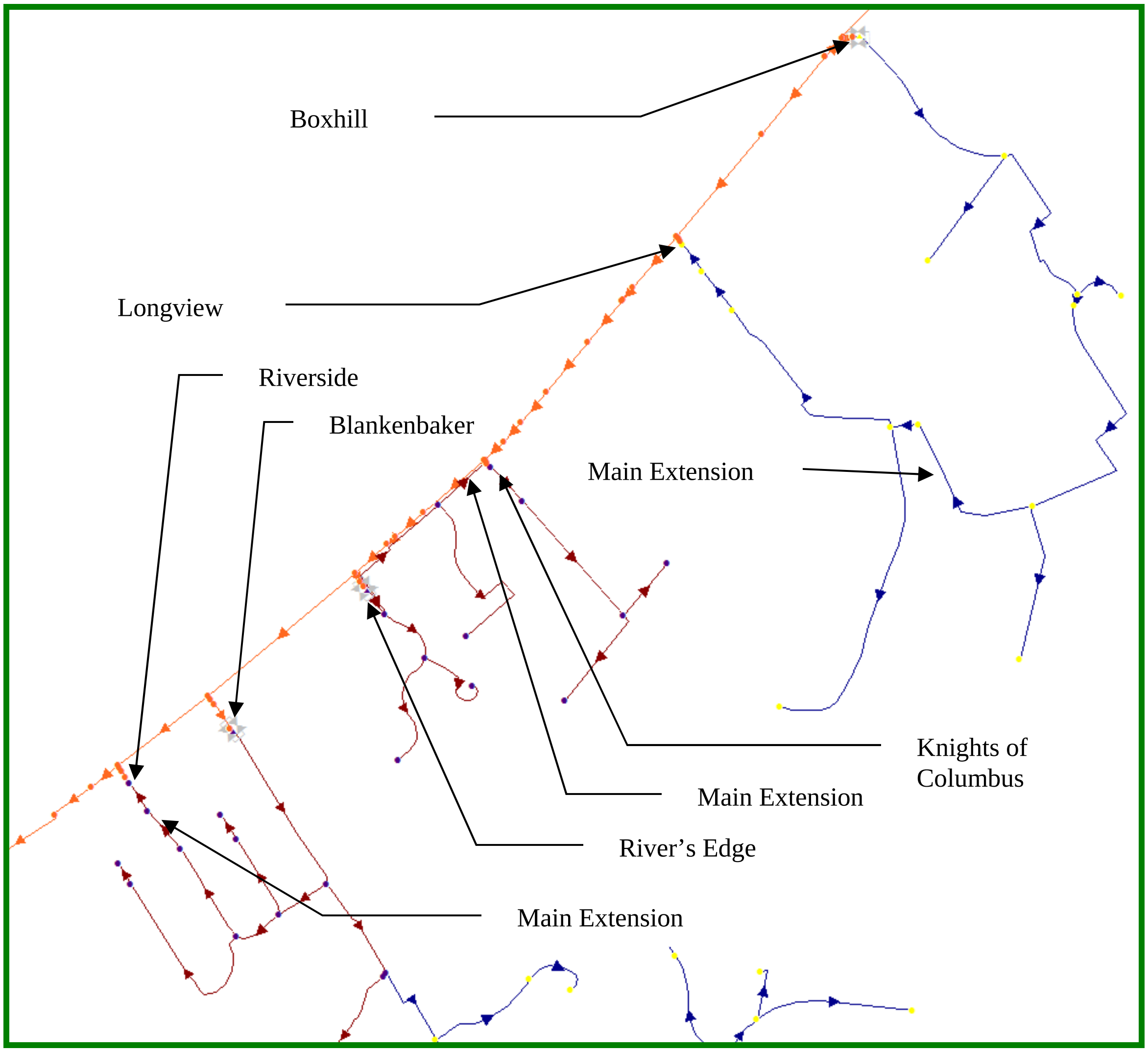
River Road Regulator Assemblies – Reinforcement 1 & 2



River Road Regulator Assemblies – Reinforcement 3



River Road Regulator Assemblies – Reinforcement 4



VIII. Plantside Drive/Blankenbaker Parkway Medium Pressure System

Gas System Overview

The Plantside/Blankenbaker Medium Pressure System feeds the area near Plantside Drive, Blankenbaker Parkway, and Electron Drive. The area is composed mostly of small commercial customers with a few residential customers. This system is connected to the Taylorsville Road medium pressure system via a 4-inch steel main at Grand Avenue and Watterson Trail.

Gas System Reinforcement Completed in 2006/2007

A 6-inch medium pressure plastic main was installed along Tucker Station Road from Betty Ray Lane, south to just past Sycamore Station Place. A 4-inch medium pressure plastic main was tied-in at this point and installed along Sycamore Station Place west and south to Tucker Station Road.

Regulator Facilities

The following regulator facility feeds the Plantside Drive/Blankenbaker Parkway medium pressure system:

- Regulator pit at Watterson Trail and Plantside Drive

Maximum Allowable Operating Pressure

This medium pressure system has a maximum allowable operating pressure of 35 psig.

Model Results

Minimum Gas System Pressure (-12ºF)

The predicted minimum gas system pressure is located on **3025 Element Lane (27.47 psig)**.

Regulator Operating Capacity

- Watterson Tr and Plantside Dr **– 82.50%**

Gas System Constraints

Many of the commercial customers fed by this medium pressure system require a delivery pressure of 5 psig. A proposed 283 acre office park for the eastern area of this system, south of I-64, on Tucker Station Road, will require a significant amount of new infrastructure (MSD is planning a 4.6 square mile area of sewer development) and an additional gas regulator facility. Currently, this system is not capable of serving this development that is predicted to have an approximate total load of 140 Mcfh.

Recommended Gas System Reinforcements:

Reinforcement 1

- Install a new medium pressure regulator facility on Tucker Station Road, north of I-64 that is fed from the existing 16-inch high pressure pipeline parallel to I-64.
- Install approximately 1,700 ft of 6-inch medium pressure plastic pipe from Sycamore Station Place south along Tucker Station Road, terminating at Pope Lick Road.

VIII. Plantside Drive/Blankenbaker Parkway Medium Pressure System (cont'd)

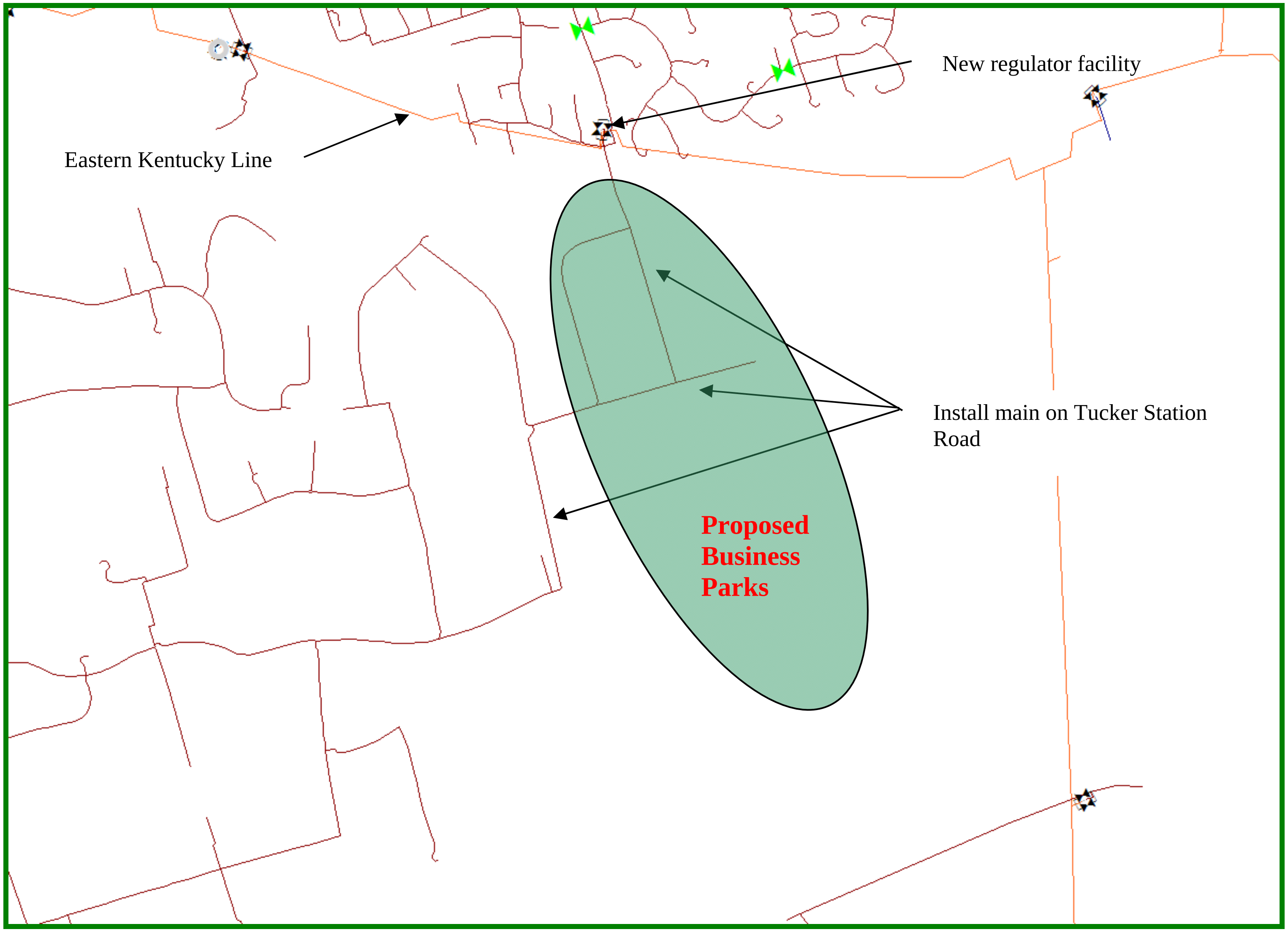
- Install approximately 2,860 ft of 6-inch medium pressure plastic pipeline west from the entrance of the proposed office park, along Tucker Station Road, to the 6-inch main ending on Plantside Drive (near the Papa John's Building). This would allow for a multiple feed system, improving system reliability.

Minimum gas system pressure (-12ºF):
- 3025 Element Ln – **27.46 psig**
- 2801 Constant Comment Place – **28.68 psig**

Regulator Operating Capacities:
- Tucker Station Rd & I-64 (4x3 Mooney assembly with 35% plates) – **33.91%**
- Watterson Tr & Plantside Dr – **82.12%**

Recommended Timeline: 2007-2008
Note: This reinforcement should be completed after the Kentucky Department of Transportation widens Tucker Station Road and Pope Lick Road.

Plantside Drive Medium Pressure Gas System – Reinforcement 1



IX. Jeffersontown/Fern Creek Medium Pressure System

Gas System Overview
The Jeffersontown and Fern Creek areas are part of a large medium pressure gas system that serves the southeastern part of Jefferson County. This system is composed of rural, residential, and small commercial customers and has continued to experience rapid growth in these sectors. The majority of Jeffersontown and Fern Creek areas are served from the following regulator facilities.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Regulator pit at Taylorsville Road and Hopewell Road (Jeffersontown Pit)
- Regulator assembly at Gentry Lane and the Calvary Line
- Regulator pit at Cedar Creek Road and the Calvary Line
- Regulator station at Hudson Lane

Maximum Allowable Operating Pressure
The Jeffersontown/Fern Creek medium pressure gas system has a maximum allowable operating pressure of 35 psig.

Model Results

Minimum Gas System Pressures (-12 ^{0}F)
- 11708 Kewana Ct – 5.63 psig
- 5207 Pine Bunch Ct – 7.67 psig
- 7701 Windgate Dr – 5.63 psig
- 8012 Kendrick Crossing Ln – 5.26 psig

Regulator Operating Capacity
- Taylorsville Rd and Hopewell Rd – 15.20%
- Gentry Lane and the Calvary Line – **91.90%**
- Cedar Creek Road and the Calvary Line – 10.67%
- Hudson Ln Station – 44.41%

Gas System Constraints
Gas system constraints in this area are primarily due to the infrastructure of small diameter piping coming from the sources. Due to current and anticipated growth it will be necessary to perform gas system reinforcement work.

IX. Jeffersontown/Fern Creek Medium Pressure System (cont'd)

Recommended Gas System Reinforcement

Reinforcement 1

Uprate the Jeffersontown/Fern Creek medium pressure distribution system from 35 psig to 60 psig. This uprate consists of approximately 14,123 services and 180 miles of main (107.3 miles of plastic and 70.8 miles of steel).

Minimum gas system pressure (-12°F)
- 11708 Kewana Ct – 30.98 psig
- 5207 Pine Bunch Ct – 34.76 psig
- 7701 Windgate Dr – 33.22 psig
- 8012 Kendrick Crossing Ln – 33.13 psig

Regulator Operating Capacity
- Taylorsville Rd and Hopewell Rd – 19.73%
- Gentry Lane and the Calvary Line – **85.53%**
- Cedar Creek Road and the Calvary Line – 13.95%
- Hudson Ln Station – 68.82%

Recommended Timeline –2008-2010

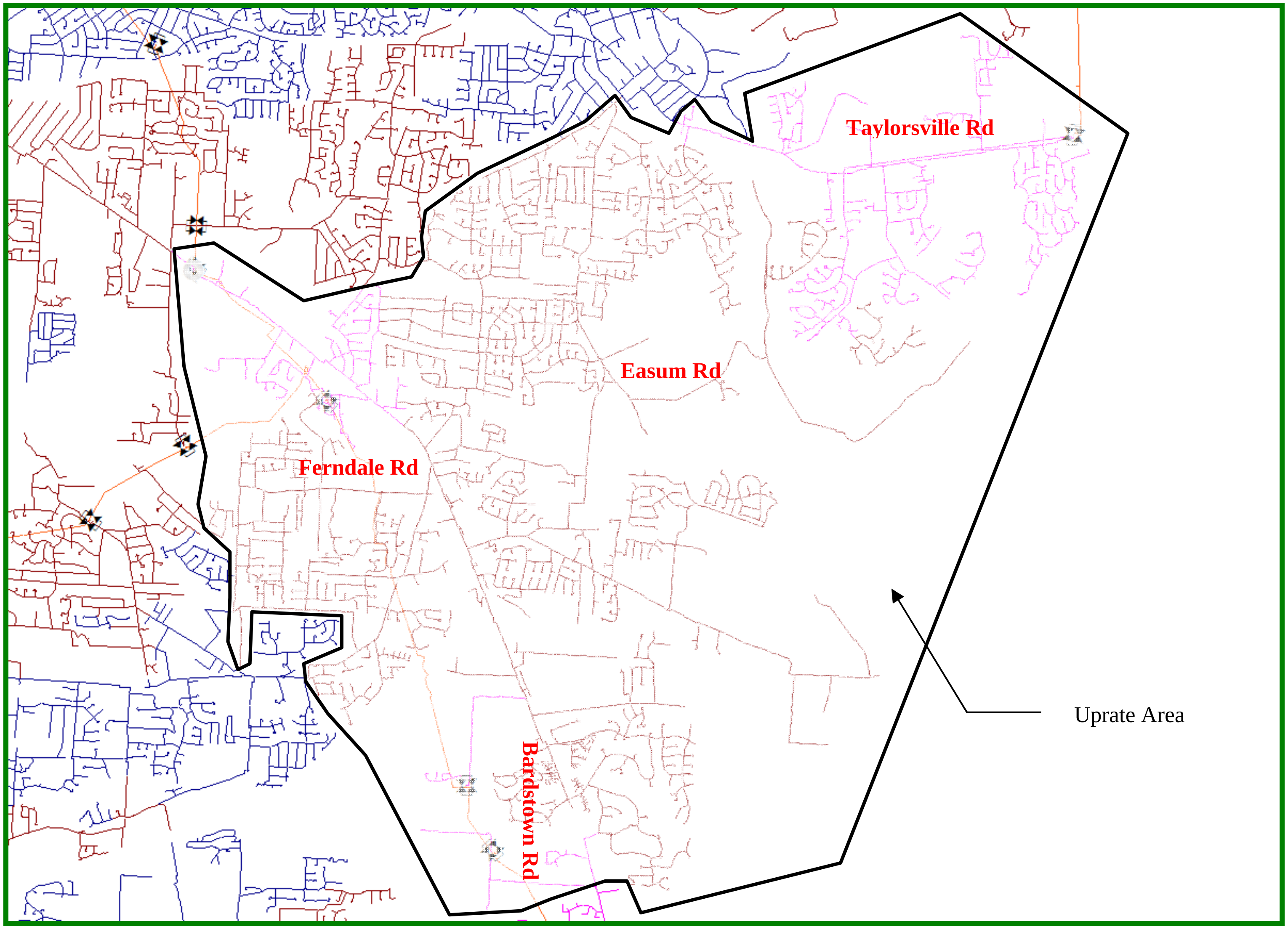
Reinforcement 2
- Loop approximately 8,370 feet of 6-inch medium pressure gas pipeline along Taylorsville Road from the outlet of the regulator facility to Saratoga Woods Drive.
- Install approximately 1,400 feet of 4-inch medium pressure plastic gas pipe east along Chenoweth Run Road from the 6-inch on Taylorsville Road.

Minimum gas system pressure (-12 ^{0}F)
- 11708 Kewana Ct – 25.07 psig
- 5207 Pine Bunch Ct – 48.82 psig
- 7701 Windgate Dr – 33.79 psig
- 8012 Kendrick Crossing Ln – 33.69 psig

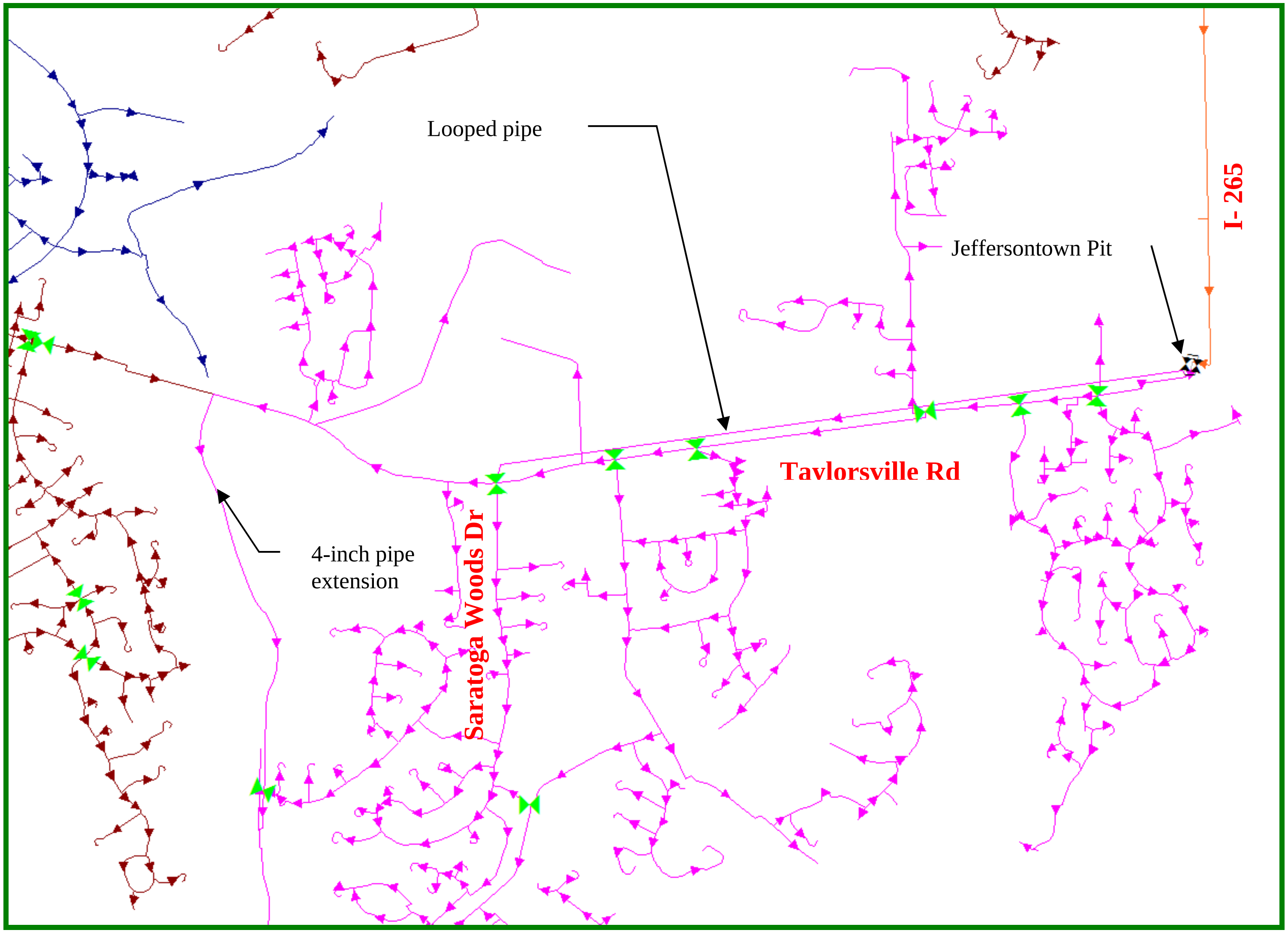
Regulator Operating Capacity
- Taylorsville Rd and Hopewell Rd – 20.36%
- Gentry Lane and the Calvary Line – **85.24%**
- Cedar Creek Road and the Calvary Line – 13.82%
- Hudson Ln Station – 68.24%

Recommended Timeline – 2008-2010

Taylorsville Road/Jeffersontown Medium Pressure Gas System – Reinforcement 1



Taylorsville Road/Jeffersontown Medium Pressure Gas System – Reinforcement 2



X. Bardstown Medium Pressure System

Gas System Overview
The Bardstown medium pressure gas system serves the City of Bardstown. This system is composed mainly of residential and commercial customers with a few large industrial customers including Owens Illinois and the Barton Distillery. It has continued to experience growth in the residential and commercial sectors especially on the western side of the Bardstown area. Expansion of an industrial park on Highway 605 near Nelson County High School is anticipated in the next 2-3 years.

Gas System Reinforcements completed in 2007
Installed approximately 1,800 ft of 8-inch medium pressure pipeline along the Bardstown Bypass (Hwy 245) to connect to the existing 6-inch and 8-inch medium pressure pipe infrastructure.

Regulator Facilities
The regulator facilities that supply gas to the Bardstown medium pressure system are as follows:

- The regulator station at the LG&E Bardstown Office on U.S. Highway 62 (Bardstown MP).
- The regulator station adjacent to Chris's Creation Cabinet Company (Chris's Creation MP).

Maximum Allowable Operating Pressure (MAOP)
The Bardstown medium pressure system has a maximum allowable operating pressure of 45 psig.

Model Results

Minimum Gas System Pressure (-12 ^{0}F)
The predicted minimum gas system pressure is located at **160 Deep Springs Dr** (**20.14 psig)**.

Regulator Operating Capacities
- Bardstown MP – **15.39**%
- Chris's Creation MP – **18.89**%

Gas System Constraints
Gas system constraints are caused by the lack of a direct gas supply route from the regulator station at the LG&E Bardstown office to the downtown Bardstown area. Due to current and anticipated growth, it will be necessary to reinforce the gas system.

X. Bardstown Medium Pressure System (cont'd)

Recommended Gas System Reinforcements

Reinforcement 1
Install approximately 1,916 ft of 4-inch plastic pipeline along Gilkey Rd and tie into the existing 8-inch steel main on Loretto Rd.

Minimum gas system pressure (-12 ^{0}F)
- 160 Deep Springs Dr – **20.14 psig**

Regulator Operating Capacities
- Bardstown MP – **15.37%**
- Chris's Creation MP – **19.03%**

Recommended Timeline – 2008-2012
Note: This reinforcement provides an alternate feed into the system.

Reinforcement 2
Install approximately 3,177 ft of 4-inch plastic pipeline along Filiatreau Ln and tie into the existing 4-inch plastic main on Glenwood Dr.

Minimum gas system pressure (-12 ^{0}F)
- 160 Deep Springs Dr – **34.15 psig**

Regulator Operating Capacities
- Bardstown MP – **14.39%**
- Chris's Creation MP – **27.54%**

Recommended Timeline – 2008-2012
Note: This reinforcement should be done in conjunction with the expansion of the Highway 605 industrial park.

X. Bardstown Medium Pressure System (cont'd)

Reinforcement 3
Install a medium pressure regulator facility off the high pressure transmission line at the intersection of North Third Street and the Bardstown Bypass (Hwy 245).

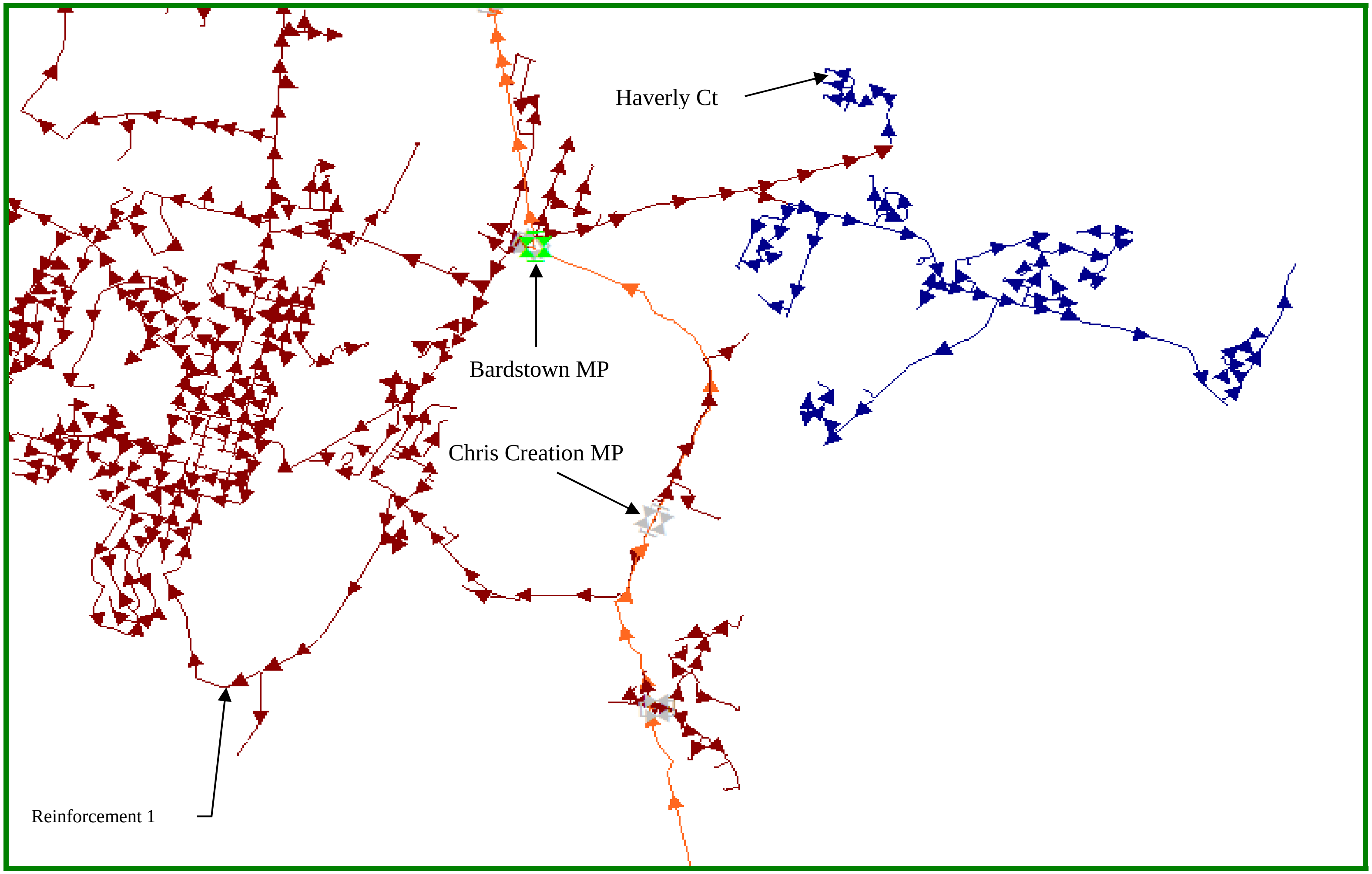
Note: Based on Reinforcement 1 of the Mt. Washington/Lebanon Junction High Pressure System (see Section XVIII; see also Section XXIII, Scenario 2), the new regulator facility would allow gas to feed directly into the center of the system to eliminate the low-pressure problem at Meadow Ridge Dr. The new low pressure point is located east of the Bardstown MP facility.

Minimum gas system pressure (-12 ^{0}F)
- 160 Deep Springs Dr – **34.74 psig**
- 116 Andrea Ct – **33.76 psig**
- 212 Meadow Ridge Dr – **43.32 psig**

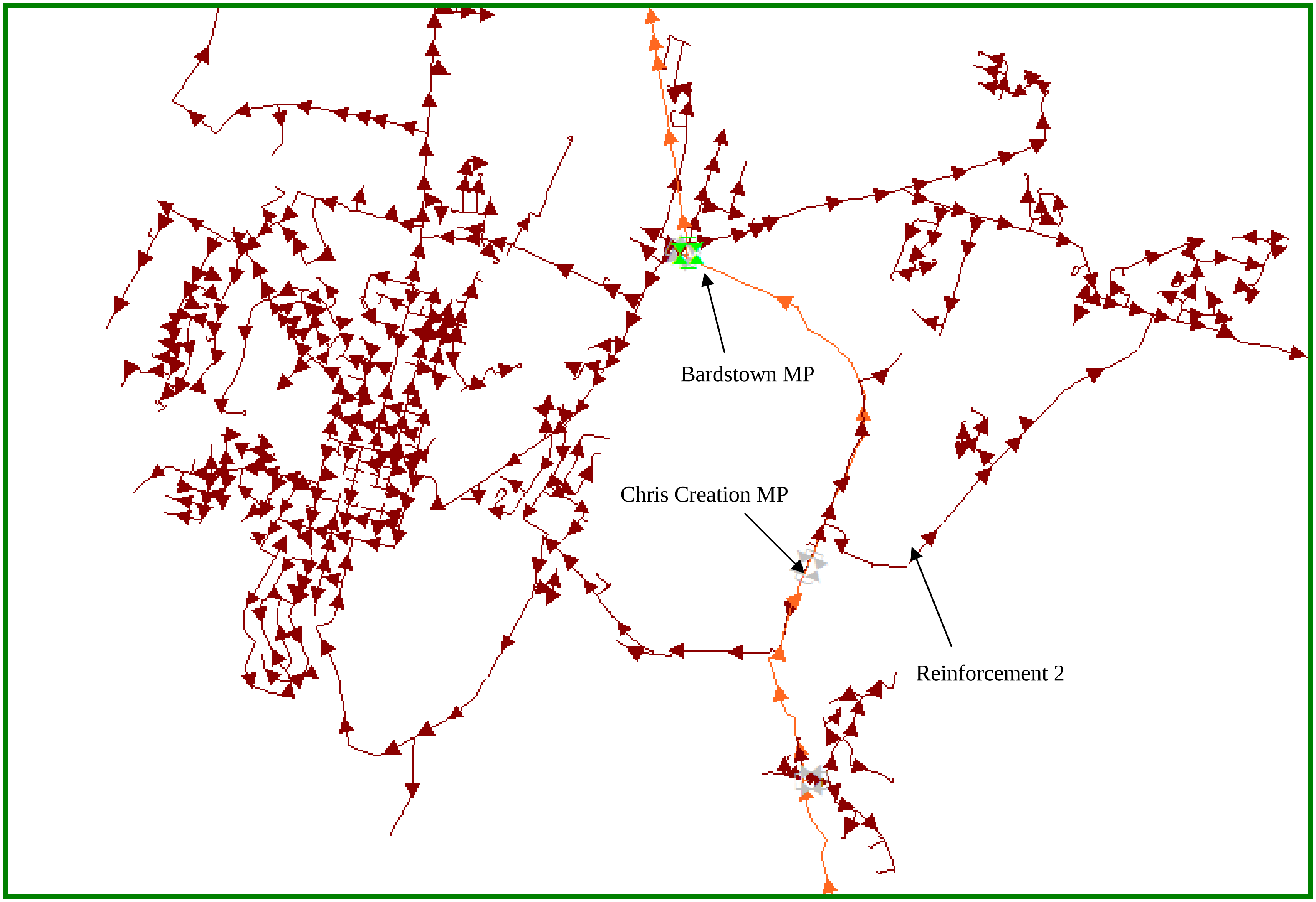
Regulator Operating Capacities
- Bards2MP (new pit) – **11.77%**
- Bardstown MP – **5.77%**
- Chris's Creation MP – **18.96%**

Recommended Timeline – TBD
Note: Should be completed in conjunction with the Mt. Washington/Lebanon Junction high-pressure pipeline project.

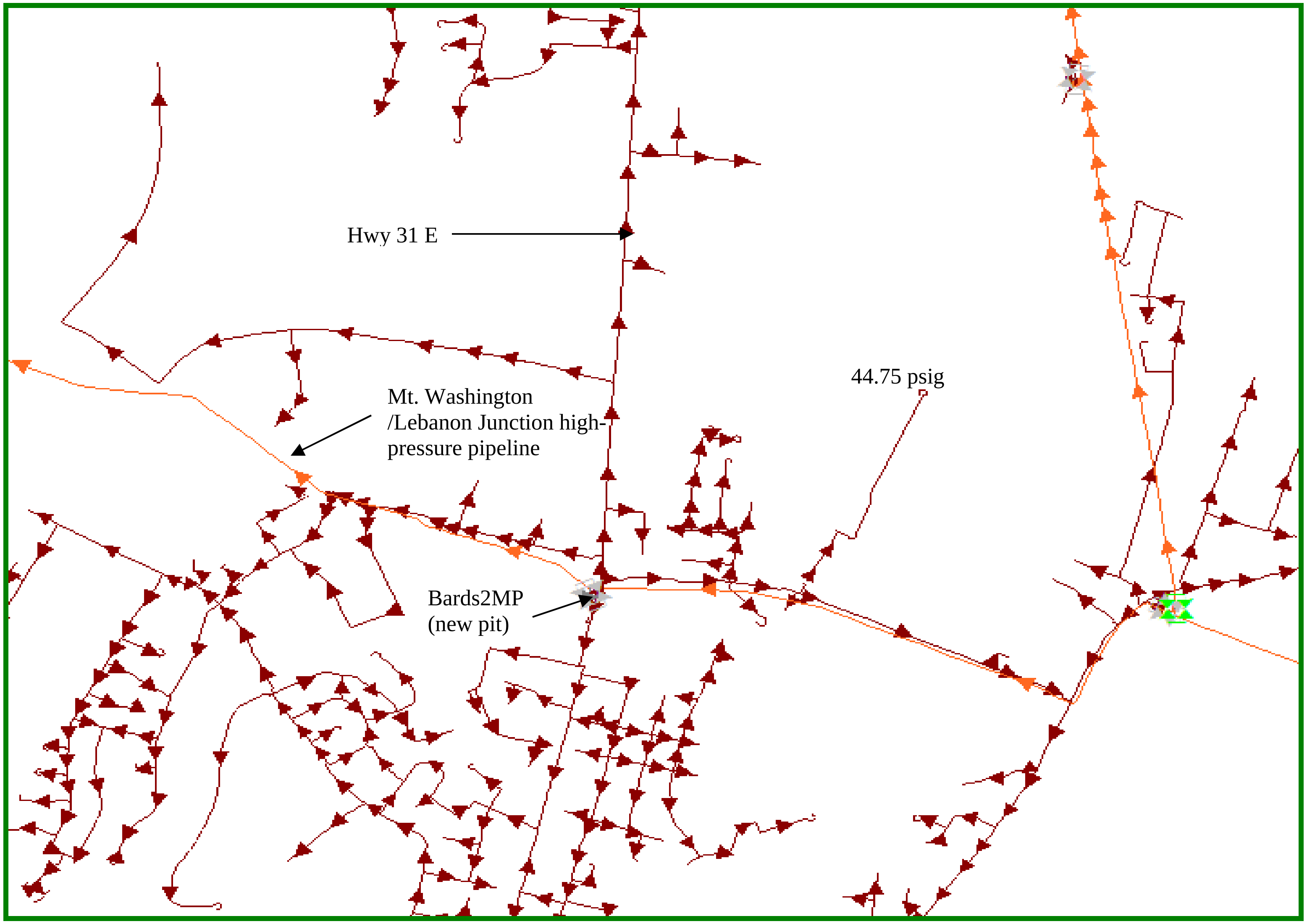
Bardstown Medium Pressure Gas System – Reinforcement 1



Bardstown Medium Pressure Gas System – Reinforcement 2



Bardstown Medium Pressure Gas System – Reinforcement 3



XI. Highway 44 Regulator Assemblies

Gas System Overview
Gas System Planning has identified nine separate regulator assemblies located along Highway 44 that could be removed to reduce the number of dead-end gas systems and/or reduce maintenance cost on unnecessary regulation facilities.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Mt Washington MP
- Hwy 44 and Woodlake
- Hwy 44 and Harris
- Hwy 44 and Fisher
- Hwy 44 and Highland Spring
- Hwy 44 and Bethel Church
- Hwy 44 and Azure
- Hwy 44 and Truman
- Hwy 44 and Kennedy
- Hwy 44 and Bogard
- Hwy 44 and Bells Mill
- Hwy 44 and Alpar
- Hwy 44 and Mockingbird
- Hwy 44 and Sunview
- Hwy 44 and Watergate
- Hwy 44 and HiLand
- Hwy 44 and Big Clifty
- Hwy 44 and Halls
- Hwy 44 and Boardwalk

Maximum Allowable Operating Pressure
These systems have a maximum allowable operating pressure of 35 psig. The maximum allowable operating pressure of the Mt Washington MP regulator station is scheduled to be uprated to 60 psig in 2007.

XI. Highway 44 Regulator Assemblies (cont'd)

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure is located on **Winding Woods Trail (30.36 psig)**.

Regulator Operating Capacities
- Mt Washington MP – **11.21%**
- Hwy 44 and Woodlake – **39.19%**
- Hwy 44 and Harris – **22.07%**
- Hwy 44 and Fisher – **63.82%**
- Hwy 44 and Highland Spring – **29.81%**
- Hwy 44 and Bethel Church – **36.50%**
- Hwy 44 and Azure – **6.61%**
- Hwy 44 and Truman – **20.11%**
- Hwy 44 and Kennedy – **4.22%**
- Hwy 44 and Bogard – **62.22%**
- Hwy 44 and Bells Mill – **20.54%**
- Hwy 44 and Alpar – **4.02%**
- Hwy 44 and Mockingbird – **39.42%**
- Hwy 44 and Sunview – **28.11%**
- Hwy 44 and Watergate – **1.19%**
- Hwy 44 and HiLand – **4.56%**
- Hwy 44 and Big Clifty – **8.06%**
- Hwy 44 and Halls – **3.70%**
- Hwy 44 and Boardwalk – **16.99%**

Recommended Gas System Reinforcements

Reinforcement 1
- Connect system served by Hwy 44 and Boardwalk to Hwy 44 and Halls system with 570 feet of 4-inch plastic main along Hwy 44.
- Connect Hwy 44 and Big Clifty to Hwy 44 and Halls system with 1,350 ft of 4-inch plastic main along Hwy 44.
- Convert six high-pressure services on the north side of Hwy 44 to medium-pressure services between Hwy 44 and Halls and Hwy 44 and Big Clifty. This will retire six long services that pass underneath Hwy 44.
- Retire Boardwalk and Big Clifty regulator assemblies.

Minimum Gas System Pressure (-12°F)
- Tanager Landing Apartments off Hwy 44 – **33.86 psig**

XI. Highway 44 Regulator Assemblies (cont'd)

Regulator Operating Capacities
- Hwy 44 and Halls Ln – **29.08%**

Recommended Timeline – 2008-2015

Reinforcement 2
- Connect systems served by Hwy 44 & Hi-Land and Hwy 44 & Watergate with 1,780 feet of 6-inch plastic mains.
- Retire Watergate Assembly.

Minimum Gas System Pressure (-12°F)
- Douglass Drive **– 34.98 psig**

Regulator Operating Capacities
- Hwy 44 and Hi-Land– **5.74%**

Recommended Timeline – 2008-2015

Reinforcement 3
- Retire Hwy 44 and Mockingbird regulator assembly. System can be served by Hwy 44 and Sunview.

Minimum Gas System Pressure (-12°F)
- Old Hickory Lane – **32.24 psig**

Regulator Operating Capacities
- Hwy 44 and Sunview **– 68.56%**

Recommended Timeline – 2008-2015
Note: Growth in area may require that the Mockingbird assembly remain. This area should be monitored before finalizing a decision.

Reinforcement 4
- Connect systems served by Hwy 44 and Bells Mill and Hwy 44 and Alpar with 2,200 feet of 4-inch plastic main along Hwy 44 and Old Hwy 44.
- Convert five existing high pressure services to medium pressure.
- Retire the Hwy 44 and Alpar regulator assembly.

Minimum Gas System Pressure (-12°F)
- Bells Mill Road and Farris Intersection **– 32.15 psig**

Regulator Operating Capacities
- Hwy 44 and Bells Mill **– 22.46%**

Recommended Timeline – 2008-2015

XI. Highway 44 Regulator Assemblies (cont'd)

Reinforcement 5

- Connect systems served by Hwy 44 & Bogard, Hwy 44 & Kennedy, Hwy 44 & Truman, and Hwy 44 & Azure with 3,900 feet of 6 inch plastic main along Hwy 44.
- Connect Systems served by Bethel Church and Highland Springs facilities with 1,300 feet of 4- or 6-inch plastic main along Hwy 44.
- Convert 24 high-pressure services along Hwy 44 to medium pressure.
- Retire Truman, Kennedy, and Bethel Church Road facilities.

Minimum Gas System Pressure (-12°F)

- Simmons Lane – **33.37 psig**

Regulator Operating Capacities

- Hwy 44 and Bogard – **67.44%**
- Hwy 44 and Azure – **25.43%**
- Hwy 44 and Highland Springs – **53.92%**

Recommended Timeline – 2008-2015

Reinforcement 6

- Connect Fisher, Harris, and Woodlake systems with 2,100 feet of 4-inch plastic pipe along Hwy 44 between Fisher and Harris, and 1,650 feet of 6-inch plastic pipe between Harris and Woodlake.
- Convert approximately 34 high-pressure services to medium pressure.
  Note: Some of these services may have been converted during 2005 work but are not currently mapped.
- Retire Hwy 44 and Harris regulator assembly.

Minimum Gas System Pressure (-12°F)

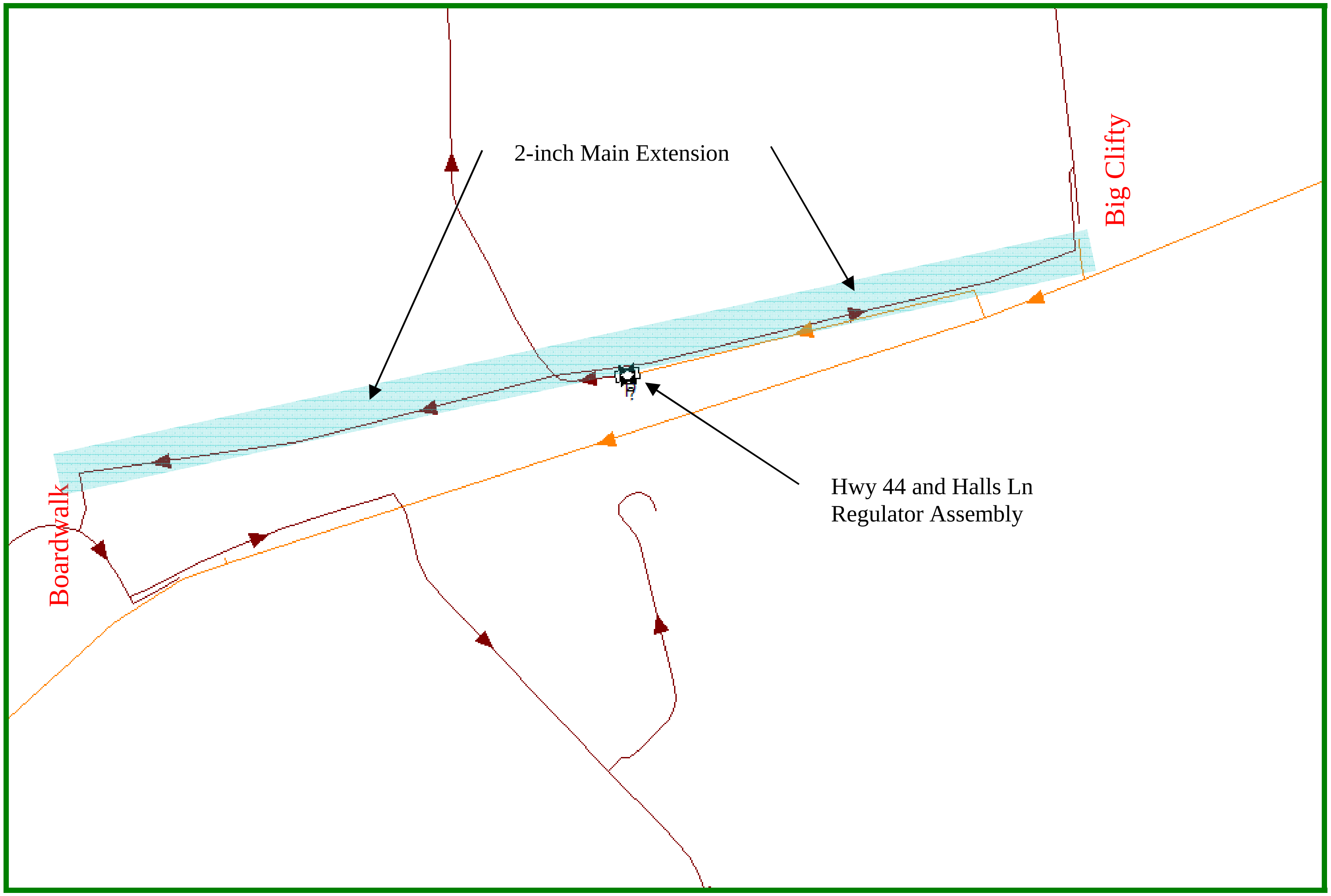
- Winding Woods Trail – **30.39 psig**

Regulator Operating Capacities

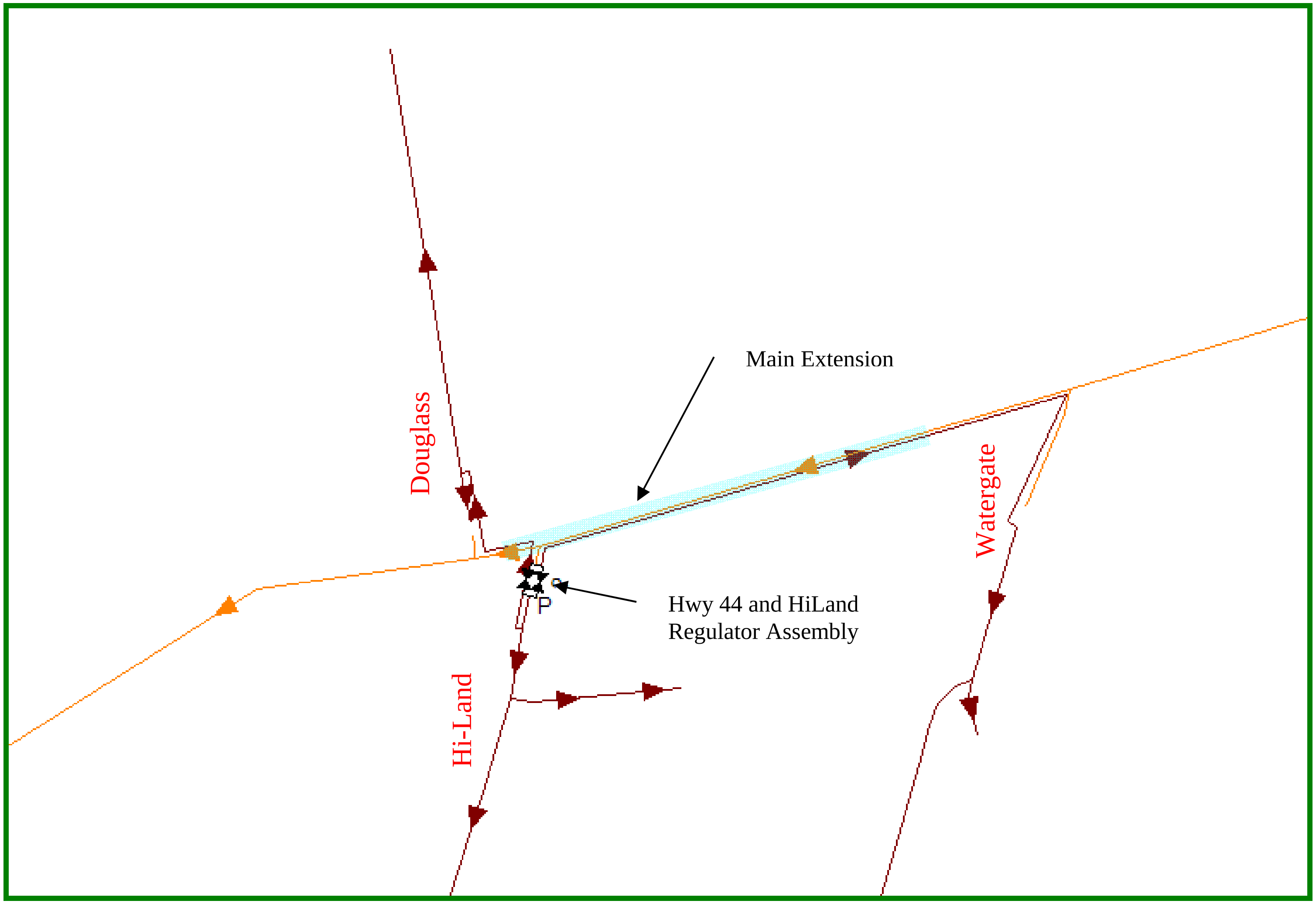
- Hwy 44 and Fisher – **60.20%**
- Hwy 44 and Woodlake – **68.68%**

Recommended Timeline – 2008-2015

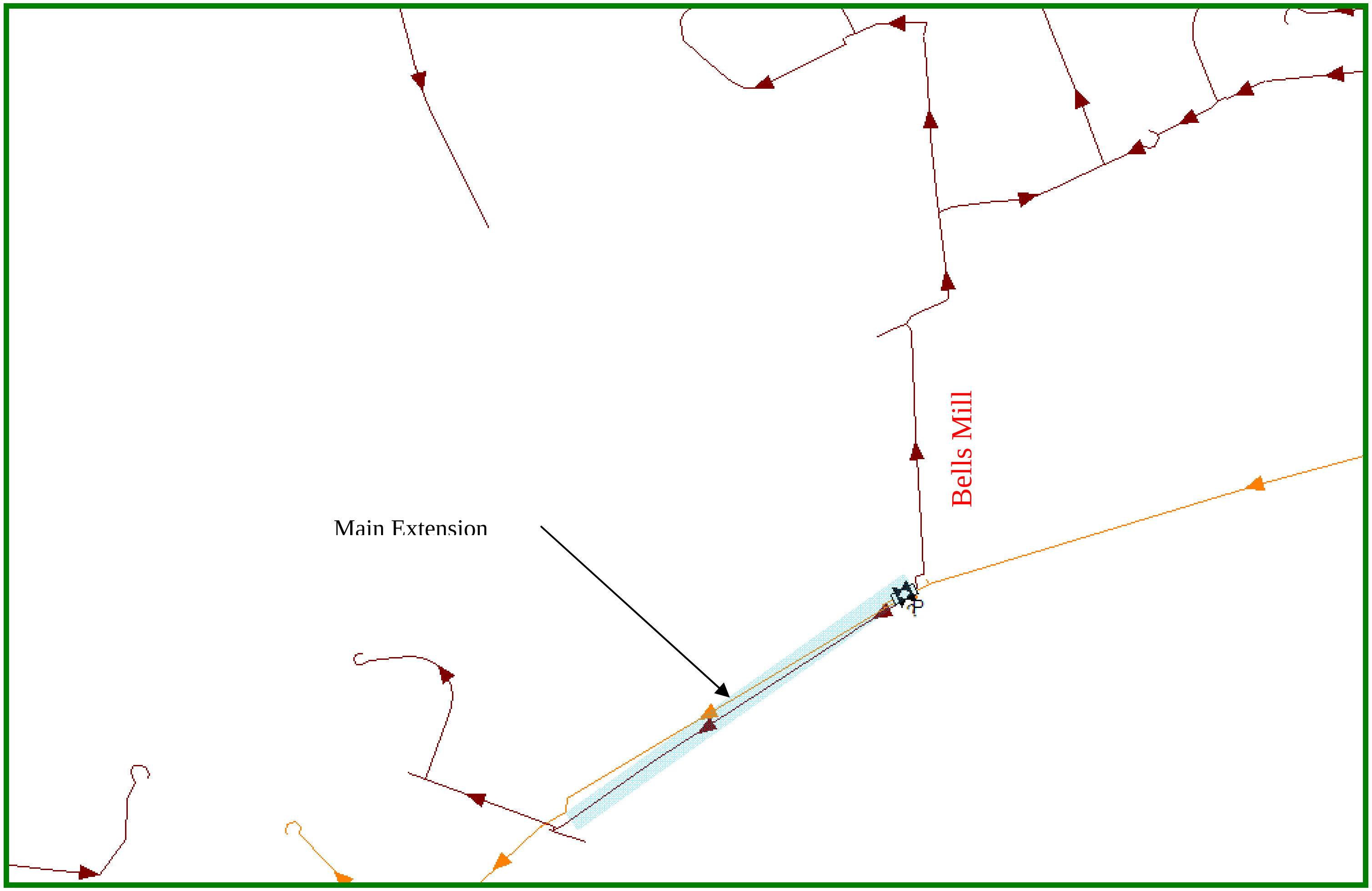
Hwy 44 Regulator Assemblies – Reinforcement 1



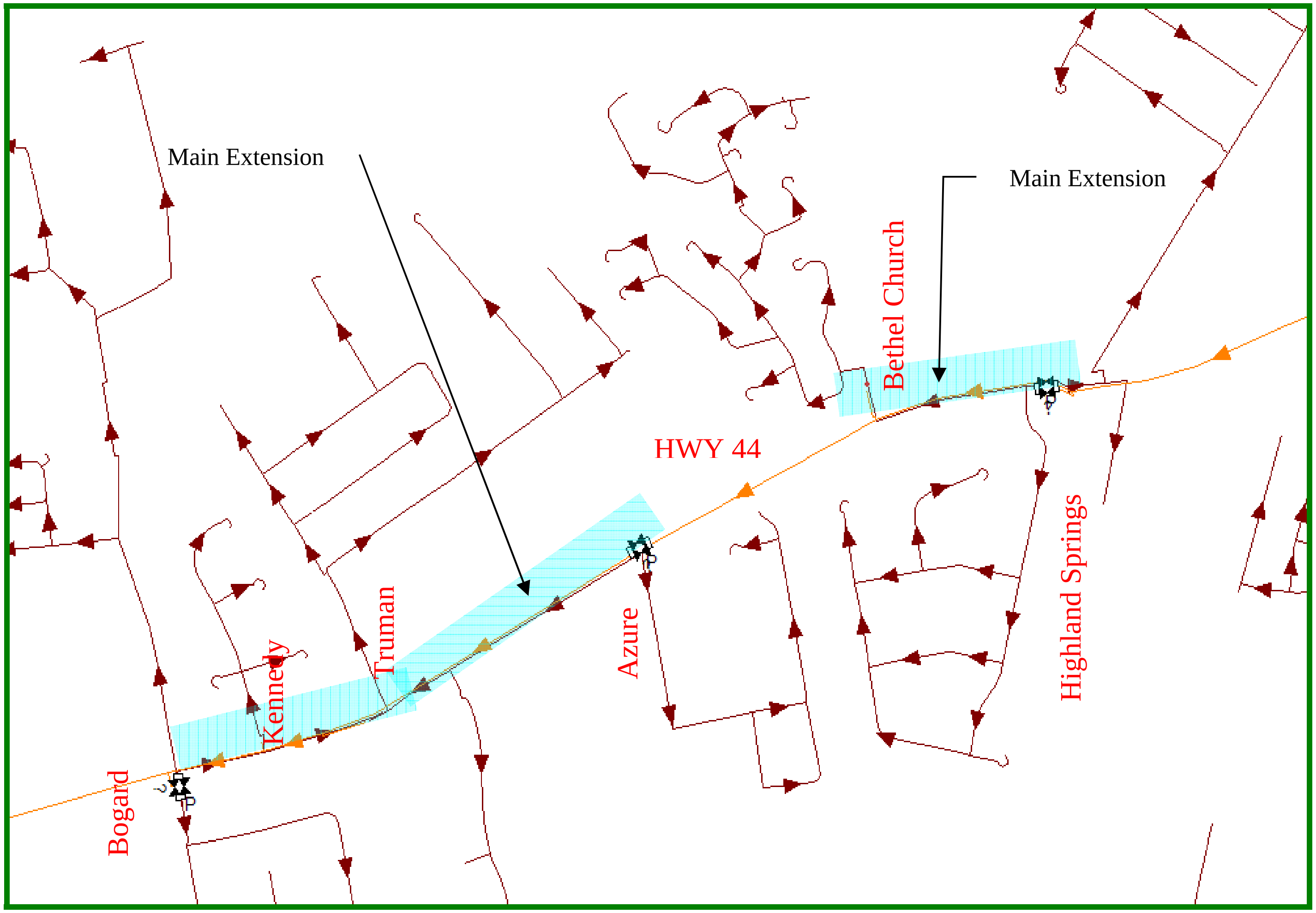
Hwy 44 Regulator Assemblies – Reinforcement 2



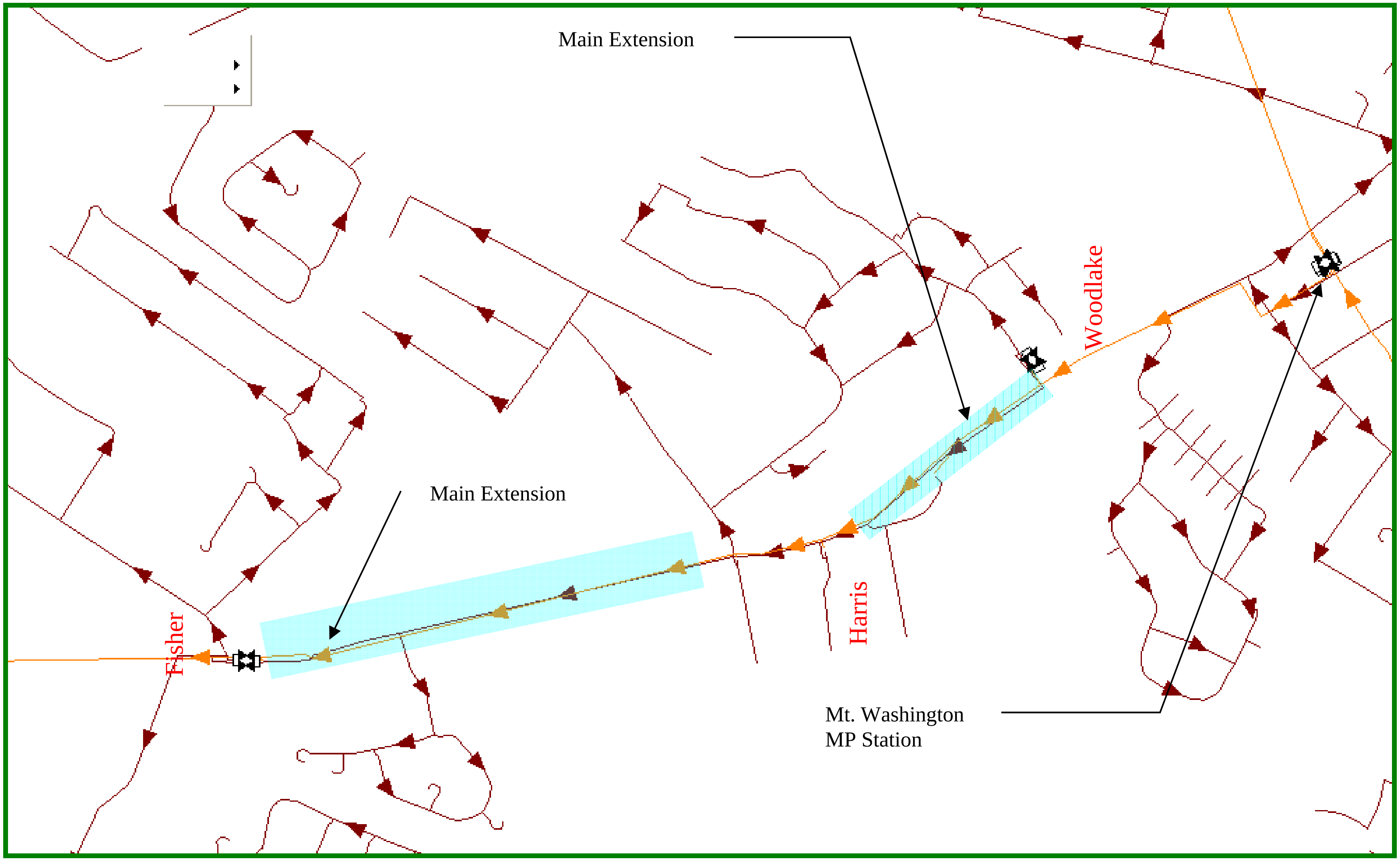
Hwy 44 Regulator Assemblies – Reinforcement 4



Hwy 44 Regulator Assemblies – Reinforcement 5



Hwy 44 Regulator Assemblies – Reinforcement 6



XII. Hodgenville Medium Pressure System

Gas System Overview

The Hodgenville medium-pressure gas system serves the City of Hodgenville. This system is composed of residential and small commercial customers. Both sectors continue to experience growth. To continue to cope with growth in Hodgenville, the gas system will need to be reinforced.

Regulator Facilities

The Hodgenville medium-pressure system is fed by the regulator station at State Highway 84 and Glendale Rd.

Maximum Allowable Operating Pressure

The Hodgenville medium-pressure system has a maximum allowable operating pressure of 20 psig.

Model Results

Minimum Gas System Pressure (-12°F)

The predicted minimum pressure is located at **2017 US Highway 31E (11.87 psig)**.

Regulator Operating Capacity

- Highway 84 and Glendale Rd – 18.24%

Recommended Gas System Reinforcement

Reinforcement 1

Uprate the Hodgenville medium pressure gas distribution system to 50 psig. This uprate will affect approximately 1,241 services and 25.3 miles of pipeline.

Minimum Gas System Pressure (-12°F)

- 2017 US Highway 31E – **46.05 psig**

Regulator Operating Capacity

- Highway 84 and Glendale Rd – **18.29%**

Recommended Timeline – 2009-2015

XIII. Waste Management Relocation Project

Gas System Overview

The Penile City Gate Station supplies gas to the Preston City Gate Station via a 20-inch transmission pipeline (the Penile to Preston Line). The Penile to Preston Line crosses Waste Management landfill property from the Outer Loop to I-65. The two primary feeds associated with this pipeline are from the Penile and Preston City Gate Stations. Due to planned construction at the landfill, approximately 6,000 ft of the Penile to Preston Line that run through the landfill property must be relocated.

Maximum Allowable Operating Pressure

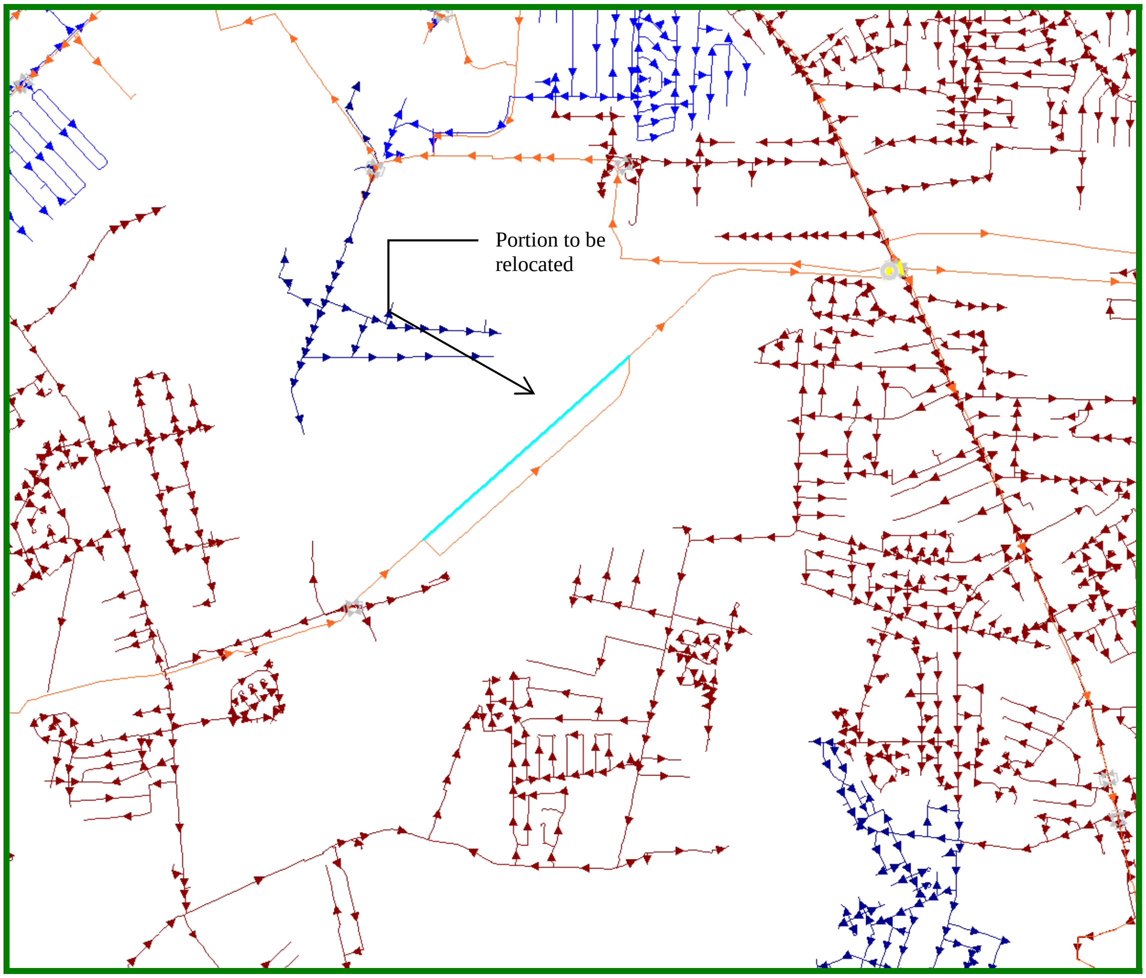
The Penile to Preston Line has a maximum allowable operating pressure of 420 psig.

Recommended Relocation

Shift the portion of the pipeline that runs through landfill property approximately 500 ft to the southeast. The pipeline should roughly run along an access road in the landfill and should reconnect with the existing pipeline before it crosses underneath I-65. This relocation will require approximately 6,600 ft of 20-inch high-pressure pipeline.

Recommended Timeline – TBD

Waste Management Relocation Project – Recommended Relocation



XIV. Minor Lane Heights Renaissance Zone

Gas System Overview

The Minor Lane Heights area is being targeted for redevelopment from residential use to commercial and industrial use as a part of a noise mitigation program associated with the Louisville International Airport. Redevelopment is scheduled to occur in five phases, beginning in early 2007 and lasting ten years.

Regulator Facilities

The regulator facilities that feed this system are as follows:

- Regulator station at Preston City Gate Station
- Regulator pit at Outer Loop and Grade Ln

Maximum Allowable Operating Pressure

The Minor Lane Heights system has a maximum allowable operating pressure of 35 psig.

Model Results

Minimum Gas System Pressure (-12°F)

The predicted minimum gas system pressure is located at the UPS Supply Chain Solutions warehouse at **2240 Outer Loop (26.03 psig)**. There is another low pressure point at the south end of Eagle Pass (26.84 psig).

Regulator Operating Capacities

- Preston City Gate Station MP – **54.13%**
- Outer Loop and Grade Ln – **26.52%**

Gas System Constraints

Most of the existing gas infrastructure in the Minor Lane Heights system is 2- and 4-inch pipe. In addition, the system is relatively distant from its supplies. This would make it difficult to serve the number of industrial customers proposed for the Renaissance Zone. Furthermore, the proposed layout of the Renaissance Zone would place much of the existing infrastructure below various structures. To account for this, and to serve the projected loads, the Minor Lane Heights system must be altered and reinforced.

XIV. Minor Lane Heights Renaissance Zone (cont'd)

Recommended Gas System Reinforcements

Reinforcement 1

- Retire existing pipeline along Paul Rd south of Zib Ln
- Install approximately 4,300 ft of 8-inch plastic main along Outer Loop, Stinnett Ln, proposed two-lane "A," and proposed boulevard "A" to serve UPS facility.

Minimum Gas System Pressure (-12°F)

- UPS Supply Chain Solutions Warehouse (2220 Outer Loop) – **27.37 psig**
- New UPS Facility – **34.36 psig**

Regulator Utilization

- Preston City Gate Station MP – **53.57%**
- Outer Loop and Grade Ln – **28.07%**

Recommended Timeline – 2007

Reinforcement 2

Install and remove gas mains according to "An Analysis of the Minors Lane Heights Renaissance Zone" dated 15 January 2007 or the latest version.

- Retire existing pipelines in the area.
- Install approximately 1,200 ft of 2-inch pipe
- Install approximately 15,400 ft of 4-inch pipe
- Install approximately 9,900 ft of 8-inch pipe

Minimum Gas System Pressure (-12°F)

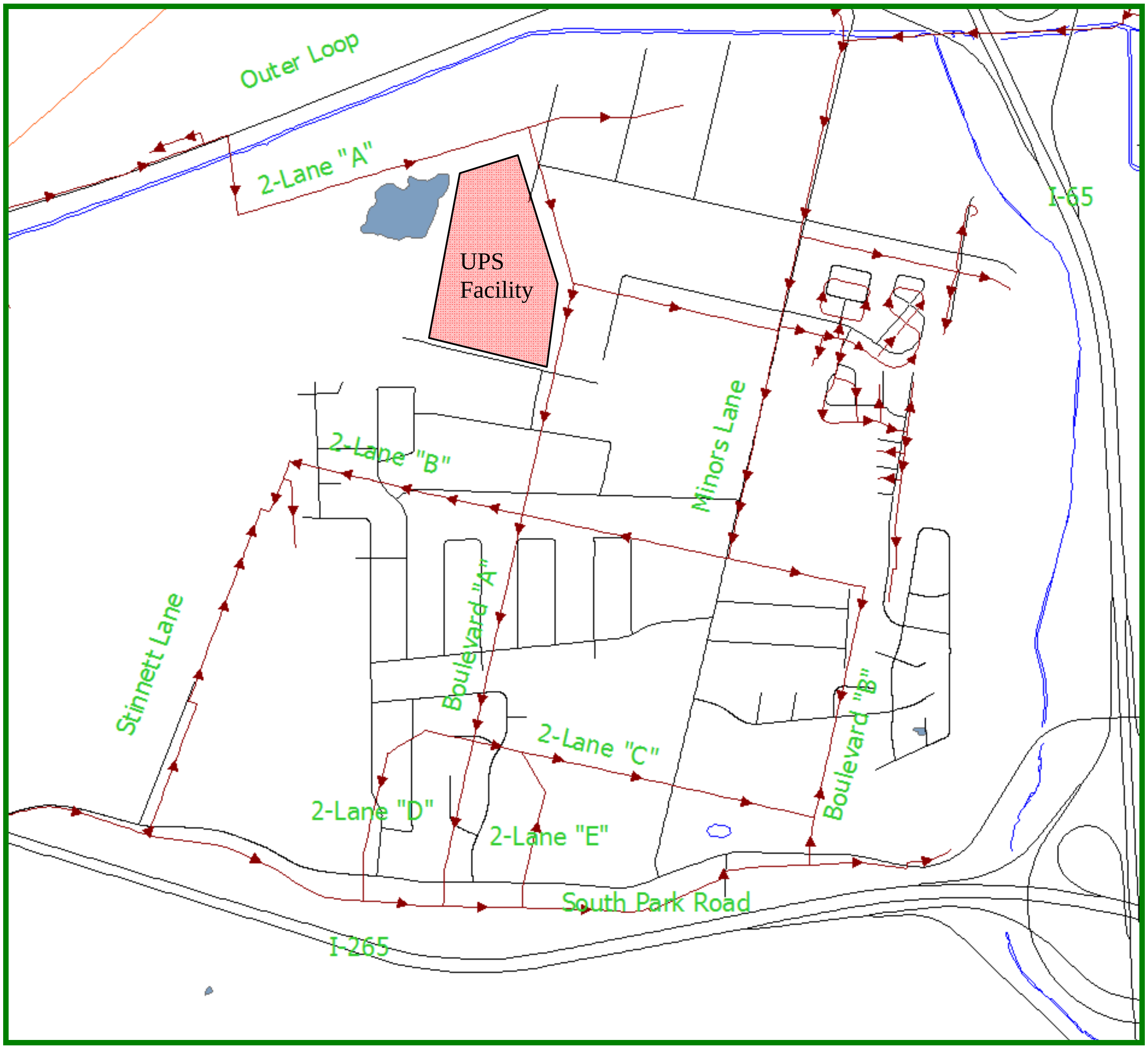
- UPS Supply Chain Solutions Warehouse (2220 Outer Loop) – **26.07 psig**

Regulator Operating Capacities

- Preston City Gate Station MP – **54.33%**
- Outer Loop and Grade Ln – **47.22%**

Recommended Timeline – 2007-2017

Minor Lane Heights Renaissance Zone – Map of Proposed Streets and Reinforcement 2



Minor Lane Heights Renaissance Zone – Reinforcement 1

XV. Mount Washington Medium Pressure System

Gas System Overview
The Mount Washington medium pressure gas system serves the City of Mount Washington and surrounding areas. This system is composed of residential and commercial customers. It continues to experience growth in the residential and commercial sectors, especially along Highway 44.

Gas System Reinforcement to Be Completed Summer 2007
The Mount Washington medium pressure distribution system will be uprated from 35 psig to 60 psig. This uprate consists of 61.5 miles of main (14.5 miles of steel and 46.9 miles of plastic) and 2,855 customer services.

Regulator Facilities
The two regulator facilities that supply gas to the Mount Washington medium pressure system are as follows:

- Regulator station located at Sunnyside Drive and Highway 44 (Mt. Washington MP)
- Regulator assembly located at Landis Lane and Bardstown Road

Maximum Allowable Operating Pressure (MAOP)
The Mount Washington medium pressure gas system will have a maximum allowable operating pressure of 60 psig after completion of the uprate.

Model Results

Minimum Gas System Pressure (-12 ^{0}F):
The predicted minimum pressure is located on **Pin Oak Drive (40.87 psig).**

Regulator Operating Capacities (-12 ^{0}F):
- Mt. Washington MP – **11.24%**
- Bardstown Rd and Landis Ln – **52.85%**

Gas System Constraints
Gas system constraints in this area are primarily due to an infrastructure of 4-inch diameter pipe along Highway 44. Due to current and anticipated growth, it will be necessary to perform gas system reinforcement work.

Recommended Gas System Reinforcements

Reinforcement 1
Install approximately 4,300 ft of 6-inch medium pressure pipeline from Oakland Hills Trail to tie into the existing 4-inch medium pressure pipeline on Waterford Road.

Minimum Gas System Pressure (-12 ^{0}F)
- Pin Oak Dr – **50.28 psig**

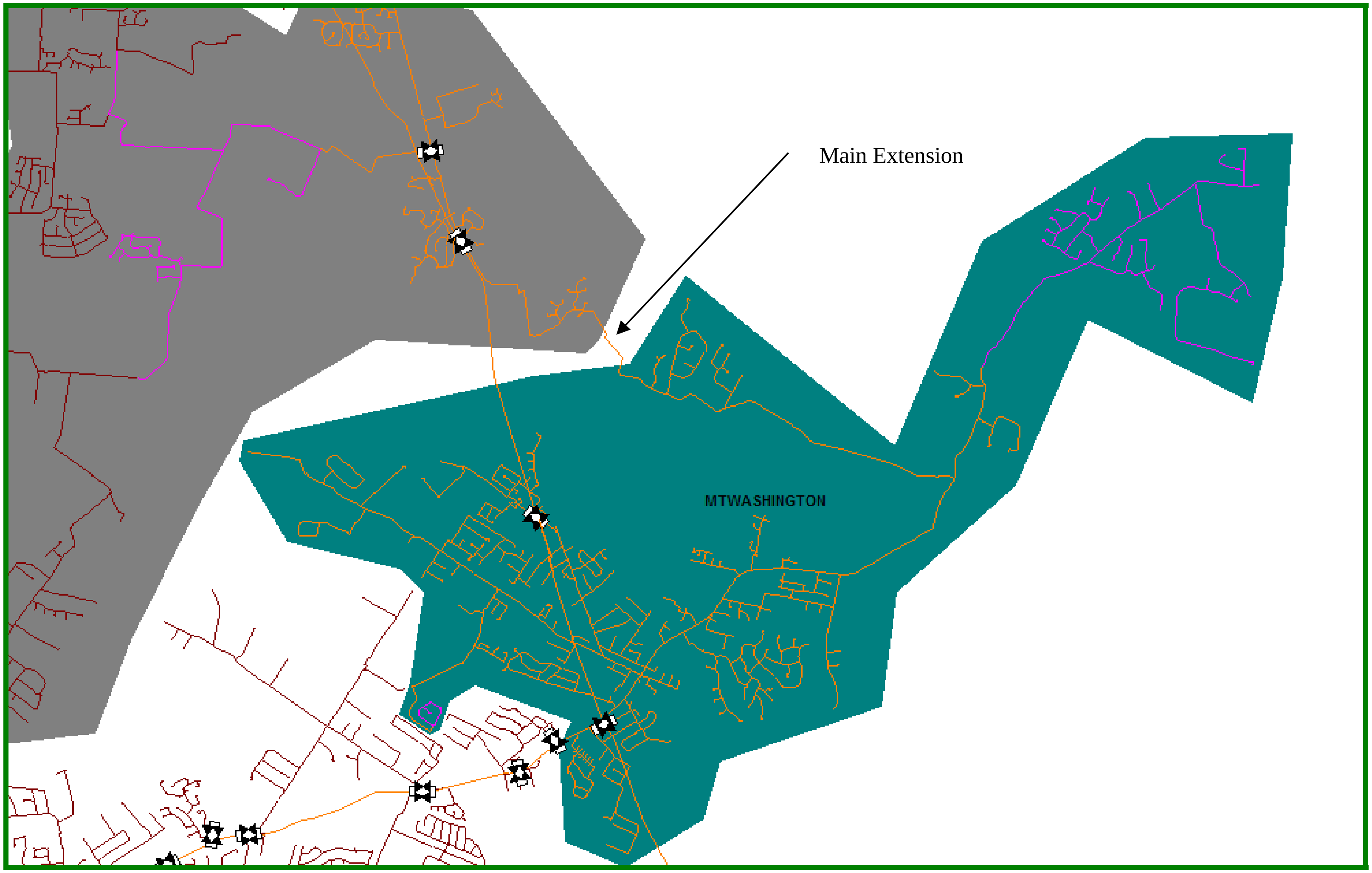
XV. Mount Washington Medium Pressure System (cont'd)

Regulator Operating Capacities (-12 ^{0}F):

- Mt. Washington MP – **10.28%**
- Bardstown Rd and Landis Ln – **50.94%**
- Vista Hills Blvd and Calvary Line – **100%**

Recommended Timeline – 2007-2008

Mount Washington Medium Pressure System – Reinforcement 1



XVI. Preston High Pressure Distribution Pipeline Reinforcement

Gas System Overview
The Preston high pressure distribution gas system serves the cities of Shepherdsville, Maryville Okolona and outlying areas. The gas supply originates from the Preston City Gate Station to the Preston High Pressure Station and gas pipeline running south. This system is a one-way feed into the Okolona and Maryville areas. These areas have continued to experience growth in the residential and commercial sectors.

Maximum Allowable Operating Pressure
The Preston high pressure system consists of an 8-inch pipeline operating at a maximum allowable pressure of 110 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure for this high pressure system is located at the inlet to the **Preston and Antle regulator pit (62.38 psig)**

Regulator Operating Capacities
- Preston City Gate Station – **95.29%**

Gas System Constraints
Gas system constraints in this area are primarily due to the one-way feed of high pressure gas feeding the distribution systems and the lack of pipe further south along Preston Highway. Due to current and anticipated growth, it will be necessary to perform gas system reinforcement work.

Recommended Gas System Reinforcements

Reinforcement 1
The State Highway Department plans on completing a corridor alignment along Cooper Chapel Road, in the City of Okolona.

- Install approximately 31,850 ft of 12-inch high pressure gas pipeline from the Calvary line to the Preston high pressure line.
- Install a new regulator facility (4x3 Mooney assemblies with 100% plates) at Preston Highway and Cooper Chapel Road to reduce the pressure from the Calvary Line to 110 psig.

Minimum Gas System Pressure (-12°F)
- Preston and Antle inlet **– 95.96 psig**

Regulator Operating Capacities
- New facility at Cooper Chapel and Preston Highway – **32.5%**

XVI. Preston High Pressure Distribution Pipeline Reinforcement (cont'd)

Eventually, the pipeline would be extended further south along Preston Highway and this would allow a second feed for the high pressure system (see Section XIX). Without the second feed, if the Preston high pressure pipeline was damaged, the areas of Okolona and Maryville and a portion of Shepherdsville would be lost.

Recommended Timeline – TBD

Reinforcement 2

- Extend the 8-inch steel high-pressure main south along Preston Highway from Mud Lane to Bells Mill Road (approx. 19,000 feet).
- Install a medium pressure regulator facility at Bells Mill Road and Preston Highway (4x3 Mooney with 100% plates) to be tied into the 8-inch medium pressure main on Preston Highway or Bells Mill Road.

Minimum Gas System Pressure (-12°F)

- Inlet to new Facility at Preston & Bells Mill **– 70.78 psig**

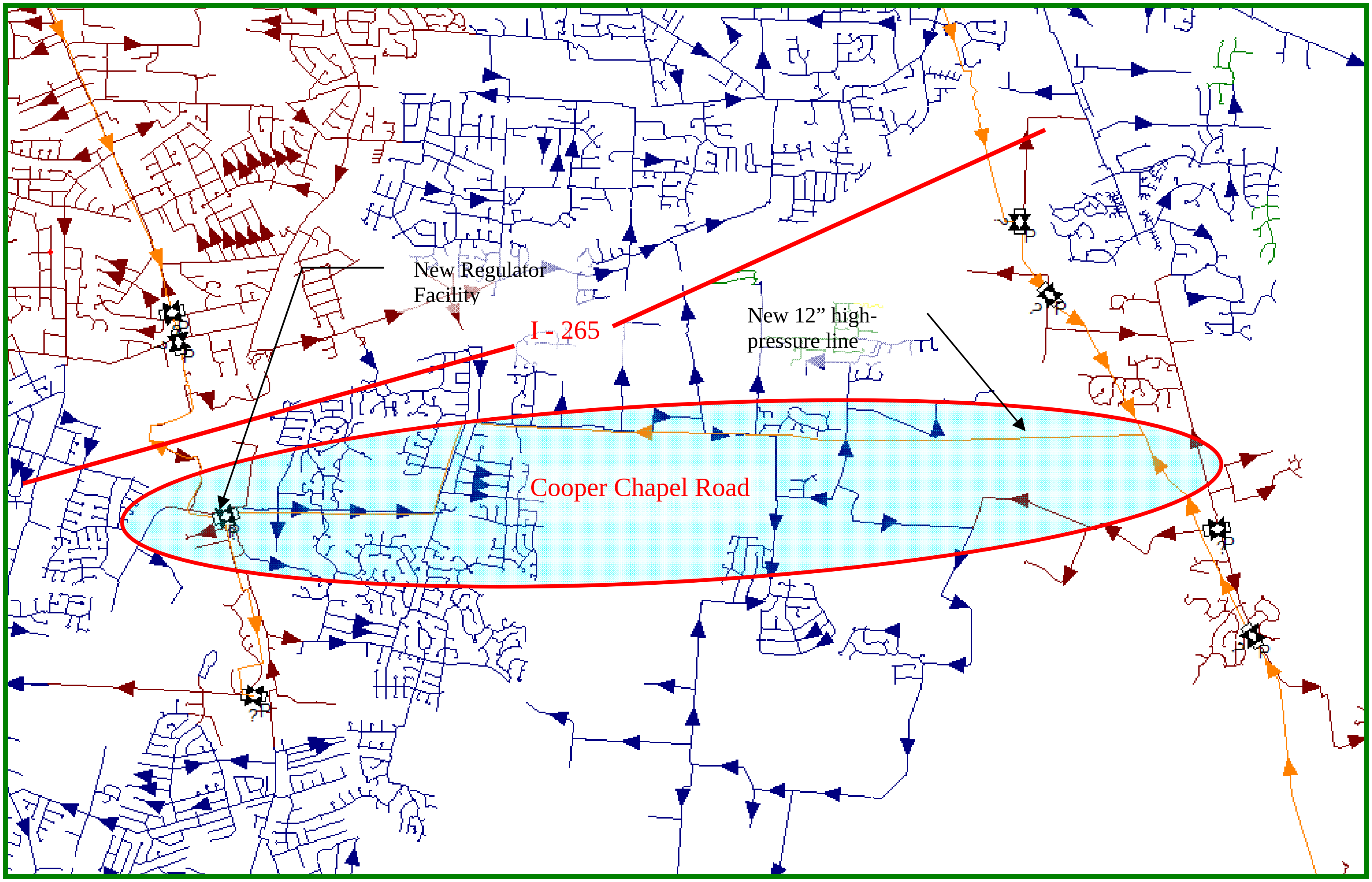
Regulator Operating Capacities

- Cooper Chapel and Preston **– 36%**
- Preston and Antle **– 58%**
- Preston and Bells Mill **– 100%**

Note: The current pressure on the Preston HP line prohibits a significant pressure differential across the new regulator assembly. The results shown are after Reinforcement 1 has been completed and assuming Shepherdsville/Northern Bullitt MP system has been uprated. Operating the Preston HP line at its 140 psig MAOP significantly improves the inlet pressure (110 psig) to the new assembly.

Recommended Timeline – TBD; after completion of Reinforcement 1

Preston Highway High Pressure Pipeline – Reinforcement 1



XVII. Mt. Washington/Lebanon Junction High Pressure Distribution System

Gas System Overview
The Mount Washington/Lebanon Junction system is a one-way feed high pressure distribution system that receives its gas supply from LG&E's Calvary gas transmission pipeline in the Mount Washington area. The high pressure system consists of 8-inch and 6-inch pipe.

There are five major existing gas loads associated with this high pressure system. They are as follows:

- City of Shepherdsville
- City of Lebanon Junction
- Jim Beam Boston Plant
- Jim Beam Clermont Plant
- Publishers Printing

There are five major new gas loads associated with this high pressure system. They are as follows:

- Heritage Hills subdivision
- Gordon Foods
- Shepherdsville Industrial Park
- Highway 480 Industrial Park
- Salt River Business Park

The following points can be summarized from the gas system planning analyses:

- The Mount Washington high pressure gas distribution system must operate at 275 psig in order to operate the Shepherdsville gas distribution system at 60 psig on a design day (-12 ^{0}F).
- LG&E can meet the gas service requirements for Publishers Printing and Jim Beam Boston on a design day (-12 ^{0}F) with the proposed gas loads for 2005 and the Mount Washington high pressure system operating at 275 psig.
- Approximately 60-65 MCFH of gas load can be added to the 6-inch high pressure pipeline near Clermont while maintaining approximately 56 psig at Boston, Kentucky with the proposed total connected gas loads and the Mount Washington high pressure system operating at 275 psig.
- LG&E can meet gas load projections until 2016 with a 2% residential and commercial load growth projection and the Shepherdsville gas distribution system uprated to 60 psig. A pipeline reinforcement project will need to be completed by November 1, 2016.
- LG&E can meet gas load projections until 2012 with a 4% residential and commercial load growth projection and the Shepherdsville gas distribution system uprated to 60 psig. A pipeline reinforcement project will need to be completed by November 1, 2012.

XVII. Mt. Washington/Lebanon Junction High Pressure Distribution System (cont'd)

- LG&E can meet gas load projections until 2011 with a 5% residential and commercial load growth projection and the Shepherdsville gas distribution system uprated to 60 psig. A pipeline reinforcement project will need to be completed by November 1, 2011.

Recommended Gas System Reinforcements

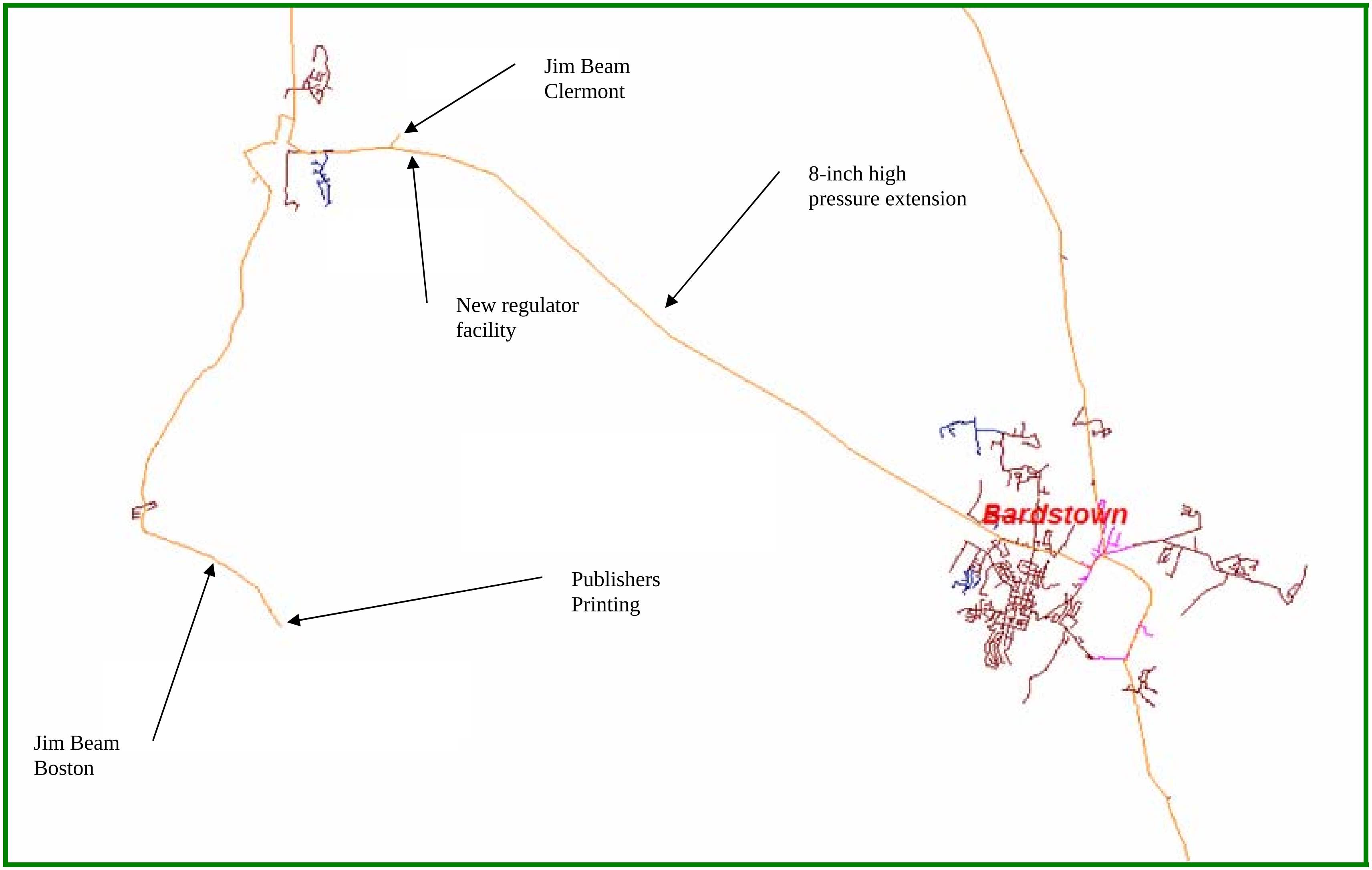
Reinforcement 1
Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line in Bardstown, KY, along Hwy 245 to Clermont, serving south to Lebanon Junction. This would require installing approximately 14.0 miles of 8-inch high-pressure (400 MAOP) piping and a new regulator facility near the Jim Beam Clermont Distillery on Hwy 245. This system reinforcement would solve current and future pressure problems as well as eliminating other risk factors by adding an additional gas supply to a dead end system.

Based on the projected load growth resulting from the two new business parks in the Shepherdsville area, Heritage Hills subdivision, Jim Beam in Boston, and Publishers Printing in Lebanon Junction, along with projected 4% growth from existing residential and commercial customer base a new pipeline is projected to be required in 2012.

Recommended Timeline – 2012-2016

Note: For further information regarding proposed reinforcements to this system, see Section XXII.

Mt. Washington High Pressure Distribution System – Reinforcement 1



XVIII. Shepherdsville/Northern Bullitt County Medium Pressure System

Gas System Overview
The Shepherdsville/Northern Bullitt medium pressure gas system serves residential and commercial customers in the City of Shepherdsville and outlying areas between I-265 and Hwy 44.

Gas System Reinforcement Completed In 2006
Separated the Shepherdsville/Northern Bullitt system from the Jefferson County system, and uprated the Shepherdsville medium pressure gas distribution system to 60 psig.

Regulator Facilities
The regulator facilities that supply gas to the Shepherdsville/Northern Bullitt medium pressure system are as follows:

- Regulator pit at Lee's Lane and Highway 44
- Regulator pit at Cedar Grove Road and I-65
- Regulator pit at Mud Lane and Antle Drive
- Regulator pit at Old Bardstown Road and Thixton Lane
- Regulator pit at Vista Hills Blvd and Calvary Line

Maximum Allowable Operating Pressure
The Shepherdsville/Northern Bullitt medium pressure gas system has a maximum allowable operating pressure of 60 psig.

Model Results

Minimum Gas System Pressure (-12 ^{0}F)
The predicted minimum gas system pressure for this medium pressure system is located at **Arbor Creek Drive (14.57 psig)**

Regulator Operating Capacities
- Hwy 44 and Lee's Ln – **59.50%**
- Cedar Grove Rd and I-65 – **27.53%**
- Mud Ln and Antle Dr – **100%**
- Old Bardstown Rd and Thixton Ln – **11.23%**
- Vista Hills Blvd and Calvary Line – **75.74%**

Gas System Constraints
Gas system constraints in this area are due to an infrastructure of small diameter pipe in the Thixton Lane and Cedar Creek Road areas in the northeastern portion of this system. There is also a severe lack of redundancy in this area which is adding to the pressure problems. Making the system more redundant in this area would prevent outages due to third-party damage or other causes.

A public works project is planned to widen (and reroute) a portion of Preston Hwy between Shepherds Way and Hebron Ln.

XVIII. Shepherdsville/Northern Bullitt County Medium Pressure System (cont'd)

Recommended Gas System Reinforcements:

Reinforcement 1
Install approximately 4,200 feet of 6-inch plastic main on Thixton Lane from Taylor Rae Drive south to the existing 6-inch plastic main located near 8506 Thixton Lane.

Minimum gas system pressure (-12 ^{0}F)
- Arbor Creek Dr – **29.66 psig**

Regulator Operating Capacities
- Hwy 44 and Lee's Ln – **56.51%**
- Cedar Grove Rd and I-65 – **26.55%**
- Mud Ln and Antle Dr – **100%**
- Old Bardstown Rd and Thixton Ln – **12.10%**
- Vista Hills Blvd and Calvary Line – **76.81%**

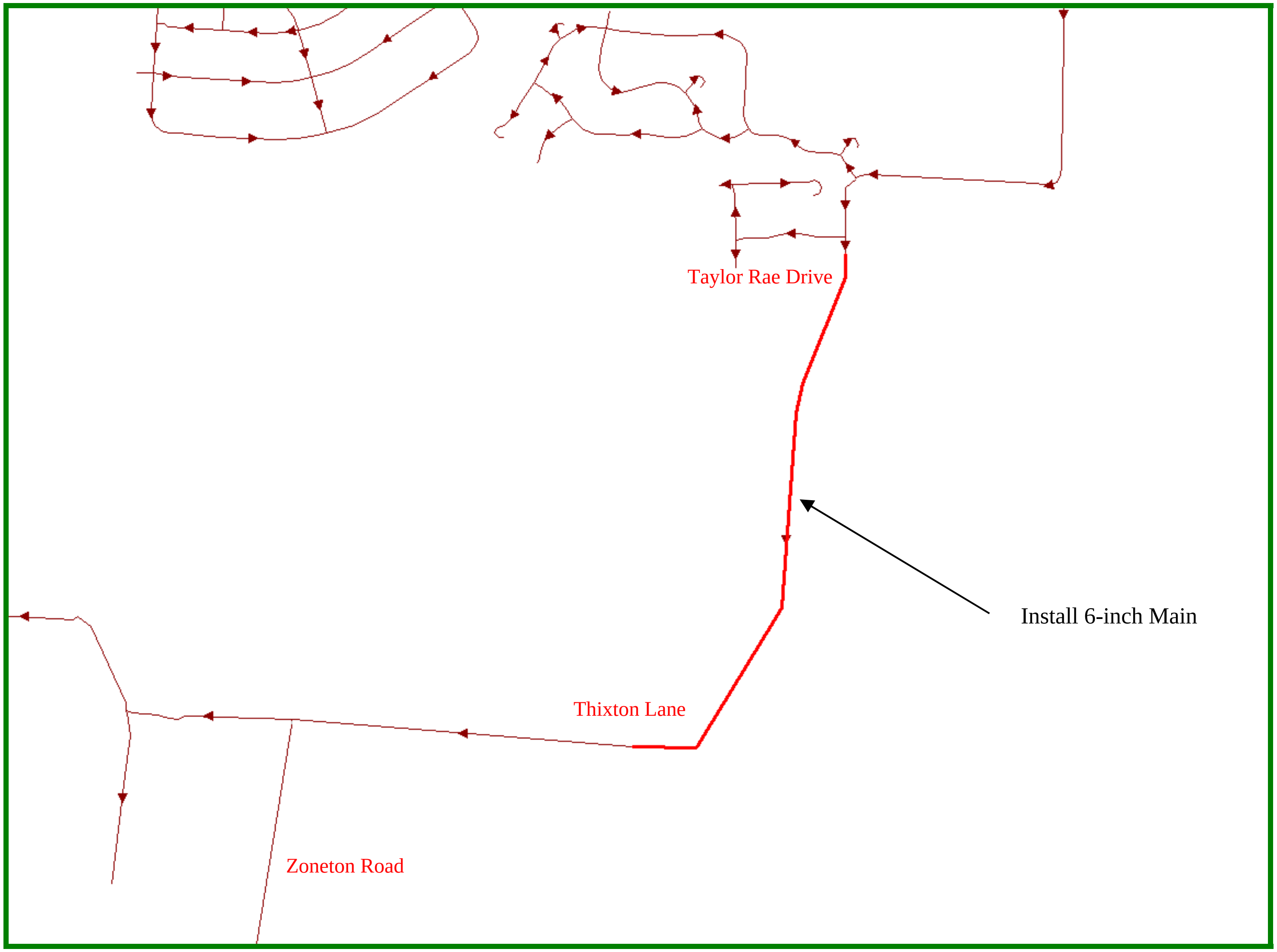
Recommended Timeline – 2009-2012

Reinforcement 2
- Extend 1,700 feet of 6-inch plastic main from John D. Harper Blvd to Cobblestone Way to serve customers and the subdivision disconnected from the 8-inch main on Preston Hwy.
- Extend 1,500 feet 4-inch plastic main from John D Harper Blvd south to Hebron Lane.
- Extend 500 feet of 6-inch main from Lodie Lane, across Preston Hwy, and reconnect to the Cobblestone Way 6-inch main

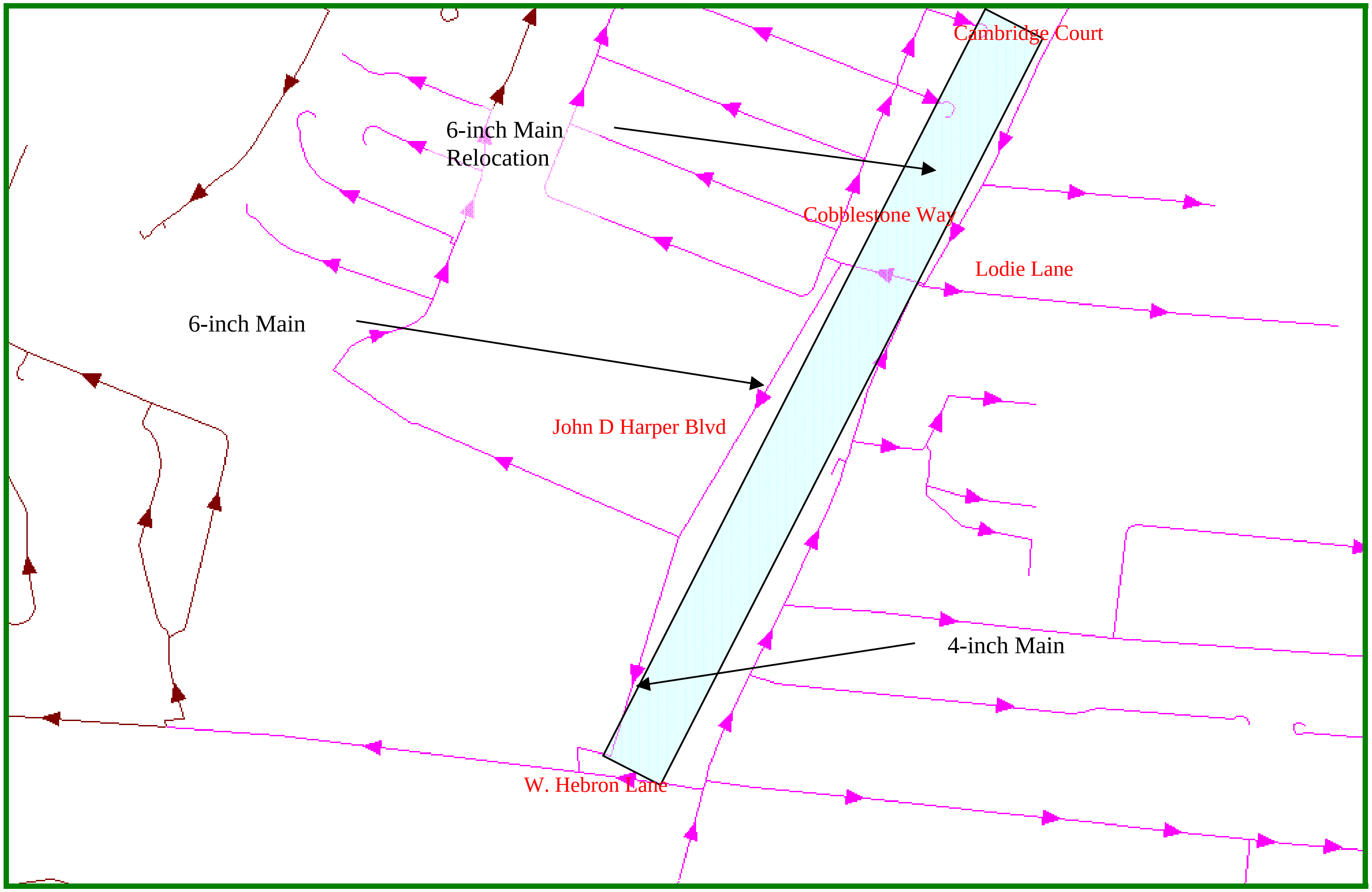
Minimum gas system pressure (-12 ^{0}F)
- John D Harper Blvd/ Enterprise Dr – **37.97 psig**
- Cambridge Ct – **38.40 psig**

Recommended Timeline – Concurrent with the highway work along Preston Highway.

Shepherdsville/N. Bullitt Medium Pressure System – Reinforcement 1



Shepherdsville/N. Bullitt Medium Pressure System – Reinforcement 2



XIX. Brandenburg High Pressure System

Gas System Overview
The Brandenburg high-pressure distribution system serves the cities of Brandenburg and Doe Valley, and the surrounding area. Gas is supplied from Doe Run storage field lines at Riggs Junction. The Brandenburg area continues to experience residential and commercial growth.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum pressure is at the inlet of the regulator pit serving the Brandenburg medium-pressure system located at **Old US 60 and Highway 933 (100.36 psig)**.

XX. Radcliff/Fort Knox Medium Pressure System

Gas System Overview
The Radcliff/Fort Knox medium pressure system serves approximately 4,800 residential and small commercial services. Currently only two customers on the system require delivery pressure above 2 psig: Cardinal Health at 2 psig and Tri-County Ford at 2.5 psig. Due to Base Realignment and Closure (BRAC) changes at Fort Knox, it is anticipated that approximately 3,500 military employees will be relocating to the Radcliff/ Fort Knox area over the next 8 years.

Gas System Reinforcement Anticipated in 2007
A new asphalt plant has requested gas at the site of the old Certified Construction Company at 1991 Illinois Avenue. The total connected load for the customer will be 75,000 cfh. The proposed reinforcement option will run 6-inch medium pressure main from the Radcliff #1 pit to the existing main on Northern Rd.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Radcliff #1 at the corner of N Dixie Blvd and Northern Rd.
- Radcliff #2 at the intersection of S Logsdon Parkway and W. Vine Street.

Maximum Allowable Operating Pressure
The Radcliff/Fort Knox medium pressure system has a maximum allowable operating pressure of 35 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure is located at 151 E Lincoln Trail Blvd (28.47 psig). Another low pressure point is at the end of Hood Ln in the Yarwood Mobile Home Park (28.68 psig)

Regulator Operating Capacity (includes asphalt plant load):
- Radcliff #1: 19.61% (35.65%)
- Radcliff #2: 69.18% (71.37%)

Gas System Constraints
The two gas supply points for this system are located centrally and on the northeastern end of the system. Rapid system expansion due to BRAC relocations is expected to tax the existing infrastructure. Any significant load increase off St. Andrews Dr will require significant reinforcement.

XX. Radcliff/Fort Knox Medium Pressure System (cont'd)

Recommended Gas System Reinforcement

Reinforcement 1

- Replace existing regulators in Radcliff #2 with 4x3 Mooney assemblies with 100% plates.
- Uprate the system from 35 psig to 60 psig. This uprate consists of approximately 4,600 service laterals and approximately 3,600 customers. There is a total of 78.5 miles of pipeline of which 9.1 miles is plastic and 69.4 miles is protected steel.

Note: Additional BRAC load was estimated to be 240 MCFH based on anticipated number of new residences and current load.

Minimum gas system pressure (-12°F)
Hood Ln in the Yarwood Mobile Home Park (46.1 psig)

Regulator Operating Capacities

- Radcliff #1 – 55.91%
- Radcliff #2 – 18.62%

Recommended Timeline – 2008-2012

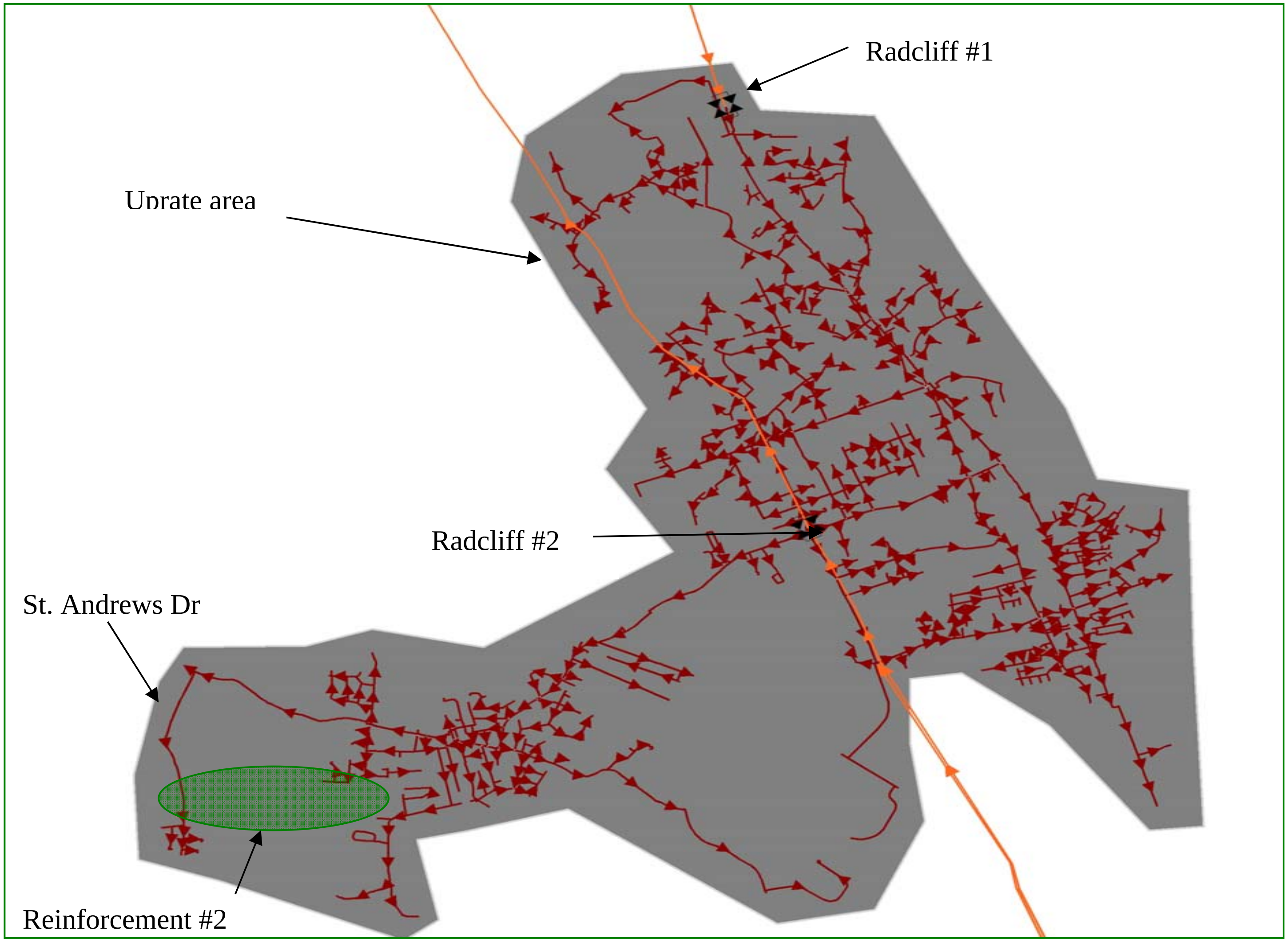
Reinforcement 2

- Install 4,800' of 4-inch PL main in Otter Creek Rd from existing 4-inch CT to 2-inch PL in St. Andrews Dr.

Note: Reinforcement needed only for significant development off St. Andrews Drive.

Recommended Timeline – TBD

Radcliff/Fort Knox – Reinforcement 1 & 2



XXI. Persimmon Ridge/Polo Fields Medium Pressure System

Gas System Overview

The 50 psig medium pressure system near Persimmon Ridge and the Polo Fields has experienced growth away from the only sources of gas in this system. In order to serve current and future loads, it has been determined that reinforcement work will need to be performed on the Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System. There are a few options available that will provide adequate pressures throughout the system.

Regulator Facilities

The regulator facilities that feed this system are as follows:

- Regulator pit at English Station Way
- Regulator pit at Old Henry Rd and Terra Crossing Blvd (Old Henry MP)
- Regulator assembly at Conner Station Rd

Maximum Allowable Operating Pressure

The Persimmon Ridge/Polo Fields medium pressure system has a maximum allowable operating pressure of 50 psig.

Model Results

Minimum Gas System Pressures (-12 ^{0}F)

- 121 Persimmon Ridge Drive – **-45.11** psig
- 17009 Bowline View Trail – **-46.65** psig
- 1601 Keever Court – **-47.70** psig

Note: The system cannot adequately serve the Polo Fields, Persimmon Ridge, and Fox Run under current conditions.

Regulator Operating Capacities

- English Station Way – **54.73**%
- Old Henry MP – **15.69**%
- Conner Station & Colt Run Rd – **6.07**%

Recommended Gas System Reinforcements

Reinforcement Option 1

Loop approximately 7,150 feet of existing 4-inch medium pressure steel and plastic main with 6-inch plastic main along State Hwy 362 (Ash Avenue) from LaGrange Road, southeast to the existing 6-inch plastic main near Ashbrooke Drive.

Minimum gas system pressure (-12 ^{0}F)

- 121 Persimmon Ridge Drive – **-25.17** psig
- 17009 Bowline View Trail – **-28.68** psig
- 1601 Keever Court – **-32.41** psig

XXI. Persimmon Ridge/Polo Fields Medium Pressure System (cont'd)

Reinforcement Option 1a
This reinforcement would be the same as Option 1, but instead of using 6-inch plastic main for the loop, 8-inch plastic main would be used.

Minimum gas system pressure (-12 ^{0}F)
- 121 Persimmon Ridge Drive – **-19.69** psig
- 17009 Bowline View Trail – **-25.53** psig
- 1601 Keever Court – **-30.25** psig

Reinforcement Option 2
Loop approximately 3,050 feet of 4-inch medium pressure steel main with 8-inch plastic main along LaGrange Road from the existing 8-inch steel main near Altawood Court, northeast to State Hwy 362 (Ash Avenue).

Minimum gas system pressure (-12 ^{0}F)
- 121 Persimmon Ridge Drive – **-34.84** psig
- 17009 Bowline View Trail – **-37.23** psig
- 1601 Keever Court – **-39.25** psig

Reinforcement Option 3
This option would combine the main replacements from Option 1/1a and Option 2. For this option we would need to install 3,050 feet of 8-inch plastic main and 7,150 feet of 6-inch or 8-inch plastic main for a total of 10,200 feet of plastic main.

Minimum gas system pressure with Option 1 & 2 (-12 ^{0}F)
- 121 Persimmon Ridge Drive – **8.50** psig
- 17009 Bowline View Trail – **5.29** psig
- 1601 Keever Court – **0.48** psig

Minimum gas system pressure with Option 1a & 2 (-12 ^{0}F)
- 121 Persimmon Ridge Drive – **11.05** psig
- 17009 Bowline View Trail – **7.95** psig
- 1601 Keever Court – **3.54** psig

Reinforcement Option 4
This option would require the installation of approximately 5,300 feet of 6-inch medium pressure plastic main along Flat Rock Road between Robin Lane and Curry Branch Road.

Minimum gas system pressure with Option 1 & 2 (-12 ^{0}F)
- 121 Persimmon Ridge Drive – **-38.79** psig
- 17009 Bowline View Trail – **-40.07** psig
- 1601 Keever Court – **-44.13** psig

XXI. Persimmon Ridge/Polo Fields Medium Pressure System (cont'd)

Reinforcement Option 5
See Section VI Old Henry Road Development for more information regarding this reinforcement.

Minimum gas system pressure (-12 ^{0}F)
- 121 Persimmon Ridge Drive – **23.97** psig
- 17009 Bowline View Trail – **20.73** psig
- 1601 Keever Court – **17.23** psig

Reinforcement Option 6
This option would require looping approximately 6,300 feet of 4-inch medium pressure steel main with 8-inch plastic main along Shelbyville Road beginning at the existing 8-inch steel main near Waterstone Way, east to Flat Rock Road.

Minimum gas system pressure (-12 ^{0}F)
- 121 Persimmon Ridge Drive – **-2.98** psig
- 17009 Bowline View Trail – **0.98** psig
- 1601 Keever Court – **-1.35** psig

Reinforcement Option 7
This reinforcement project combines Option 4 and Option 6. The main needed for this project would be 6,300 feet of 8-inch plastic and 5,300 feet of 6-inch plastic for a total of 11,600 feet of plastic main.

Minimum gas system pressure (-12 ^{0}F)
- 121 Persimmon Ridge Drive – **15.73** psig
- 17009 Bowline View Trail – **16.86** psig
- 1601 Keever Court – **13.96** psig

Reinforcement Option 8
This reinforcement project combines Options 1a, 2, 4, and 6. The main needed for this project would be 16,500 feet of 8-inch plastic main and 5,300 feet of 6-inch plastic main for a total of 21,800 feet of plastic main.

Minimum gas system pressure (-12 ^{0}F)
- 121 Persimmon Ridge Drive – **25.72** psig
- 17009 Bowline View Trail – **25.97** psig
- 1601 Keever Court – **23.41** psig

XXI. Persimmon Ridge/Polo Fields Medium Pressure System (cont'd)

Reinforcement Option 9

This is the same reinforcement work as Option 8 with the addition of the Old Henry Road extension (Option 5). This project would require approximately 23,300 feet of 8-inch plastic and 5,300 feet of 6-inch plastic main for a total of 28,600 feet of plastic main.

Minimum gas system pressure (-12 ^{0}F)

- 121 Persimmon Ridge Drive – **32.72** psig
- 17009 Bowline View Trail – **31.98** psig
- 1601 Keever Court – **29.52** psig

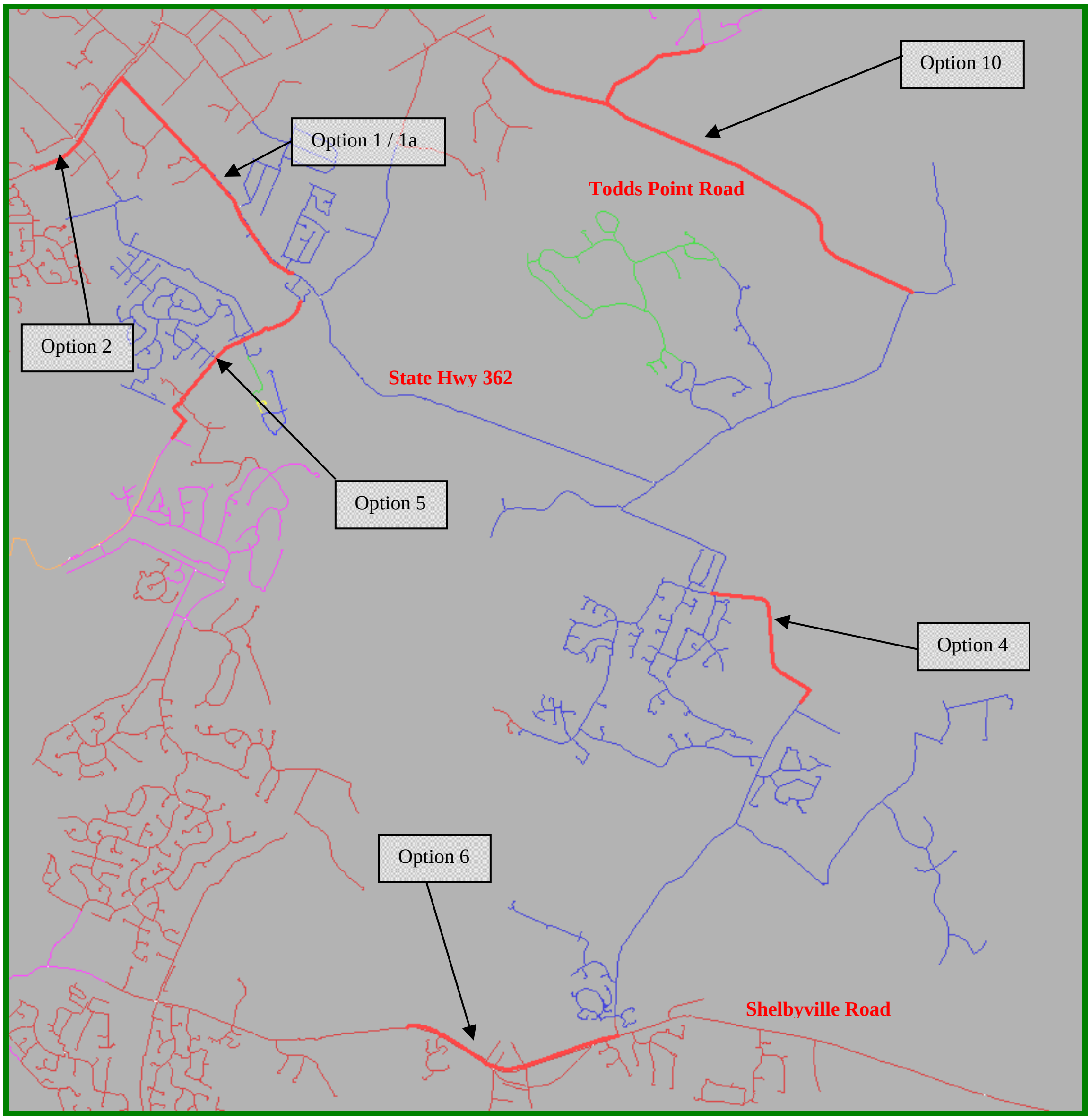
Reinforcement Option 10

This option requires installing approximately 13,400 of 6-inch plastic main on Todds Point Road from the existing 4-inch plastic main near Chapel Drive, southeast to the existing 6-inch plastic main on Aiken Road. Also, an additional 3,400 feet of 6-inch plastic main would need to be installed on State Hwy 1818 from Todds Point Road, northeast to Abbott Lane to connect with a small existing 35 psig system. This existing system would have to be uprated from 35 psig to 50 psig, and the orifice plates at the Abbotts Ln & Myers Ln regulator assembly would need to be changed to 1/2". This option would require installing a total of 16,800 feet of 6-inch plastic main and would require uprating the system consisting 116 services from 35 psig to 50 psig. While this option may not be currently feasible, it would provide another feed into this area and allow for additional growth.

Minimum gas system pressure (-12 ^{0}F)

- 121 Persimmon Ridge Drive – **30.88** psig
- 17009 Bowline View Trail – **25.56** psig
- 1601 Keever Court – **21.25** psig

Persimmon Ridge/Polo Fields Reinforcement Options 1-10



- Option 3: Combines Option 1/1a and Option 2
- Option 7: Combines Option 4 and Option 6
- Option 8: Combines Option 1a, 2, 4, and 6
- Option 9: Combines Option 1a, 2, 4, 5, and 6

XXII. Appendix – Mt. Washington High Pressure Distribution System

Options Considered
An attempt was made to parallel the existing 8-inch and 6-inch piping in order to solve the pressure and capacity problems. Almost the entire route (approximately 21 miles) of the system would have to be paralleled in order to correct the pressure and capacity problems.

Scenario 1
Install a high-pressure system reinforcement that would bring high-pressure gas from the Preston Highway regulator station to the Shepherdsville regulator pit at Lee Lane and Highway 44 (approximately 12.5 miles). In addition, the existing 6-inch piping (approximately 12 miles) would have to be paralleled in order to alleviate the restriction to moving the gas to the south end of the system.

Scenario 2
Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line in Bardstown, KY, along Hwy 245 to Clermont, serving south to Lebanon Junction. This would require installing approximately 14.0 miles of 8-inch high-pressure (400 psig MAOP) piping and a new regulator facility near the Jim Beam Clermont Distillery on Hwy 245. This system reinforcement would solve current and future pressure problems as well as eliminating other risk factors by adding an additional gas supply to a dead end system.

Scenario 3
Install a high-pressure system reinforcement that would bring high-pressure gas from the Magnolia line to the south end of the system. This would require installing approximately 13 miles of 8-inch high-pressure (520 psig MAOP) piping along Highway 434 and a new regulator assembly at the south end of the system. This system reinforcement would correct the current and future pressure and capacity problems by providing a new gas supply in the areas where there is the largest load concentration. In addition, the system reinforcement would provide a second gas supply to the model thus eliminating the risks associated with a dead end system.

XXI. Appendix – Mt. Washington High Pressure Distribution System (cont'd)

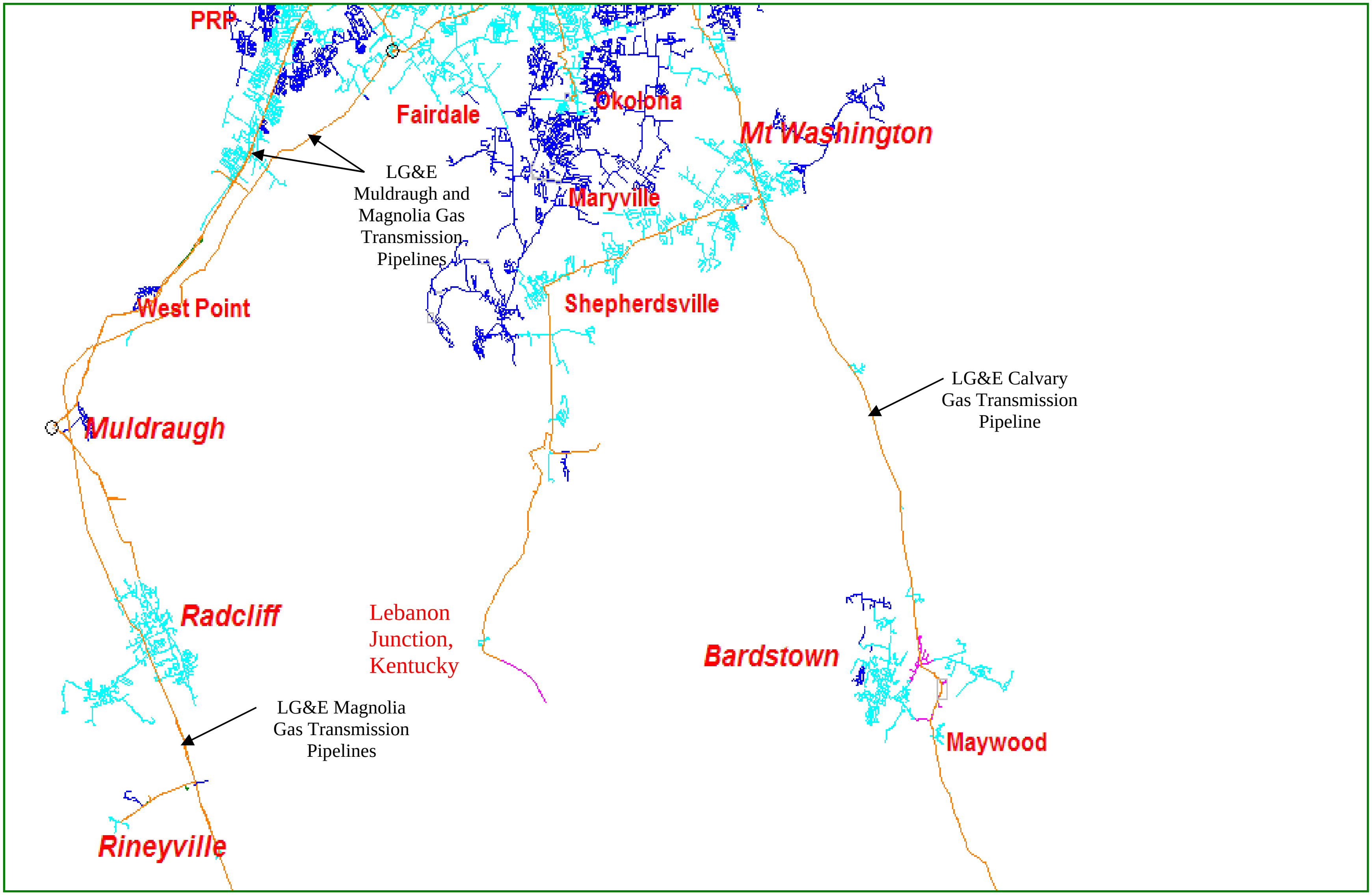
Scenario 4

Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line to the south end of the system. This would require installing approximately 16 miles of 8-inch high-pressure (400 psig MAOP) piping and a new regulator assembly at the south end of the system. This system reinforcement would correct the current and future pressure and capacity problems by providing a new gas supply in the areas where there is the largest load concentration. In addition, the system reinforcement would provide a second gas supply to the model thus eliminating the risks associated with a dead end system.

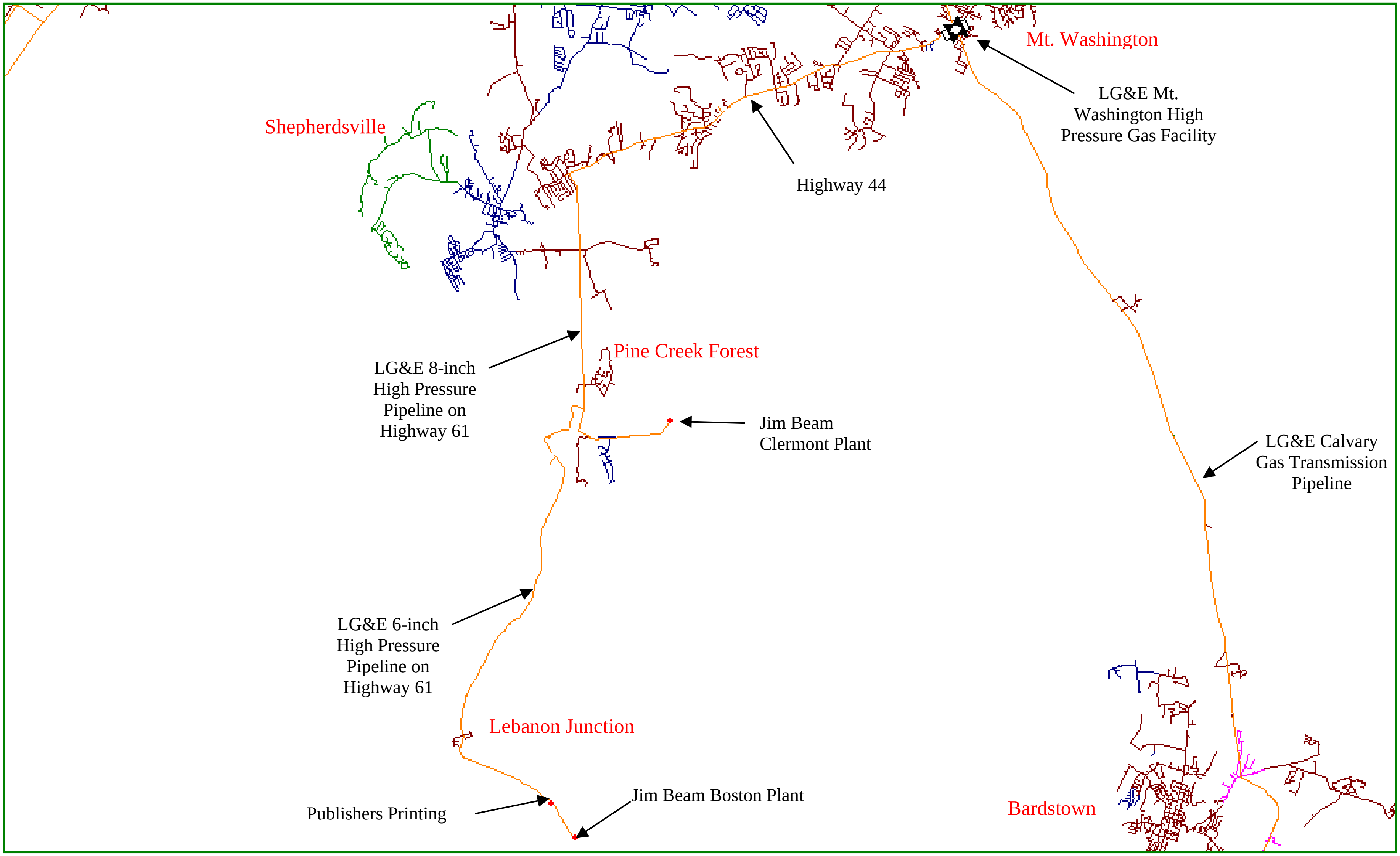
Scenario 5

Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line along Hwy 509 and Hwy 245 into Lebanon Junction. This would require installing approximately 12.5 miles of 8-inch high-pressure (400 psig MAOP) piping and a new regulator facility near the Jim Beam Distillery on Hwy 245. This system reinforcement would solve current and future pressure problems as well as eliminating other risk factors by adding an additional gas supply to a dead end system.

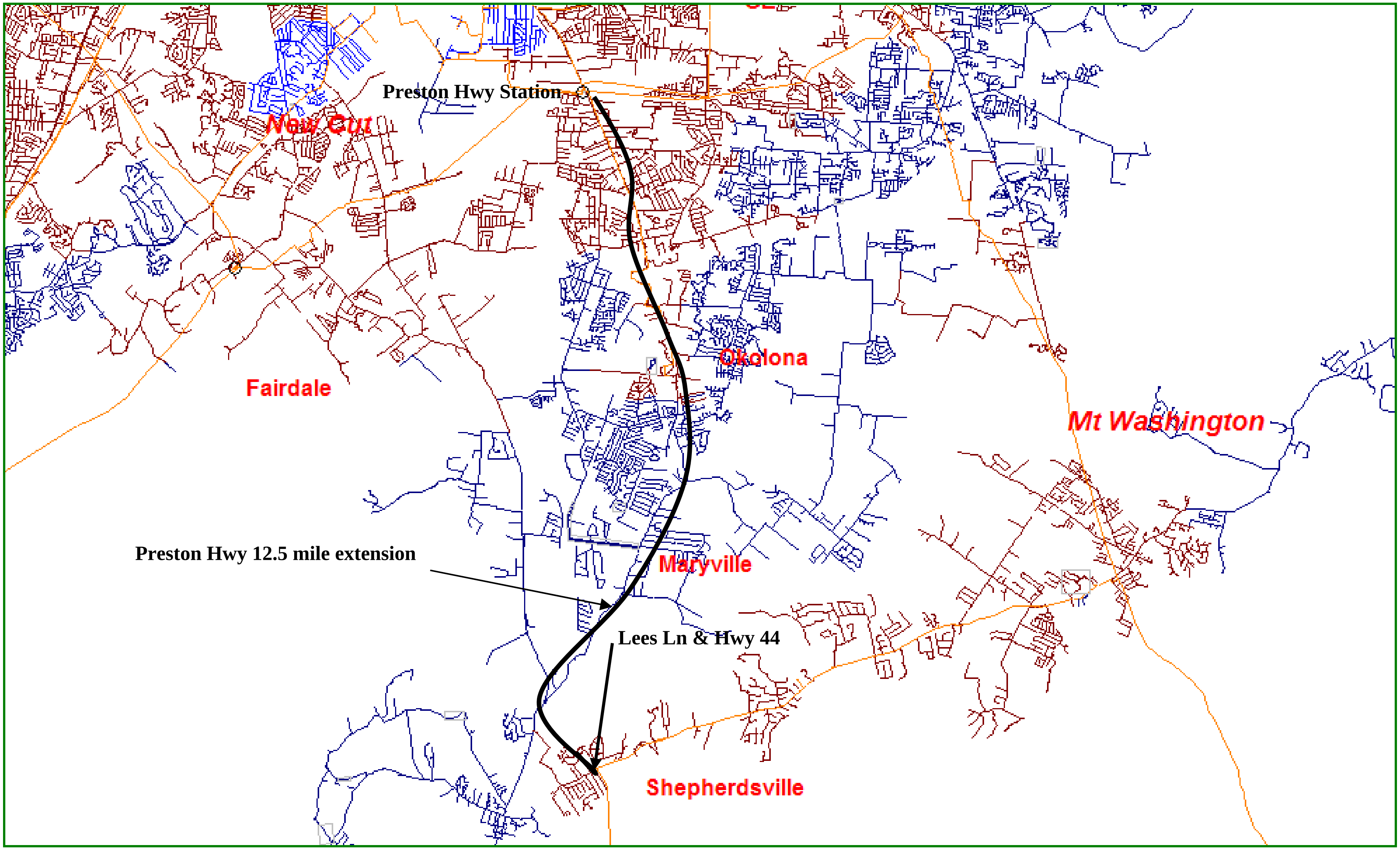
Mt. Washington High Pressure Distribution System – Overview



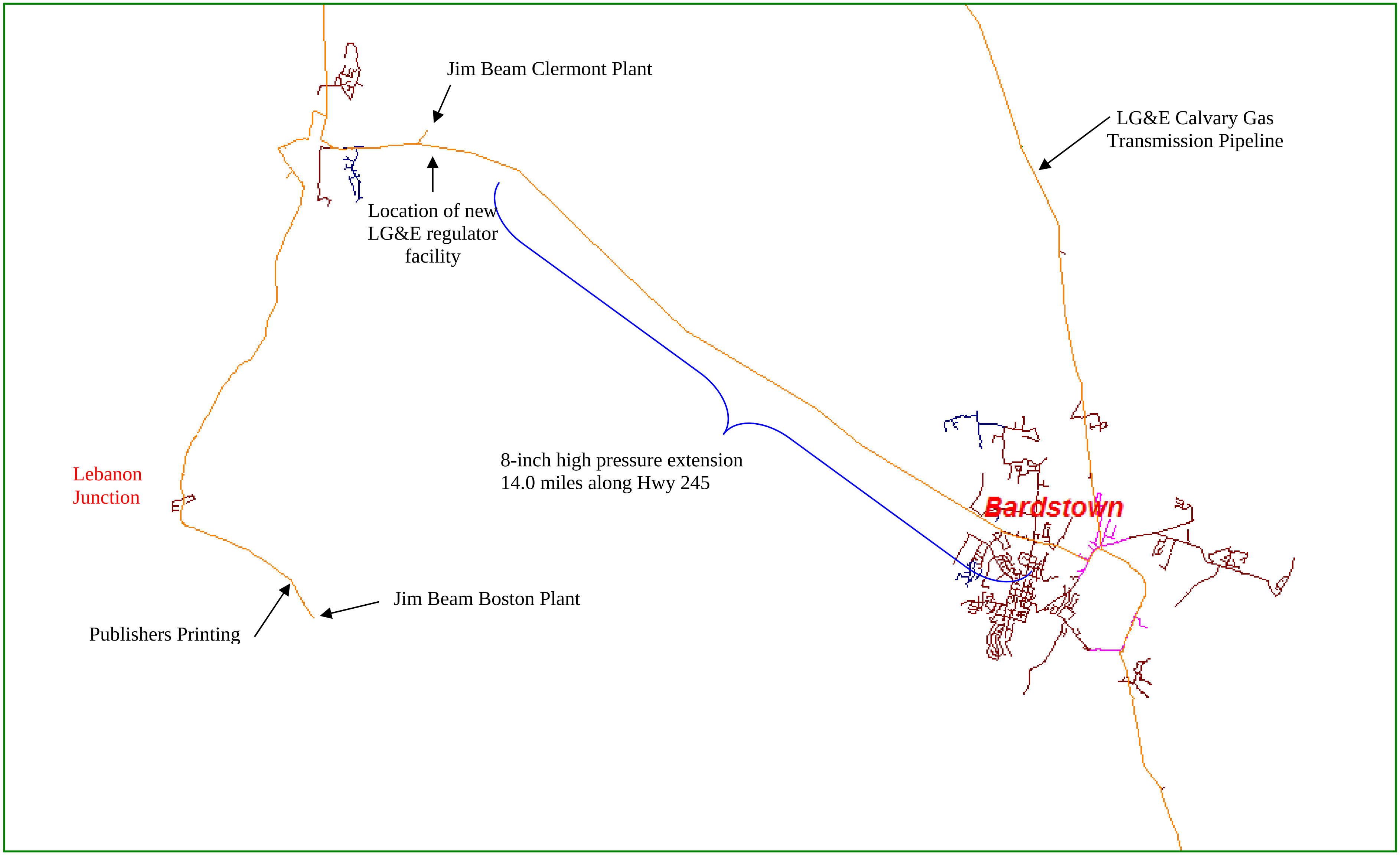
Mt. Washington High Pressure Distribution System – Mt. Washington Overview



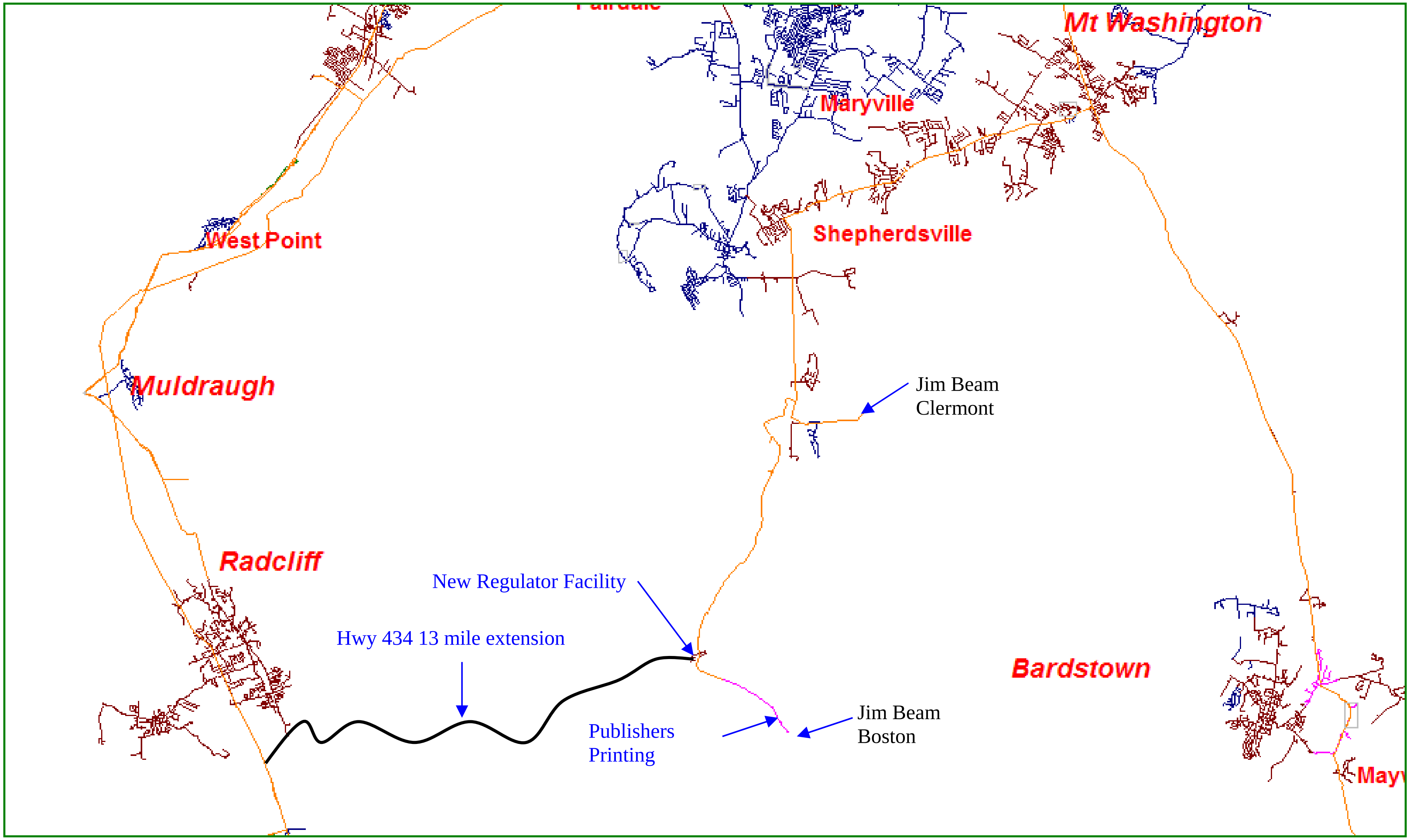
Mt. Washington High Pressure Distribution System – Scenario 1



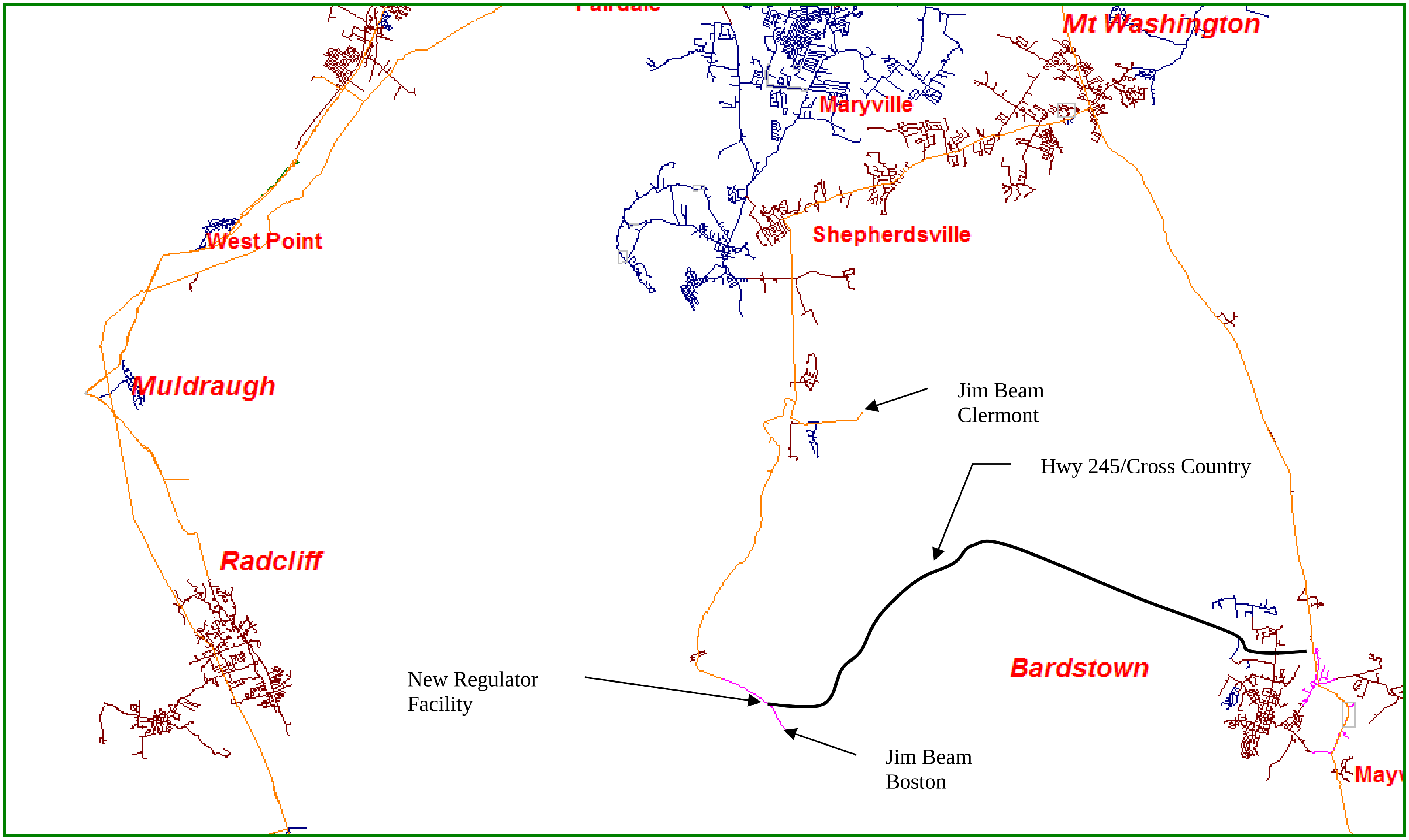
Mt. Washington High Pressure Distribution System – Scenario 2



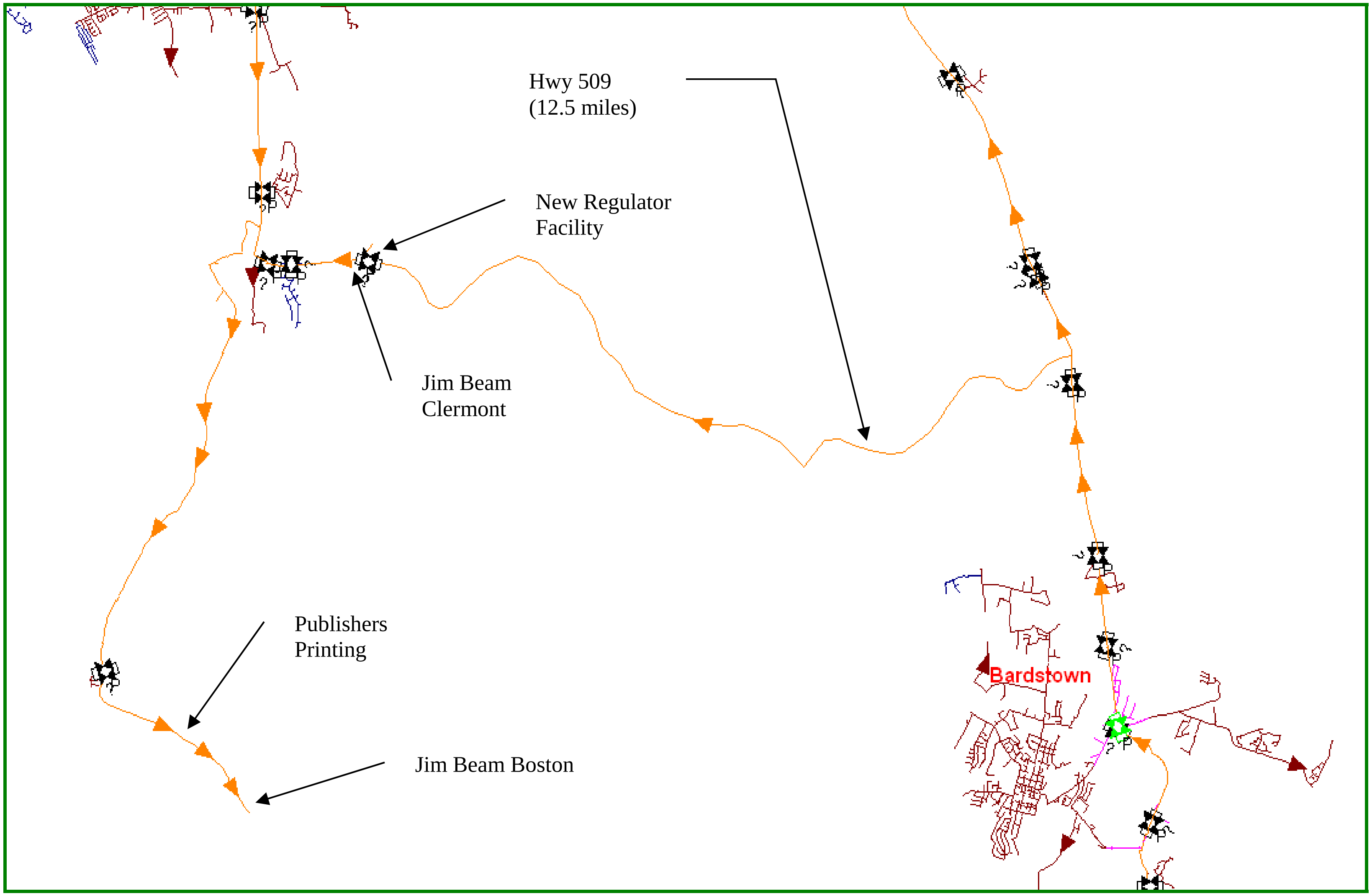
Mount Washington/Lebanon Junction High Pressure Gas System – Scenario 3



Mt. Washington High Pressure Distribution System – Scenario 4



Mt. Washington High Pressure Distribution System – Scenario 5



Louisville Gas and Electric

Gas System Planning
Ten-Year Gas Construction Plan

July 2008

Table of Contents

I. Crestwood-Eminence-Bedford High Pressure Distribution System

Gas System Overview
The Crestwood-Bedford high-pressure distribution system serves the Crestwood area, Smithfield, Campbellsburg, and Bedford. It is fed by the Elder Park, Bedford, and Crestwood city gate stations. The system serves a small number of large industrial and commercial customers, including Safety Kleen, Steel Technologies, Rosehill Greenhouses, and Hussey Copper.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Elder Park City Gate Station
- Crestwood City Gate Station
- Bedford City Gate Station

Maximum Allowable Operating Pressure
From Crestwood to Eminence, the Crestwood-Bedford high-pressure system has a maximum allowable operating pressure of 350 psig. From Eminence to Bedford, it has a maximum allowable operating pressure of 380 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure is at 4021 Hwy 146 **(70.4 psig).**

Regulator Operating Capacities
- Elder Park City Gate Station – **21.6%**
- Crestwood City Gate Station – **67.8%**
- Bedford City Gate Station **– 73.1%**

Gas System Constraints
The system is composed primarily of 4-inch pipeline, limiting the system's capacity for expansion.

I. Crestwood-Eminence-Bedford High Pressure Distribution System (cont'd)

Recommended Gas System Reinforcements

Reinforcement 1
Connect the Ballardsville gas transmission line to the Crestwood-Bedford HP system with 5,900 feet of 8" steel gas transmission pipeline along Hwy 53 from Moody Lane to Hwy 22. **NOTE:** Reinforcement done as part of Section II Reinforcement 2.

Minimum Gas System Pressure (-12°F)
- 4021 Hwy 146 – **171.1 psig**

Regulator Operating Capacities
- Bedford City Gate Station – **57.9%**

Recommended Timeline – 2009-2012

Reinforcement 2
Remove the Eminence high pressure regulator pit and replace with a full port motor operated ball valve at that location.

If the Eminence high pressure regulator pit was to fail, approximately 1,693 customers in the Eminence and New Castle areas would be lost. Installing a motor operated ball valve at the Eminence station could help prevent this loss of service. This ball valve could also be used to isolate either side of the Crestwood–Bedford line should a failure occur.

Minimum Gas System Pressure (-12°F)
- Inlet to Pleasureville – **68.7 psig**

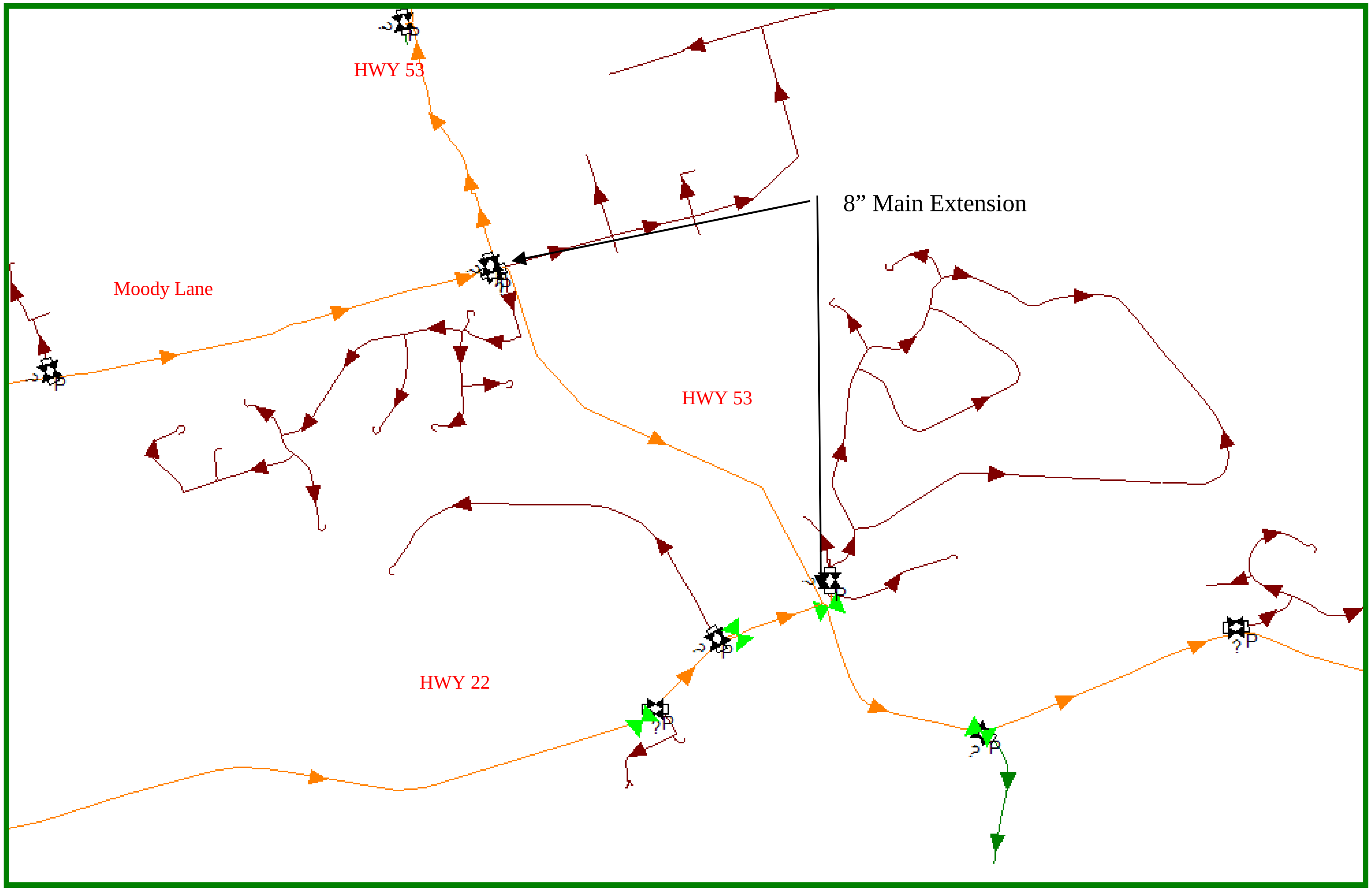
Regulator Operating Capacities
- Bedford City Gate Station – **73.4%**
- Crestwood City Gate Station – **57.8%**

Recommended Timeline – 2009-2010

Reinforcement 3
- Install a new city gate station near L'Esprit Farms at the intersection of E Hwy 146 and Lake Jericho. This station will be fed from the Texas Gas Transmission pipeline.
- Extend approximately 4 miles of high pressure steel pipeline southwest along E Hwy 146 to connect with the Elder Park/Ballardsville Line.
- Extend approximately 5.4 miles of high pressure steel pipeline southeast along Hwy 153 (Lake Jericho to connect with Crestwood-Bedford HP line at Smithfield Rd).

Recommended Timeline – 2018

Crestwood-Eminence-Bedford High Pressure Gas System – Reinforcement 1



II. East End Gate Stations

Gas System Overview
The Elder Park City Gate Station is located on Elder Park Road just east of Highway 393 and serves from Elder Park to Zorn Avenue in Louisville. The Crestwood City Gate Station is located on Highway 22 west of Abbott Lane and serves the area from Lake Forest and Pee Wee Valley to Ballardsville and Eminence. The LaGrange City Gate Station is located on Highway 146 west of Button Lane and serves the City of LaGrange and the Crestwood/Buckner area north of I-71. These systems serve rural, residential, commercial, and small industrial customers.

Maximum Allowable Operating Pressure
The Elder Park system has a maximum allowable operating pressure of 400 psig. The Crestwood system has a maximum allowable operating pressure of 350 psig. East of the La Grange City Gate Station, the LaGrange system has a maximum allowable operating pressure of 100 psig. West of the LaGrange City Gate Station, the LaGrange system has a maximum allowable operating pressure of 200 psig.

Gas System Constraints
If any of these three gate stations was temporarily turned off (e.g., for maintenance or due to an accident), there would be insufficient pressure to serve the system that is fed by that gate station.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure on the Elder Park system is located at the inlet to the **Zorn Ave regulator station (190.9 psig).**

The predicted minimum gas system pressure on the Crestwood system is located at **4021 Hwy 146 (70.35 psig).**

The predicted minimum gas system pressure on the LaGrange system is located at **20 Quality Place (69.0 psig)**.

Regulator Operating Capacities
- Elder Park City Gate Station – **21.6%**
- Crestwood City Gate Station – **67.8%**
- LaGrange City Gate Station – **33.9%**

Recommended Gas System Reinforcements

Recommended Gate Station Operating Conditions
- Operate the Elder Park City Gate Station at 350 psig
- Operate the Crestwood City Gate Station at 350 psig
- Operate the LaGrange City Gate Station at 90 psig

II. East End Gate Stations (cont'd)

Reinforcement 1
Connect the Elder Park system to the Crestwood system

- Connect the Elder Park line to the Crestwood line via Hwy 393 with approximately 4,770 feet of 8-inch pipeline.
- Connect the Elder Park line to the Crestwood line via Hwy 53 with approximately 5,900 feet of 8-inch pipeline

Minimum Gas System Pressure (-12°F)
- Zorn Inlet – **256.7 psig**
- 4021 Hwy 146 – **171.1 psig**

Regulator Operating Capacities
- Elder Park City Gate Station – **24.7%**
- Crestwood City Gate Station – **35.2%**
- LaGrange City Gate Station – **34.5%**

Recommended Timeline – 2009-2012

Reinforcement 2
Connect the Elder Park system to the LaGrange system

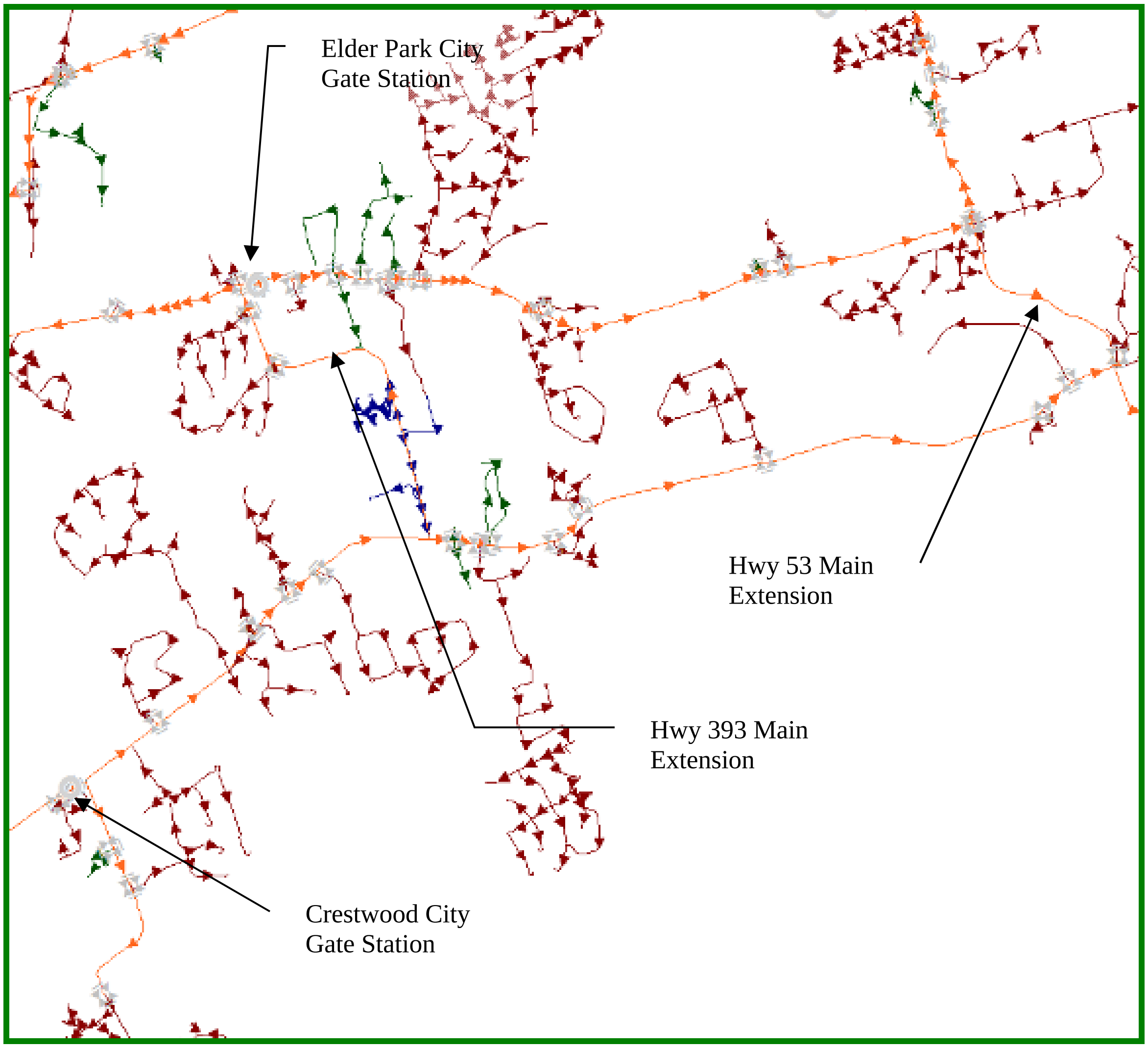
- Connect the Elder Park line to the LaGrange line via Hwy 393 with approximately 6,600 feet of 8-inch pipeline.
- Connect the Elder Park line to the LaGrange line via Hwy 146 and Fox Run Rd with approximately 4,300 feet of 8-inch pipeline.
- Install a new regulator facility at Hwy 393 and Hwy 146 to reduce the pressure from the new pipeline along Hwy 393 to 90 psig.
- Install a new regulator facility at the tie-in point on Fox Run Rd or at Hwy 146 and Quality Place to reduce the pressure from the new pipeline along Hwy 146 and Fox Run Rd to 90 psig.

Minimum Gas System Pressure (-12°F)
- Zorn Inlet – **233.7 psig**
- Pleasureville Inlet – **77.8 psig**
- 4705 Hwy 146 – **37.0 psig**

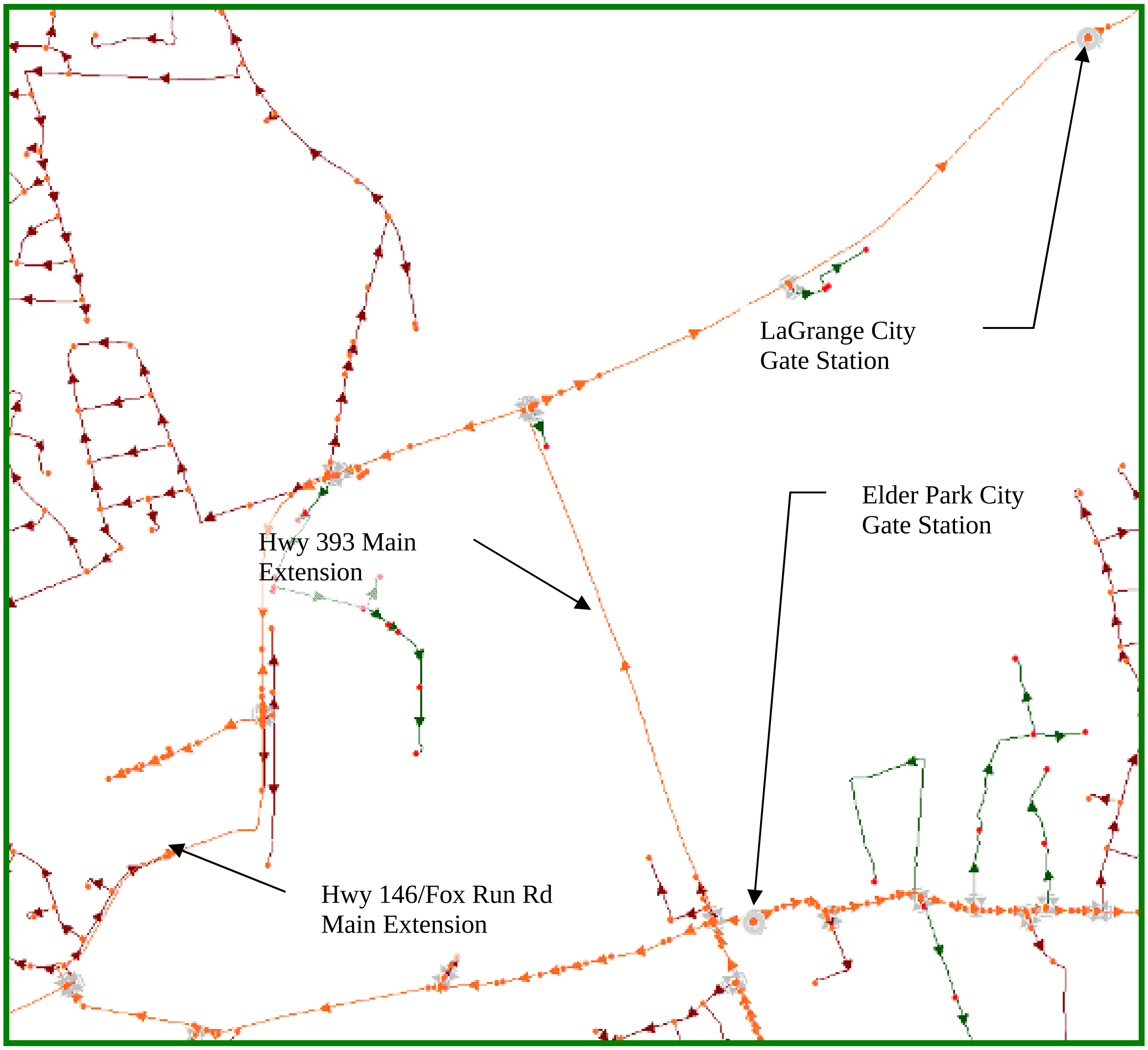
Regulator Operating Capacities
- Elder Park City Gate Station – **26.4%**
- Crestwood City Gate Station – **59.9%**
- LaGrange City Gate Station – **16.9%**

Recommended Timeline – 2009 – 2012

East End Gate Stations – Reinforcement 1



East End Gate Stations – Reinforcement 2



III. East End 30 psig System

Gas System Overview

The East End 30 psig system is a segment of a large medium pressure gas system which serves a portion of the Prospect area. This area is composed primarily of residential and commercial customers. It has continued to experience growth in the residential sectors with homes ranging from 4,000 to 5,000 sq. ft, including the Harrods Glen subdivision and a proposed Wolf Pen development.

Regulator Facilities

The regulator facilities that supplies gas to the Harrods Creek area is as follows:

- The regulator pit at River Rd and Wolf Pen Branch Rd (U.S. Highway 42).

Maximum Allowable Operating Pressure (MAOP)

The Harrods Creek system has a maximum allowable operating pressure of 30 psig.

Model Results

Minimum Gas System Pressure (-12 ^{0}F)

The predicted minimum gas system pressure is located on **Wolfpen Ridge Ct (-1.5 psig)**.

Regulator Operating Capacities

- BLANKENBAKER LN. & RIVER RD. (G-335) – 17.0%
- HUBBARDS LN. & WESTPORT RD. (G-174) – 70.5%
- BROWNS LN. & ALTON RD. (G13149) – 69.0%
- SHERBURN LN.& EASTERN KY. LINE (G-426) – 23.0%
- SHELBYVILLE RD. EAST OF BRAMPTON (G-319) – 100.0%
- GLENVIEW AVE. & RIVER RD. (G-329) – 15.3%
- RIVER RD. & WOLF PEN BRANCH RD. (G-330) – 48.5%
- US 60 AND URTON LN (G397) – 50.7%
- DORSEY LN. & WARD AVE. (G-513) – 42.6%
- LAGRANGE RD. & ENGLISH STATION R (G-398) – 9.5%
- HURSTBOURNE LN. & I-64 (G-439) – 72.2%
- WEST RD. & FREYS HILL RD. (G-492) – 71.0%
- WHIPPS MILL RD. & HOUNZ LN. (G-298) – 74.5%
- SHELBYVILLE RD. & MOSER RD. (G-261) – 71.9%

Gas System Constraints

Gas system constraints are caused by the small diameter piping infrastructure within this area. Due to current and anticipated growth, it will be necessary to perform gas system reinforcement work.

III. East End 30 psig System (cont'd)

Recommended Gas System Reinforcements

Reinforcement 1

Close valve 375163 at Springdale Dr and Barbour Ln. This is a temporary fix for the winter of 2008. This isolates a small subsystem that is fed only by the River Rd & Wolf Pen Branch Rd facility. This needs to be followed in 2009 by Reinforcement 2

Minimum gas system pressure (-12 ^{0}F)

- Wolfpen Ridge Ct (10.6 psig).

Regulator Operating Capacities

- River Rd and Wolf Pen Branch Rd (U.S. Highway 42) – **15.37%**

Recommended Timeline – 2008

Reinforcement 2

Uprate the East End 30 psig system to 50 psig and open valve 375163. This uprate will allow for furture tie-in to the Persimmon Ridge/Polo Fields medium pressure system to the north.

Minimum gas system pressure (-12 ^{0}F)

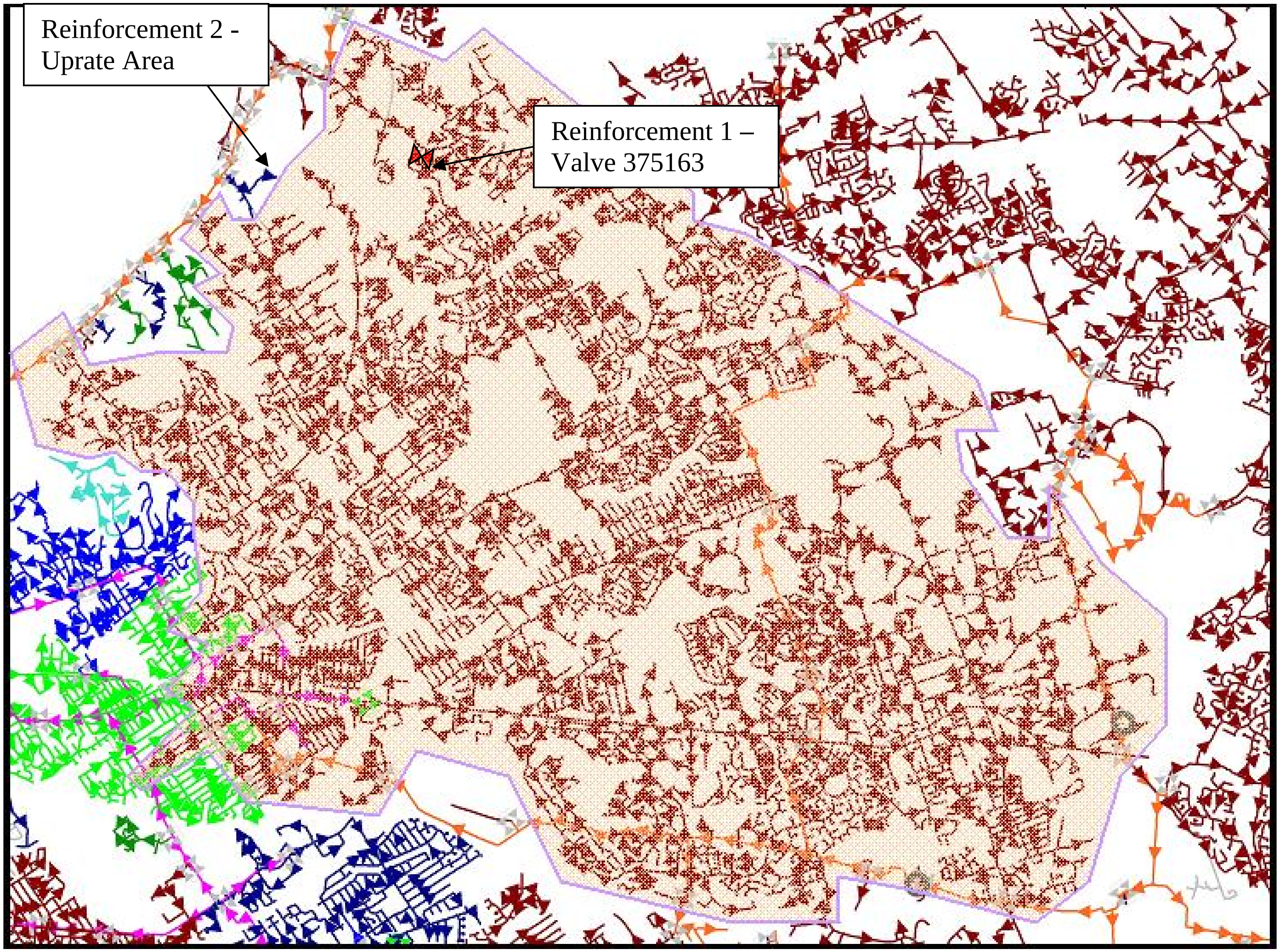
- Wolfpen Ridge Ct (33.2 psig).

Regulator Operating Capacities

- BLANKENBAKER LN. & RIVER RD. (G-335) –13.3%
- HUBBARDS LN. & WESTPORT RD. (G-174) – 98.9%
- BROWNS LN. & ALTON RD. (G13149) – 80.8%
- SHERBURN LN.& EASTERN KY. LINE (G-426) – 27.5%
- SHELBYVILLE RD. EAST OF BRAMPTON (G-319) –100%
- GLENVIEW AVE. & RIVER RD. (G-329) – 12.2%
- RIVER RD. & WOLF PEN BRANCH RD. (G-330) – 39.1%
- US 60 AND URTON LN (G397) – 52.4%
- DORSEY LN. & WARD AVE. (G-513) – 46.2%
- LAGRANGE RD. & ENGLISH STATION R (G-398) – 9.9%
- HURSTBOURNE LN. & I-64 (G-439) – 77.7%
- WEST RD. & FREYS HILL RD. (G-492) – 77.0%
- WHIPPS MILL RD. & HOUNZ LN. (G-298) – 85.7%
- SHELBYVILLE RD. & MOSER RD. (G-261) – 79.1%

Recommended Timeline – 2009

East End 30 psig - Reinforcements 1 & 2



IV. LaGrange Medium Pressure Systems

Gas System Overview
The LaGrange Medium pressure systems are fed from the LaGrange and Elder Park City Gate Stations (see Section II). The system consists of several single-feed systems and one larger, multiple-feed system.

The Oldham County Economic Development Campus (OCEDA) is a 1000+ acre community that will contain office buildings, single and multifamily dwellings, a new school, and mixed use lands. Currently, gas infrastructure does not exist to support this development.

Maximum Allowable Operating Pressure
These subsystems have maximum allowable operating pressures of 10, 30, and 35 psig, as detailed below.

Model Results

Minimum Gas System Pressure (-12°F)

Sub-System MAOP	Location	Pressure
10 psig systems	3500 Mattingly Rd [6447519]	**6.7 psig**
30 psig system	300 blk Crystal Wash Dr[6487436]	**21.9 psig**
35 psig systems	Kamer Ct [6430958]	**28.4 psig**

Regulator Operating Capacities:
35 psig Systems
- HOFFMAN LN & PARKVIEW MANOR TBD – 4.8%
- BUTTON CT & COMMERCE PKWY G-21254 – 15.5%
- ALLEN LN & ARTISAN PKWY TBD – 6.9%
- HWY 53 & CHERRY CREEK DR TBD – 37.2%
- NEW CEDAR POINT RD. & OLD LAGRAN G-364 – 42.5%
- ELDER PARK RD. G-433 – 34.7%
- MOODY LN & HWY 53 G-559 – 24.0%
- E.MOODY LN.& CAL AVE G-593 – 7.3%
- DEER RUN DR G-553 – 15.1%
- GRANGER RD. & HWY.53 G-545 – 21.1%
- PARK RD. & HWY. 53 G-558 – 14.2%
- ZHALE SMITH RD & HWY 53 G-591 – 7.0%
- SPRINGHOUSE ESTATES SECTION 1 G-599 – 42.5%
- HWY 146 & FORT PICKENS RD G13112 – 0.0%
- PRESTWICK DR. & HWY. 53 G13115 – 37.9%
- CRYSTAL DR.& GRANGE DR. G18329 – 22.9%

IV. LaGrange Medium Pressure Systems (cont'd)

30 psig systems
- Regulator pit at Woodlawn Ave and Lagrange Rd **– 11.5%**
- Lagrange medium pressure regulator pit **– 51.1%**
- Regulator pit at Hoffman Ln **– 39.6%**

10 psig systems
- Regulator pit at Hwy 146 **– 17.6%**
- Regulator pit at Hwy 393 & Hwy 146 **– 1.1%**
- Regulator pit at Kings Ln & Hwy 146 **– 1.3 %**
- Regulator assembly at Georgie Way and Moody Ln **– 4.1%**
- Regulator assembly at Hazelwood Dr & Elder Park Rd **– 15.9%**
- Regulator assembly at Sycamore Rd and Elder Park Rd **– 28.2%**

Gas System Constraints
Areas of low pressure are constrained by small diameter piping and single regulator stations feeding the systems.

Gas System Reinforcements Completed in 2007

Gas system reinforcements completed in 2007 include:

- Replace 1/8" orifice plates at Cherry Creek Rd and Hwy 53 regulator assembly (35 psig system) with ¼" orifice plates.
- Extend 4" PL main in Hwy 53 from existing 6" PL at Cherry Creek Rd to 4" CT at Gleneagles Way. Retire regulator pit at Hwy 53 & Glen Eagle Subdivision.
- The OCEDA Economic Development Campus is under construction. 3,500' of 4" PL has been extended in New Moody Ln from Baptist Hospital Northeast to the new Rawlings Group Office Campus.

Recommended Gas System Reinforcements:

Reinforcement 1
Extend gas mains and uprate LaGrange MP system as described in "An Analysis of the OCEDA Economic Development Campus" dated 7 November 2005 or latest version. As described in the report, this system will have an estimated new gas load of up to 387 MCFH. The proposed reinforcement project requires installing:

- 16,400 ft of 4 inch pipe
- 16,500 ft of 6 inch pipe
- An uprate of 10.8 miles of existing pipeline and 440 existing customers
- A new regulator facility at Moody Lane and North Fible Lane

IV. LaGrange Medium Pressure Systems (cont'd)

Minimum gas system pressure (-12ºF):
- 2300 Stonybrook Ct – **49.6 psig**

Regulator Operating Capacities:
- Moody Ln and North Fible Ln – **1%**
- Granger Rd and Hwy 53 **– 18.2%**
- Elder Park Rd **– 17.4%**

Recommended Timeline – 2009-2011

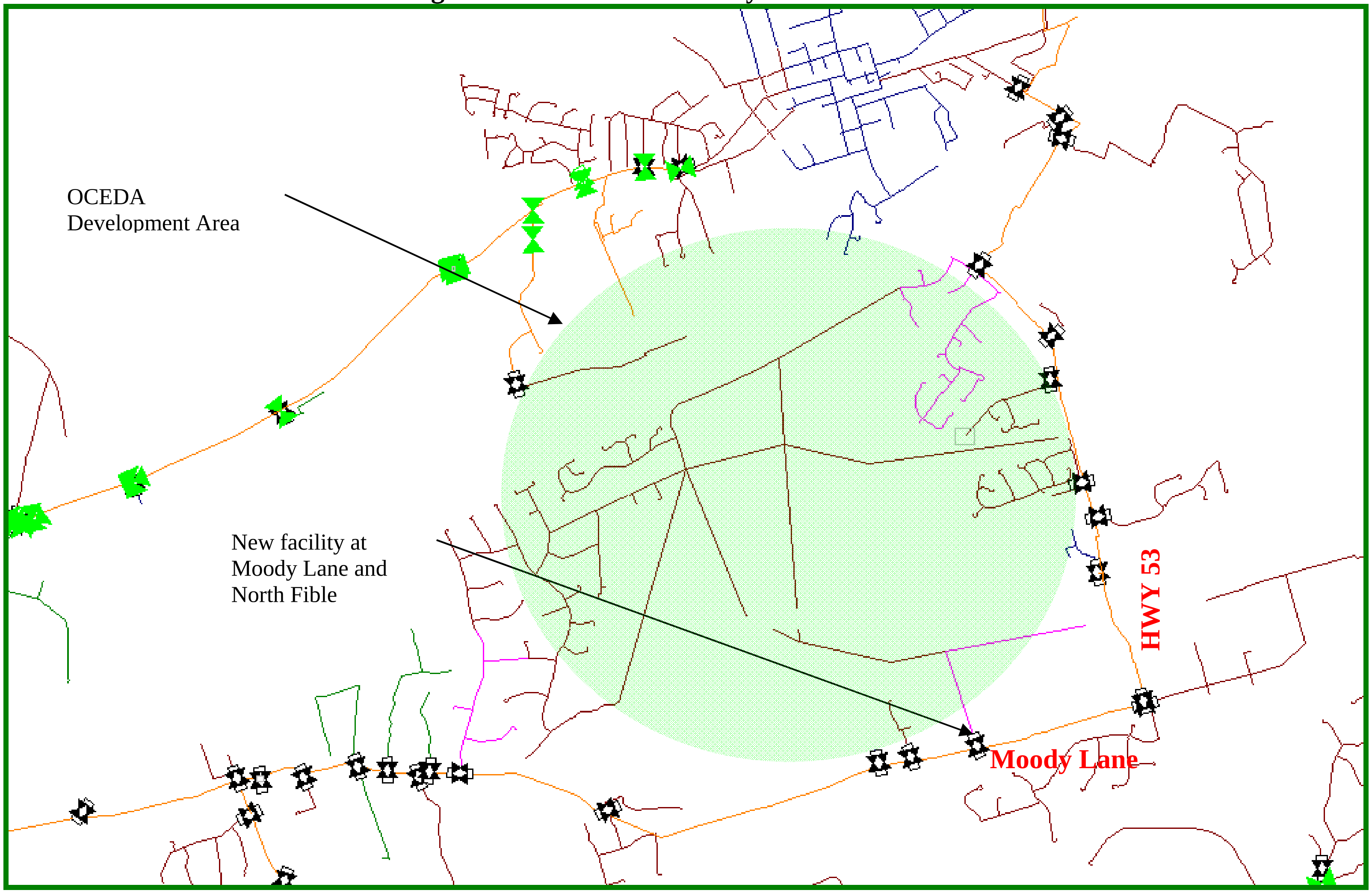
Reinforcement 2
Extend gas mains and uprate Hwy 393 & Hwy 146 system as described in "An Analysis of Proposed Development at Buckner Crossings" dated 16 October 2006 or latest version. As described in the report, this system will have an estimated new gas load of up to 90MCFH. The proposed reinforcement requires installing:

- 5,100 ft of 6-inch pipe
- 5,300 ft of 4-inch pipe
- 13,100 ft of 2-inch pipe
- Uprate 400 ft of existing pipeline and 5 existing customers
- Replace regulator facility at Commerce Pkwy & Button Court Ln
- Remove regulator facility at Hwy 393 & Hwy 146
- Install regulator facility at Hwy 393 & Commerce Pkwy

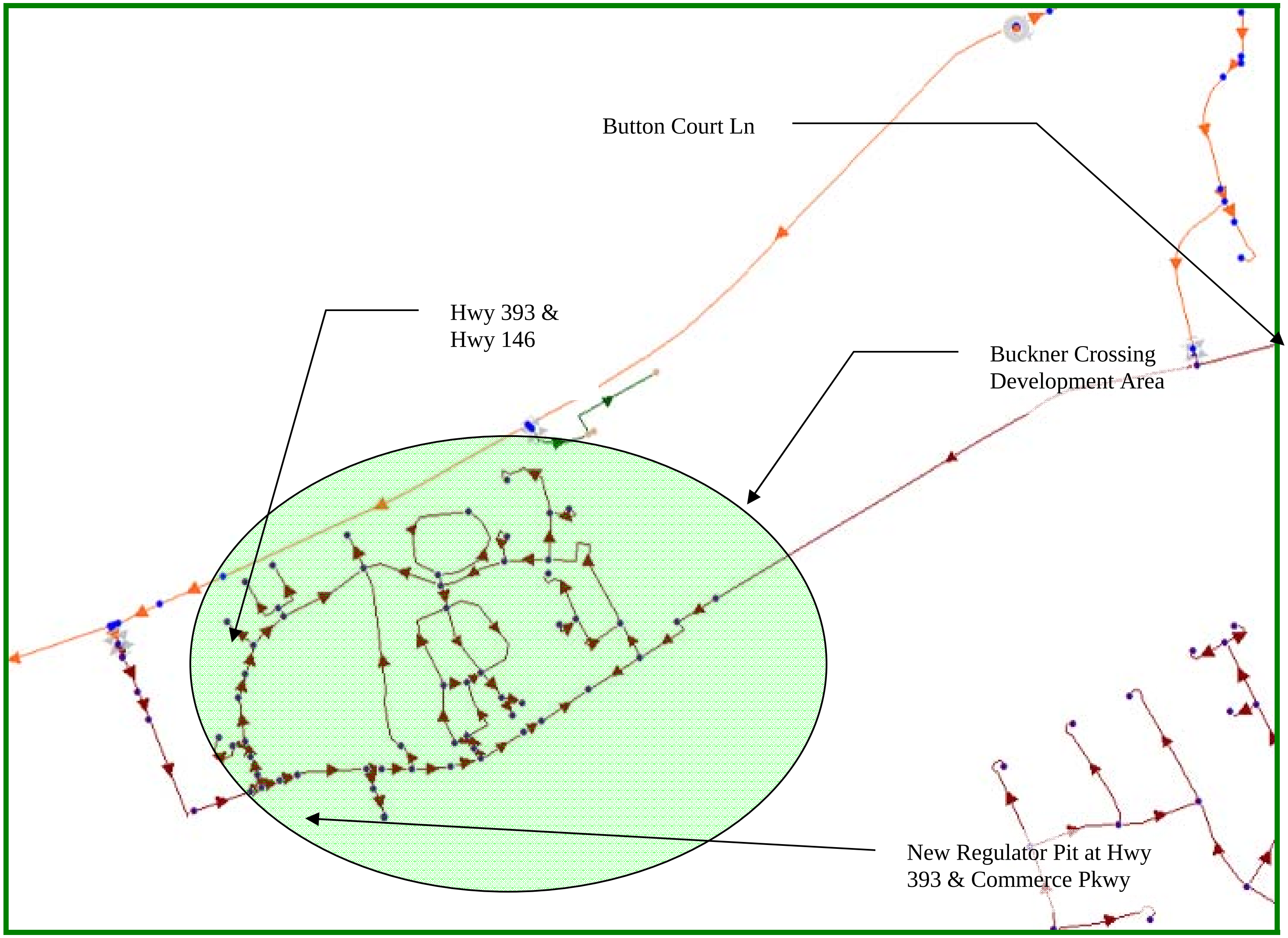
Minimum Gas System Pressure (-12°F)
- Northern Patio Home Circle – **30.6 psig**

Regulator Operating Capacity
- Hwy 393 & Commerce Pkwy – **4.2%**
- Commerce Pkwy & Button Court Ln – **11.4%**

LaGrange Medium Pressure Gas System – Reinforcement 1



LaGrange Medium Pressure Gas System – Reinforcment 2



V. River Road Regulator Assemblies

Gas System Overview
Gas System Planning has identified eight regulator facilities on River Rd that could be removed to reduce the number of dead-end gas systems and reduce maintenance costs by removing unnecessary equipment. All regulators are fed by the Elder Park Line.

Gas System Reinforcement Completed in 2007
As part of the Farm Tap upgrade project, several medium pressure reinforcements will be made, resulting in the removal of two River Road Assemblies. The reinforcements are:

- Installed 1,900 feet of 4-inch PL main in River Road from River Creek Dr up to Harrods Creek. Tie-in to regulator assembly at River Rd & Creekside Ct, uprate the River Creek Drive system from 10- 35 psig and remove the River Creek Dr regulator assembly. New main will allow eventual tie-in to Harrods Creek MP system and retirement of River Creek Dr regulator assembly.
- Installed 2,200 feet of 4-inch PL main in River Road from 7009 River Rd to 7314 River Rd. Tie in to systems at River Rd & Private Dr, River Rd & Transylvania and River Rd & Mayfair Rd. Retire regulator assemblies at Private Dr and Mayfair Rd.

Regulator Facilities
The regulator facilities in this area are as follows:

- RIVER RD. & LONGVIEW AVE. G-622 16.8%
- RIVER RD. & WOODSIDE RD. G-623 12.2%
- RIVERSIDE DR. & RIVER RD. G18717 1.4%
- 4410 RIVER RD. G18718 6.0%
- RIVER RD. & BOX HILL LN. G-515 12.6%
- RIVER RD. & LIME KILN LN. G-624 23.6%
- BLANKENBAKER LN. & RIVER RD. G-335 13.0%
- GLENVIEW AVE. & RIVER RD. G-329 12.3%
- RIVER RD. & RIVERS EDGE RD. SUB. G-600 9.2%
- RIVER RD.PIT SERVING RIVERCREEK G-590 16.1%
- RIVER RD.& JUNIPER BEACH DR. G-610 5.0%
- RIVER RD. &HARBORTOWN RD. G-621 5.0%

Maximum Allowable Operating Pressure
The Elder Park Line has a maximum allowable operating pressure of 400 psig, but is typically operated at 250 psig.

The Longview Ave and Woodside Rd systems have a maximum allowable operating pressure of 10 psig.

The Riverside Dr, Knights of Columbus, Boxhill Ln, and Lime Kiln Ln systems have a maximum allowable operating pressure of 20 psig.

V. River Road Regulator Assemblies (cont'd)

The Blankenbaker Ln and Glenview Ave systems have a maximum allowable operating pressure of 30 psig. These systems are part of the East End 30 psig system (section III). Reinforcements connecting to this system are assumed to take place following the uprate to 50 psig.

The River's Edge Rd, Juniper Beach Dr, Harbortown Rd, and River Creek Dr systems have a maximum allowable operating pressure of 35 psig.

Recommended Gas System Reinforcements

Reinforcement 1
- Install approximately 2,800 ft of 4-inch plastic gas main along River Rd to connect the River Rd & River Creek Dr and River Rd & Harbortown Rd systems.
- Install approximately 840 ft of 2-inch plastic gas main along Juniper Beach Rd to connect the River Rd & Juniper Beach Dr and River Rd & Harbortown Rd systems.
- Remove the River Rd & Juniper Beach Dr and Creekside Ct regulator assemblies and the River Rd & Harbortown Rd regulator pit.

Minimum Gas System Pressure
- 5300 Juniper Beach Rd – **34.4 psig**

Regulator Operating Capacity
- River Rd & River Creek Dr – **28.9%**

Recommended Timeline – 2008-2011

Reinforcement 2
- Uprate River Rd & Woodside Rd medium pressure system from 10 psig to 50 psig.
- Uprate River Rd & Lime Kiln Ln medium pressure system from 20 psig to 50 psig.
- Install approximately 850 ft of 4-inch plastic gas main along Arden Rd to connect Woodside Rd and Glenview Ave systems.
- Install approximately 1,200 ft of 4-inch plastic gas main along Lime Kiln Ln to connect Lime Kiln Ln and Glenview Ave systems.

V. River Road Regulator Assemblies (cont'd)

- Remove the River Rd & Woodside Rd and River Rd & Lime Kiln Ln regulator assemblies.

Minimum Gas System Pressure (-12°F)
- Wolfpen Ridge Ct **– 32.6 psig**

Regulator Operating Capacity
- River Rd & Glenview Ave **– 13.2%**

Recommended Timeline – 2008-2011

Reinforcement 3
- Uprate River Rd & Longview Ave medium pressure system from 10 psig to 20 psig.
- Install approximately 775 ft of 2-inch plastic gas main along Longview Ln to connect Longview Ave and Boxhill Ln systems.
- Remove the River Rd & Longview Ave regulator assembly

Minimum Gas System Pressure (-12°F)
- 4508 Longview Ln **– 11.9 psig**

Regulator Operating Capacity
- River Rd & Boxhill Ln **– 23.2 %**

Recommended Timeline – 2008-2011

Reinforcement 4
- Uprate River Rd & Knights of Columbus medium pressure system from 20 psig to 35 psig.
- Install approximately 350 ft of 2-inch plastic gas main along River Rd to connect River's Edge Rd and Knights of Columbus systems.
- Remove the River Rd & Knights of Columbus regulator assembly.

Minimum Gas System Pressure (-12°F)
- Southeast end of the former Knights of Columbus system **– 34.7 psig**

Regulator Operating Capacity
- River Rd & River's Edge Rd **– 13.4%**

Recommended Timeline – 2008-2011

V. River Road Regulator Assemblies (cont'd)

Reinforcement 5

- Uprate River Rd & Riverside Dr medium pressure system from 20 psig to 50 psig.
- Install approximately 250 ft of 2-inch plastic gas main along Riverside Dr to connect Riverside Dr and Blankenbaker Ln systems.
- Remove the River Rd & Riverside Dr regulator assembly.

Minimum Gas System Pressure (-12°F)

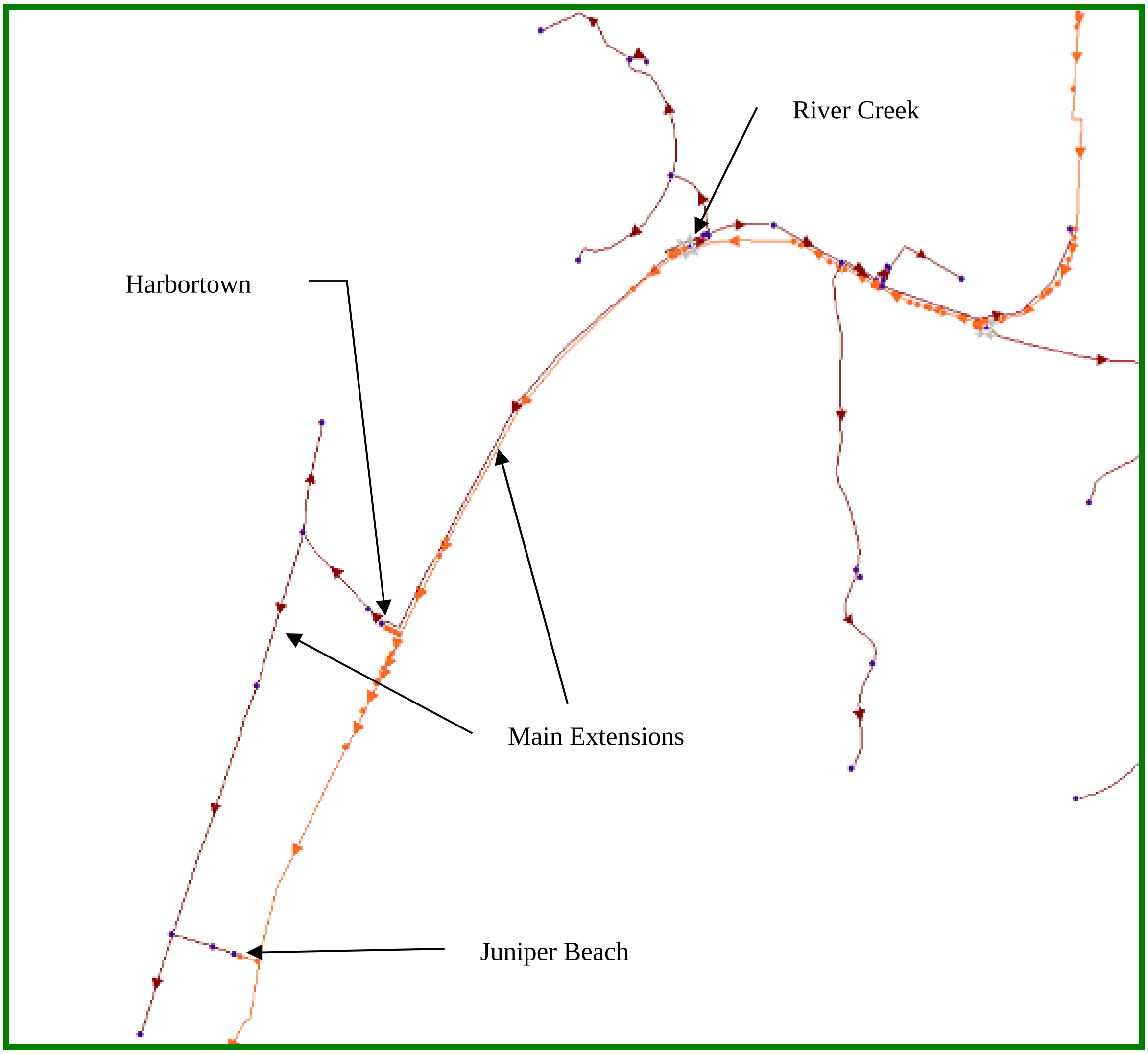
- Wolfpen Ridge Ct **– 32.6 psig**

Regulator Operating Capacity

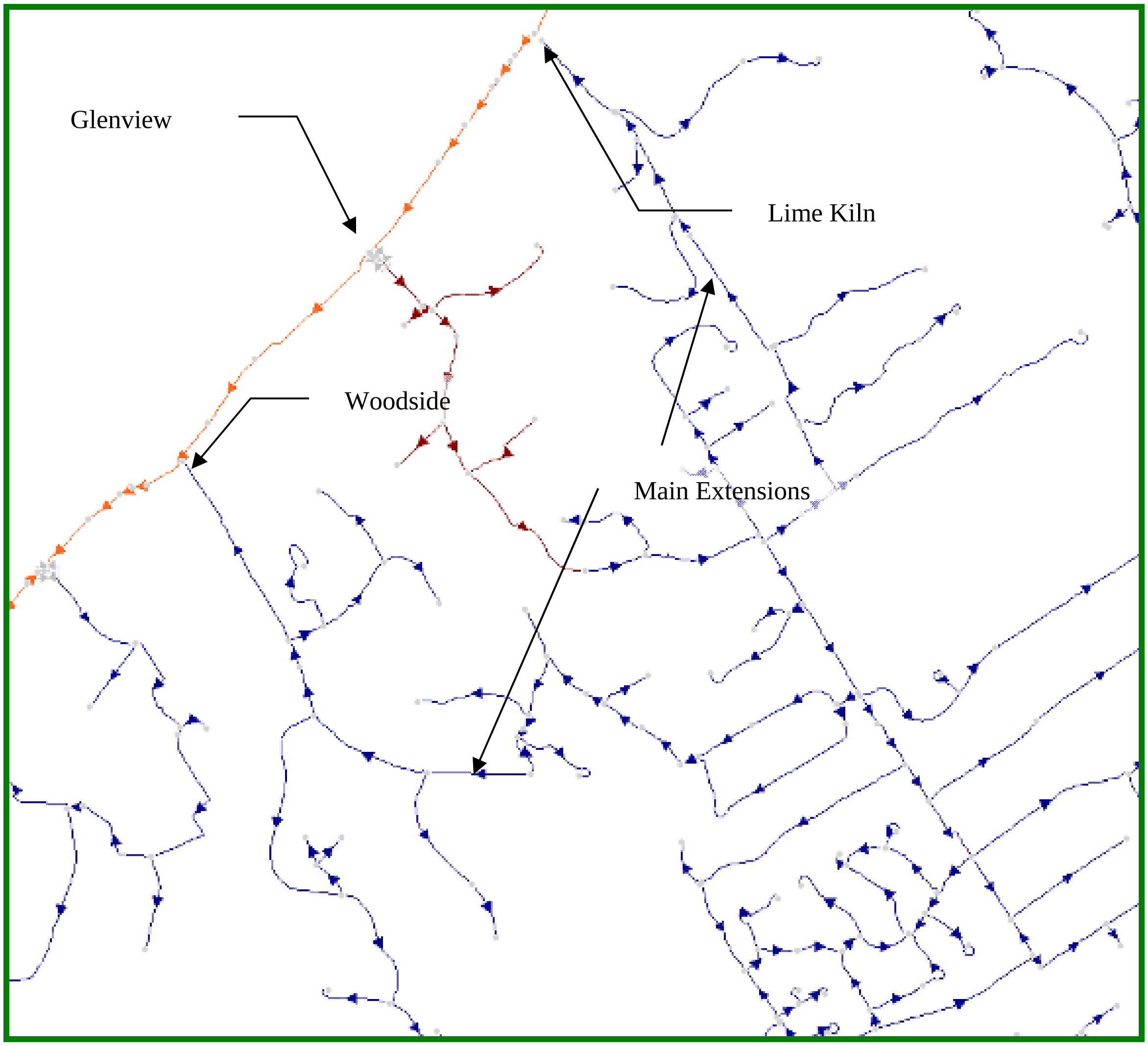
- Blankenbaker Ln & River Rd **– 13.9%**

Recommended Timeline – 2008-2011

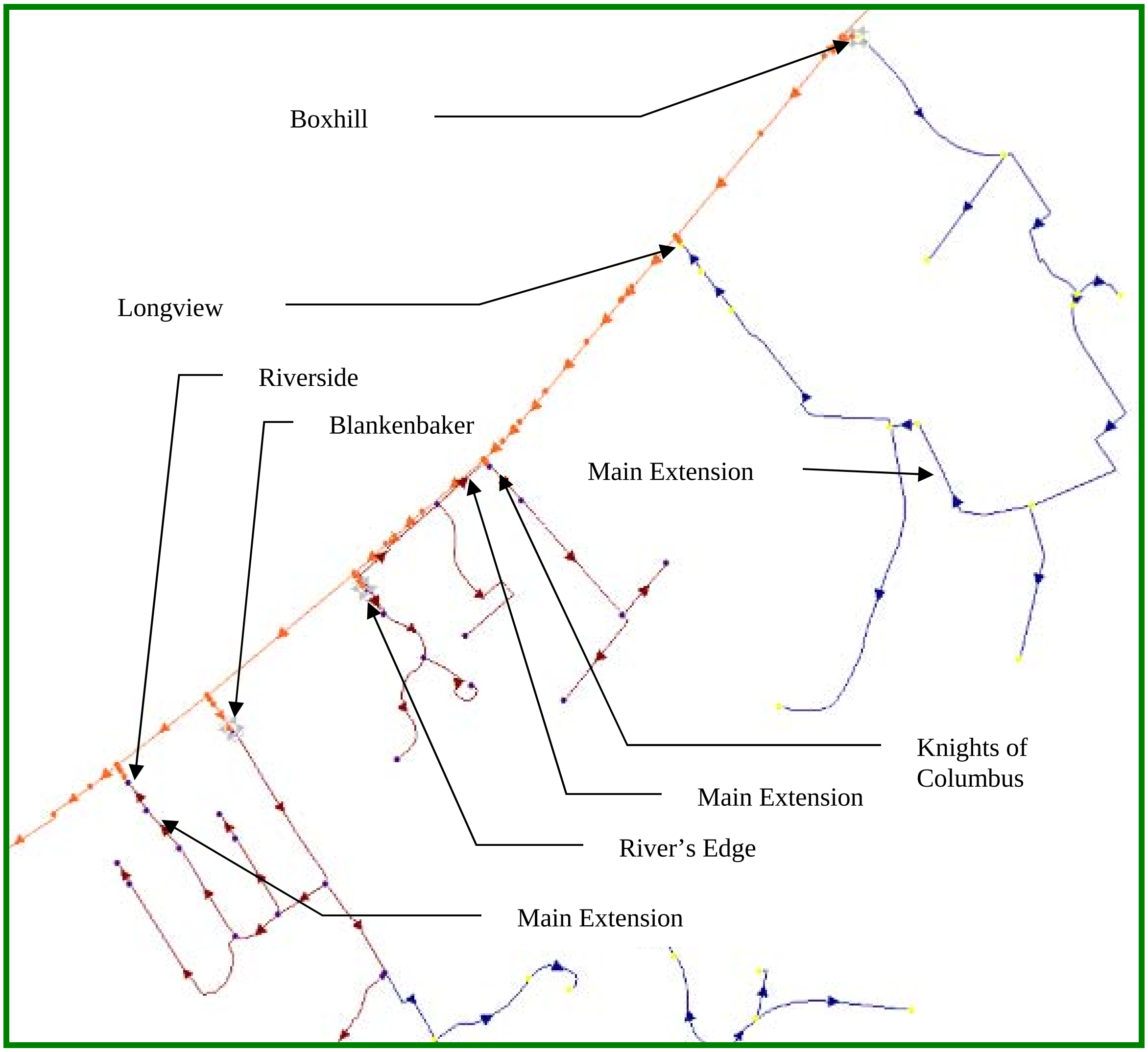
River Road Regulator Assemblies – Reinforcement 1



River Road Regulator Assemblies – Reinforcement 2



River Road Regulator Assemblies – Reinforcement 3



VI. Plantside Drive/Blankenbaker Parkway Medium Pressure System

Gas System Overview
The Plantside/Blankenbaker Medium Pressure System feeds the area near Plantside Drive, Blankenbaker Parkway, and Electron Drive. The area is composed mostly of small commercial customers with a few residential customers. This system is connected to the Taylorsville Road medium pressure system via a 4-inch steel main at Grand Avenue and Watterson Trail.

Maximum Allowable Operating Pressure
This medium pressure system has a maximum allowable operating pressure of 35 psig.

Regulator Operating Capacity
- Watterson Tr and Plantside Dr – **52.4%**

Gas System Constraints
Many of the commercial customers fed by this medium pressure system require a delivery pressure of 5 psig. A proposed 283 acre office park for the eastern area of this system, south of I-64, on Tucker Station Road, will require a significant amount of new infrastructure (MSD is planning a 4.6 square mile area of sewer development) and an additional gas regulator facility. Currently, this system is not capable of serving this development that is predicted to have an approximate total load of 140 Mcfh.

Recommended Gas System Reinforcements:

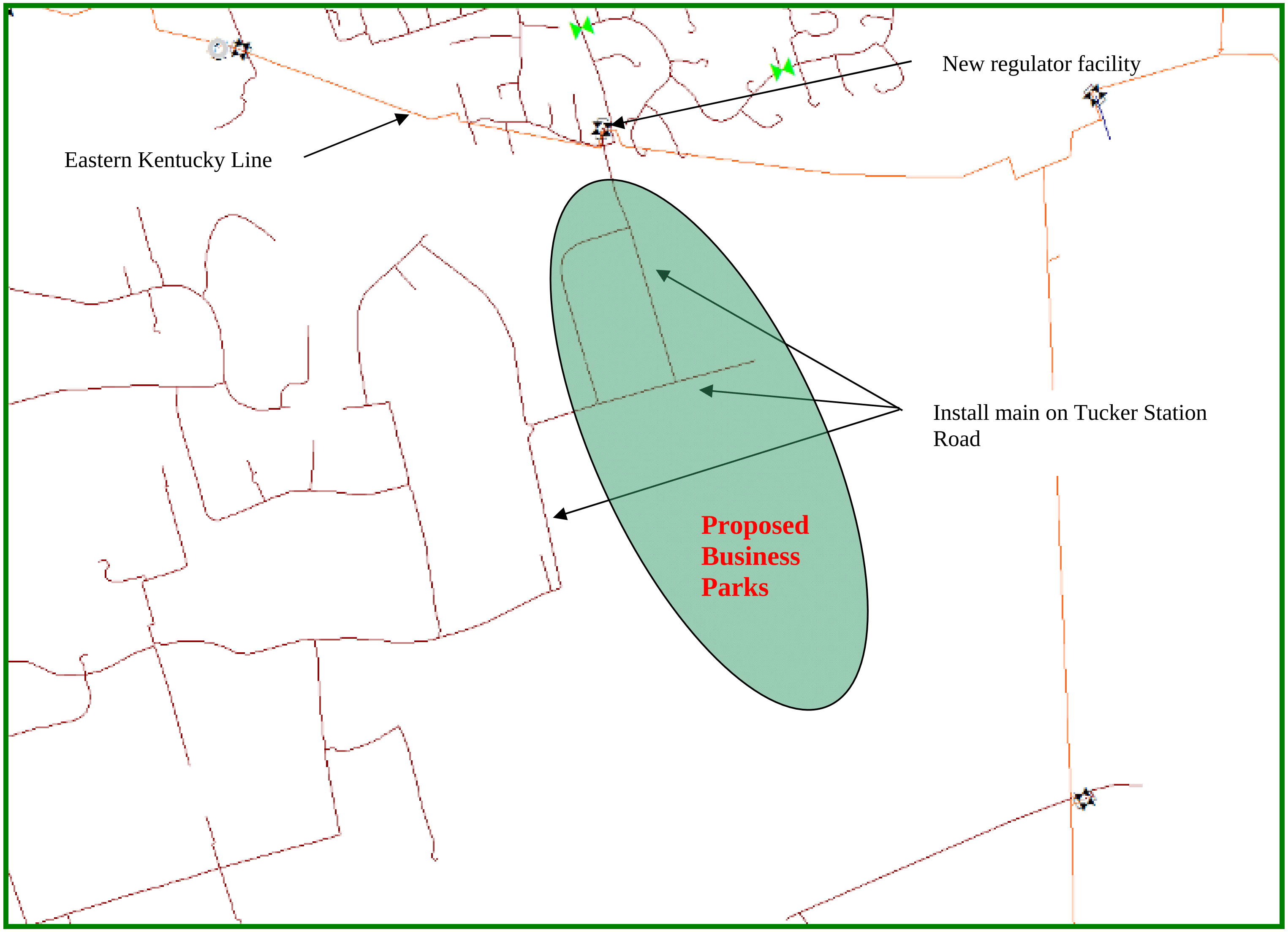
Reinforcement 1
- Install a new medium pressure regulator facility on Tucker Station Road, north of I-64 that is fed from the existing 16-inch high pressure pipeline parallel to I-64.
- Install approximately 1,700 ft of 6-inch medium pressure plastic pipe from Sycamore Station Place south along Tucker Station Road, terminating at Pope Lick Road.
- Install approximately 2,860 ft of 6-inch medium pressure plastic pipeline west from the entrance of the proposed office park, along Tucker Station Road, to the 6-inch main ending on Plantside Drive (near the Papa John's Building). This would allow for a multiple feed system, improving system reliability.

Minimum gas system pressure (-12°F):
- 3025 Element Ln – **31.23 psig**
- 2801 Constant Comment Place – **32.0 psig**

Regulator Operating Capacities:
- Tucker Station Rd & I-64 (4x3 Mooney assembly with 35% plates) – **4.4%**
- Watterson Tr & Plantside Dr – **46.7%**

Recommended Timeline: 2008-2009
Note: This reinforcement should be completed after the Kentucky Department of Transportation widens Tucker Station Road and Pope Lick Road.

Plantside Drive Medium Pressure Gas System – Reinforcement 1



VII. Jeffersontown/Fern Creek Medium Pressure System

Gas System Overview

The Jeffersontown and Fern Creek areas are part of a large medium pressure gas system that serves the southeastern part of Jefferson County. This system is composed of rural, residential, and small commercial customers and has continued to experience rapid growth in these sectors. The majority of Jeffersontown and Fern Creek areas are served from the following regulator facilities.

Regulator Facilities

The regulator facilities that feed this system are as follows:

- Regulator pit at Taylorsville Road and Hopewell Road (Jeffersontown Pit)
- Regulator assembly at Gentry Lane and the Calvary Line
- Regulator pit at Cedar Creek Road and the Calvary Line
- Regulator station at Hudson Lane

Maximum Allowable Operating Pressure

The Jeffersontown/Fern Creek medium pressure gas system has a maximum allowable operating pressure of 35 psig.

Model Results

Minimum Gas System Pressures (-12 ^{0}F)

- 11708 Kewana Ct – 8.6 psig
- 5207 Pine Bunch Ct – 13.4 psig
- 7701 Windgate Dr – 17.5 psig
- 8012 Kendrick Crossing Ln – 10.7 psig

Regulator Operating Capacity

- Taylorsville Rd and Hopewell Rd – 14.4%
- Gentry Lane and the Calvary Line – **84.6%**
- Cedar Creek Road and the Calvary Line – 8.2%
- Hudson Ln Station – 40.7%

Gas System Constraints

Gas system constraints in this area are primarily due to the infrastructure of small diameter piping coming from the sources. Due to current and anticipated growth it will be necessary to perform gas system reinforcement work.

VII. Jeffersontown/Fern Creek Medium Pressure System (cont'd)

Recommended Gas System Reinforcement

Reinforcement 1
Uprate the Jeffersontown/Fern Creek medium pressure distribution system from 35 psig to 60 psig. This uprate consists of approximately 14,123 services and 180 miles of main (107.3 miles of plastic and 70.8 miles of steel).

Minimum gas system pressure (-12°F)
- 11708 Kewana Ct – 34.6 psig
- 5207 Pine Bunch Ct – 39.4 psig
- 7701 Windgate Dr – 40.6 psig
- 8012 Kendrick Crossing Ln – 37.1 psig

Regulator Operating Capacity
- Taylorsville Rd and Hopewell Rd – 19.1%
- Gentry Lane and the Calvary Line – **100%**
- Cedar Creek Road and the Calvary Line – 11.0%
- Hudson Ln Station – 62.8%

Recommended Timeline –2008-2010

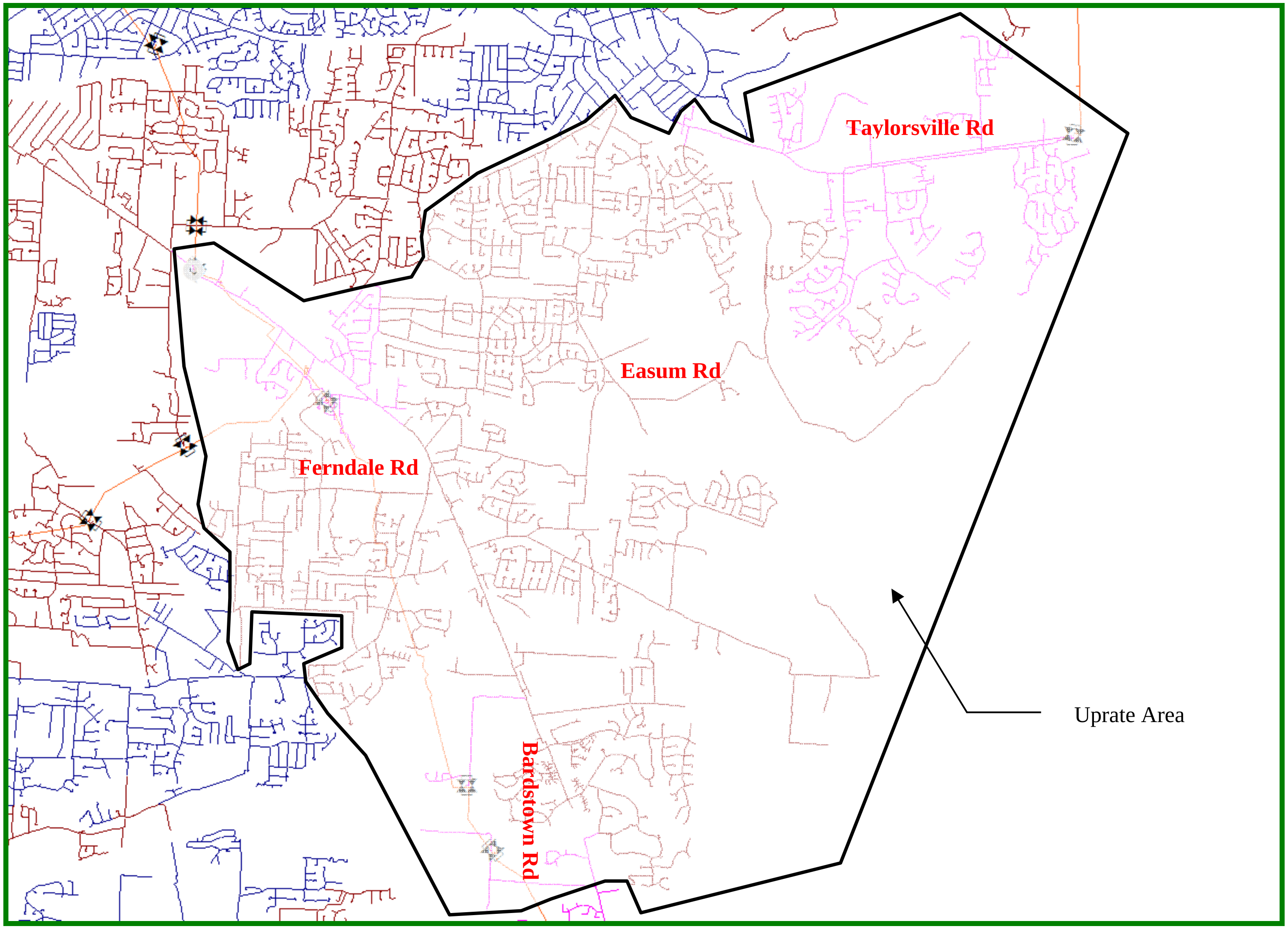
Reinforcement 2
- Loop approximately 8,370 feet of 6-inch medium pressure gas pipeline along Taylorsville Road from the outlet of the regulator facility to Saratoga Woods Drive.
- Install approximately 1,400 feet of 4-inch medium pressure plastic gas pipe east along Chenoweth Run Road from the 6-inch on Taylorsville Road.

Minimum gas system pressure (-12 ^{0}F)
- 11708 Kewana Ct – 39.2 psig
- 5207 Pine Bunch Ct – 47.9 psig
- 7701 Windgate Dr – 43.3 psig
- 8012 Kendrick Crossing Ln – 39.8 psig

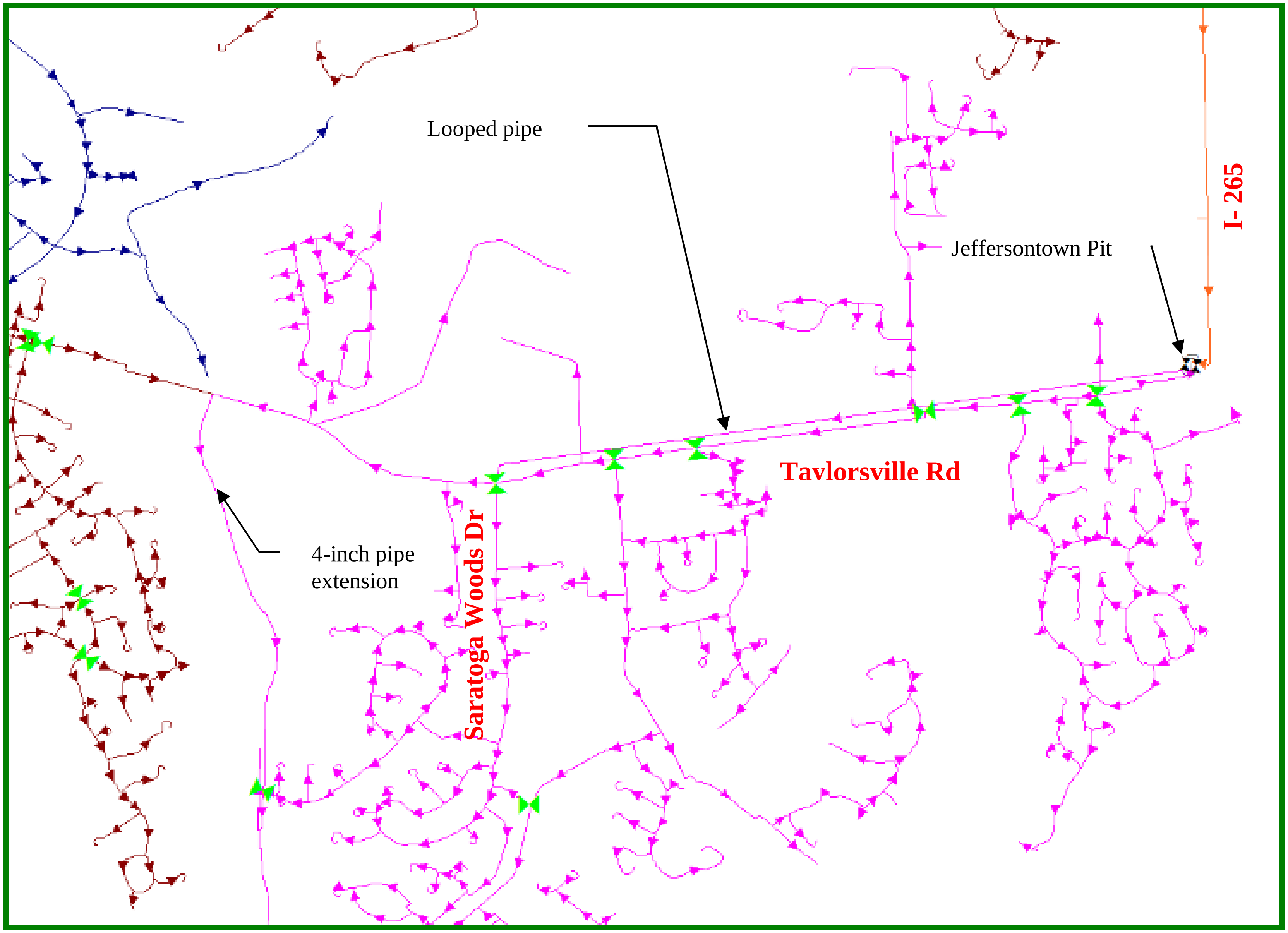
Regulator Operating Capacity
- Taylorsville Rd and Hopewell Rd – 23.6%
- Gentry Lane and the Calvary Line – **100%**
- Cedar Creek Road and the Calvary Line – 10.3%
- Hudson Ln Station – 58.8%

Recommended Timeline – 2008-2010

Taylorsville Road/Jeffersontown Medium Pressure Gas System – Reinforcement 1



Taylorsville Road/Jeffersontown Medium Pressure Gas System – Reinforcement 2



VIII. Bardstown Medium Pressure System

Gas System Overview
The Bardstown medium pressure gas system serves the City of Bardstown. This system is composed mainly of residential and commercial customers with a few large industrial customers including Owens Illinois and the Barton Distillery. It has continued to experience growth in the residential and commercial sectors especially on the western side of the Bardstown area. Expansion of an industrial park on Highway 605 near Nelson County High School is anticipated in the next 2-3 years.

Gas System Reinforcements completed in 2007
Installed approximately 1,800 ft of 8-inch medium pressure pipeline along the Bardstown Bypass (Hwy 245) to connect to the existing 6-inch and 8-inch medium pressure pipe infrastructure.

Gas System Reinforcements to be completed in 2008
Uprate the Bardstown medium pressure system to a maximum allowable operating pressure of 60 psig.

Regulator Facilities
The regulator facilities that supply gas to the Bardstown medium pressure system are as follows:

- The regulator station at the LG&E Bardstown Office on U.S. Highway 62 (Bardstown MP).
- The regulator station adjacent to Chris's Creation Cabinet Company (Chris's Creation MP).

Maximum Allowable Operating Pressure (MAOP)
The Bardstown medium pressure system has a maximum allowable operating pressure of 45 psig.

Model Results

Minimum Gas System Pressure (-12 ^{0}F)
- 100 Brighton Ct [13891047] – 35.6 psig

Regulator Operating Capacities
- Bardstown MP **– 17.0**%
- Chris's Creation MP **– 14.5**%

Gas System Constraints
Gas system constraints are caused by the lack of a direct gas supply route from the regulator station at the LG&E Bardstown office to the downtown Bardstown area. Due to current and anticipated growth, it will be necessary to reinforce the gas system.

VIII. Bardstown Medium Pressure System (cont'd)

Recommended Gas System Reinforcements

Reinforcement 1
Install approximately 1,916 ft of 4-inch plastic pipeline along Gilkey Rd and tie into the existing 8-inch steel main on Loretto Rd.

Minimum gas system pressure (-12 ^{0}F)
- 160 Deep Springs Dr **– 52.4 psig**

Regulator Operating Capacities
- Bardstown MP **– 17.8%**
- Chris's Creation MP **– 14.9%**

Recommended Timeline – 2009-2011
Note: This reinforcement provides an alternate feed into the system. If Reinforcement 4 is completed, this reinforcement is not needed.

Reinforcement 2
Install approximately 3,177 ft of 4-inch plastic pipeline along Filiatreau Ln and tie into the existing 4-inch plastic main on Glenwood Dr.

Minimum gas system pressure (-12 ^{0}F)
- American Dr @ Ballard Springs Ct **– 47.9 psig**

Regulator Operating Capacities
- Bardstown MP **– 19.5%**
- Chris's Creation MP **– 26.8%**

Recommended Timeline – 2010-2012
Note: This reinforcement should be done in conjunction with the expansion of the Highway 605 industrial park. Results include Flowers Foods Bakery.

Reinforcement 3
Uprate Bardstown System from 45 psig to 60 psig. This includes 76.4 miles of main and 3,400 services. Results include Flowers Foods Bakery 55 MCFH load.

Minimum gas system pressure (-12 ^{0}F)
- 100 Brighton Ct– **52.1 psig**
- American Dr @ Ballard Springs Ct **– 30.2 psig**

Regulator Operating Capacities
- Bardstown MP **– 20.4%**
- Chris's Creation MP **– 14.5%**

VIII. Bardstown Medium Pressure System (cont'd)

Recommended Timeline – 2010
Note: This reinforcement is being done to support the expansion of the Highway 605 industrial park.

Reinforcement 4
Install a high pressure distribution regulator facility (2 – 4" Mooney 100%) upstream of the existing medium pressure facility at Chris's Creations. Install 9,200 feet of 8-inch steel from the new facility to the medium pressure plastic installed in Reinforcement 3. Tie-in to existing medium pressure main with a new 4X3 Mooney regulator facility.

Minimum gas system pressure (-12 ^{0}F)
- Brighton Ct– **52.6 psig**

Regulator Operating Capacities
- Bardstown MP **– 15.8%**
- Chris's Creation MP **– 41.8%**
- Bardstown MP 2 (NEW) **– 10.6%**

Recommended Timeline – 2009
Note: This reinforcement is being done to support the expansion of the Highway 605 industrial park. This reinforcement provides an alternate feed into the system.

Reinforcement 5
Install a medium pressure regulator facility off the high pressure transmission line at the intersection of North Third Street and the Bardstown Bypass (Hwy 245).

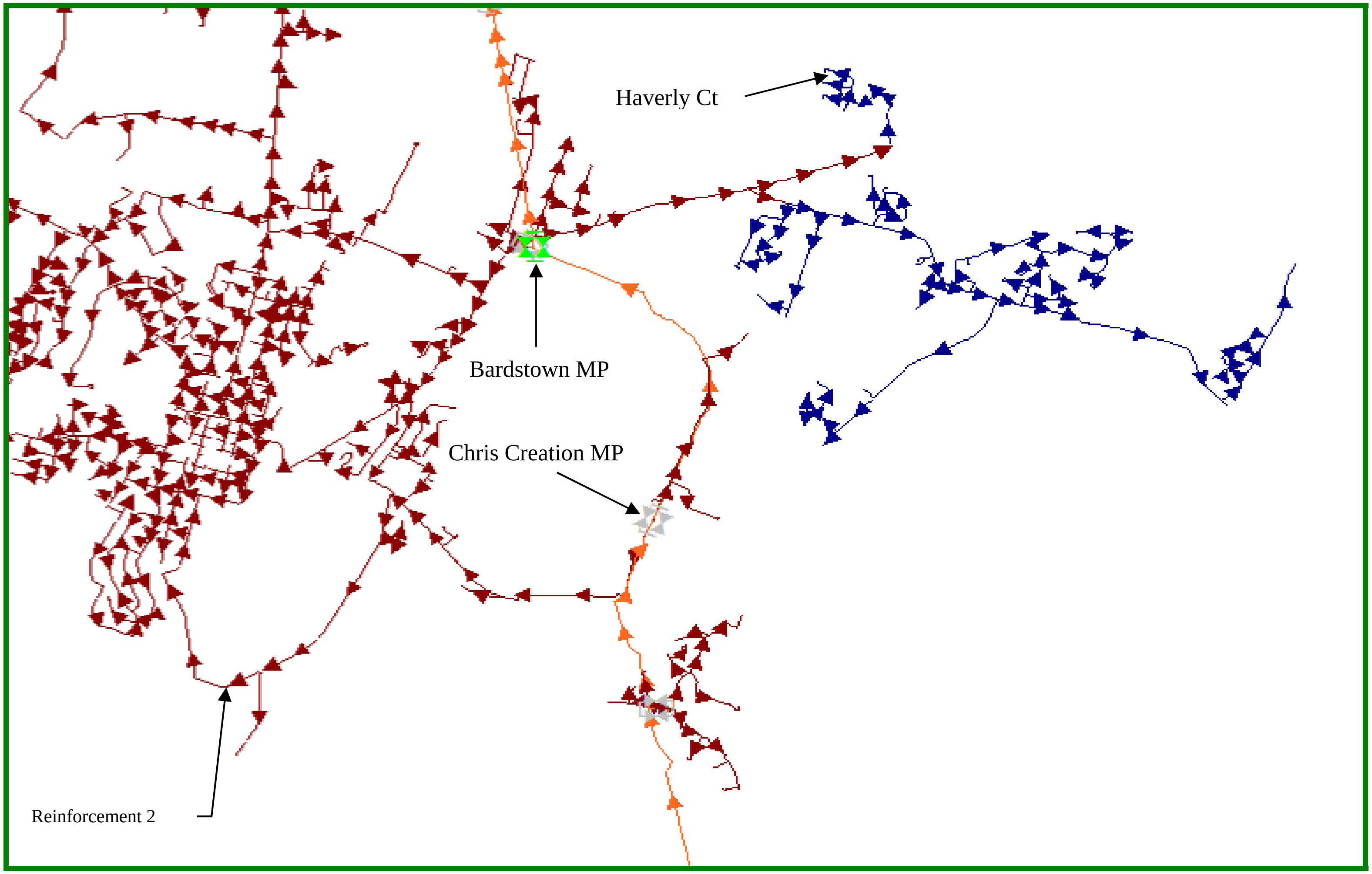
Note: Based on Reinforcement 1 of the Mt. Washington/Lebanon Junction High Pressure System (see Section XVIII; see also Section XXIII, Scenario 2), the new regulator facility would allow gas to feed directly into the center of the system to eliminate the low-pressure problem at Meadow Ridge Dr. The new low pressure point is located east of the Bardstown MP facility.

Minimum gas system pressure (-12 ^{0}F)
- 160 Deep Springs Dr **– 34.7 psig**
- 116 Andrea Ct **– 33.7 psig**
- 212 Meadow Ridge Dr **– 43.3 psig**

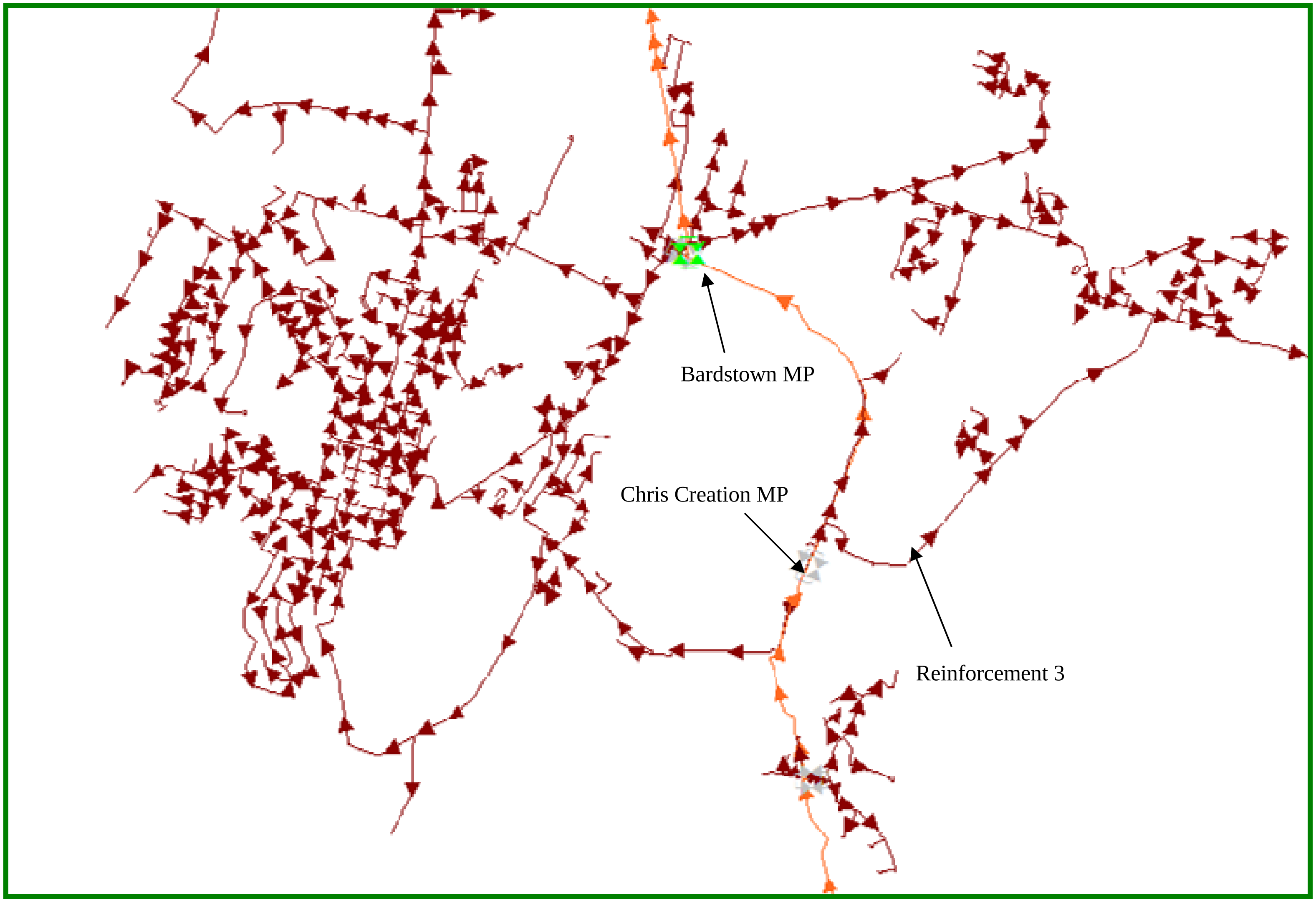
Regulator Operating Capacities
- Bards2MP (new pit) **– 11.8%**
- Bardstown MP **– 5.8%**
- Chris's Creation MP **– 18.9%**

Recommended Timeline – TBD
Note: Should be completed in conjunction with the Mt. Washington/Lebanon Junction high-pressure pipeline project.

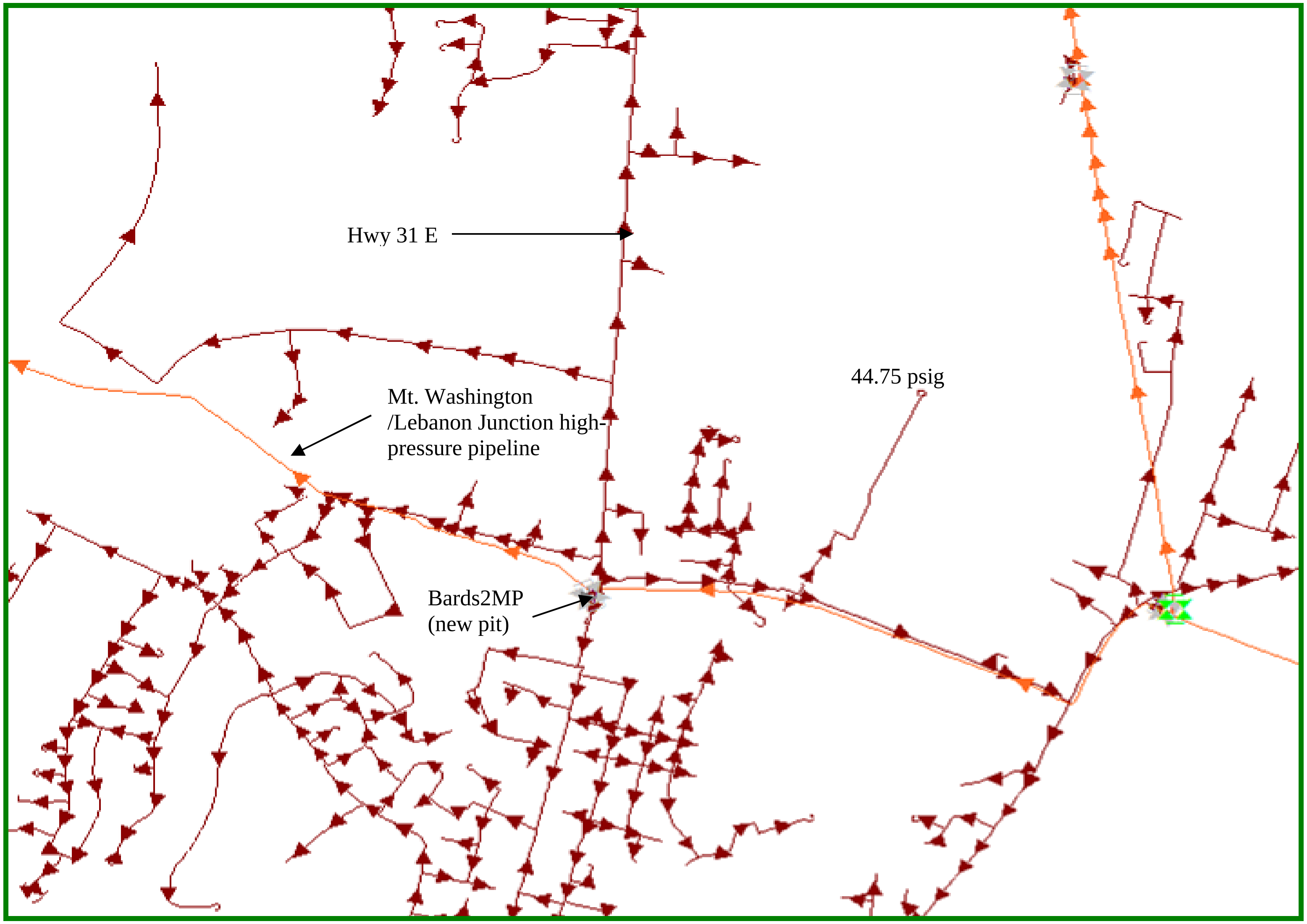
Bardstown Medium Pressure Gas System – Reinforcement 1



Bardstown Medium Pressure Gas System – Reinforcement 2



Bardstown Medium Pressure Gas System – Reinforcement 5



IX. Highway 44 Regulator Assemblies

Gas System Overview
Gas System Planning has identified nine separate regulator assemblies located along Highway 44 that could be removed to reduce the number of dead-end gas systems and/or reduce maintenance cost on unnecessary regulation facilities.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Mt Washington MP
- Hwy 44 and Woodlake
- Hwy 44 and Harris
- Hwy 44 and Fisher
- Hwy 44 and Highland Spring
- Hwy 44 and Bethel Church
- Hwy 44 and Azure
- Hwy 44 and Truman
- Hwy 44 and Kennedy
- Hwy 44 and Bogard
- Hwy 44 and Bells Mill
- Hwy 44 and Alpar
- Hwy 44 and Mockingbird
- Hwy 44 and Sunview
- Hwy 44 and Watergate
- Hwy 44 and HiLand
- Hwy 44 and Big Clifty
- Hwy 44 and Halls
- Hwy 44 and Boardwalk

Maximum Allowable Operating Pressure
These systems have a maximum allowable operating pressure of 35 psig. The maximum allowable operating pressure of the Mt Washington MP regulator station is 60 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure is located on **Winding Woods Trail (30.4 psig)**.

IX. Highway 44 Regulator Assemblies (cont'd)

Regulator Operating Capacities
- Mt Washington MP – **9.3%**
- Hwy 44 and Woodlake – **21.5%**
- Hwy 44 and Harris – **21.0%**
- Hwy 44 and Fisher – **74.5%**
- Hwy 44 and Greenbrian – **33.8%**
- Hwy 44 and Bethel Church – **17.6%**
- Hwy 44 and Azure – **6.8%**
- Hwy 44 and Truman – **21.0%**
- Hwy 44 and Kennedy – **5.7%**
- Hwy 44 and Bogard – **45.1%**
- Hwy 44 and Bells Mill – **19.2%**
- Hwy 44 and Alpar – **3.8%**
- Hwy 44 and Mockingbird – **43.1%**
- Hwy 44 and Sunview – **42.1%**
- Hwy 44 and Watergate – **1.1%**
- Hwy 44 and HiLand – **5.3%**
- Hwy 44 and Big Clifty – **8.3%**
- Hwy 44 and Halls – **3.0%**
- Hwy 44 and Boardwalk – **11.5%**

Recommended Gas System Reinforcements

Reinforcement 1
- Connect system served by Hwy 44 and Boardwalk to Hwy 44 and Halls system with 570 feet of 4-inch plastic main along Hwy 44.
- Connect Hwy 44 and Big Clifty to Hwy 44 and Halls system with 1,350 ft of 4-inch plastic main along Hwy 44.
- Convert six high-pressure services on the north side of Hwy 44 to medium-pressure services between Hwy 44 and Halls and Hwy 44 and Big Clifty. This will retire six long services that pass underneath Hwy 44.
- Retire Boardwalk and Big Clifty regulator assemblies.

Minimum Gas System Pressure (-12°F)
- Tanager Landing Apartments off Hwy 44 – **34.5 psig**

Regulator Operating Capacities
- Hwy 44 and Halls Ln – **24.8%**

Recommended Timeline – 2009-2011

IX. Highway 44 Regulator Assemblies (cont'd)

Reinforcement 2

- Connect systems served by Hwy 44 & Hi-Land and Hwy 44 & Watergate with 1,780 feet of 6-inch plastic mains.
- Retire Watergate Assembly.

Minimum Gas System Pressure (-12°F)

- Douglass Drive – **34.9 psig**

Regulator Operating Capacities

- Hwy 44 and Hi-Land– **6.7 %**

Recommended Timeline – 2009-2011

Reinforcement 3

- Retire Hwy 44 and Mockingbird regulator assembly. System can be served by Hwy 44 and Sunview.

Minimum Gas System Pressure (-12°F)

- Old Hickory Lane – **29.4 psig**

Regulator Operating Capacities

- Hwy 44 and Sunview – **90.9%**

Recommended Timeline – 2009-2011
Note: Growth in area may require that the Mockingbird assembly remain. This area should be monitored before finalizing a decision.

Reinforcement 4

- Connect systems served by Hwy 44 and Bells Mill and Hwy 44 and Alpar with 2,200 feet of 4-inch plastic main along Hwy 44 and Old Hwy 44.
- Convert five existing high pressure services to medium pressure.
- Retire the Hwy 44 and Alpar regulator assembly.

Minimum Gas System Pressure (-12°F)

- 440 East Millwater Falls – **31.3 psig**

Regulator Operating Capacities

- Hwy 44 and Bells Mill – **22.9%**

Recommended Timeline – 2009-2011

IX. Highway 44 Regulator Assemblies (cont'd)

Reinforcement 5

- Connect systems served by Hwy 44 & Bogard, Hwy 44 & Kennedy, Hwy 44 & Truman, and Hwy 44 & Azure with 3,900 feet of 6 inch plastic main along Hwy 44.
- Connect Systems served by Bethel Church and Highland Springs facilities with 1,300 feet of 4- or 6-inch plastic main along Hwy 44.
- Convert 24 high-pressure services along Hwy 44 to medium pressure.
- Retire Truman, Kennedy, and Bethel Church Road facilities.

Minimum Gas System Pressure (-12°F)

- Winding Woods Trail **– 27.2 psig**

Regulator Operating Capacities

- Hwy 44 and Bogard **– 60.1%**
- Hwy 44 and Azure **– 22.8%**
- Hwy 44 and Highland Springs **– 6.7%**

Recommended Timeline – 2009-2011

Reinforcement 6

- Connect Fisher, Harris, and Woodlake systems with 2,100 feet of 4-inch plastic pipe along Hwy 44 between Fisher and Harris, and 1,650 feet of 6-inch plastic pipe between Harris and Woodlake.
- Convert approximately 34 high-pressure services to medium pressure.
  Note: Some of these services may have been converted during 2005 work but are not currently mapped.
- Retire Hwy 44 and Harris regulator assembly.

Minimum Gas System Pressure (-12°F)

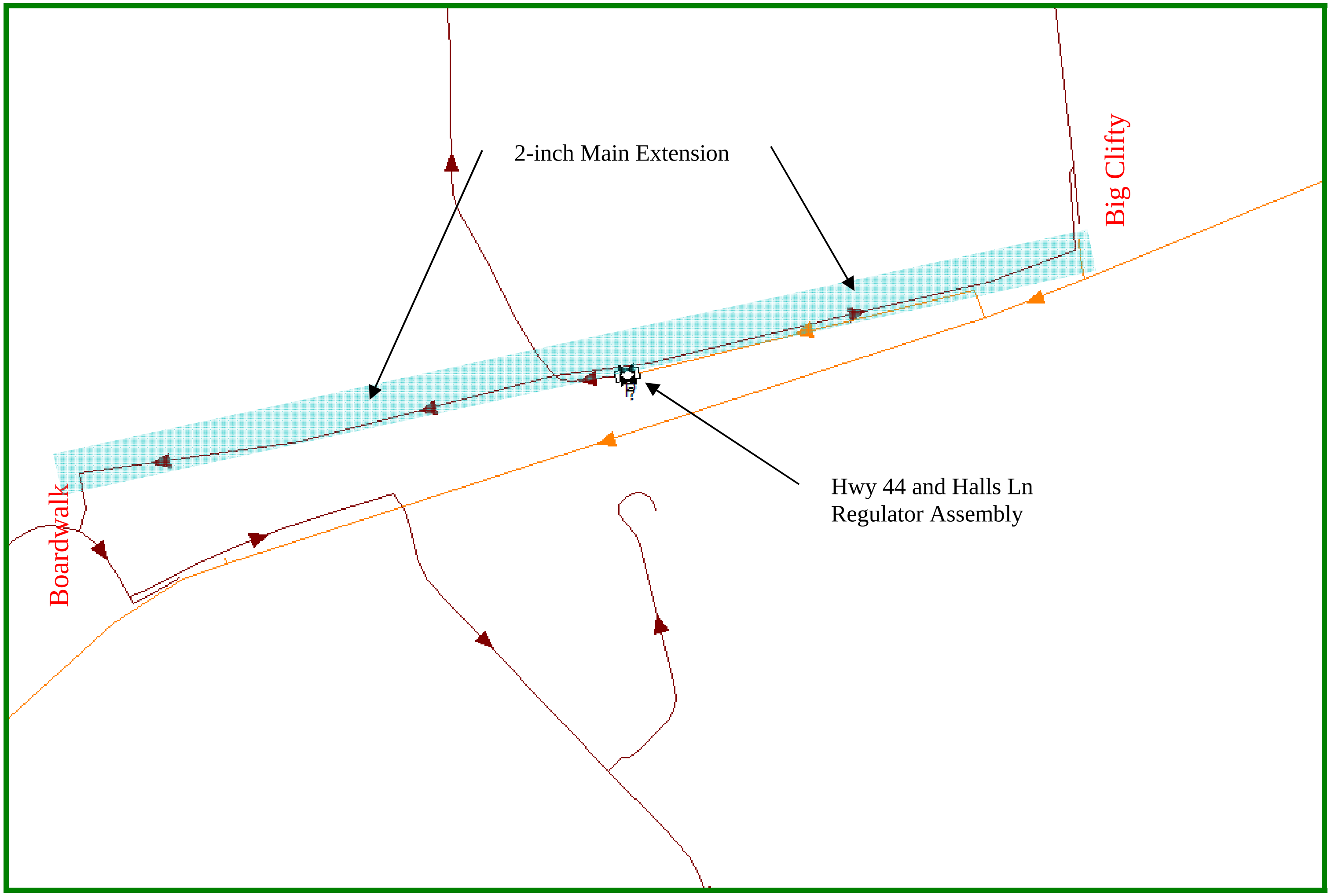
- Winding Woods Trail **– 27.2 psig**

Regulator Operating Capacities

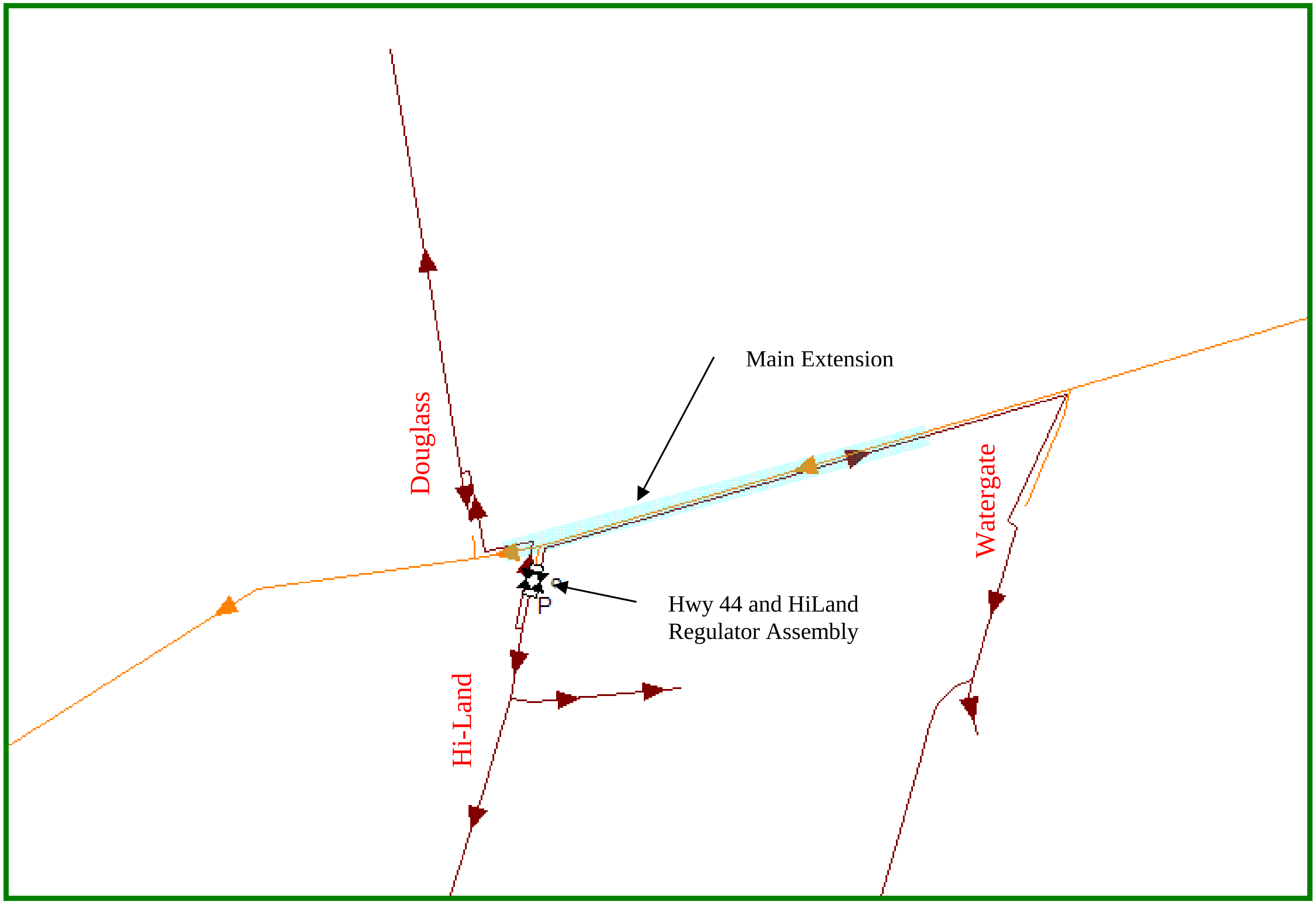
- Hwy 44 and Fisher **– 74.6%**
- Hwy 44 and Woodlake **– 53.0%**

Recommended Timeline – 2009-2011

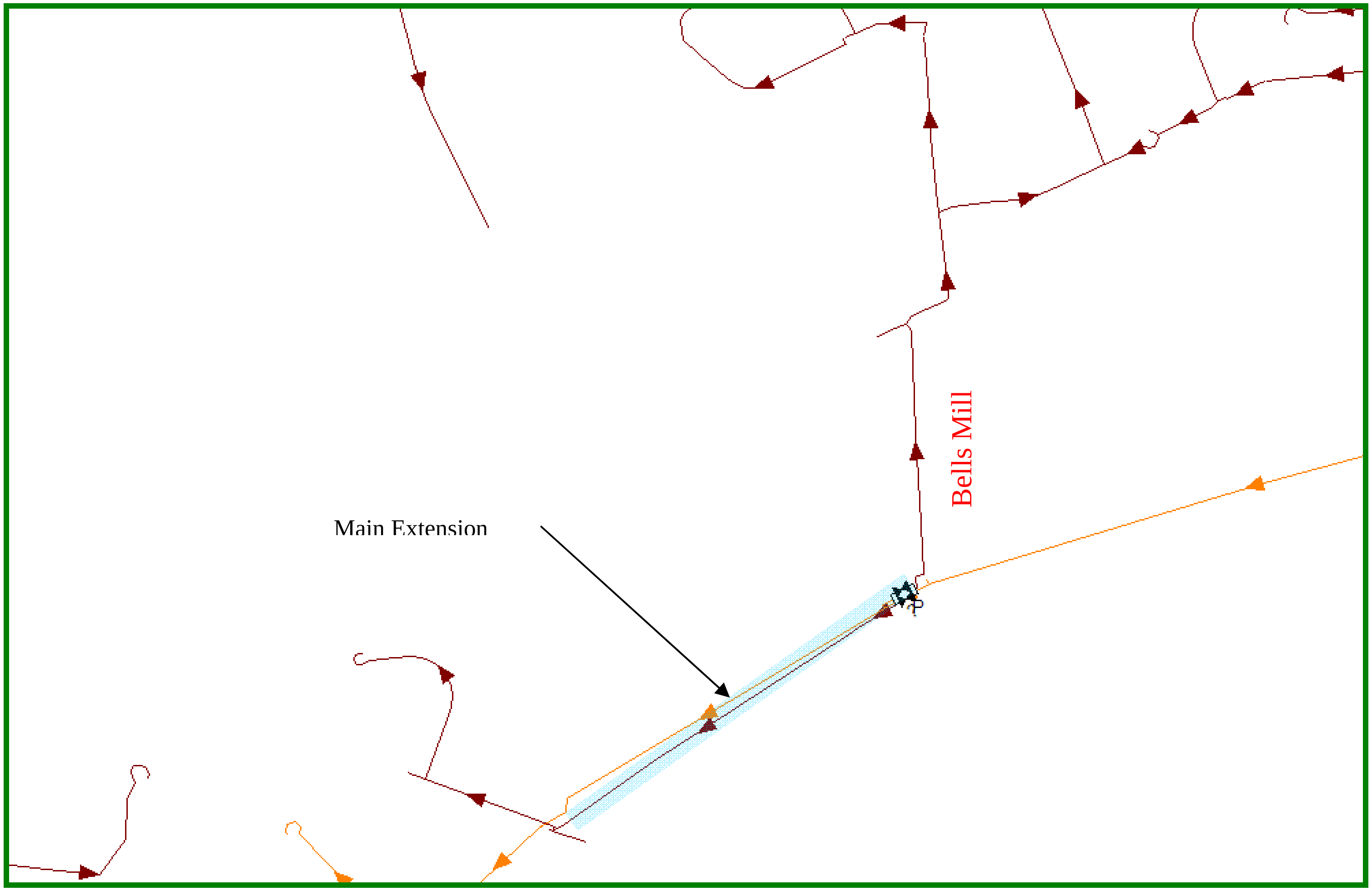
Hwy 44 Regulator Assemblies – Reinforcement 1



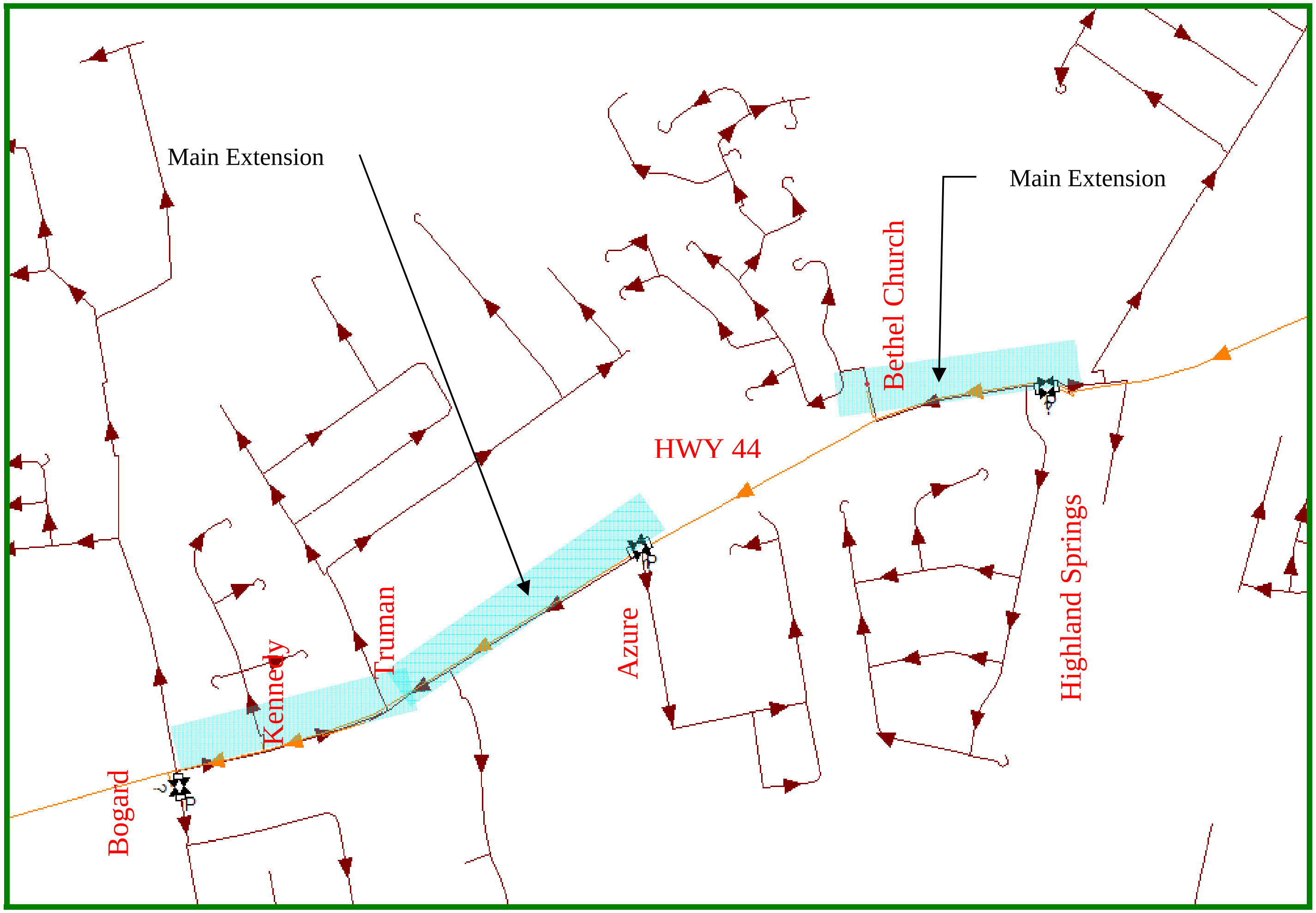
Hwy 44 Regulator Assemblies – Reinforcement 2



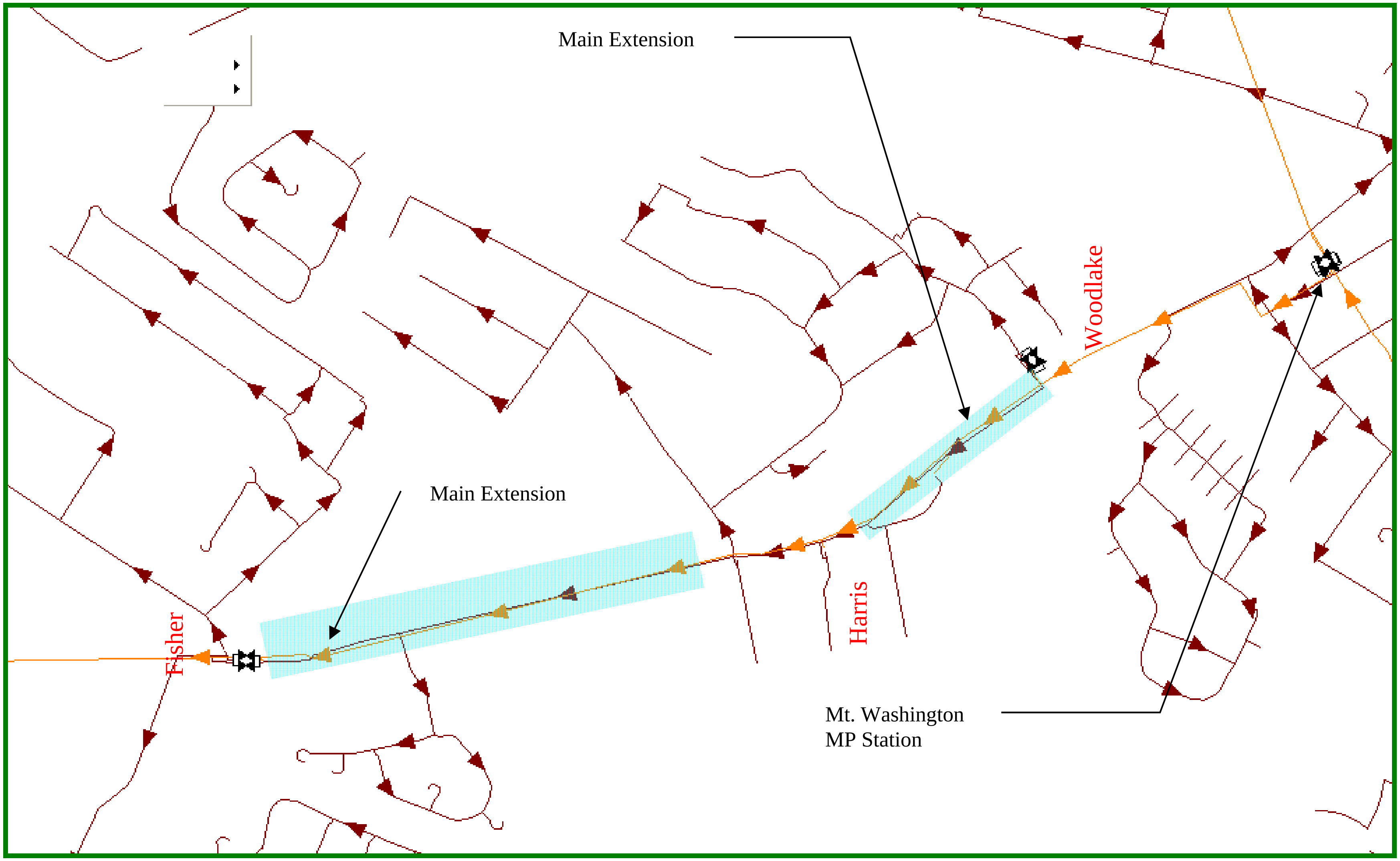
Hwy 44 Regulator Assemblies – Reinforcement 4



Hwy 44 Regulator Assemblies – Reinforcement 5



Hwy 44 Regulator Assemblies – Reinforcement 6



X. Hodgenville Medium Pressure System

Gas System Overview
The Hodgenville medium-pressure gas system serves the City of Hodgenville. This system is composed of residential and small commercial customers. Both sectors continue to experience growth. To continue to cope with growth in Hodgenville, the gas system will need to be reinforced.

Regulator Facilities
The Hodgenville medium-pressure system is fed by the regulator station at State Highway 84 and Glendale Rd.

Maximum Allowable Operating Pressure
The Hodgenville medium-pressure system has a maximum allowable operating pressure of 20 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum pressure is located at **2017 US Highway 31E (15.8 psig)**.

Regulator Operating Capacity
- Highway 84 and Glendale Rd – 15.0%

Recommended Gas System Reinforcement

Reinforcement 1
Uprate the Hodgenville medium pressure gas distribution system to 50 psig. This uprate will affect approximately 1,241 services and 25.3 miles of pipeline.

Minimum Gas System Pressure (-12°F)
- 2017 US Highway 31E – **47.7 psig**

Regulator Operating Capacity
- Highway 84 and Glendale Rd **– 15.8%**

Recommended Timeline – 2008-2009

XI. Waste Management Relocation Project

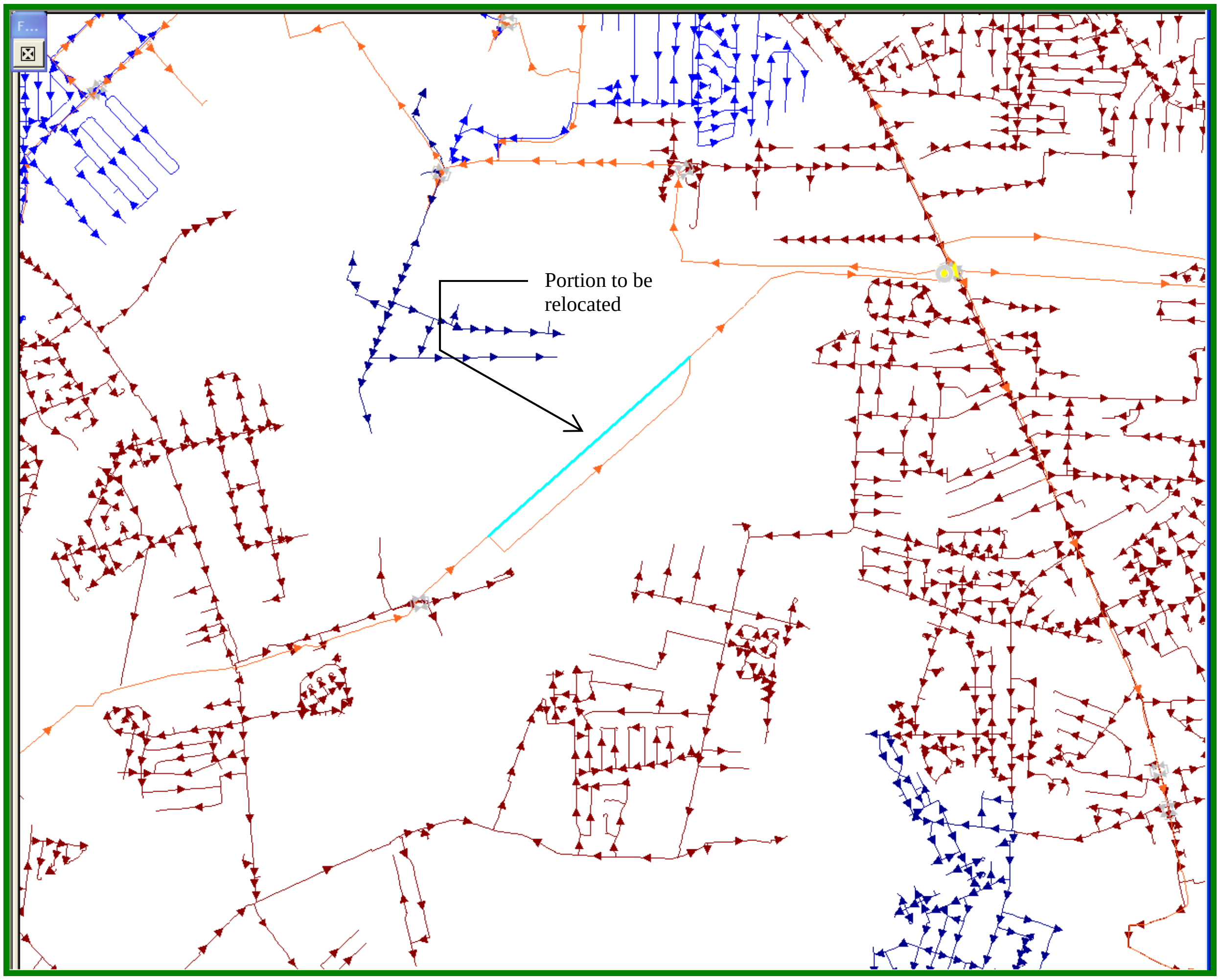
Gas System Overview
The Penile City Gate Station supplies gas to the Preston City Gate Station via a 20-inch transmission pipeline (the Penile to Preston Line). The Penile to Preston Line crosses Waste Management landfill property from the Outer Loop to I-65. The two primary feeds associated with this pipeline are from the Penile and Preston City Gate Stations. Due to planned construction at the landfill, approximately 6,000 ft of the Penile to Preston Line that run through the landfill property must be relocated.

Maximum Allowable Operating Pressure
The Penile to Preston Line has a maximum allowable operating pressure of 420 psig.

Recommended Relocation
Shift the portion of the pipeline that runs through landfill property approximately 500 ft to the southeast. The pipeline should roughly run along an access road in the landfill and should reconnect with the existing pipeline before it crosses underneath I-65. This relocation will require approximately 6,600 ft of 20-inch high-pressure pipeline.

Recommended Timeline – 2008 - 2009

Waste Management Relocation Project – Recommended Relocation



XII. Minor Lane Heights Renaissance Zone

Gas System Overview
The Minor Lane Heights area is being targeted for redevelopment from residential use to commercial and industrial use as a part of a noise mitigation program associated with the Louisville International Airport. Redevelopment is scheduled to occur in five phases, beginning in early 2007 and lasting ten years.

Gas System Reinforcement Completed in 2007

- Retire existing pipeline along Paul Rd south of Zib Ln
- Install approximately 4,300 ft of 8-inch plastic main along Outer Loop, Stinnett Ln, proposed Air Commerce Way to serve UPS facility.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Regulator station at Preston City Gate Station
- Regulator pit at Outer Loop and Grade Ln

Maximum Allowable Operating Pressure
The Minor Lane Heights system has a maximum allowable operating pressure of 35 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure is located at the UPS Supply Chain Solutions warehouse at **2240 Outer Loop (29.9 psig)**. There is another low pressure point at the south end of Eagle Pass (29.6 psig).

Regulator Operating Capacities

- Preston City Gate Station MP – **49.3%**
- Outer Loop and Grade Ln – **29.2%**

Gas System Constraints
Most of the existing gas infrastructure in the Minor Lane Heights system is 2- and 4-inch pipe. In addition, the system is relatively distant from its supplies. This would make it difficult to serve the number of industrial customers proposed for the Renaissance Zone. Furthermore, the proposed layout of the Renaissance Zone would place much of the existing infrastructure below various structures. To account for this, and to serve the projected loads, the Minor Lane Heights system must be altered and reinforced.

XII. Minor Lane Heights Renaissance Zone (cont'd)

Recommended Gas System Reinforcements

Reinforcement 1
Install and remove gas mains according to "An Analysis of the Minors Lane Heights Renaissance Zone" dated 15 January 2007 or the latest version.

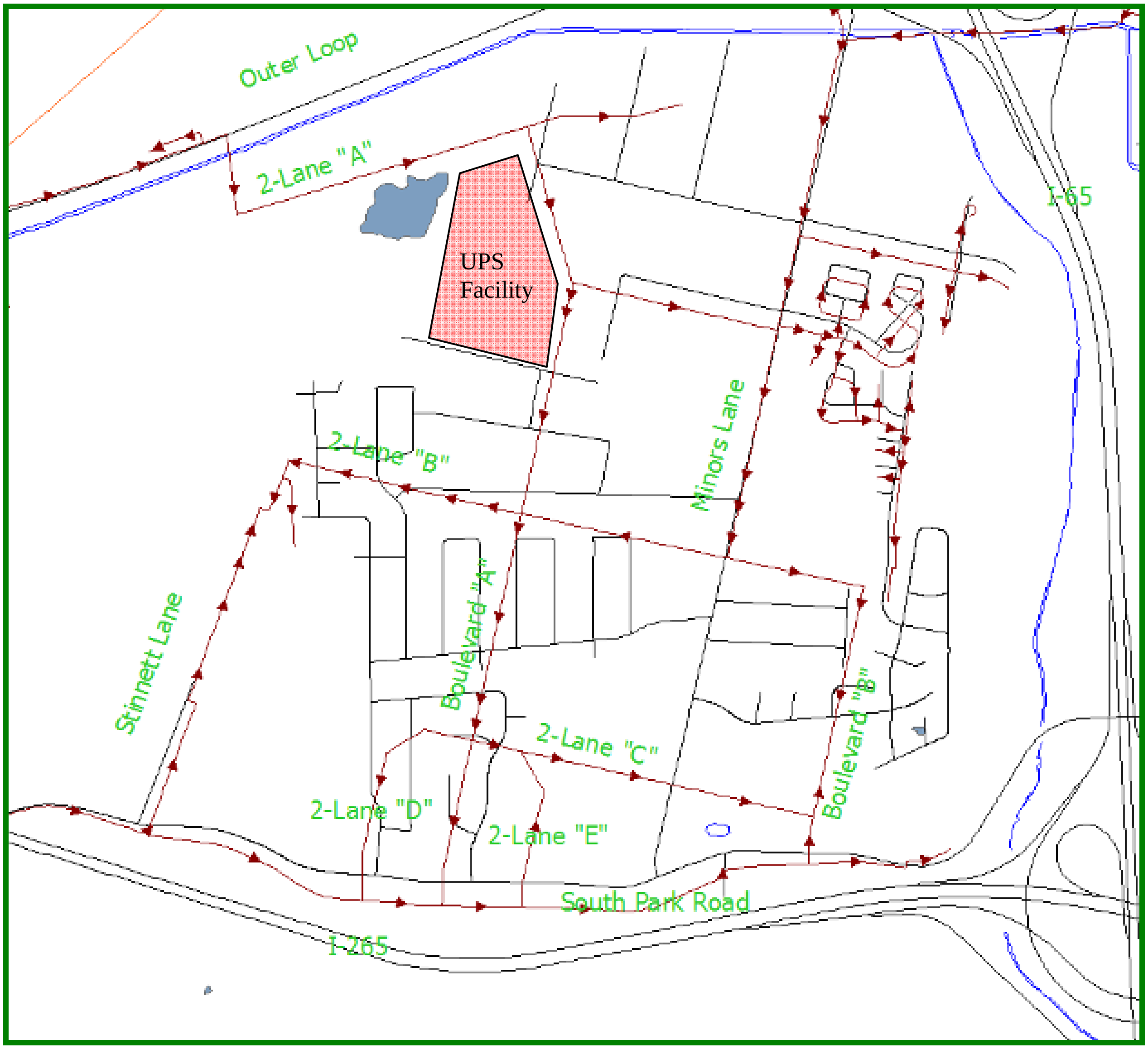
- Retire existing pipelines in the area.
- Install approximately 1,200 ft of 2-inch pipe
- Install approximately 15,400 ft of 4-inch pipe
- Install approximately 5,600 ft of 8-inch pipe

Minimum Gas System Pressure (-12°F)
- UPS Supply Chain Solutions Warehouse (2220 Outer Loop) **– 32.3 psig**

Regulator Operating Capacities
- Preston City Gate Station MP **– 53.1%**
- Outer Loop and Grade Ln **– 41.5%**

Recommended Timeline – 2009-2019

Minor Lane Heights Renaissance Zone – Map of Proposed Streets and Reinforcement 1



XIII. Mount Washington Medium Pressure System

Gas System Overview
The Mount Washington medium pressure gas system serves the City of Mount Washington and surrounding areas. This system is composed of residential and commercial customers. It continues to experience growth in the residential and commercial sectors, especially along Highway 44.

Regulator Facilities
The two regulator facilities that supply gas to the Mount Washington medium pressure system are as follows:

- Regulator station located at Sunnyside Drive and Highway 44 (Mt. Washington MP)
- Regulator assembly located at Landis Lane and Bardstown Road

Maximum Allowable Operating Pressure (MAOP)
The Mount Washington medium pressure gas system has a maximum allowable operating pressure of 60 psig.

Model Results

Minimum Gas System Pressure (-12 ^{0}F):
The predicted minimum pressure is located on **Pin Oak Drive (37.4 psig).**

Regulator Operating Capacities (-12 ^{0}F):
- Mt. Washington MP – **9.3%**
- Bardstown Rd and Landis Ln – **42.1%**

Gas System Constraints
Gas system constraints in this area are primarily due to an infrastructure of 4-inch diameter pipe along Highway 44. Due to current and anticipated growth, it will be necessary to perform gas system reinforcement work.

Recommended Gas System Reinforcements

Reinforcement 1
Install approximately 4,300 ft of 6-inch medium pressure pipeline from Oakland Hills Trail to tie into the existing 4-inch medium pressure pipeline on Waterford Road.

Minimum Gas System Pressure (-12 ^{0}F)
- Pin Oak Dr – **51.7 psig**

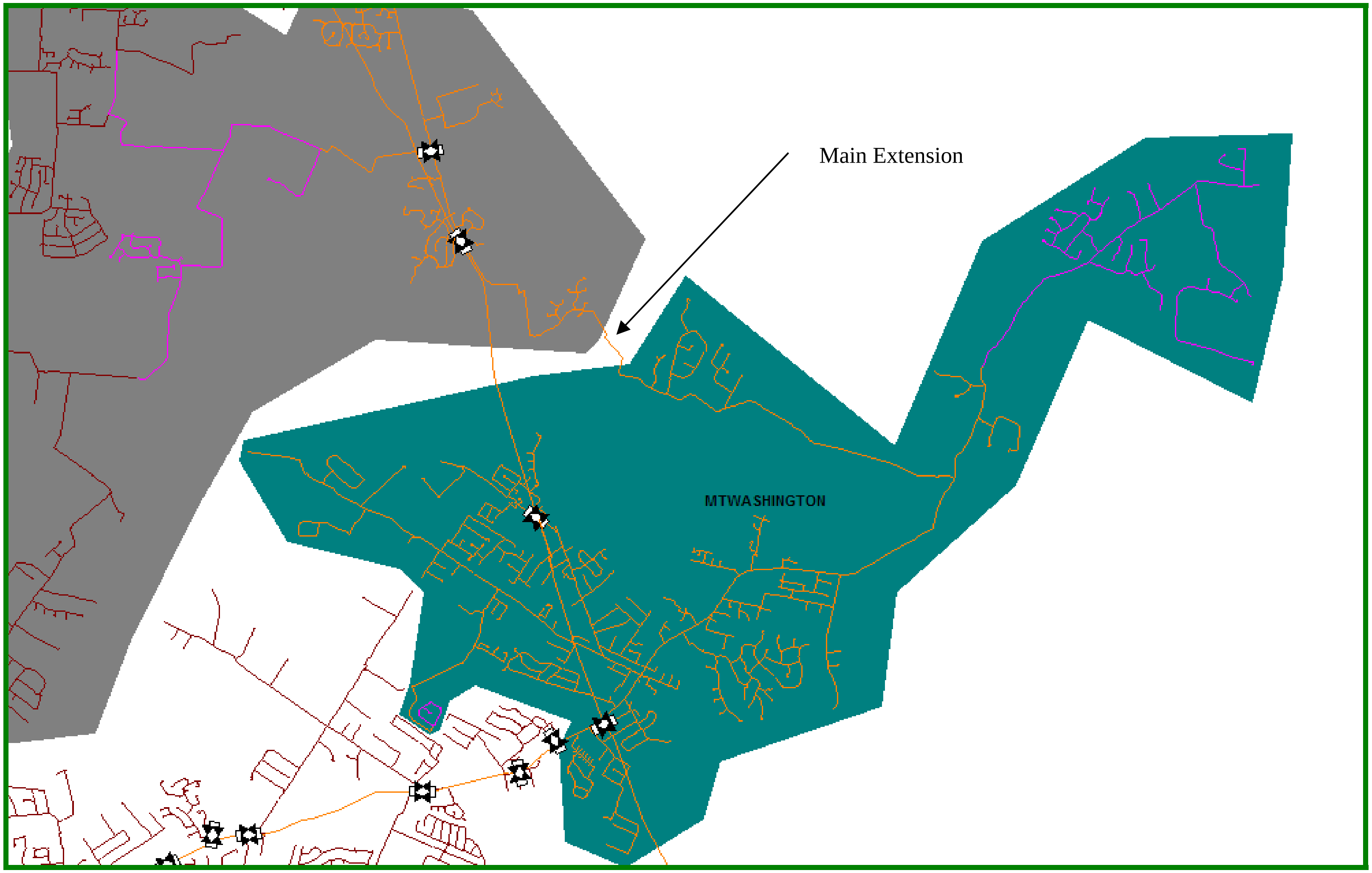
XIII. Mount Washington Medium Pressure System (cont'd)

Regulator Operating Capacities (-12 ^{0}F):

- Mt. Washington MP – **8.0%**
- Bardstown Rd and Landis Ln – **39.9%**
- Vista Hills Blvd and Calvary Line – **100%**

Recommended Timeline – 2008-2009

Mount Washington Medium Pressure System – Reinforcement 1



XIV. Preston High Pressure Distribution Pipeline Reinforcement

Gas System Overview
The Preston high pressure distribution gas system serves the cities of Shepherdsville, Maryville Okolona and outlying areas. The gas supply originates from the Preston City Gate Station to the Preston High Pressure Station and gas pipeline running south. This system is a one-way feed into the Okolona and Maryville areas. These areas have continued to experience growth in the residential and commercial sectors.

Maximum Allowable Operating Pressure
The Preston high pressure system consists of an 8-inch pipeline operating at a maximum allowable pressure of 110 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure for this high pressure system is located at the inlet to the **Preston and Antle regulator pit (68.5 psig)**

Regulator Operating Capacities
- Preston City Gate Station – **37.2%**

Gas System Constraints
Gas system constraints in this area are primarily due to the one-way feed of high pressure gas feeding the distribution systems and the lack of pipe further south along Preston Highway. Due to current and anticipated growth, it will be necessary to perform gas system reinforcement work.

Recommended Gas System Reinforcements

Reinforcement 1
The State Highway Department plans on completing a corridor alignment along Cooper Chapel Road, in the City of Okolona.

- Install approximately 31,850 ft of 12-inch high pressure gas pipeline from the Calvary line to the Preston high pressure line.
- Install a new regulator facility (4x3 Mooney assemblies with 100% plates) at Preston Highway and Cooper Chapel Road to reduce the pressure from the Calvary Line to 110 psig.

Minimum Gas System Pressure (-12°F)
- Preston and Antle inlet **– 96.3 psig**

Regulator Operating Capacities
- New facility at Cooper Chapel and Preston Highway **– 42.3%**

XIV. Preston High Pressure Distribution Pipeline Reinforcement (cont'd)

Eventually, the pipeline would be extended further south along Preston Highway and this would allow a second feed for the high pressure system (see Section XIX). Without the second feed, if the Preston high pressure pipeline was damaged, the areas of Okolona and Maryville and a portion of Shepherdsville would be lost.

Recommended Timeline – TBD

Reinforcement 2

- Extend the 8-inch steel high-pressure main south along Preston Highway from Mud Lane to Bells Mill Road (approx. 19,000 feet).
- Install a medium pressure regulator facility at Bells Mill Road and Preston Highway (4x3 Mooney with 100% plates) to be tied into the 8-inch medium pressure main on Preston Highway or Bells Mill Road.

Minimum Gas System Pressure (-12°F)

- Inlet to new Facility at Preston & Bells Mill **– 70.5 psig**

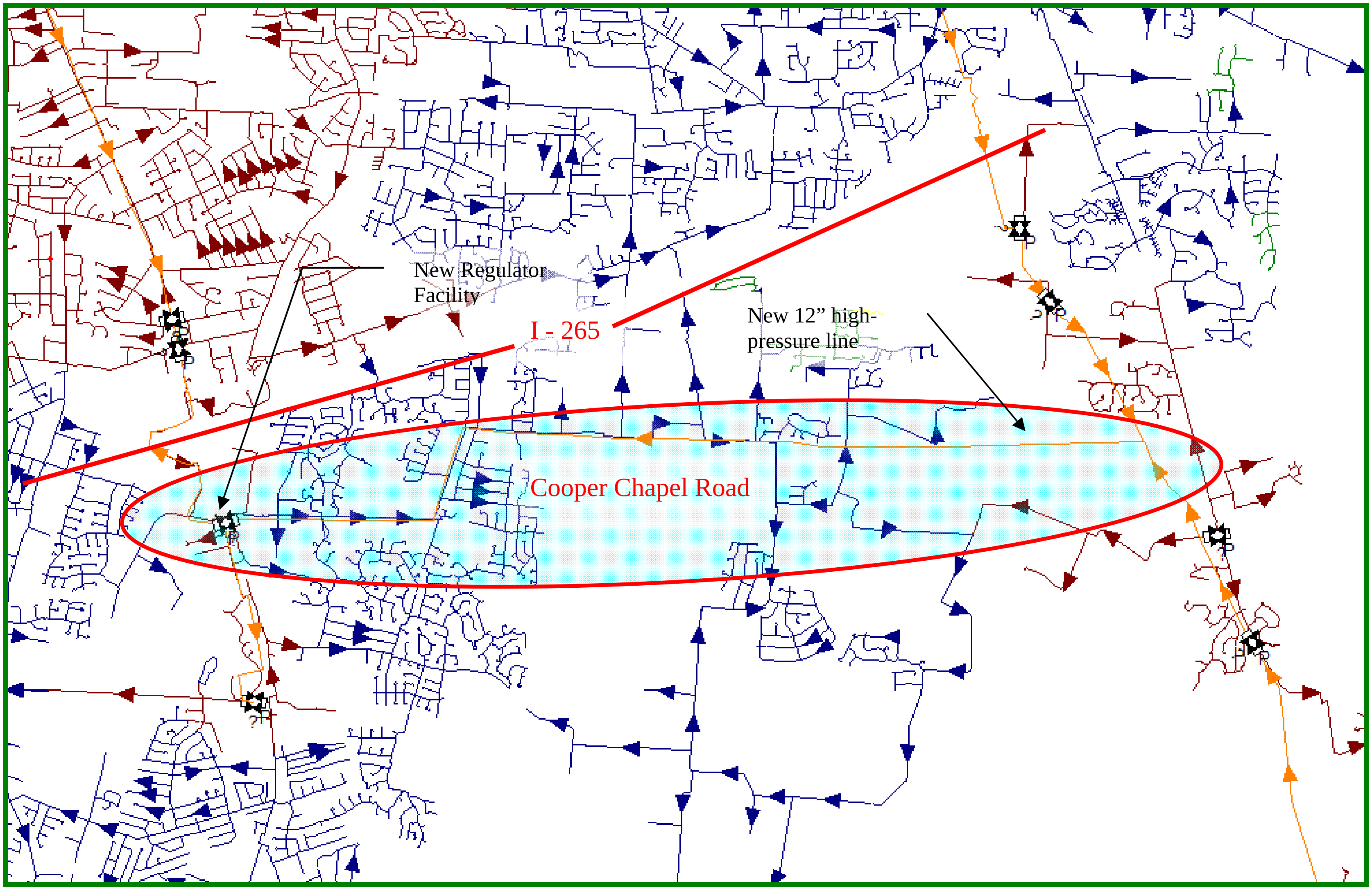
Regulator Operating Capacities

- Cooper Chapel and Preston **– 49.9%**
- Preston and Antle **– 58.2%**
- Preston and Bells Mill **– 100%**

Note: The current pressure on the Preston HP line prohibits a significant pressure differential across the new regulator assembly. The results shown are after Reinforcement 1 has been completed and assuming Shepherdsville/Northern Bullitt MP system has been uprated. Operating the Preston HP line at its 140 psig MAOP significantly improves the inlet pressure (110 psig) to the new assembly.

Recommended Timeline – TBD; after completion of Reinforcement 1

Preston Highway High Pressure Pipeline – Reinforcement 1



XV. Mt. Washington/Lebanon Junction High Pressure Distribution System

Gas System Overview
The Mount Washington/Lebanon Junction system is a one-way feed high pressure distribution system that receives its gas supply from LG&E's Calvary gas transmission pipeline in the Mount Washington area. The high pressure system consists of 8-inch and 6-inch pipe.

There are five major existing gas loads associated with this high pressure system. They are as follows:

- City of Shepherdsville
- City of Lebanon Junction
- Jim Beam Boston Plant
- Jim Beam Clermont Plant
- Publishers Printing

There are five major new gas loads associated with this high pressure system. They are as follows:

- Heritage Hills subdivision
- Gordon Foods
- Shepherdsville Industrial Park
- Highway 480 Industrial Park
- Salt River Business Park

The following points can be summarized from the gas system planning analyses:

- The Mount Washington high pressure gas distribution system must operate at 275 psig in order to operate the Shepherdsville gas distribution system at 60 psig on a design day (-12 ^{0}F).
- LG&E can meet the gas service requirements for Publishers Printing and Jim Beam Boston on a design day (-12 ^{0}F) with the proposed gas loads for 2005 and the Mount Washington high pressure system operating at 275 psig.
- Approximately 60-65 MCFH of gas load can be added to the 6-inch high pressure pipeline near Clermont while maintaining approximately 56 psig at Boston, Kentucky with the proposed total connected gas loads and the Mount Washington high pressure system operating at 275 psig.
- LG&E can meet gas load projections until 2016 with a 2% residential and commercial load growth projection and the Shepherdsville gas distribution system uprated to 60 psig. A pipeline reinforcement project will need to be completed by November 1, 2016.
- LG&E can meet gas load projections until 2012 with a 4% residential and commercial load growth projection and the Shepherdsville gas distribution system uprated to 60 psig. A pipeline reinforcement project will need to be completed by November 1, 2012.

XV. Mt. Washington/Lebanon Junction High Pressure Distribution System (cont'd)

- LG&E can meet gas load projections until 2011 with a 5% residential and commercial load growth projection and the Shepherdsville gas distribution system uprated to 60 psig. A pipeline reinforcement project will need to be completed by November 1, 2011.

Recommended Gas System Reinforcements

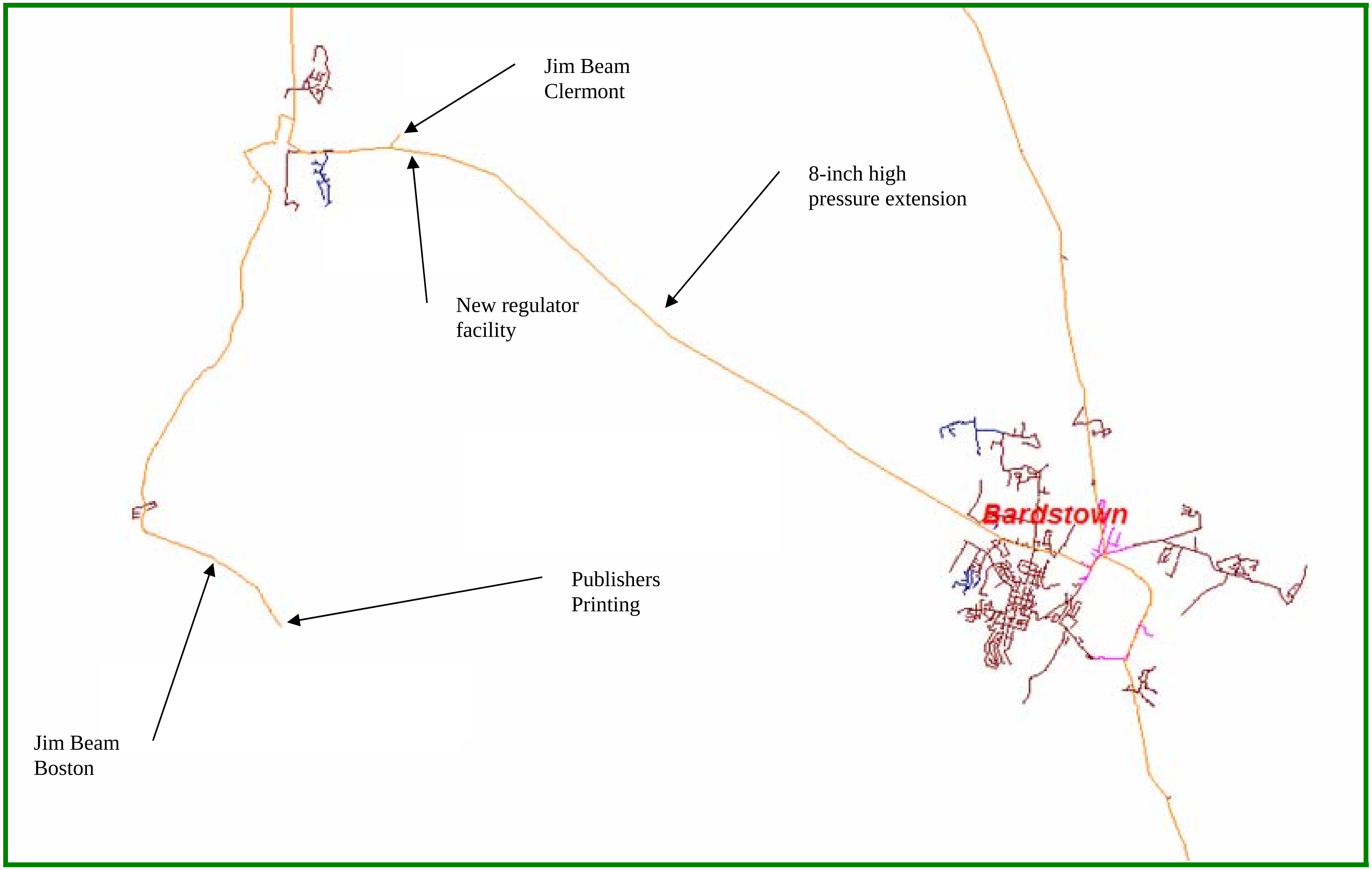
Reinforcement 1
Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line in Bardstown, KY, along Hwy 245 to Clermont, serving south to Lebanon Junction. This would require installing approximately 14.0 miles of 8-inch high-pressure (400 MAOP) piping and a new regulator facility near the Jim Beam Clermont Distillery on Hwy 245. This system reinforcement would solve current and future pressure problems as well as eliminating other risk factors by adding an additional gas supply to a dead end system.

Based on the projected load growth resulting from the two new business parks in the Shepherdsville area, Heritage Hills subdivision, Jim Beam in Boston, and Publishers Printing in Lebanon Junction, along with projected 4% growth from existing residential and commercial customer base a new pipeline is projected to be required in 2012.

Recommended Timeline – 2012

Note: For further information regarding proposed reinforcements to this system, see Section XXII.

Mt. Washington High Pressure Distribution System – Reinforcement 1



XVI. Shepherdsville/Northern Bullitt County Medium Pressure System

Gas System Overview
The Shepherdsville/Northern Bullitt medium pressure gas system serves residential and commercial customers in the City of Shepherdsville and outlying areas between I-265 and Hwy 44.

Regulator Facilities
The regulator facilities that supply gas to the Shepherdsville/Northern Bullitt medium pressure system are as follows:

- Regulator pit at Lee's Lane and Highway 44
- Regulator pit at Cedar Grove Road and I-65
- Regulator pit at Mud Lane and Antle Drive
- Regulator pit at Old Bardstown Road and Thixton Lane
- Regulator pit at Vista Hills Blvd and Calvary Line

Maximum Allowable Operating Pressure
The Shepherdsville/Northern Bullitt medium pressure gas system has a maximum allowable operating pressure of 60 psig.

Model Results

Minimum Gas System Pressure (-12 ^{0}F)
The predicted minimum gas system pressure for this medium pressure system is located at **8804 Cedar Creek Rd (39.8 psig)**

Regulator Operating Capacities
- Hwy 44 and Lee's Ln – **36.6%**
- Cedar Grove Rd and I-65 – **14.7%**
- Mud Ln and Antle Dr – **100%**
- Old Bardstown Rd and Thixton Ln – **6.4%**
- Vista Hills Blvd and Calvary Line – **47.6%**

Gas System Constraints
Gas system constraints in this area are due to an infrastructure of small diameter pipe in the Thixton Lane and Cedar Creek Road areas in the northeastern portion of this system. There is also a severe lack of redundancy in this area which is adding to the pressure problems. Making the system more redundant in this area would prevent outages due to third-party damage or other causes.

A public works project is planned to widen (and reroute) a portion of Preston Hwy between Shepherds Way and Hebron Ln.

XVI. Shepherdsville/Northern Bullitt County Medium Pressure System (cont'd)

Recommended Gas System Reinforcements:

Reinforcement 1

Install approximately 4,200 feet of 6-inch plastic main on Thixton Lane from Taylor Rae Drive south to the existing 6-inch plastic main located near 8506 Thixton Lane.

Minimum gas system pressure (-12 ^{0}F)

- 517 Lakes of Dogwood Blvd – **40.7 psig**

Regulator Operating Capacities

- Hwy 44 and Lee's Ln – **36.2%**
- Cedar Grove Rd and I-65 – **14.8%**
- Mud Ln and Antle Dr – **100%**
- Old Bardstown Rd and Thixton Ln – **7.5%**
- Vista Hills Blvd and Calvary Line – **100%**

Recommended Timeline – 2009

Reinforcement 2

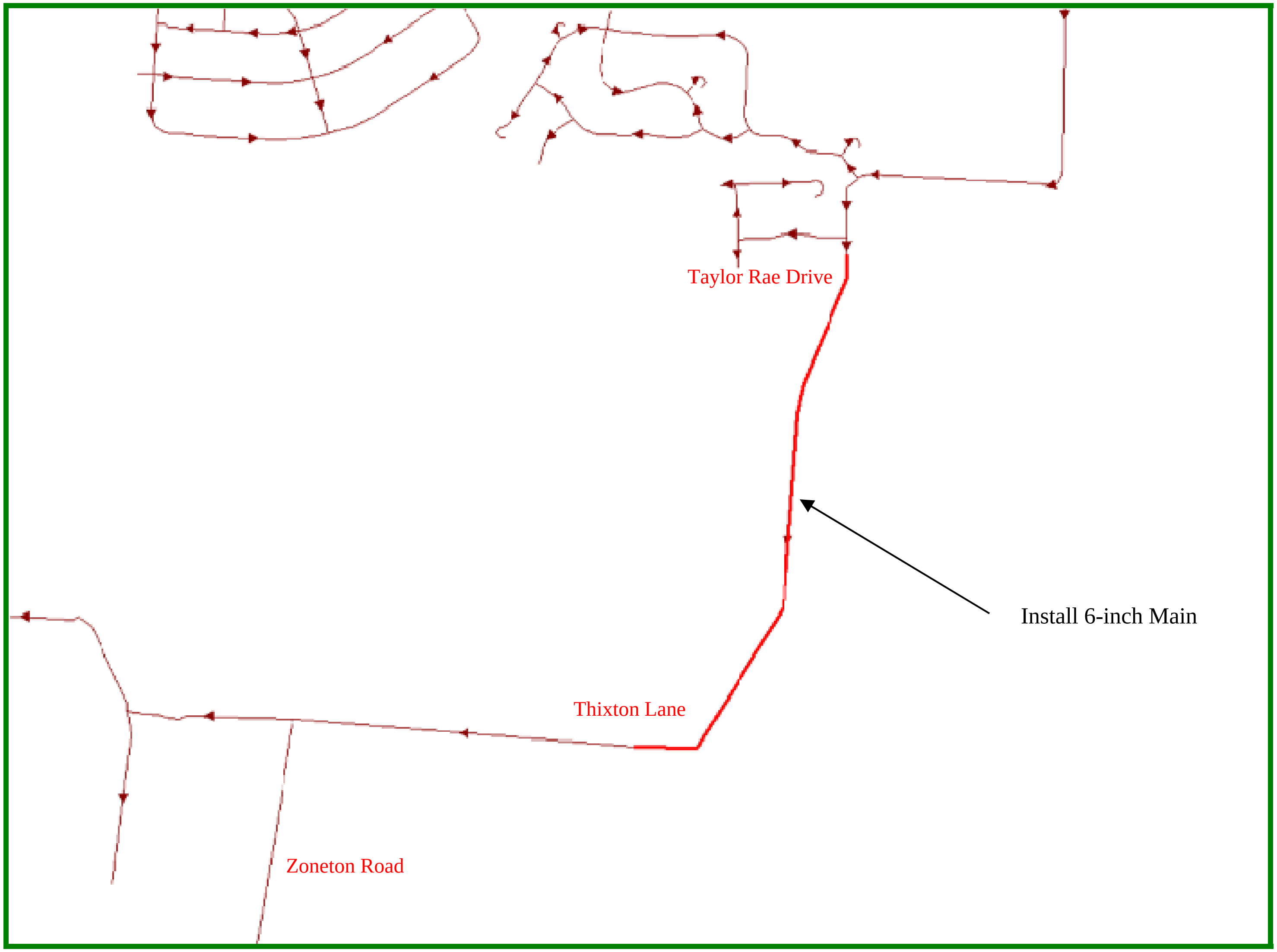
- Extend 1,700 feet of 6-inch plastic main from John D. Harper Blvd to Cobblestone Way to serve customers and the subdivision disconnected from the 8-inch main on Preston Hwy.
- Extend 1,500 feet 4-inch plastic main from John D Harper Blvd south to Hebron Lane.
- Extend 500 feet of 6-inch main from Lodie Lane, across Preston Hwy, and reconnect to the Cobblestone Way 6-inch main

Minimum gas system pressure (-12 ^{0}F)

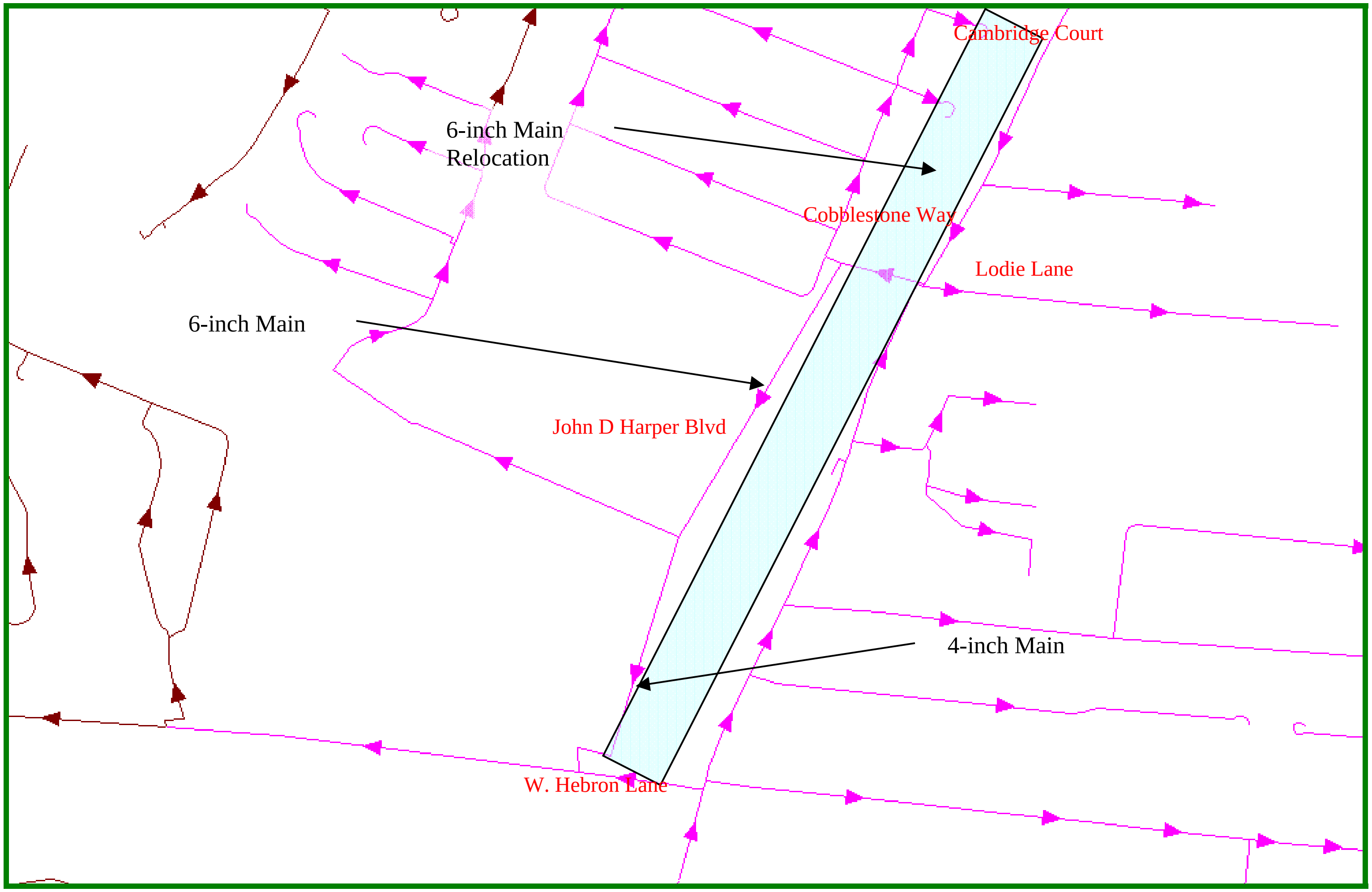
- 8804 Cedar Creek Rd – **42.6 psig**
- Reichmuth Ln – **46.9 psig**

Recommended Timeline – Concurrent with the highway work along Preston Highway.

Shepherdsville/N. Bullitt Medium Pressure System – Reinforcement 1



Shepherdsville/N. Bullitt Medium Pressure System – Reinforcement 2



XVII. Brandenburg High Pressure System

Gas System Overview
The Brandenburg high-pressure distribution system serves the cities of Brandenburg and Doe Valley, and the surrounding area. Gas is supplied from Doe Run storage field lines at Riggs Junction. The Brandenburg area continues to experience residential and commercial growth.

Note: The pipeline in this system may be in poor condition. Field data collected during the 2002/2003 heating season indicated pressure loss higher than predicted from the system model. This may be due to water intrusion and iron sulfide in the pipeline. Further data should be collected to monitor the condition of this pipeline.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum pressure is at the inlet of the regulator pit serving the Brandenburg medium-pressure system located at **Old US 60 and Highway 933 (105.8 psig)**.

XVIII. Radcliff/Fort Knox Medium Pressure System

Gas System Overview

The Radcliff/Fort Knox medium pressure system serves approximately 4,600 residential and small commercial customers. Currently only two customers on the system require delivery pressure above 2 psig: Cardinal Health at 2 psig and Tri-County Ford at 2.5 psig. Due to Base Realignment and Closure (BRAC) changes at Fort Knox, it is anticipated that approximately 3,500 military employees will be relocating to the Radcliff/ Fort Knox area over the next 8 years.

Regulator Facilities

The regulator facilities that feed this system are as follows:

- Radcliff #1 at the corner of N Dixie Blvd and Northern Rd.
- Radcliff #2 at the intersection of S Logsdon Parkway and W Vine Street.

Maximum Allowable Operating Pressure

The Radcliff/Fort Knox medium pressure system has a maximum allowable operating pressure of 35 psig.

Model Results

Minimum Gas System Pressure (-12°F)

The predicted minimum gas system pressure is located at **1004 Muirfield Ct (32.7 psig).**

Regulator Operating Capacity (includes asphalt plant load):

- Radcliff #1: 19.6% (31.8%)
- Radcliff #2: 69.2% (50.7%)

Gas System Constraints

The two gas supply points for this system are located centrally and on the northeastern end of the system. Rapid system expansion due to BRAC relocations is expected to tax the existing infrastructure. Any significant load increase off St. Andrews Dr will require significant reinforcement.

XVIII. Radcliff/Fort Knox Medium Pressure System (cont'd)

Recommended Gas System Reinforcement

Reinforcement 1

- Replace existing regulators in Radcliff #2 with 4x3 Mooney assemblies with 100% plates.
- Uprate the system from 35 psig to 60 psig.

Note: Additional BRAC load was estimated to be 240 MCFH based on anticipated number of new residences and current load.

Minimum gas system pressure (-12°F)
Hood Ln in the Yarwood Mobile Home Park (57.3 psig)
568 St. Andrews Rd (54.4 psig)

Regulator Operating Capacities

- Radcliff #1 – 33.9%
- Radcliff #2 – 20.7%

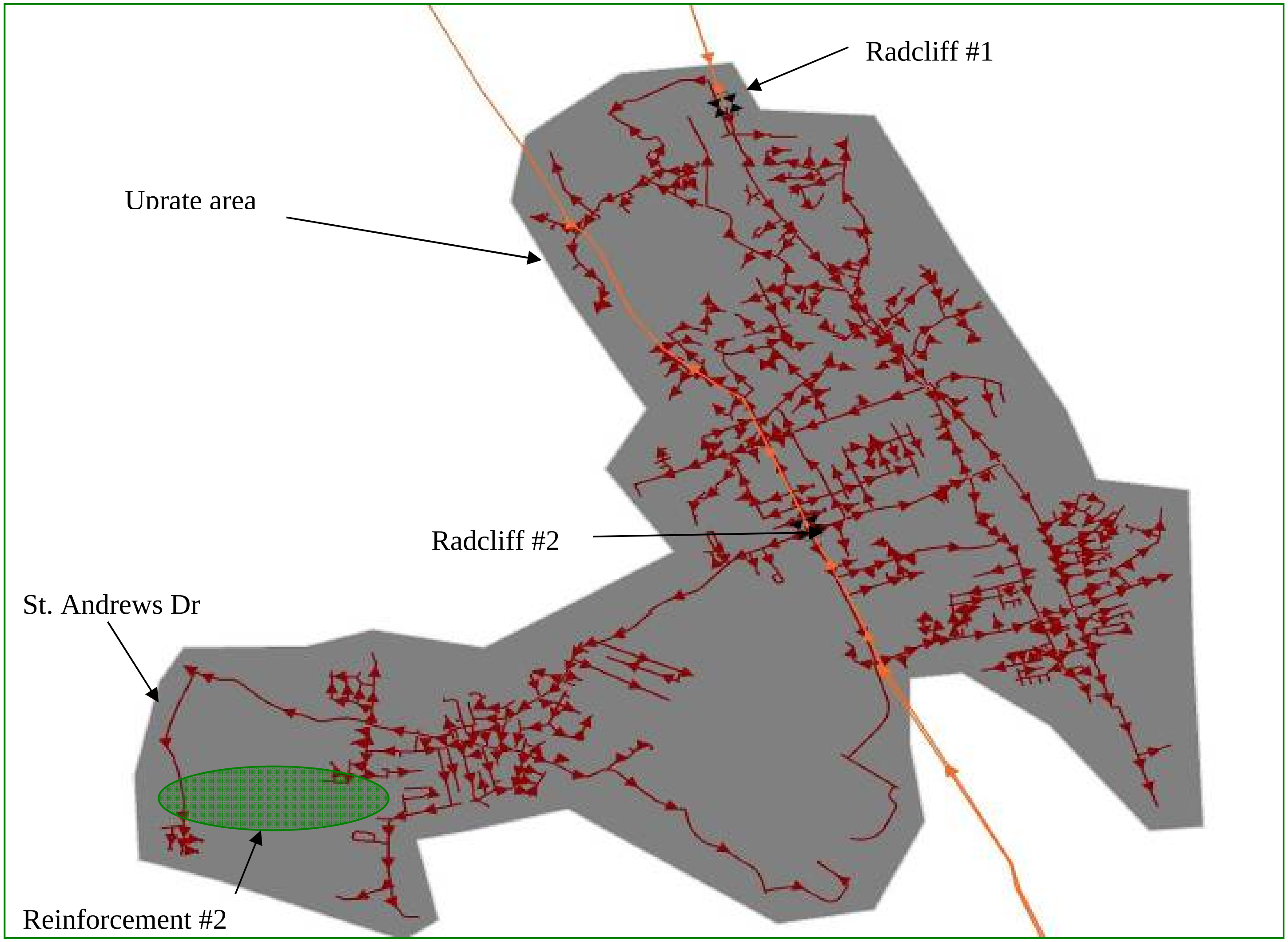
Recommended Timeline – 2009-2011

Reinforcement 2

- Install 4,800' of 4-inch PL main in Otter Creek Rd from existing 4-inch CT to 2-inch PL in St. Andrews Dr.

Note: Reinforcement needed only for significant development off St. Andrews Drive.

Radcliff/Fort Knox – Reinforcement 1 & 2



XIX. Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System

Gas System Overview

The Crestwood/Pee Wee Valley/Simpsonville medium-pressure system will require reinforcement to continue to serve the Norton Commons development and the Old Brownsboro Crossing commercial park, which includes a professional medical center, office buildings, and retail/restaurants. This system also feeds near Persimmon Ridge and the Polo Fields. It has experienced growth away from the only sources of gas in this system. In order to serve current and future loads, it has been determined that reinforcement work will need to be performed on the Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System. There are a few options available that will provide adequate pressures throughout the system.

Gas System Reinforcement Completed in 2007

- Old Henry Road Reinforcement
    - Install 5,700 ft of 8-inch medium pressure pipe north along Old Henry Rd to tie into the 8-inch main at 9207 Ash Land Ct.

Maximum Allowable Operating Pressure

The Crestwood/Pee Wee Valley/Simpsonville medium pressure system has a maximum allowable operating pressure of 50 psig.

Model Results

Minimum gas system pressure (-12 ^{0}F)

- Sasse Way – **13.6 psig**

Regulator Operating Capacities

- HWY 1694 & WORTHINGTON LN – 14.7%
- OLD HENRY RD & TERRA CROSSING BV – 24.8%
- CONNER STATION & COLT RUN RD – 6.2%
- CRESTWOOD & OLD LAGRANGE RD. G-381 – 42.9%
- LAKESHORE DR. & OLD VEECHDALE RD G13108 – 40.3%
- ENGLISH STATION WAY G-580 – 51.0%
- WESTPORT RD.& MURPHY LN. G-456 – 84.3%
- OLD LAGRANGE RD.& COLLINS LN. G-578 – 26.9%

XIX. Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System (cont'd)

Recommended Gas System Reinforcements

Reinforcement Option 1
Loop approximately 7,150 feet of existing 4-inch medium pressure steel and plastic main with 6-inch plastic main along State Hwy 362 (Ash Avenue) from LaGrange Road, southeast to the existing 6-inch plastic main near Ashbrooke Drive.

Minimum gas system pressure (-12 ^{0}F)
- 2629 Hedgepath Trl – **19.9** psig
- 3405 Sasse Way – **13.0** psig
- 1601 Keever Court – **19.3** psig

Reinforcement Option 1a
This reinforcement would be the same as Option 1, but instead of using 6-inch plastic main for the loop, 8-inch plastic main would be used.

Minimum gas system pressure (-12 ^{0}F)
- 2629 Hedgepath Trl – **20.4** psig
- 3405 Sasse Way – **12.8** psig
- 1601 Keever Court – **19.8** psig

Reinforcement Option 2
Loop approximately 3,050 feet of 4-inch medium pressure steel main with 8-inch plastic main along LaGrange Road from the existing 8-inch steel main near Altawood Court, northeast to State Hwy 362 (Ash Avenue).

Minimum gas system pressure (-12 ^{0}F)
- 2629 Hedgepath Trl – **19.5** psig
- 3405 Sasse Way – **20.2** psig
- 1601 Keever Court – **19.0** psig

Reinforcement Option 3
This option would combine the main replacements from Option 1/1a and Option 2. For this option we would need to install 3,050 feet of 8-inch plastic main and 7,150 feet of 6-inch or 8-inch plastic main for a total of 10,200 feet of plastic main.

Minimum gas system pressure with Option 1 & 2 (-12 ^{0}F)
- 2629 Hedgepath Trl – **26.1** psig
- 3405 Sasse Way – **20.0** psig
- 1601 Keever Court – **25.2** psig

Minimum gas system pressure with Option 1a & 2 (-12 ^{0}F)
- 2629 Hedgepath Trl – **26.8** psig
- 3405 Sasse Way – **19.8** psig
- 1601 Keever Court – **25.9** psig

XIX. Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System (cont'd)

Reinforcement Option 4
This option would require the installation of approximately 5,300 feet of 6-inch medium pressure plastic main along Flat Rock Road between Robin Lane and Curry Branch Road.

Minimum gas system pressure (-12 ^{0}F)

- 2629 Hedgepath Trl – **18.9** psig
- 3405 Sasse Way – **15.2** psig
- 1601 Keever Court – **16.8** psig

Reinforcement Option 5
This option would require looping approximately 6,300 feet of 4-inch medium pressure steel main with 8-inch plastic main along Shelbyville Road beginning at the existing 8-inch steel main near Waterstone Way, east to Flat Rock Road.

Minimum gas system pressure (-12 ^{0}F)

- 2629 Hedgepath Trl – **22.5** psig
- 3405 Sasse Way – **16.2** psig
- 1601 Keever Court – **22.7** psig

Reinforcement Option 6
This reinforcement project combines Option 4 and Option 5. The main needed for this project would be 6,300 feet of 8-inch plastic and 5,300 feet of 6-inch plastic for a total of 11,600 feet of plastic main.

Minimum gas system pressure (-12 ^{0}F)

- 2629 Hedgepath Trl – **29.9** psig
- 3405 Sasse Way – **18.8** psig
- 1601 Keever Court – **28.7** psig

Reinforcement Option 7
This reinforcement project combines Options 1a, 2, 4, and 5. The main needed for this project would be 16,500 feet of 8-inch plastic main and 5,300 feet of 6-inch plastic main for a total of 21,800 feet of plastic main.

Minimum gas system pressure (-12 ^{0}F)

- 2629 Hedgepath Trl – **34.7** psig
- 3405 Sasse Way – **22.3** psig
- 1601 Keever Court – **33.4** psig

XIX. Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System (cont'd)

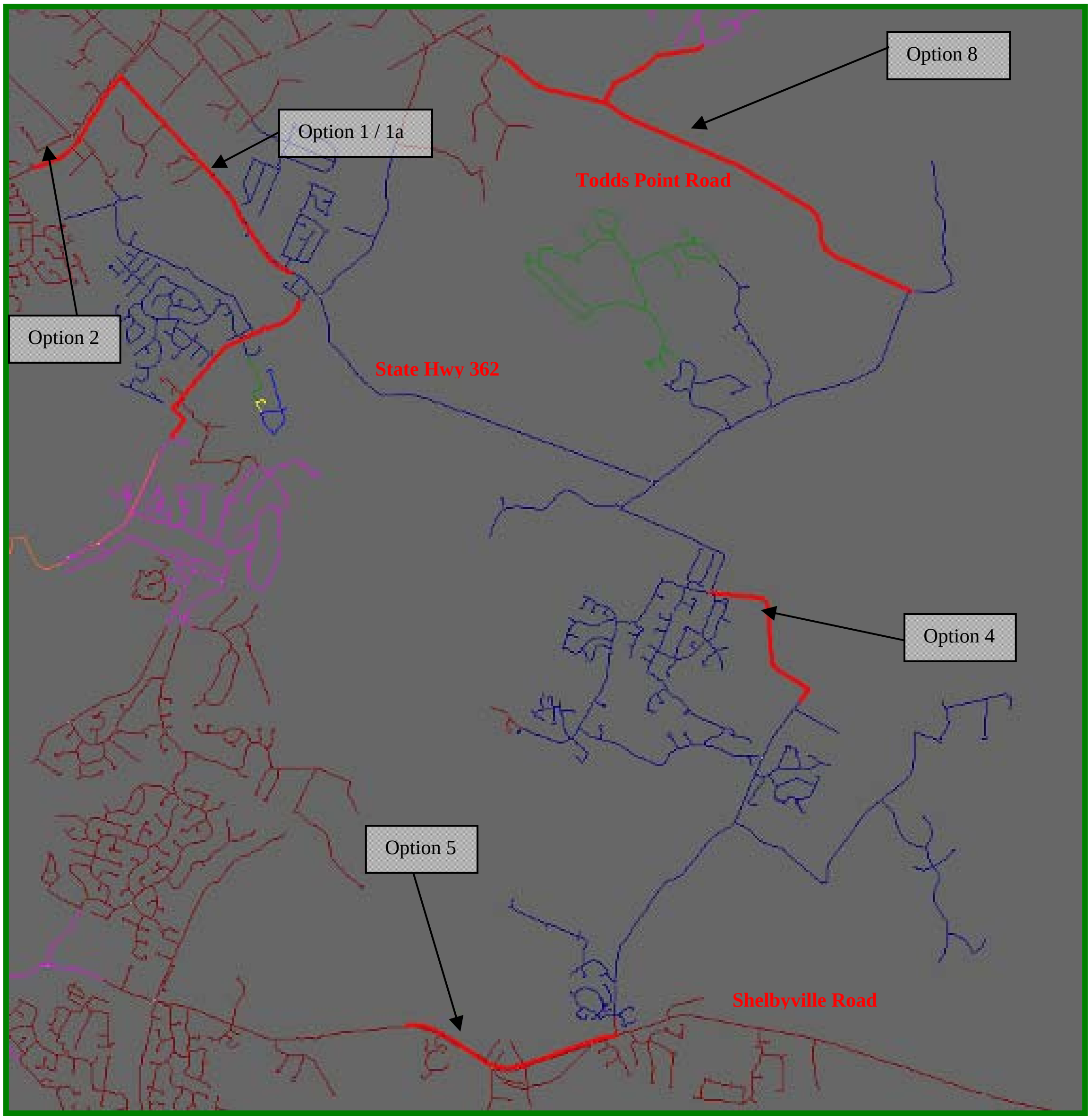
Reinforcement Option 8

This option requires installing approximately 13,400 of 6-inch plastic main on Todds Point Road from the existing 4-inch plastic main near Chapel Drive, southeast to the existing 6-inch plastic main on Aiken Road. Also, an additional 3,400 feet of 6-inch plastic main would need to be installed on State Hwy 1818 from Todds Point Road, northeast to Abbott Lane to connect with a small existing 35 psig system. This existing system would have to be uprated from 35 psig to 50 psig, and the orifice plates at the Abbotts Ln & Myers Ln regulator assembly would need to be changed to 1/2". This option would require installing a total of 16,800 feet of 6-inch plastic main and would require uprating the system consisting 116 services from 35 psig to 50 psig. While this option may not be currently feasible, it would provide another feed into this area and allow for additional growth.

Minimum gas system pressure (-12 ^{0}F)

- 2629 Hedgepath Trl – **34.5** psig
- 3405 Sasse Way – **22.1** psig
- 1601 Keever Court – **32.9** psig

Crestwood/Pee Wee Valley/Simpsonville Reinforcement Options 1-8



- Option 3: Combines Option 1/1a and Option 2
- Option 6: Combines Option 4 and 5
- Option 7: Combines Option 1a, 2, 4 and 5

XX. Appendix – Mt. Washington High Pressure Distribution System

Options Considered
An attempt was made to parallel the existing 8-inch and 6-inch piping in order to solve the pressure and capacity problems. Almost the entire route (approximately 21 miles) of the system would have to be paralleled in order to correct the pressure and capacity problems.

Scenario 1
Install a high-pressure system reinforcement that would bring high-pressure gas from the Preston Highway regulator station to the Shepherdsville regulator pit at Lee Lane and Highway 44 (approximately 12.5 miles). In addition, the existing 6-inch piping (approximately 12 miles) would have to be paralleled in order to alleviate the restriction to moving the gas to the south end of the system.

Project estimated cost: $10.9 MM

Scenario 2
Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line in Bardstown, KY, along Hwy 245 to Clermont, serving south to Lebanon Junction. This would require installing approximately 14.0 miles of 8-inch high-pressure (400 psig MAOP) piping and a new regulator facility near the Jim Beam Clermont Distillery on Hwy 245. This system reinforcement would solve current and future pressure problems as well as eliminating other risk factors by adding an additional gas supply to a dead end system.

Project estimated cost: $6.2 MM

Scenario 3
Install a high-pressure system reinforcement that would bring high-pressure gas from the Magnolia line to the south end of the system. This would require installing approximately 13 miles of 8-inch high-pressure (520 psig MAOP) piping along Highway 434 and a new regulator assembly at the south end of the system. This system reinforcement would correct the current and future pressure and capacity problems by providing a new gas supply in the areas where there is the largest load concentration. In addition, the system reinforcement would provide a second gas supply to the model thus eliminating the risks associated with a dead end system.

Project estimated cost: $5.8 MM

XX. Appendix – Mt. Washington High Pressure Distribution System (cont'd)

Scenario 4

Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line to the south end of the system. This would require installing approximately 16 miles of 8-inch high-pressure (400 psig MAOP) piping and a new regulator assembly at the south end of the system. This system reinforcement would correct the current and future pressure and capacity problems by providing a new gas supply in the areas where there is the largest load concentration. In addition, the system reinforcement would provide a second gas supply to the model thus eliminating the risks associated with a dead end system.

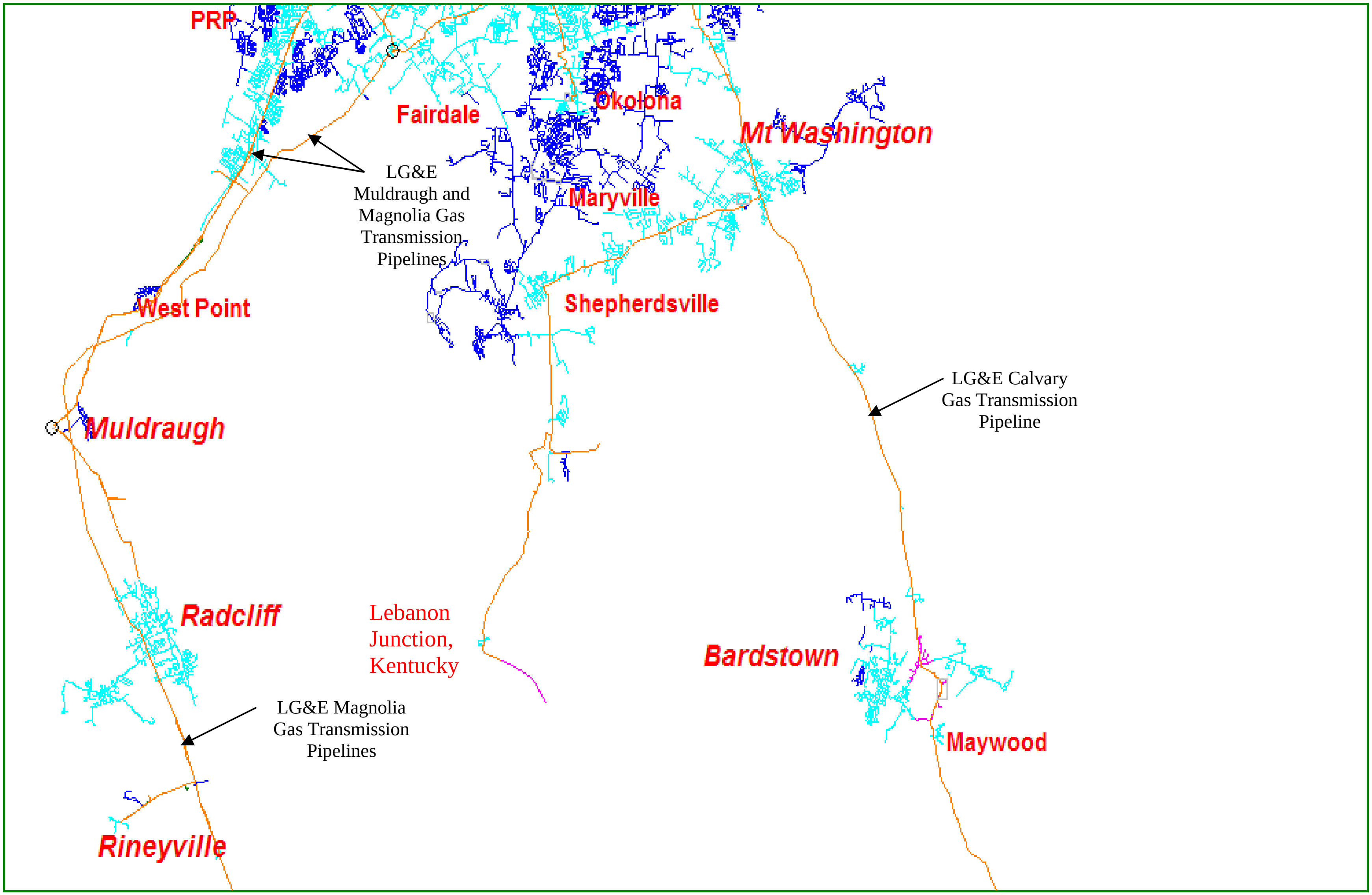
Project estimated cost: $7.1 MM

Scenario 5

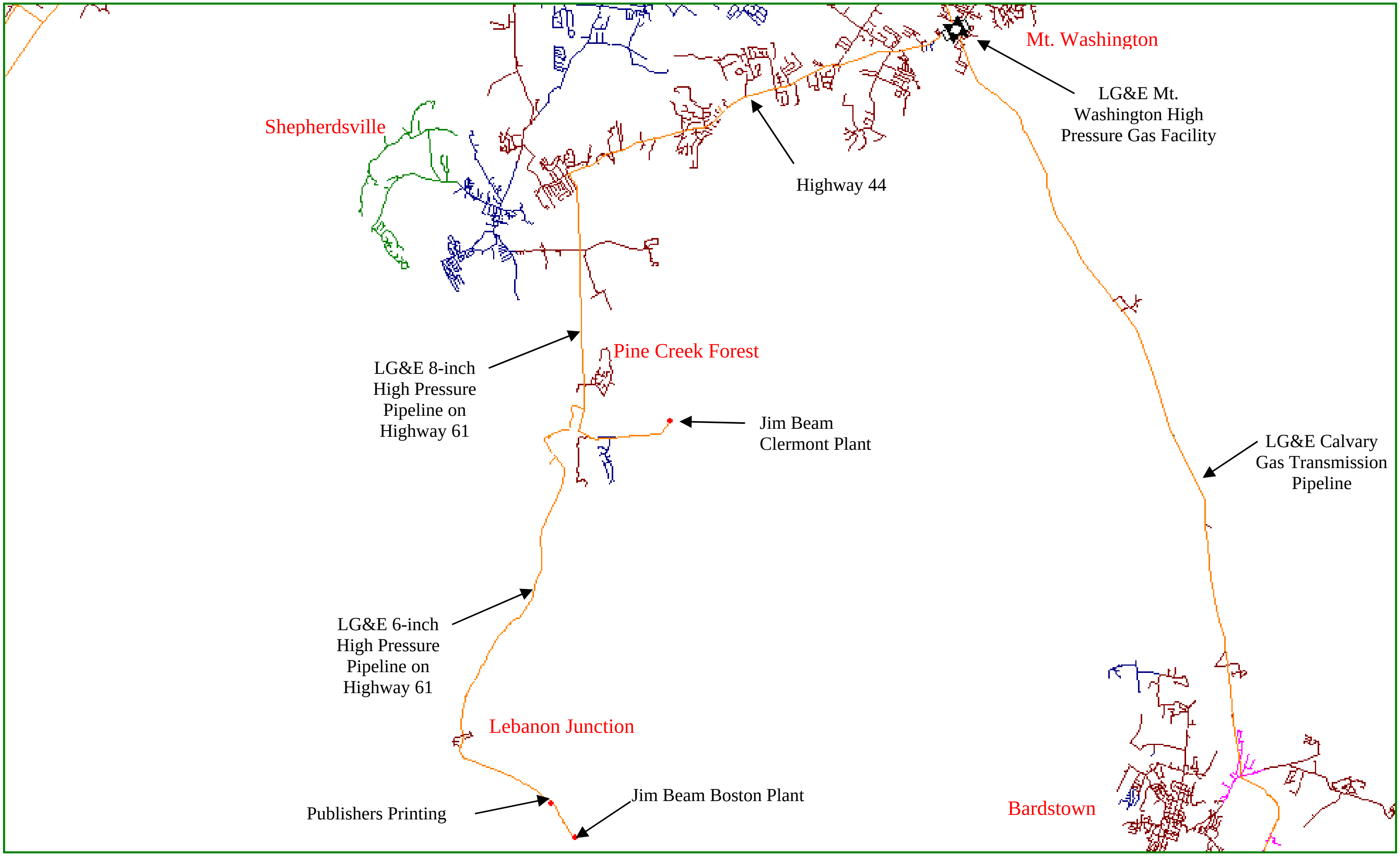
Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line along Hwy 509 and Hwy 245 into Lebanon Junction. This would require installing approximately 12.5 miles of 8-inch high-pressure (400 psig MAOP) piping and a new regulator facility near the Jim Beam Distillery on Hwy 245. This system reinforcement would solve current and future pressure problems as well as eliminating other risk factors by adding an additional gas supply to a dead end system.

Project estimated cost: $5.5 MM

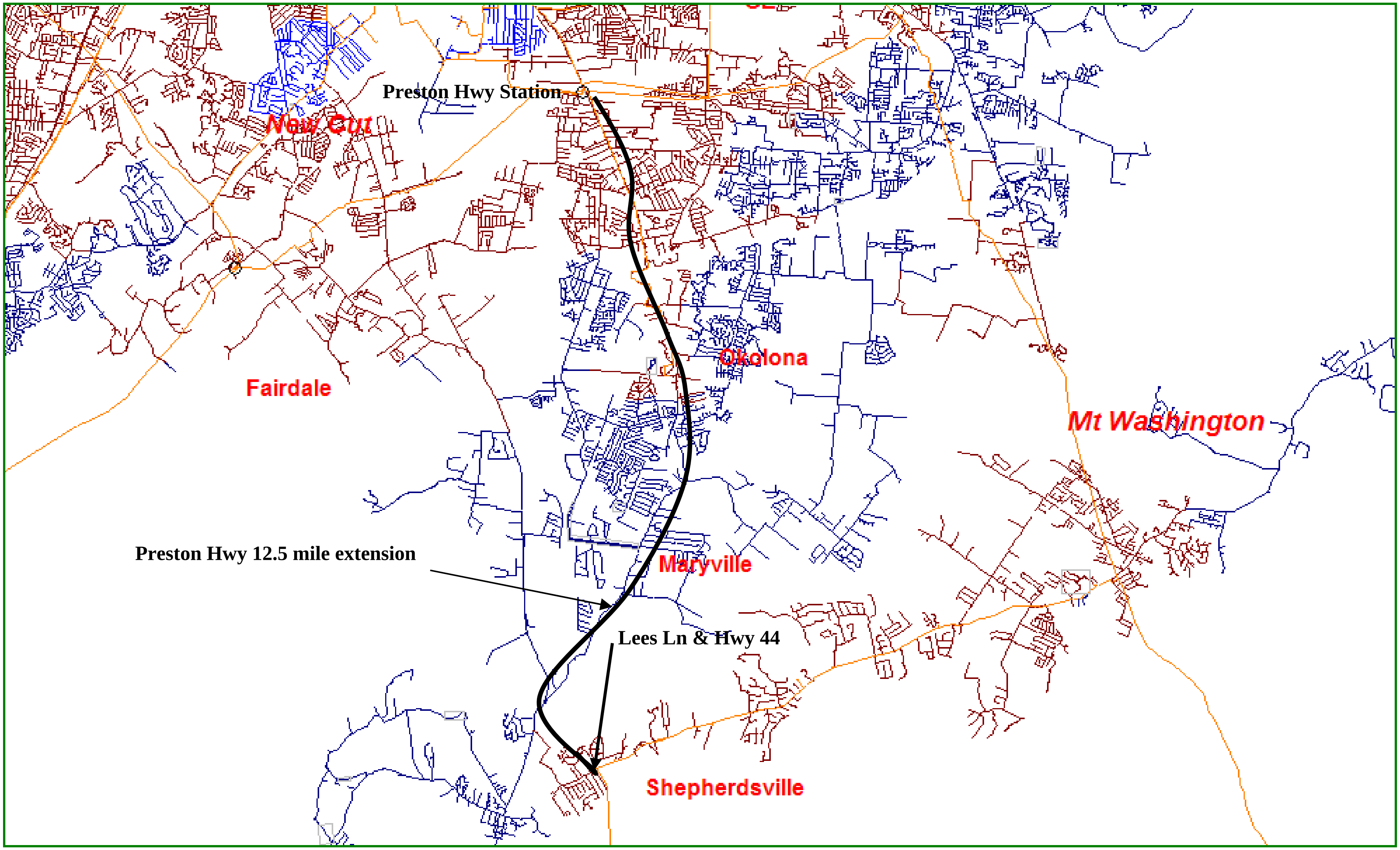
Mt. Washington High Pressure Distribution System – Overview



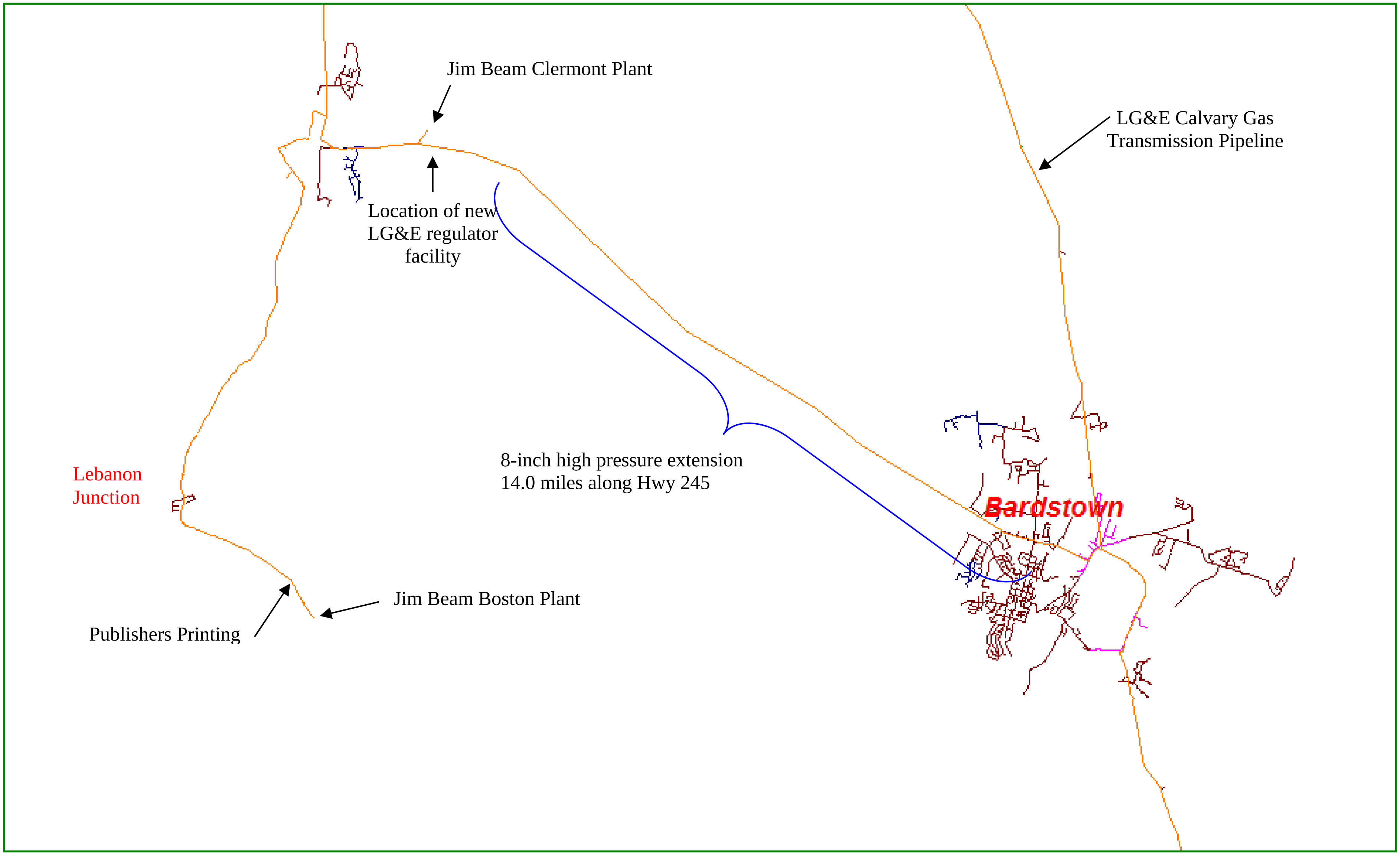
Mt. Washington High Pressure Distribution System – Mt. Washington Overview



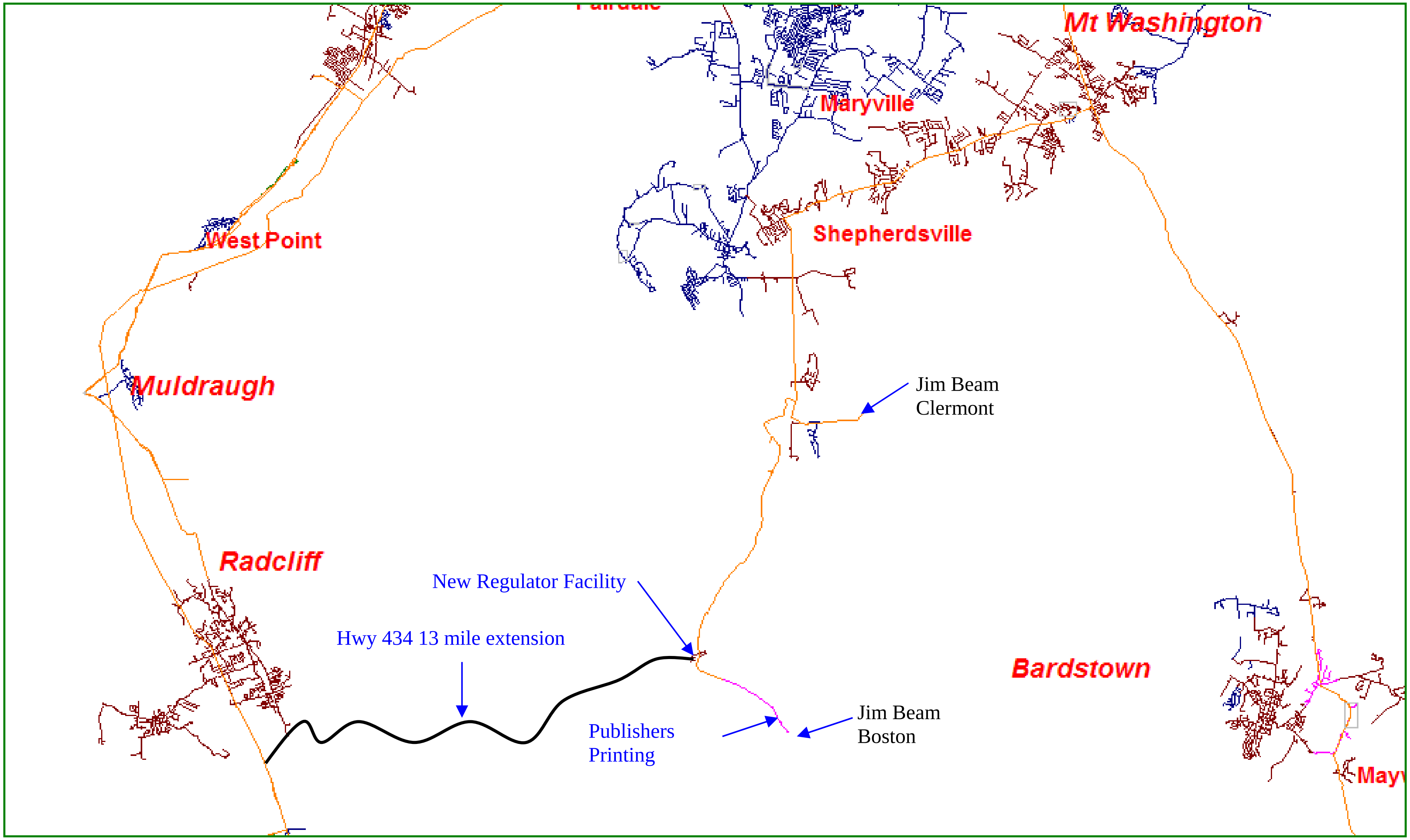
Mt. Washington High Pressure Distribution System – Scenario 1



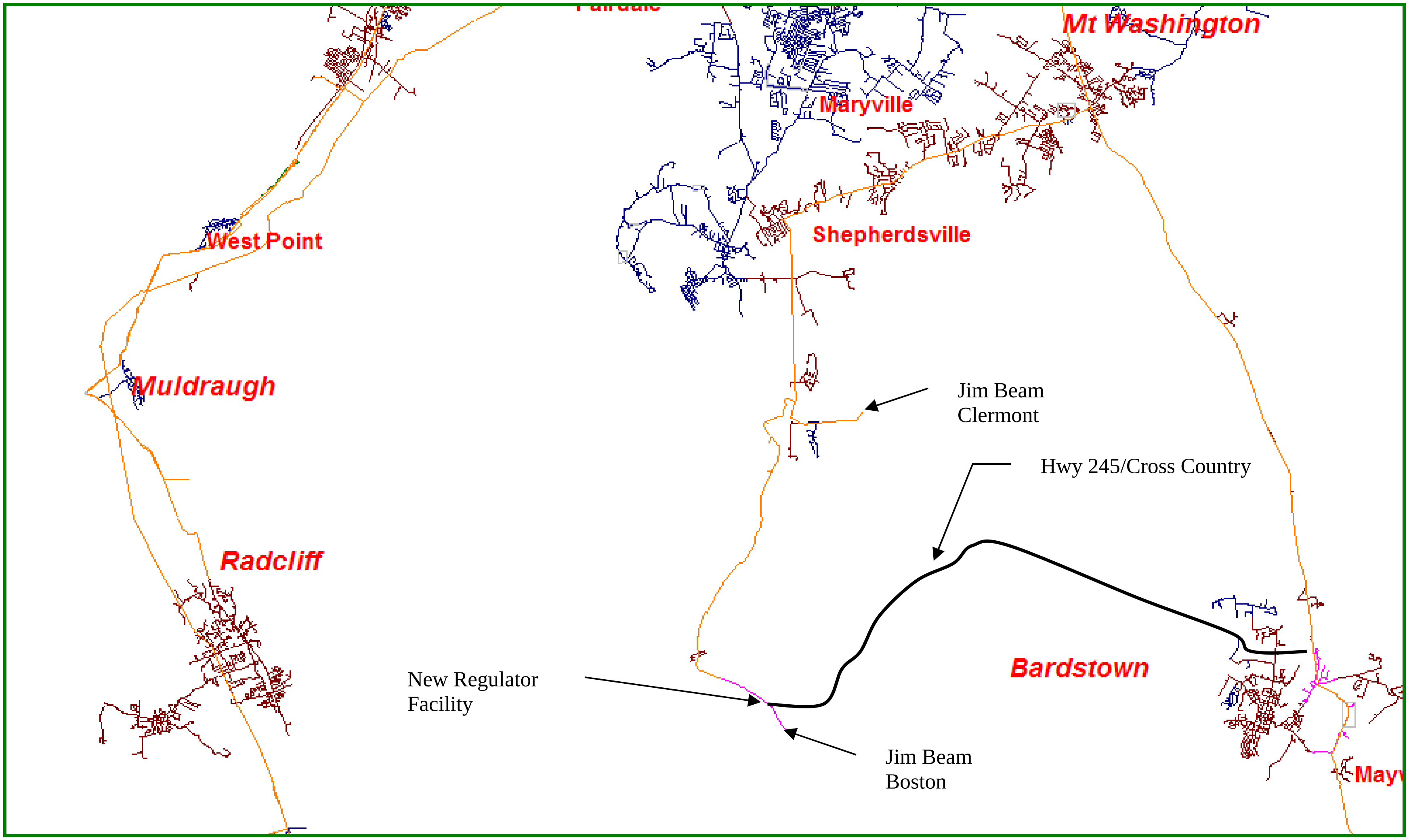
Mt. Washington High Pressure Distribution System – Scenario 2



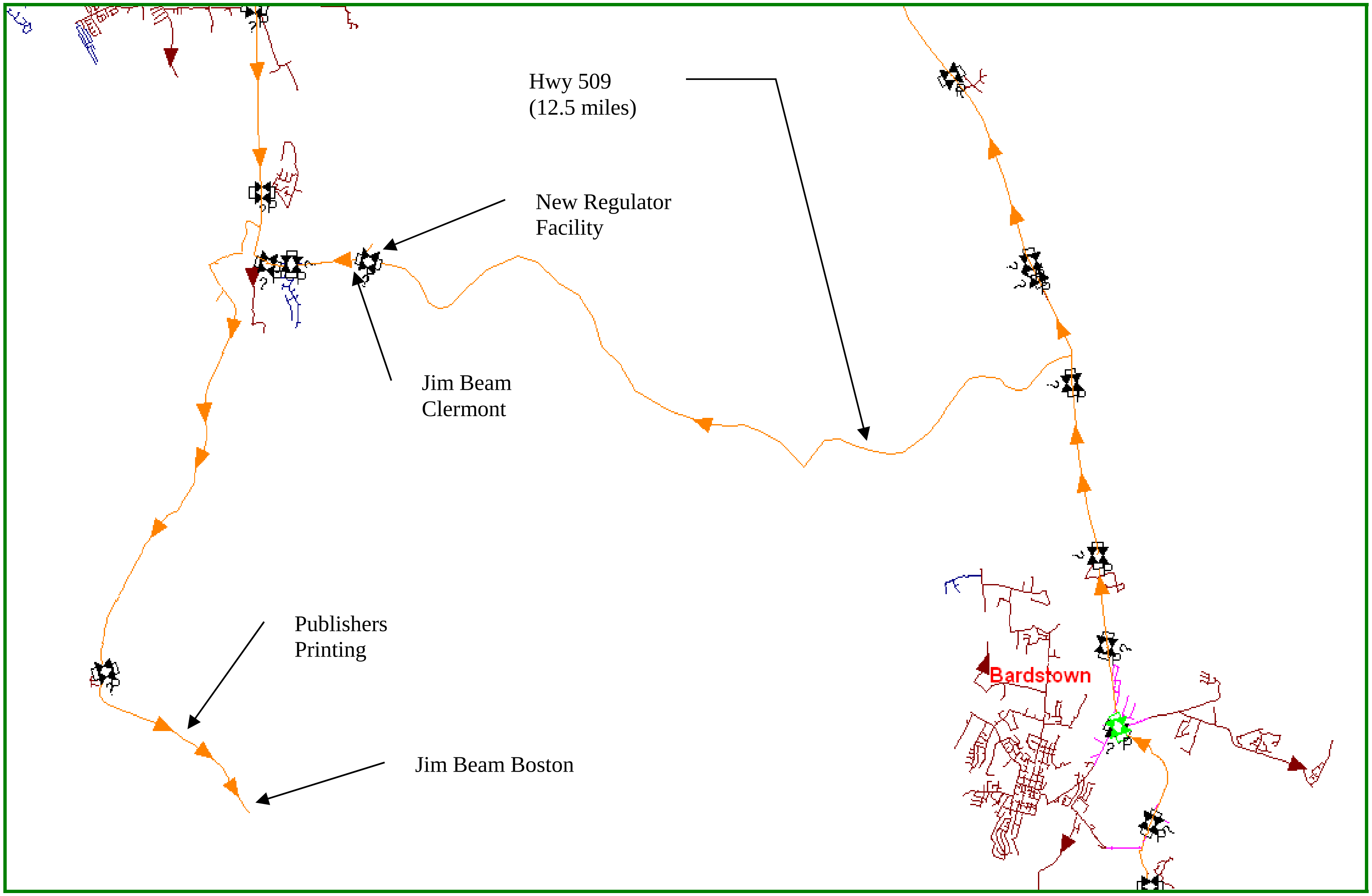
Mount Washington/Lebanon Junction High Pressure Gas System – Scenario 3



Mt. Washington High Pressure Distribution System – Scenario 4

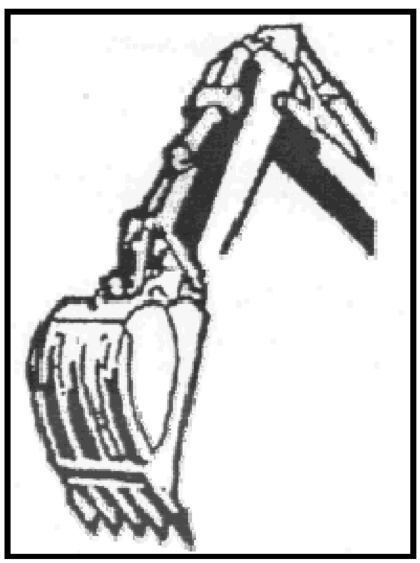


Mt. Washington High Pressure Distribution System – Scenario 5



Louisville Gas and Electric

Gas System Planning
Gas Construction Plan



August 2010

Table of Contents

I. Crestwood-Eminence-Bedford High Pressure Distribution System

Gas System Overview

The Crestwood-Bedford high-pressure distribution system serves the Crestwood area, Smithfield, Campbellsburg, and Bedford. It is supplied by the Eminence, Bedford, and Crestwood city gate stations. The system serves a small number of large industrial and commercial customers, including Safety Kleen, Steel Technologies, Rosehill Greenhouses, and Hussey Copper.

Regulator Facilities

The regulator facilities that feed this system are as follows:

- Elder Park City Gate Station
- Crestwood City Gate Station
- Bedford City Gate Station

Maximum Allowable Operating Pressure

From Crestwood to Eminence, the Crestwood-Bedford high-pressure system has a maximum allowable operating pressure of 350 psig. From Eminence to Bedford, it has a maximum allowable operating pressure of 380 psig.

Model Results

Minimum Gas System Pressure (-12°F)

The predicted minimum gas system pressure is at 4021 Hwy 146 **(80.93 psig).**

Regulator Operating Capacities

- Elder Park City Gate Station – **16.9%**
- Crestwood City Gate Station – **56.8%**
- Bedford City Gate Station **– 100%**

Note: The reported capacities are without the proposed gas regulation equipment upgrades at the Bedford city gate station (2010) and the Crestwood city gate station (2011).

Gas System Constraints

The system is composed primarily of 4-inch pipeline, limiting the system's capacity for expansion.

I. <u>Crestwood-Eminence-Bedford High Pressure Distribution System (cont'd)</u>

Recommended Gas System Reinforcements

<u>Reinforcement 1</u>
Connect the Ballardsville gas transmission line to the Crestwood-Bedford high pressure system with 5,800 feet of 8" steel gas transmission pipeline along Hwy 53 from Moody Lane to Hwy 22. **NOTE:** This reinforcement is referenced in Section II as part of Reinforcement 1.

Minimum Gas System Pressure (-12°F)
- 4021 Hwy 146 – **163.61 psig**

Regulator Operating Capacities
- Elder Park City Gate Station – **17.4%**
- Crestwood City Gate Station – **50.7%**
- Bedford City Gate Station – **100%**
  Recommended Timeline – 2010-2013

<u>Reinforcement 2</u>
Remove the Eminence high pressure regulator pit and replace with a full port motor operated ball valve at that location. If the Eminence high pressure regulator pit was to fail, approximately 1,693 customers in the Eminence and New Castle areas would be lost. Installing a motor operated ball valve at the Eminence station could help prevent this loss of service. This ball valve could also be used to isolate either side of the Crestwood–Bedford line should a failure occur.

Minimum Gas System Pressure (-12°F)
Inlet to Pleasureville – **68.7 psig**

Regulator Operating Capacities
Bedford City Gate Station – **73.4%**
Crestwood City Gate Station – **57.8%**

Recommended Timeline – 2010-2015

<u>Reinforcement 3</u>
- Install a new city gate station near L'Esprit Farms at the intersection of East Highway 146 and Lake Jericho. This station will be fed from the Texas Gas Transmission pipeline.
- Extend approximately 4 miles of high pressure steel pipeline southwest along East Highway 146 to connect with the Elder Park/Ballardsville pipeline.
- Install a regulator station where Hwy 146 connects with the Elder Park/Ballardsville pipeline to lower the pressure to 100 psig from the new city gate station.
- Extend approximately 5.4 miles of high pressure steel pipeline southeast along Hwy 153 (Lake Jericho to connect with Crestwood-Bedford high pressure pipeline at Smithfield Rd).

I. Crestwood-Eminence-Bedford High Pressure Distribution System (cont'd)

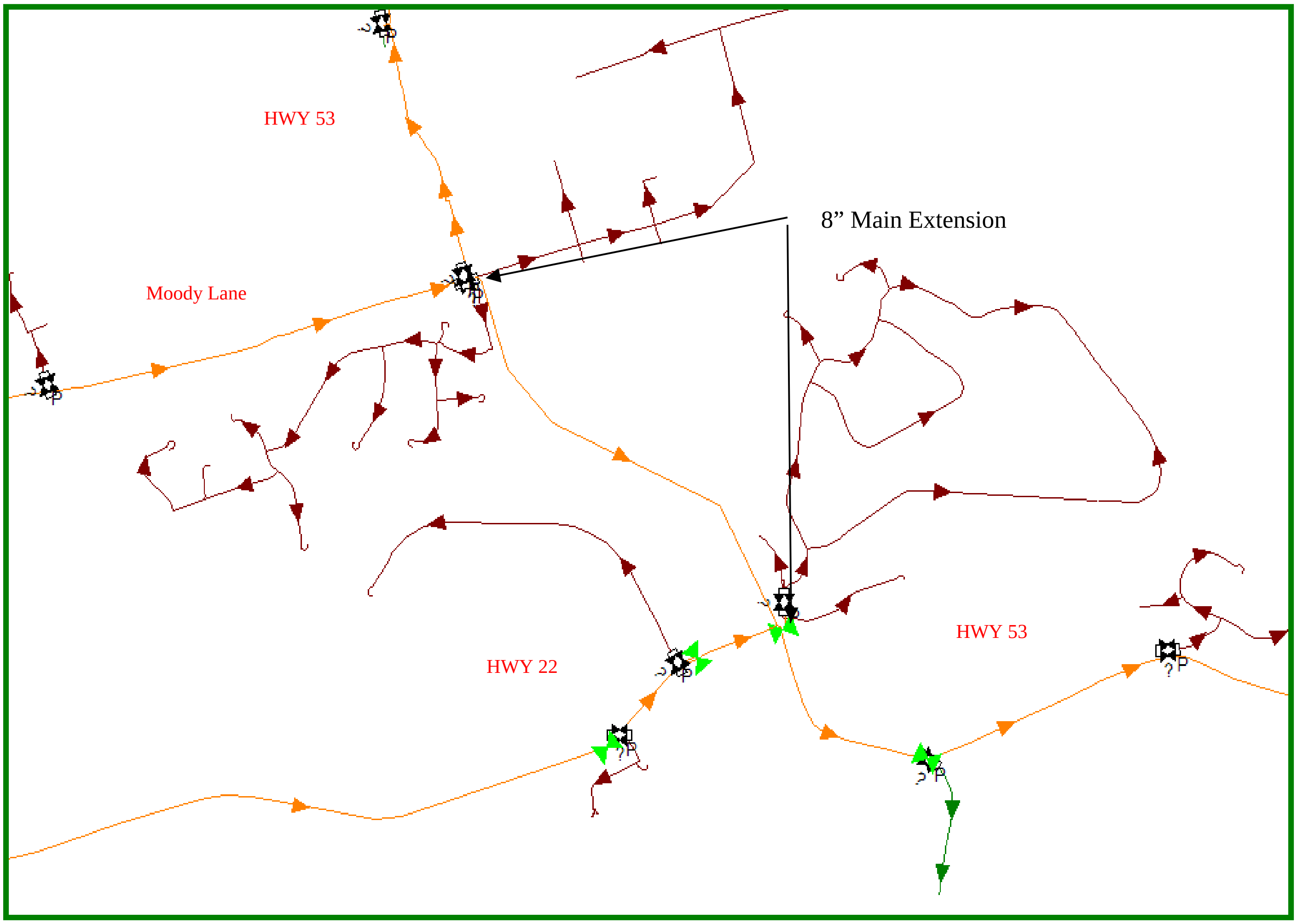
Minimum Gas System Pressure (-12°F)

- 4021 Hwy 146 – **270.25 psig**

Regulator Operating Capacities

- Elder Park City Gate Station – **16.3%**
- Crestwood City Gate Station – **37.4%**
- Bedford City Gate Station –**90%**

Crestwood-Eminence-Bedford High Pressure Gas System – Reinforcement 1



II. East End Gate Stations

Gas System Overview

The Elder Park City Gate Station is located on Elder Park Road just east of Highway 393 and serves from Elder Park to Zorn Avenue in Louisville. The Crestwood City Gate Station is located on Highway 22 west of Abbott Lane and serves the area from Lake Forest and Pee Wee Valley to Ballardsville and Eminence. The LaGrange City Gate Station is located on Highway 146 west of Button Lane and serves the City of LaGrange and the Crestwood/Buckner area north of I-71. These systems serve rural, residential, commercial, and small industrial customers.

Maximum Allowable Operating Pressure

The Elder Park system has a maximum allowable operating pressure of 400 psig. The Crestwood system has a maximum allowable operating pressure of 350 psig. East of the La Grange City Gate Station, the LaGrange system has a maximum allowable operating pressure of 100 psig. West of the LaGrange City Gate Station, the LaGrange system has a maximum allowable operating pressure of 200 psig.

Gas System Constraints

If any of these three gate stations was temporarily turned off (e.g., for maintenance or due to an accident), there would be insufficient pressure to serve the system that is fed by that gate station.

Model Results

Minimum Gas System Pressure (-12°F)

The predicted minimum gas system pressure on the Elder Park system is located at the inlet to the **Zorn Ave regulator station (253.6 psig).**

The predicted minimum gas system pressure on the Crestwood system is located at **4021 Hwy 146 (80.9 psig).**

The predicted minimum gas system pressure on the LaGrange system is located at **20 Quality Place (86.5 psig)**.

Regulator Operating Capacities

- Elder Park City Gate Station – **16.9%**
- Crestwood City Gate Station – **56.81%**
- LaGrange City Gate Station – **46.7%**

Recommended Gas System Reinforcements

Recommended Gate Station Operating Conditions

- Operate the Elder Park City Gate Station at 350 psig
- Operate the Crestwood City Gate Station at 350 psig
- Operate the LaGrange City Gate Station at 90 psig

II. <u>East End Gate Stations (cont'd)</u>

<u>Reinforcement 1</u>
Connect the Elder Park system to the Crestwood system

- Connect the Elder Park line to the Crestwood line via Hwy 393 with approximately 7,500 feet of 8-inch pipeline.
- Connect the Elder Park line to the Crestwood line via Hwy 53 with approximately 5,800 feet of 8-inch pipeline

Minimum Gas System Pressure (-12°F)
- Zorn Inlet **– 311.1 psig**
- 4021 Hwy 146 – **224.4 psig**

Regulator Operating Capacities
- Elder Park City Gate Station – **19.3%**
- Crestwood City Gate Station – **32.2%**
- LaGrange City Gate Station **– 46.7%**

Recommended Timeline – 2010 - 2015

<u>Reinforcement 2</u>
Connect the Elder Park system to the LaGrange system

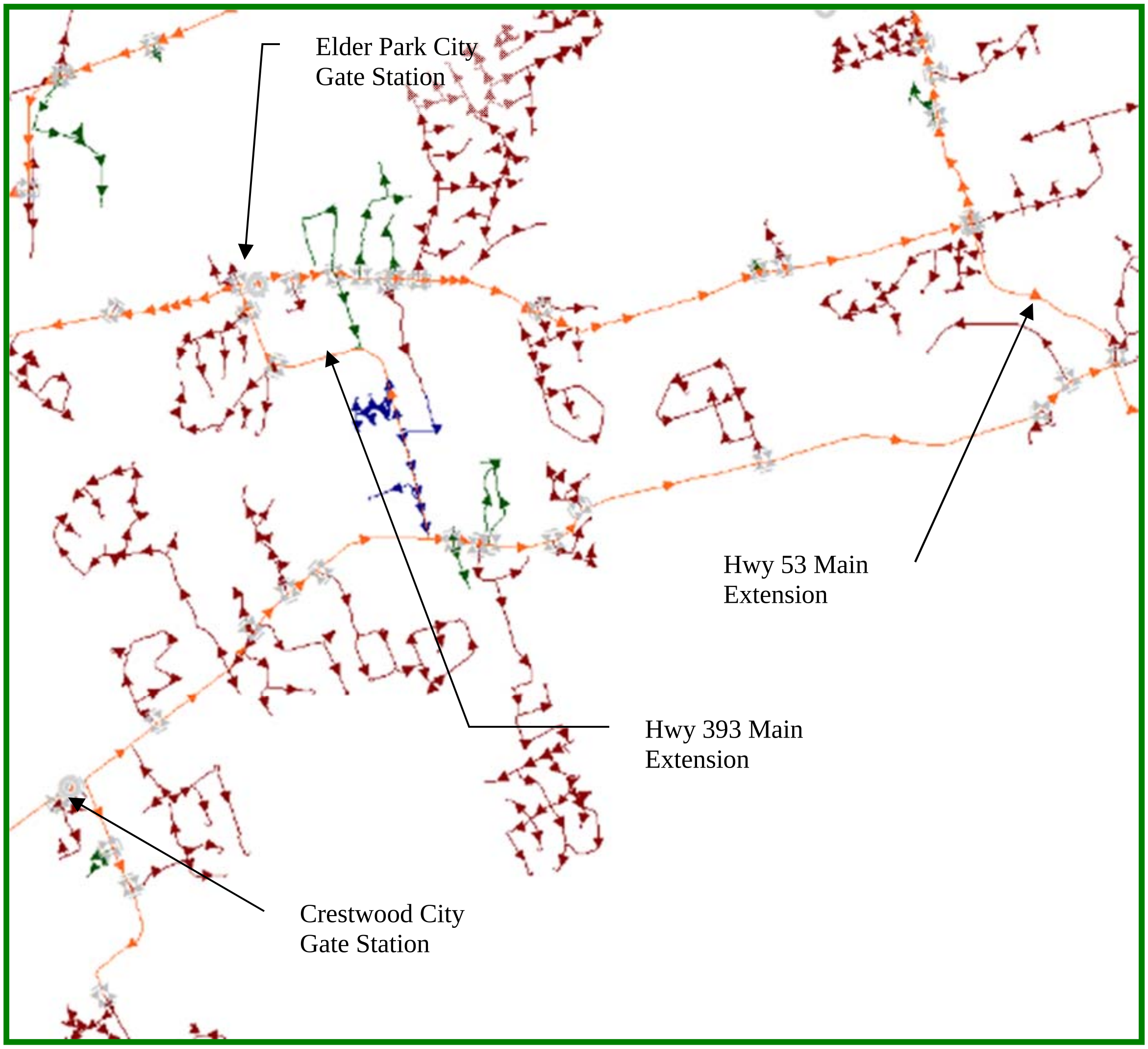
- Connect the Elder Park line to the LaGrange line via Hwy 393 with approximately 6,600 feet of 8-inch pipeline.
- Connect the Elder Park line to the LaGrange line via Hwy 146 and Fox Run Rd with approximately 4,400 feet of 8-inch pipeline.
- Install a new regulator facility at Hwy 393 and Hwy 146 to reduce the pressure from the new pipeline along Hwy 393 to 90 psig.
- Install a new regulator facility at the tie-in point on Fox Run Rd or at Hwy 146 and Quality Place to reduce the pressure from the new pipeline along Hwy 146 and Fox Run Rd to 90 psig.

Minimum Gas System Pressure (-12°F)
- Zorn Inlet **– 310.8 psig**
- Springhouse Estates Inlet – **88.6 psig**
- 4701 Hwy 146 – **80.9 psig**

Regulator Operating Capacities
- Elder Park City Gate Station **– 18.8%**
- Crestwood City Gate Station – **56.8%**
- LaGrange City Gate Station – **29.1%**

Recommended Timeline – 2010 – 2015

East End Gate Stations – Reinforcement 1



East End Gate Stations – Reinforcement 2

III. LaGrange Medium Pressure Systems

Gas System Overview
The LaGrange Medium pressure systems are fed from the LaGrange and Elder Park City Gate Stations (see Section II). The system consists of several single-feed systems and one larger, multiple-feed system.

The Oldham County Economic Development Campus (OCEDA) is a 1000+ acre community that will contain office buildings, single and multifamily dwellings, a new school, and mixed use lands. Currently, gas infrastructure does not exist to support this development.

Maximum Allowable Operating Pressure
These subsystems have maximum allowable operating pressures of 10, 30, and 35 psig, as detailed below.

Model Results

Minimum Gas System Pressure (-12°F)

Sub-System MAOP	Location	Pressure
10 psig systems	3500 Mattingly Rd [6447519]	**7.4 psig**
30 psig system	Parker Pl [6480299]	**21.7 psig**
35 psig systems	Kamer Ct [6430958]	**28.7 psig**

Regulator Operating Capacities:
35 psig Systems
- Hoffman Ln & Parkview Manor – 3.8%
- Button Ct & Commerce Pkwy G-21254 – 19.3%
- Allen Ln & Artisan Pkwy – 6%
- Hwy 53 & Cherry Creek Dr – 37.3%
- New Cedar Point Rd. & Old LaGrange G-364 – 54.3%
- Elder Park Rd. G-433 – 35.9%
- Moody Ln & Hwy 53 G-559 – 23.8%
- E. Moody Ln.& Cal Avenue G-593 – 7.8%
- Deer Run Drive G-553 – 14.1%
- Granger Rd. & Hwy 53 G-545 – 34%
- Park Rd. & Hwy 53 G-558 – 19.8%
- Zhale Smith Rd & Hwy 53 G-591 – 9.9%
- Springhouse Estates Section 1 G-599 – 71.6%
- Hwy 146 & Fort Pickens Rd G13112 – 0.0%
- Prestwick Dr. & Hwy. 53 G13115 – 38.6%
- Crystal Dr.& Grange Dr. G18329 – 22.6%

III. LaGrange Medium Pressure Systems (cont'd)

30 psig systems
- Regulator pit at Woodlawn Ave and Lagrange Rd **– 16%**
- Lagrange medium pressure regulator pit **– 69.8%**
- Regulator pit at Hoffman Ln **– 47.1%**

10 psig systems
- Regulator pit at Hwy 146 **– 20.4%**
- Regulator pit at Hwy 393 & Hwy 146 **– 1.2%**
- Regulator pit at Kings Ln & Hwy 146 **– 1.6 %**
- Regulator assembly at Georgie Way and Moody Ln **– 4%**
- Regulator assembly at Hazelwood Dr & Elder Park Rd **– 14.1%**
- Regulator assembly at Sycamore Rd and Elder Park Rd **– 26.8%**

Gas System Constraints
Areas of low pressure are constrained by small diameter piping and single regulator stations feeding the systems.

Gas System Reinforcements Note

- Due to economic conditions, these plans have been put on hold for the time being.

Recommended Gas System Reinforcements:

Reinforcement 1
Extend gas mains and uprate LaGrange MP system as described in "An Analysis of the OCEDA Economic Development Campus" dated 7 November 2005 or latest version. As described in the report, this system will have an estimated new gas load of up to 387 Mcfh. The proposed reinforcement project requires installing:

- 15,000 ft of 4 inch pipe
- 4,000 ft of 6 inch pipe
- 12,000 ft of 8 inch pipe
- An uprate of 11.6 miles of existing pipeline and 467 existing customers
- A new regulator facility at Moody Lane and North Fible Lane

Minimum gas system pressure (-12°F):
- 2300 Stonybrook Ct – **42.7 psig**

Regulator Operating Capacities:
- Moody Ln and North Fible Ln – **15.5%**
- Granger Rd and Hwy 53 **– 46.6%**
- Elder Park Rd **– 32.9%**

Recommended Timeline – TBD

III. <u>LaGrange Medium Pressure Systems (cont'd)</u>

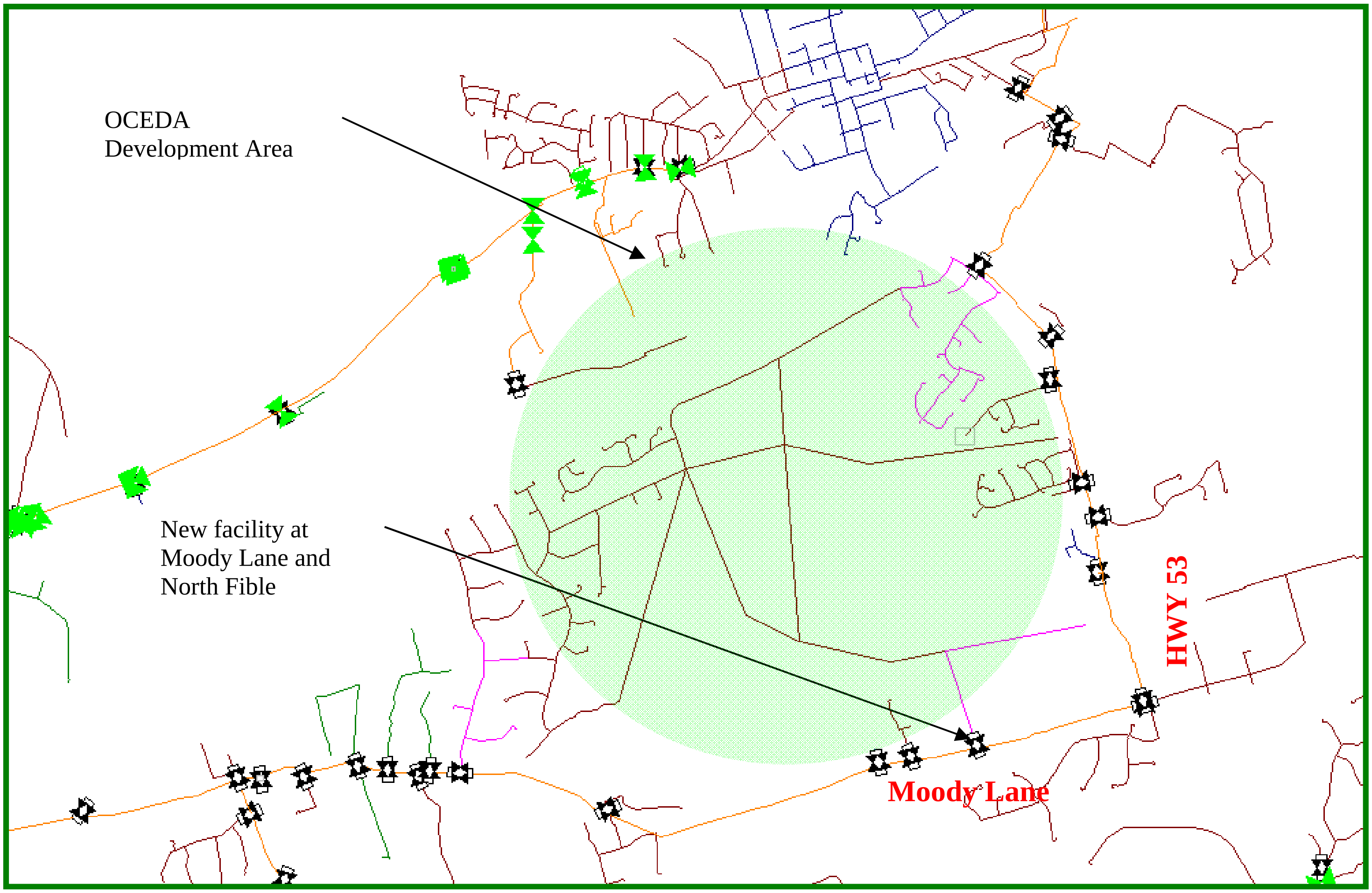
<u>Reinforcement 2</u>
Extend gas mains and uprate Hwy 393 & Hwy 146 system as described in "An Analysis of Proposed Development at Buckner Crossings" dated 16 October 2006 or latest version. As described in the report, this system will have an estimated new gas load of up to 90 Mcfh. The proposed reinforcement requires installing:

- 5,100 ft of 6-inch pipe
- 5,300 ft of 4-inch pipe
- 13,100 ft of 2-inch pipe
- Uprate 400 ft of existing pipeline and 5 existing customers
- Replace regulator facility at Commerce Pkwy & Button Court Ln
- Remove regulator facility at Hwy 393 & Hwy 146
- Install regulator facility at Hwy 393 & Commerce Pkwy

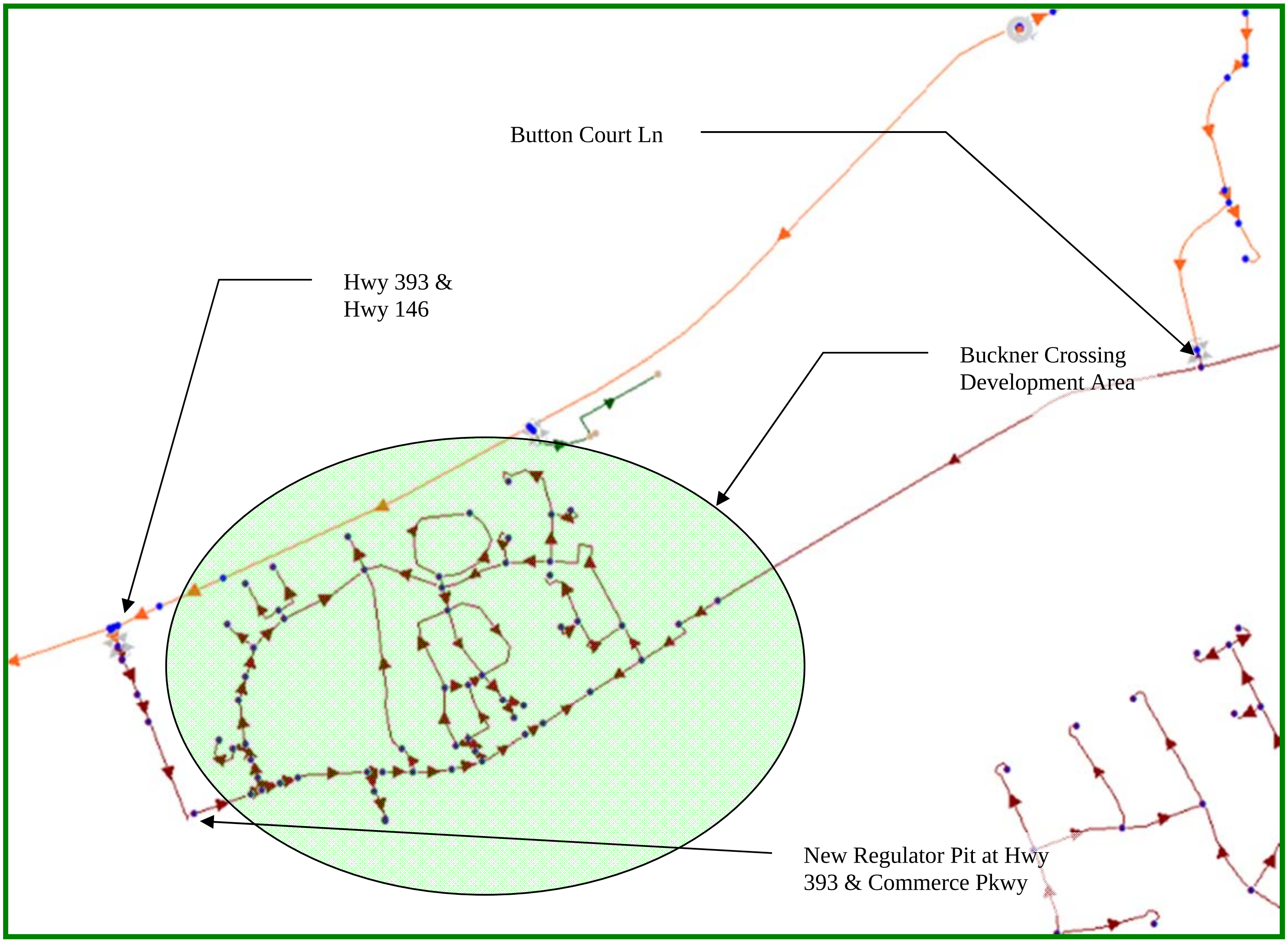
Minimum Gas System Pressure (-12°F)
- Southern Patio Home Area **– 29.3 psig**

Regulator Operating Capacity
- Hwy 393 & Commerce Pkwy **– 89.4%**
- Commerce Pkwy & Button Court Ln **– 18%**

LaGrange Medium Pressure Gas System – Reinforcement 1



LaGrange Medium Pressure Gas System – Reinforcment 2



IV. <u>River Road Regulator Assemblies</u>

Gas System Overview
Gas System Planning has identified eight regulator facilities on River Rd that could be removed to reduce the number of dead-end gas systems and reduce maintenance costs by removing unnecessary equipment. All regulators are fed by the Elder Park pipeline.

<u>Gas System Reinforcement Completed in 2007</u>
As part of the Farm Tap upgrade project, several medium pressure reinforcements have been made, resulting in the removal of two River Road assemblies. The reinforcements are:

- Installed 1,900 feet of 4-inch PL main in River Road from River Creek Dr up to Harrods Creek. Tie-in to regulator assembly at River Rd & Creekside Ct, uprate the River Creek Drive system from 10- 35 psig and remove the Creekside Ct regulator assembly. New main will allow eventual tie-in to Harrods Creek MP system and retirement of River Creek Dr regulator assembly.
- Installed 2,200 feet of 4-inch PL main in River Road from 7009 River Rd to 7314 River Rd. Tie in to systems at River Rd & Private Dr, River Rd & Transylvania and River Rd & Mayfair Rd. Retire regulator assemblies at Private Dr and Mayfair Rd.

<u>Regulator Facilities</u>
The regulator facilities in this area with their operating capacity and maximum allowable operating pressure are as follows:

- River Road & Longview Avenue. G-622 - 18% (MAOP=10 psig).
- River Road & Woodside Road. G-623 - 15.9% (MAOP=35 psig).
- River Road & Box Hill Lane. G-515 - 13.3% (MAOP=20 psig).
- River Road & Lime Kiln Ln. G-624 - 25.3% (MAOP=20 psig).
- Blankenbaker Lane & River Road. G-335 - 12.3% (MAOP=50 psig).
- Glenview Ave. & River Road. G-329 - 14.4% (MAOP=50 psig).
- River Road & Rivers Edge Rd Sub. G-600 - 13.4% (MAOP =35 psig).
- River Road pit serving Rivercreek G-590 - 24.2% (MAOP=35 psig).
- River Road & Juniper Beach Dr. G-610 - 5.6% (MAOP=35 psig).
- River Road & Harbortown Rd. G-621 - 6.7% (MAOP=35 psig).
- River Road & Wolf Pen Branch Rd. – 46.2% (MAOP=50 psig).

<u>Maximum Allowable Operating Pressure</u>
The Elder Park Line has a maximum allowable operating pressure of 400 psig, but is typically operated at 250 psig.

IV. River Road Regulator Assemblies (cont'd)

Recommended Gas System Reinforcements

Reinforcement 1

- Install approximately 2,800 ft of 4-inch plastic gas main along River Rd to connect the River Rd & River Creek Dr and River Rd & Harbortown Rd systems.
- Install approximately 300 ft of 2-inch plastic gas main along Juniper Beach Rd to connect the River Rd & Juniper Beach Dr and River Rd & Harbortown Rd systems.
- Remove the River Rd & Juniper Beach Dr and the River Rd & Harbortown Rd regulator pit.

Minimum Gas System Pressure

- 5300 Juniper Beach Rd – **34.2 psig**

Recommended Timeline – 2010-2015

Reinforcement 2

- Uprate River Rd & Woodside Rd medium pressure system from 10 psig to 50 psig.
- Uprate River Rd & Lime Kiln Ln medium pressure system from 20 psig to 50 psig.
- Install approximately 850 ft of 4-inch plastic gas main along Arden Rd to connect Woodside Rd and Glenview Ave systems.
- Install approximately 1,200 ft of 4-inch plastic gas main along Lime Kiln Ln to connect Lime Kiln Ln and Glenview Ave systems.
- Remove the River Rd & Woodside Rd and River Rd & Lime Kiln Ln regulator assemblies.

Minimum Gas System Pressure (-12°F)

- 3950 Kresge Way – **25.03 psig**

Recommended Timeline – 2010-2015

Reinforcement 3

- Uprate River Rd & Longview Ave medium pressure system from 10 psig to 35 psig.
- Install approximately 1,200 ft of 2-inch plastic gas main along River Road to connect Longview Ave and Rivers Edge systems.
- Remove the River Rd & Longview Ave regulator assembly

Minimum Gas System Pressure (-12°F)

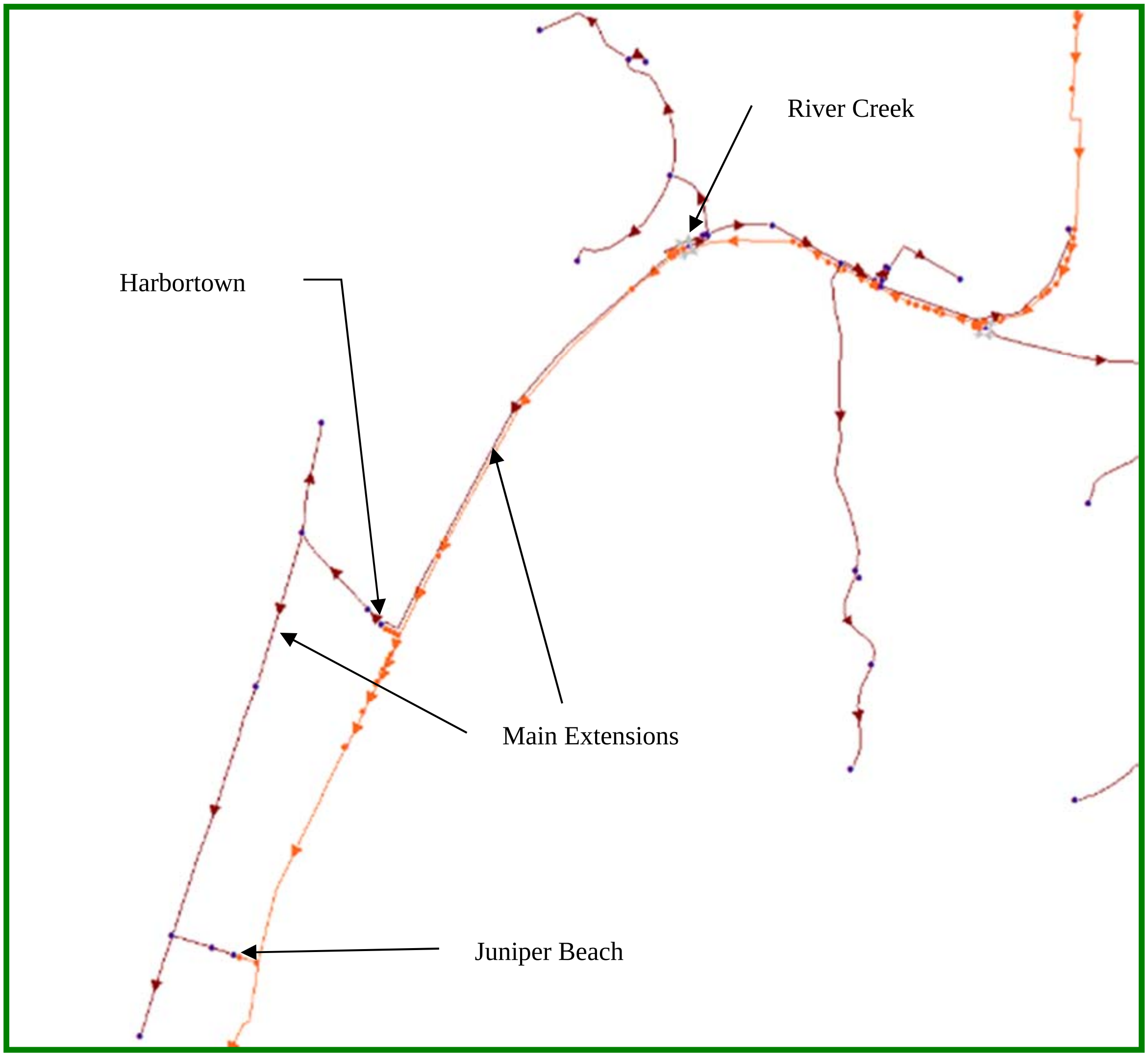
- 6120 Longview Ln – **32.69 psig**

Regulator Operating Capacity

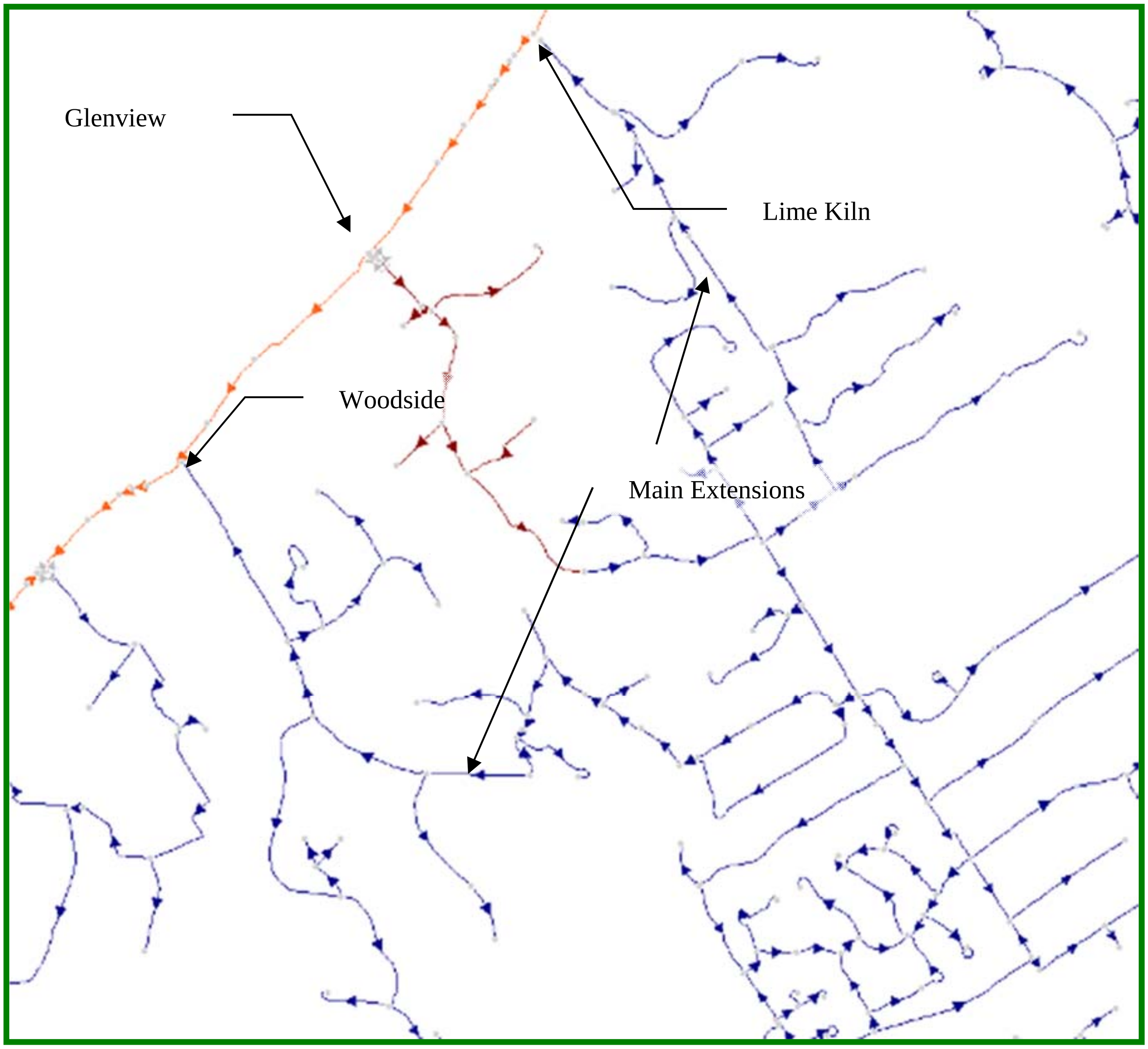
- River Rd & Rivers Edge Rd – **22.2 %**

Recommended Timeline –2010

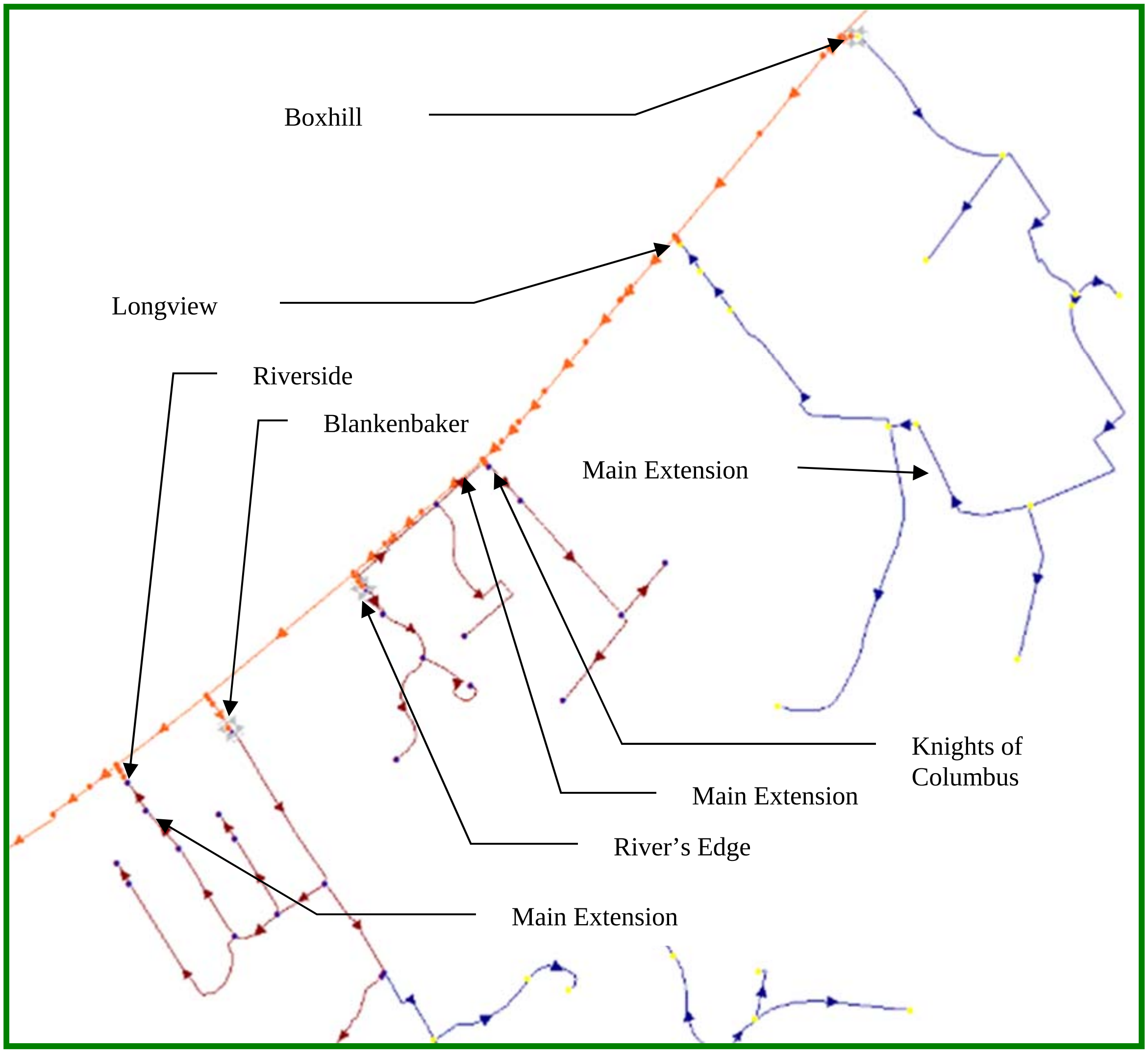
River Road Regulator Assemblies – Reinforcement 1



River Road Regulator Assemblies – Reinforcement 2



River Road Regulator Assemblies – Reinforcement 3



V. Plantside Drive/Blankenbaker Parkway Medium Pressure System

Gas System Overview
The Plantside/Blankenbaker Medium Pressure System feeds the area near Plantside Drive, Blankenbaker Parkway, and Electron Drive. The area is composed mostly of small commercial customers with a few residential customers. This system is connected to the Taylorsville Road medium pressure system via a 4-inch steel main at Grand Avenue and Watterson Trail.

Maximum Allowable Operating Pressure
This medium pressure system has a maximum allowable operating pressure of 35 psig.

Regulator Operating Capacity
- Watterson Tr and Plantside Dr – **66.5%**
- Tucker Station Rd & I-64 – **3.2%**

Gas System Constraints
Many of the commercial customers fed by this medium pressure system require a delivery pressure of 5 psig. A proposed 283 acre office park for the eastern area of this system, south of I-64, on Tucker Station Road, will require a significant amount of new infrastructure (MSD is planning a 4.6 square mile area of sewer development) and an additional gas regulator facility. Currently, this system is not capable of serving this development that is predicted to have an approximate total load of 140 Mcfh.

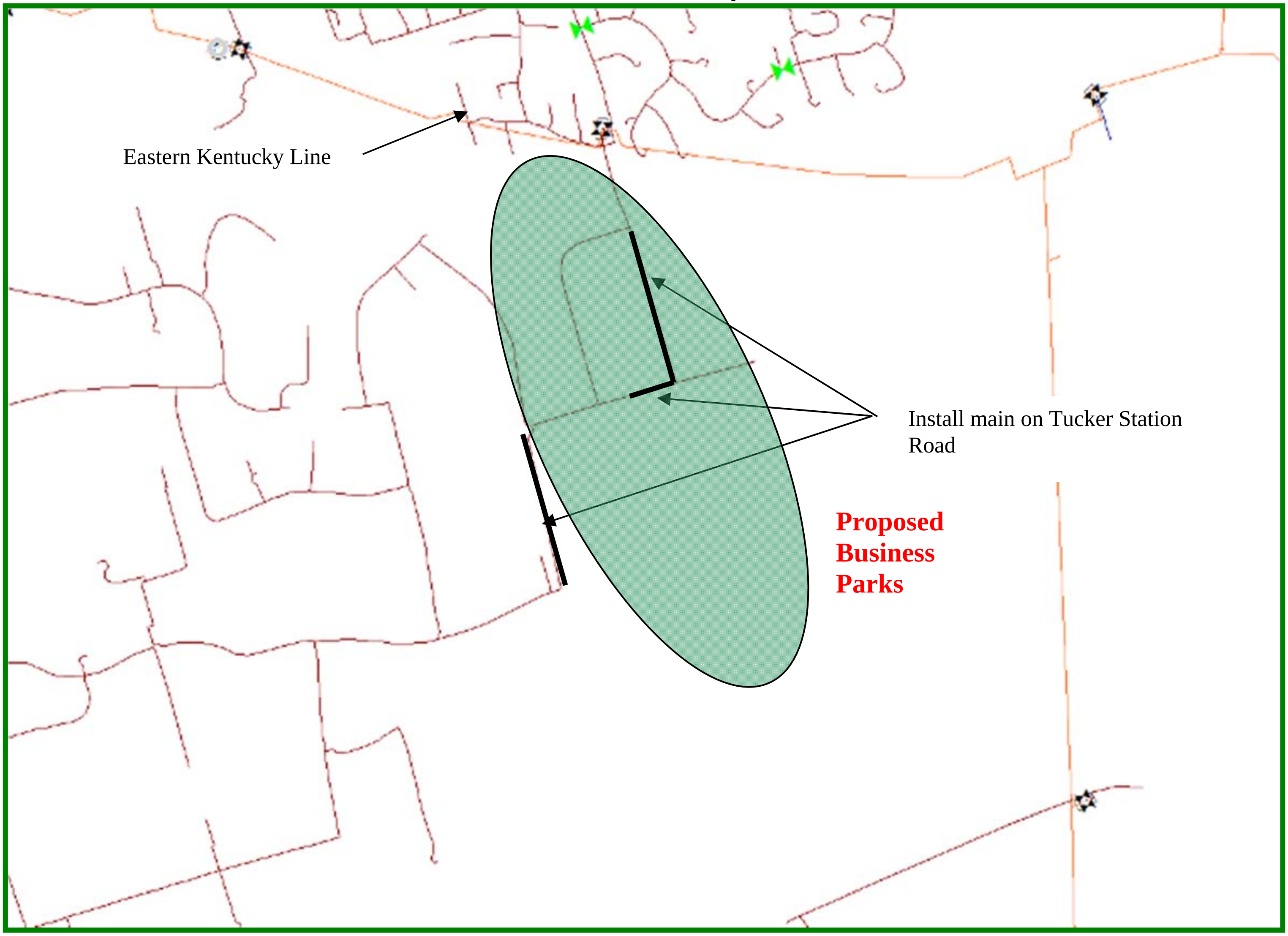
Recommended Gas System Reinforcements:
Reinforcement 1
- Install approximately 1,700 feet of 6-inch medium pressure plastic pipeline west from Tucker Station & Lakefront Place, along Tucker Station Road, to the 6-inch pipeline ending on Plantside Drive (near Papa John's building). This would allow for a multiple feed system, improving system reliability.
- Install approximately 850 ft of 6-inch medium pressure plastic pipeline west from the entrance of the proposed office park, along Tucker Station Road, to the 6-inch main ending east of Sycamore Place.
- Install approximately 1,200 ft of 6-inch medium pressure plastic pipe from Sycamore Station Place south along Tucker Station Road, terminating at Pope Lick Road.

Minimum gas system pressure (-12°F):
- 3025 Element Ln – **30.5 psig**
- 2801 Constant Comment Pl – **30.6 psig**

Regulator Operating Capacities:
- Tucker Station Rd & I-64 – **21.7%**
- Watterson Tr & Plantside Dr – **82.7%**

Recommended Timeline: 2010-2015

Plantside Drive Medium Pressure Gas System – Reinforcement 1



VI. Bardstown Medium Pressure System

Gas System Overview

The Bardstown medium pressure gas system serves the City of Bardstown. This system is composed mainly of residential and commercial customers with a few large industrial customers including Owens Illinois and the Barton Distillery. It has continued to experience growth in the residential and commercial sectors especially on the western side of the Bardstown area. Expansion of an industrial park on Highway 605 near Nelson County High School is anticipated in the next 3-5 years.

Regulator Facilities

The regulator facilities that supply gas to the Bardstown medium pressure system are as follows:

- The regulator station at the LG&E Bardstown Office on U.S. Highway 62 (Bardstown MP).
- The regulator station adjacent to Chris's Creation Cabinet Company (Chris's Creation MP).

Maximum Allowable Operating Pressure (MAOP)

The Bardstown medium pressure system has a maximum allowable operating pressure of 60 psig.

Model Results

Minimum Gas System Pressure (-12 ^{0}F)

- 1755 Parkway Dr [39612160]- 24.55 psig

Regulator Operating Capacities

- Bardstown MP – **20.8**%
- Chris's Creation MP – **16.5**%

Gas System Constraints

Gas system constraints are caused by the lack of a direct gas supply route from the regulator station at the LG&E Bardstown office to the downtown Bardstown area. Due to current and anticipated growth, it will be necessary to reinforce the gas system.

Recommended Gas System Reinforcements

Reinforcement 1

Install approximately 1,650 ft of 4-inch plastic pipeline along property lines from Armag Ave to the existing 4-inch plastic on Spencer Mattingly Rd.

Minimum gas system pressure (-12 ^{0}F)

- 1755 Parkway Dr – **45.4 psig**

VI. <u>Bardstown Medium Pressure System (cont'd)</u>

Regulator Operating Capacities
- Bardstown MP – **18.9%**
- Chris's Creation MP – **32.5%**

Recommended Timeline – 2010-2012

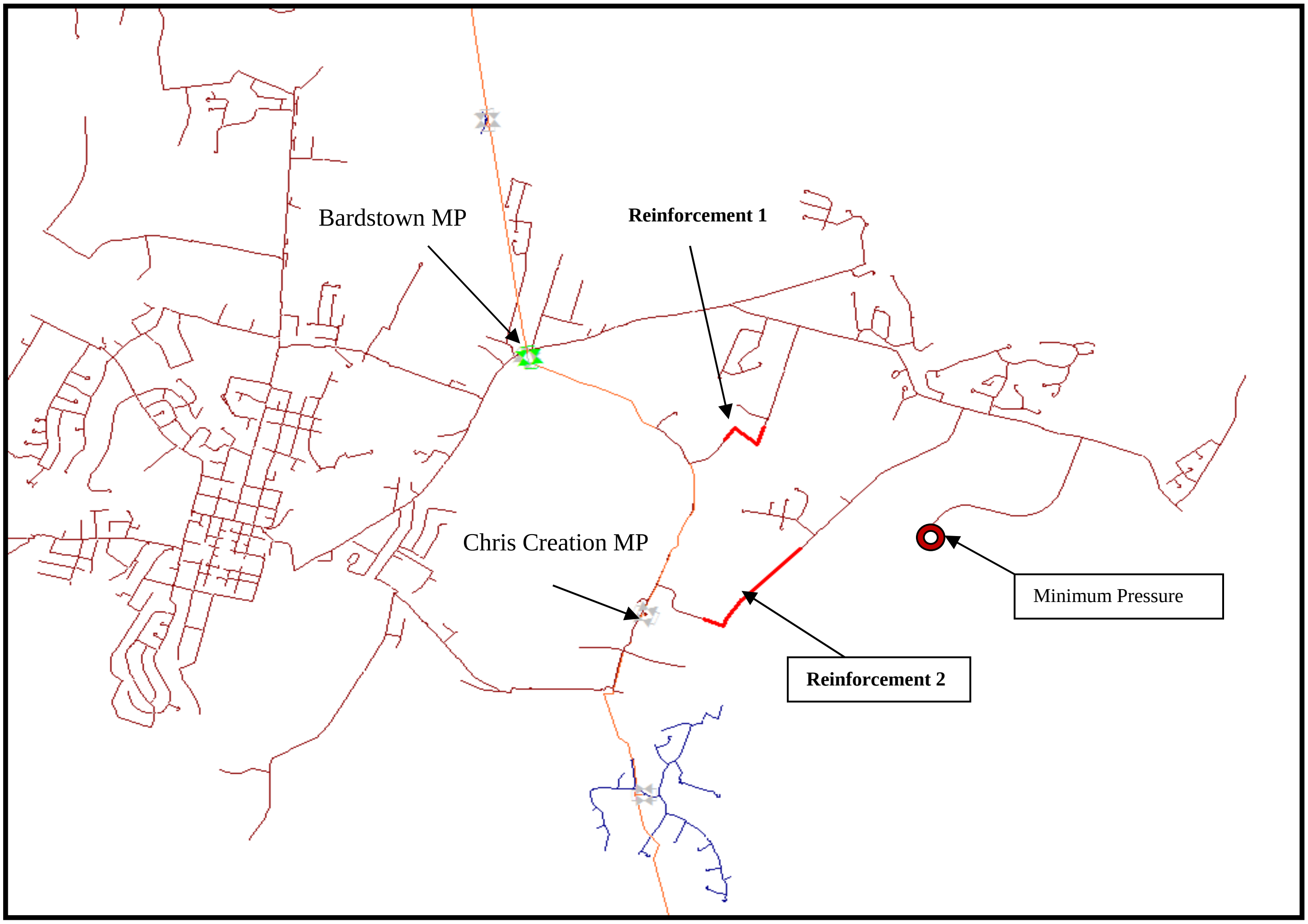
<u>Reinforcement 2</u>
Install approximately 3,500 ft of 4-inch plastic pipeline along Filiatreau Ln and tie into the existing 4-inch plastic main on Glenwood Dr.

Minimum gas system pressure (-12 ^{0}F)
- 1755 Parkway Dr **– 45.7 psig**

Regulator Operating Capacities
- Bardstown MP **– 19%**
- Chris's Creation MP **– 31.5%**

Recommended Timeline – TBD
Note: This reinforcement should be done in conjunction with the expansion of the Highway 605 industrial park. Results include Flowers Foods Bakery.

Bardstown Medium Pressure Gas System



VII. Highway 44 Regulator Assemblies

Gas System Overview
Gas System Planning has identified nine separate regulator assemblies located along Highway 44 that could be removed to reduce the number of dead-end gas systems and/or reduce maintenance cost on unnecessary regulation facilities.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Mt Washington MP
- Hwy 44 and Woodlake
- Hwy 44 and Harris
- Hwy 44 and Fisher
- Hwy 44 and Highland Spring
- Hwy 44 and Bethel Church
- Hwy 44 and Azure
- Hwy 44 and Truman
- Hwy 44 and Kennedy
- Hwy 44 and Bogard
- Hwy 44 and Bells Mill
- Hwy 44 and Alpar
- Hwy 44 and Mockingbird
- Hwy 44 and Sunview
- Hwy 44 and Watergate
- Hwy 44 and HiLand
- Hwy 44 and Big Clifty
- Hwy 44 and Halls
- Hwy 44 and Boardwalk

Maximum Allowable Operating Pressure
These systems have a maximum allowable operating pressure of 35 psig. The maximum allowable operating pressure of the Mt Washington MP regulator station is 60 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure is located on **Winding Woods Trail (26.7 psig)**.

VII. Highway 44 Regulator Assemblies (cont'd)

Regulator Operating Capacities

- Mt Washington MP – **10.4%**
- Hwy 44 and Woodlake – **21.4%**
- Hwy 44 and Harris – **21.4%**
- Hwy 44 and Fisher – **72.9%**
- Hwy 44 and Highland Springs – **56.5%**
- Hwy 44 and Bethel Church – **20.7%**
- Hwy 44 and Azure – **6.9%**
- Hwy 44 and Truman – **22.7%**
- Hwy 44 and Kennedy – **5.9%**
- Hwy 44 and Bogard – **51.7%**
- Hwy 44 and Bells Mill – **21%**
- Hwy 44 and Alpar – **1.8%**
- Hwy 44 and Mockingbird – **47.8%**
- Hwy 44 and Sunview – **42.6%**
- Hwy 44 and Watergate – **1%**
- Hwy 44 and HiLand – **5.2%**
- Hwy 44 and Big Clifty – **10%**
- Hwy 44 and Halls – **13.4%**
- Hwy 44 and Boardwalk – **15.3%**

Recommended Gas System Reinforcements

Reinforcement 1

- Connect system served by Hwy 44 and Boardwalk to Hwy 44 and Halls system with 500 feet of 4-inch plastic main along Hwy 44.
- Connect Hwy 44 and Big Clifty to Hwy 44 and Halls system with 1,400 ft of 4-inch plastic main along Hwy 44.
- Convert six high-pressure services on the north side of Hwy 44 to medium-pressure services between Hwy 44 and Halls and Hwy 44 and Big Clifty. This will retire six long services that pass underneath Hwy 44.
- Change the orifice size of Hwy 44 and Halls Ln to ¼"
- Retire Boardwalk and Big Clifty regulator assemblies.

Minimum Gas System Pressure (-12°F)

- 504 Chimney Rock Dr. – **34.4 psig**

Regulator Operating Capacities

- Hwy 44 and Halls Ln – **32.6%**

Recommended Timeline – 2010-2015

VII. Highway 44 Regulator Assemblies (cont'd)

Reinforcement 2

- Connect systems served by Hwy 44 & Hi-Land and Hwy 44 & Watergate with 1,500 feet of 6-inch plastic mains.
- Retire Watergate Assembly.

Minimum Gas System Pressure (-12°F)

- Douglas Drive **– 34.9 psig**

Regulator Operating Capacities

- Hwy 44 and Hi-Land– **6.2 %**

Recommended Timeline – 2010-2015

Reinforcement 3

- Retire Hwy 44 and Mockingbird regulator assembly. System can be served by Hwy 44 and Sunview.

Minimum Gas System Pressure (-12°F)

- Old Hickory Lane **– 28.3 psig**

Regulator Operating Capacities

- Hwy 44 and Sunview **– 91.8%**

Recommended Timeline – 2010-2015
Note: Growth in area may require that the Mockingbird assembly remain. This area should be monitored before finalizing a decision.

Reinforcement 4

- Connect systems served by Hwy 44 and Bells Mill and Hwy 44 and Alpar with 2,100 feet of 4-inch plastic main along Hwy 44 and Old Hwy 44.
- Convert five existing high pressure services to medium pressure.
- Retire the Hwy 44 and Alpar regulator assembly.

Minimum Gas System Pressure (-12°F)

- 468 East Millwater Falls **– 29.04 psig**

Regulator Operating Capacities

- Hwy 44 and Bells Mill **– 24.3%**

Recommended Timeline – 2010-2015

VII. Highway 44 Regulator Assemblies (cont'd)

Reinforcement 5

- Connect systems served by Hwy 44 & Bogard, Hwy 44 & Kennedy, Hwy 44 & Truman, and Hwy 44 & Azure with 3,300 feet of 6 inch plastic main along Hwy 44.
- Connect Systems served by Bethel Church and Highland Springs facilities with 1,400 feet of 4- or 6-inch plastic main along Hwy 44.
- Convert 24 high-pressure services along Hwy 44 to medium pressure.
- Retire Truman, Kennedy, and Bethel Church Road facilities.

Minimum Gas System Pressure (-12°F)

- Winding Woods Trail **– 26.7 psig**

Regulator Operating Capacities

- Hwy 44 and Bogard – **44.1%**
- Hwy 44 and Azure – **42.8%**
- Hwy 44 and Highland Springs – **75.9%**

Recommended Timeline – 2010-2015

Reinforcement 6

- Connect Fisher, Harris, and Woodlake systems with 2,100 feet of 4-inch plastic pipe along Hwy 44 between Fisher and Harris, and 1,900 feet of 6-inch plastic pipe between Harris and Woodlake.
- Convert approximately 34 high-pressure services to medium pressure.
  Note: Some of these services may have been converted during 2005 work but are not currently mapped.
- Retire Hwy 44 and Harris regulator assembly.

Minimum Gas System Pressure (-12°F)

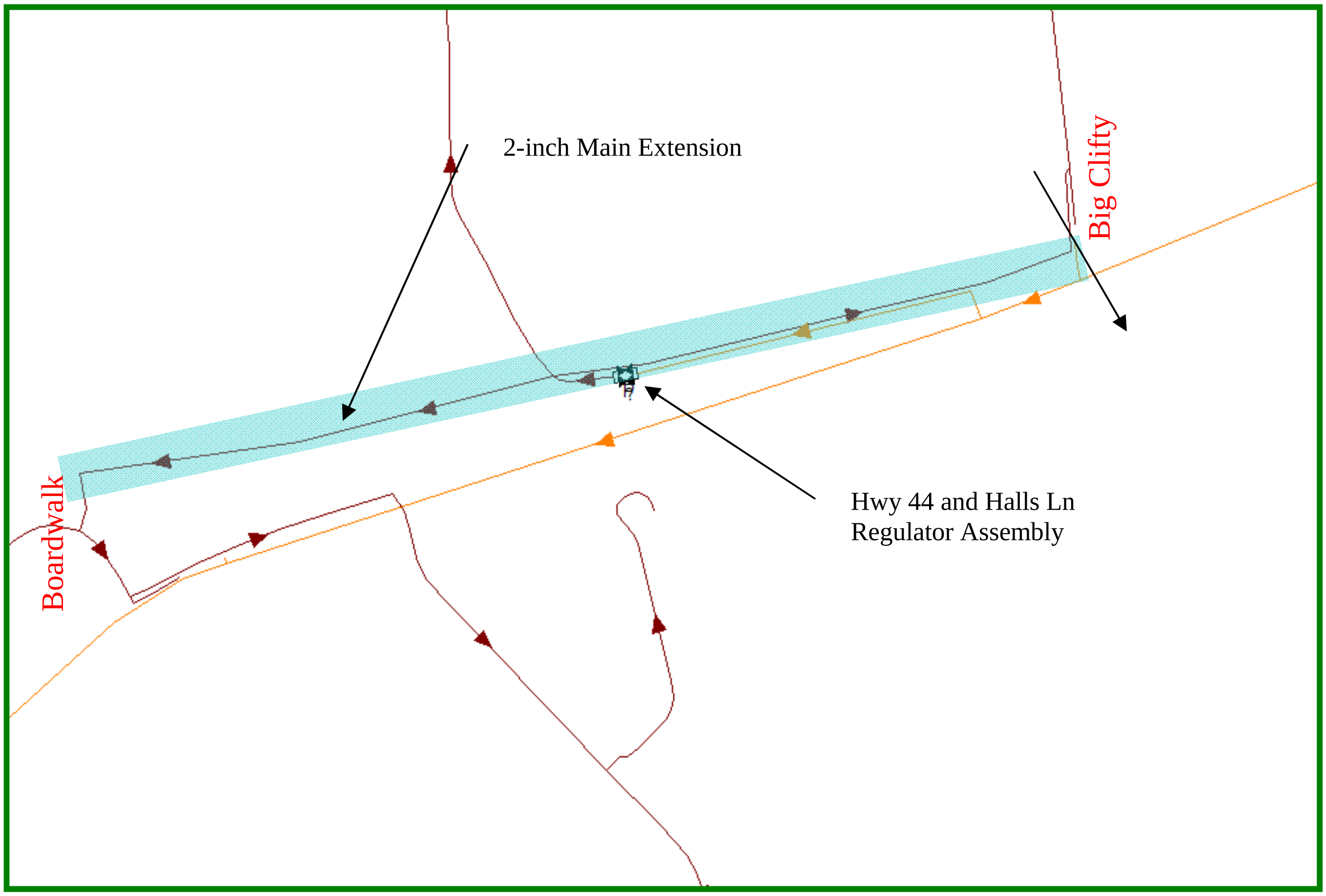
- Winding Woods Trail **– 26.9 psig**

Regulator Operating Capacities

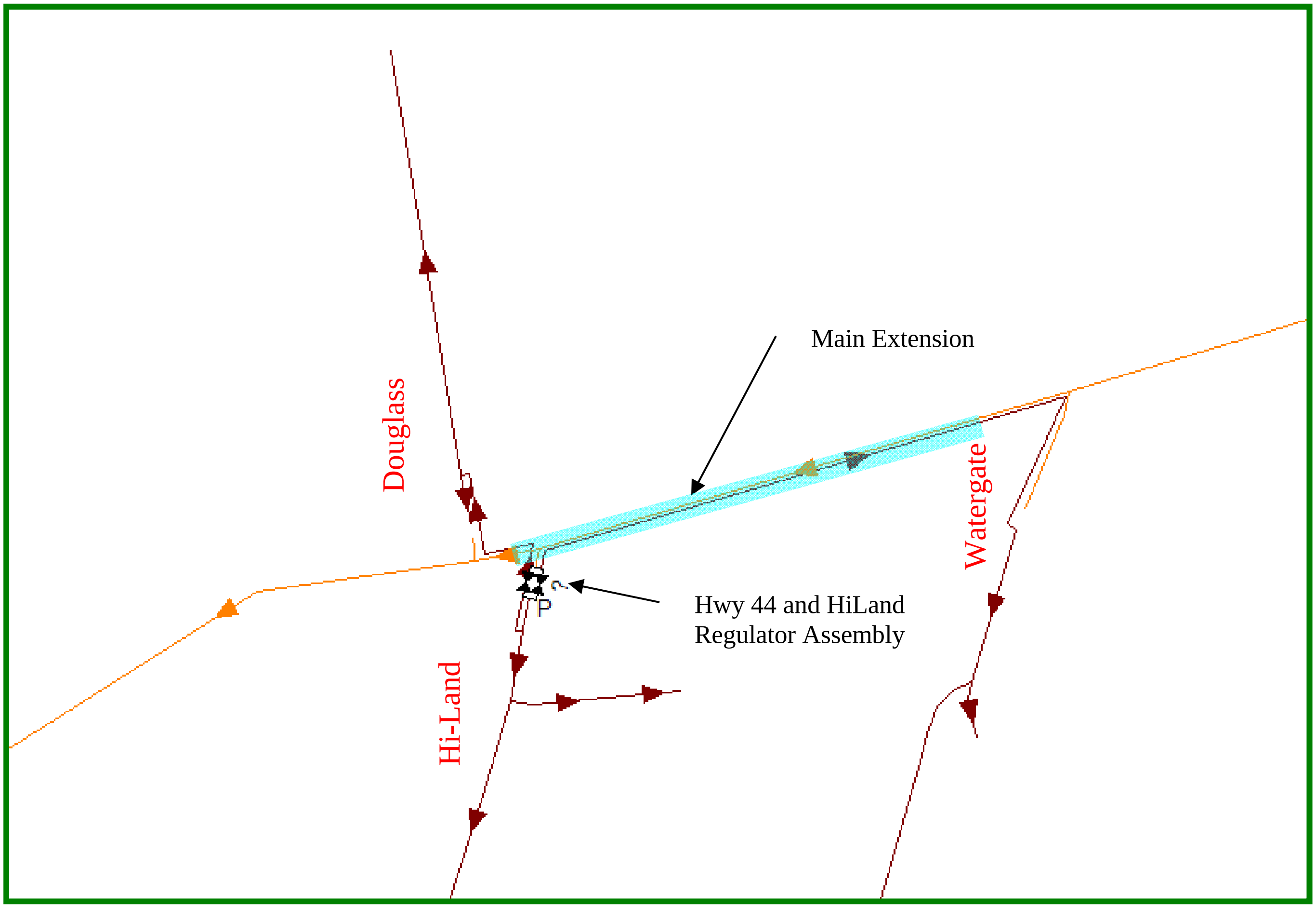
- Hwy 44 and Fisher **– 65.2%**
- Hwy 44 and Woodlake **– 63.8%**

Recommended Timeline – 2010-2015

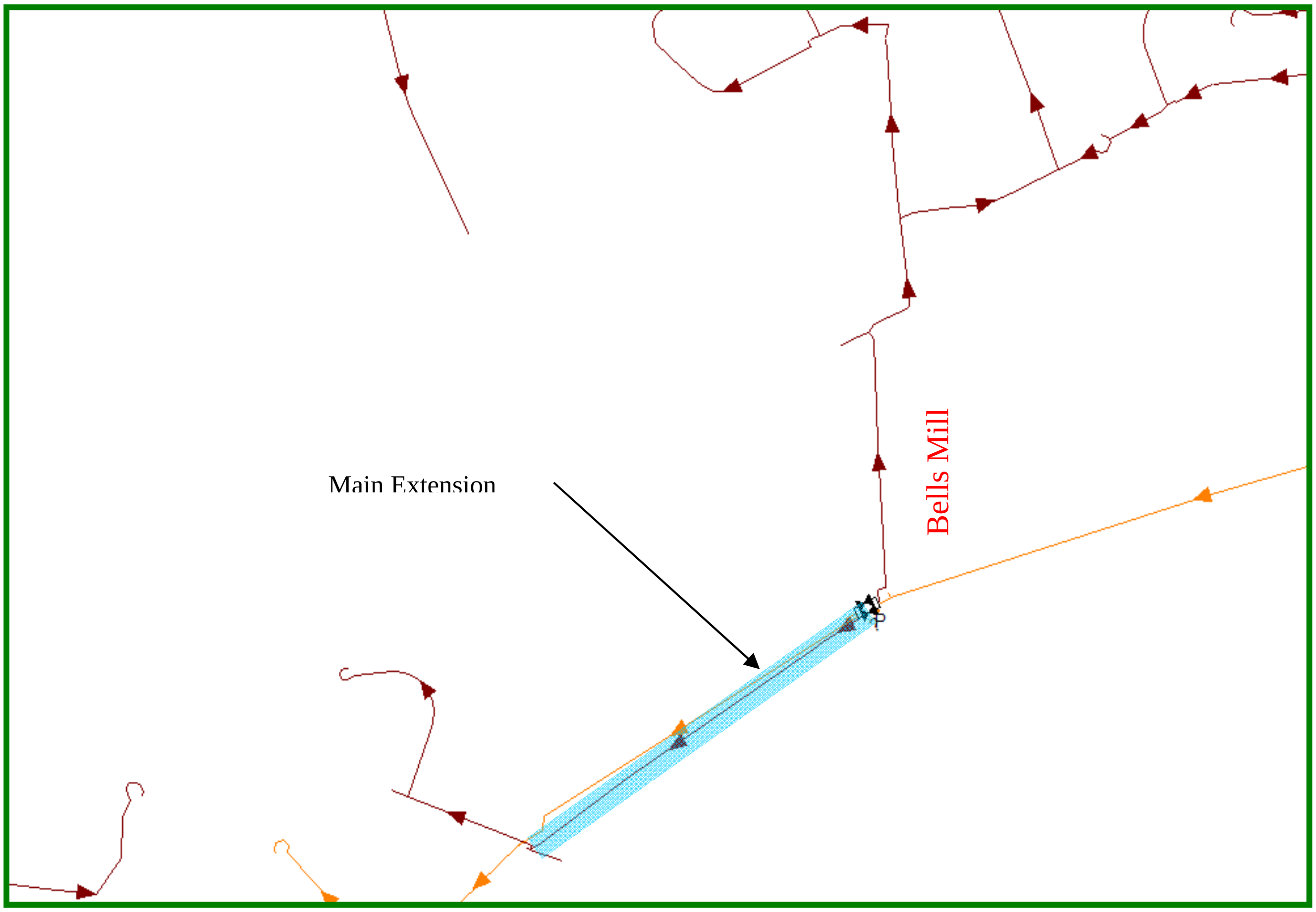
Hwy 44 Regulator Assemblies – Reinforcement 1



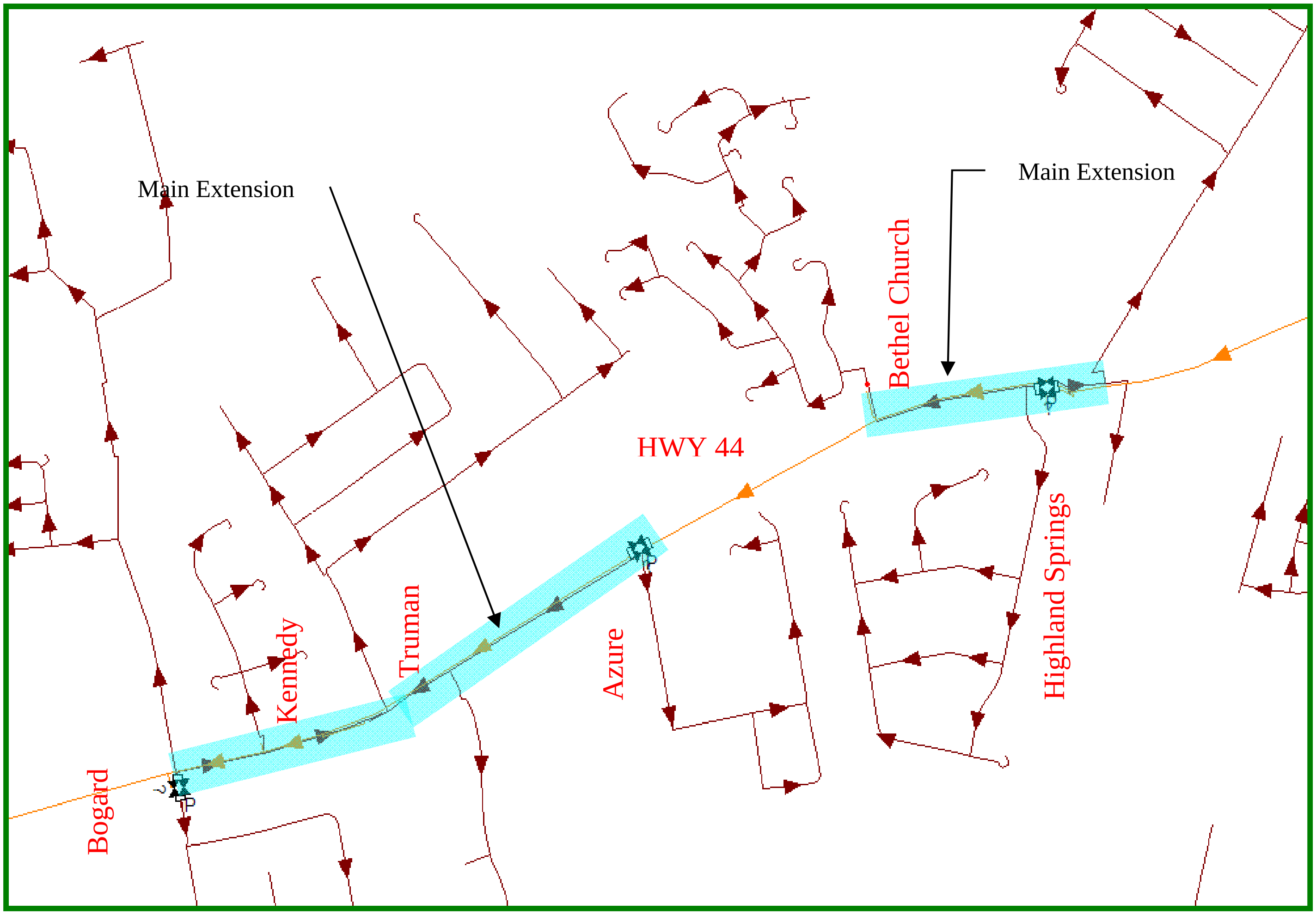
Hwy 44 Regulator Assemblies – Reinforcement 2



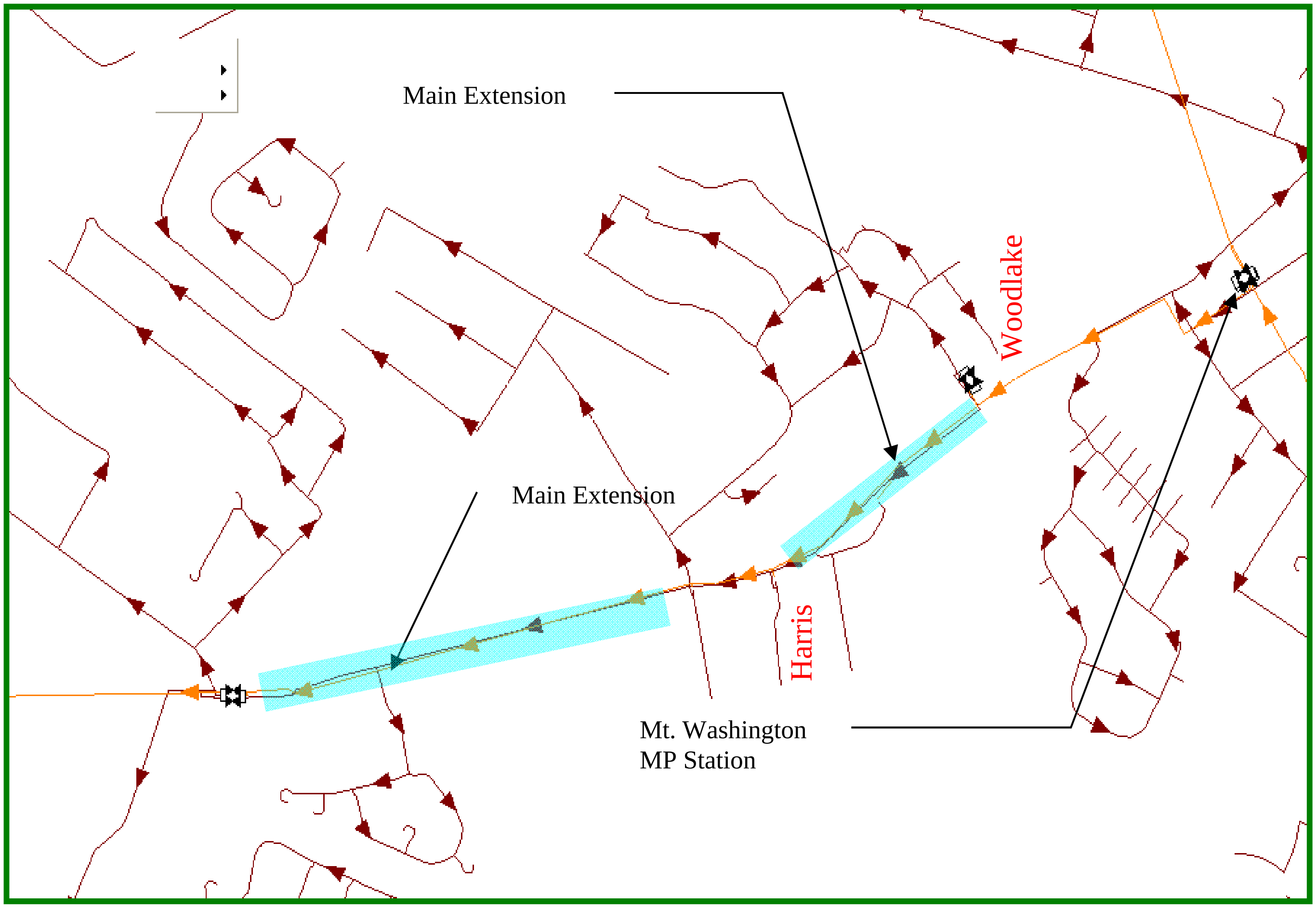
Hwy 44 Regulator Assemblies – Reinforcement 4



Hwy 44 Regulator Assemblies – Reinforcement 5



Hwy 44 Regulator Assemblies – Reinforcement 6



VIII. <u>Hodgenville Medium Pressure System</u>

Gas System Overview

The Hodgenville medium-pressure gas system serves the City of Hodgenville. This system is composed of residential and small commercial customers. Both sectors continue to experience growth. To continue to cope with growth in Hodgenville, the gas system will need to be reinforced.

<u>Regulator Facilities</u>

The Hodgenville medium-pressure system is fed by the regulator station at State Highway 84 and Glendale Rd.

<u>Maximum Allowable Operating Pressure</u>

The Hodgenville medium-pressure system has a maximum allowable operating pressure of 20 psig.

Model Results

<u>Minimum Gas System Pressure (-12°F)</u>

The predicted minimum pressure is located at **2017 US Highway 31E (16.4 psig)**.

<u>Regulator Operating Capacity</u>

- Hodgenville Station – 22.6%

Recommended Gas System Reinforcement

<u>Reinforcement 1</u>

Uprate the Hodgenville medium pressure gas distribution system to 50 psig. This uprate will affect approximately 1,091 services and 25.5 miles of pipeline.

Minimum Gas System Pressure (-12°F)

- 2017 US Highway 31E – **48.1 psig**

Regulator Operating Capacity

- Highway 84 and Glendale Rd – **22.7%**

Recommended Timeline – 2017

IX. Minor Lane Heights Renaissance Zone

Gas System Overview

The Minor Lane Heights area is being targeted for redevelopment from residential use to commercial and industrial use as a part of a noise mitigation program associated with the Louisville International Airport. Redevelopment is scheduled to occur in five phases, beginning in early 2007 and lasting ten years.

Gas System Reinforcement Completed in 2007

- Retire existing pipeline along Paul Rd south of Zib Ln
- Install approximately 4,300 ft of 8-inch plastic main along Outer Loop, Stinnett Ln, proposed Air Commerce Way to serve UPS facility.

Regulator Facilities

The regulator facilities that feed this system are as follows:

- Regulator station at Preston City Gate Station
- Regulator pit at Outer Loop and Grade Ln

Maximum Allowable Operating Pressure

The Minor Lane Heights system has a maximum allowable operating pressure of 60 psig.

Model Results

Minimum Gas System Pressure (-12°F)

The predicted minimum gas system pressure is located at the UPS Supply Chain Solutions warehouse at **2240 Outer Loop (46.1 psig)**. There is another low pressure point at the south end of Eagle Pass (46.6 psig).

Regulator Operating Capacities

- Preston City Gate Station MP – **52.7%**
- Outer Loop and Grade Ln – **47.3%**

Gas System Constraints

Most of the existing gas infrastructure in the Minor Lane Heights system is 2- and 4-inch pipe. In addition, the system is relatively distant from its supplies. This would make it difficult to serve the number of industrial customers proposed for the Renaissance Zone. Furthermore, the proposed layout of the Renaissance Zone would place much of the existing infrastructure below various structures. To account for this, and to serve the projected loads, the Minor Lane Heights system must be altered and reinforced.

IX. Minor Lane Heights Renaissance Zone (cont'd)

Recommended Gas System Reinforcements

Reinforcement 1
Install and remove gas mains according to "An Analysis of the Minors Lane Heights Renaissance Zone" dated 15 January 2007 or the latest version.

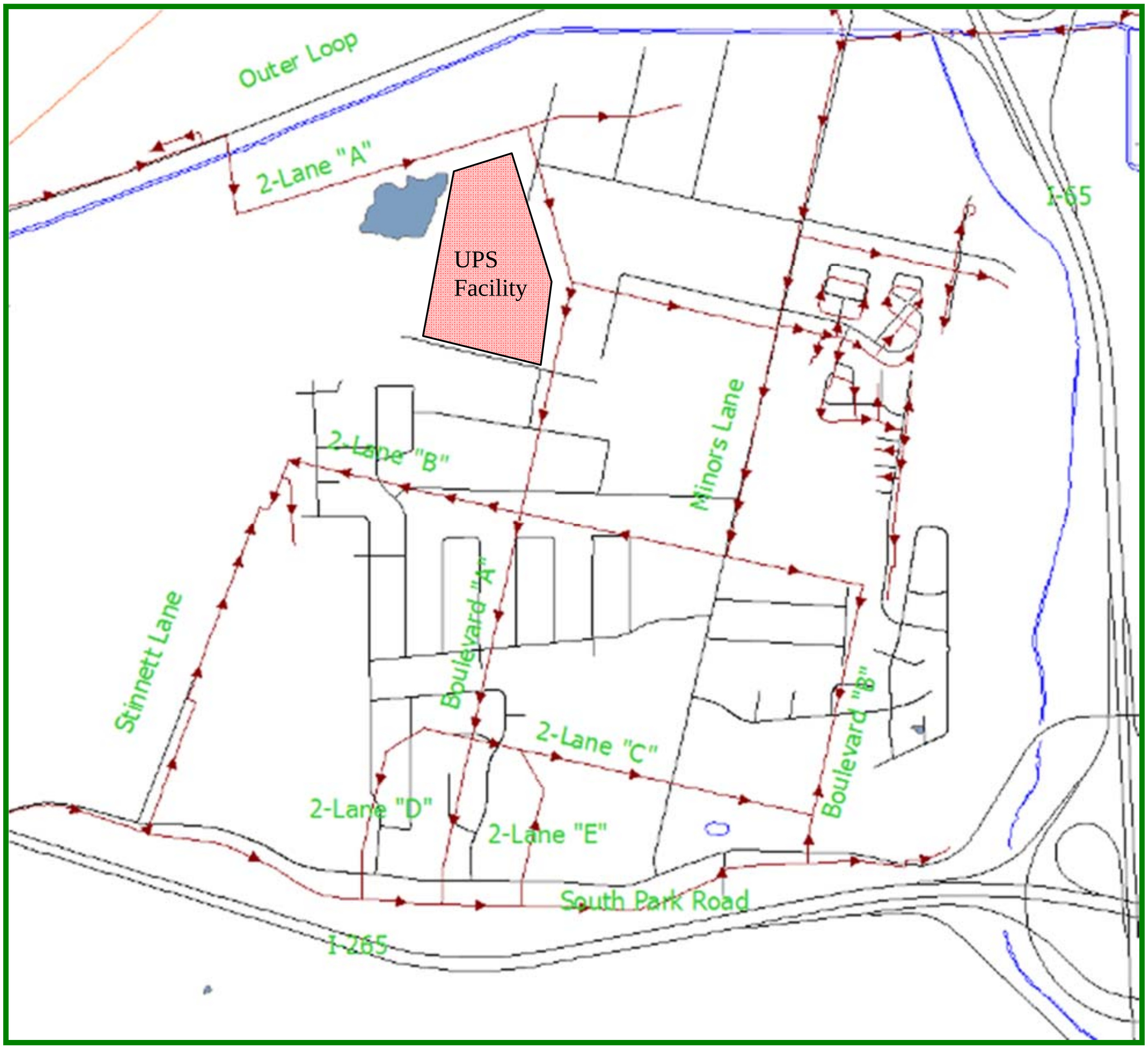
- Retire existing pipelines in the area.
- Install approximately 12,470 ft of 4-inch pipe
- Install approximately 1.975 ft of 6-inch pipe
- Install approximately 4,600 ft of 8-inch pipe

Minimum Gas System Pressure (-12°F)
- UPS Supply Chain Solutions Warehouse (2220 Outer Loop) **– 53.14 psig**

Regulator Operating Capacities
- Preston City Gate Station MP **– 52.6%**
- Outer Loop and Grade Ln **– 54.4%**

Recommended Timeline – 2010-2019

Minor Lane Heights Renaissance Zone – Map of Proposed Streets and Reinforcement 1



X. Mount Washington Medium Pressure System

Gas System Overview

The Mount Washington medium pressure gas system serves the City of Mount Washington and surrounding areas. This system is composed of residential and commercial customers. It continues to experience growth in the residential and commercial sectors, especially along Highway 44.

Regulator Facilities

The two regulator facilities that supply gas to the Mount Washington medium pressure system are as follows:

- Regulator station located at Sunnyside Drive and Highway 44 (Mt. Washington MP)
- Regulator assembly located at Landis Lane and Bardstown Road

Maximum Allowable Operating Pressure (MAOP)

The Mount Washington medium pressure gas system has a maximum allowable operating pressure of 60 psig.

Model Results

Minimum Gas System Pressure (-12 ^{0}F):

The predicted minimum pressure is located on **Pin Oak Drive (28.1 psig).**

Regulator Operating Capacities (-12 ^{0}F):

- Mt. Washington MP **– 10.5%**
- Bardstown Rd and Landis Ln **– 25.3%**

Gas System Constraints

Gas system constraints in this area are primarily due to an infrastructure of 4-inch diameter pipe along Highway 44. Due to current and anticipated growth, it will be necessary to perform gas system reinforcement work.

Recommended Gas System Reinforcements

Reinforcement 1

Install approximately 3,600 ft of 6-inch medium pressure pipeline from Oakland Hills Trail to tie into the existing 4-inch medium pressure pipeline on Waterford Road.

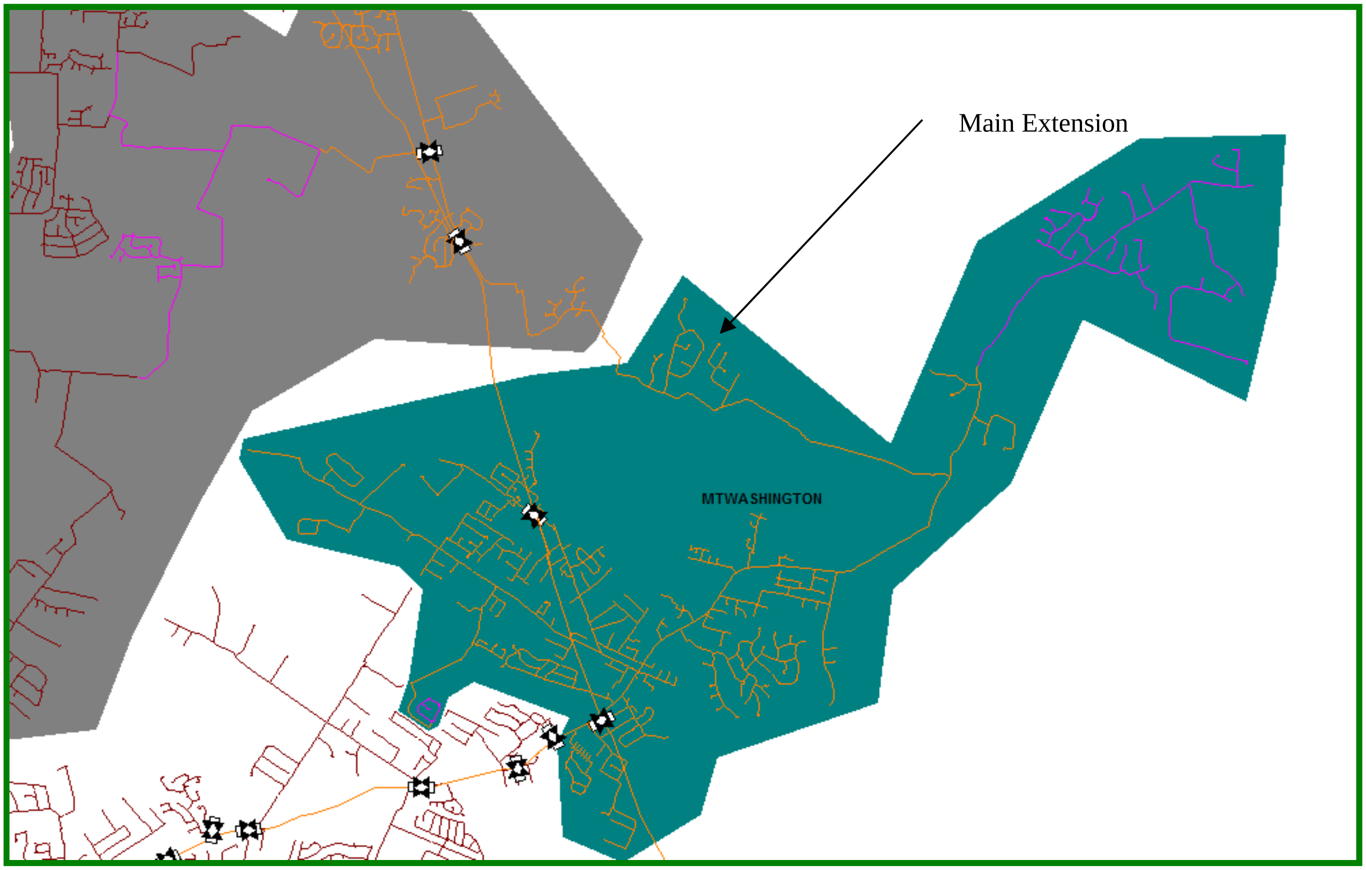
Minimum Gas System Pressure (-12 ^{0}F)

- Pin Oak Dr **– 49.93 psig**

Regulator Operating Capacities (-12 ^{0}F):

- Mt. Washington MP **– 8.8%**
- Bardstown Rd and Landis Ln **– 23.5%**
- Vista Hills Blvd and Calvary Line **– 100%**
  Recommended Timeline – 2011-2015 – This should be done in conjunction with the development of the Oakland Hills subdivision.

Mount Washington Medium Pressure System – Reinforcement 1



XI. Preston High Pressure Distribution System

Gas System Overview

The Preston high pressure distribution gas system serves the cities of Shepherdsville, Maryville Okolona and outlying areas. The gas supply originates from the Preston City Gate Station to the Preston High Pressure Station and gas pipeline running south. This system is a one-way feed into the Okolona and Maryville areas. These areas have continued to experience growth in the residential and commercial sectors.

Maximum Allowable Operating Pressure

The Preston high pressure system consists of an 8-inch pipeline operating at a maximum allowable pressure of 110 psig.

Model Results

Minimum Gas System Pressure (-12°F)

The predicted minimum gas system pressure for this high pressure system is located at the inlet to the **Preston and Antle regulator pit (68.4 psig)**

Regulator Operating Capacities

- Preston City Gate Station **– 50.5%**

Gas System Constraints

Gas system constraints in this area are primarily due to the one-way feed of high pressure gas feeding the distribution systems and the lack of pipe further south along Preston Highway. Due to current and anticipated growth, it will be necessary to perform gas system reinforcement work.

Note: The current pressure on the Preston high pressure line prohibits a significant pressure differential across the existing and any new gas regulation facilities. The Preston high pressure pipeline is required to operate very low (75-85 psig) in order to maximize gas withdrawal from the Magnolia compressor station. Operating the Preston high pressure pipeline at its 140 psig MAOP significantly improves the inlet pressure (110 psig) to the existing gas regulation facilities.

XII. Penile Gas System Uprate Project

Gas System Overview

The 35 psig system north of the Penile City Gate Station is made up of Third Street Rd, St. Anthony's Church Rd, Arnoldtown Rd, New Cut Rd, Windsor Forest Subdivision, and other residential and commercial customers. It is bordered to the North by St. Andrews Church Rd, to the South by Pond Creek, to the East by the existing EP system, and to the West by Lakeridge Dr. This uprate includes 97.5 miles of pipe and approximately 8,130 services.

Regulator Facilities

The regulator facilities that supply the gas to the Penile uprate area include:

- St. Andrews Church Road & I.C.R.R.
- New Cut Road & Old 3rd Street Road
- Old 3rd Street Road & Bamberrie Cr.
- Penile City Gate Station medium pressure facility.

Maximum Allowable Operating Pressure

The system has a maximum allowable operating pressure of 35 psig.

Model Results

Gas Regulator Facility Upgrades

- Change the regulation equipment at New Cut Road & Old 3rd Street Road to 3" Mooneys @ 100%.
- Change the regulation equipment at Old 3rd Street Road & Bamberrie Cr. to 3" Mooneys @ 100%.
- Change the set point pressure at Old Third Street Road & Manslick Road to its MAOP of 99 psig.
- Retire the Penile City Gate Station medium pressure gas facility.

Recommended Timeline – 2010

Medium Pressure Gas System Uprate

- Uprate the 35 psig system area to 60 psig and connect it to the existing 60 psig system below.
- Close Valves: 11819094, 12533053, 12332647, 11810152, 12533654, 12304851
- Open Valves: 12333758, 7484120
- Uprate regulators to 60 psig: 11814741, 12564146, 12342053_1, 12443141

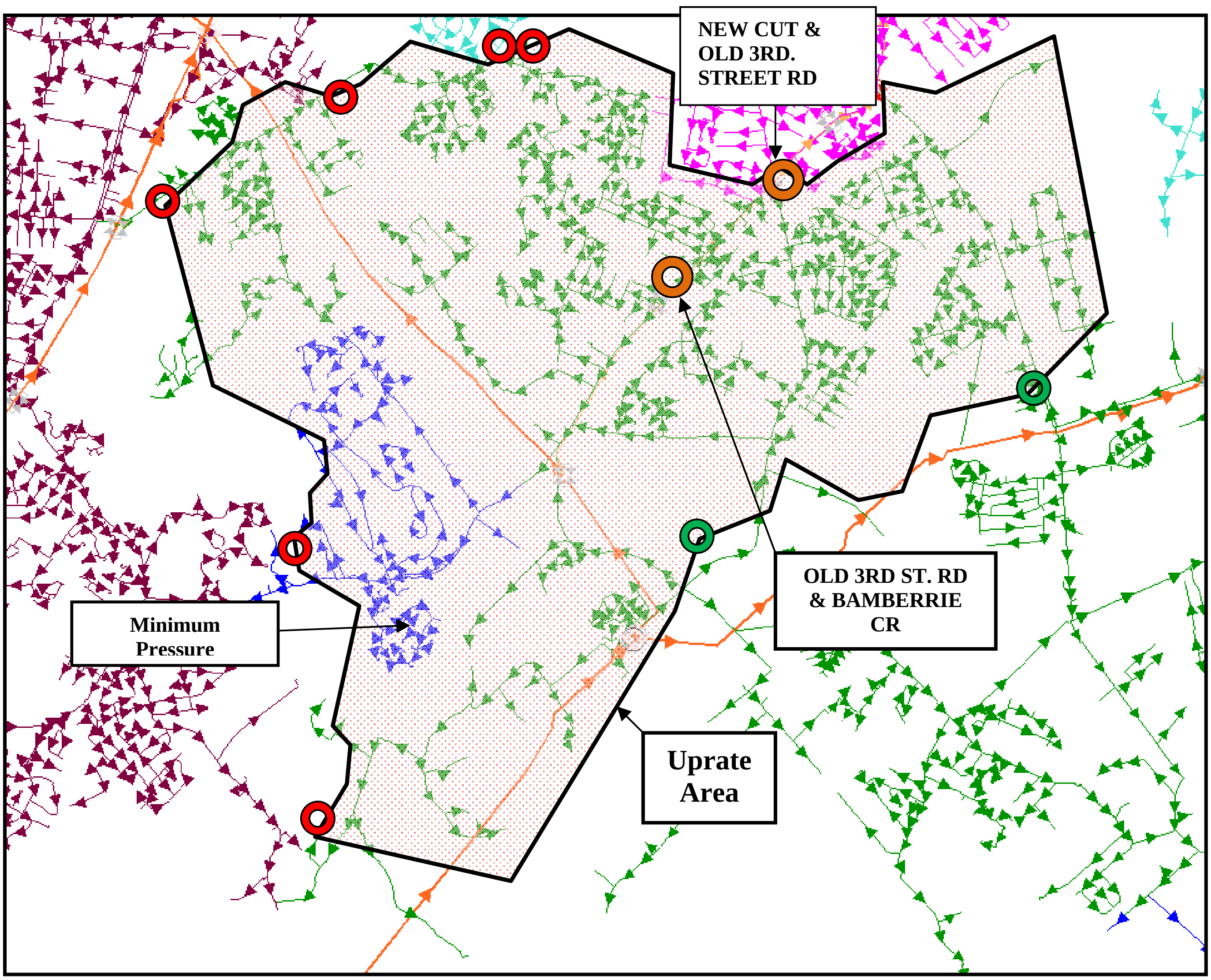
Minimum gas system pressure (-12ºF):

- 9605 Britannia Ct (33.8 psig)

Regulator Operating Capacities:

- St. Andrews Church Road & I.C.R.R. 10.6%
- New Cut Road. & Old 3rd Street Road 32.5%
- Old 3rd Street Road & Bamberrie Cr. 26%

Recommended Timeline – 2012-2013



= closed = open valve = regulator facility

XIII. Mt. Washington/Lebanon Junction High Pressure Distribution System

Gas System Overview
The Mount Washington/Lebanon Junction system is a one-way feed high pressure distribution system that receives its gas supply from LG&E's Calvary gas transmission pipeline in the Mount Washington area. The high pressure system consists of 8-inch and 6-inch pipe.

There are five major existing gas loads associated with this high pressure system. They are as follows:

- City of Shepherdsville
- City of Lebanon Junction
- Jim Beam Boston Plant
- Jim Beam Clermont Plant
- Publishers Printing

There are five major new gas loads associated with this high pressure system. They are as follows:

- Heritage Hills subdivision
- Gordon Foods
- Shepherdsville Industrial Park
- Highway 480 Industrial Park
- Salt River Business Park

The following points can be summarized from the gas system planning analyses:

- The Mount Washington high pressure gas distribution system must operate at 275 psig in order to operate the Shepherdsville gas distribution system at 60 psig on a design day (-12 ^{0}F).
- LG&E can meet the gas service requirements for Publishers Printing and Jim Beam Boston on a design day (-12 ^{0}F) with the proposed gas loads and the Mount Washington high pressure system operating at 275 psig.
- Approximately 60-65 Mcfh of gas load can be added to the 6-inch high pressure pipeline near Clermont while maintaining approximately 56 psig at Boston, Kentucky with the proposed total connected gas loads and the Mount Washington high pressure system operating at 275 psig.

XIII. Mt. Washington/Lebanon Junction High Pressure Distribution System (cont'd)

Recommended Gas System Reinforcements

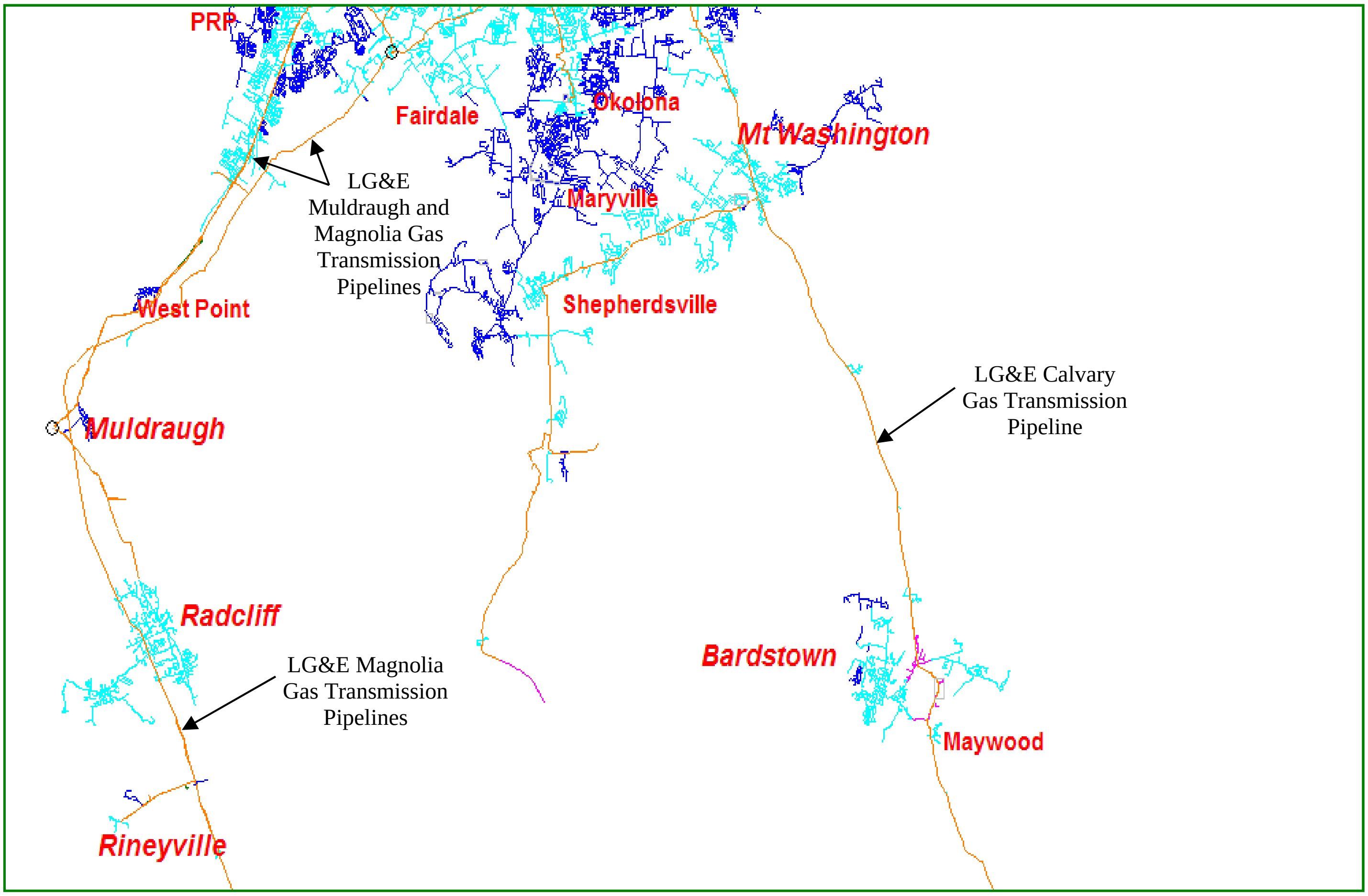
Reinforcement 1
Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line in Bardstown, KY, along Hwy 245 to Clermont, serving south to Lebanon Junction. This would require installing approximately 14.0 miles of 8-inch high-pressure (400 MAOP) piping and a new regulator facility near the Jim Beam Clermont Distillery on Hwy 245. This system reinforcement would solve current and future pressure problems as well as eliminating other risk factors by adding an additional gas supply to a dead end system.

Based on the projected load growth resulting from the two new business parks in the Shepherdsville area, Heritage Hills subdivision, Jim Beam in Boston, and Publishers Printing in Lebanon Junction, along with projected 4% growth from existing residential and commercial customer base a new pipeline is projected to be required in 2012.

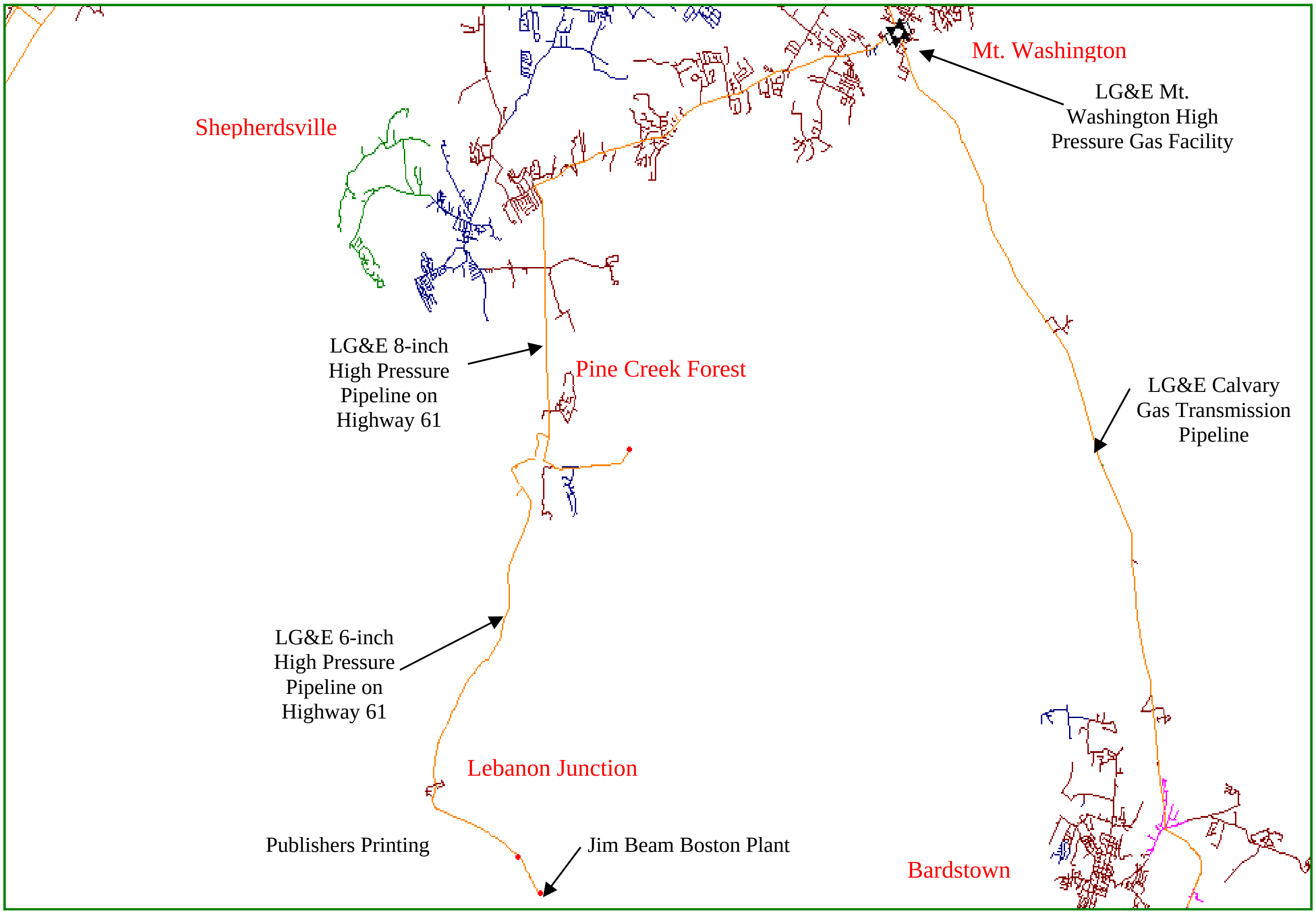
Recommended Timeline – 2012

Reinforcement 2
Install a high-pressure system reinforcement that would bring high-pressure gas from the Magnolia line to the south end of the system. This would require installing approximately 13 miles of 8-inch high-pressure (520 psig MAOP) piping along Highway 434 and a new regulator assembly at the south end of the system. This system reinforcement would correct the current and future pressure and capacity problems by providing a new gas supply in the areas where there is the largest load concentration. In addition, the system reinforcement would provide a second gas supply to the model thus eliminating the risks associated with a dead end system.

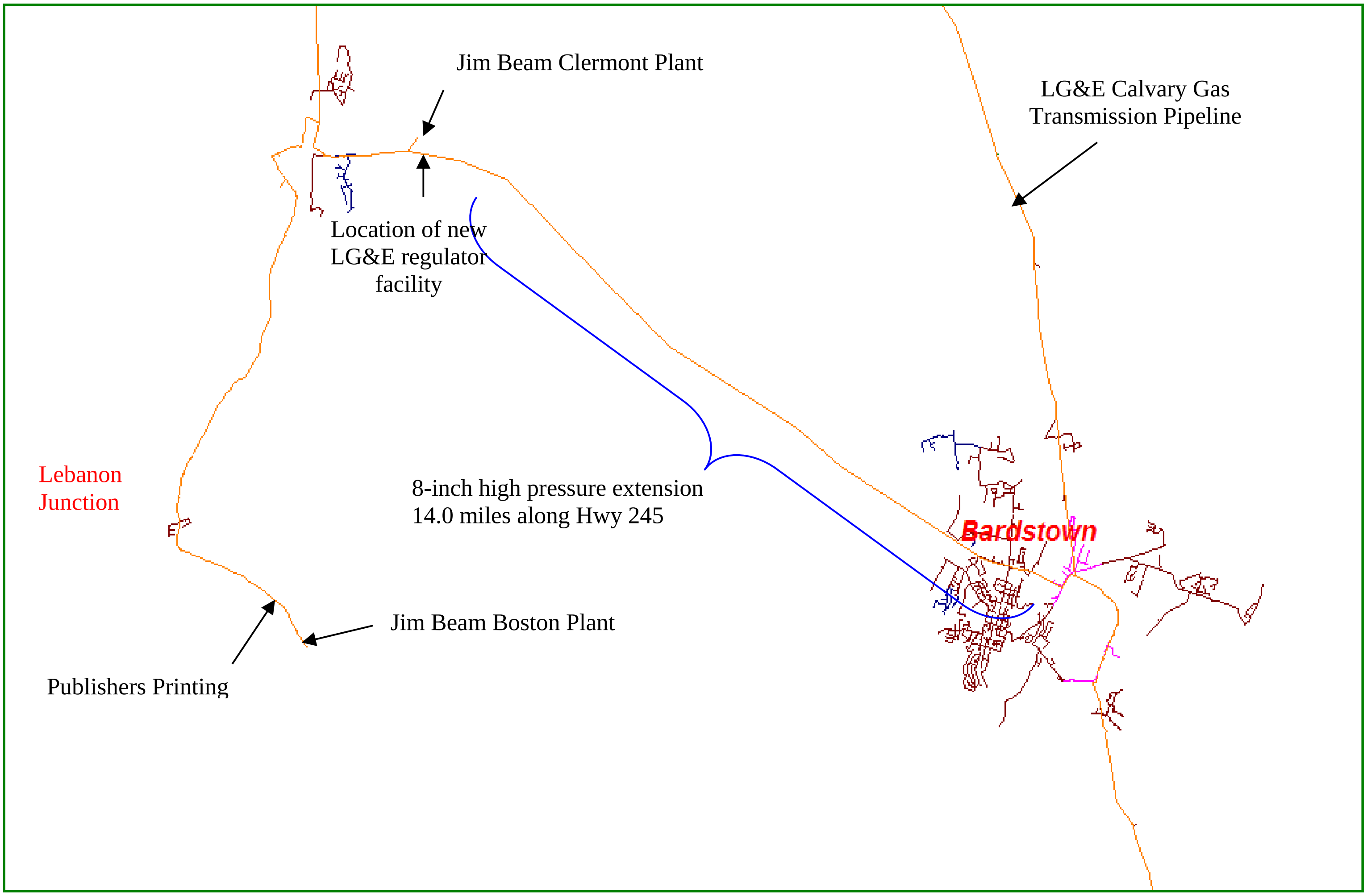
Mt. Washington High Pressure Distribution System - Overview



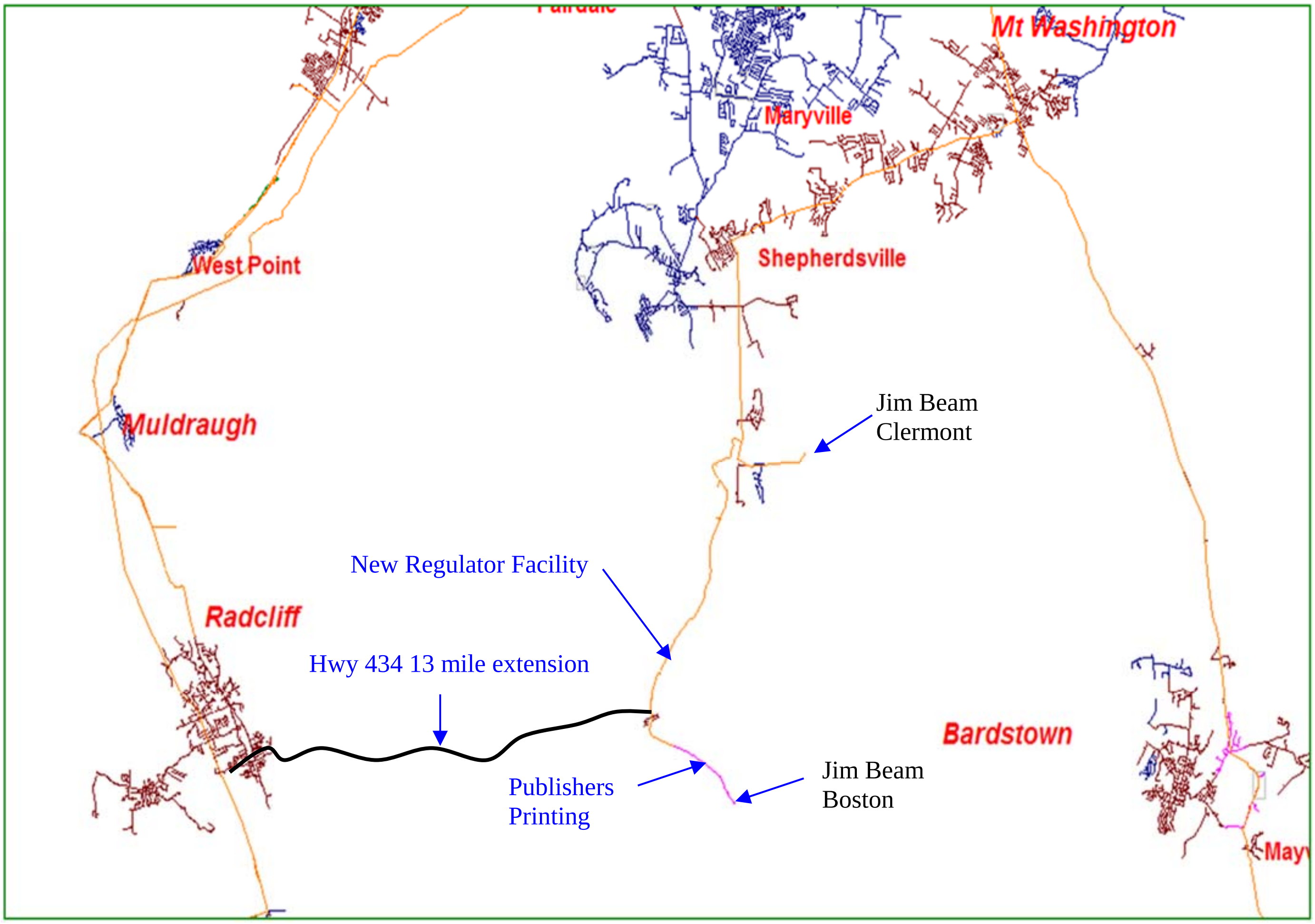
Mt. Washington High Pressure Distribution System – Mt. Washington Overview



Mt. Washington High Pressure Distribution System – Reinforcement 1



Mount Washington/Lebanon Junction High Pressure Gas System – Reinforcement 2



XIV. <u>Shepherdsville/Northern Bullitt County Uprate Project</u>

Gas System Overview
The Shepherdsville/Northern Bullitt medium pressure gas system serves residential and commercial customers in Jefferson County and outlying areas between I-64 and I-264.

<u>Regulator Facilities in uprated area</u>
The regulator facilities that supply gas to the Shepherdsville/Northern Bullitt medium pressure system and are located in the uprate area are as follows:

- Regulator pit at Lee's Lane and Hwy 44
- Regulator pit at Cedar Grove Road and I-65
- Regulator pit at Mud Lane and Antle Drive
- Regulator pit at Old Bardstown Rd and Thixton Ln
- Regulator pit at Vista Hills Blvd and Calvary Line

<u>Maximum Allowable Operating Pressure</u>
The Shepherdsville/Northern Bullitt medium pressure gas system has a maximum allowable operating pressure of 60 psig.

The medium pressure gas distribution system to the north of the 60 psig gas system has a maximum allowable operating pressure of 35 psig.

Model Results

Minimum Gas System Pressure (-12 ^{0}F)
- 4002 Neagli Court **(5.15 psig)**
- 11103 Brook Bend Court **(6.36 psig)**

<u>Regulator Operating Capacities</u>
- Lee's Lane and Hwy 44- **20.5%**
- Cedar Grove Road and I-65- **18.6%**
- Mud Lane and Antle Drive- **100%**
- Old Bardstown Rd and Thixton Ln- **6.6%**
- Vista Hills Blvd and Calvary Line- **51%**

<u>Gas System Constraints</u>
Gas system constraints in this area are due to low inlet pressures on the Preston high pressure distribution pipeline. This high pressure gas system has a maximum allowable operating pressure of 110 psig. The pressure on the Preston high pressure distribution system is the most problematic during the end of the gas withdrawal season for the Magnolia compressor station.

XIV. Shepherdsville/Northern Bullitt County Uprate Project (cont'd)

Recommended Reinforcement

- Increase the boundaries for the 60 psig system to include the problem areas in the 35 psig system to the north.
- Uprate 153.4 miles of pipeline and approximately 14,675 customers
- Close valves 7458949, 7462206, 7498477, 7499040, 7533181, 7500148, 7514342, 7471363, 7471663
- Open valves 7510213, 7466257, 7466165, 7516765, 14935942, 7508381, 7462477, 7471635, 7471736, 7521689, 7489936, 7489066
- Uprate the regulator station at Preston Hwy and South Park Road to 60 psig.
- Uprate Preston & Springview to 60 psig. Replace the gas regulation equipment with low differential equipment.
- Mud Lane & Antle Drive - Replace the gas regulation equipment with low differential equipment.

Minimum gas system pressure (-12 ^{0}F) 60 psig system

- Entire 60psig- Kewana Ct (**33.5 psig)**
- Entire 60psig- Kendrick Crossing (**36.2 psig)**

Minimum gas system pressure (-12 ^{0}F) 35 psig system

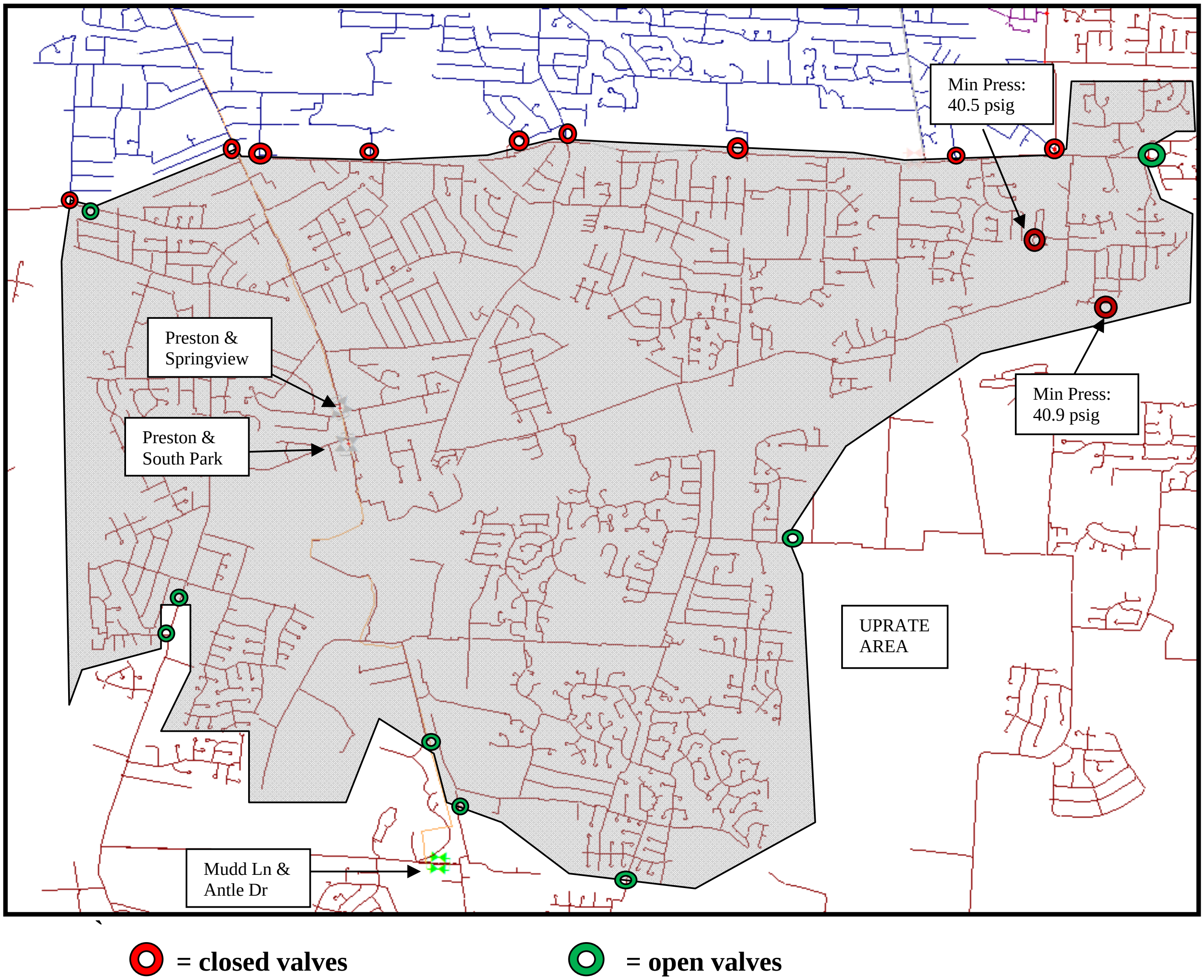
- Inlet to Gardiner Ln & Schuff- (**11 psig**)
- 3202 Oak Haven Ct- (**18.2 psig**)

Regulator Operating Capacities

- Lee's Lane and Hwy 44- **23.4%**
- Cedar Grove Road and I-65- **20%**
- Mud Lane and Antle Drive- **100%**
- Old Bardstown Rd and Thixton Ln- **7.1%**
- Vista Hills Blvd and Calvary Line- **52.8%**
- Preston Hwy and South Park Road- **43.9%**
- Preston Hwy and Springview- **51.2%**

Recommended Timeline – 2011

Shepherdsville/Northern Bullitt County Uprate Project



XV. Radcliff/Fort Knox Medium Pressure System

Gas System Overview

The Radcliff/Fort Knox medium pressure system serves approximately 4,600 residential and small commercial customers. Currently only two customers on the system require delivery pressure above 2 psig: Cardinal Health at 2 psig and Tri-County Ford at 2.5 psig. Due to Base Realignment and Closure (BRAC) changes at Fort Knox, it is anticipated that approximately 3,500 military employees will be relocating to the Radcliff/ Fort Knox area over the next 8 years.

Regulator Facilities

The regulator facilities that feed this system are as follows:

- Radcliff #1 at the corner of N Dixie Blvd and Northern Rd.
- Radcliff #2 at the intersection of S Logsdon Parkway and W Vine Street.

Maximum Allowable Operating Pressure

The Radcliff/Fort Knox medium pressure system has a maximum allowable operating pressure of 35 psig.

Model Results

Minimum Gas System Pressure (-12°F)

The predicted minimum gas system pressure is located at **480 Berkley Ct (32.6 psig).**

Regulator Operating Capacity (includes asphalt plant load):

- Radcliff #1: 23.6% (23.6%)
- Radcliff #2: 47% (47%)

Gas System Constraints

The two gas supply points for this system are located centrally and on the northeastern end of the system. Rapid system expansion due to BRAC relocations is expected to tax the existing infrastructure. Any significant load increase off of St. Andrews Dr will require significant reinforcement.

XV. Radcliff/Fort Knox Medium Pressure System (cont'd)

Recommended Gas System Reinforcement

Reinforcement 1

- Replace existing regulators in Radcliff #2 with 4x3 Mooney assemblies with 100% plates.
- Uprate the system from 35 psig to 60 psig.

Note: Additional BRAC load was estimated to be 240 Mcfh based on anticipated number of new residences and current load. This load was proportionately distributed throughout the system.

Minimum gas system pressure (-12°F)
1004 Muirfield Ct (32.7 psig)
568 St. Andrews Rd (54.33 psig)

Regulator Operating Capacities

- Radcliff #1 – 49.4%
- Radcliff #2 – 14.1%

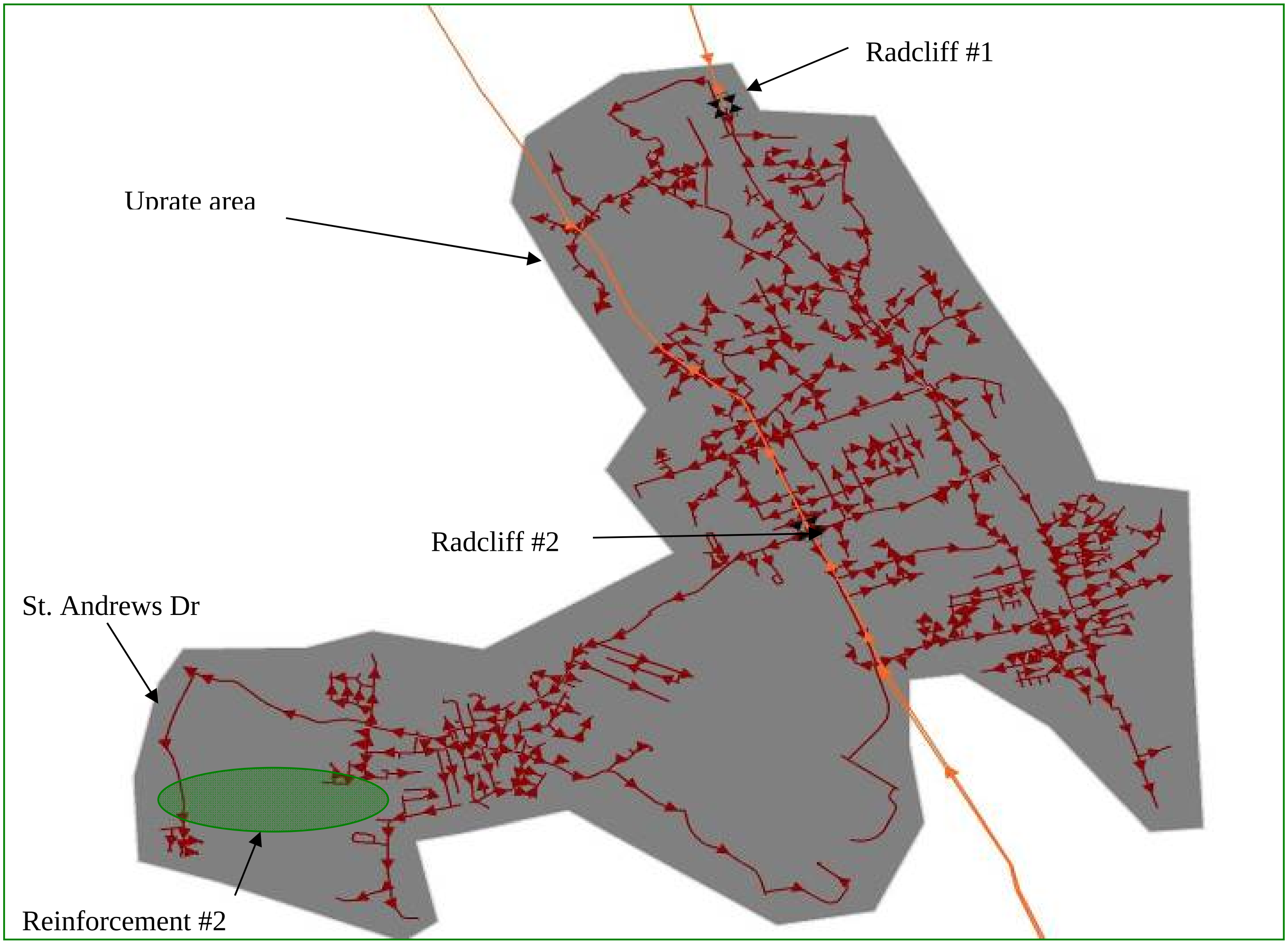
Recommended Timeline – 2010-2018

Reinforcement 2

- Install 4,800' of 4-inch plastic main in Otter Creek Rd from existing 4-inch steel main to the 2-inch plastic main in St. Andrews Dr.

Note: Reinforcement needed only for significant development off St. Andrews Drive.

Radcliff/Fort Knox – Reinforcement 1 & 2



XVI. Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System

Gas System Overview

The Crestwood/Pee Wee Valley/Simpsonville medium-pressure system will require reinforcement to continue to serve the new developments in the area which include professional medical centers, office buildings, and retail/restaurants. This system also supplies the Persimmon Ridge and the Polo Fields developments. The system has experienced growth away from the only sources of gas in this system. In order to serve current and future loads, it has been determined that reinforcement work will need to be performed on the Crestwood/Pee Wee Valley/Simpsonville medium pressure system. There are a few options available that will provide adequate pressures throughout the system.

Gas System Reinforcement Completed in 2007

- Old Henry Road Reinforcement
  - Install 5,700 ft of 8-inch medium pressure pipe north along Old Henry Rd to tie into the 8-inch main at 9207 Ash Land Ct.

Maximum Allowable Operating Pressure

The Crestwood/Pee Wee Valley/Simpsonville medium pressure system has a maximum allowable operating pressure of 50 psig.

Model Results

Minimum gas system pressure (-12 ^{0}F)

- 1400 Rutland Club Ct **– 29.53 psig**

Regulator Operating Capacities

- Hwy 1694 & Worthington Lane – 17.4%
- Old Henry Road & Terra Crossing Blvd. – 51.4%
- Connor Station Road & Colt Run Road – 6.4%
- Crestwood & Old LaGrange Road. G-381 – 30.7%
- Lakeshore Drive. & Old Veechdale Road G13108 – 45.7%
- English Station Way. G-580 – 49.8%
- Westport Road & Murphy Lane. G-456 – 89.8%
- Old LaGrange Road & Collins Lane. G-578 – 22%

XVI. Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System (cont'd)

Reinforcement Option 1
This option would require the installation of approximately 5,100 feet of 6-inch medium pressure plastic main along Flat Rock Road between Robin Lane and Curry Branch Road.

Minimum gas system pressure (-12 ^{0}F)
- 1400 Rutland Club Ct – **29.6** psig
- 16302 Draw Rein Ct – **29.6** psig

Reinforcement Option 2
This option would require the installation of approximately 8,300 feet of 4-inch medium pressure plastic main along Percy Mill Rd/Johnson Rd beginning at the existing 2-inch main on Percy Mill Rd and ending at the existing 4-inch main on Crosstimbers Dr.

Note: This option would require crossing Floyds Fork.

Minimum gas system pressure (-12 ^{0}F)
- 1400 Rutland Club Ct – **32.6** psig
- 16302 Draw Rein Ct – **32.6** psig

Reinforcement Option 3
- Extend 6-inch plastic main on Aiken Rd 13,150 feet to the existing 6-inch main at Flat Rock Rd.
- Install 3,000 feet of 4-inch plastic on Johnson Rd from Aiken Rd. south to Crosstimbers Dr.

Note: This option would require crossing Floyds Fork.

Minimum gas system pressure (-12 ^{0}F)
- 10523 Championship Ct. – **36.37** psig
- 5704 Laurel Ln – **36.47** psig

Reinforcement Option 4
- Install 6,600 feet of 8-inch high pressure main along Gilliland Rd from the Eastern KY line north to Shelbyville Rd.
- Install 3,500 feet of 8-inch high pressure main along Shelbyville Rd east to Flat Rock Rd.
- Install 9,000 feet of 8-inch high pressure main from the intersection of Shelbyville Rd and Flat Rock Rd northeast to Polo Fields Ln.
- Install Regulator Station at Polo Fields Ln with a set pressure of 50 psig.

Note: This option would require crossing I- 64.

Minimum gas system pressure (-12 ^{0}F)
- 10523 Championship Ct. – **36.4** psig
- 5704 Laurel Ln – **36.5** psig

XVI. Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System (cont'd)

Reinforcement Option 5

This reinforcement is a combination of reinforcements 1 and 3. It requires the installation of 18,250 feet of 6-inch main and 3,000 feet of 4-inch main. It also requires crossing Floyds Fork.

Minimum gas system pressure (-12 ^{0}F)

- 10523 Championship Ct. – **36.4** psig
- 1605 Polo Club Ct. – **19** psig

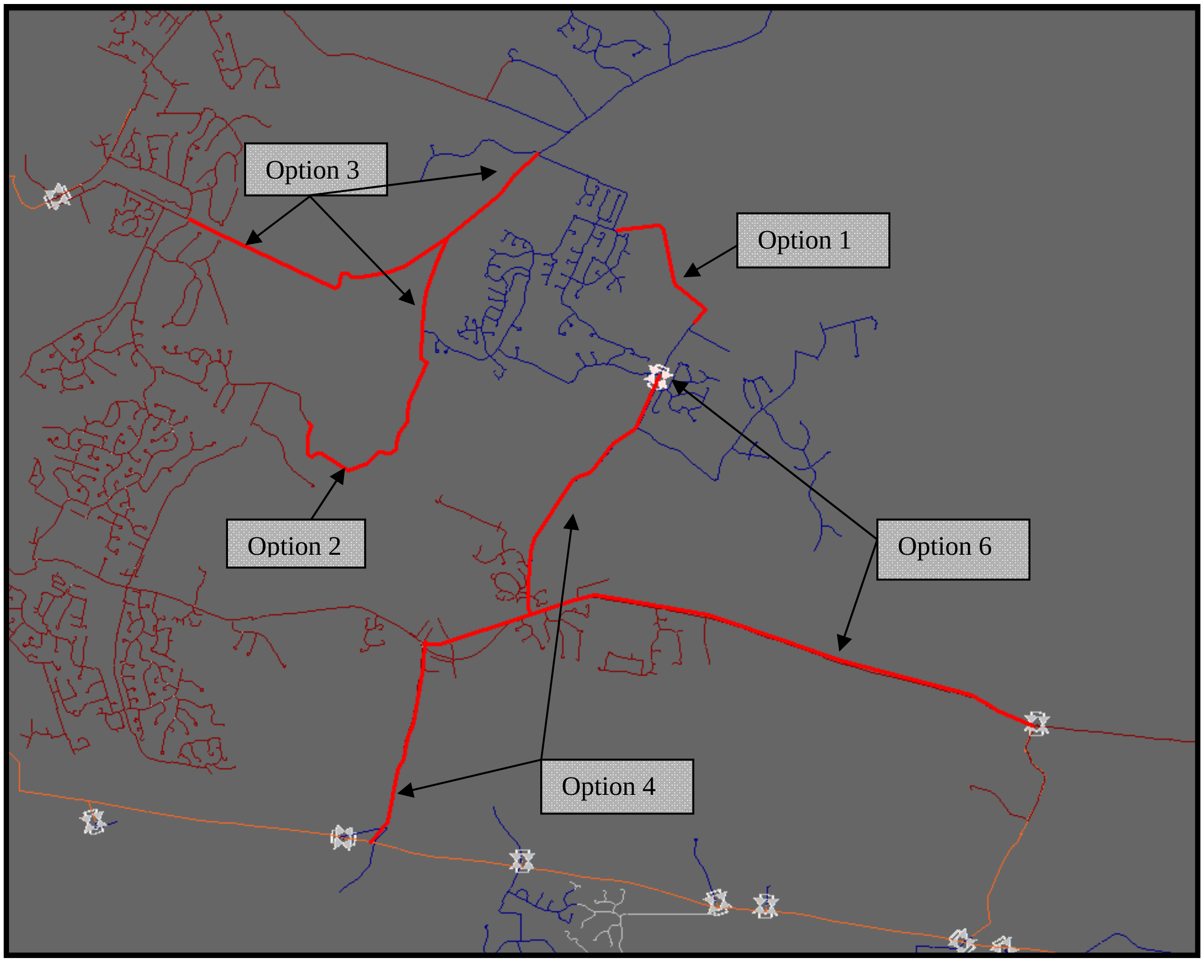
Reinforcement Option 6

- Perform reinforcement 1
- Install 16,500 feet of 8-inch high pressure along Shelbyville Rd from Conner Station and Colt Run Rd RS to Flat Rock Rd.
- Install 9,000 feet of 8-inch high pressure along Flat Rock Rd to Polo Fields Ln.
- Install a regulator station set at 50 psig that feeds Polo Fields Ln from the new high pressure.

Minimum gas system pressure (-12 ^{0}F)

- 2631 Hedgepath Trail – **39.8** psig
- 2102 Polo Creek Ln. – **39.9** psig

Crestwood/Pee Wee Valley/Simpsonville Reinforcement Options 1-6



Note: Option 5 combines Option 1 and Option 3

XVII. East End 20-inch Gas Transmission Pipeline Reinforcement Project

Gas System Overview and Constraints

The concerns for the East side of the gas system stems from the lack of flexibility under design conditions. When the weather is cold, high demand volumes limit how the gas can be delivered. Under design conditions, the East side of the gas system is supplied only by the Texas Gas transmission system and system constrains limit how well other sources would be able to supply that demand.

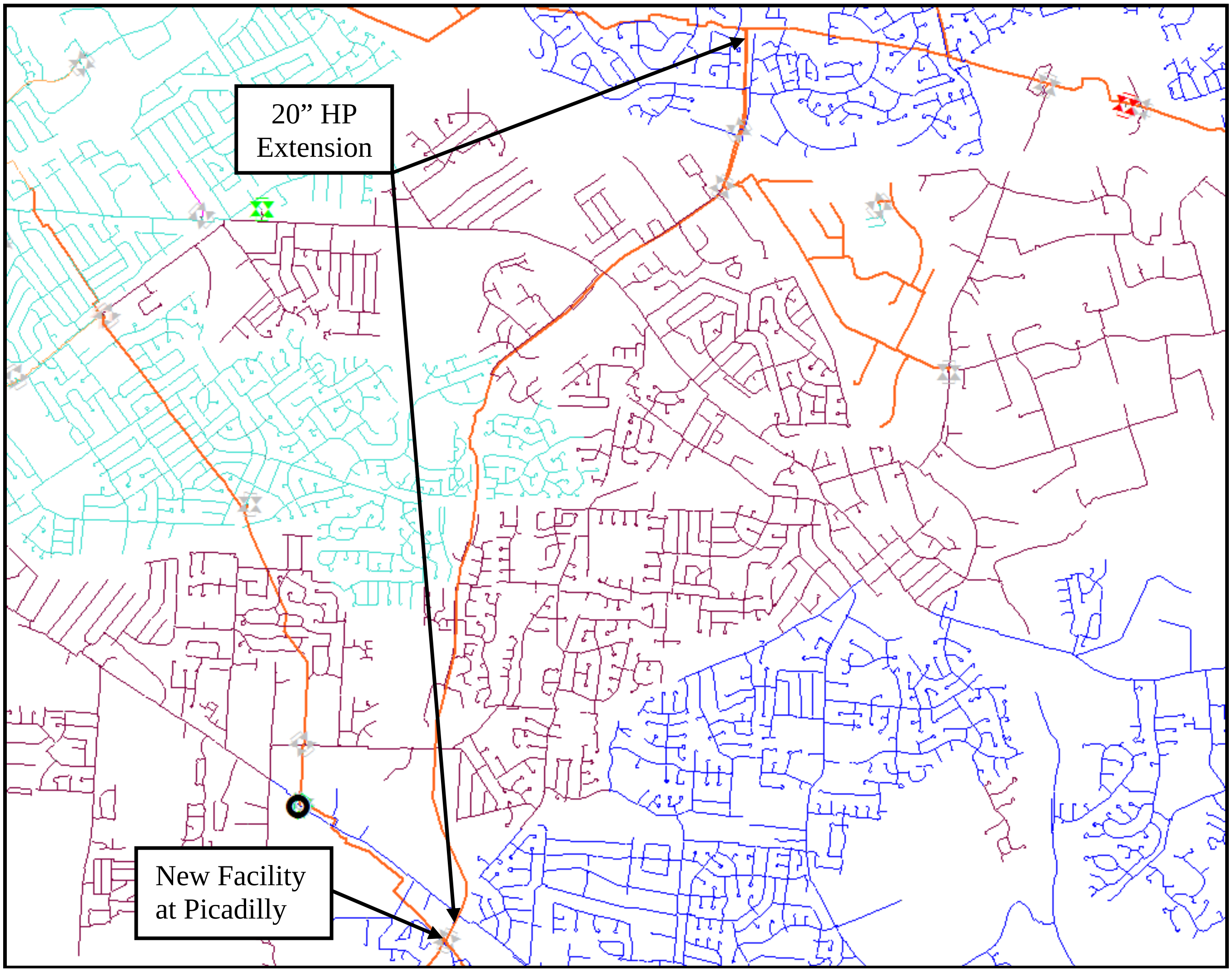
While the demand distribution percentage between east and west remains consistent based on city gate station supply, the total supply volume increases by a factor of 10 from a 0 HDD to a design day. In warmer weather, the lower total demand gives Gas Control more flexibility in how to transport gas through the system. As the total demand increases, that flexibility decreases due to various infrastructure constraints.

Recommended Gas System Reinforcements

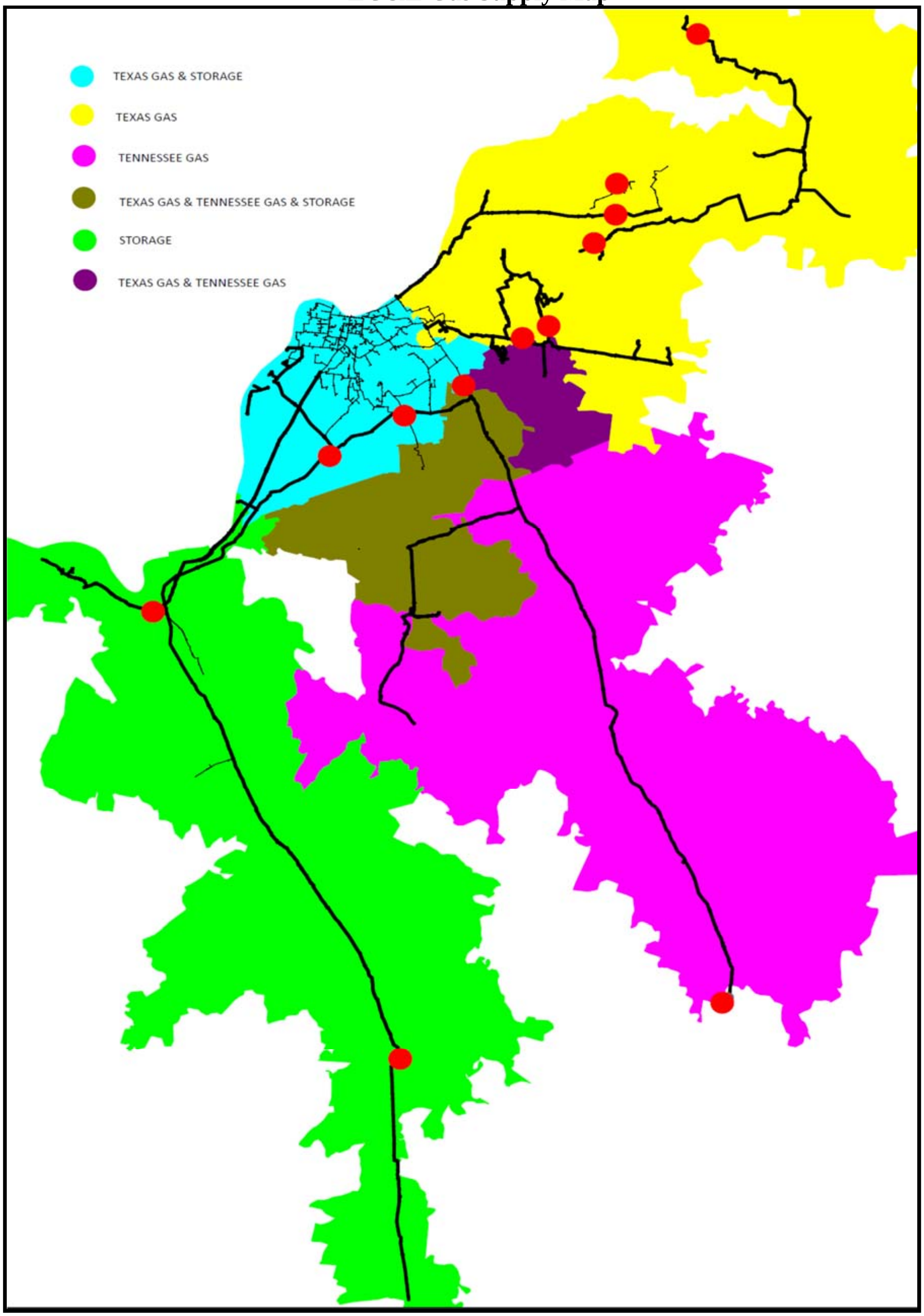
Install a 20-inch pipeline approximately 5.3 miles along Hurstbourne Parkway from the Piccadilly valve assembly to the 12-inch Eastern Kentucky pipeline located at Hurstbourne Lane and Timberwood Circle.

This will enable gas from the Bardstown Road city gate station or from the Calvary pipeline to be moved into the east end gas system. This will also enable storage gas to supplement the area surrounded by the Bardstown Road city gate station. This assumes that pipeline modifications are made to bring a new pipeline from the Magnolia/Muldraugh gas storage areas to the Preston city gate station. This will help eliminate the dependency on the Western Kentucky pipelines (blue, yellow and green) and the St. Helens gas regulation facility.

East End 20-inch Gas Transmission Pipeline Reinforcement Project



LG&E Gas Supply Map



XVIII. New City Gate Station – Oldham County

Gas System Overview

As gas system load growth continues eastward consideration should be given to retire the LaGrange city gate station and construct a new city gate station further east. The LaGrange city gate station is located in a poor location in the bend of Highway 146 adjacent to the railroad.

Recommend installing a new city gate station just north of the intersection of Old Sligo Road and Yager Lane in LaGrange. This station will be supplied by the Texas Gas transmission system.

Recommended Gas System Reinforcements

Reinforcement 1

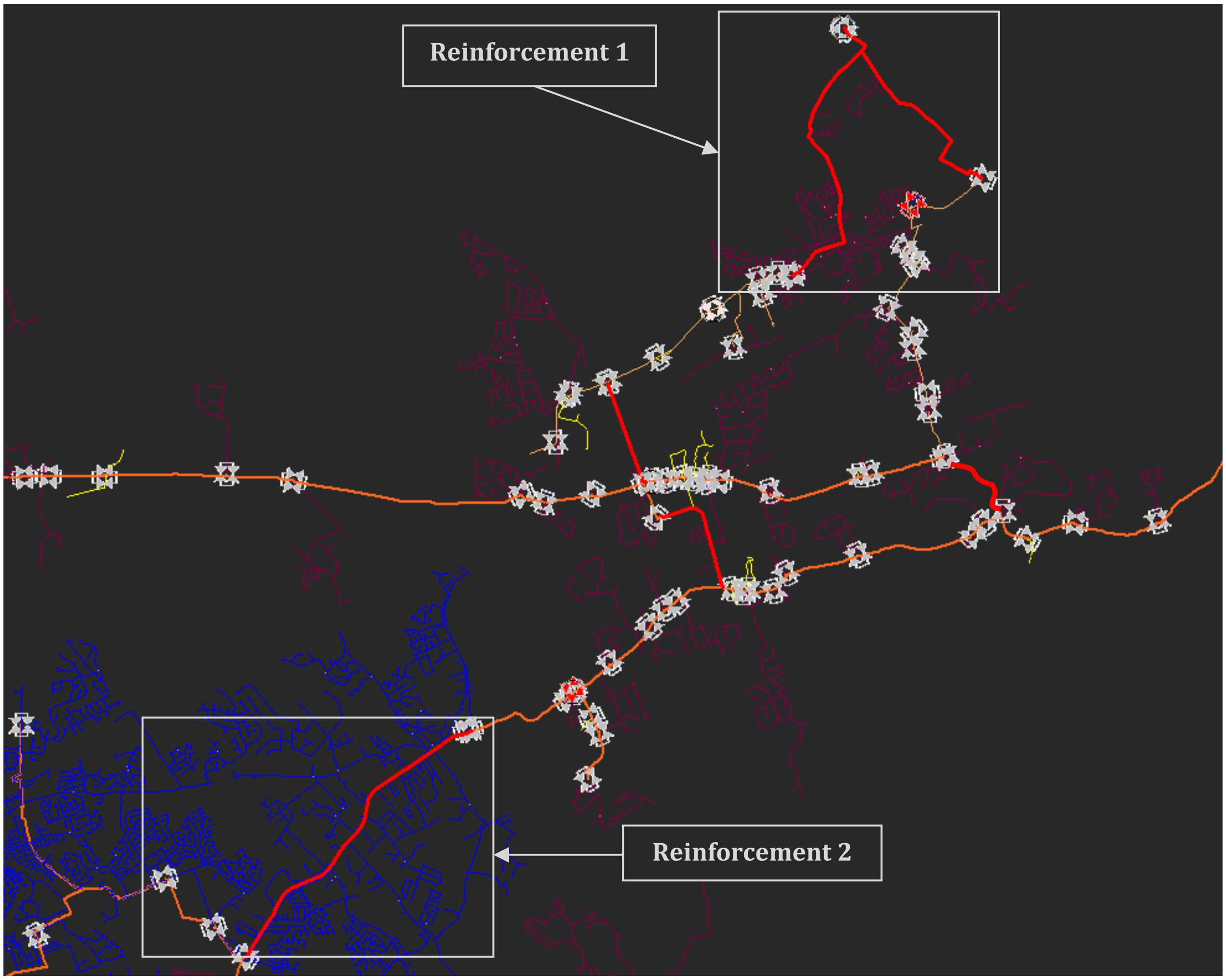
- Extend approximately 1.6 miles of 8-inch pipe along Yager Ln and then southwest on Old Sligo Rd.
- Follow N Hwy 53 south with 1.4 miles of 8-inch pipe to Jefferson Street in downtown LaGrange.
- Follow Jefferson Street to the west with 4,000 ft of 8-inch pipe to 710 W Jefferson Street.
- Install a new regulator facility to reduce gas from the new transmission line to 90 psig and connect to the existing 8” high pressure system.
- At the intersection of Old Sligo Rd and Fort Pickens Rd (from the new city gate station) extend the 6-inch main south 2.4 miles along Fort Pickens Rd to the existing 6-inch steel pipeline. Attach pipes with new regulator facility at Fort Pickens Rd and E Highway 146.

  - 4x3 Mooney (35%) for City Gate Station- Utilization: 41%
  - 4x3 Mooney (35%) at 710 W Jefferson St- Utilization: 39.4%
  - 2” Mooney (35%) at Fort Pickens and E Highway 146- Utilization: 32%
  - **Total mileage: 6 miles**

Reinforcement 2

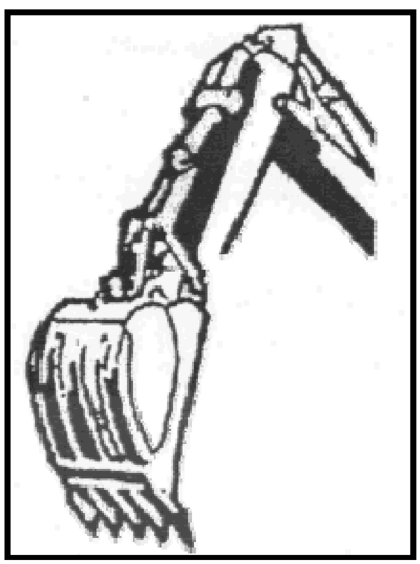
- Install a new high pressure regulator facility at Hwy 22 and Old Lagrange Rd in Crestwood.
- From that new facility, extend 4-inch pipe west 3.9 miles along W Hwy 146/LaGrange Rd. Connect to existing 4-inch high pressure.
- This will provide connectivity between the Eastern Kentucky pipeline system and the Crestwood/Ballardsville/LaGrange systems.

  - 2” Mooney (35%) at Hwy 22 and Old LaGrange- Utilization: 35%.
  - **Total mileage: 3.9 miles**


Reinforcement 1
Reinforcement 2

Louisville Gas and Electric

Gas System Planning
Long Term Gas System Construction Plans



May 2013

Table of Contents

I. Crestwood-Eminence-Bedford High Pressure Distribution System

Gas System Overview
The Crestwood-Bedford high-pressure distribution system serves the Crestwood area, Smithfield, Campbellsburg, and Bedford. It is fed by the Eminence, Bedford, and Crestwood city gate stations. The system serves a small number of large industrial and commercial customers, including Safety Kleen, Steel Technologies, Rosehill Greenhouses, and Hussey Copper.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Eminence City Gate Station
- Crestwood City Gate Station
- Bedford City Gate Station

Maximum Allowable Operating Pressure
From Crestwood to Eminence, the Crestwood-Bedford high-pressure system has a maximum allowable operating pressure of 350 psig. From Eminence to Bedford, it has a maximum allowable operating pressure of 380 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure is at 4021 Hwy 146 **(198.19 psig).**

Regulator Operating Capacities
- Elder Park City Gate Station – **16.0%**
- Crestwood City Gate Station – **41.6%**
- Bedford City Gate Station **– 33%**

Note: The reported capacities are with the gas regulation equipment upgrades at the Bedford city gate station (2010) and the Crestwood city gate station (2012).

Gas System Constraints
The system is composed primarily of 4-inch pipeline, limiting the system's capacity for expansion.

I. Crestwood-Eminence-Bedford High Pressure Distribution System (cont'd)

Recommended Gas System Reinforcements

Reinforcement 1
Connect the Ballardsville gas transmission line to the Crestwood-Bedford HP system with 5,500 feet of 8" steel gas transmission pipeline along Hwy 53 from Moody Lane to Hwy 22. **NOTE:** Reinforcement done as part of Section II Reinforcement 1.

Minimum Gas System Pressure (-12°F)
- 4021 Hwy 146 – **214.2 psig**

Regulator Operating Capacities
- Elder Park City Gate Station – **16.3%**
- Crestwood City Gate Station – **39.3%**
- Bedford City Gate Station **– 33.1%**

Reinforcement 2
Remove the Eminence high pressure regulator pit and replace with a full port motor operated ball valve at that location. If the Eminence high pressure regulator pit was to fail, approximately 1,693 customers in the Eminence and New Castle areas would be lost. Installing a motor operated ball valve at the Eminence station could help prevent this loss of service. This ball valve could also be used to isolate either side of the Crestwood–Bedford line should a failure occur.

Minimum Gas System Pressure (-12°F)
Inlet to Pleasureville – **68.7 psig**

Regulator Operating Capacities
Bedford City Gate Station – **73.4%**
Crestwood City Gate Station – **57.8%**

Reinforcement 3
- Install a new city gate station near L'Esprit Farms at the intersection of E Hwy 146 and Lake Jericho. This station will be fed from the Texas Gas Transmission pipeline.
- Extend approximately 4 miles of high pressure steel pipeline southwest along E Hwy 146 to connect with the Elder Park/Ballardsville Line.
- Install a regulator station where Hwy 146 connects with the Elder Park/Ballardsville Line to lower the pressure to 100 psig from the new city gate station.
- Extend approximately 5.4 miles of high pressure steel pipeline southeast along Hwy 153 (Lake Jericho to connect with Crestwood-Bedford HP line at Smithfield Rd).

I. Crestwood-Eminence-Bedford High Pressure Distribution System (cont'd)

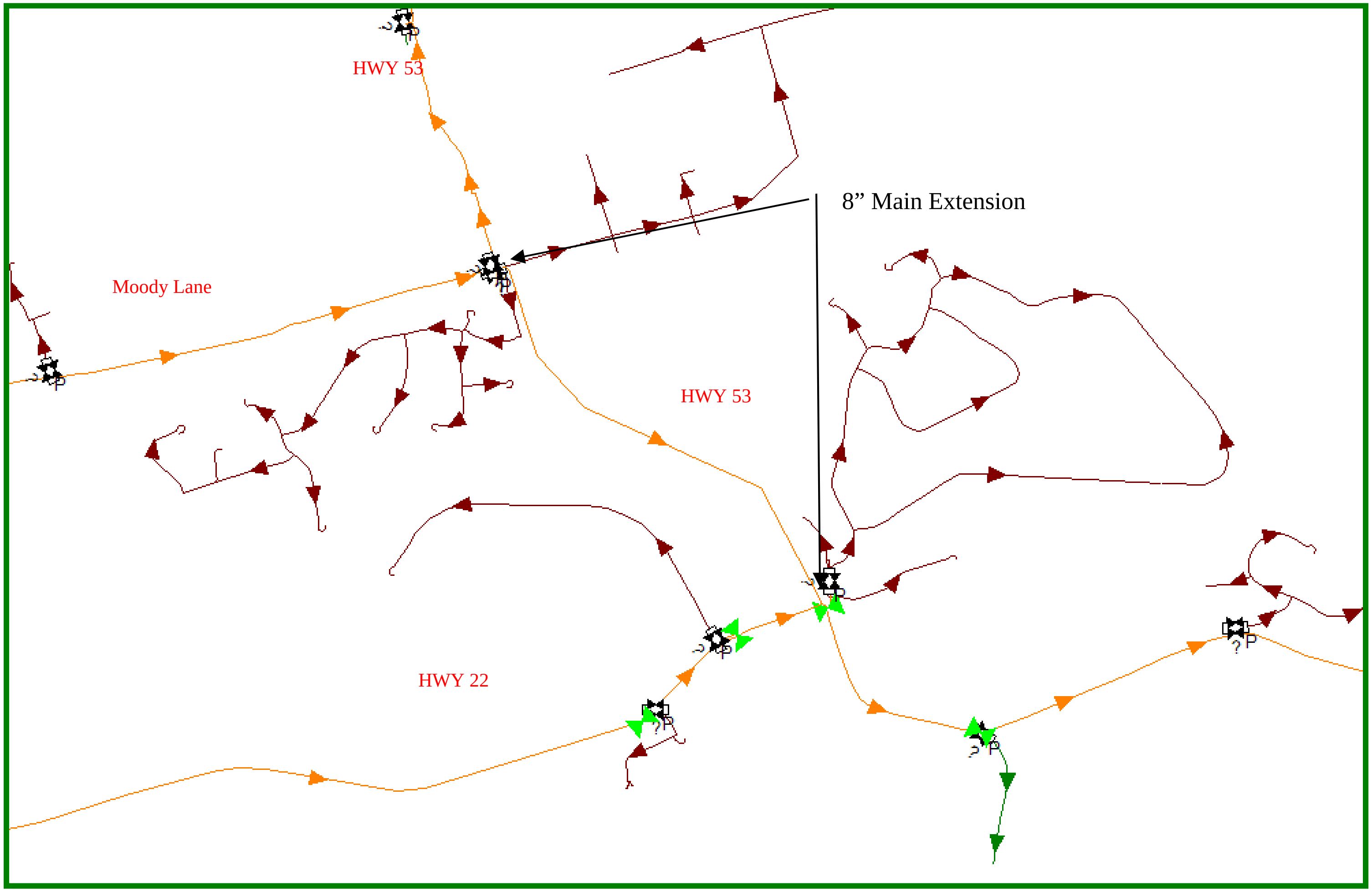
Minimum Gas System Pressure (-12°F)
- 4021 Hwy 146 – **259.31 psig**

Regulator Operating Capacities
- Elder Park City Gate Station – **15.4%**
- Crestwood City Gate Station – **35.0%**
- Bedford City Gate Station –**23.9%**

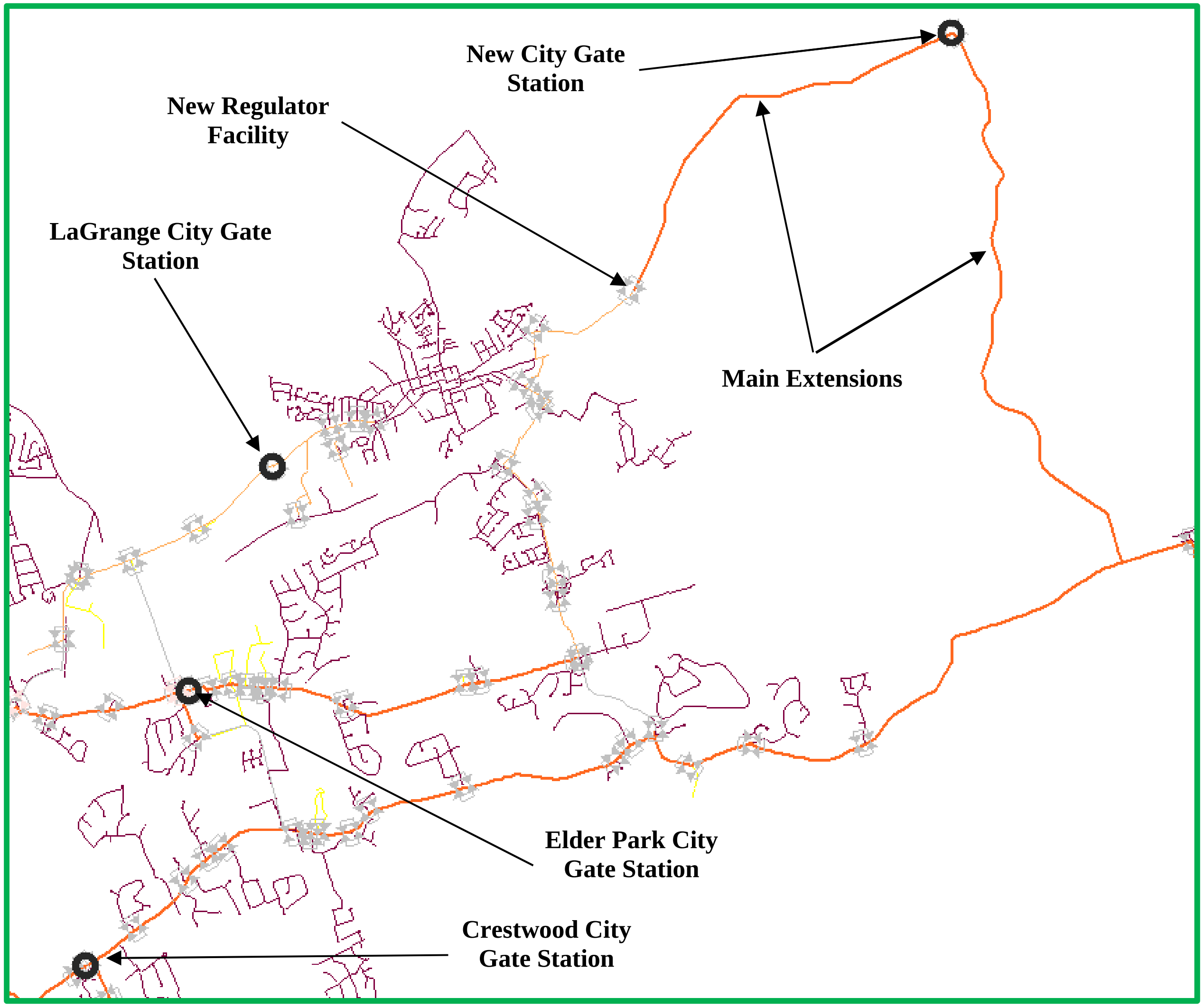
Reinforcement 4
- Install a new City Gate Station just north of the intersection of Old Sligo Rd and Yager Ln in LaGrange. This station will be fed from the Texas Gas Transmission Line.
- Extend approximately 1.6 miles of 8-inch pipe along Yager Ln and then southwest on Old Sligo Rd.
- Follow N Hwy 53 south with 1.4 miles of 8-inch pipe to Jefferson Street in downtown LaGrange.
- Follow Jefferson Street to the west with 4,000 feet of 8-inch pipe to 710 W Jefferson Street.
- Install a new regulator facility to reduce gas from the new transmission line to 90 psig and connect to the existing 8" HP.
- At the intersection of Old Sligo Rd and Fort Pickens Rd (from the new city gate station) extend the 6-inch main south 2.4 miles along Fort Pickens Rd to the existing 6-inch steel pipeline. Attach pipes with new regulator facility at Fort Pickens Rd and E Highway 146.

    - 4x3 Mooney (35%) for City Gate Station- Utilization: 41%
    - 4x3 Mooney (35%) at 710 W Jefferson St- Utilization: 39.4%
    - 2" Mooney (35%) at Fort Pickens and E Highway 146- Utilization: 32%

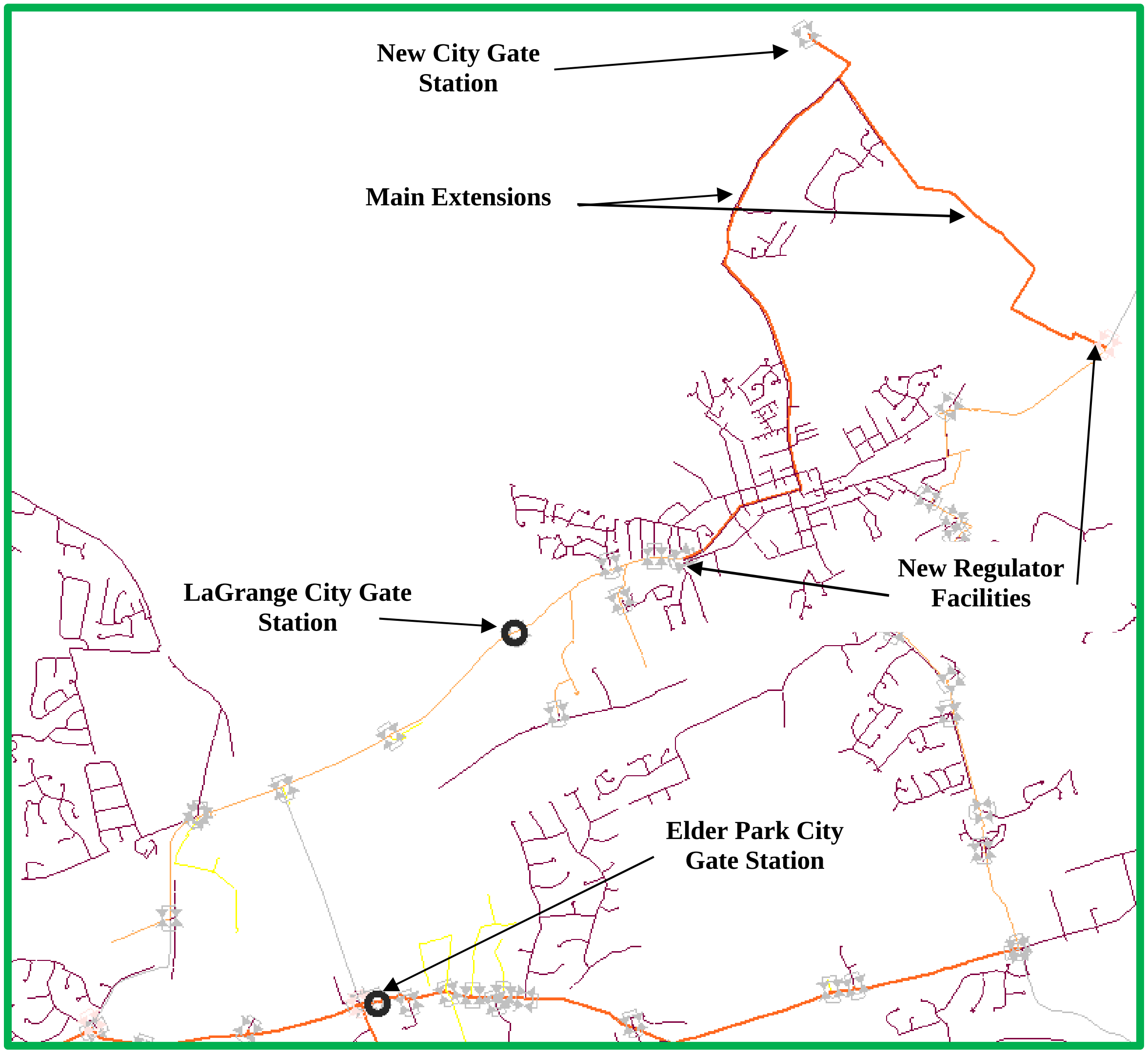
Crestwood-Eminence-Bedford High Pressure Gas System – Reinforcement 1



Crestwood-Eminence-Bedford High Pressure Gas System – Reinforcement 3



Crestwood-Eminence-Bedford High Pressure Gas System – Reinforcement 4



II. East End Gate Stations Gas System Overview

The Elder Park City Gate Station is located on Elder Park Road just east of Highway 393 and serves from Elder Park to Zorn Avenue in Louisville. The Crestwood City Gate Station is located on Highway 22 west of Abbott Lane and serves the area from Lake Forest and Pee Wee Valley to Ballardsville and Eminence. The LaGrange City Gate Station is located on Highway 146 west of Button Lane and serves the City of LaGrange and the Crestwood/Buckner area north of I-71. These systems serve rural, residential, commercial, and small industrial customers.

Maximum Allowable Operating Pressure
The Elder Park system has a maximum allowable operating pressure of 400 psig. The Crestwood system has a maximum allowable operating pressure of 350 psig. East of the La Grange City Gate Station, the LaGrange system has a maximum allowable operating pressure of 100 psig. West of the LaGrange City Gate Station, the LaGrange system has a maximum allowable operating pressure of 200 psig.

Gas System Constraints
If any of these three gate stations was temporarily turned off (e.g., for maintenance or due to an accident), there would be insufficient pressure to serve the system that is fed by that gate station.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure on the Elder Park system is located at the inlet to the **Zorn Ave regulator station (258.6 psig).**
The predicted minimum gas system pressure on the Crestwood system is located at **4021 Hwy 146 (198.2 psig).**
The predicted minimum gas system pressure on the LaGrange system is located at **20 Quality Place (87.2 psig)**.

Regulator Operating Capacities
- Elder Park City Gate Station – **16.0%**
- Crestwood City Gate Station – **41.6%**
- LaGrange City Gate Station – **31.1%**

Recommended Gas System Reinforcements

Recommended Gate Station Operating Conditions
- Operate the Elder Park City Gate Station at 300 psig
- Operate the Crestwood City Gate Station at 350 psig
- Operate the LaGrange City Gate Station at 90 psig

II. East End Gate Stations Overview (cont'd)

Reinforcement 1
Connect the Elder Park system to the Crestwood system

- Connect the Elder Park line to the Crestwood line via Hwy 393 with approximately 7,500 feet of 8-inch pipeline.
- Connect the Elder Park line to the Crestwood line via Hwy 53 with approximately 5,800 feet of 8-inch pipeline
  - (NOTE: this only helps the systems if the Crestwood facility is shut down.)

Minimum Gas System Pressure (-12°F)
- Zorn Inlet – **315.5 psig**
- 4021 Hwy 146 – **243.9 psig**

Regulator Operating Capacities
- Elder Park City Gate Station – **15.7%**
- Crestwood City Gate Station – **44.9%**
- LaGrange City Gate Station – **31.1%**

Reinforcement 2
Connect the Elder Park system to the LaGrange system

- Connect the Elder Park line to the LaGrange line via Hwy 393 with approximately 6,600 feet of 8-inch pipeline.
- Connect the Elder Park line to the LaGrange line via Hwy 146 and Fox Run Rd with approximately 4,400 feet of 8-inch pipeline.
- Install a new regulator facility at Hwy 393 and Hwy 146 to reduce the pressure from the new pipeline along Hwy 393 to 90 psig.
- Install a new regulator facility at the tie-in point on Fox Run Rd or at Hwy 146 and Quality Place to reduce the pressure from the new pipeline along Hwy 146 and Fox Run Rd to 90 psig.
  - (NOTE: this only helps the systems if the LaGrange facility is shut down.)

Minimum Gas System Pressure (-12°F)
- Zorn Inlet – **258.8 psig**
- Springhouse Estates Inlet – **88.9 psig**
- 4021 Hwy 146 – **198.2 psig**

Regulator Operating Capacities
- Elder Park City Gate Station – **16.7%**
- Crestwood City Gate Station – **41.6%**
- LaGrange City Gate Station – **23.3%**

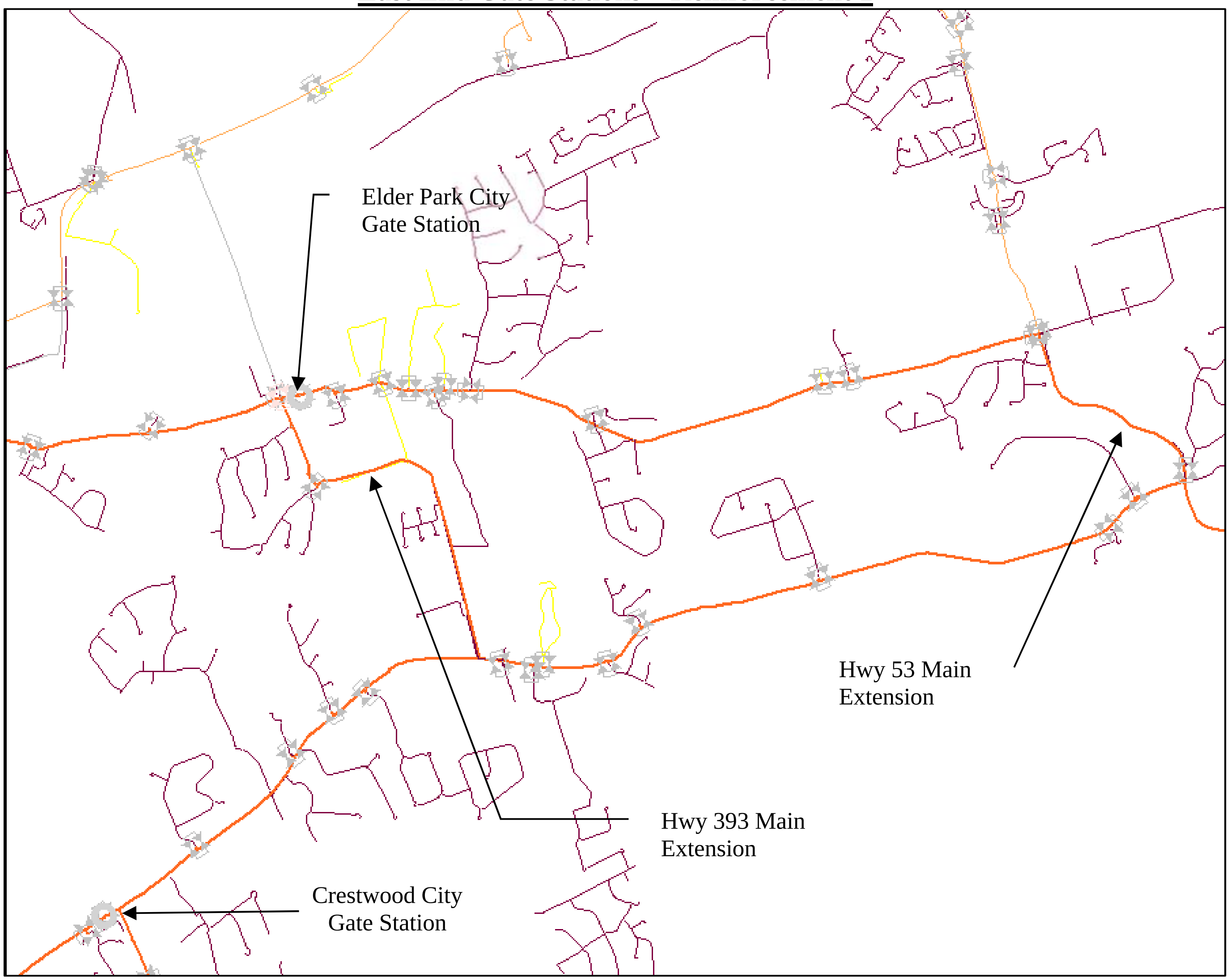
II. East End Gate Stations Overview (cont'd)

Reinforcement 3

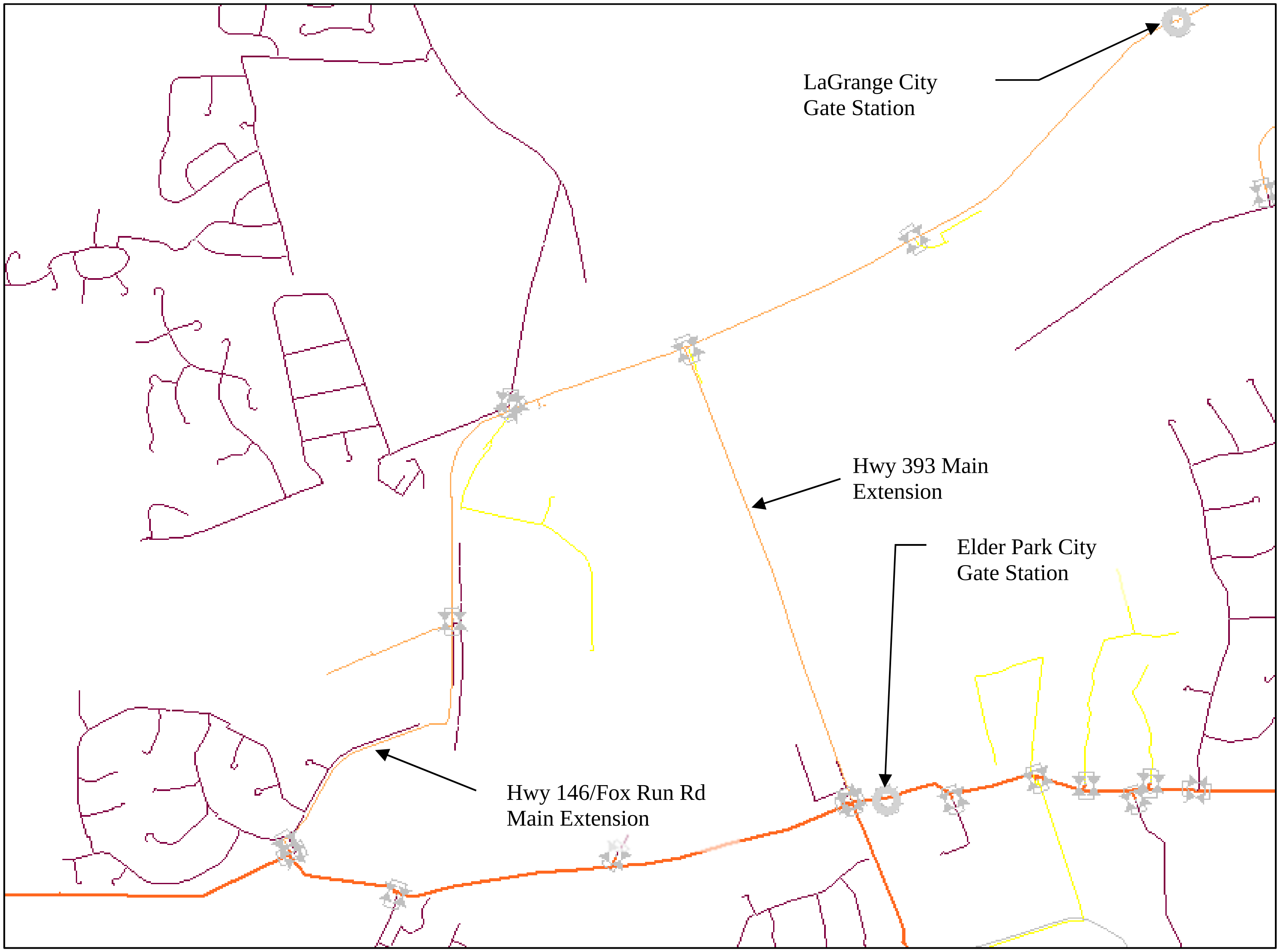
- Install a new high pressure regulator facility at Hwy 22 and Old Lagrange Rd in Crestwood.
- From that new facility, extend 4-inch pipe west 3.9 miles along W Hwy 146/LaGrange Rd. Connect to existing 4-inch high pressure.

2" Mooney (35%) at Hwy 22 and Old LaGrange- Utilization: 32.3%

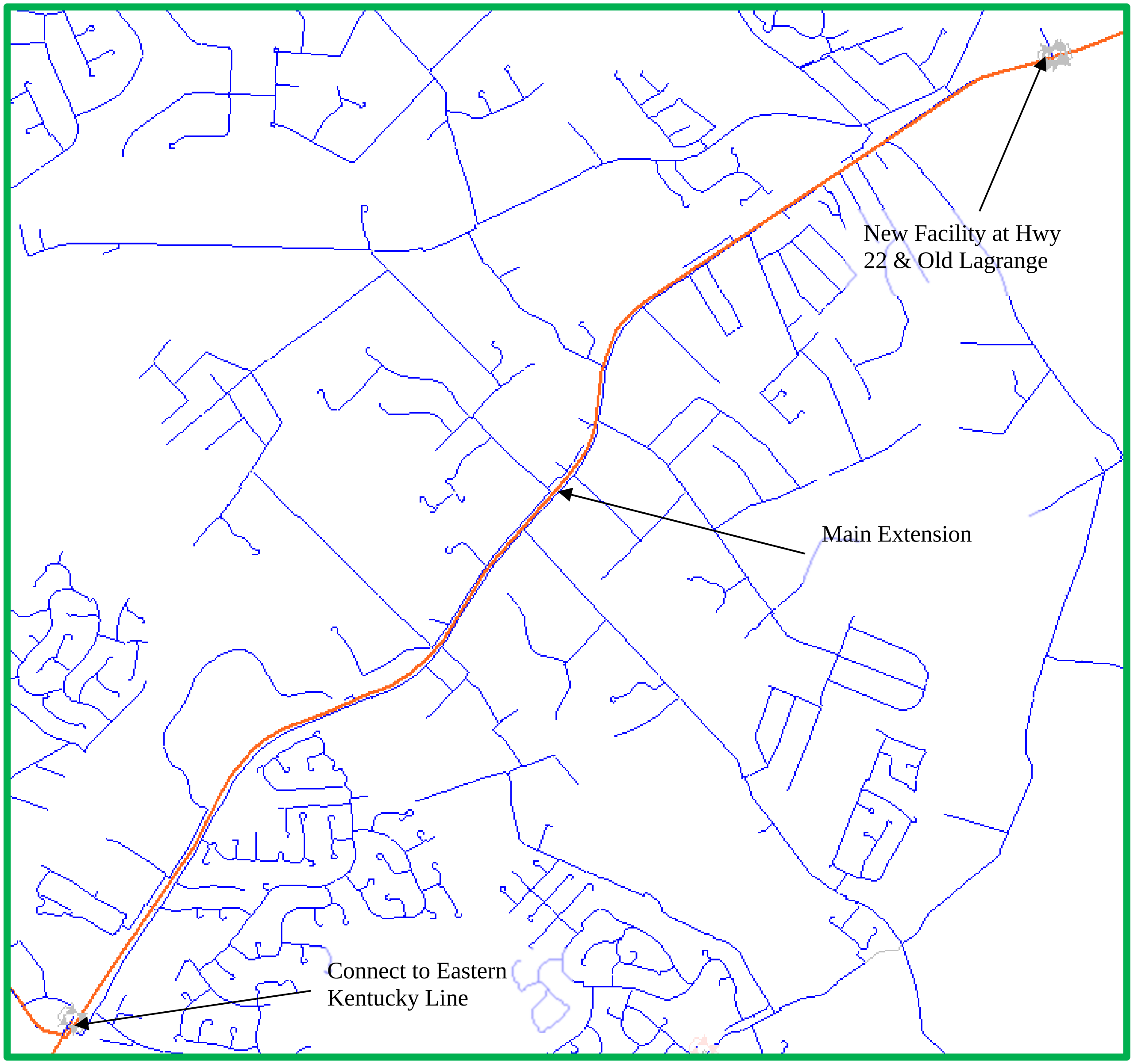
<u>East End Gate Stations – Reinforcement 1</u>



East End Gate Stations – Reinforcement 2



East End Gate Stations – Reinforcement 3



III. LaGrange Medium Pressure Systems

Gas System Overview

The LaGrange Medium pressure systems are fed from the LaGrange and Elder Park City Gate Stations (see Section II). The system consists of several single-feed systems and one larger, multiple-feed system.

The Oldham County Economic Development Campus (OCEDA) is a 1000+ acre community that will contain office buildings, single and multifamily dwellings, a new school, and mixed use lands. Currently, gas infrastructure does not exist to support this development.

Maximum Allowable Operating Pressure

These subsystems have maximum allowable operating pressures of 10, 30, and 35 psig, as detailed below.

Model Results

Minimum Gas System Pressure (-12ºF)

Sub-System MAOP	**Location**	**Pressure**
10 psig systems	3500 Mattingly Rd [6447519]	**7.7 psig**
30 psig system	Parker Pl [6480299]	**24.75 psig**
35 psig systems	Kamer Ct [6430958]	**29.3 psig**

Regulator Operating Capacities:

35 psig Systems

- HOFFMAN LN & PARKVIEW MANOR TBD – 3.6%
- BUTTON CT & COMMERCE PKWY G-21254 – 17.6%
- ALLEN LN & ARTISAN PKWY TBD – 5.7%
- HWY 53 & CHERRY CREEK DR TBD – 52.4%
- NEW CEDAR POINT RD. & OLD LAGRAN G-364 – 51%
- ELDER PARK RD. G-433 – 33.7%
- MOODY LN & HWY 53 G-559 – 22.6%
- E.MOODY LN.& CAL AVE G-593 – 7.4%
- DEER RUN DR G-553 – 13.4%
- GRANGER RD. & HWY.53 G-545 – 27.5%
- PARK RD. & HWY. 53 G-558 – 20%
- ZHALE SMITH RD & HWY 53 G-591 – 9.5%
- SPRINGHOUSE ESTATES SECTION 1 G-599 – 41%
- HWY 146 & FORT PICKENS RD G13112 – 0.06%
- PRESTWICK DR. & HWY. 53 G13115 – 36.7%
- CRYSTAL DR.& GRANGE DR. G18329 – 21.5%
- HWY 146 & I-71 **– 16.6%**

III. LaGrange Medium Pressure Systems (cont'd)

30 psig systems

- Regulator pit at Woodlawn Ave and Lagrange Rd **– 13.7%**
- Lagrange medium pressure regulator pit **– 56%**
- Regulator pit at Hoffman Ln **– 55.9%**

10 psig systems

- Regulator pit at Hwy 393 & Hwy 146 **– 1.2%**
- Regulator pit at Kings Ln & Hwy 146 **– 1.5 %**
- Regulator assembly at Georgie Way and Moody Ln **– 3.7%**
- Regulator assembly at Hazelwood Dr & Elder Park Rd **– 13.4%**
- Regulator assembly at Sycamore Rd and Elder Park Rd **– 25.5%**

Gas System Constraints
Areas of low pressure are constrained by small diameter piping and single regulator stations feeding the systems.

Gas System Reinforcements Note

- Due to economic conditions, these plans have been put on hold for the time being.

Recommended Gas System Reinforcements:

Reinforcement 1
Extend gas mains and uprate LaGrange MP system as described in "An Analysis of the OCEDA Economic Development Campus" dated 7 November 2005 or latest version. As described in the report, this system will have an estimated new gas load of up to 387 MCFH. The proposed reinforcement project requires installing:

- 15,000 feet of 4 inch pipe
- 4,000 feet of 6 inch pipe
- 12,000 feet of 8 inch pipe
- An uprate of 11.6 miles of existing pipeline and 467 existing customers
- A new regulator facility at Moody Lane and North Fible Lane

Minimum gas system pressure (-12ºF):

- 2300 Stonybrook Ct – **42.7 psig**

Regulator Operating Capacities:

- Moody Ln and North Fible Ln – **15.5%**
- Granger Rd and Hwy 53 **– 46.6%**
- Elder Park Rd **– 32.9%**

III. LaGrange Medium Pressure Systems (cont'd)

Reinforcement 2

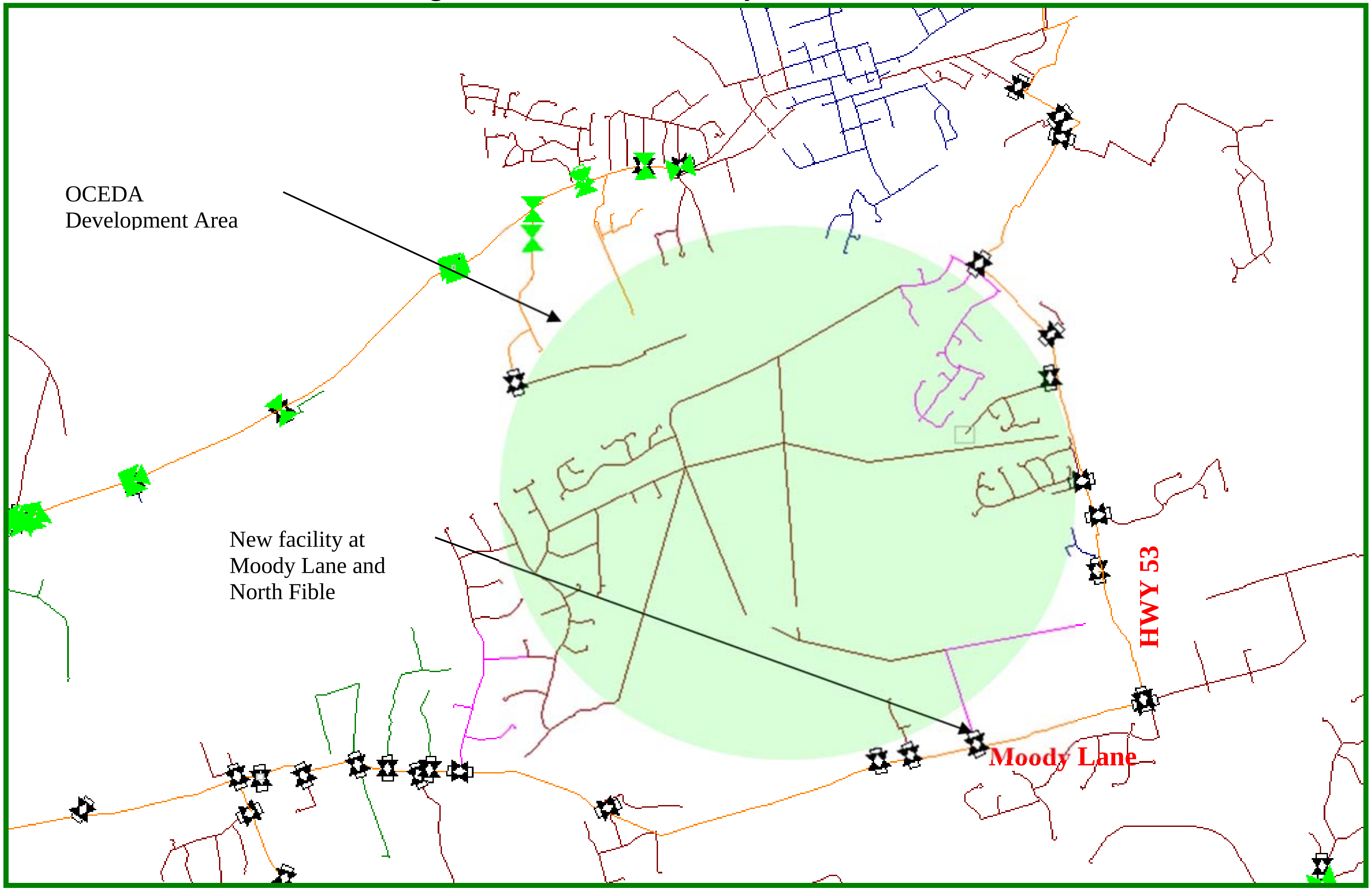
Extend gas mains and uprate Hwy 393 & Hwy 146 system as described in "An Analysis of Proposed Development at Buckner Crossings" dated 16 October 2006 or latest version. As described in the report, this system will have an estimated new gas load of up to 90MCFH. The proposed reinforcement requires installing:

- 5,100 feet of 6-inch pipe
- 5,300 feet of 4-inch pipe
- 13,100 feet of 2-inch pipe
- Uprate 400 feet of existing pipeline and 5 existing customers
- Replace regulator facility at Commerce Pkwy & Button Court Ln
- Remove regulator facility at Hwy 393 & Hwy 146
- Install regulator facility at Hwy 393 & Commerce Pkwy

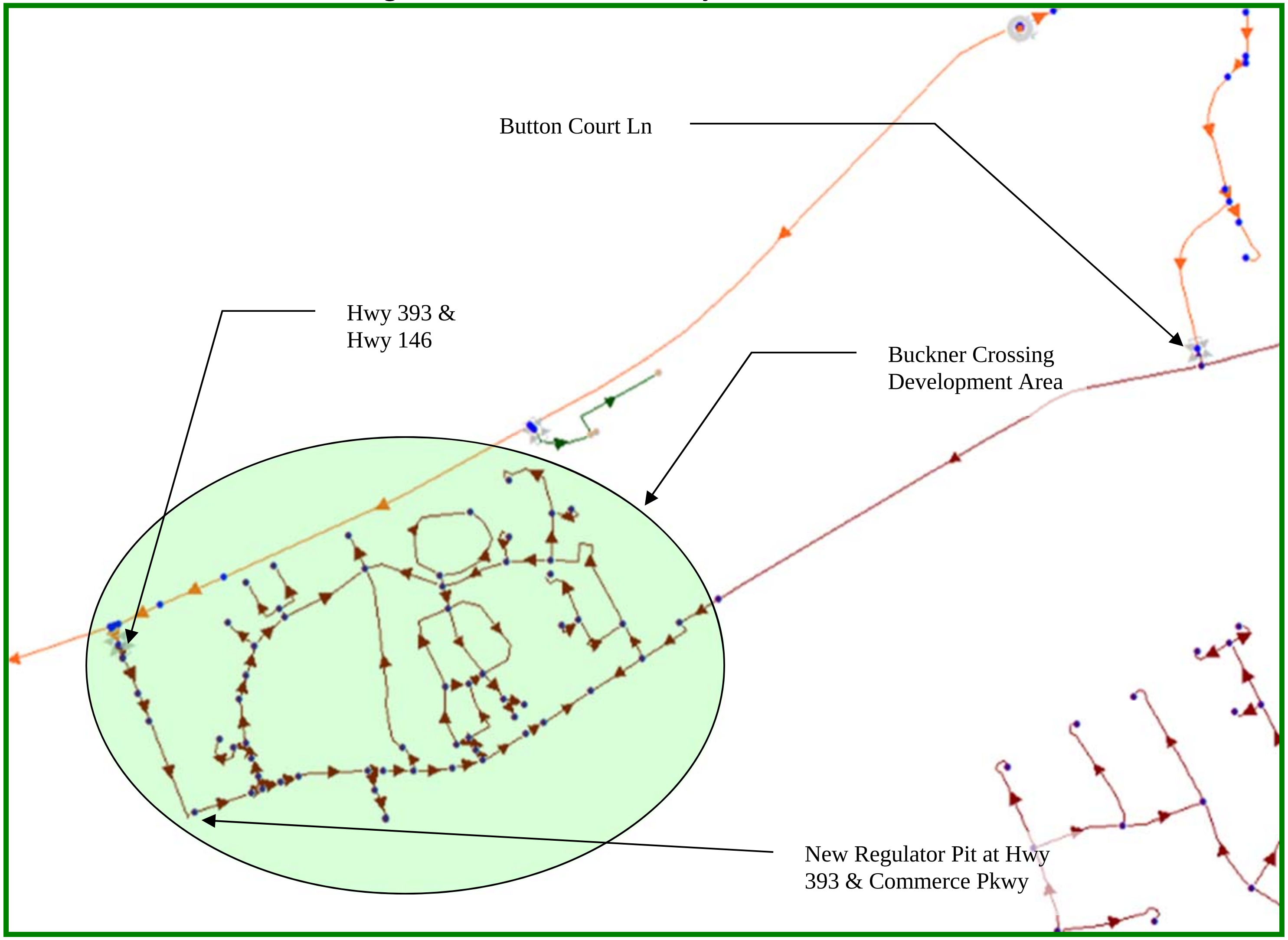
Minimum Gas System Pressure (-12°F)
- Southern Patio Home Area **– 29.3 psig**

Regulator Operating Capacity
- Hwy 393 & Commerce Pkwy **– 89.4%**
- Commerce Pkwy & Button Court Ln **– 18%**

LaGrange Medium Pressure Gas System – Reinforcement 1



LaGrange Medium Pressure Gas System – Reinforcement 2



IV. Prospect Medium Pressure System

The system surrounding Hwy 1793 in Oldham County needs piping reinforcement. Due to long stretches of small diameter piping the area along Belknap Beach Road and River Glen Lane is suffering. The system is fed by two regulator facilities off of Hwy 42 set at 35 psig and the minimum pressure at these points is 19 psig. Located just 250 feet away is a 20 psig system, fed by the Riverbluff Farms facility on Hwy 42, which supplies the River Glen area. It is recommended that these 2 systems are tied together to reinforce the system and reduce consequence from an emergency.

Minimum Gas System Pressure (-12°F)
Louisville Yacht Club- **19.3 psig**
14462 River Glades Drive- **19.6 psig**

Regulator Operating Capacities
- Riverbluff Farms & Hwy 42 – **8.4%**
- Hwy 42 & Hwy 1793 – **43.6%**
- Hwy 42 & Barbizon Place – **6.2%**

Recommended Gas System Reinforcements:

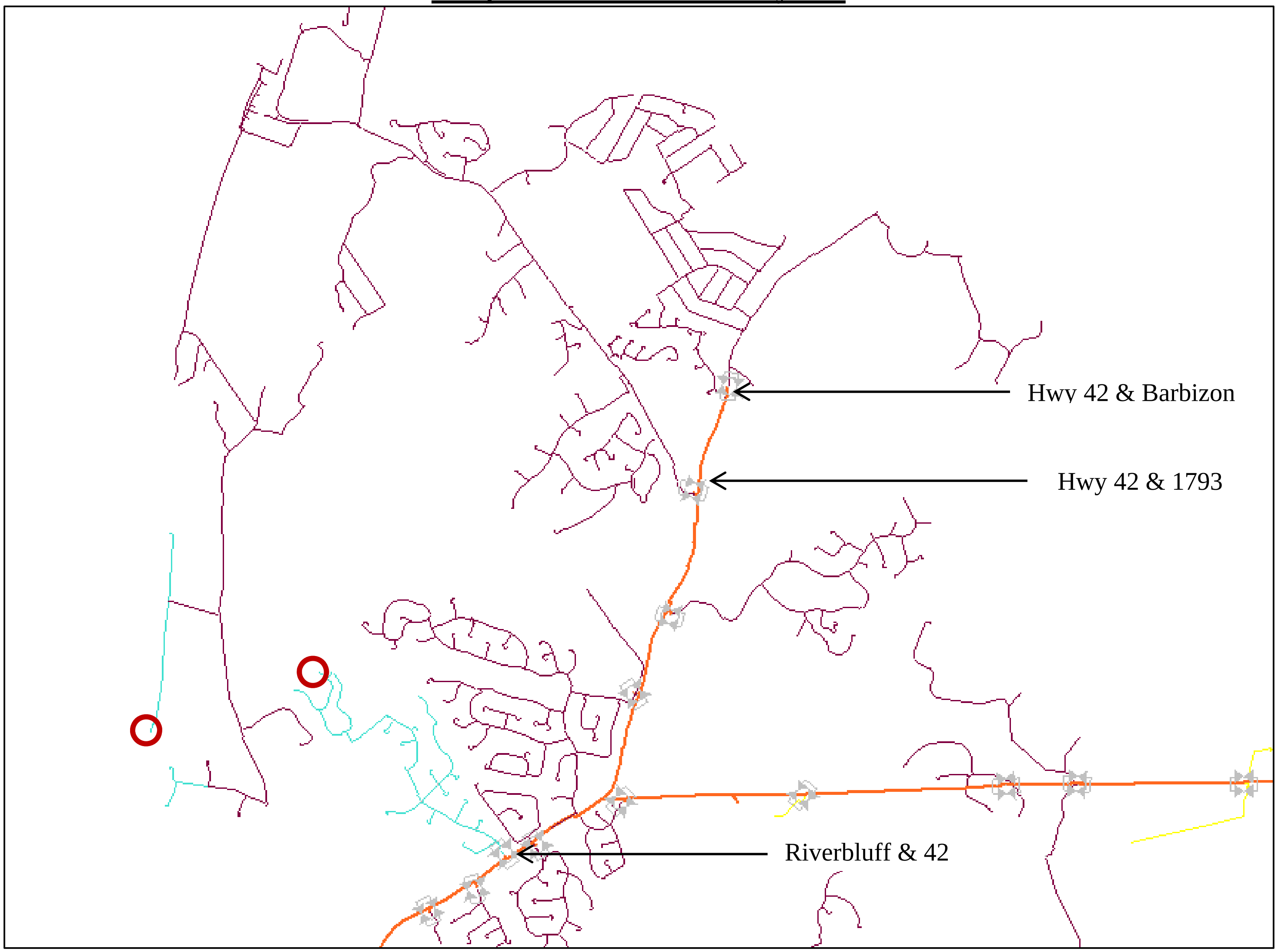
Reinforcement 1
Install new pipe to connect the two systems.

- Uprate the Riverbluff Farms system to 35 psig
- Install 1500’ of 4-inch pipe to connect the existing 4-inch on River Glades Dr to the existing 4-inch on S Rose Island Rd.

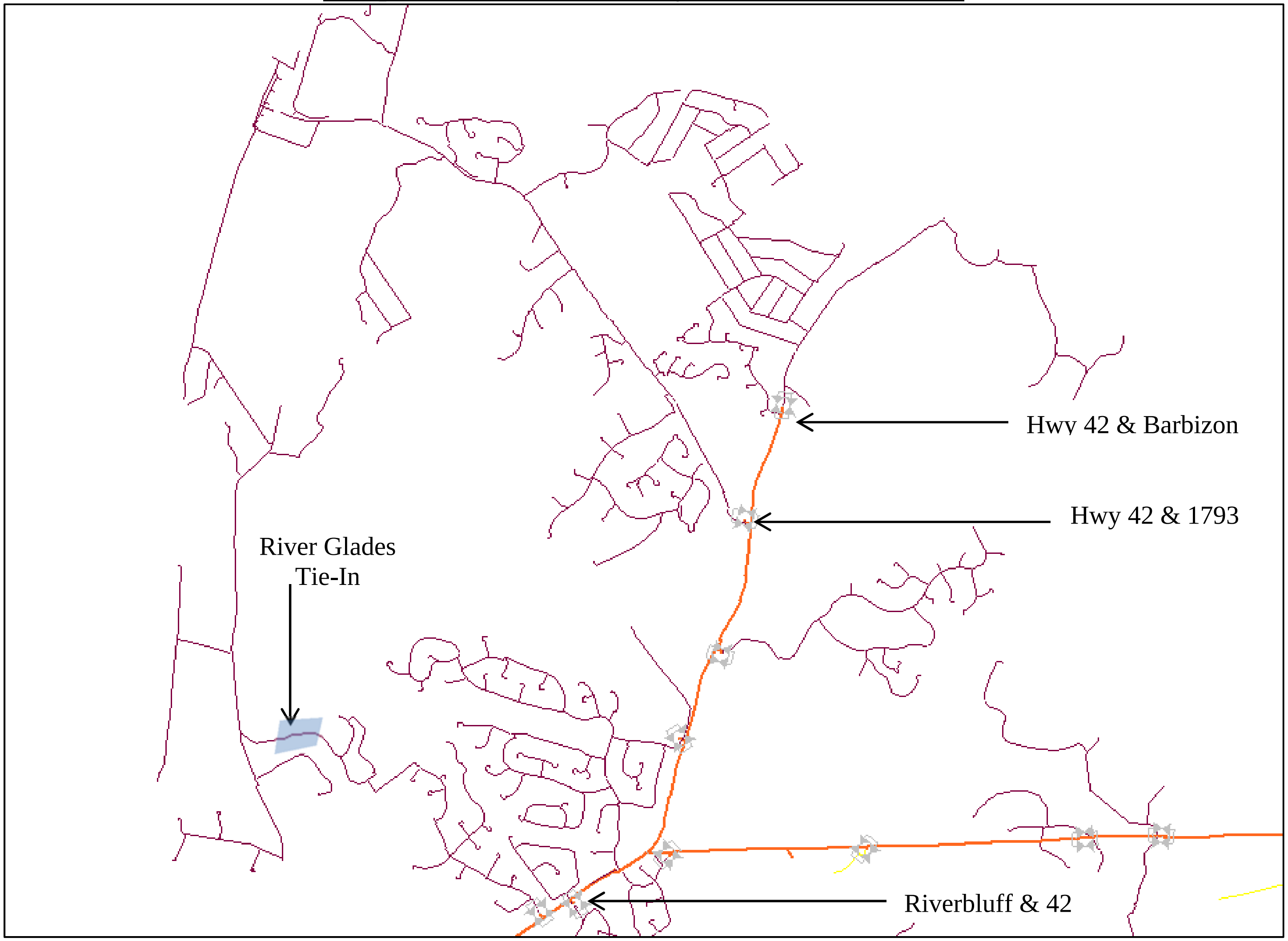
Minimum Gas System Pressure (-12°F)
Louisville Yacht Club- **29.8 psig**
14462 River Glades Drive- **32.0 psig**

Regulator Operating Capacities
- Riverbluff Farms & Hwy 42 – **19.0%**
- Hwy 42 & Hwy 1793 – **34.0%**
- Hwy 42 & Barbizon Place – **5.1%**

Prospect Medium Pressure System



Prospect Medium Pressure System- Reinforcement 1



V. Windsor Forest 35 psig Medium Pressure System

The Windsor Forest area of the west end system has experience lower minimum pressures since the retirement of the Preston City Gate medium pressure facility. It is bordered by Pond Creek to the south and is just a natural ending point for all flows of gas in that system. There are currently plans to install a medium pressure facility and Old 3rd & Manslick to feed this system.

Existing Model Results

Minimum Gas System Pressure (-12°F)
Britannia Court- **9.6 psig**
Twin Lakes Court- **10 psig**

Regulator Operating Capacities
- Dixie Hwy & East Pages Ln **– 55.3%**
- St. Andrews Church Rd & ICRR **– 48.0%**
- Old 3rd St. Rd. & Bamberrie Cr **– 24.2%**
- New Cut Rd & Old 3rd Street Rd- **21.0%**

Recommended Reinforcements:

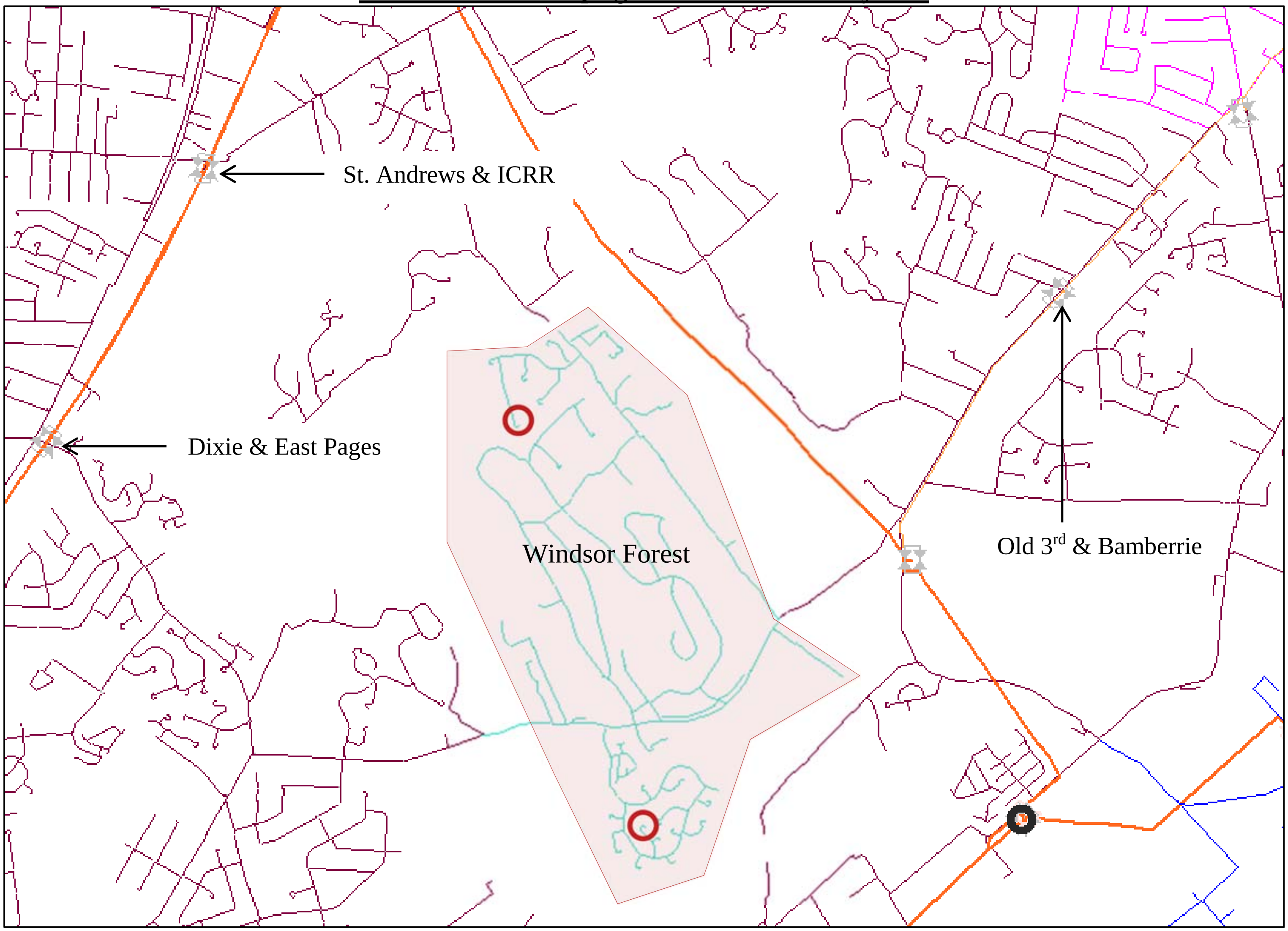
Reinforcement 1

- (Already Planned) Install a 2” Mooney assembly from the 12-inch high pressure distribution piping along Manslick Rd. Install 100 feet of 8-inch inlet piping and 100 feet of 4-inch outlet piping.
- Install approximately 230 feet of 4-inch pipe on Arnoldtown Road just north of Windsor Lakes Pkwy.

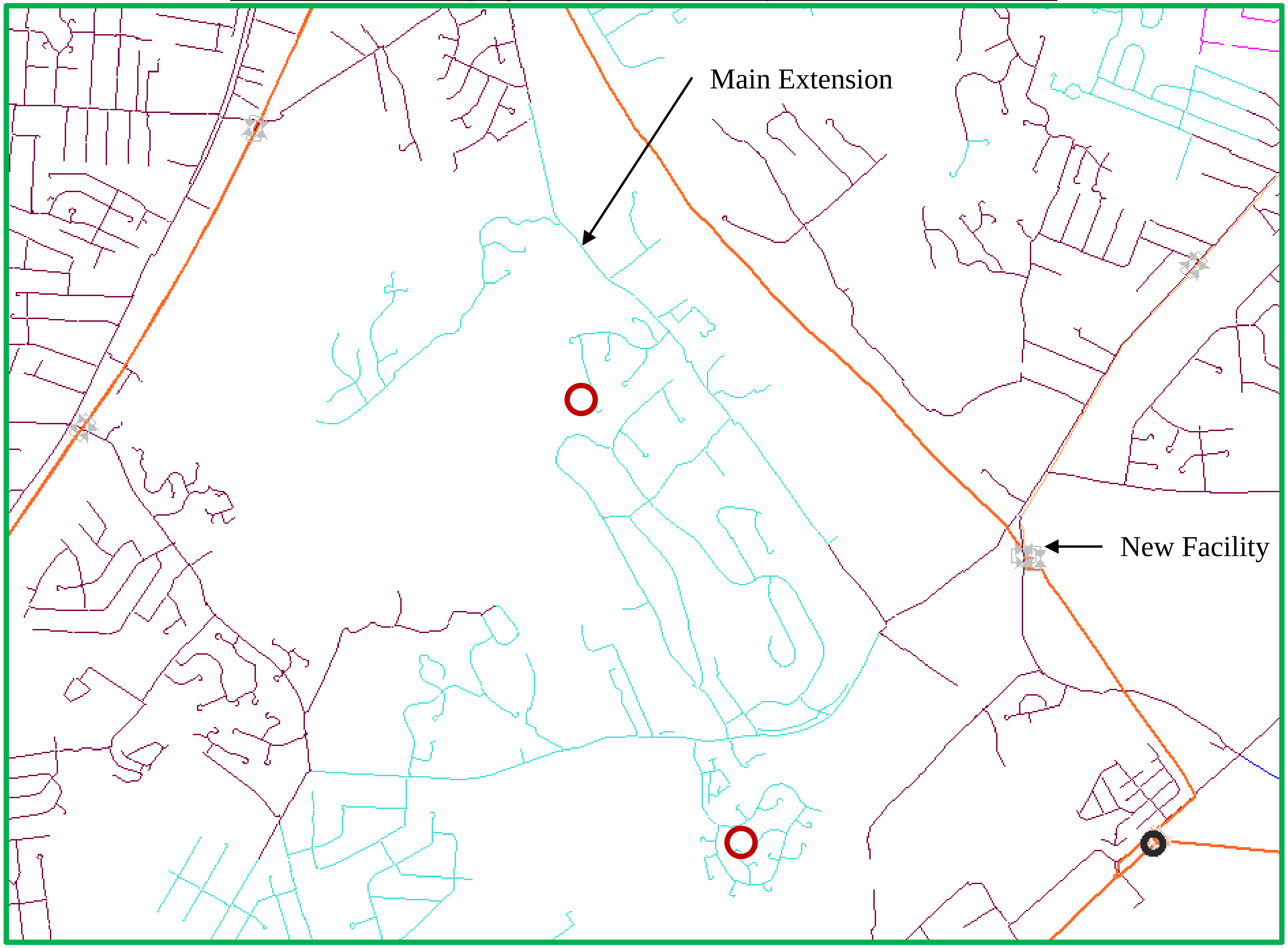
Minimum Gas System Pressure (-12°F)
Britannia Court- **17.4 psig**
Twin Lakes Court- **18.7 psig**

Regulator Operating Capacities
- Dixie Hwy & East Pages Ln **– 53.8%**
- St. Andrews Church Rd & ICRR **– 48.1%**
- Old 3rd St. Rd. & Bamberrie Cr **– 19.6%**
- New Cut Rd & Old 3rd Street Rd- **15.2%**
- New Station at Old 3rd & Manslick- **39.1%**

Windsor Forest 35 psig Medium Pressure System



Windsor Forest 35 psig Medium Pressure System- Reinforcement 1



VI. River Road/Highway 42 Regulator Assemblies

Gas System Overview
Gas System Planning has identified eleven regulator facilities on River Rd that could be removed to reduce the number of dead-end gas systems and reduce maintenance costs by removing unnecessary equipment. All regulators are fed by the Elder Park Line.

Gas System Reinforcement Completed
As part of the Farm Tap upgrade project, several medium pressure reinforcements were made, resulting in the removal of two River Road Assemblies. The reinforcements are:

- The Jeffersontown system was uprated to 50 psig MAOP in 2008 which uprated the Blankenbaker, Glenview, and Lime Kiln facilities.

Regulator Facilities
The regulator facilities in these areas are as follows:

- RIVER RD. & WOODSIDE RD. G-623 16.5%
- RIVER RD. & BOX HILL LN. G-515 12.5%
- RIVER RD. & LIME KILN LN. G-624 11.5%
- BLANKENBAKER LN. & RIVER RD. G-335 10.7%
- RIVER RD & GLENVIEW G-329 6.4%
- RIVER RD. & RIVERS EDGE SUB. G-600 20.6%
- RIVER RD.PIT SER RIVERCREEK G-590 22.4%
- RIVER RD.& JUNIPER BEACH DR. G-610 5.2%
- RIVER RD. &HARBORTOWN RD. G-621 6.4%
- RIVERBLUFF FARMS & HWY. 42 G-339 8.4%
- RIVER RD. & DUROC ACE. G-579 6.8%
- HUNTING CREEK G-328 22.0%
- COVEREDBRIDGE & WOODBRIDGE G-18983 3.0%
- COVEREDBRIDGE RD & COVERED COVE G-584 1.1%
- MELROSE RETAIL G-19321 1.9%
- HWY. 42 & HUNTERS RIDGE DR. G-607 15.5%
- HWY. 42 & HAYFIELD WAY G18755 10.9%
- HIGH MEADOWS PIKE G-543 13.6%
- HWY. 42 & HILLCREST SUB. G-612 12.4%

Maximum Allowable Operating Pressure
The Elder Park Line has a maximum allowable operating pressure of 400 psig, but is typically operated at 300 psig.

The Lime Kiln Ln, Glenview, and Woodside Rd system has a maximum allowable operating pressure of 50 psig.

All other systems have a maximum allowable operating pressure of 35 psig.

VI. River Road/ Hwy 42 Regulator Assemblies (cont'd)

The Ballardsville Line contains many regulators with subsystems that could be combined for better flow and less maintenance. The Glenview and Indian Hills areas of Jefferson County along River Road contain five facilities that could be retired.
The Blankenbaker Ln, Lime Kiln Ln, Glenview, and Woodside Rd systems have a maximum allowable operating pressure of 50 psig.
The River's Edge Rd, Juniper Beach Dr, Harbortown Rd, and Rivercreek Dr, and Box Hill Ln systems have a maximum allowable operating pressure of 35 psig.

Recommended Gas System Reinforcements

Reinforcement 1

- Install approximately 2,800 feet of 4-inch plastic gas main along River Rd to connect the River Rd & River Creek Dr and River Rd & Harbortown Rd systems.
- Install approximately 300 feet of 2-inch plastic gas main along Juniper Beach Rd to connect the River Rd & Juniper Beach Dr and River Rd & Harbortown Rd systems.
- Remove the River Rd & Juniper Beach Dr and the River Rd & Harbortown Rd regulator pit.

Minimum Gas System Pressure (-12°F)

- 5301 Juniper Beach Rd – **34.2 psig**

Regulator Facility Utilization (-12°F)

- River Rd. Pit serving Rivercreek – **34%**

Reinforcement 2

- Install approximately 850 feet of 4-inch plastic gas main along Arden Rd and 540 feet of 2-inch plastic gas main on Glenview Ave at Orion Rd to connect Woodside Rd and Glenview Ave systems.
- Install approximately 2500 feet of 4-inch plastic gas main along River Rd and 1,200 feet of 4-inch plastic gas main along Lime Kiln Ln to connect Lime Kiln Ln and Glenview Ave systems.
- Remove the River Rd & Woodside Rd and River Rd & Lime Kiln Ln regulator assemblies.

Minimum Gas System Pressure (-12°F)

- Wolfpen Ridge Ct – **27.3 psig**
- Phoenix Hill Dr- **34.3 psig**

Regulator Facility Utilization (-12°F)

- River Rd. & Glenview – **9.8%**

VI. River Road/ Hwy 42 Regulator Assemblies (cont'd)

Reinforcement 3

- Uprate the Rivers Edge and Box Hill Ln systems to 50 psig.
- Install approximately 800 feet of 2-inch plastic gas main along Longview Ln to connect Longview Ave to the Box Hill Ln system.
- Install approximately 1450 feet of 2-inch plastic gas main along River Rd to connect the Woodside Rd and Box Hill Ln systems.
- Install approximately 1200 feet of 4-inch plastic gas main on River Rd to connect the Blankenbaker and Rivers Edge systems.
- Retire the River Rd & Rivers Edge facility

Minimum Gas System Pressure (-12°F)

- Phoenix Hill Drive **– 34.4 psig**
- Cedar Ridge Court**- 32.7 psig**

Regulator Operating Capacity

- River Rd & Box Hill Ln **– 39.5 %**
- Blankenbaker & River Rd **11.8%**

Reinforcement 4

- Install 900 feet of 4-inch pipe along Hwy 42 from Hunting Creek Drive to Covered Bridge Rd and 2200 feet of 4-inch pipe from Hwy 42 to the Covered Bridge regulator facility.
- Retire the Covered Bridge & Woodbridge facility and the Covered Bridge & Covered Cove facility.

Minimum Gas System Pressure (-12°F)

- Beachland Beach Road **– 26.6 psig**
- Talahi Way**- 34.7 psig**

Regulator Operating Capacity

- River Rd & Duroc Ave **– 6.8 %**
- Hunting Creek- **21.9%**
- Hwy 42 & Hayfield- **4.3%**

VI. River Road/ Hwy 42 Regulator Assemblies (cont'd)

Reinforcement 5

- Install 3600 feet of 4-inch pipe along Hwy 42 from the existing 4-inch pipe just west of Hayfield Way to the Melrose Retail facility, connecting it to the Hwy 42 & Hayfield Way, Riverbluff Farms & Hwy 42, Hwy 42 & Hunters Ridge Rd, and Melrose Retail facilities.
- Install 130' of 2-inch plastic on Ridgemoor Drive to cross Hwy 42 and connect the subsystems.
- Retire the Riverbluff Farms & Hwy 42, Hwy 42 & Hunters Ridge Rd, Melrose Retail facilities, and High Meadows Pike facilities.

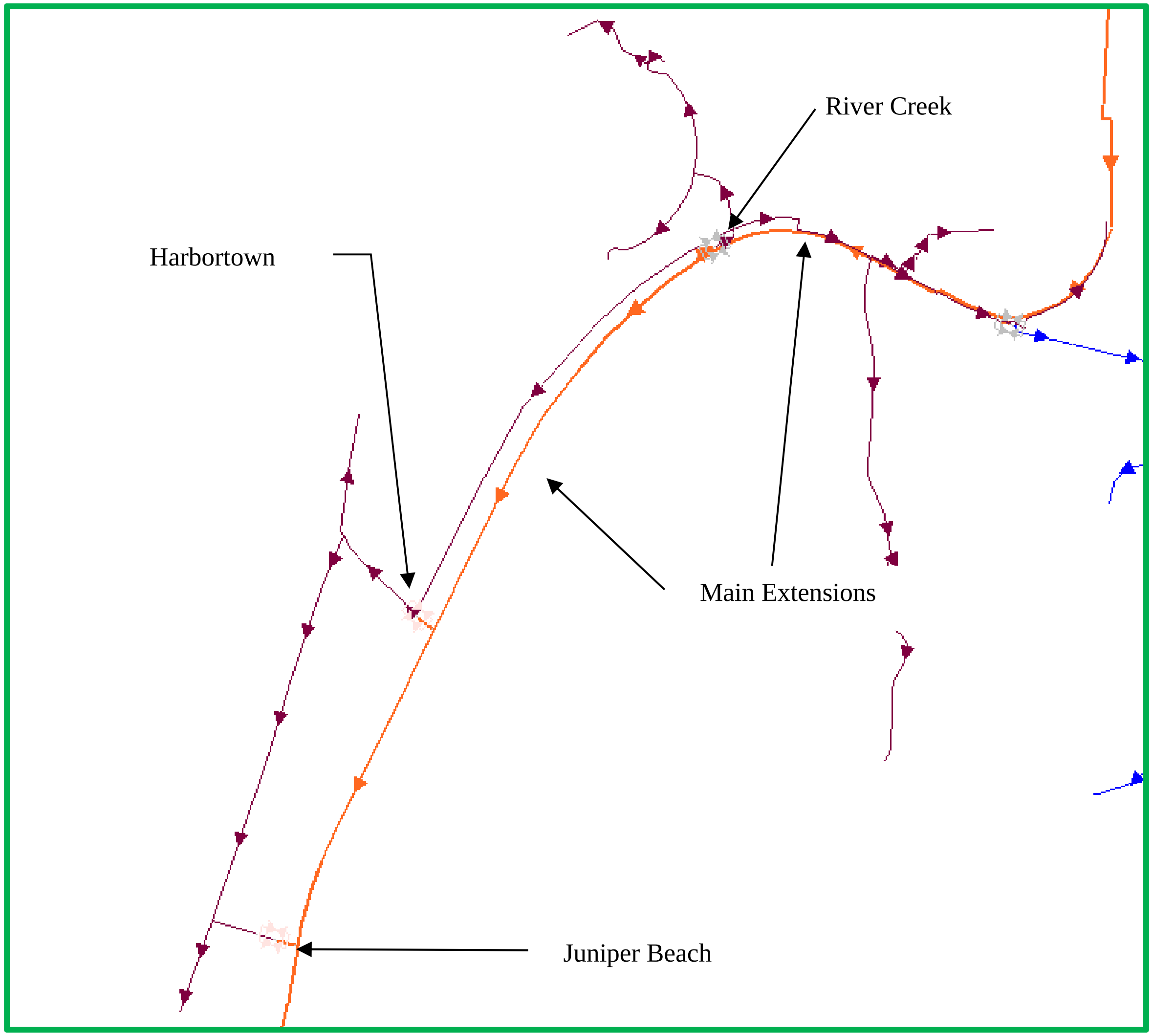
Minimum Gas System Pressure (-12°F)

- Beachland Beach Road – **26.6psig**
- Deercross Drive- **32.0 psig**

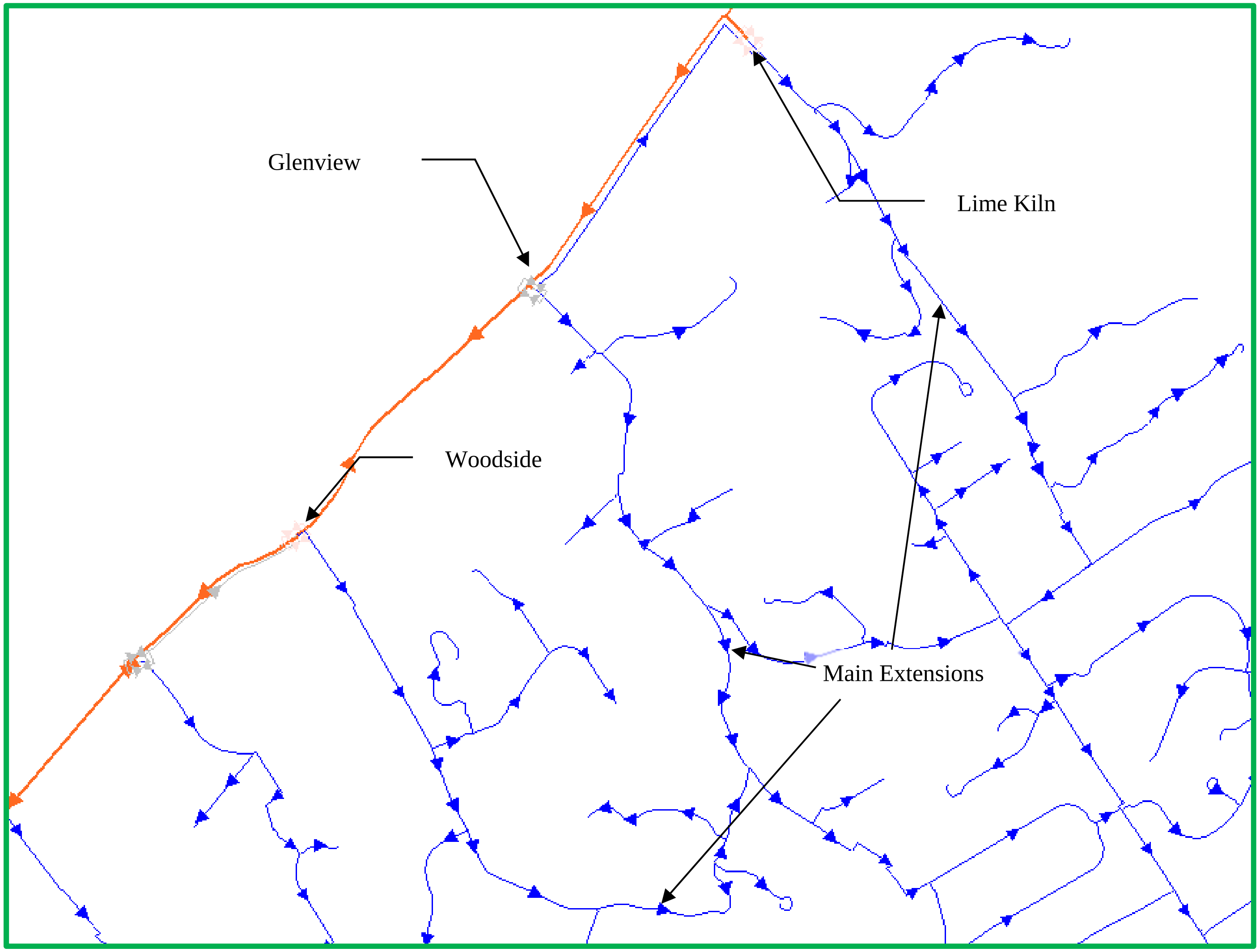
Regulator Operating Capacity

- Highway 42 & Hayfield – **10.9 %**
- Hwy. 42 & Hillcrest Sub. **12.4%**
- River Rd. & Duroc Ave- **6.8%**
- Hunting Creek- **22.1%**

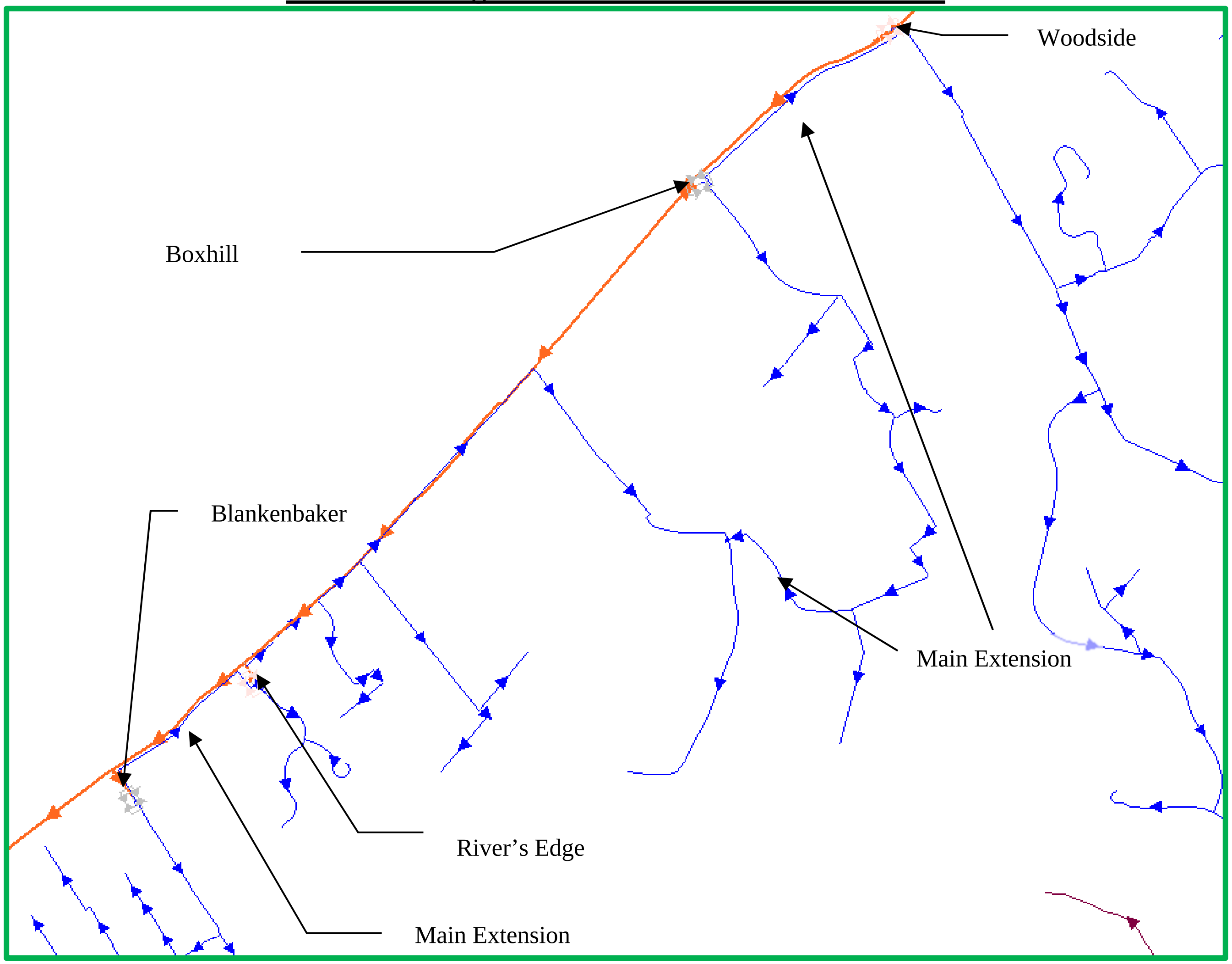
River Road Regulator Assemblies – Reinforcement 1



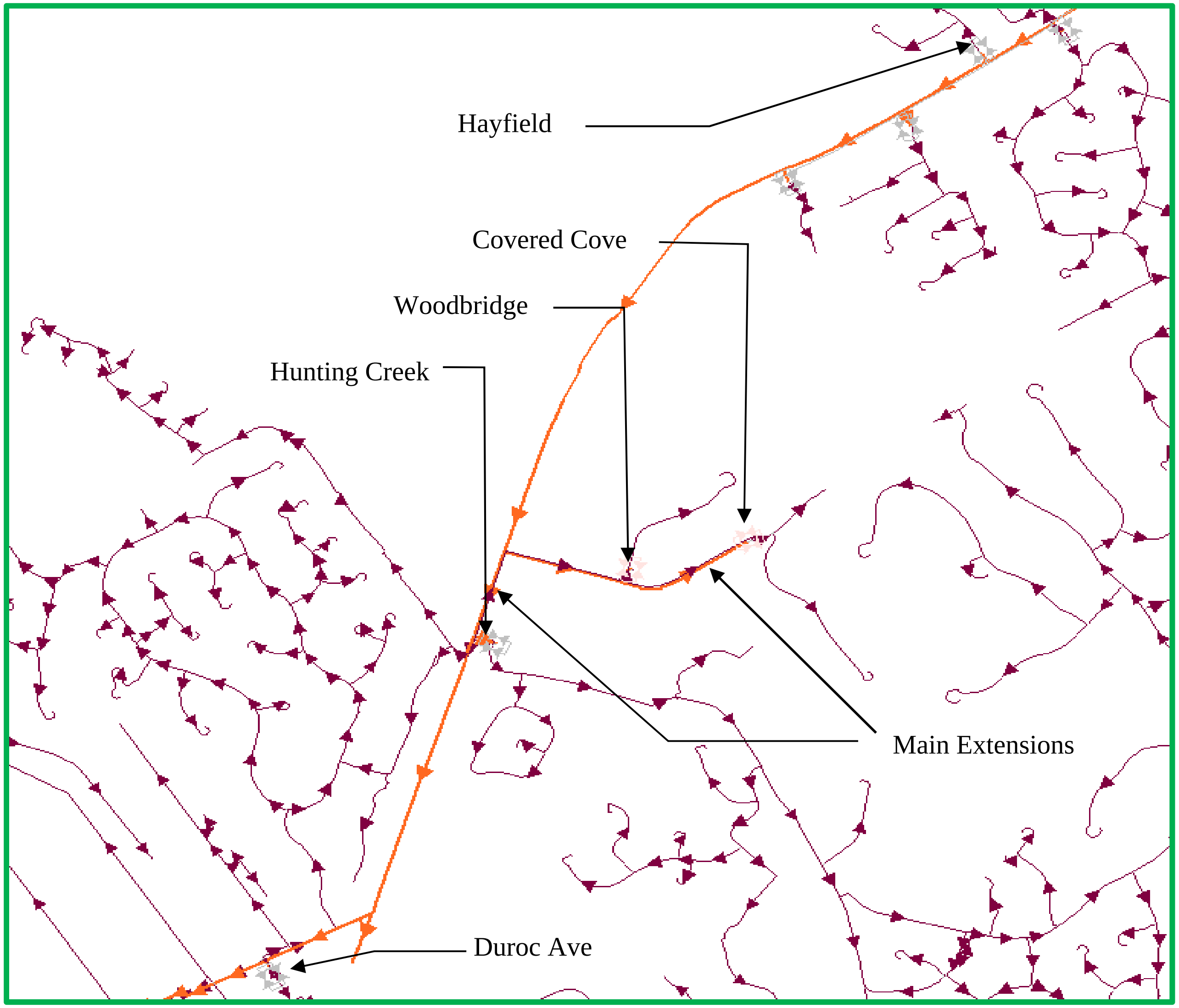
River Road Regulator Assemblies – Reinforcement 2



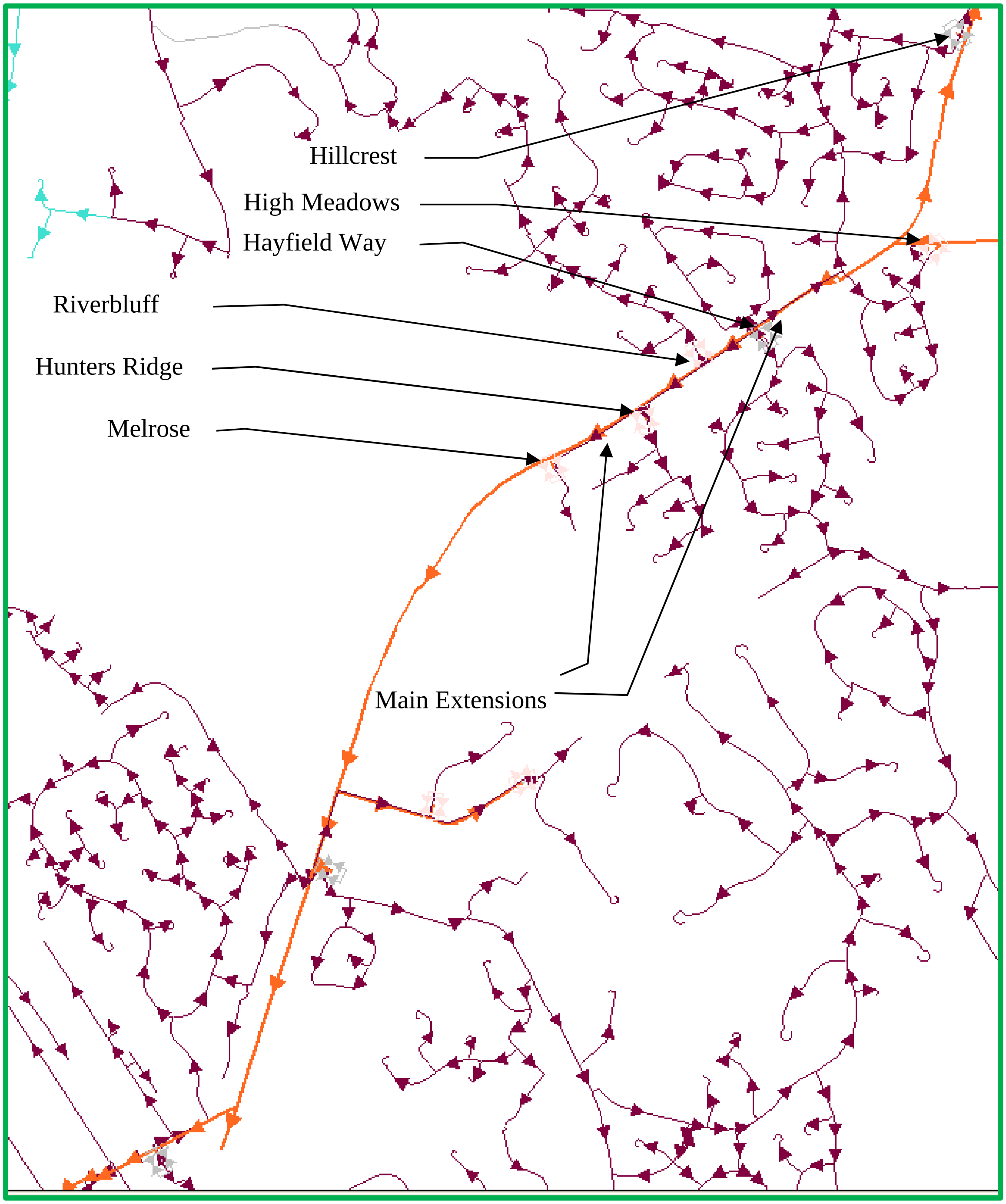
River Road Regulator Assemblies – Reinforcement 3



River Road Regulator Assemblies – Reinforcement 4



River Road Regulator Assemblies – Reinforcement 5



VII. Plantside Drive/Blankenbaker Parkway Medium Pressure System

Gas System Overview

The Plantside/Blankenbaker Medium Pressure System feeds the area near Plantside Drive, Blankenbaker Parkway, and Electron Drive. The area is composed mostly of small commercial customers with a few residential customers. This system is connected to the Taylorsville Road medium pressure system via a 4-inch steel main at Grand Avenue and Watterson Trail.

Maximum Allowable Operating Pressure

This medium pressure system has a maximum allowable operating pressure of 35 psig.

Regulator Operating Capacity

- Watterson Tr and Plantside Dr – **40.9%**
- Tucker Station Rd & I-64 – **2.7%**

Gas System Constraints

Many of the commercial customers fed by this medium pressure system require a delivery pressure of 5 psig. A proposed 283 acre office park for the eastern area of this system, south of I-64, on Tucker Station Road, will require a significant amount of new infrastructure (MSD is planning a 4.6 square mile area of sewer development) and an additional gas regulator facility. Currently, this system is not capable of serving this development that is predicted to have an approximate total load of 140 Mcfh.

Recommended Gas System Reinforcements:

Reinforcement 1

- Install approximately 1,200 feet of 6-inch medium pressure plastic pipe from Sycamore Station Place south along Tucker Station Road, terminating at Pope Lick Road.
- Install approximately 2,400 feet of 6-inch medium pressure plastic pipeline west from the existing 4-inch main at Tucker Station and Sycamore Station to 12711 S Pope Lick Rd. This would feed the proposed businesses expected to fill the area.

Minimum gas system pressure (-12ºF):

- 10315 Watterson Trail – **24.1 psig**
- Sycamore Station Place – **30.0 psig**

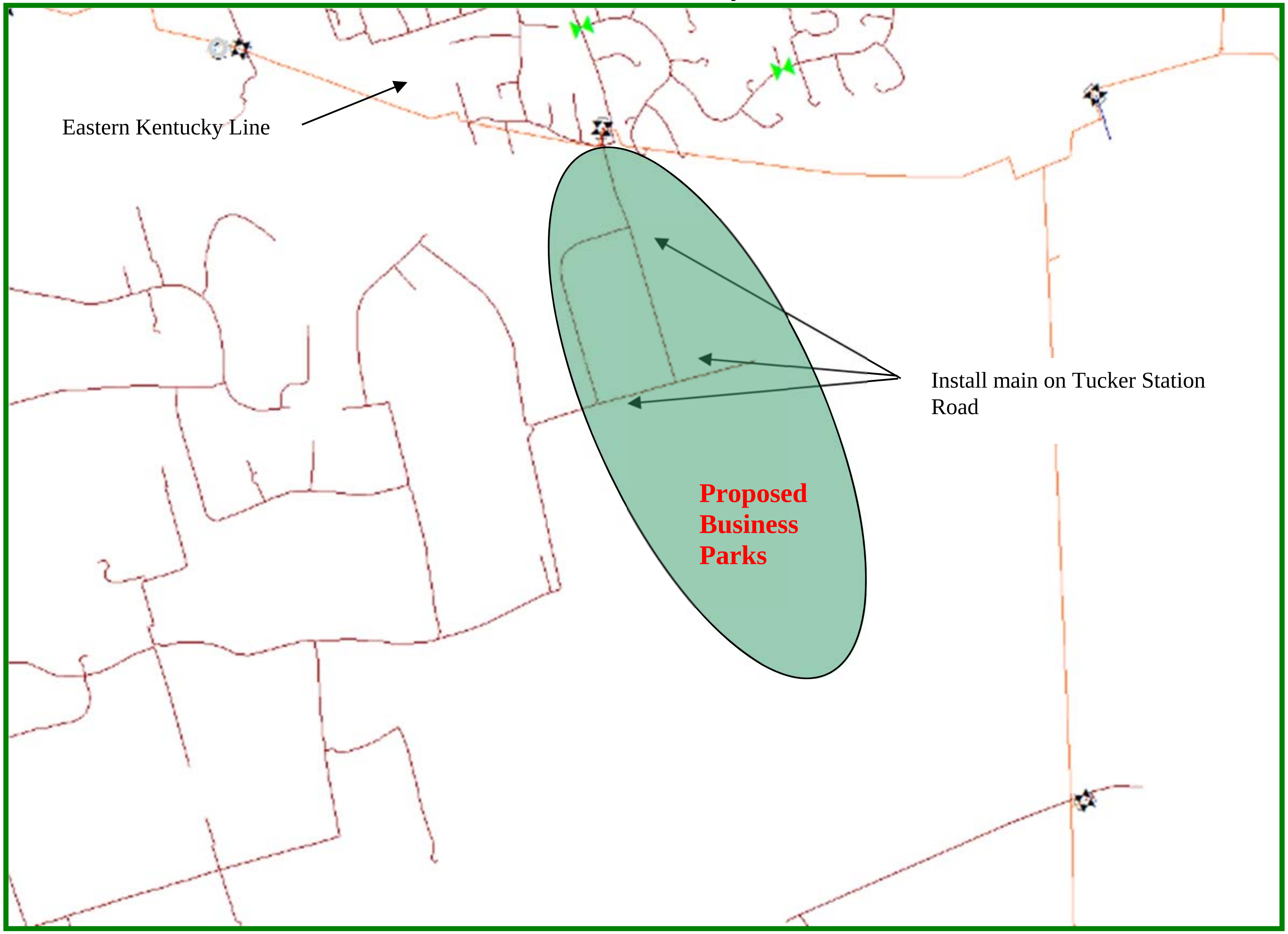
Regulator Operating Capacities:

- Tucker Station Rd & I-64 – **20.5%**
- Watterson Tr & Plantside Dr – **45.0%**

Recommended Timeline:

Note: This reinforcement should be completed after the Kentucky Department of Transportation widens Tucker Station Road and Pope Lick Road.

Plantside Drive Medium Pressure Gas System – Reinforcement 1



VIII. Jeffersontown/Fern Creek Medium Pressure System

Gas System Overview

The Jeffersontown and Fern Creek areas are part of a large medium pressure gas system that serves the southeastern part of Jefferson County. This system is composed of rural, residential, and small commercial customers and has continued to experience rapid growth in these sectors. The majority of Jeffersontown and Fern Creek areas are served from the following regulator facilities.

Regulator Facilities

The regulator facilities that feed this system are as follows:

- Regulator pit at Taylorsville Road and Hopewell Road (Jeffersontown Pit)
- Regulator assembly at Gentry Lane and the Calvary Line
- Regulator pit at Cedar Creek Road and the Calvary Line
- Regulator station at Hudson Lane

Maximum Allowable Operating Pressure

The Jeffersontown/Fern Creek medium pressure gas system has a maximum allowable operating pressure of 55 psig.

Model Results

Minimum Gas System Pressures (-12 ^{0}F)

- 11708 Kewana Ct – 21.66 psig

Regulator Operating Capacity

Cedar Creek & Calvary- **15.4%**
Cedar Grove & I-65- **31.1%**
Hudson Ln. Station- **73.8%**
Hwy 44 & Lees Ln- **22.9%**
Jeffersontown Pit- **15.5%**
Mud Ln & Antle Dr- **100%**
Old Bardstown & Thixton- **9.8%**
Outer Loop & Grade Ln- **40.4%**
Preston Hwy & Springview- **59.3%**
Preston Hwy & South Park- **39.7%**
Vista Hills & Calvary Line- **64.3%**

Gas System Constraints

Gas system constraints in this area are primarily due to the infrastructure of small diameter piping coming from the sources as well as isolated areas. Due to current and anticipated growth it will be necessary to perform gas system reinforcement work.

VIII. Jeffersontown/Fern Creek Medium Pressure System (cont'd)

Recommended Gas System Reinforcement

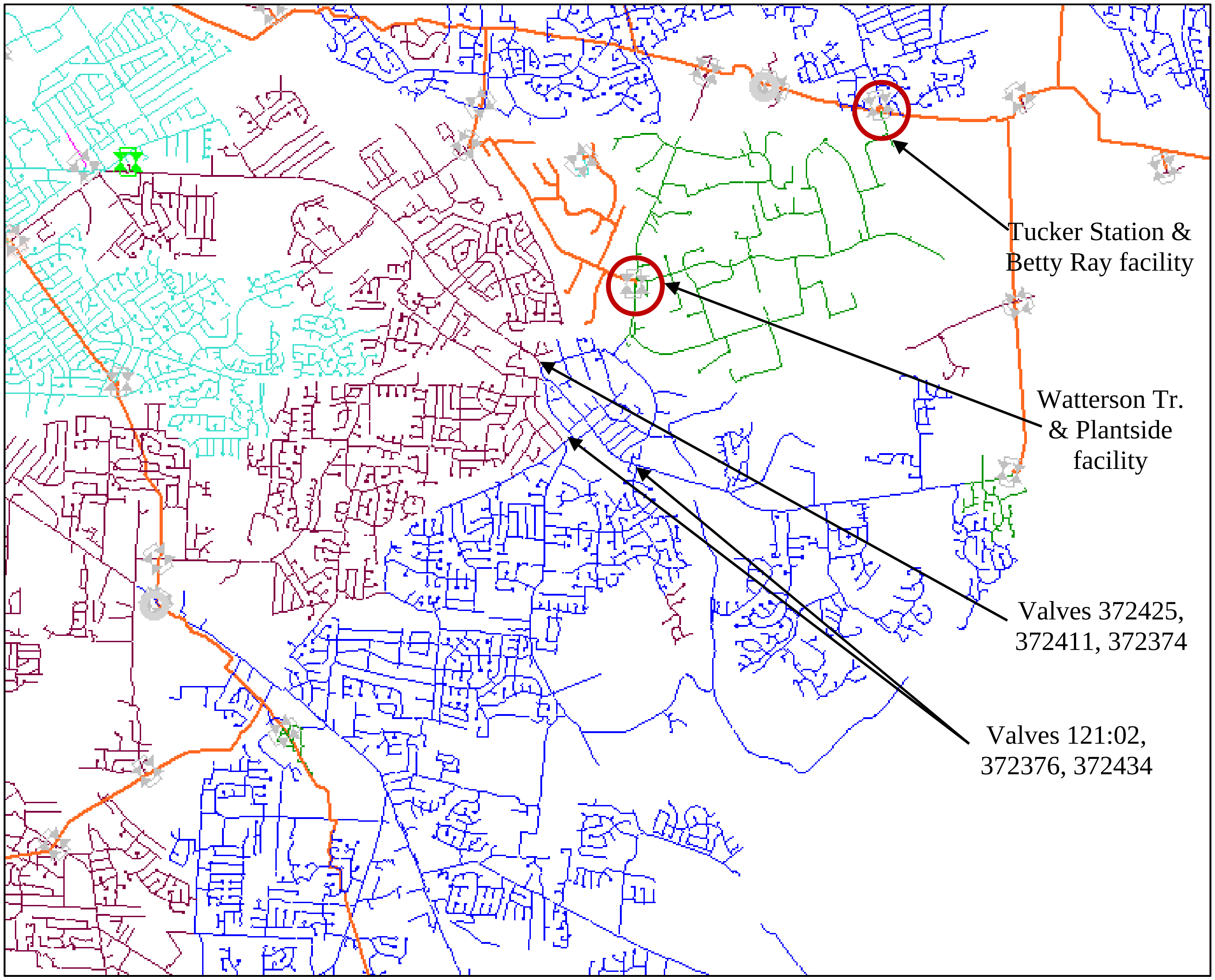
Reinforcement 1
Uprate the Bluegrass Industrial Park to 55 PSIG and connect to the Jeffersontown 60psig system

- Close valves 372425, 372411 and 372374
- Uprate the Watterson Trail & Plantside Dr and Tucker Station Rd. & Betty Ray Ln facilities to 55psig.
- Open valves 121:02, 372376, and 372434

Minimum gas system pressure (-12°F)
- 11708 Kewana Ct – 33.6 psig

Regulator Operating Capacity
- Cedar Creek & Calvary- **14.3%**
- Cedar Grove & I-65- **30.7%**
- Hudson Ln. Station- **68.1%**
- Hwy 44 & Lees Ln- **22.7%**
- Jeffersontown Pit- **15.6%**
- Mud Ln & Antle Dr- **100%**
- Old Bardstown & Thixton- **9.6%**
- Outer Loop & Grade Ln- **39.9%**
- Preston Hwy & Springview- **57.9%**
- Preston Hwy & South Park- **38.7%**
- Vista Hills & Calvary Line- **63.6%**

Jeffersontown/Fern Creek Medium Pressure System- Reinforcement



IX. Bardstown Medium Pressure System

Gas System Overview

The Bardstown medium pressure gas system serves the City of Bardstown. This system is composed mainly of residential and commercial customers with a few large industrial customers including Owens Illinois and the Barton Distillery. It has continued to experience growth in the residential and commercial sectors especially on the western side of the Bardstown area. Expansion of an industrial park on Highway 605 near Nelson County High School is anticipated in the next 2-3 years.

Gas System Reinforcements completed in 2012

Approximately 1,300 feet of 4-inch pipe was installed to connect the gap from Armag Ave to Spencer Mattingly Road.

Regulator Facilities

The regulator facilities that supply gas to the Bardstown medium pressure system are as follows:

- The regulator station at the LG&E Bardstown Office on U.S. Highway 62 (Bardstown MP).
- The regulator station adjacent to Chris's Creation Cabinet Company (Chris's Creation MP).

Maximum Allowable Operating Pressure (MAOP)

The Bardstown medium pressure system has a maximum allowable operating pressure of 55 psig.

Model Results

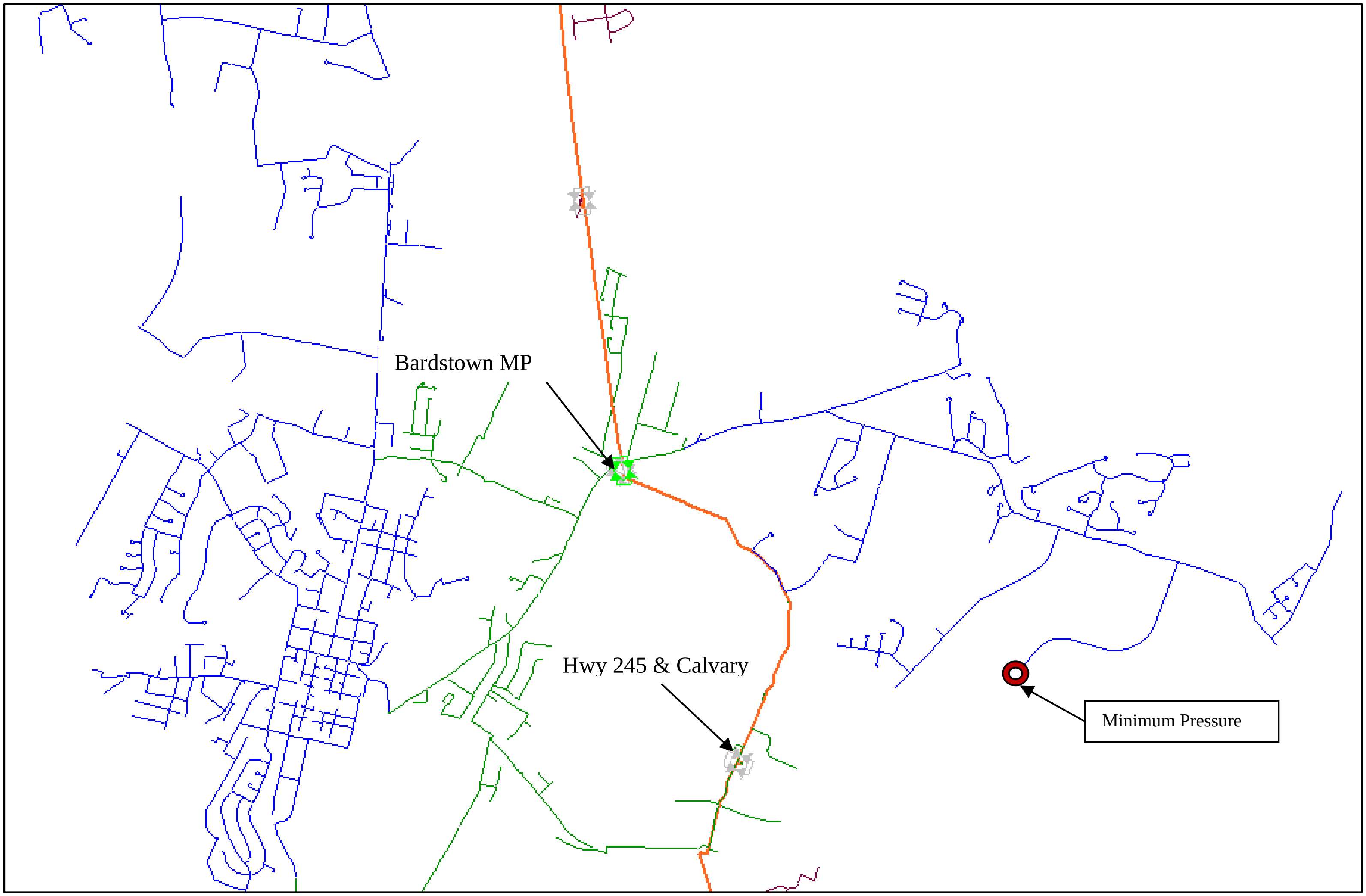
Minimum Gas System Pressure (-12 ^{0}F)

- 1755 Parkway Drive- 41.33 psig

Regulator Operating Capacities

- Bardstown MP – **26.5**%
- Hwy 245 & Calvary – **45.8**%

Bardstown Medium Pressure Gas System



X. Highway 44 Regulator Assemblies

Gas System Overview
Gas System Planning has identified nine separate regulator assemblies located along Highway 44 that could be removed to reduce the number of dead-end gas systems and/or reduce maintenance cost on unnecessary regulation facilities.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Mt Washington MP
- Hwy 44 and Woodlake
- Hwy 44 and Harris
- Hwy 44 and Fisher
- Hwy 44 and Highland Spring
- Hwy 44 and Bethel Church
- Hwy 44 and Azure
- Hwy 44 and Truman
- Hwy 44 and Kennedy
- Hwy 44 and Bogard
- Hwy 44 and Bells Mill
- Hwy 44 and Alpar
- Hwy 44 and Mockingbird
- Hwy 44 and Sunview
- Hwy 44 and Watergate
- Hwy 44 and Hi-Land
- Hwy 44 and Big Clifty
- Hwy 44 and Halls
- Board Walk Ave & Hwy 44

Maximum Allowable Operating Pressure
These systems have a maximum allowable operating pressure of 35 psig. The maximum allowable operating pressure of the Mt Washington MP regulator station is 60 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure is located on **Winding Woods Trail (27.4 psig)**.

X. Highway 44 Regulator Assemblies (cont'd)

Regulator Operating Capacities

- Mt Washington MP – **11.8%**
- Hwy 44 and Woodlake – **22.8%**
- Hwy 44 and Harris – **23.0%**
- Hwy 44 and Fisher – **79.4%**
- Hwy 44 and Highland Springs – **63.7%**
- Hwy 44 and Bethel Church – **23.2%**
- Hwy 44 and Azure – **7.8%**
- Hwy 44 and Truman – **26.8%**
- Hwy 44 and Kennedy – **6.8%**
- Hwy 44 and Bogard – **1.9%**
- Hwy 44 and Bells Mill – **25.9%**
- Hwy 44 and Alpar – **2.2%**
- Hwy 44 and Mockingbird – **57.9%**
- Hwy 44 and Sunview – **53.1%**
- Hwy 44 and Watergate – **1.3%**
- Hwy 44 and HiLand – **6.5%**
- Hwy 44 and Big Clifty – **13.8%**
- Hwy 44 and Halls – **18.3%**
- Hwy 44 and Boardwalk – **20.1%**

Recommended Gas System Reinforcements

Reinforcement 1

- Connect system served by Hwy 44 and Boardwalk to Hwy 44 and Halls system with 600 feet of 4-inch plastic main along Hwy 44 and Halls Ln.
- Connect Hwy 44 and Big Clifty to Hwy 44 and Halls system with 1,100 feet of 4-inch plastic main along Hwy 44.
- Convert six high-pressure services on the north side of Hwy 44 to medium-pressure services between Hwy 44 and Halls and Hwy 44 and Big Clifty. This will retire six long services that pass underneath Hwy 44.
- Change the orifice size of Hwy 44 and Halls Ln to ¼"
- Retire Boardwalk and Big Clifty regulator assemblies.

Minimum Gas System Pressure (-12°F)

- Tanager Lane – **34.3 psig**

Regulator Operating Capacities

- Hwy 44 and Halls Ln – **43.3%**

X. Highway 44 Regulator Assemblies (cont'd)

Reinforcement 2

- Connect systems served by Hwy 44 & Hi-Land and Hwy 44 & Watergate with 1,500 feet of 6-inch plastic mains.
- Retire Watergate Assembly.

Minimum Gas System Pressure (-12°F)

- Douglas Drive **– 34.9 psig**

Regulator Operating Capacities

- Hwy 44 and Hi-Land– **7.9 %**

Reinforcement 3

- Retire Hwy 44 and Mockingbird regulator assembly. System can be served by Hwy 44 and Sunview.
- Change the orifice size of Hwy 44 & Sunview to 3/8".

Minimum Gas System Pressure (-12°F)

- Old Hickory Lane **– 28.7 psig**

Regulator Operating Capacities

- Hwy 44 and Sunview **– 53.1%**

Note: Growth in area may require that the Mockingbird assembly remain. This area should be monitored before finalizing a decision.

Reinforcement 4

- Connect systems served by Hwy 44 and Bells Mill and Hwy 44 and Alpar with 2,100 feet of 4-inch plastic main along Hwy 44 and Old Hwy 44.
- Convert five existing high pressure services to medium pressure.
- Retire the Hwy 44 and Alpar regulator assembly.

Minimum Gas System Pressure (-12°F)

- 468 East Millwater Falls **– 29.6 psig**

Regulator Operating Capacities

- Hwy 44 and Bells Mill **– 29.4%**

X. Highway 44 Regulator Assemblies (cont'd)

Reinforcement 5

- Connect systems served by Hwy 44 & Bogard, Hwy 44 & Kennedy, Hwy 44 & Truman, and Hwy 44 & Azure with 3,300 feet of 6 inch plastic main along Hwy 44.
- Connect systems served by Hwy 44 & Azure and Hwy 44 & Bethel Church with 1,950 feet of 4-inch plastic pipe along Hwy 44.
- Connect systems served by Bethel Church and Highland Springs facilities with 1,400 feet of 4- or 6-inch plastic main along Hwy 44.
- Change the orifice size of Hwy 44 & Azure to 3/8"
- Convert 24 high-pressure services along Hwy 44 to medium pressure.
- Retire Truman, Kennedy, Azure, and Bethel Church Road facilities.

Minimum Gas System Pressure (-12°F)

- Winding Woods Trail **– 29.6 psig**

Regulator Operating Capacities

- Hwy 44 and Bells Mill Rd **– 30.9%**
- Hwy 44 and Bogard**– 30.7%**
- Hwy 44 and Highland Springs **– 91.6%**
- Hwy 44 and Fisher Ln **– 80.3%**

Reinforcement 6

- Connect Fisher, Harris, and Woodlake systems with 2,100 feet of 4-inch plastic pipe along Hwy 44 between Fisher and Harris, and 1,000 feet of 6-inch plastic pipe between Harris and Woodlake from Half Moon Drive to Woodlake Drive.
- Convert approximately 34 high-pressure services to medium pressure.
  Note: Some of these services may have been converted during 2005 work but are not currently mapped.
- Retire Hwy 44 and Harris regulator assembly.

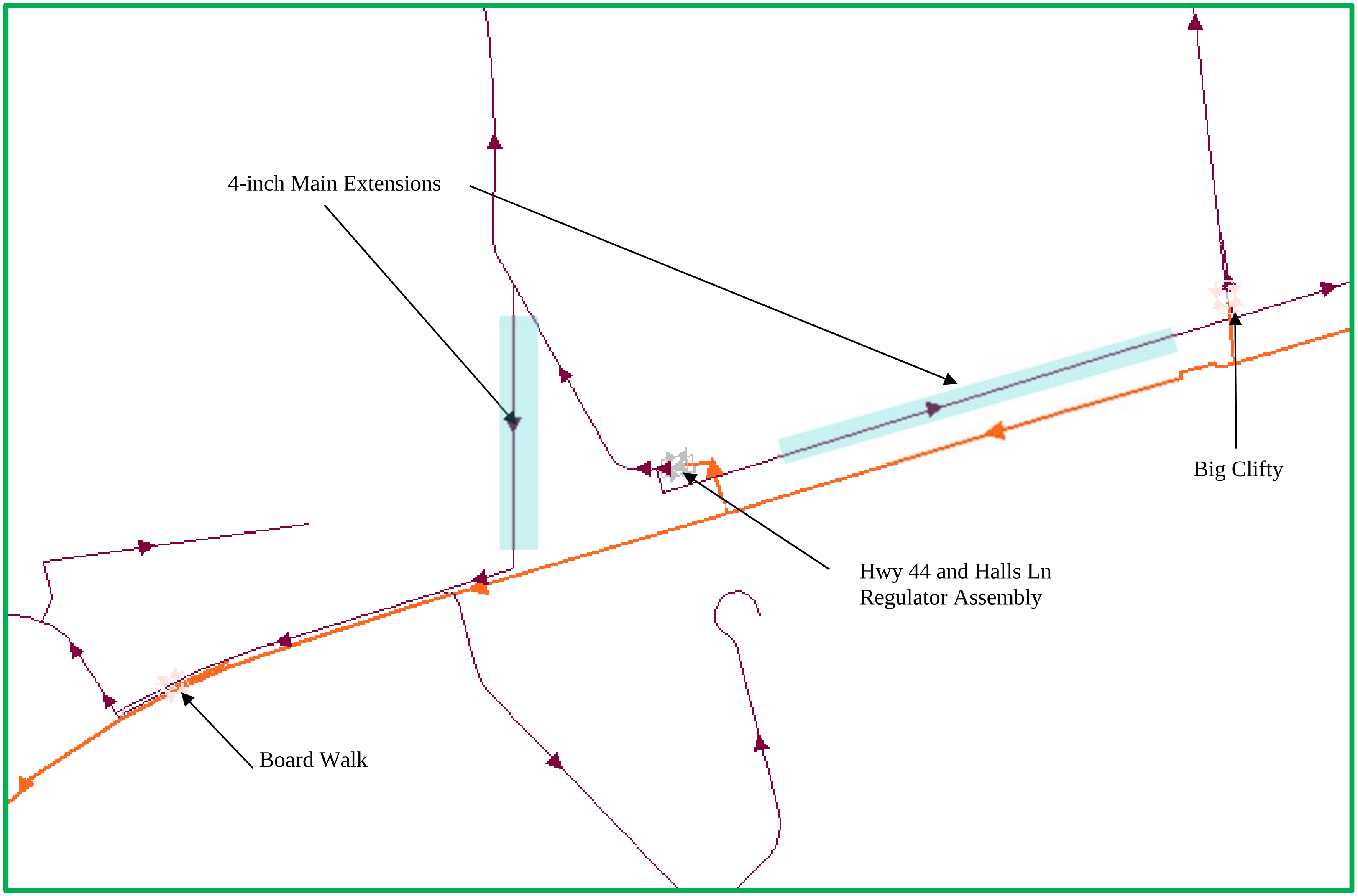
Minimum Gas System Pressure (-12°F)

- Winding Woods Trail **– 27.4 psig**

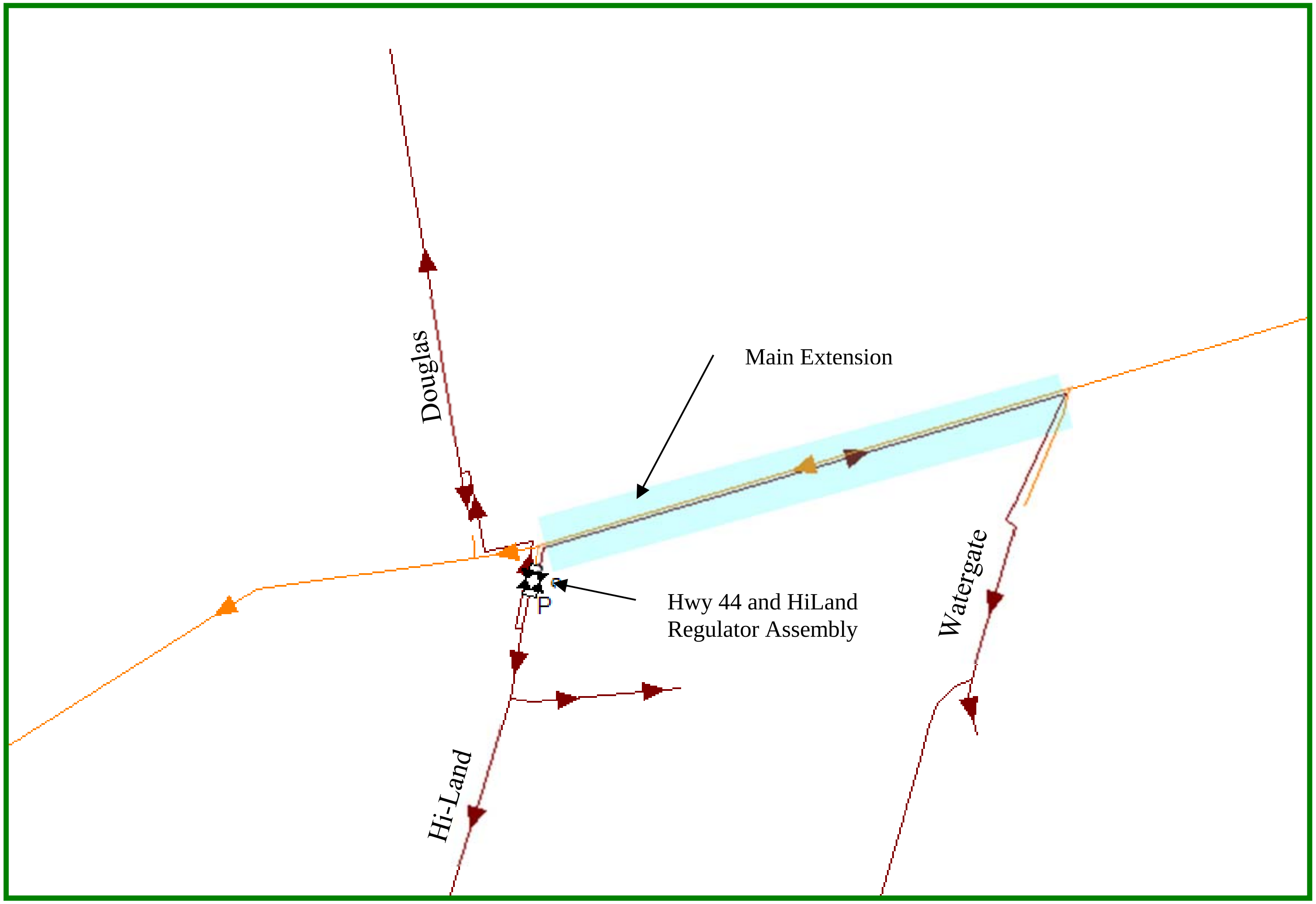
Regulator Operating Capacities

- Hwy 44 and Fisher **– 78.9%**
- Hwy 44 and Woodlake **– 47.9%**

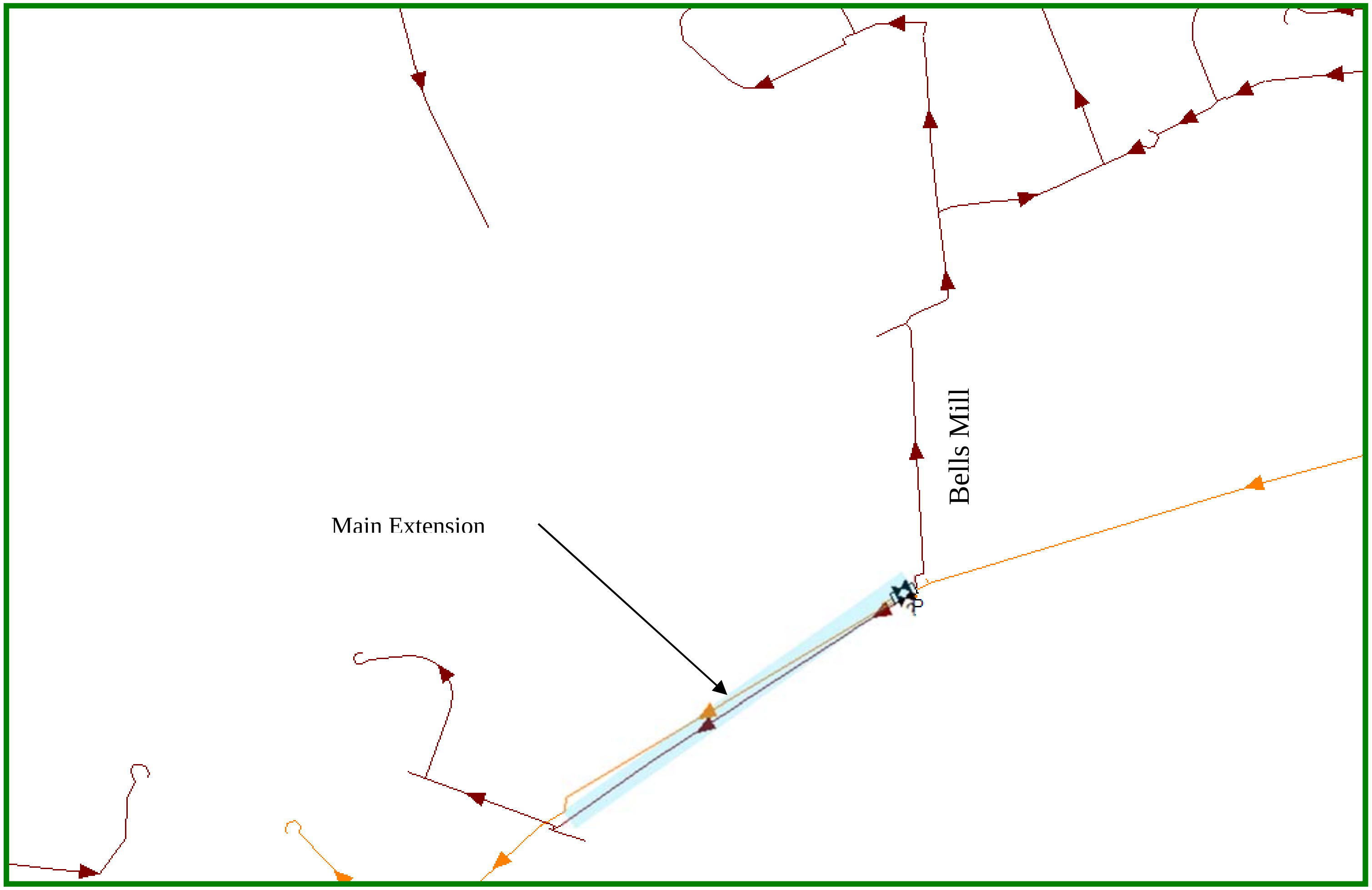
Hwy 44 Regulator Assemblies – Reinforcement 1



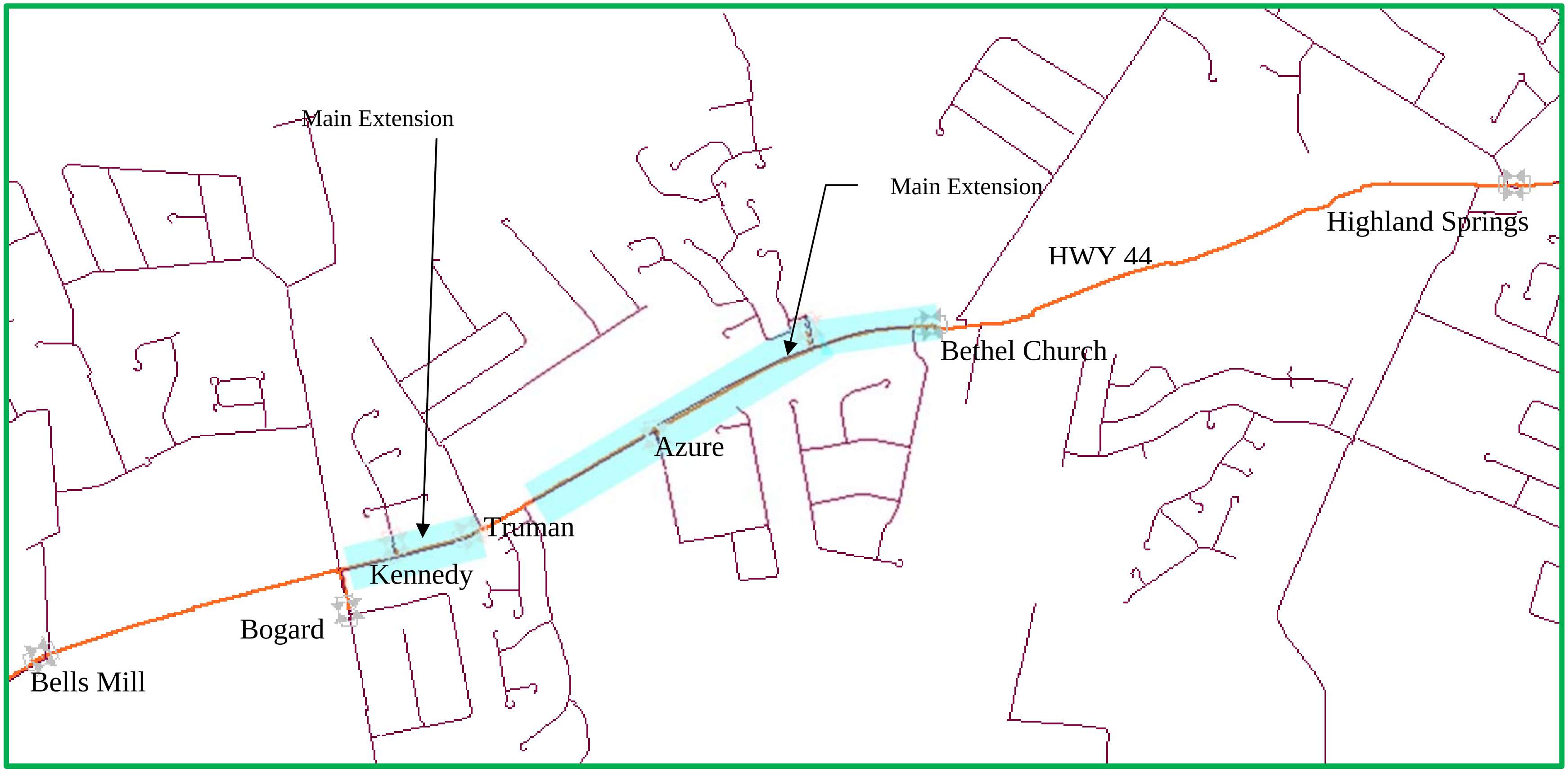
<u>Hwy 44 Regulator Assemblies – Reinforcement 2</u>



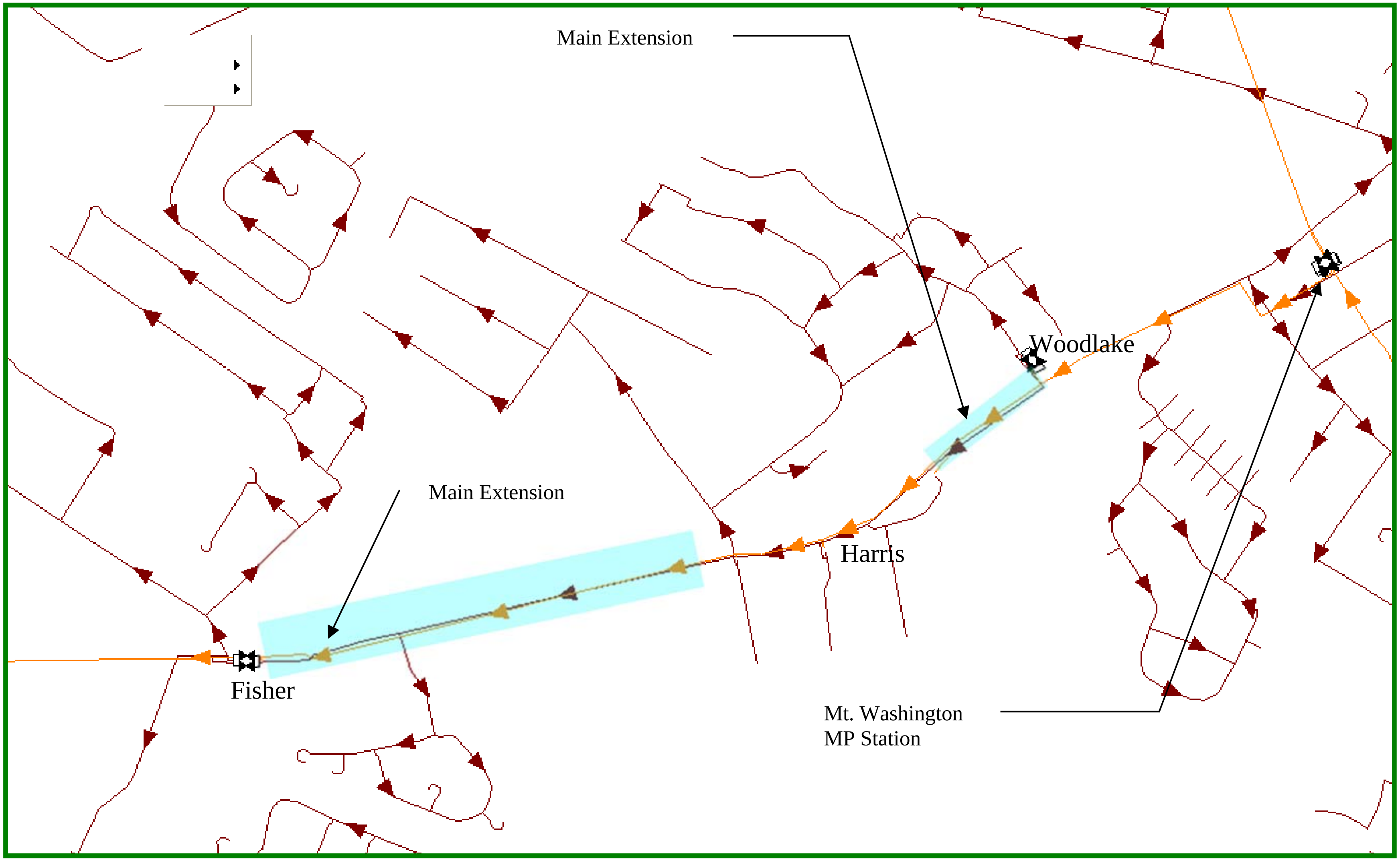
Hwy 44 Regulator Assemblies – Reinforcement 4



Hwy 44 Regulator Assemblies – Reinforcement 5



Hwy 44 Regulator Assemblies – Reinforcement 6



XI. Hodgenville Medium Pressure System

Gas System Overview

The Hodgenville medium-pressure gas system serves the City of Hodgenville. This system is composed of residential and small commercial customers. Both sectors continue to experience growth. To continue to cope with growth in Hodgenville, the gas system will need to be reinforced.

Regulator Facilities

The Hodgenville medium-pressure system is fed by the regulator station at State Highway 84 and Glendale Rd.

Maximum Allowable Operating Pressure

The Hodgenville medium-pressure system has a maximum allowable operating pressure of 20 psig.

Model Results

Minimum Gas System Pressure (-12°F)

The predicted minimum pressure is located at **2017 US Highway 31E (16.7 psig)**.

Regulator Operating Capacity

- Hodgenville Station – 22.6%

Recommended Gas System Reinforcement

Reinforcement 1

Uprate the Hodgenville medium pressure gas distribution system to 45psig. This uprate will affect approximately 1,091 services and 25.5 miles of pipeline.

Minimum Gas System Pressure (-12°F)

- 2017 US Highway 31E – **43.2 psig**

Regulator Operating Capacity

- Hodgenville Station – **20.6%**

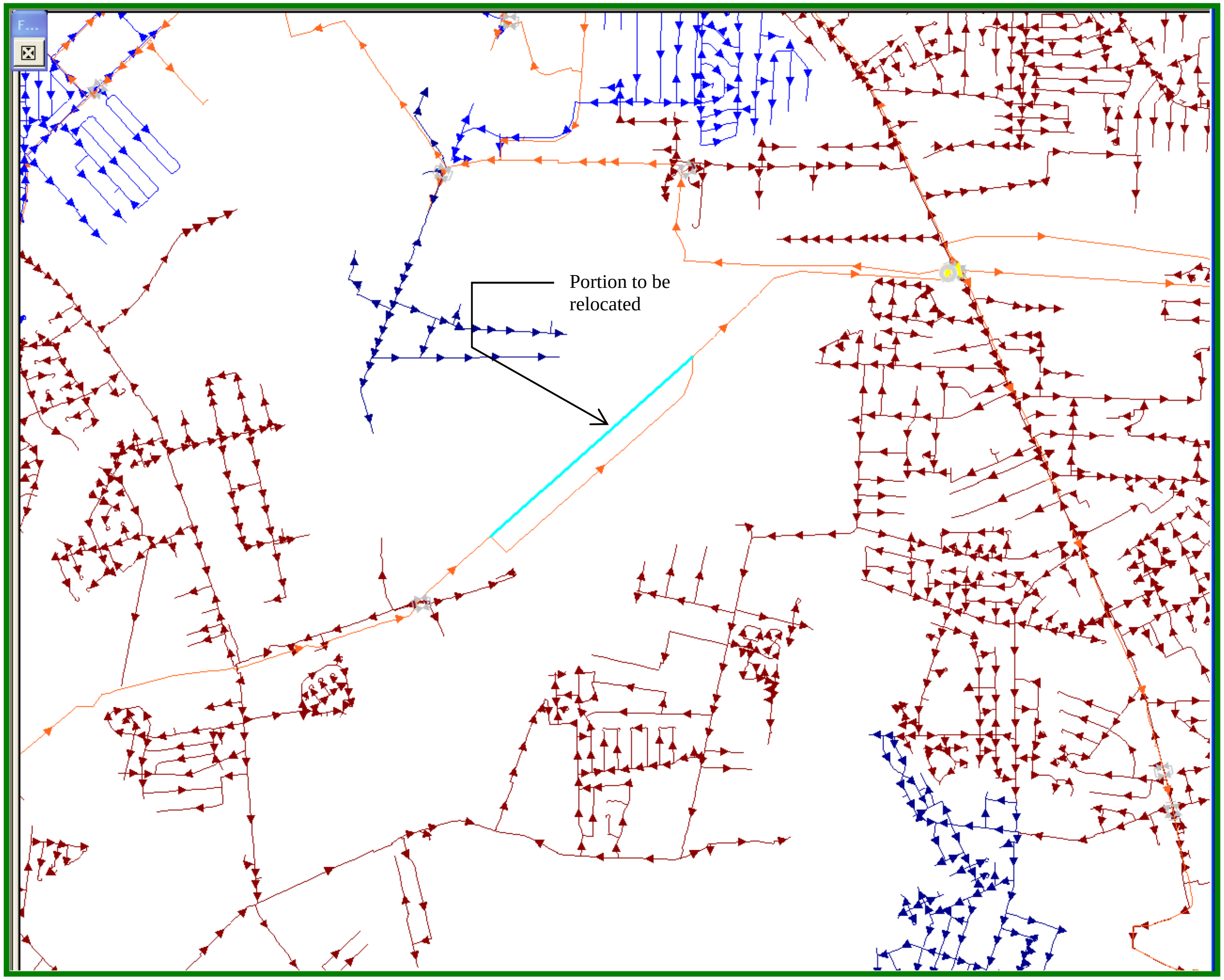
XII. Waste Management Relocation Project

Gas System Overview
The Penile City Gate Station supplies gas to the Preston City Gate Station via a 20-inch transmission pipeline (the Penile to Preston Line). The Penile to Preston Line crosses Waste Management landfill property from the Outer Loop to I-65. The two primary feeds associated with this pipeline are from the Penile and Preston City Gate Stations. Due to planned construction at the landfill, approximately 6,000 feet of the Penile to Preston Line that run through the landfill property must be relocated.

Maximum Allowable Operating Pressure
The Penile to Preston Line has a maximum allowable operating pressure of 420 psig.

Recommended Relocation
Shift the portion of the pipeline that runs through landfill property approximately 500 feet to the southeast. The pipeline should roughly run along an access road in the landfill and should reconnect with the existing pipeline before it crosses underneath I-65. This relocation will require approximately 6,600 feet of 20-inch high-pressure pipeline.

Waste Management Relocation Project – Recommended Relocation



XIII. Minor Lane Heights Renaissance Zone

Gas System Overview

The Minor Lane Heights area is being targeted for redevelopment from residential use to commercial and industrial use as a part of a noise mitigation program associated with the Louisville International Airport. Redevelopment is scheduled to occur in five phases, beginning in early 2007 and lasting ten years.

Gas System Reinforcement Completed in 2007

- Retire existing pipeline along Paul Rd south of Zib Ln
- Install approximately 4,300 feet of 8-inch plastic main along Outer Loop, Stinnett Ln, and proposed Air Commerce Way to serve UPS facility.

Regulator Facilities

The regulator facilities that feed this system are as follows:

- Regulator station at Preston City Gate Station
- Regulator pit at Outer Loop and Grade Ln

Maximum Allowable Operating Pressure

The Minor Lane Heights system has a maximum allowable operating pressure of 60 psig.

Model Results

Minimum Gas System Pressure (-12°F)

The predicted minimum gas system pressure is located at the UPS Supply Chain Solutions warehouse at **2240 Outer Loop (46.1 psig)**. There is another low pressure point at the south end of Eagle Pass (46.6 psig).

Regulator Operating Capacities

- Preston City Gate Station MP – **52.7%**
- Outer Loop and Grade Ln – **47.3%**

Gas System Constraints

Most of the existing gas infrastructure in the Minor Lane Heights system is 2- and 4-inch pipe. In addition, the system is relatively distant from its supplies. This would make it difficult to serve the number of industrial customers proposed for the Renaissance Zone. Furthermore, the proposed layout of the Renaissance Zone would place much of the existing infrastructure below various structures. To account for this, and to serve the projected loads, the Minor Lane Heights system must be altered and reinforced.

XIII. Minor Lane Heights Renaissance Zone (cont'd)

Recommended Gas System Reinforcements

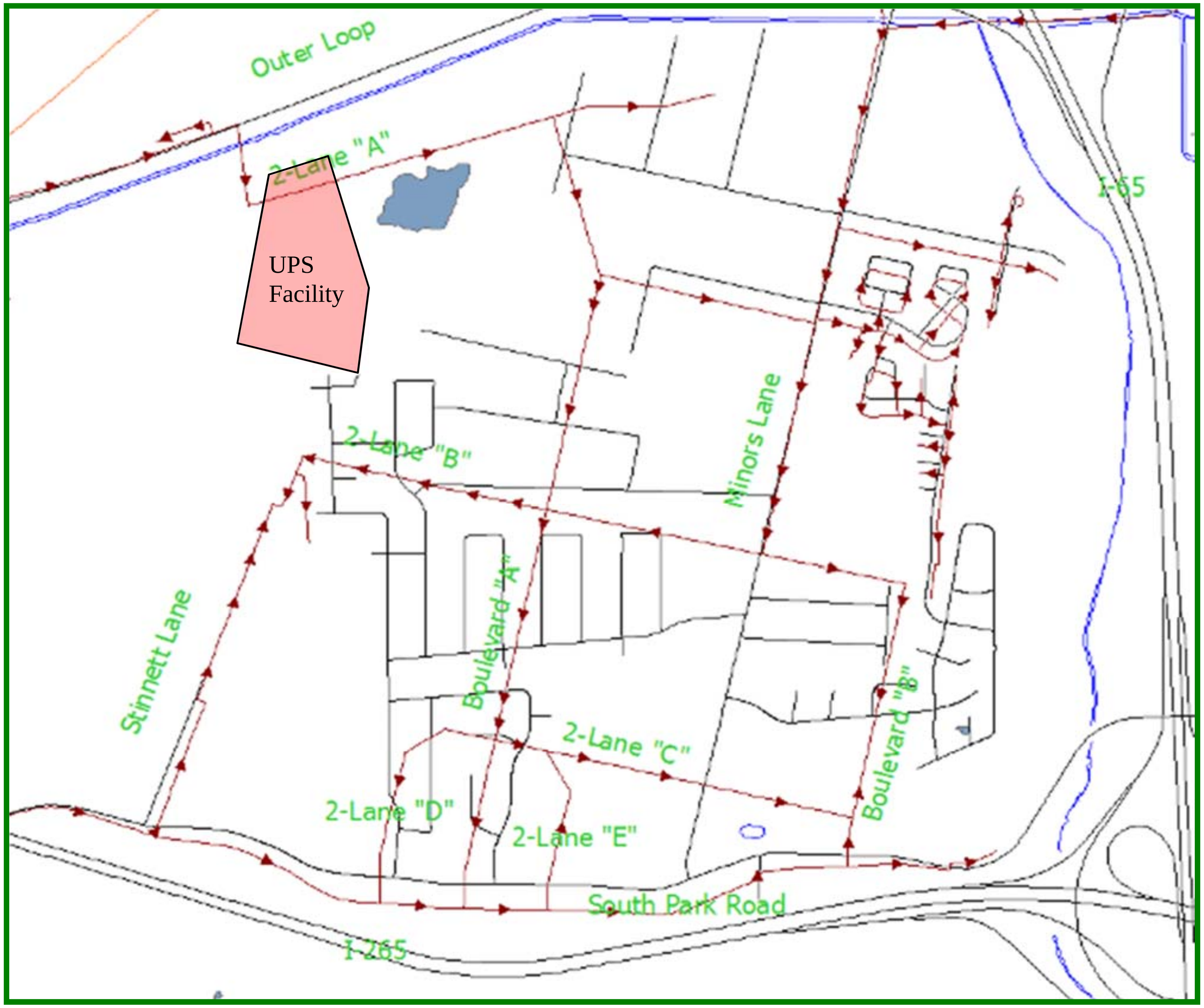
Reinforcement 1
Install and remove gas mains according to "An Analysis of the Minors Lane Heights Renaissance Zone" dated 15 January 2007 or the latest version.

- Retire existing pipelines in the area.
- Install approximately 1,200 feet of 2-inch pipe
- Install approximately 15,400 feet of 4-inch pipe
- Install approximately 5,600 feet of 8-inch pipe

Minimum Gas System Pressure (-12°F)
- UPS Supply Chain Solutions Warehouse (2220 Outer Loop) **– 32.3 psig**

Regulator Operating Capacities
- Preston City Gate Station MP **– 53.1%**
- Outer Loop and Grade Ln **– 41.5%**

Minor Lane Heights Renaissance Zone – Map of Proposed Streets and Reinforcement 1



XIV. Mount Washington Medium Pressure System

Gas System Overview
The Mount Washington medium pressure gas system serves the City of Mount Washington and surrounding areas. This system is composed of residential and commercial customers. It continues to experience growth in the residential and commercial sectors, especially along Highway 44.

Regulator Facilities
The two regulator facilities that supply gas to the Mount Washington medium pressure system are as follows:

- Regulator station located at Sunnyside Drive and Highway 44 (Mt. Washington MP)
- Regulator assembly located at Landis Lane and Bardstown Road

Maximum Allowable Operating Pressure (MAOP)
The Mount Washington medium pressure gas system has a maximum allowable operating pressure of 60 psig and is set at 55 psig.

Model Results

Minimum Gas System Pressure (-12 ^{0}F):
The predicted minimum pressure is located on **Pin Oak Drive (22.7 psig).**
Regulator Operating Capacities (-12 ^{0}F):
- Mt. Washington MP – **11.8%**
- Bardstown Rd and Landis Ln – **28.2%**

Gas System Constraints
Gas system constraints in this area are primarily due to an infrastructure of 4-inch diameter pipe along Highway 44. Due to current and anticipated growth, it will be necessary to perform gas system reinforcement work.

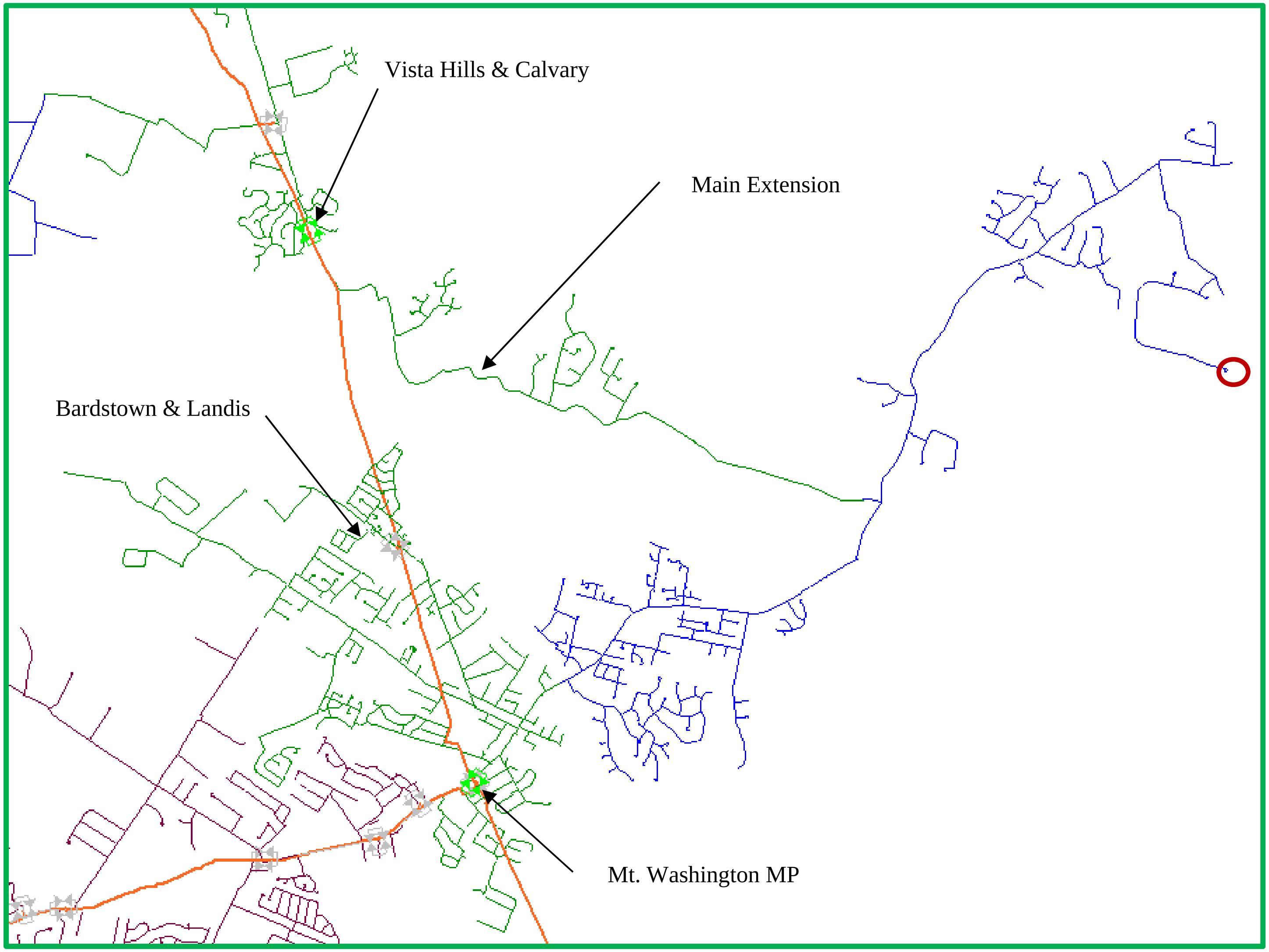
Recommended Gas System Reinforcements

Reinforcement 1
Install approximately 5,900 feet of 6-inch medium pressure pipeline from Oakland Hills Trail to tie into the existing 4-inch medium pressure pipeline on Waterford Road.

Minimum Gas System Pressure (-12 ^{0}F)
- Pin Oak Dr – **45.3 psig**

Regulator Operating Capacities (-12 ^{0}F):
- Mt. Washington MP – **9.7%**
- Bardstown Rd and Landis Ln – **26.0%**
- Vista Hills Blvd and Calvary Line – **100%**

Mount Washington Medium Pressure System – Reinforcement 1



XV. Preston High Pressure Distribution Pipeline Reinforcement

Gas System Overview
The Preston high pressure distribution gas system serves the cities of Shepherdsville, Maryville Okolona and outlying areas. The gas supply originates from the Preston City Gate Station to the Preston High Pressure Station and gas pipeline running south. This system is a one-way feed into the Okolona and Maryville areas. These areas have continued to experience growth in the residential and commercial sectors.

Maximum Allowable Operating Pressure
The Preston high pressure system consists of an 8-inch pipeline operating at a maximum allowable pressure of 110 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure for this high pressure system is located at the inlet to the **Preston and Antle regulator pit (51.3 psig)**

Regulator Operating Capacities
- Preston City Gate Station **– 28.6%**

Gas System Constraints
Gas system constraints in this area are primarily due to the one-way feed of high pressure gas feeding the distribution systems and the lack of pipe further south along Preston Highway. Due to current and anticipated growth, it will be necessary to perform gas system reinforcement work.

Recommended Gas System Reinforcements

Reinforcement 1
The State Highway Department plans on completing a corridor alignment along Cooper Chapel Road, in the City of Okolona.

- Install approximately 37,490 feet of 12-inch high pressure gas pipeline from the Calvary line at Old Bardstown & Thixton to the Preston high pressure line.
- Install a new regulator facility (4x3 Mooney assemblies with 100% plates) at Preston Highway and Cooper Chapel Road to reduce the pressure from the Calvary Line to 110 psig.

Minimum Gas System Pressure (-12°F)
- Preston and Antle inlet **– 87.5 psig**

Regulator Operating Capacities
- New facility at Cooper Chapel and Preston Highway **– 61.3%**

XV. Preston High Pressure Distribution Pipeline Reinforcement (cont'd)

Eventually, the pipeline would be extended further south along Preston Highway and this would allow a second feed for the high pressure system (see Section XIX). Without the second feed, if the Preston high pressure pipeline was damaged, the areas of Okolona and Maryville and a portion of Shepherdsville would be lost.

Reinforcement 2

- Extend the 8-inch steel high-pressure main south along Preston Highway from Mud Lane to Bells Mill Road (approx. 20,000 feet).
- Install a medium pressure regulator facility at Bells Mill Road and Preston Highway (4x3 Mooney with 100% plates) to be tied into the 8-inch medium pressure main on Preston Highway or Bells Mill Road.

Minimum Gas System Pressure (-12°F)

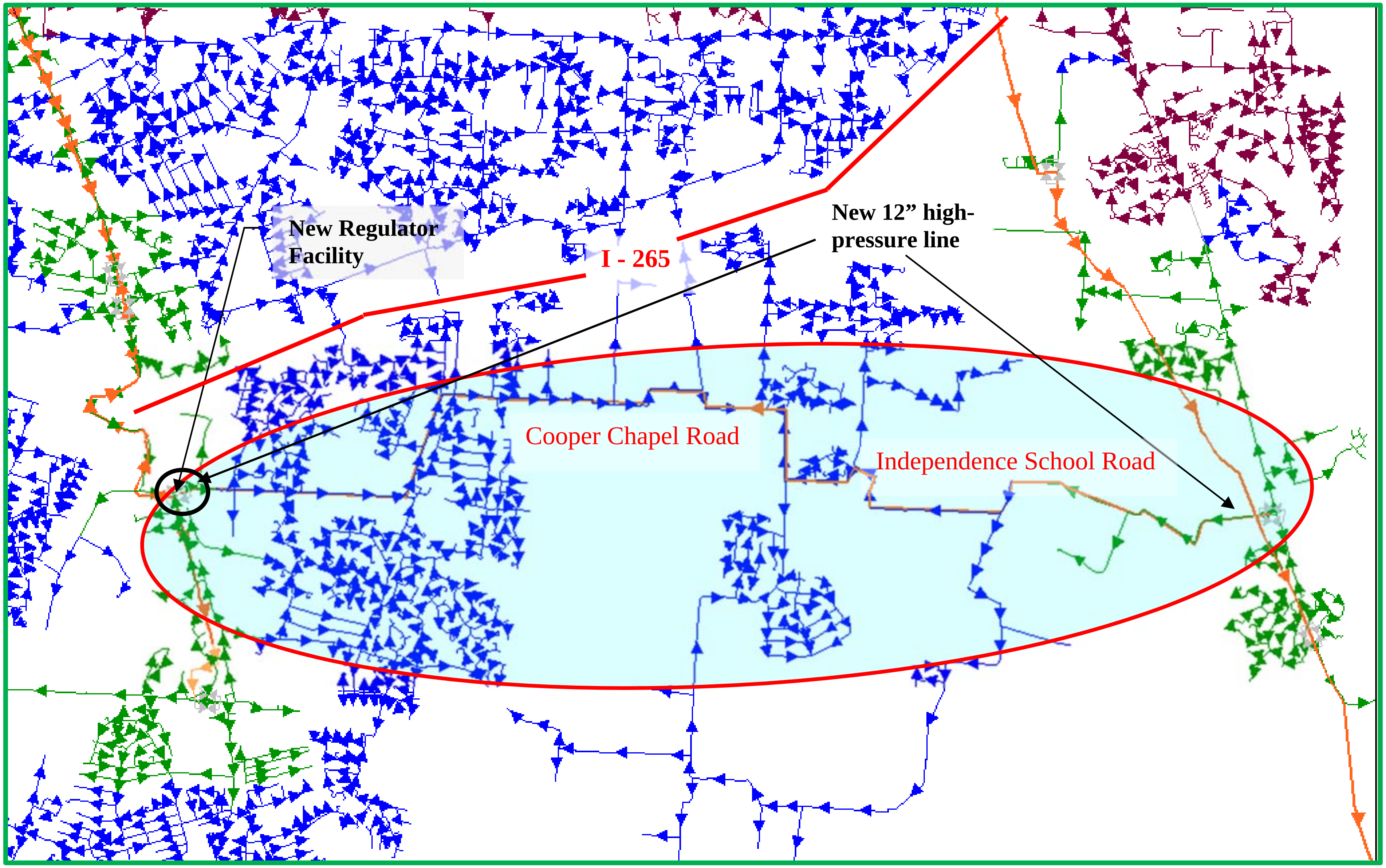
- Inlet to new Facility at Preston & Bells Mill **– 70.1 psig**

Regulator Operating Capacities

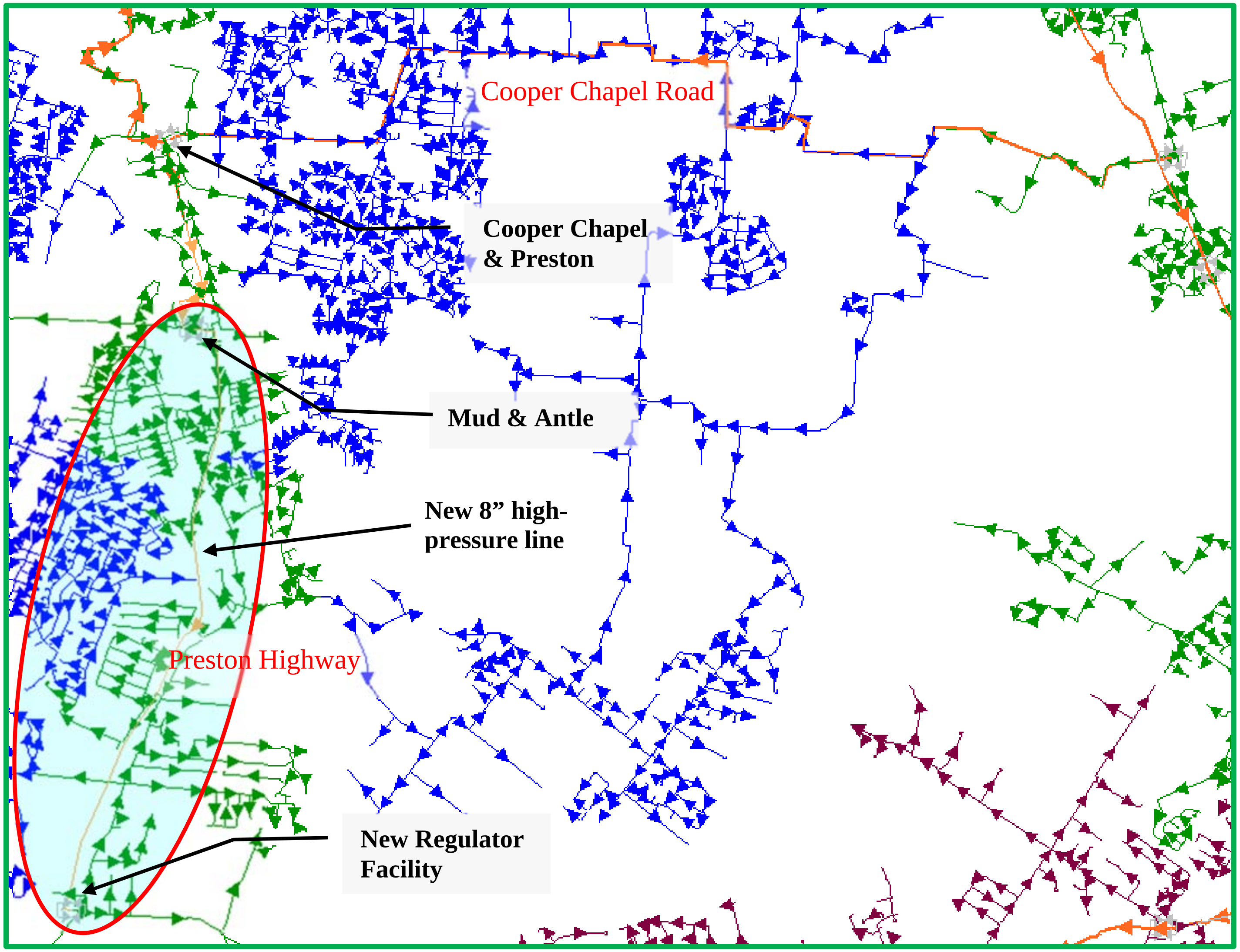
- Cooper Chapel and Preston **– 70.6%**
- Mud and Antle **– 28.6%**
- Preston and Bells Mill **– 51.5%**

Note: The current pressure on the Preston HP line prohibits a significant pressure differential across the new regulator assembly. The results shown are after Reinforcement 1 has been completed. Operating the Preston HP line at its 140 psig MAOP significantly improves the inlet pressure (110 psig) to the new assembly.

Preston Highway High Pressure Pipeline – Reinforcement 1



Preston Highway High Pressure Pipeline – Reinforcement 2



XVI. Mt. Washington/Lebanon Junction High Pressure Distribution System

Gas System Overview
The Mount Washington/Lebanon Junction system is a one-way feed high pressure distribution system that receives its gas supply from LG&E's Calvary gas transmission pipeline in the Mount Washington area. The high pressure system consists of 8-inch and 6-inch pipe.

There are five major existing gas loads associated with this high pressure system. They are as follows:

- City of Shepherdsville
- City of Lebanon Junction
- Jim Beam Boston Plant
- Jim Beam Clermont Plant
- Publishers Printing

There are five major new gas loads associated with this high pressure system. They are as follows:

- Heritage Hills subdivision
- Gordon Foods
- Shepherdsville Industrial Park
- Highway 480 Industrial Park
- Salt River Business Park

The following points can be summarized from the gas system planning analyses:

- The Mount Washington high pressure gas distribution system must operate at 275 psig in order to operate the Shepherdsville gas distribution system at 60 psig on a design day (-12 ^{0}F).
- Due to the reduction in the contract from Tennessee Gas at Calvary in 2012, the Mount Washington high pressure facility is drooping with an inlet pressure of 261 psig
- LG&E can meet the gas service requirements for Publishers Printing and Jim Beam Boston on a design day (-12 ^{0}F) with the existing loads for 2013 and the Mount Washington high pressure system operating at 275 psig.
- LG&E cannot meet the gas service requirements for Publishers Printing and Jim Beam Boston on a design day (-12 ^{0}F) with the proposed gas loads and the Mount Washington high pressure system operating at 275 psig.
- Approximately 45 MCFH of gas load can be added to the 6-inch high pressure pipeline near Clermont while maintaining approximately 55 psig at Boston, Kentucky with the proposed total connected gas loads and the Mount Washington high pressure system operating at 275 psig.
- LG&E can meet gas load projections until 2016 with a 2% residential and commercial load growth projection and the Shepherdsville gas distribution system

uprated to 60 psig. A pipeline reinforcement project will need to be completed by November 1, 2016.

- LG&E can meet gas load projections until 2012 with a 4% residential and commercial load growth projection and the Shepherdsville gas distribution system uprated to 60 psig. A pipeline reinforcement project will need to be completed by November 1, 2012.

XVII. Mt. Washington/Lebanon Junction High Pressure Distribution System (cont'd)

- LG&E can meet gas load projections until 2011 with a 5% residential and commercial load growth projection and the Shepherdsville gas distribution system uprated to 60 psig. A pipeline reinforcement project will need to be completed by November 1, 2011.

Recommended Gas System Reinforcements

Reinforcement 1
Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line in Bardstown, KY, along Hwy 245 to Clermont, serving south to Lebanon Junction. This would require installing approximately 14.0 miles of 8-inch high-pressure (400 MAOP) piping and a new regulator facility near the Jim Beam Clermont Distillery on Hwy 245. This system reinforcement would solve current and future pressure problems as well as eliminating other risk factors by adding an additional gas supply to a dead end system.

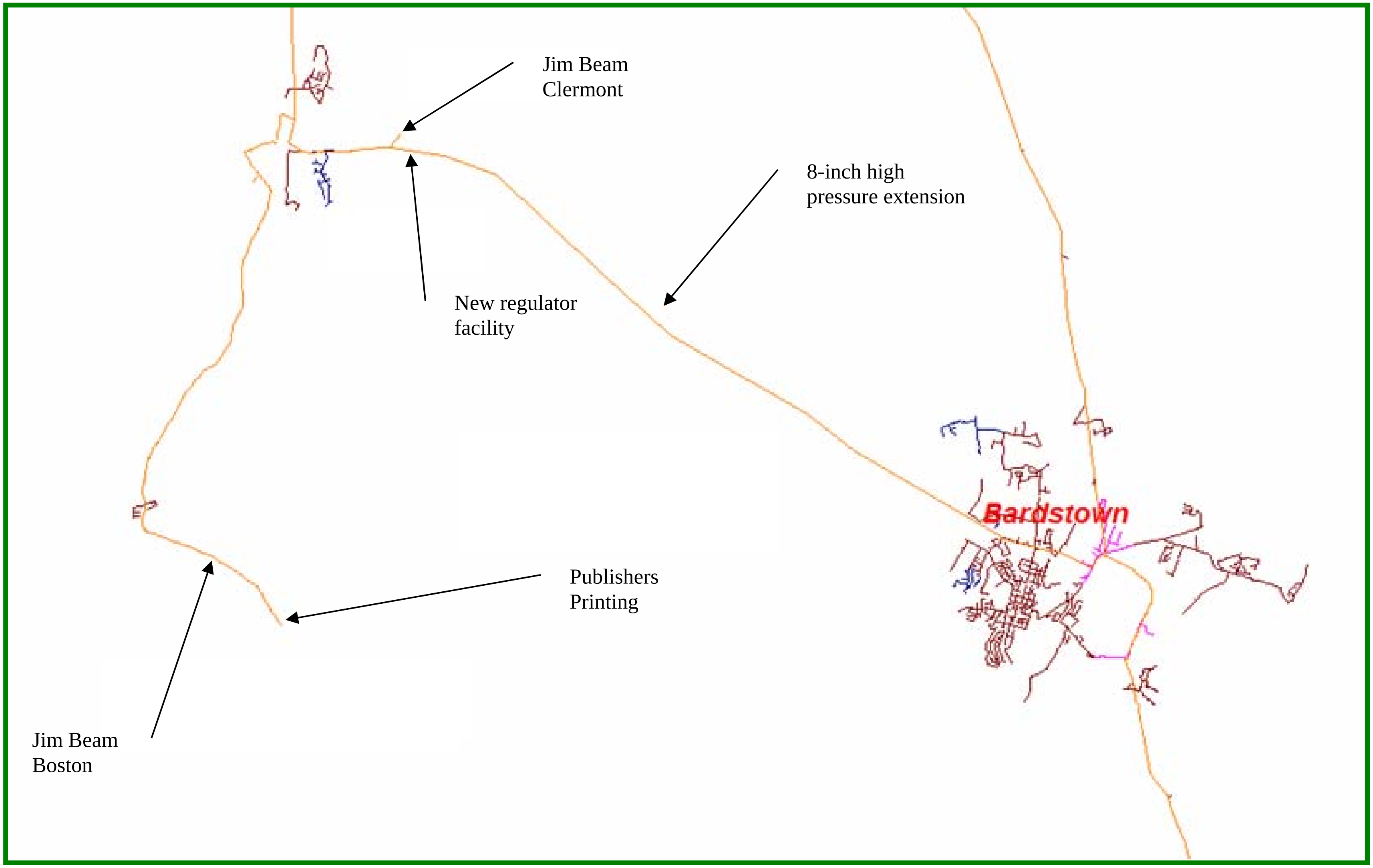
Based on the projected load growth resulting from the two new business parks in the Shepherdsville area, Heritage Hills subdivision, Jim Beam in Boston, and Publishers Printing in Lebanon Junction, along with projected 4% growth from existing residential and commercial customer base a new pipeline is projected to be required in 2012.

Recommended Timeline – 2016

Note: For further information regarding proposed reinforcements to this system, see Section XXII.

THIS IS NOT AN OPTION AT CALVARY'S CURRENT CONTRACT AMOUNT.

Mt. Washington High Pressure Distribution System – Reinforcement 1



XVII. Brandenburg High Pressure System

Gas System Overview

The Brandenburg high-pressure distribution system serves the cities of Brandenburg and Doe Valley, and the surrounding area. Gas is supplied from Doe Run storage field lines at Riggs Junction. The Brandenburg area continues to experience residential and commercial growth.

Note: The pipeline in this system may be in poor condition. Field data collected during the 2002/2003 heating season indicated pressure loss higher than predicted from the system model. This may be due to water intrusion and iron sulfide in the pipeline. Further data should be collected to monitor the condition of this pipeline.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum pressure is at the inlet of the regulator pit serving the Brandenburg medium-pressure system located at **Old US 60 and Highway 933 (133.0 psig)**.

Area Reinforcements

The Brandenburg high-pressure distribution system is comprised of 4.3 miles of 4-inch pipeline that would need to be reinforced or replaced to support future growth. It is recommended to either loop the 4.3 miles of 4 inch high pressure pipe or replace it with 8-inch pipe.

XVIII. Radcliff/Fort Knox Medium Pressure System

Gas System Overview
The Radcliff/Fort Knox medium pressure system serves approximately 4,600 residential and small commercial customers. Currently only two customers on the system require delivery pressure above 2 psig: Cardinal Health at 2 psig and Tri-County Ford at 2.5 psig. Due to Base Realignment and Closure (BRAC) changes at Fort Knox, it is anticipated that approximately 3,500 military employees will be relocating to the Radcliff/ Fort Knox area over the next 8 years.

Regulator Facilities
The regulator facilities that feed this system are as follows:

- Radcliff #1 at the corner of N Dixie Blvd and Northern Rd.
- Radcliff #2 at the intersection of S Logsdon Parkway and W Vine Street.

Maximum Allowable Operating Pressure
The Radcliff/Fort Knox medium pressure system has a maximum allowable operating pressure of 35 psig.

Model Results

Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure is located at **480 Berkley Ct (32.8 psig) a**nd **569 St. Andrews Dr (33.0 psig)**

Regulator Operating Capacity (includes asphalt plant load):
- Radcliff #1: 23.1%
- Radcliff #2: 47.5%

Gas System Constraints
The two gas supply points for this system are located centrally and on the northeastern end of the system. Rapid system expansion due to BRAC relocations is expected to tax the existing infrastructure. Any significant load increase off St. Andrews Dr will require significant reinforcement.

XVIII. Radcliff/Fort Knox Medium Pressure System (cont'd)

Recommended Gas System Reinforcement

Reinforcement 1

- Replace existing regulators in Radcliff #2 with 2" Mooney assemblies with 100% plates.
- Uprate the system from 35 psig to 55 psig.

Note: Additional BRAC load was estimated to be 240 MCFH based on anticipated number of new residences and current load. This load was proportionately distributed throughout the system.

Minimum gas system pressure (-12°F)

- 480 Berkley Ct **(50.2 psig)**
- 568 St. Andrews Rd (**50.7 psig**)

Regulator Operating Capacities

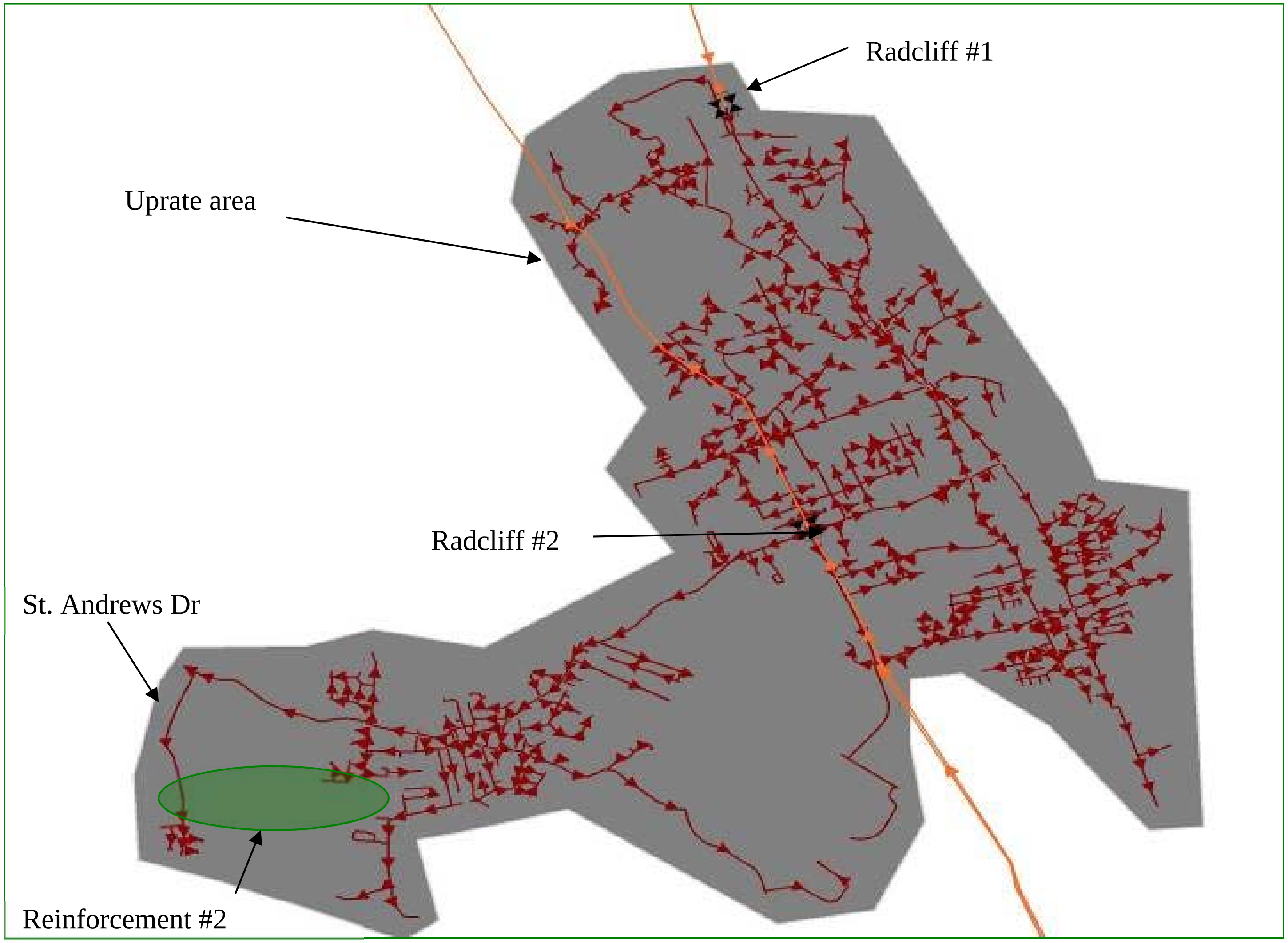
- Radcliff #1 – 47.8%
- Radcliff #2 – 43.6%

Reinforcement 2

- Install 4,800' of 4-inch PL main in Otter Creek Rd from existing 4-inch CT to 2-inch PL in St. Andrews Dr.

Note: Reinforcement needed only for significant development off St. Andrews Drive.

Radcliff/Fort Knox – Reinforcements



XIX. Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System

Gas System Overview
The Crestwood/Pee Wee Valley/Simpsonville medium-pressure system will require reinforcement to continue to serve the Norton Commons development and the Old Brownsboro Crossing commercial park, which includes a professional medical center, office buildings, and retail/restaurants. This system also feeds near Persimmon Ridge and the Polo Fields. It has experienced growth away from the only sources of gas in this system. In order to serve current and future loads, it has been determined that reinforcement work will need to be performed on the Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System. There are a few options available that will provide adequate pressures throughout the system.

Maximum Allowable Operating Pressure
The Crestwood/Pee Wee Valley/Simpsonville medium pressure system has a maximum allowable operating pressure of 45 psig.

Model Results

Minimum gas system pressure (-12 ^{0}F)
- 1400 Rutland Club Ct – **22.3 psig**
- 18521 Bridgemore– **24.3 psig**
- 10523 Championship Court- **31.4 psig**

Regulator Operating Capacities
- Hwy 1694 & Worthington – 14.6%
- Old Henry & Terra Crossing – 47.1%
- Conner Station & Colt Run – 6.0%
- Crestwood & Old LaGrange – 30.4%
- Lakeshore Drive & Old Veechdale – 40.6%
- English Station Way – 46.5%
- Westport Road & Murphy Lane – 76.8%
- Old LaGrange Road & Collins Lane G-578 – 14.3%

XIX. Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System (cont'd)

Reinforcement Option 1
Extend the 8" high pressure gas main on Aiken Road and install a facility at Aiken Road and Flat Rock Road

- Install approximately 3 miles of 8-inch steel high pressure main along Aiken Road from the existing 8-inch on Old Henry Road to Flat Rock Road.
- Install a 4x3 Mooney assembly (35%) at Aiken and Flat Rock to feed the medium pressure system.

Minimum gas system pressure (-12 ^{0}F)
- 1400 Rutland Club Ct – **36.6 psig**
- 18521 Bridgemore– **34.5 psig**
- 10523 Championship Court- **31.4 psig**

Regulator Operating Capacities
- New Facility @ Aiken & Flat Rock- 30.5%

NOTE: This would require crossing Floyd's Fork

Reinforcement Option 2a
Extend the 4" high pressure gas main on Abbott Lane and install a facility at Aiken Road and Floydsburg Road.

- Install approximately 3 miles of 4-inch steel high pressure pipe along Aiken Road from the existing 4-inch on Abbott Lane along State Hwy 1818 and Floydsburg Road to Aiken Road.
- Install a 2" Mooney assembly (35%) at Aiken Road and Floydsburg Road to feed the medium pressure system.

Minimum gas system pressure (-12 ^{0}F)
- 1400 Rutland Club Ct – **32.8 psig**
- 18521 Bridgemore– **31.4 psig**
- 10523 Championship Court- **31.4 psig**

Regulator Operating Capacities
- New Facility @ Aiken & Floydsburg- 28.5%

NOTE: This would require crossing Floyd's Fork

XIX. Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System (cont'd)

Reinforcement Option 2b

- Complete Reinforcement 2a.
- Install 1.3 miles of 4-inch plastic medium pressure pipe along Johnson Road and Aiken Road from Crosstimbers Drive to Flat Rock Road.

Minimum gas system pressure (-12 ^{0}F)

- 1400 Rutland Club Ct – **35.5 psig**
- 18521 Bridgemore– **31.4 psig**
- 10523 Championship Court- **31.4 psig**

NOTE: This would require crossing Floyd's Fork

Reinforcement Option 2c

- Complete Reinforcement 2a and 2b.
- Install approximately 1 mile of 6-inch plastic pipe along Flat Rock Road from Curry Branch Road to Long Run Park Road.
- Install approximately 1200 feet of 4-inch plastic pipe along Moser Farm Road beginning at Hitt Lane and ending at the existing 4-inch pipe on Moser Farm Road.

Minimum gas system pressure (-12 ^{0}F)

- 1400 Rutland Club Ct – **35.7 psig**
- 18521 Bridgemore– **34.4 psig**
- 10523 Championship Court- **36.2 psig**

NOTE: This would require crossing Floyd's Fork

Reinforcement Option 3a

- Install approximately 1 mile of 6-inch plastic pipe along Flat Rock Road from Curry Branch Road to Long Run Park Road.
- Install approximately 1200 feet of 4-inch plastic pipe along Moser Farm Road beginning at Hitt Lane and ending at the existing 4-inch pipe on Moser Farm Road.
- Install 1.3 miles of 4-inch plastic medium pressure pipe along Johnson Road and Aiken Road from Crosstimbers Drive to Flat Rock Road.
- Install approximately 3,000 feet of 4-inch pipe along Bridgemore Lane from the existing 2-inch pipe south to connect at Shelbyville Road

XIX. Crestwood/Pee Wee Valley/Simpsonville Medium Pressure System (cont'd)

Minimum gas system pressure (-12 ^{0}F)
- 1400 Rutland Club Ct – **25.4 psig**
- 18521 Bridgemore– **34.8 psig**
- 10523 Championship Court- **36.1 psig**

Reinforcement Option 3b
- Complete Reinforcement 3a
- Install approximately 1.6 miles of 6-inch main along Aiken Road from the existing 6-inch at Arnold Palmer Blvd to Johnson Road.

Minimum gas system pressure (-12 ^{0}F)
- 1400 Rutland Club Ct – **33.9 psig**
- 18521 Bridgemore– **38.4 psig**
- 10523 Championship Court- **36.2 psig**
- 5302 Manor Court- **32.9 psig**

NOTE: This would require crossing Floyd's Fork

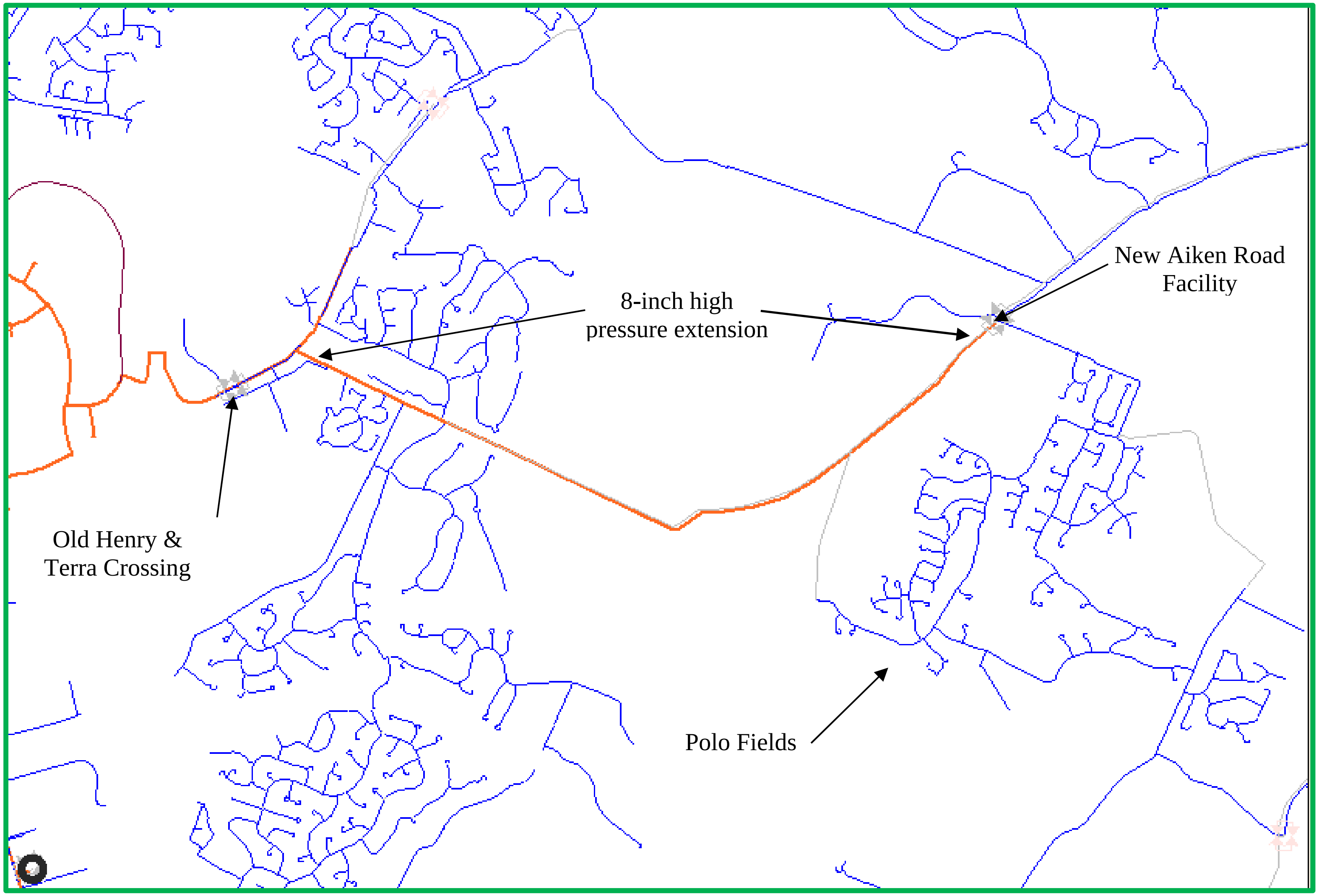
Reinforcement Option 4
As a long term reinforcement, it is recommended to connect the Crestwood high pressure line and the Simpsonville high pressure line to bring a high pressure feed into the Polo Fields are for future development.

- Install approximately 10.6 miles of 4-inch high pressure main from the existing 6-inch on Abbott Lane (Crestwood line) to the existing 8-inch on Colt Run Road via Long Run Road and Shelbyville Road.
- Install a 2" Mooney assembly (35%) at the intersection of Abbot Lane and Flat Rock Road to reduce the pressure from the Crestwood line to 180 psig.
- Install a 2" Mooney assembly at Long Run Road and Pope Dale Road to feed the 45 psig medium pressure system.

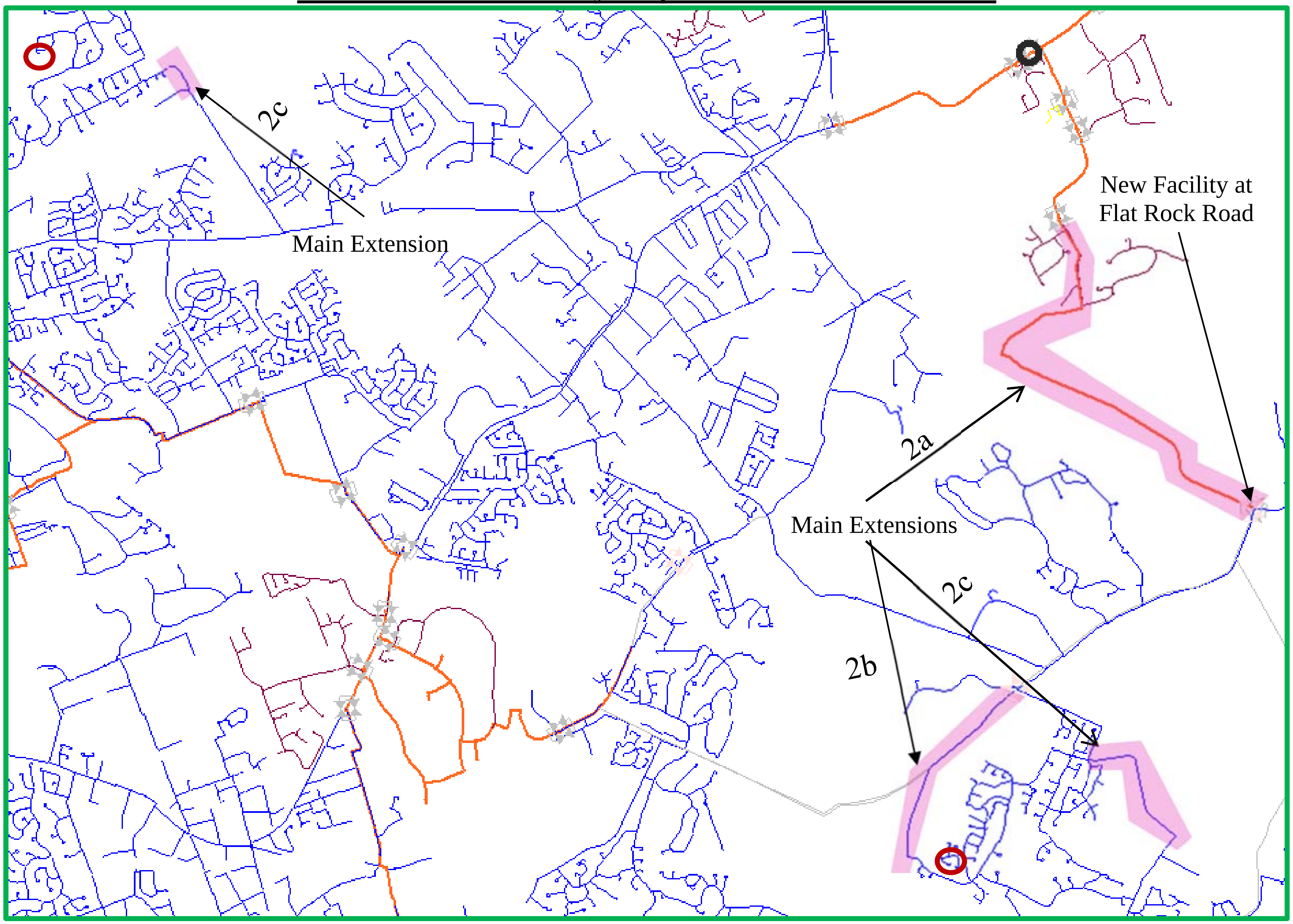
Minimum gas system pressure (-12 ^{0}F)
- 1400 Rutland Club Ct – **30.3 psig**
- 18521 Bridgemore– **43.4 psig**
- 10523 Championship Court- **31.4 psig**
- 5302 Manor Court- **34.2 psig**

NOTE: This would require crossing Floyd's Fork

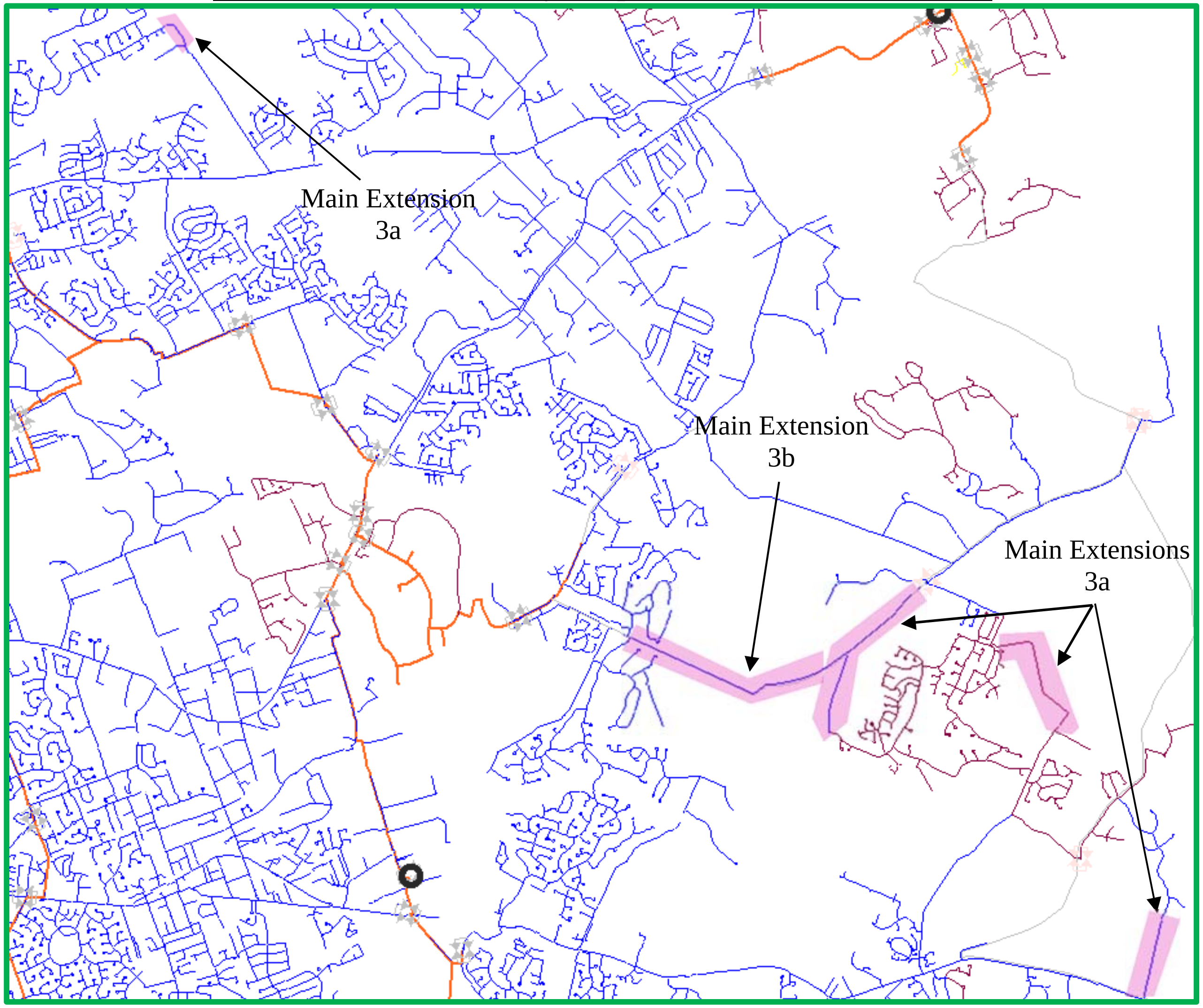
Crestwood/Pee Wee Valley/Simpsonville- Reinforcement 1



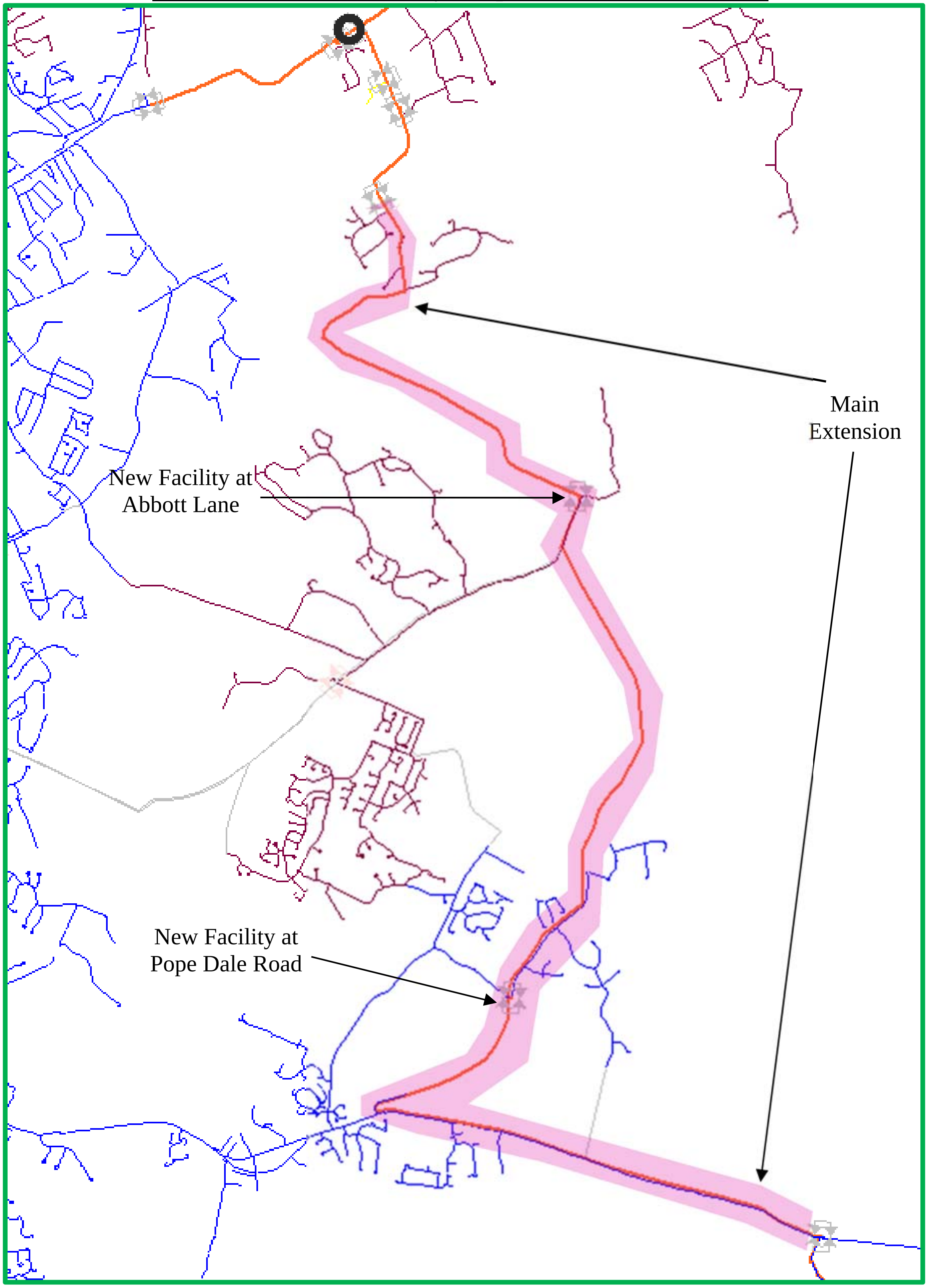
<u>Crestwood/Pee Wee Valley/Simpsonville- Reinforcement 2ab</u>



Crestwood/Pee Wee Valley/Simpsonville- Reinforcement 3ab



<u>Crestwood/Pee Wee Valley/Simpsonville- Reinforcement</u>



XX. Crestwood/Picadilly High Pressure Extension

The Ellingsworth City Gate Station is located on Blankenbaker Parkway just north of Interstate 64 and serves from Cannons Lane Station in Louisville to Simpsonville and Crestwood. The Bardstown City Gate Station is located on Bardstown Road near Watterson Trail and serves the area from the Bardstown Road Station to Bardstown, KY.

Maximum Allowable Operating Pressure
The Ellingsworth system has a maximum allowable operating pressure of 200 psig and is fed by the Ellingsworth and English Station City Gate Stations. The Bardstown system has a maximum allowable operating pressure of 400 psig from Bardstown Road Station to Bardstown, KY.

Gas System Constraints
If either of the gate stations that feed the Eastern Kentucky Line were temporarily turned off (e.g., for maintenance or due to an accident), there would be insufficient pressure to serve the system that is fed by that gate station.

Model Results

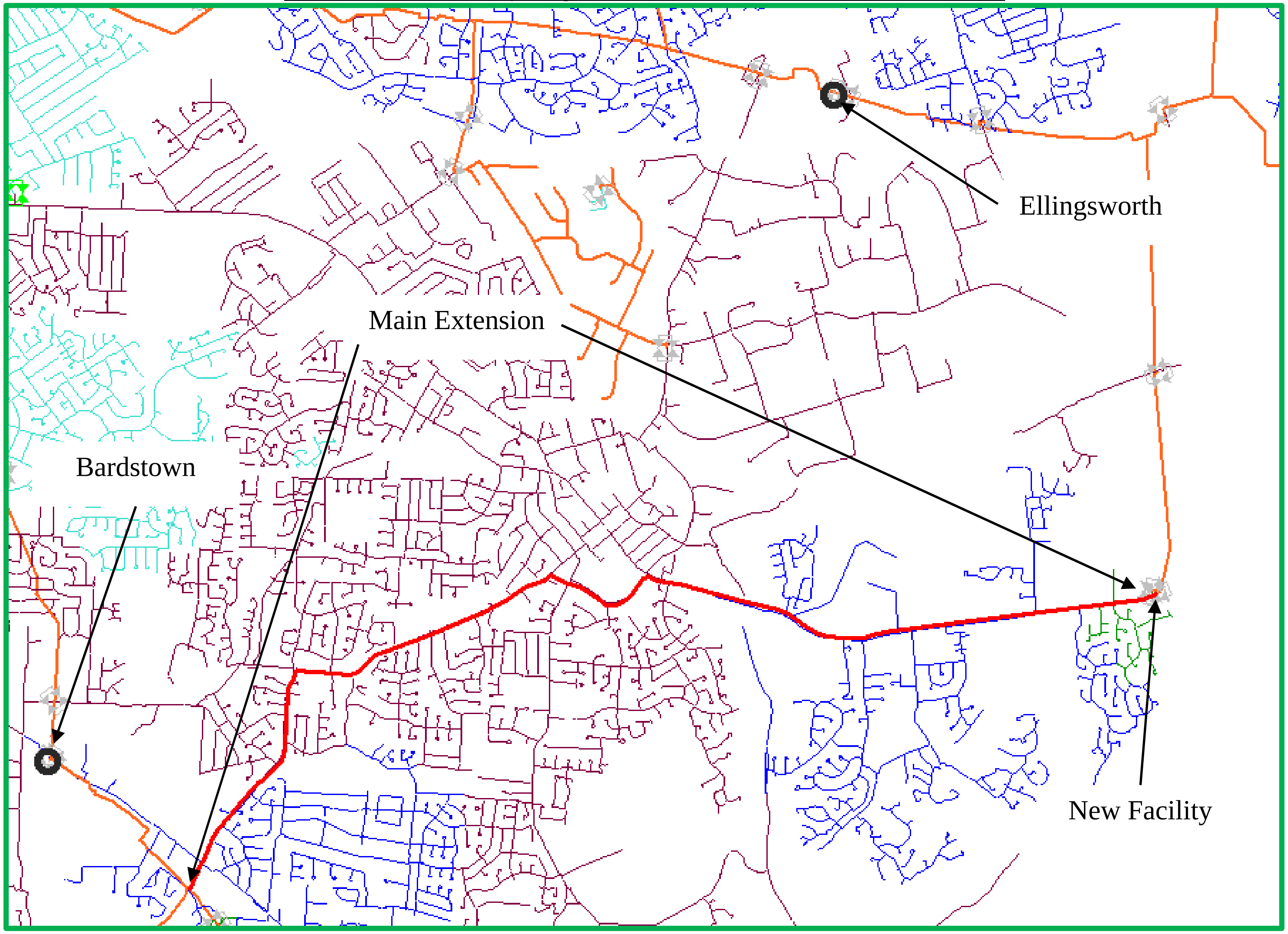
Minimum Gas System Pressure (-12°F)
The predicted minimum gas system pressure on the Ellingsworth system is located at the inlet to the **Watterson Trail & Plantside Drive facility (112.9 psig).**
The predicted minimum gas system pressure on the Bardstown system is located at the inlet to **Mount Washington Station (261.01 psig).**

Regulator Operating Capacities
- Ellingsworth City Gate Station **– 23.8%**
- English Station City Gate Station **– 29.1%**
- Bardstown City Gate Station **– 70.5%**

Recommended Gas System Reinforcements

Attach the Eastern Kentucky Line to the Bardstown Line by installing 6.2 miles of 8-inch high pressure pipe from the Jeffersontown Pit at Taylorsville Road and Interstate 265 to the Picadilly valves at the intersection of S Hurstbourne Parkway and Hames. Install a 2” Mooney assembly at Taylorsville Road and I-265 to reduce the pressure to 180 psig.

Crestwood/Picadilly High Pressure Extension Reinforcement



XXI. Appendix – Mt. Washington High Pressure Distribution System

Options Considered

An attempt was made to parallel the existing 8-inch and 6-inch piping in order to solve the pressure and capacity problems. Almost the entire route (approximately 21 miles) of the system would have to be paralleled in order to correct the pressure and capacity problems.

Scenario 1

Install a high-pressure system reinforcement that would bring high-pressure gas from the Preston Highway regulator station to the Shepherdsville regulator pit at Lees Lane and Highway 44 (approximately 12.5 miles). A new regulator facility with a set pressure of 275 psig would have to be installed from the existing 16 inch HP at Preston City Gate Station. In addition, the existing 6-inch piping (approximately 12 miles) would have to be paralleled in order to alleviate the restriction to moving the gas to the south end of the system.

Scenario 2

Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line in Bardstown, KY, along Hwy 245 to Clermont, serving south to Lebanon Junction. This would require installing approximately 14.0 miles of 8-inch high-pressure (400 psig MAOP) piping and a new regulator facility near the Jim Beam Clermont Distillery on Hwy 245. This system reinforcement would solve current and future pressure problems as well as eliminating other risk factors by adding an additional gas supply to a dead end system.

Scenario 3

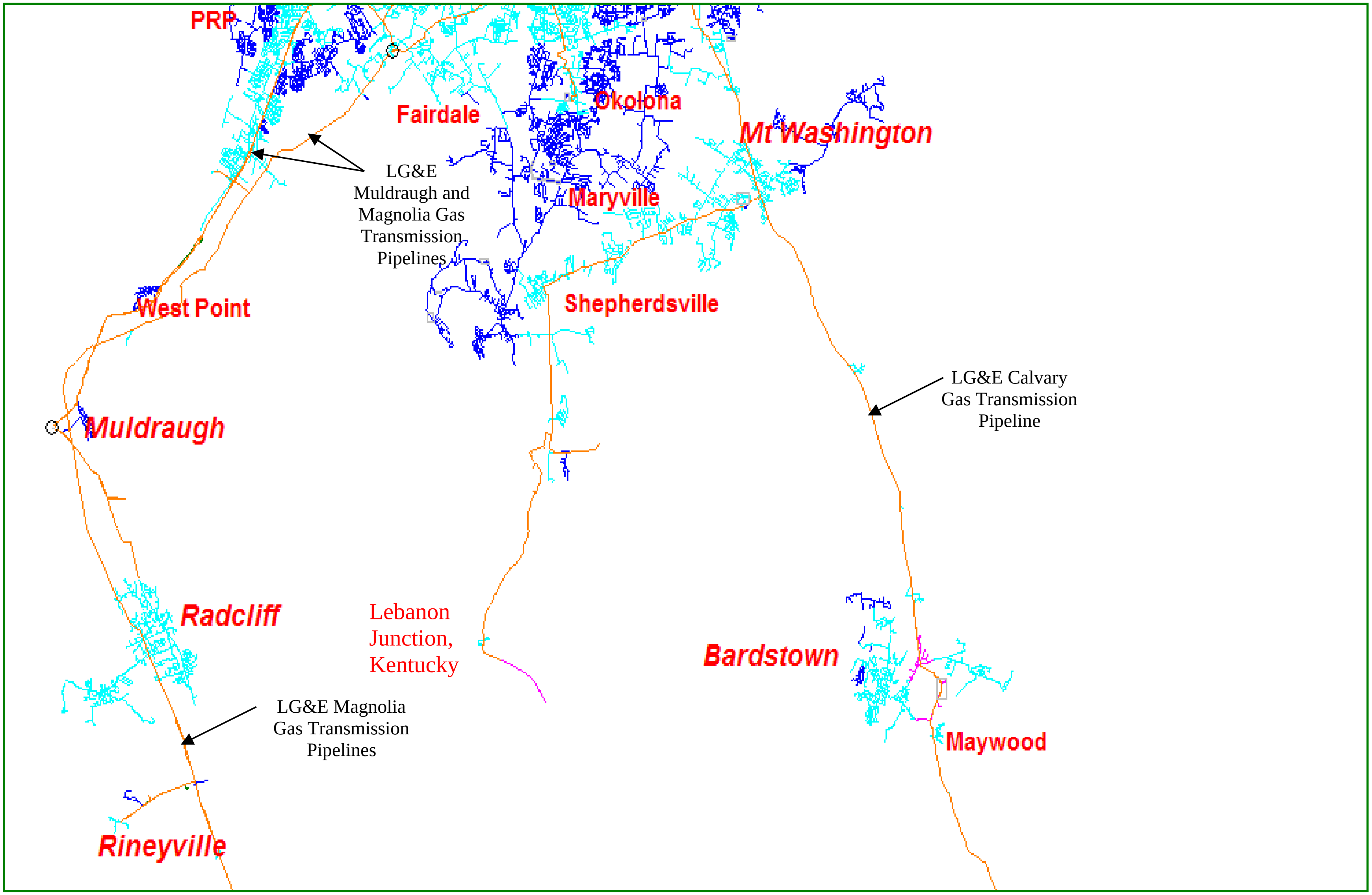
Install a high-pressure system reinforcement that would bring high-pressure gas from the Magnolia line to the south end of the system. This would require installing approximately 13 miles of 8-inch high-pressure (520 psig MAOP) piping along Highway 434 and a new regulator assembly at the south end of the system. This system reinforcement would correct the current and future pressure and capacity problems by providing a new gas supply in the areas where there is the largest load concentration. In addition, the system reinforcement would provide a second gas supply to the model thus eliminating the risks associated with a dead end system.

XXI. Appendix – Mt. Washington High Pressure Distribution System (cont'd)

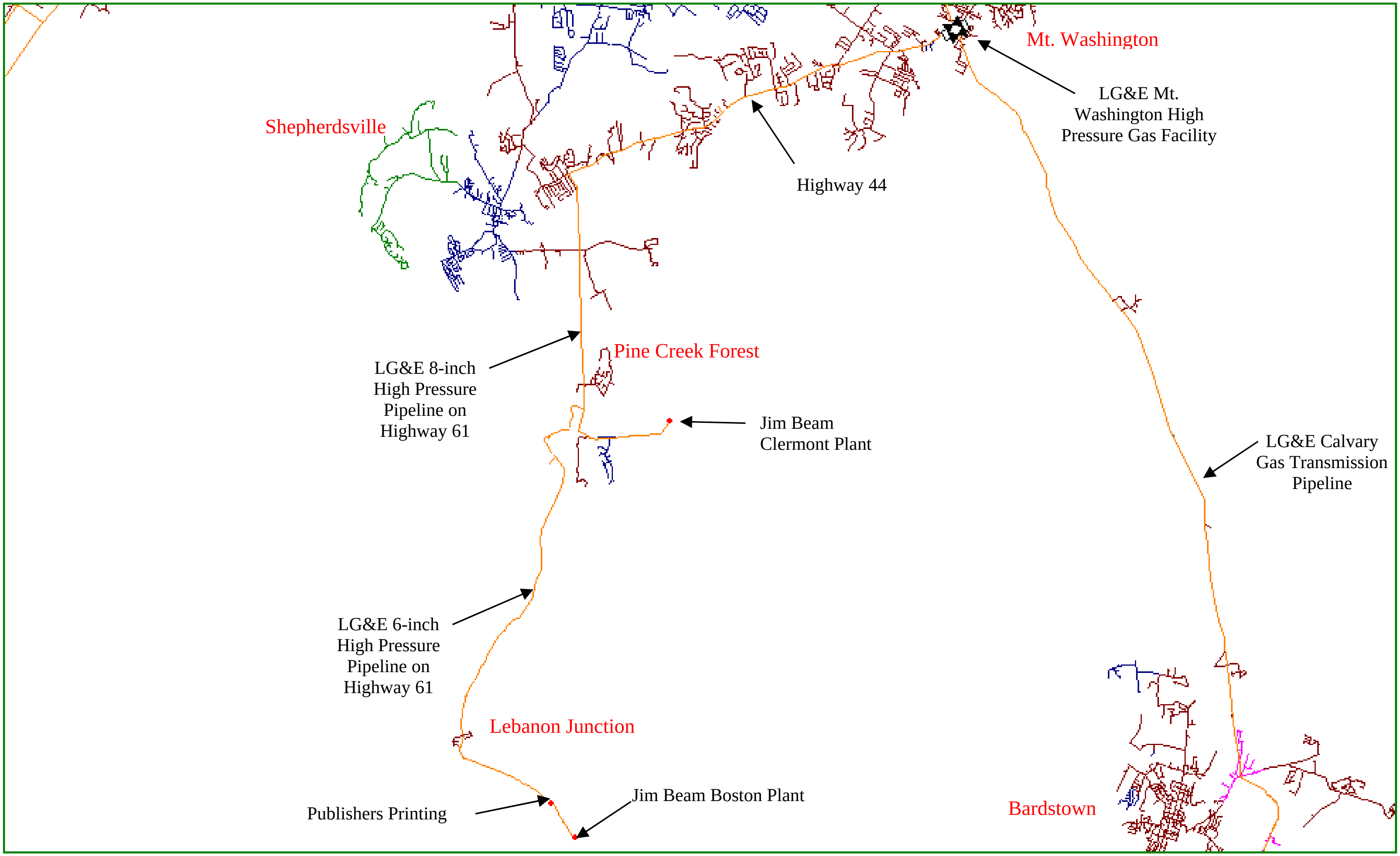
Scenario 4
Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line to the south end of the system. This would require installing approximately 16 miles of 8-inch high-pressure (400 psig MAOP) piping and a new regulator assembly at the south end of the system. This system reinforcement would correct the current and future pressure and capacity problems by providing a new gas supply in the areas where there is the largest load concentration. In addition, the system reinforcement would provide a second gas supply to the model thus eliminating the risks associated with a dead end system.

Scenario 5
Install a high-pressure system reinforcement that would bring high-pressure gas from the Calvary line along Hwy 509 and Hwy 245 into Lebanon Junction. This would require installing approximately 12.5 miles of 8-inch high-pressure (400 psig MAOP) piping and a new regulator facility near the Jim Beam Distillery on Hwy 245. This system reinforcement would solve current and future pressure problems as well as eliminating other risk factors by adding an additional gas supply to a dead end system.

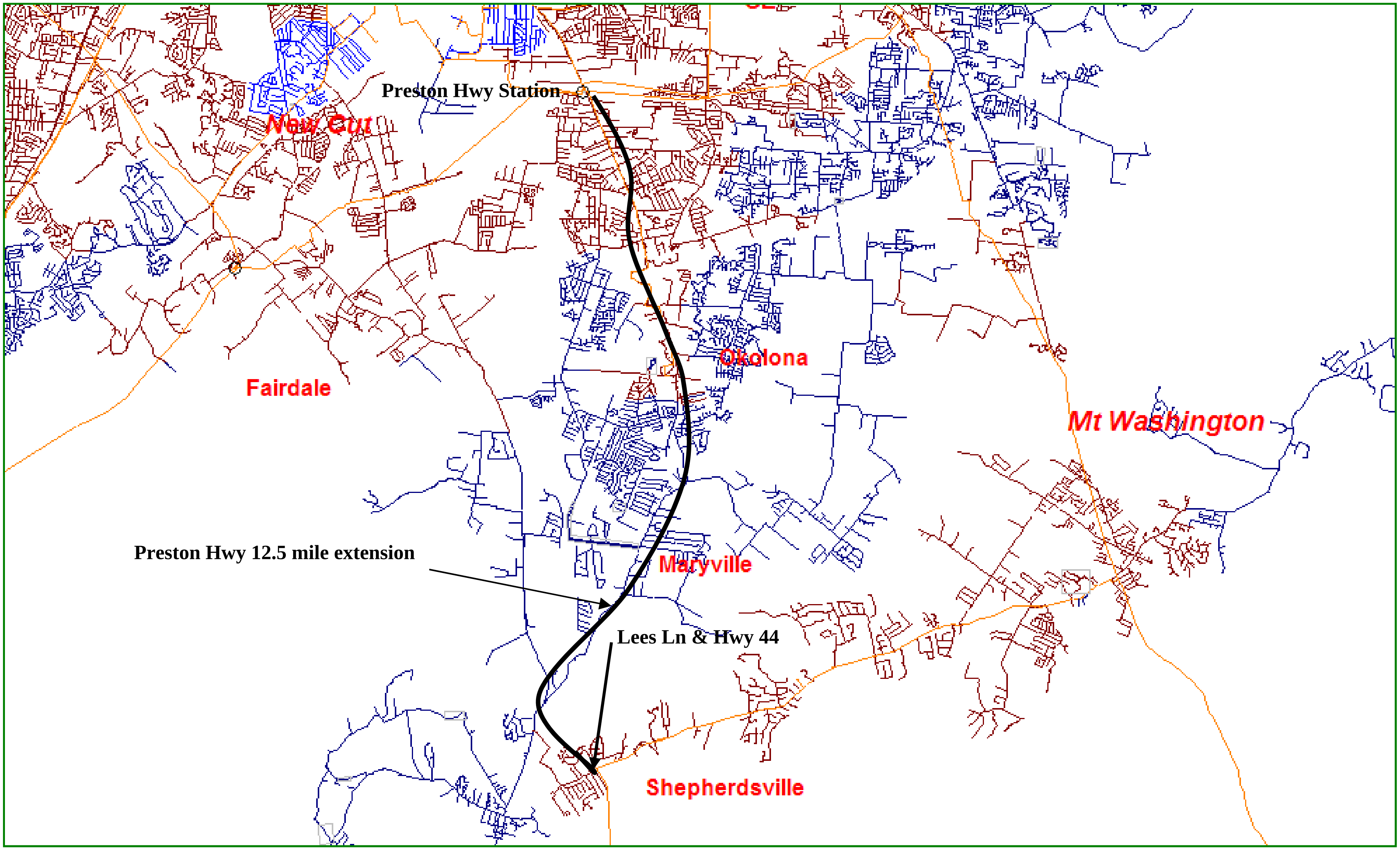
Mt. Washington High Pressure Distribution System – Overview



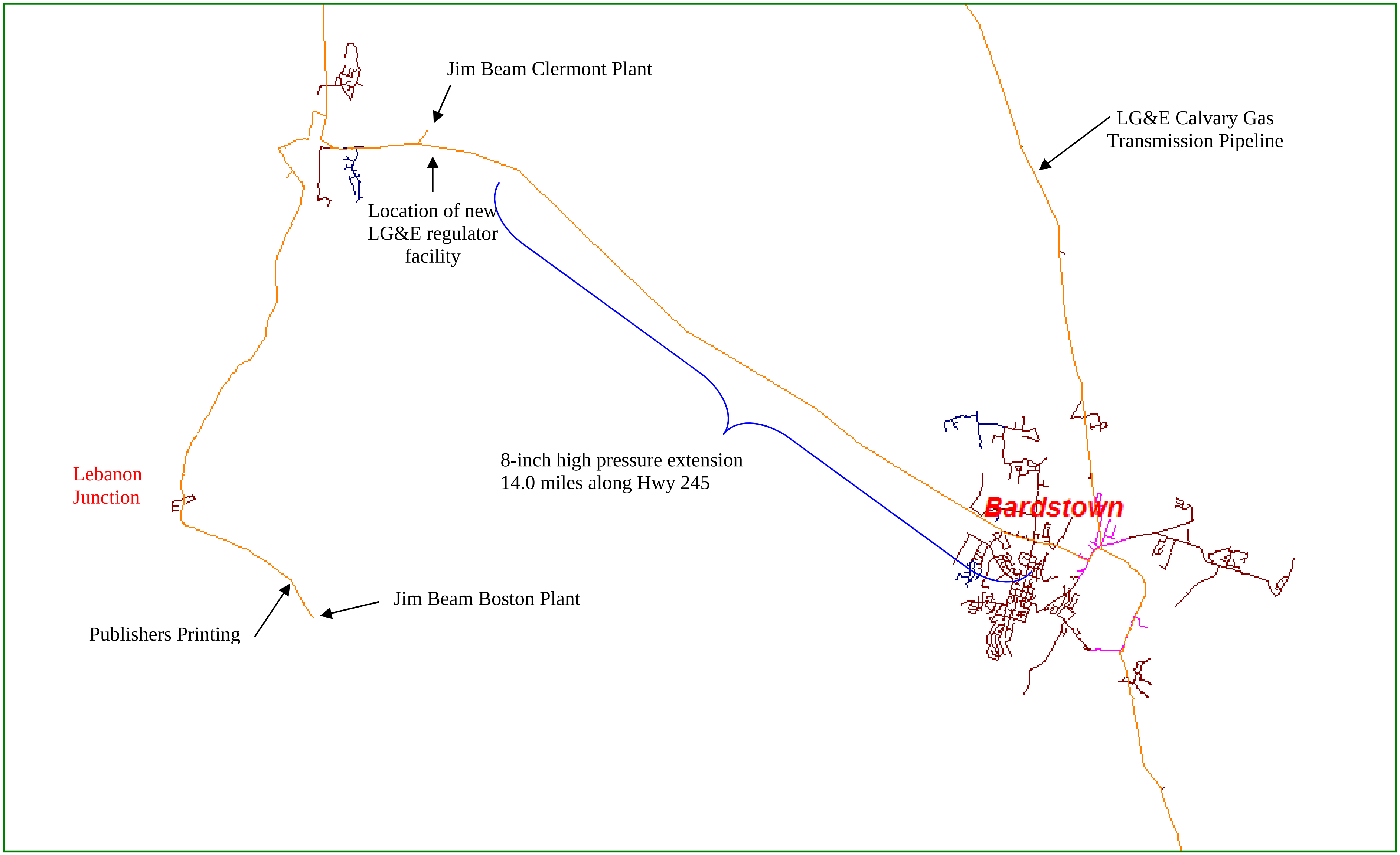
Mt. Washington High Pressure Distribution System – Mt. Washington Overview



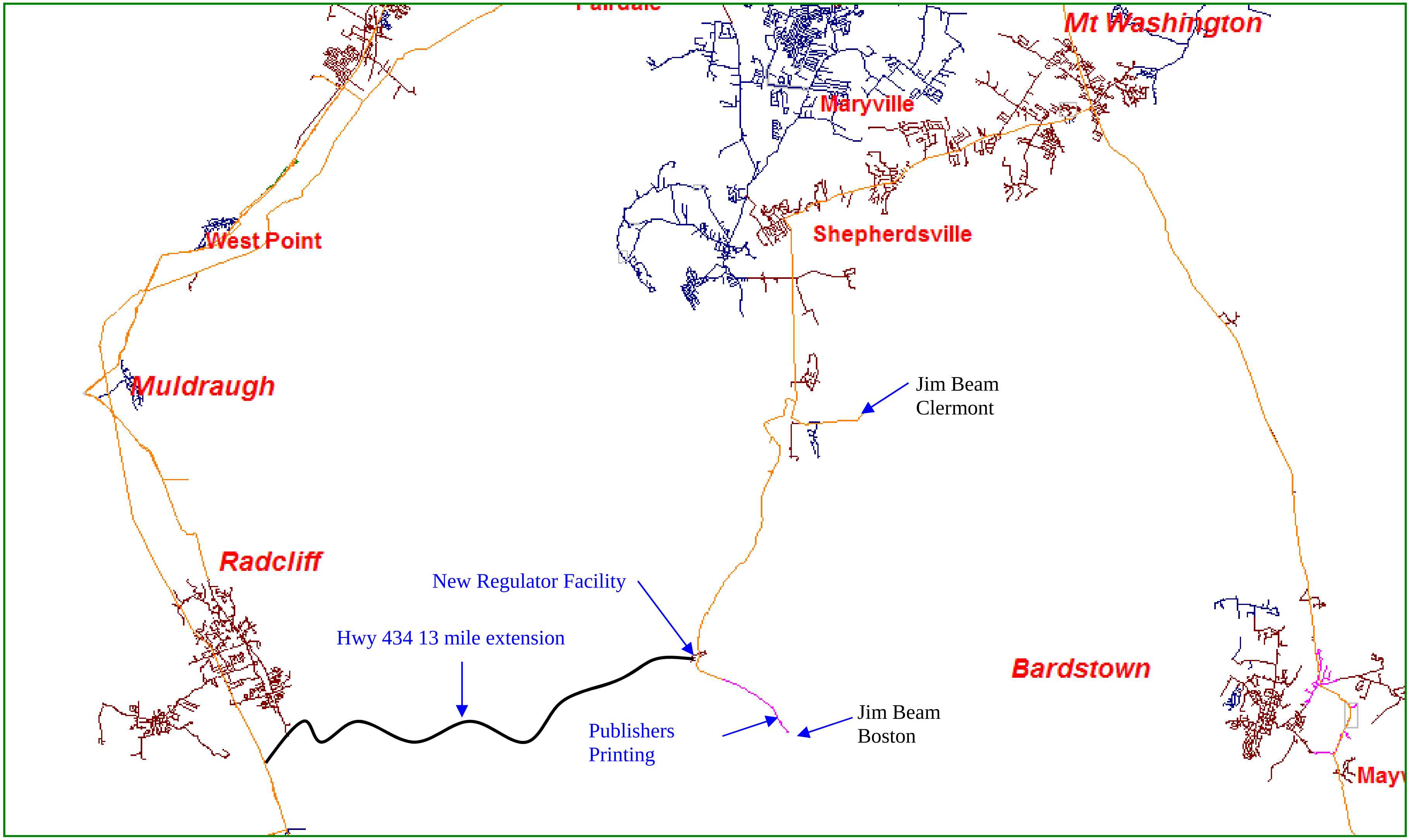
Mt. Washington High Pressure Distribution System – Scenario 1



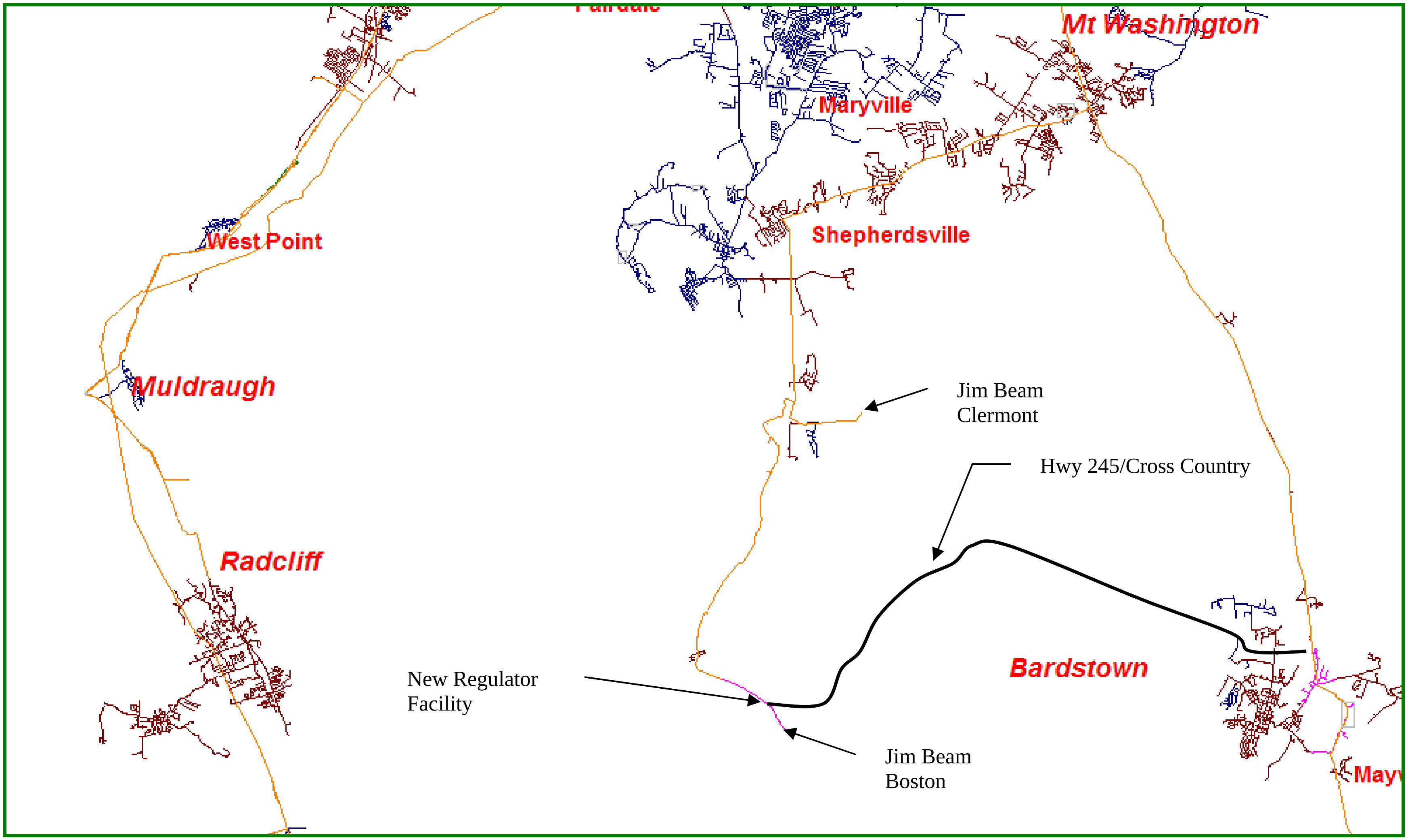
Mt. Washington High Pressure Distribution System – Scenario 2



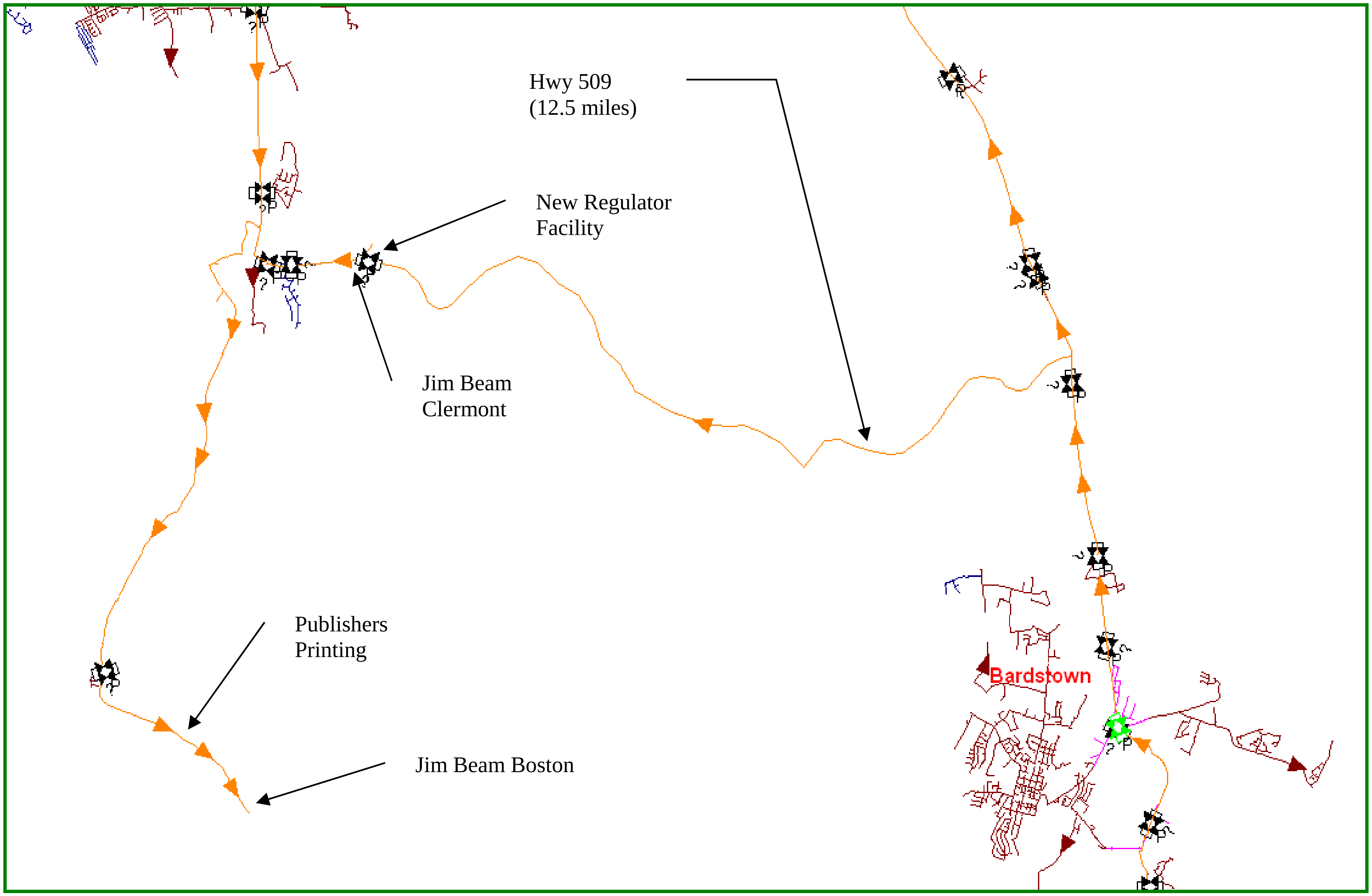
Mount Washington/Lebanon Junction High Pressure Gas System – Scenario 3



Mt. Washington High Pressure Distribution System – Scenario 4



Mt. Washington High Pressure Distribution System – Scenario 5



GAS SYSTEM PLANNING

LONG-TERM CONSTRUCTION PLAN

APRIL 2015

LG&E KU

Louisville Gas & Electric

TABLE OF CONTENTS

I. Crestwood-Eminence-Bedford High Pressure Distribution

The Crestwood-Bedford high-pressure distribution system serves the areas of Crestwood, Smithfield, Campbellsburg and Bedford. The system is supplied by the Bedford and Crestwood city gate stations and serves a small number of large industrial and commercial customers including Safety Kleen, Steel Technologies, Rose Hill Greenhouse, and Hussey Copper. The Elder Park City Gate Station supplies the Ballardsville pipeline from Zorn Avenue city gate in Louisville to Moody Lane station at Highway 53 in Oldham County.

Maximum Allowable Operating Pressure

From Crestwood to Eminence, the Crestwood-Bedford high-pressure system has a maximum allowable operating pressure of 350 psig. From Eminence to Bedford, it has a maximum allowable operating pressure of 380 psig. The Ballardsville pipeline has a maximum allowable operating pressure of 400 psig.

Minimum Gas System Pressure (-12°F)

350 psig	Eminence Station	189.3 psig
380 psig	Pleasureville, KY	182.3 psig
400 psig	Zorn Ave Station	124.6 psig

Regulator Operating Capacities

Crestwood City Gate	20.6%	Bedford City Gate	34.4%
Elder Park City Gate	25.5%		

Gas System Constraints

The Crestwood-Bedford line and Ballardsville Line are dependent upon the successful operation of all three facilities. If any of these three gate stations were temporarily turned off (e.g., for maintenance or due to an accident), there would be insufficient pressure to serve the system that is supplied by that gate station. In addition, the system is primarily composed of 4-inch pipeline, limiting the system's capacity for expansion.

Recommended Gate Station Operating Conditions

- Operate the Elder Park City Gate Station at 300 psig
- Operate the Crestwood City Gate Station at 350 psig
- Operate the Bedford City Gate Station at 300 psig

I. Crestwood-Eminence-Bedford High Pressure Distribution Cont'd

Reinforcement 1

Connect the Ballardsville pipeline to the Crestwood-Bedford pipeline.
- Install 6,000 feet of 8-inch steel gas transmission pipeline on Highway 53 from Moody Lane to Highway 22.

Minimum Gas System Pressure (-12F):
- Eminence Station ....212.7 psig
- Pleasureville, KY ....205.4 psig
- Zorn Ave Station ....124.6 psig

Regulator Operating Capacities:
- Crestwood City Gate 19.2%
- Bedford City Gate 32.2%
- Elder Park City Gate 25.9%

Reinforcement 2

Replace the Eminence high pressure regulator pit with a control valve.
- Installing a control valve at the Eminence station could be used to isolate either side of the Crestwood-Bedford pipeline should a failure occur and/or in case of emergency shutdown of either city gate station.
  - The Eminence medium pressure system will lose pressure.

Minimum Gas System Pressure (-12F):
- Pleasureville, KY ....277 psig

Regulator Operating Capacities:
- Crestwood City Gate 40%
- Bedford City Gate 16%

Reinforcement 3a

Install a new city gate station to supply the LaGrange high pressure system.
- Install a new city gate station near L'Esprit Farms from the Texas Gas Transmission pipeline at the intersection of E Hwy 146 and Lake Jericho in LaGrange.
- Extend 4 miles of 8-inch pipe along E Hwy 146 to the Elder Park/Ballardsville line.
- Install a regulator station to lower the pressure to 100 psig from the new city gate.
- Extend approximately 5.4 miles of high pressure steel pipeline southeast along Hwy 153 (Lake Jericho to connect with Crestwood-Bedford HP line at Smithfield Rd).

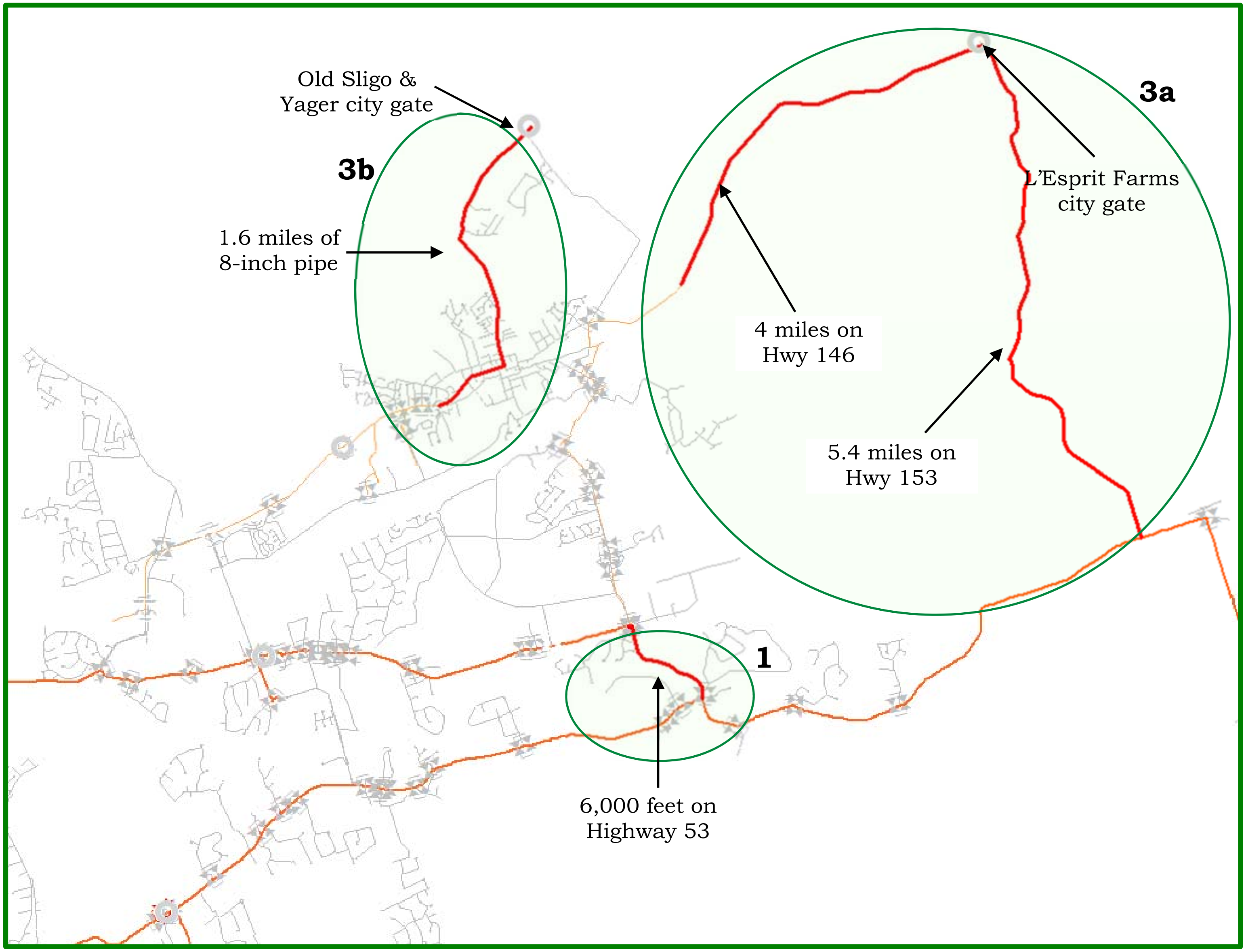
Minimum Gas System Pressure (-12F):
- Eminence Station ....316 psig
- Pleasureville, KY ....310 psig

Regulator Operating Capacities:
- Crestwood City Gate 14%
- Bedford City Gate 33%

Reinforcement 3b

Install a new city gate station to supply the Bedford-Crestwood & Ballardsville lines.
- Install a new city gate station, fed from the Texas Gas Transmission Pipeline, at Old Sligo Rd and Yager Ln. in LaGrange.
- Extend 1.6 miles of 8-inch pipe along Yager Ln, Old Sligo Rd., and 1.4 miles along N Hwy 53 to Jefferson Street, and 4,000 feet along Jefferson Street.
- Install a regulator station on Jefferson Street to lower the pressure to 90 psig from the new city gate station.
- Extend approximately 5.4 miles of high pressure steel pipeline southeast along Hwy 153 (Lake Jericho to connect with Crestwood-Bedford HP line at Smithfield Rd).

Crestwood-Eminence-Bedford Reinforcement Overview



II. East End Gate Stations Gas Systems Overview

The Elder Park City Gate Station is located on Elder Park Road just east of Highway 393. It serves the Ballardsville pipeline on the northeast border of Louisville from Elder Park to Zorn Avenue. The Crestwood City Gate Station is located on Highway 22 west of Abbott Lane and serves the area from Lake Forest and Pee Wee Valley to Crestwood, Ballardsville and Eminence. The LaGrange City Gate Station is located on Highway 146 west of Button Lane and serves the City of LaGrange and the Crestwood/Buckner area north of I-71. These systems serve rural, residential, commercial, and small industrial customers.

Maximum Allowable Operating Pressure

The Elder Park system has a maximum allowable operating pressure of 400 psig. The Crestwood system has a maximum allowable operating pressure of 350 psig. East of the La Grange City Gate Station, the LaGrange system has a maximum allowable operating pressure of 100 psig. West of the LaGrange City Gate Station, the LaGrange system has a maximum allowable operating pressure of 200 psig.

Minimum Gas System Pressure (-12°F)

200 psig	1 Quality Place	84.9 psig
350 psig	Pleasureville, KY	252.0 psig
400 psig	Zorn Ave Station	124.6 psig

Regulator Operating Capacities

Crestwood City Gate 20.6%
Elder Park City Gate 25.5%
LaGrange City Gate 34.4%

Gas System Constraints

The Crestwood, Ballardsville, and LaGrange systems are dependent upon the successful operation of all three facilities. Each facility independently controls the gas to its area. If any of these three gate stations were temporarily turned off (e.g., for maintenance or due to an accident), there would be insufficient pressure to serve the system that is supplied by that gate station. An interconnection of the systems is recommended for reliability.

II. East End Gate Stations Gas Systems Overview

Reinforcement 1

Connect the Elder Park System to the Crestwood system in case of emergency or scheduled shutdown of the Crestwood City Gate Stations.

- Install 7,500' of 8-inch pipe on Highway 393.
- Install 6,000' of 8-inch pipe on Highway 53 (Also in Section I).

Minimum Gas System Pressure (-12F):

- Zorn Ave Inlet .... 124.9 psig
- Pleasureville, KY .... 254.0 psig
- 1 Quality Place .... 85.1 psig

Regulator Operating Capacities:

- Crestwood City Gate 22.0%
- Elder Park City Gate 25.0%
- LaGrange City Gate 40.6%

Reinforcement 2

Connect the Elder Park System to the LaGrange System in case of an emergency or scheduled shut down of the LaGrange City Gate Station.

- Install 6,600 of 8-inch pipe on Highway 393 from Elder Park Road to Hwy 146.
- Install a facility at Hwy 393 and Hwy 146 to reduce the pressure to 90 psig.
    - 4" Mooney regulators

Minimum Gas System Pressure (-12F):

- Zorn Ave Inlet .... 123.0 psig
- Pleasureville, KY .... 252.0 psig
- 1 Quality Place .... 87.4 psig

Regulator Operating Capacities:

- Crestwood City Gate 19.4%
- Elder Park City Gate 29.3%
- Hwy 146 & Hwy 393 .... 20.5%

Reinforcement 3

Combine Reinforcement 1 and 2 in case of an emergency or scheduled shutdown of the Lagrange City Gate Station and/or the Crestwood City Gate Station.

- Install 7,500' of 8-inch pipe on Highway 393.
- Install 5,900' of 8-inch pipe on Highway 53.
- Install 6,600 of 8-inch pipe on Highway 393 from Elder Park Road to Hwy 146.
- Install a facility at Hwy 393 and Hwy 146 to reduce the pressure to 90 psig.

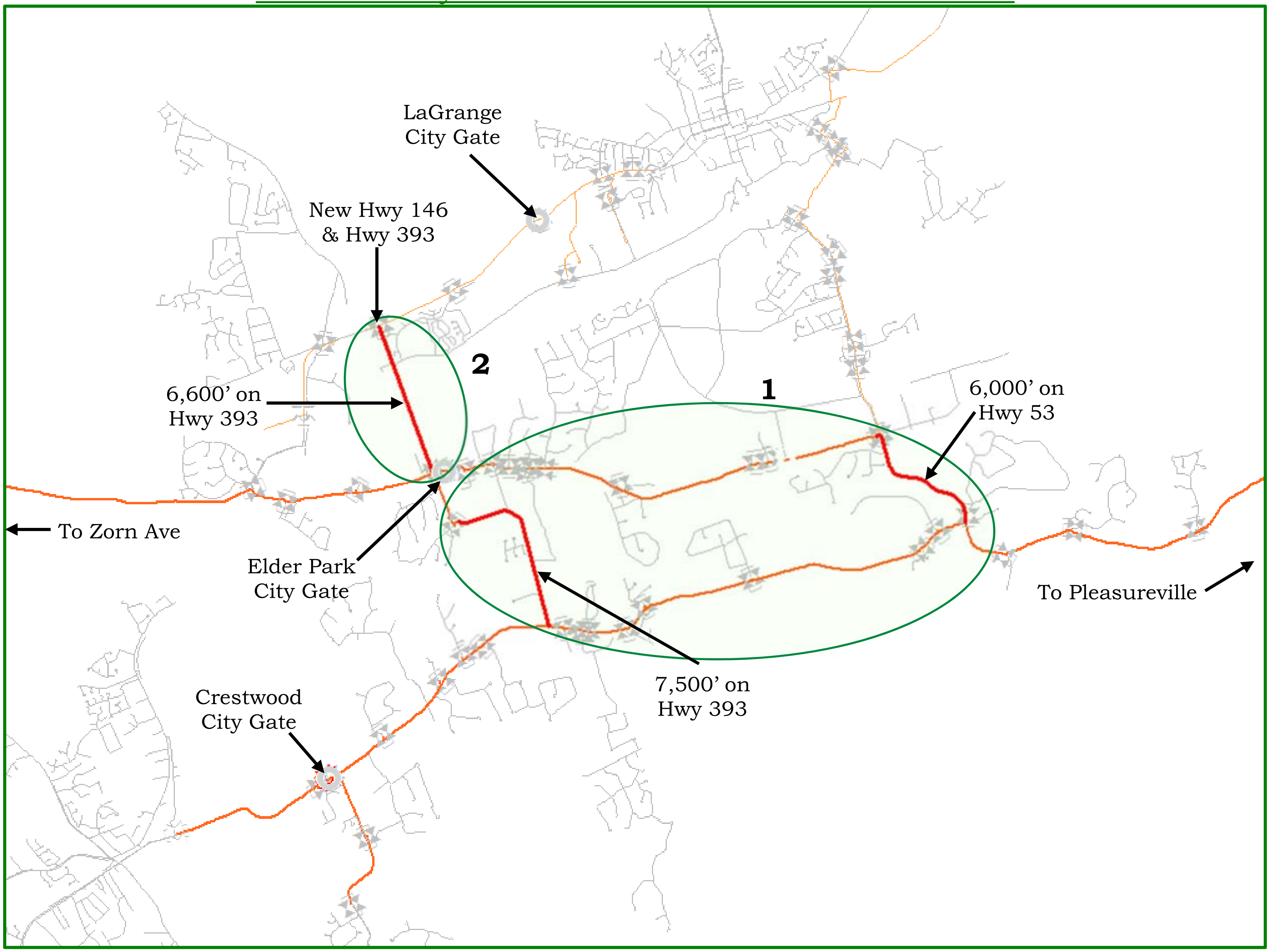
Minimum Gas System Pressure (-12F):

- Zorn Ave Inlet .... 123.0 psig
- Pleasureville, KY .... 253.4 psig
- 1 Quality Place .... 87.1 psig

Regulator Operating Capacities:

- Crestwood City Gate 0%
- Elder Park City Gate 33.4%
- LaGrange City Gate 0%

East End City Gate Stations Reinforcement Overview



III. LaGrange Medium Pressure Systems

The LaGrange Medium pressure systems are supplied from the LaGrange and Elder Park City Gate Stations (see Section II). The system consists of several single-supply systems and one larger, multiple-supply system.

The Oldham County Economic Development Campus (OCEDA) is a 1000+ acre community that will contain office buildings, single and multifamily dwellings, a new school, and mixed use lands. Currently, gas infrastructure does not exist to support this development.

Maximum Allowable Operating Pressure

These subsystems have maximum allowable operating pressures of 10, 30, and 35 psig, as detailed below.

Minimum Gas System Pressure (-12°F)

10 psig	E Dogwood Circle	9.54 psig
25 psig	Parker Drive	15.5 psig
30 psig	Kamer Court	23.2 psig

Regulator Operating Capacities

30 psig Systems:

Hoffman Ln and Parkview Mano	4%
Button Ct and Commerce Pkwy	19%
Allen Ln and Artisan Pkwy	6%
Hwy 53 and Cherry Creek Dr	54%
New Cedar Point & Old Lagrange	55%
Regulator Pit at Elder Park Rd	35%
Moody Ln and Hwy 53	23%
E Moody Ln and Cal Ave	8%
Deer Run Rd and Fox Trail Dr	14%
Granger Rd and Hwy 53	28%
Park Rd and Hwy 53	20%
Zhale Smith Rd and Hwy 53	10%
Springhouse Estates Subdivision	42%
Hwy 146 and Fort Pickens Rd	2%
Prestwick Dr and Hwy 53	37%
Crystal Dr and Grange Dr	22%

25 psig Systems:

Woodlawn Ave & Lagrange	16%
Lagrange medium pressure pit	68%
Hoffman Ln	46%

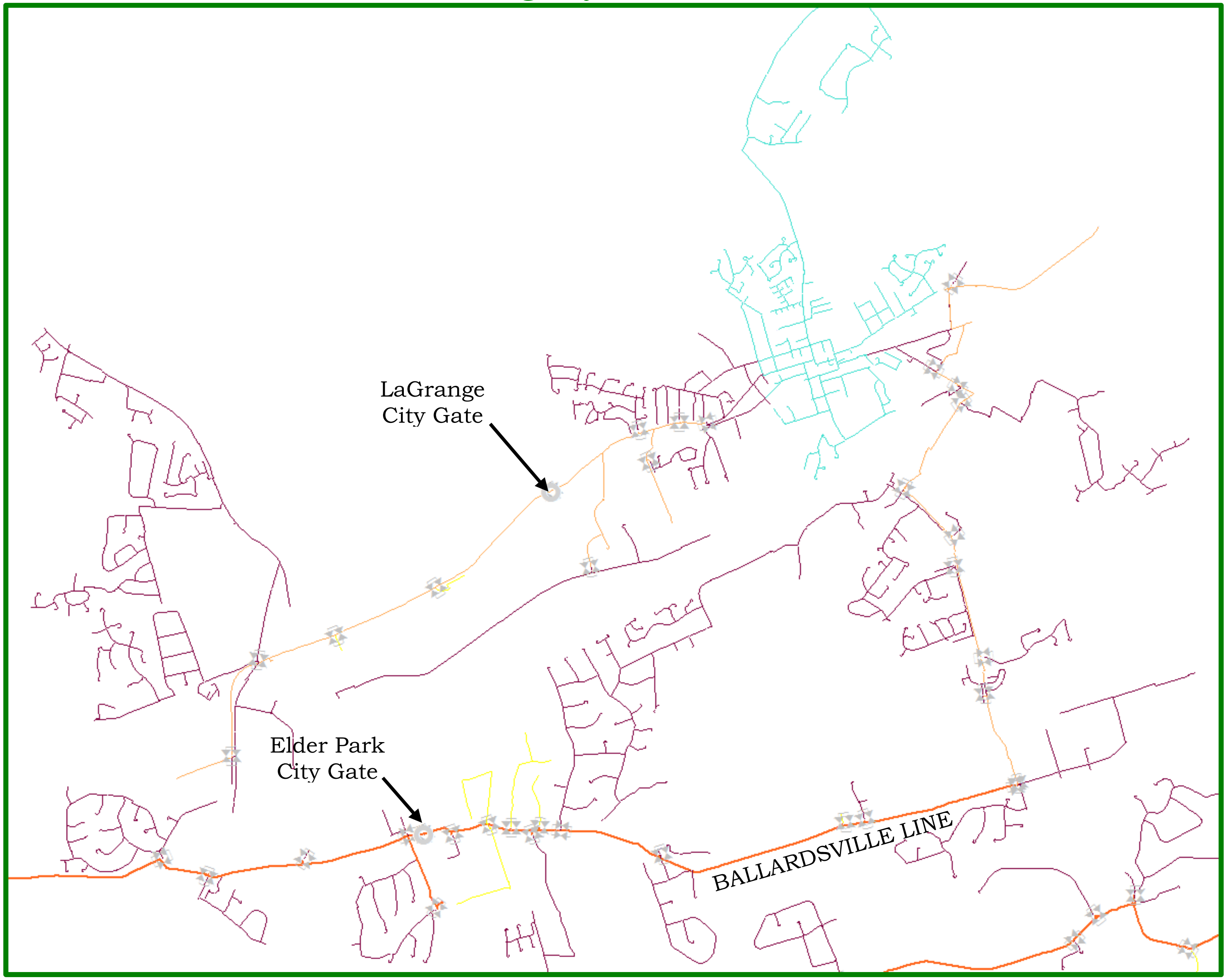
10 psig Systems:

Hwy 393 & Hwy 146	1%
Kings Ln & Hwy 146	2 %
Georgie Way and Moody Ln	4%
Hazelwood Dr & Elder Park Rd	14%
Sycamore & Elder Park	26%

Gas System Constraints

Areas of low pressure are constrained by small diameter piping and single regulator stations supplying the systems. The recent reduction in system operating pressure due to new MAOP interpretations of regulations has also put a strain on deliverability. There are multiple single-supply facilities in the LaGrange area that could be removed to reduce the number of dead-end gas systems and reduce O&M costs by removing equipment.

LaGrange System Overview



III. LaGrange Medium Pressure Systems Cont'd

Reinforcement Purpose

Install piping reinforcements within the LaGrange 30 psig system to address the minimum pressure point and minimize the system pressure drop.

Reinforcement 1a

- Reduce the set pressure of the Hwy 146 & Fort Pickens Rd facility to 25 psig and increase the equipment orifices.
- Install 600' of 4-inch pipe from the regulator facility to the existing 4-inch pipe on E Jefferson St.

Regulator Operating Capacities:
- Hoffman Ln 33.3%
- Woodlawn Ave & Lagrange 13.0%
- Lagrange med pressure pit 50.6%
- Hwy 146 & Fort Pickens Rd 67.5%

Minimum Gas System Pressure (-12F):
- 503 Parker Place .... 19.6 psig

Reinforcement 1b

- Follow reinforcement 1a.
- Reduce the set pressure of the Button Ct & Commerce Pkwy facility to 25 psig and increase the equipment orifice.
- Install 3,600' of 4-inch pipe along Commerce Pkwy to connect the existing systems.

Regulator Operating Capacities:
- Hoffman Ln 33.3%
- Woodlawn Ave & Lagrange 13.0%
- Lagrange med pressure pit 50.6%
- Hwy 146 & Fort Pickens 67.5%
- Button Ct & Commerce Pky 25.3%

Minimum gas system pressure (-12°F):
- Cedar Springs Pkwy .... 21 psig
- 503 Parker Place .... 19.6 psig

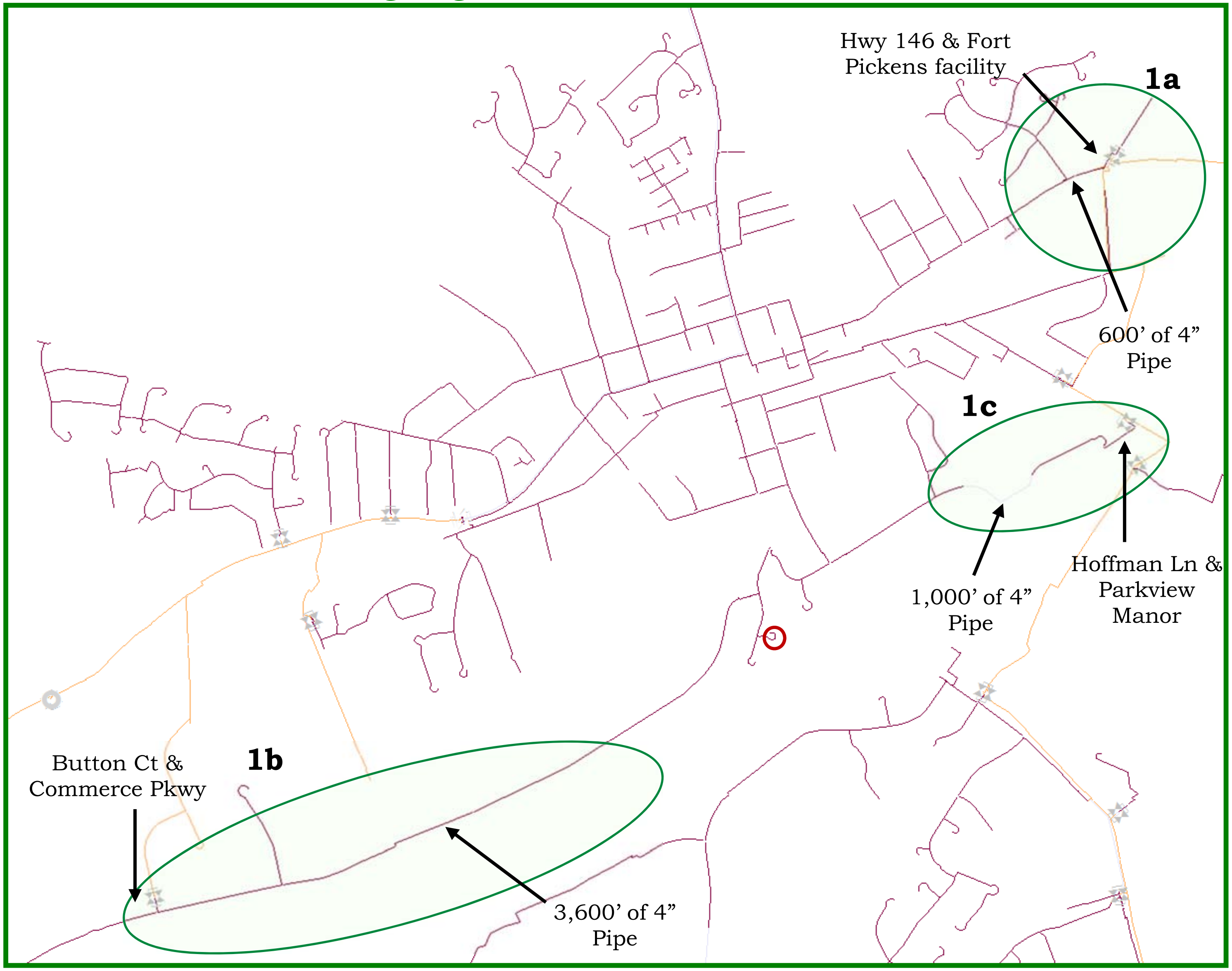
Reinforcement 1c

- Follow reinforcement 1b.
- Reduce the set pressure of the Hoffman Ln & Parkview Manor facility to 25 psig.
- Install 1,000' of 4-inch pipe along Crystal Drive to connect the systems.

Regulator Operating Capacities:
- Hoffman Ln 33.3%
- Woodlawn Ave & Lagrange 13.0%
- Lagrange med pressure pit 50.6%
- Hwy 146 & Fort Pickens 67.5%
- Hoffman & Parkview Manor 62.3%

Minimum gas system pressure (-12°F):
- Cedar Springs Pkwy .... 21.4 psig
- 503 Parker Place .... 19.6 psig

Lagrange Reinforcement 1 Overview



III. LaGrange Medium Pressure Systems Cont'd

Reinforcement Purpose

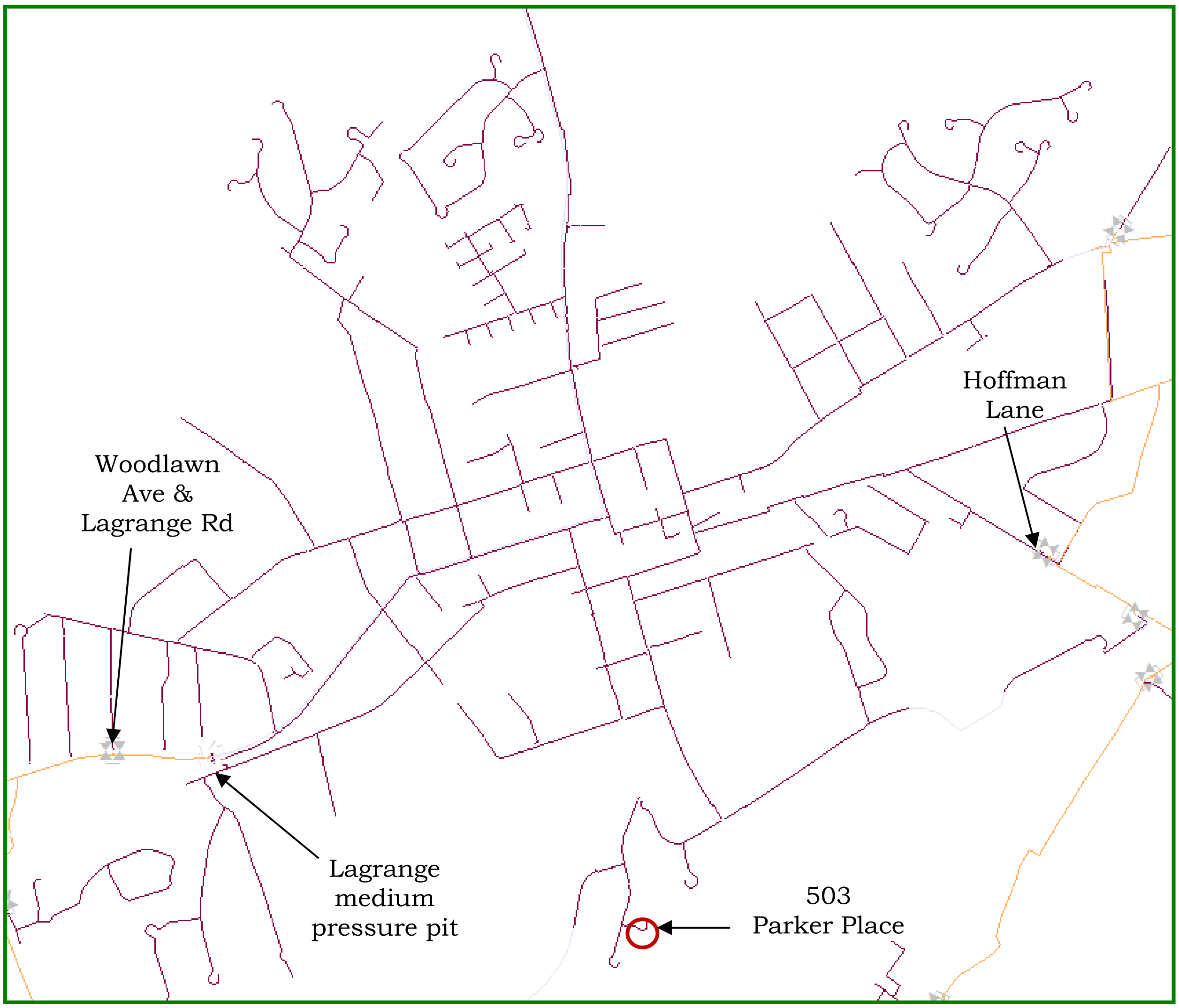
Uprate the LaGrange 30 psig medium pressure system to 35 psig to increase the capacity of the system and improve minimum pressures.

Reinforcement 2

- Uprate the Hoffman Ln, Lagrange Medium Pressure City, and Woodlawn Ave & Lagrange Rd facilities to a set pressure of 30 psig.

Regulator Operating Capacities:
- Hoffman Ln 46.4%
- Woodlawn & Lagrange Rd 15.8%
- Lagrange City 69.3%

Minimum gas system pressure (-12°F):
- 503 Parker Place .... 21.8 psig
- 1037 Shoreline Dr .... 22.4 psig



III. LaGrange Medium Pressure Systems Cont'd

Reinforcement Purpose

There are multiple single-supply facilities in the LaGrange area which could be combined to reduce the number of dead-end systems and reduce O&M costs by removing equipment.

Reinforcement 3a

Combine single-supply systems along Hwy 53 and retire regulator facilities.

- Install a total of 3,000' of 4-inch pipe along Hwy 53 to connect the Granger Rd & Hwy 53, Zhale Smith Rd & Hwy 53, Hwy 53 & Cherry Creek Dr, Prestwick Dr & Hwy 53, and Park Rd & Hwy 53 systems.
- Remove the Zhale Smith Rd & Hwy 53, Prestwick Dr & Hwy 53, and Park Rd & Hwy 53 regulator facilities.

Regulator Operating Capacities:

- Elder Park Rd 34.5%
- Granger Rd & Hwy 53 .... 26.8%
- Hwy 53 & Cherry Creek Dr 86.4%

Minimum gas system pressure (-12°F):

- 2115 Prestwick Dr .... 27.7 psig

Reinforcement 3b

Combine single-supply systems along Elder Park Rd and retire regulator facilities.

- Install a total of 1,800' of 2-inch pipe to connect the three (3) 10 psig systems.
- Retire the Sycamore Rd & Elder Park Rd, and Hazelwood Dr & Elder Park Rd regulator facilities.

Regulator Operating Capacities:

- Elder Park & Elder Park Cutoff ... 83%

Minimum gas system pressure (-12°F):

- 2810 Borowick Ct .... 9.1 psig

Reinforcement 3c

Combine single-supply systems along W Hwy 146 and retire regulator facilities.

- Reduce set pressure of Hoffman Ln & Parkview, Allen Ln & Artisan Pkwy, and Button Ct & Commerce Pkwy facilities to 25 psig.
- Install 9,000' of 4-inch pipe to connect systems and provide reinforcement.
- Retire Allen Ln & Artisan, Woodlawn Ave & Lagrange Rd, and Hoffman Ln facilities.
- (Optional Reinforcement: Install 9,700' of 6" pipe along Fort Pickens Rd to reinforce and facilitate growth).

Regulator Operating Capacities:

- Springhouse Estates 57.3%
- Lagrange med pressure pit 56.8%
- Hoffman & Parkview Manor ... 85.5%
- Button Ct & Commerce Pkwy ... 31%
- Hwy 146 & Fort Pickens Rd ... 35.6%

Minimum gas system pressure (-12°F):

- Cedar Springs Pkwy .... 19.1 psig

III. LaGrange Medium Pressure Systems Cont'd

Reinforcement 3d

Combine single-supply systems along Hwy 146 and retire regulator facilities.

- Install a total of 4,800' of 4-inch pipe to connect the systems.
- Uprate the Hwy 146 system to 35 psig.
- Remove the Industrial Park Rd & Hwy 146, Button Ct & Commerce Pky, and Hwy 393 regulator facilities.

Regulator Operating Capacities:

- Fox Run Rd 37.3%
- New Cedar Point & Old Lagrange 1.2%

Minimum gas system pressure (-12°F):

- 5303 Kamer Ct .... 23.2 psig

Reinforcement 4

Combine all regulator retirement reinforcements 3a-3d.

- Install 3.5 miles of 2-inch and 4-inch pipe.
- Uprate the Hwy 146 system to 35 psig.
- Remove the following 11 facilities: Zhale Smith Rd & Hwy 53, Prestwick Dr & Hwy 53, Park Rd & Hwy 53, Sycamore Rd & Elder Park Rd, Hazelwood Dr & Elder Park Rd, Allen Ln & Artisan, Woodlawn Ave & Lagrange Rd, Hoffman Ln, Industrial Park Rd & Hwy 146, Button Ct & Commerce Pky, and Hwy 393.

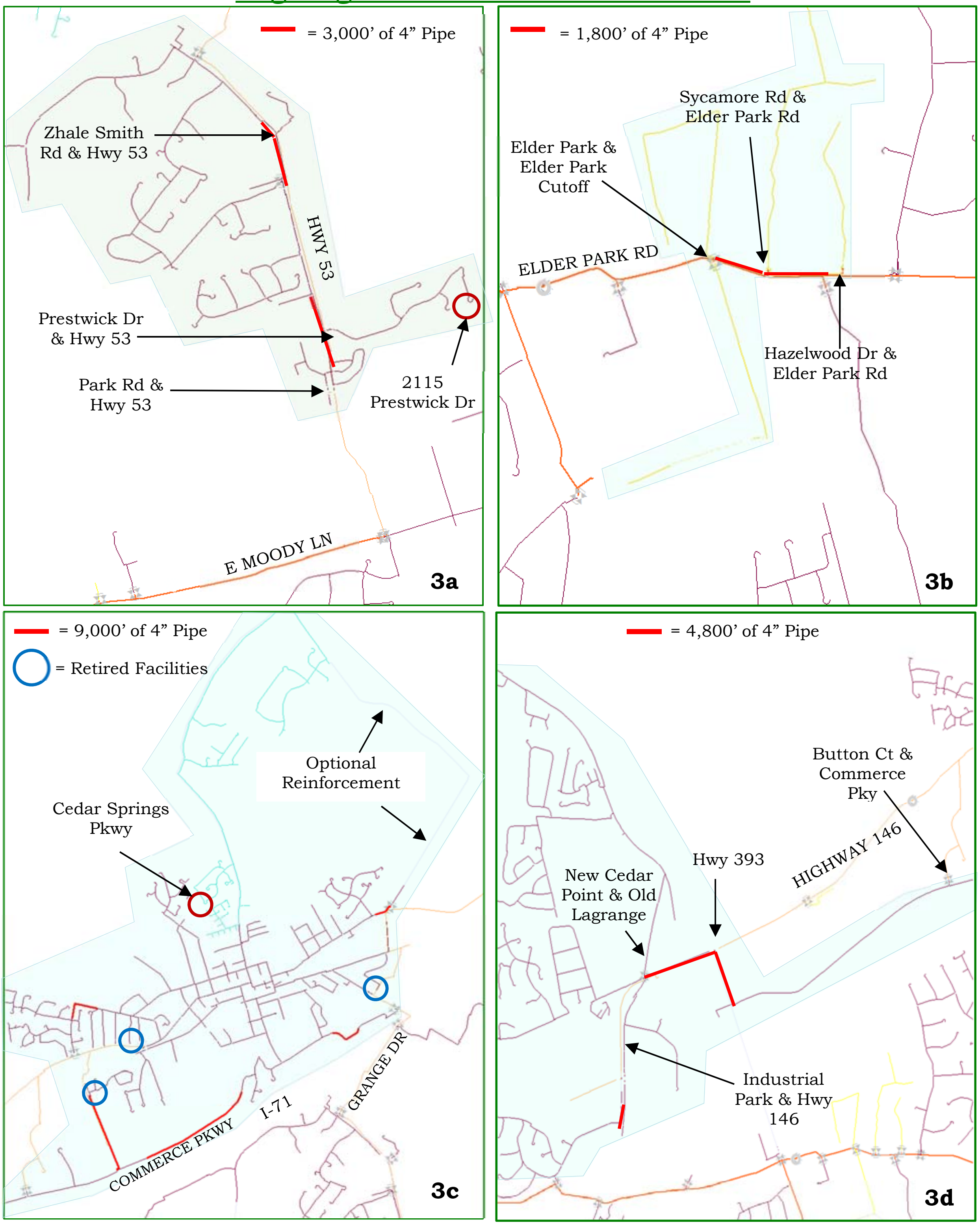
Regulator Operating Capacities:

- Springhouse Estates 58.4%
- Lagrange med pressure pit 59.4%
- Hoffman & Parkview Manor 89.5%
- Hwy 146 & Fort Pickens Rd 37.3%
- New Cedar Pt & Old Lag 66.4%
- Fox Run Road 38.1%
- Hwy 53 & Cherry Creek 86.4%
- Elder Park Rd 34.7%
- Grange Dr & Hwy 53 .... 26.6%

Minimum gas system pressure (-12°F):

- Cedar Springs Pkwy .... 19.1 psig
- 2115 Prestwick Drive .... 27.7 psig
- 2810 Borowick Circle .... 9.1 psig
- 5303 Kamer Court .... 23.1 psig

Lagrange Reinforcement 3 Overview



III. LaGrange Medium Pressure Systems Cont'd

Reinforcement Purpose

Extend gas mains and uprate LaGrange medium pressure system as described in "An Analysis of the OCEDA Economic Development Campus" dated November 7th, 2005 or latest version. As described in the report, this system will have an estimated new gas load of up to 387 Mcfh.

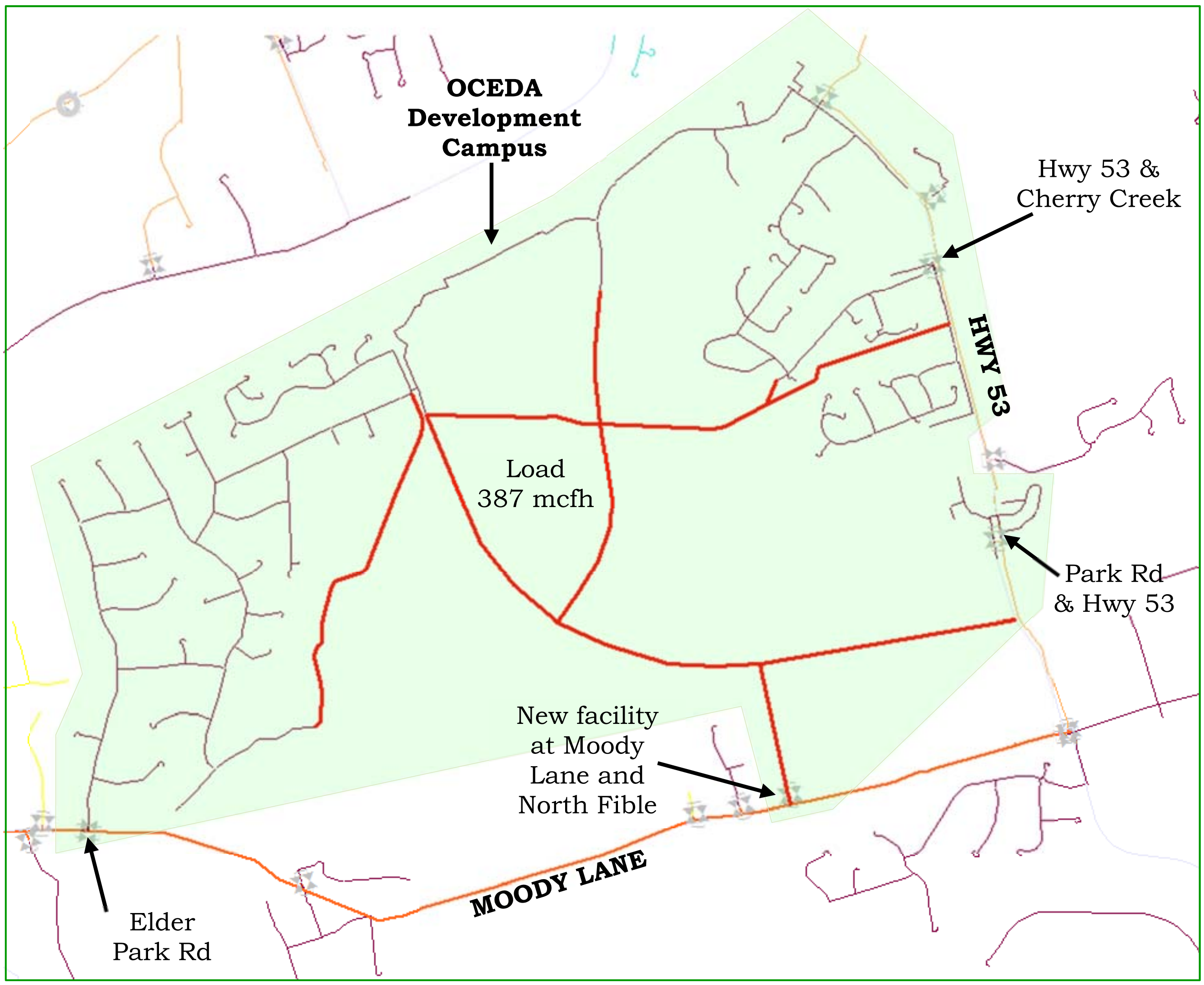
Reinforcement 1

Uprate the system to 50 psig.
Install
- 12,000' of 4 inch pipe
- 20,500' of 8 inch pipe
- Facility at Moody Ln & N Fible Ln

Upgrade Equipment
- Hwy 53 & Cherry Creek
- Park Rd & Hwy 53
- Elder Park Rd

Minimum gas system pressure (-12°F):
- 2303 Stoneybrook Ct ....40.7 psig

Regulator Operating Capacities:
- Moody Ln & N Fible 34.1%
- Hwy 53 & Cherry Creek 91.4%
- Elder Park Rd 23.3%
- Grange Dr & Hwy 53 ....77.5%
- Park Rd & Hwy 53 ....30.1%



III. LaGrange Medium Pressure Systems Cont'd

Reinforcement Purpose

Extend gas pipelines and uprate Hwy 393 & Hwy 146 system as described in "An Analysis of Proposed Development at Buckner Crossings" dated October 16th, 2006 or latest version. As described in the report, this system will have an estimated new gas load of up to 90 Mcfh.

Reinforcement 1

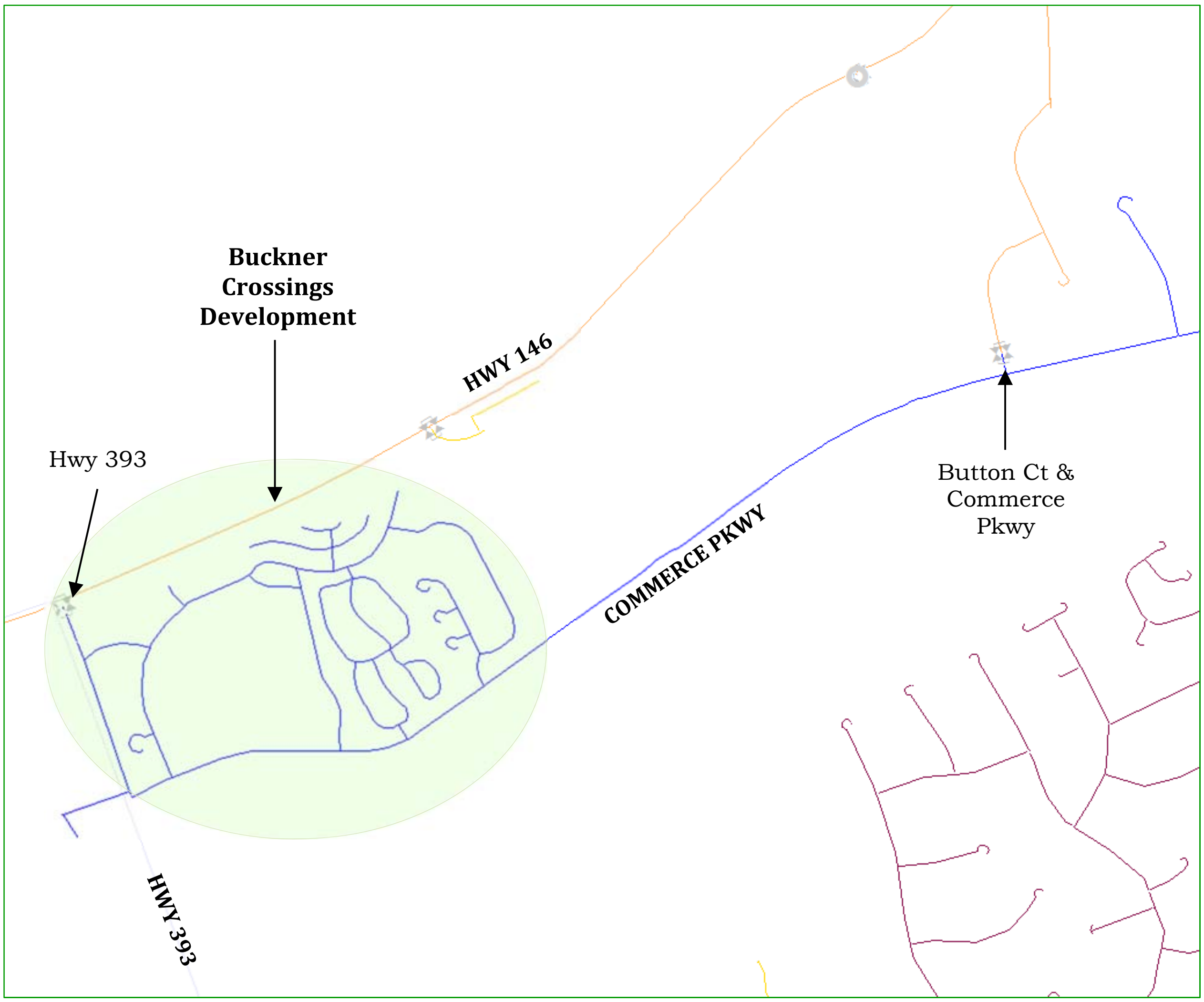
Uprate the system to 50 psig.

Install
- 6,600' of 2 inch pipe
- 6,300' of 4 inch pipe
- 5,200' of 6 inch pipe

Upgrade Equipment
- Hwy 393
- Button Ct & Commerce Pkwy

Minimum gas system pressure (-12°F):
- New Development ....41.0 psig

Regulator Operating Capacities:
- Hwy 393 ....36.7%
- Button Ct & Commerce Pky 46.3%



IV. Prospect Medium Pressure System

The Prospect system surrounds Hwy 1793 and the Harmony Landing Country Club in Oldham County. This system was recently uprated to 60 psig and is supplied by two regulator facilities off of Hwy 42. Located nearby are 20 and 35 psig systems, supplied by the Riverbluff Farms and the Hillcrest Sub facilities on Hwy 42, which supply the River Glen and Hillcrest areas.

Maximum Allowable Operating Pressure

These subsystems have maximum allowable operating pressures of 20, 35 and 60 psig, as detailed below.

Minimum Gas System Pressure (-12°F)

System	Location	Pressure
15 psig	River Glades Dr	14.6 psig
30 psig	Deer Pointe Pl	23.1 psig
55 psig	Louisville Yacht Club	44.4 psig

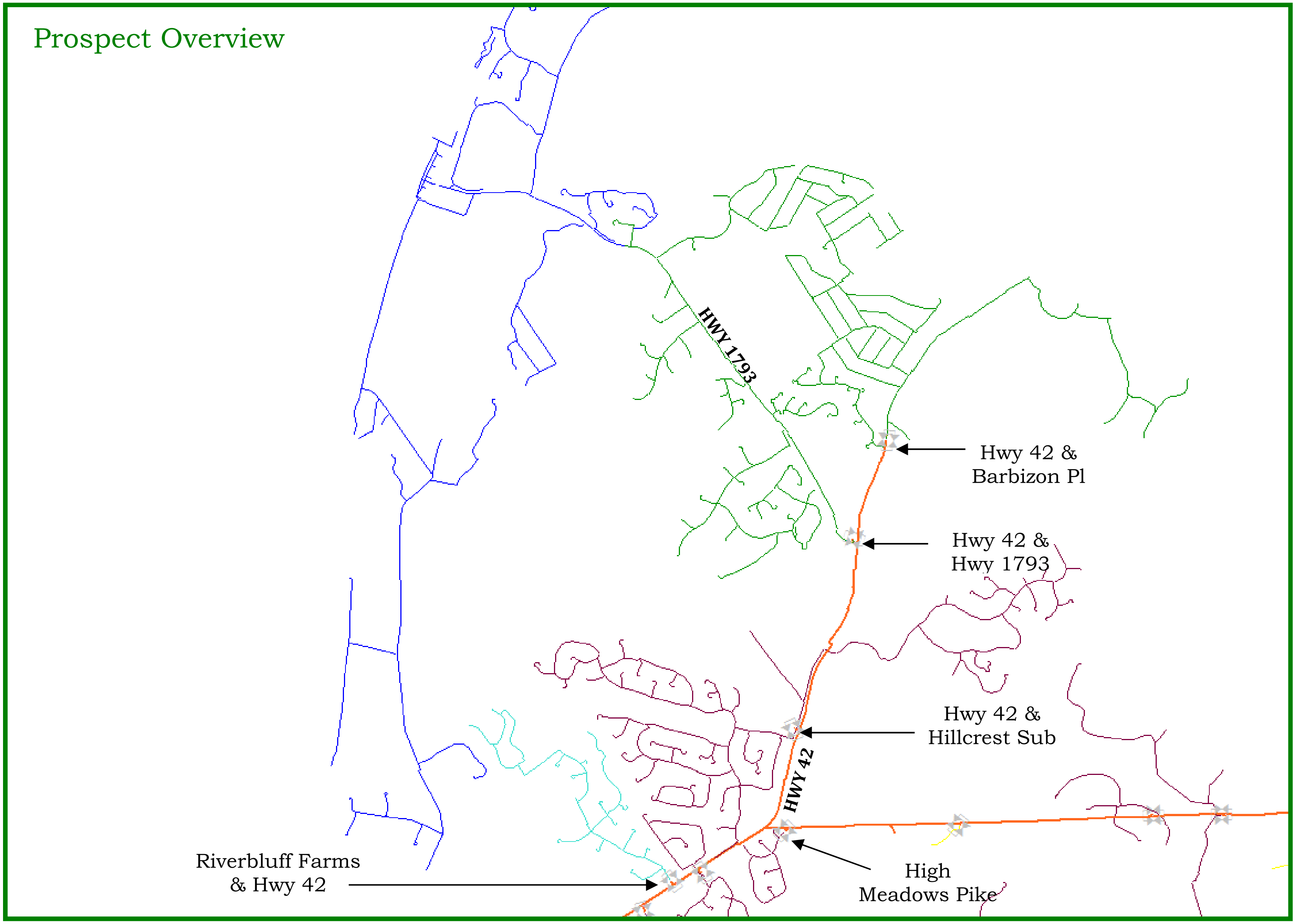
Regulator Operating Capacities

Hwy 42 & Barbizon Place 8.1%
Hwy 42 & Hwy 1793 .... 57.4%
Riverbluff Farms & Hwy 42 ..... 11.1%
Hwy 42 & Hillcrest Sub 31.6%

Gas System Constraints

Areas of low pressure are constrained by small diameter piping and one-way supply points within the system. It is recommended that the existing systems are connected together to reinforce the system and reduce consequence in the case of an emergency.

Prospect Overview



IV. Prospect Medium Pressure System Cont'd

Reinforcement 1a

Perform uprates and installations as necessary to connect the systems.
- Uprate the Riverbluff Farms & Hwy 42 facility to 60 psig MAOP (NOP = 55 psig).
- Install 1,500' of 4-inch pipe along River Glades Drive to S Rose Island Rd between the existing 4-inch pipelines.

Minimum gas system pressure (-12°F):
- Louisville Yacht Club ....51.3 psig

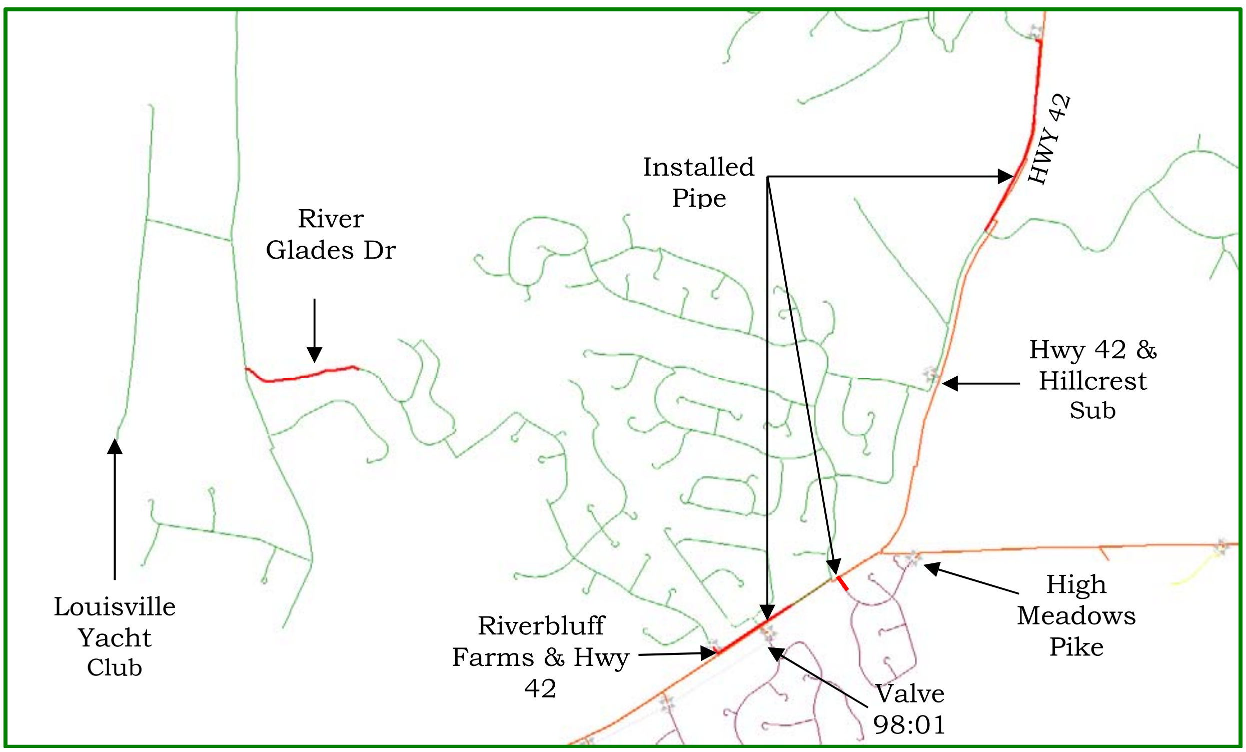
Regulator Operating Capacities:
- Hwy 42 & Barbizon Pl 6.6%
- Hwy 42 & Hwy 1793 ....44.8%
- Riverbluff Farms & Hwy 42 ....25.7%

Reinforcement 1b

Perform uprates and installations to join the Prospect system to the Hillcrest system.
- Complete Reinforcement 1a.
- Uprate the Hwy 42 & Hillcrest and High Meadows Pike facilities to 60 psig MAOP.
- Install 1,200' of 4" pipe on Hwy 42, tying into the existing main on Hayfield.
- Install 2,600' of 4" pipe on Hwy 42 from Paramont Way to Hwy 1793.
- Install 200' of 4-inch pipe at High Meadows Pike and Hwy 42.
- Close valve 98:01.

Minimum gas system pressure (-12°F):
- Louisville Yacht Club ....51.3 psig

Regulator Operating Capacities:
- Hwy 42 & Barbizon Pl 6.6%
- Hwy 42 & Hwy 1793 ....59.8%
- Riverbluff Farms & Hwy 42 ....48.6%
- Hwy 42 & Hillcrest Sub 18.8%



V. River Road/Highway 42 Regulator Assemblies

The Elder Park line contains multiple single-feed subsystems ranging in pressure in addition to its contribution to the Jefferson County 50 psig subsystem. Gas System Planning has identified multiple subsystems along River Road that could be combined and regulator facilities that could be removed.

Maximum Allowable Operating Pressure

The Elder Park Line has a maximum allowable operating pressure of 400 psig, but is typically operated at 300 psig. All medium pressure subsystems have maximum allowable operating pressures of 50 psig, 35 psig, 20 psig, and 10 psig as listed below.

Regulator Operating Capacities

30 psig Systems:

River Rd & Woodside Rd................28%
River Rd &Harbortown Rd............10%
River Rd & Duroc Ave......................10%
River Rd & Juniper Beach Dr.........8%
River Rd & River's Edge.................36%
River Rd Pit Serving Rivercreek...35%
River Rd & Mockingbird Valley......8%
Hwy 42 & Hayfield Way............. ......6%

Hwy 42 & Hunters Ridge Dr.........21%
Hwy. 42 & Hillcrest Sub.................32%
Coveredbridge & Covered Cov......... 1%
Coveredbridge & Woodbridge..........1%
High Meadows Pike...........................18%
Hunting Creek.....................................30%
Melrose Retail...3%

45 psig Systems:

Blankenbaker Ln & River Rd.......20%
Glenview Ave & River Rd................11%
River & Wolf Pen Branch Rd.....100%

10 psig:

River Rd & Waldoah Pl 8%

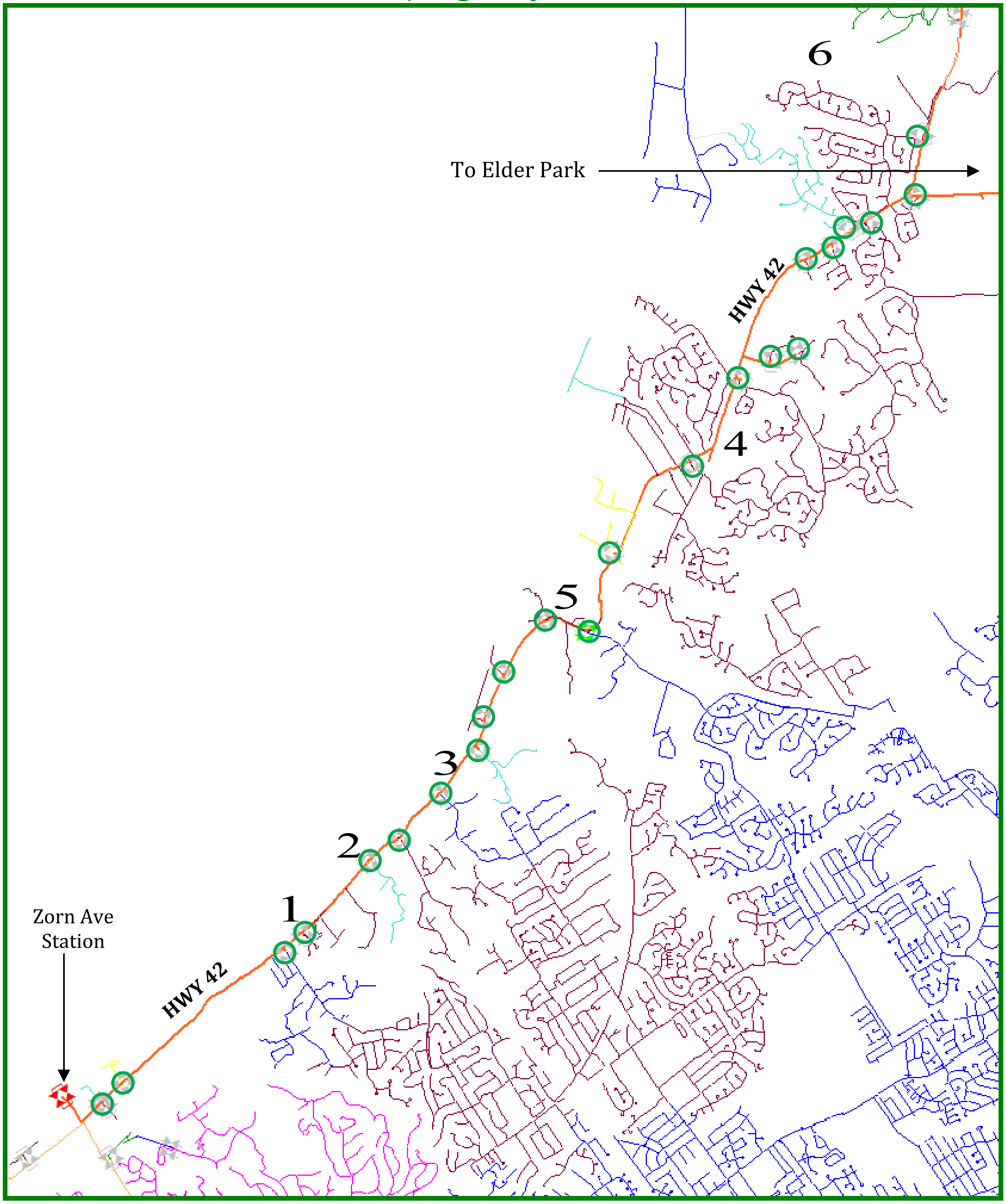
15 psig:

River Rd. & Box Hill Ln..................21%
River Rd & Lime Kiln Ln..................19%
River Rd & Kingfish Pit 43%
Riverbluff Farms & Hwy 42 11%

Gas System Constraints

Maintenance and operating costs can be reduced by eliminating a number of gas regulator facilities. In addition, a reduction of single-supply systems in case of emergency will facilitate lesser system consequences and the merging of systems will improve gas flow.

River Road/Highway 42 Overview



V. River Road/Highway 42 Regulator Assemblies Cont'd

Reinforcement 1

Combine Kingfish, Mockingbird Valley, and Waldoah systems and remove regulators.

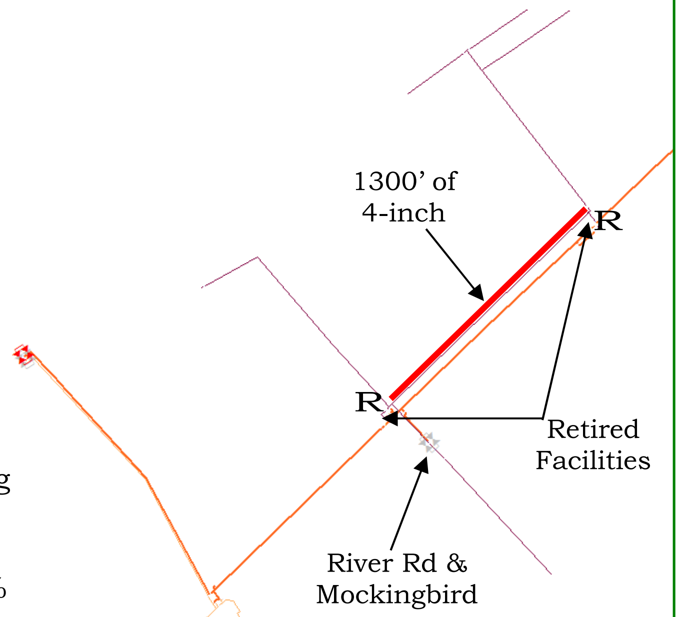
- Uprate the Kingfish and Waldoah systems to 35 psig.
- Install 1,300' of 4-inch pipe along River Rd to connect the systems.
- Retire the River Rd & Kingfish and River Rd & Waldoah regulator facilities.

Minimum gas system pressure (-12°F):

- 2930 Waldoah Beach Rd..........30 psig

Regulator Operating Capacities:

- River Rd & Mockingbird Valley.....86%



Reinforcement 2

Combine Box Hill Ln and Rivers Edge Rd systems and remove Box Hill Ln regulator station.

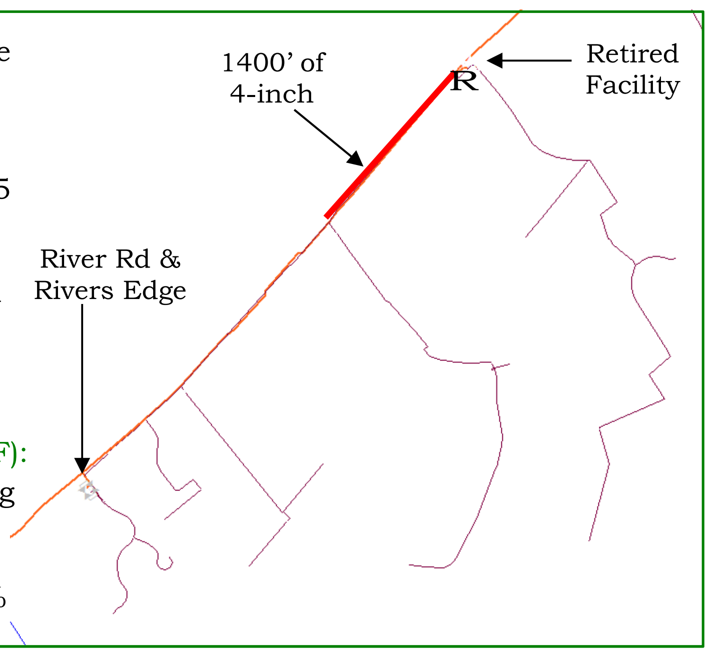
- Uprate the Box Hill Ln system to 35 psig.
- Install 1,400' of 4-inch pipe along River Rd to connect the Box Hill Ln and Rivers Edge Rd systems.
- Retire the River Rd & Box Hill Ln facility.

Minimum gas system pressure (-12°F):

- 6524 Longview Lane...............23 psig

Regulator Operating Capacities:

- River Rd & Rivers Edge Rd........56%



Installed Pipe — Retired facility R

V. River Road/Highway 42 Regulator Assemblies Cont'd

Reinforcement 3

Combine Woodside, Glenview, and Lime Kiln systems and remove regulators.

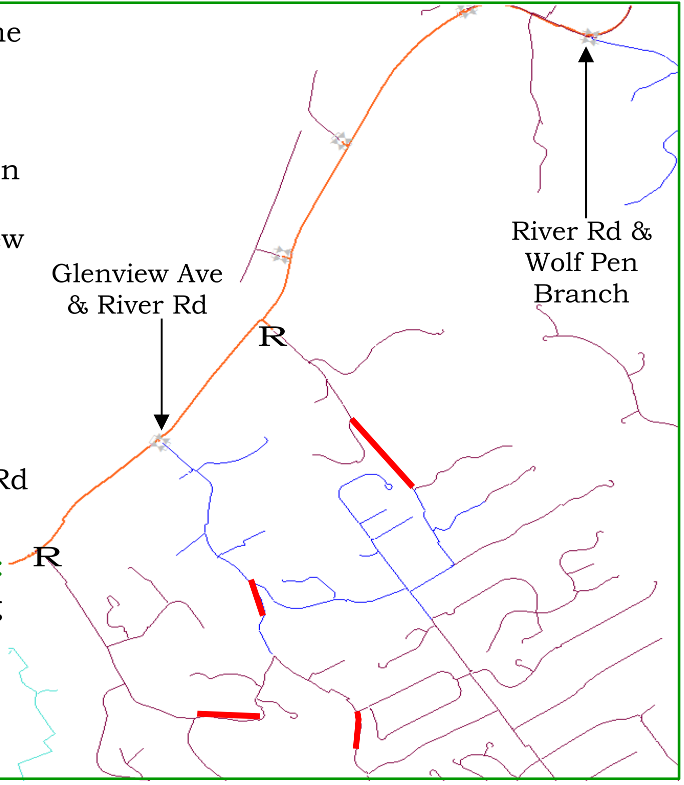
- Uprate Woodside and Lime Kiln systems to 35 psig
- Install 900' of 4-inch pipe from Arden Rd to Woodside Rd.
- Install 600' of 4-inch pipe on Glenview Ave at Brittany Woods and 550' at Orion Rd.
- Install 1,100' of 4-inch pipe on Lime Kiln Ln at Orchard Ridge Ln.
- Retire the Woodside Rd & Lime Kiln facilities.
- Increase the orifice size of the River Rd & Wolf Pen Branch Rd facility.

Minimum gas system pressure (-12°F):

- Wolfpen Ridge Court..................29 psig

Regulator Operating Capacities:

- Glenview Ave & River Rd..........13%
- River Rd & Wolf Pen Branch 62%



Reinforcement 4

Combine Transylvania Ave. Hunter's Ridge, and Hwy 42 with the Duroc Ave system and remove regulator stations.

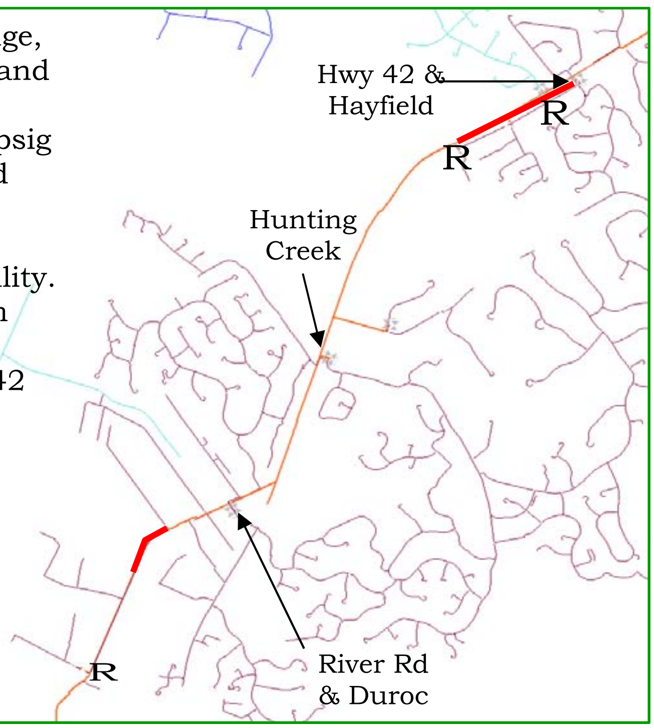
- Uprate the Transylvania system to 35 psig
- Install 1,200' of 4-inch pipe at River Rd and Timber Ridge Dr to connect the systems.
- Retire the River Rd & Transylvania facility.
- Install 2,700' of 4-inch on Hwy 42 from Hayfield Way to 13310 Hwy 42.
- Retire Hunters Ridge and 13310 Hwy 42 facilities.

Minimum gas system pressure (-12°F):

- Louisville Sailing Club............19 psig

Regulator Operating Capacities:

- River Rd & Duroc Ave.................64%
- Hunting Creek............................30%
- Hwy 42 & Hayfield Way...............56%



Installed Pipe Retired facility R

V. River Road/Highway 42 Regulator Assemblies Cont'd

Reinforcement 5

Combine Rivercreek and Wolfpen Branch systems and retire Rivercreek facility.

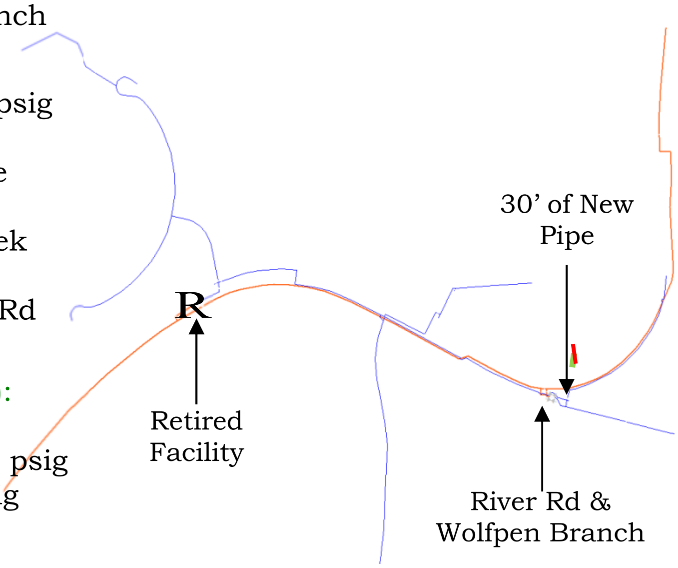
- Uprate the Rivercreek system to 50 psig
- Install 30' of 4-inch pipe at River Rd and Wolf Pen Branch Rd to tie in the systems.
- Retire the River Rd Serving Rivercreek facility.
- Increase the orifice size of the River Rd & Wolfpen Branch facility.

Minimum gas system pressure (-12°F):

- 7604 Wolfpen Ridge Ct .....30 psig
- Wolf Pen Branch Facility outlet.....45 psig
- 5700 Captains Quarters Rd.....44 psig

Regulator Operating Capacities:

- River Rd & Wolfpen Branch.........65%



Reinforcement 6

Combine Prospect systems and retire regulator facilities.

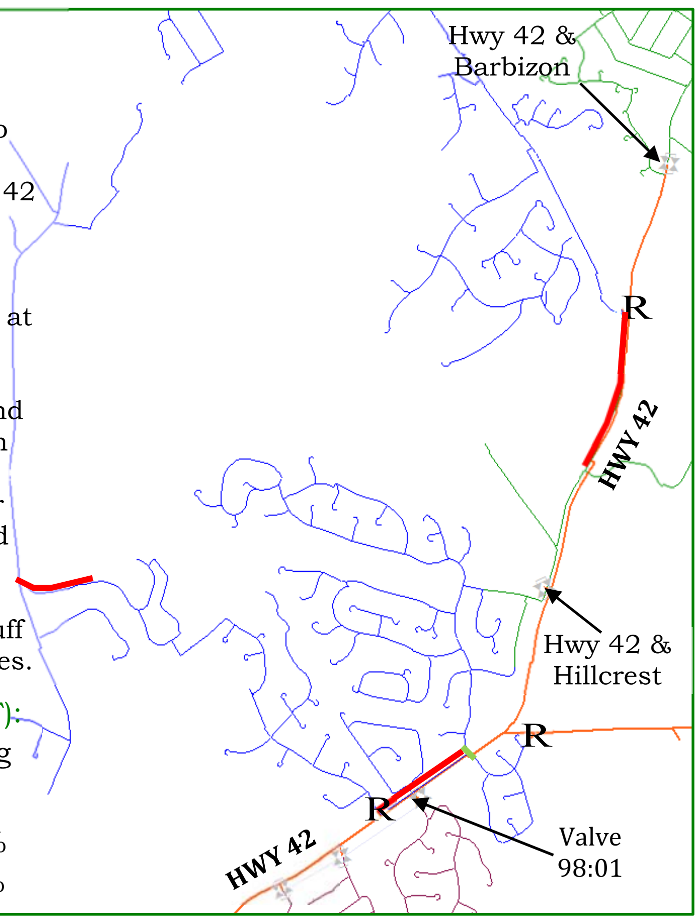
- Uprate the Riverbluff Farms, High Meadows Pike, and Hillcrest facilities to 60 psig MAOP.
- Install 1,225' of 4-inch pipe along Hwy 42 at Hayfield Way to connect the High Meadows, Hayfield, and Riverbluff systems.
- Install 2,600' of 4-inch pipe on Hwy 42 at Paramont Way to connect the Hillcrest and Prospect systems.
- Install 200' of 4-inch pipe at Hwy 42 and High Meadows Pike to connect the High Meadows and Hillcrest systems.
- Install 1,500' of 4-inch pipe along River Glades Ln to connect the Riverbluff and Prospect systems.
- Close valve 98:01.
- Retire the High Meadows Pike, Riverbluff Farms and Hwy 42 & Hwy 1793 facilities.

Minimum gas system pressure (-12°F):

- Louisville Yacht Club...............44 psig

Regulator Operating Capacities:

- Hwy 42 & Hillcrest.........................53%
- Hwy 42 & Barbizon Pl.................10%



Installed Pipe

Retired facility R

VI. Crestwood/ Simpsonville Medium Pressure System

The Crestwood/Simpsonville medium pressure system is a 45 psig single system covering the mid-eastern portion of the LG&E system. It includes areas of East Jefferson County, Crestwood, Anchorage, Simpsonville and Peewee Valley and is bordered by I-265, I-71, and Shelbyville Rd. This system is supplied by eight regulator facilities from both the Eastern Kentucky and the Crestwood high pressure pipelines. The area experiences continual high end residential and commercial growth that is putting a strain on the gas supply.

Maximum Allowable Operating Pressure

This Crestwood/Simpsonville system has a maximum allowable operating pressure of 50 psig (NOP = 45 psig).

Minimum Gas System Pressure (-12°F)

45 psig	Rutland Club Court	20.8 psig
	Bridgemore Ln	23.1 psig
	Cherry Hills Court	23.9 psig
	Championship Ct	30.7 psig
	Pebble Court	31.1 psig
	Clore Lane	35.6 psig

Regulator Operating Capacities

45 psig Systems:

Hwy 1694 & Worthington Ln............16%
Old Henry & Terra Crossing Bv.........48%
Conner Station & Colt Run Rd..........10%
W Hwy 22 & Old Lagrange Rd............32%
Lakeshore Dr & Old Veechdale Rd.....24%
Westport Rd & Murphy Ln..................78%
English Station Way..............................48%
Old Lagrange Rd & Collins Ln........ ....22%

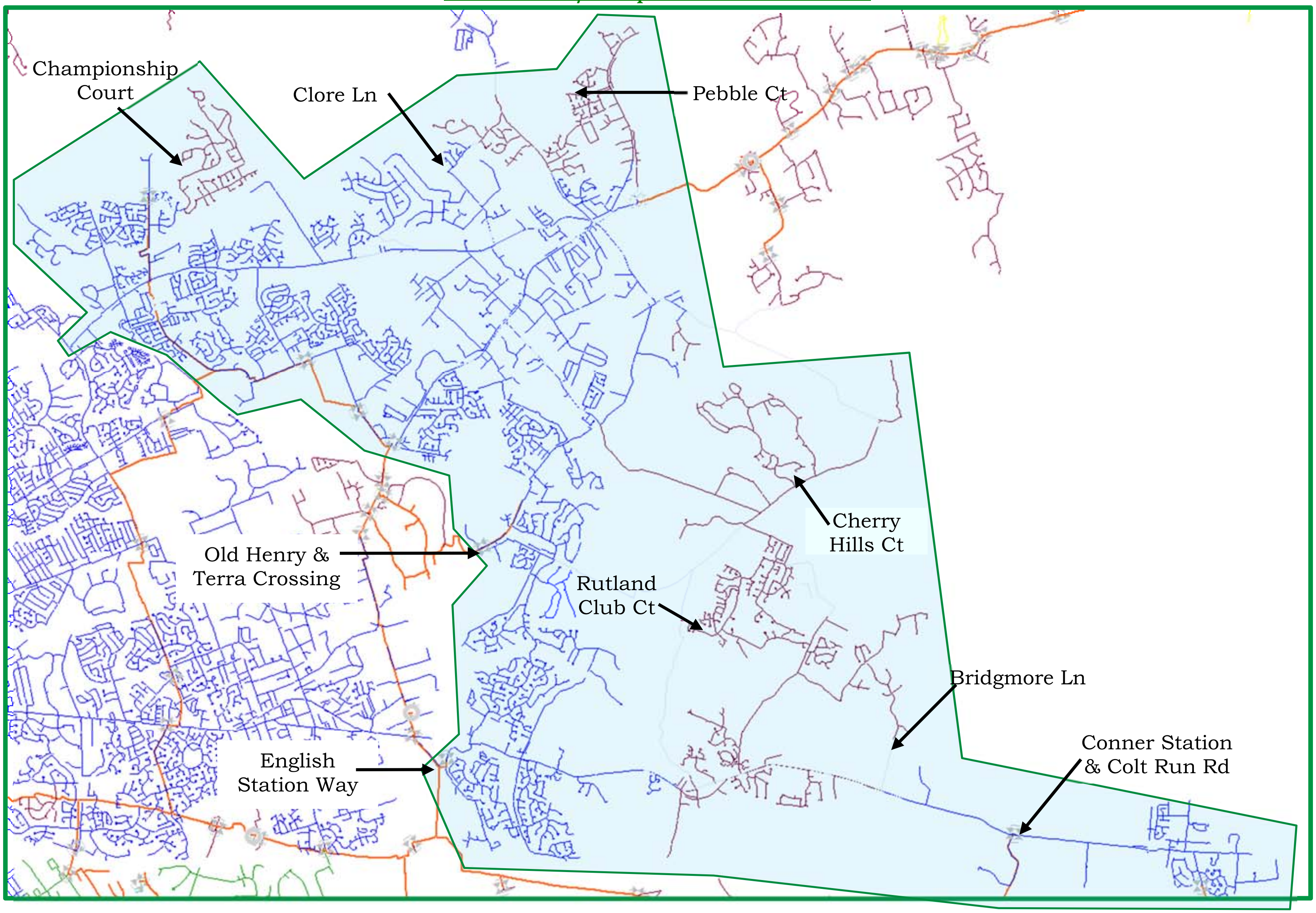
55psig Systems:

Glenarm & Halls Hill..............................16%

Gas System Constraints

The Crestwood/Simpsonville medium pressure system suffers from small diameter trunk lines, unfortunate location barriers such as Floyd's Fork River, and consistent growth. It has already experienced growth away from any strong sources of gas supplies and the infrastructure is no longer conducive to supporting new development. In order to serve current and future loads, it has been determined that reinforcements are necessary. The neighborhoods of Persimmon Ridge and Polo Fields represent the bulk of the existing constraining system while new subdivisions such as Norton Commons and Brookfield are adding strain to the north.

Crestwood/Simpsonville Overview



VI. Crestwood/ Simpsonville Medium Pressure System Cont'd

Reinforcement 1a

General Reinforcements: Add reinforcements to improve system flow.

- Install 4 miles of 4-inch high pressure steel from the Crestwood MP station to the Old Lagrange & Collins Ln facility.
- Install a 2" Mooney assembly to separate the Crestwood line.
- Install a 2" Mooney assembly at Lagrange Rd and Ash Ave.

Minimum gas system pressure (-12°F):

- 6400 Clore Ln .... 39.0 psig
- 6202 Pebble Ct .... 30.0 psig
- 10523 Championship Ct .... 30.7 psig

Regulator Operating Capacities:

- W Hwy 22 & Old Lagrange 28.5%
- Old Lagrange Rd & Collins Ln 17.5%
- Westport Rd & Murphy Ln 76.4%
- Hwy 1694 & Worthington 15.4%
- Hwy 146 & Ash Ave 32.2%

Reinforcement 1b

Install 1a and add additional small reinforcements to improve system flow.

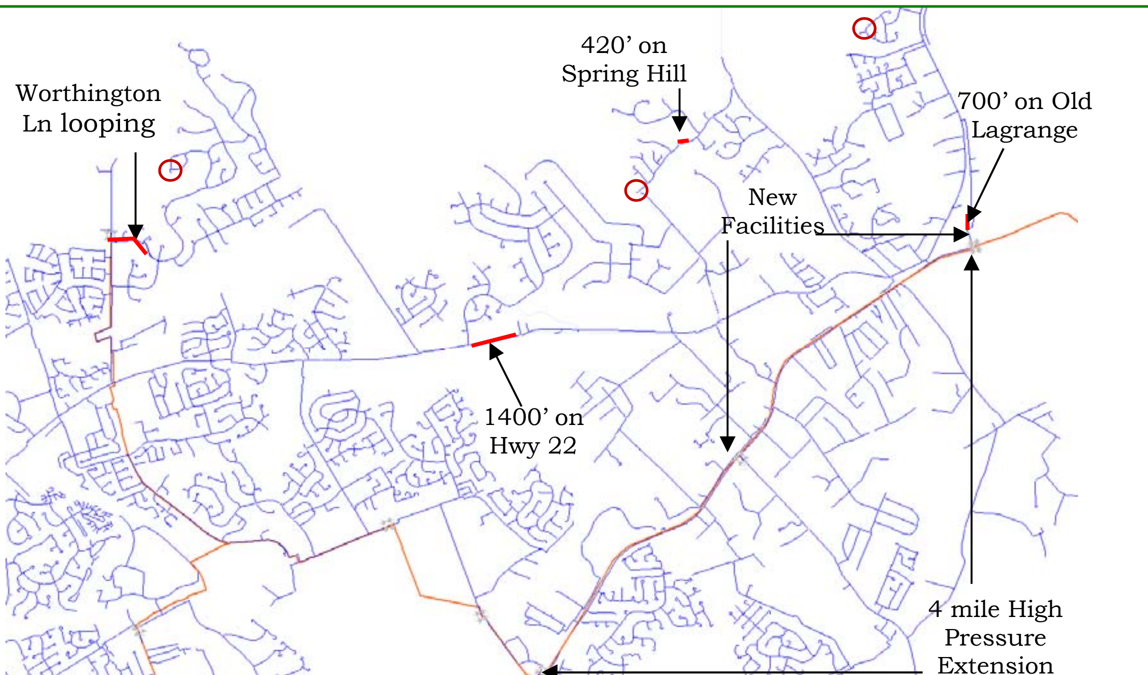
- Install 1,400' of 8-inch pipe on W Hwy 22 at Orchard Grass Blvd.
- Install 420' of 4-inch pipe on Spring Hill Trace at Morningside Dr.
- Install 700' of 4-inch pipe on Old Lagrange Rd at the Hwy 329 Bypass
- Loop 2,000' of 6-inch pipe on Worthington Ln at Brownsboro Rd.

Minimum gas system pressure (-12°F):

- 6400 Clore Ln .... 39.1 psig
- 6202 Pebble Ct .... 37.7 psig
- 10523 Championship Ct .... 38.1 psig

Regulator Operating Capacities:

- W Hwy 22 & Old Lagrange 28.6%
- Old Lagrange Rd & Collins 17.2%
- Westport Rd & Murphy Ln 74.3%
- Hwy 146 & Fort Pickens 17.6



VI. Crestwood/ Simpsonville Medium Pressure System Cont'd

Reinforcement 2a

Accounting for growth: Install reinforcements to increase the pressure at Clore Ln after 100 Mcfh has been added.

- Complete Reinforcement 1b
- Loop 2 miles of 6-inch pipe along Hwy 22 and Clore Ln from the Crestwood pit to Spring Hill Trace.

Minimum gas system pressure (-12°F):
- 6400 Clore Ln........33.5 psig
- 6202 Pebble Ct........34.7 psig
- 10523 Championship Ct........38.0 psig

Regulator Operating Capacities:
- W Hwy 22 & Old Lagrange........43.6%
- Old Lagrange Rd & Collins........17.9%
- Westport Rd & Murphy Ln........76.7%
- Hwy 1694 & Worthington Ln........18.0%

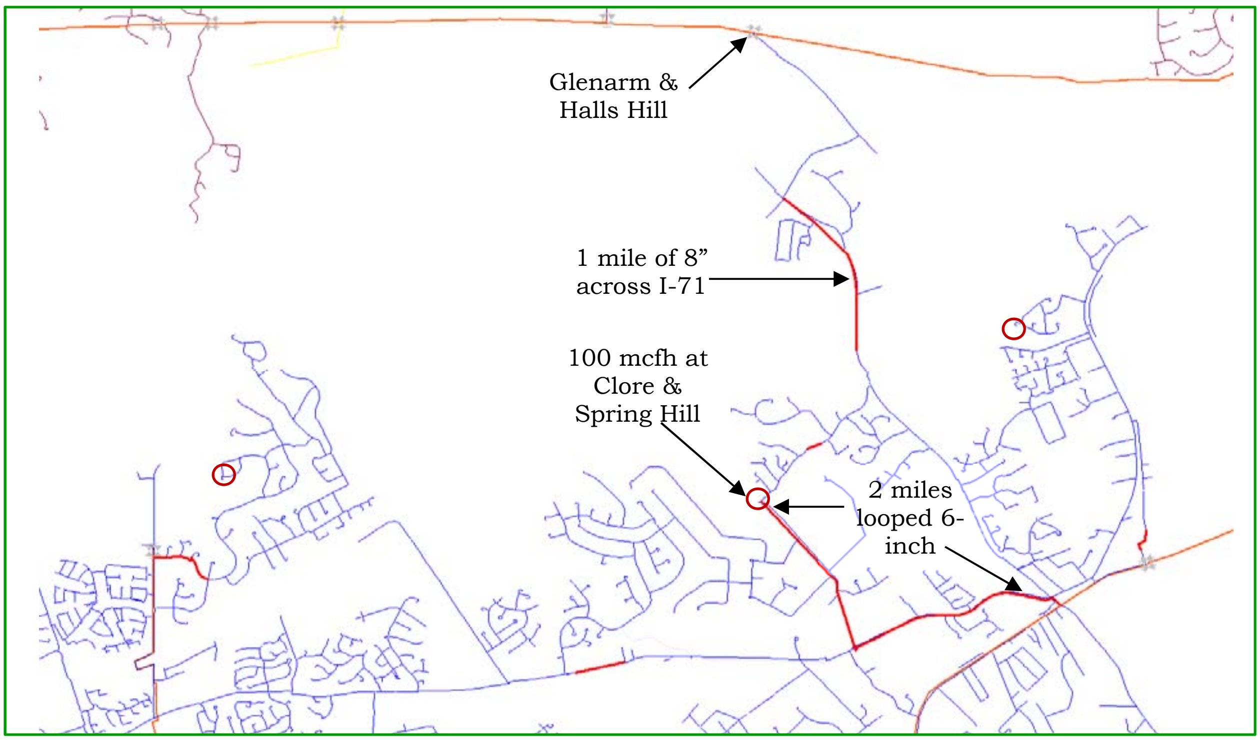
Reinforcement 2b

Accounting for growth: In addition to reinforcement 2a, install pipe across I-71 to connect to the Glenarm & Halls Hill system.

- Uprate the Glenarm & Halls Hill system to 50 psig (45 MOP)
- Install 1 mile of 8-inch pipe across I-71 and Harrod's Creek at Hwy 329 to Zaring Road to connect and loop existing pipe.

Minimum gas system pressure (-12°F):
- 6400 Clore Ln........35.9 psig
- 6202 Pebble Ct........37.6 psig
- 10523 Championship Ct........38.1 psig

Regulator Operating Capacities:
- W Hwy 22 & Old Lagrange........36.6%
- Old Lagrange Rd & Collins........17.6%
- Westport Rd & Murphy Ln........75.5%
- Glenarm & Halls Hill........88.9%



VI. Crestwood/ Simpsonville Medium Pressure System Cont'd

Reinforcement 3a

Improve minimum system pressures in Polo Fields.

- Install 1 mile of 6-inch pipe on Flat Rock Rd near Long Run Golf Course.
- Install 1,600' of 4-inch pipe on Bridgemore Ln to connect to the existing pipe on Shelbyville Rd.
- Loop 4.3 miles of pipe along Shelbyville Rd with new 6-inch pipe from the existing 8-inch to Conner Station & Colt Run Rd facility. Connect to Flat Rock Road.

Minimum gas system pressure (-12°F):

- 1415 Rutland Club Ct ....30.8 psig
- 18521 Bridgemore Ln..........40.9 psig
- 1205 Cherry Hills Ct ....32.0 psig

Regulator Operating Capacities:

- Conner Station & Colt Run Rd.....8.3%
- English Station Way....................45.9%
- Old Henry & Terra Crossing 44.7%

Reinforcement 3b

Improve minimum system pressures in Polo Fields.

- Install 2.5 miles of 6-inch pipe along Aiken Road from Arnold Palmer Blvd to Flat Rock Rd (cross Floyds Fork).
- Install 2.5 miles of 6-inch pipe along Johnson Rd from Aiken Rd to the existing main at Shelbyville Rd (cross Brush Run).
  - Both require the crossing of waterways.

Minimum gas system pressure (-12°F):

- 1415 Rutland Club Ct ....33.5 psig
- 18521 Bridgemore Ln............31.4 psig
- 1205 Cherry Hills Ct ....34.1 psig

Regulator Operating Capacities:

- Conner Station & Colt Run Rd.....4.5%
- English Station Way....................47.5%
- Old Henry & Terra Crossing 51.9%

Reinforcement 3c

Improve minimum system pressures in Polo Fields.

- Combine Reinforcements 3a and 3b.

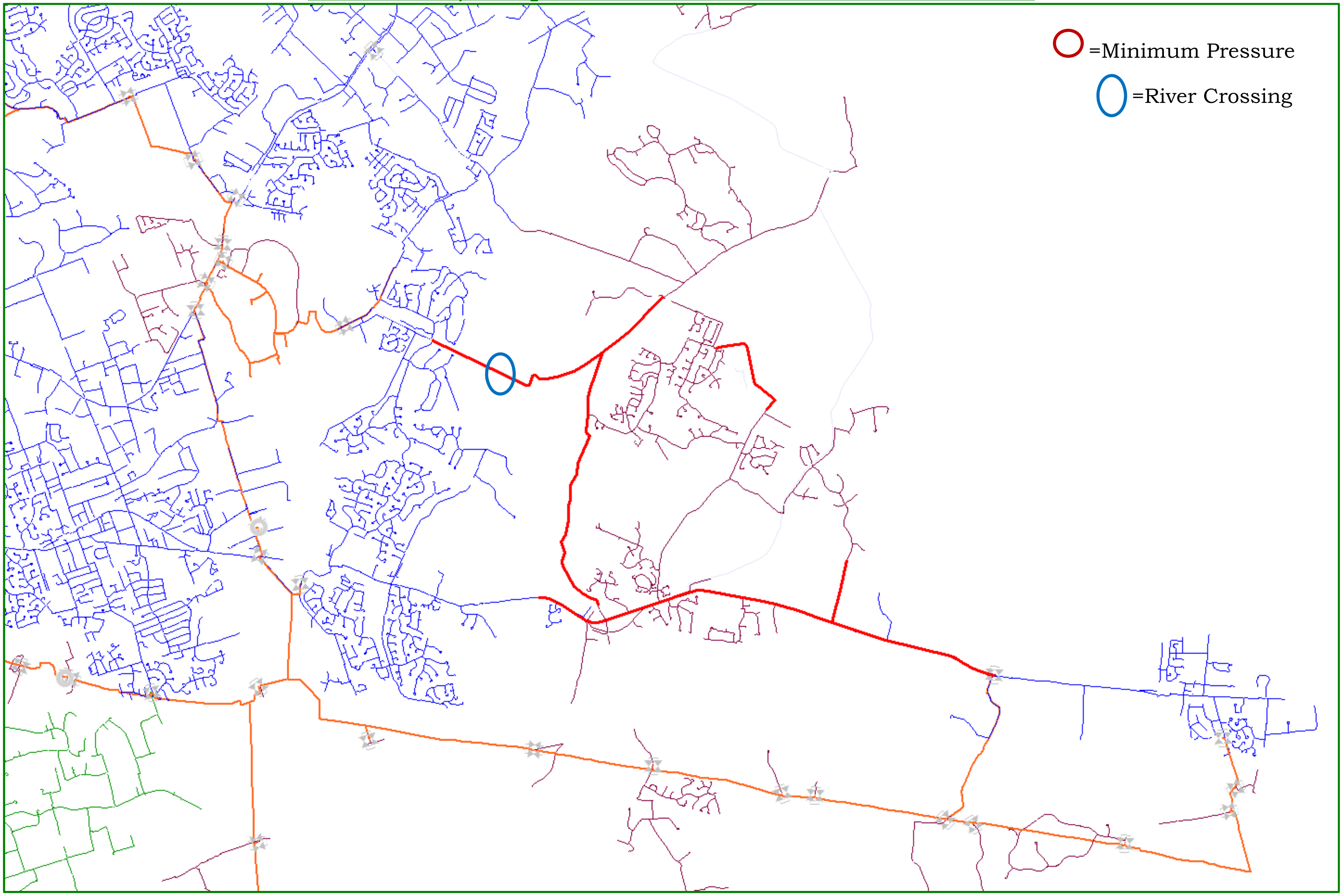
Minimum gas system pressure (-12°F):

- 1415 Rutland Club Ct ....37.0 psig
- 18521 Bridgemore Ln........41.5 psig
- 1205 Cherry Hills Ct ....36.8 psig

Regulator Operating Capacities:

- Conner Station & Colt Run Rd.....7.8%
- English Station Way....................45.3%
- Old Henry & Terra Crossing 47.8%

Crestwood/Simpsonville Reinforcement 3 Overview



LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 441

Responding Witness: Lonnie E. Bellar

Q-441. Provide a copy of the latest study LG&E- KU conducted regarding the feasibility and cost effectiveness of joining a Regional Transmission Organization.

A-441. See attached.

12/11/2012

RTO Membership Analysis

1 Executive Summary

A cross-functional team was assembled to conduct a high level analysis of the estimated costs and benefits of LG&E-KU ("LKE" or "the Companies") regional transmission organization (RTO) membership, specifically for Midwest Independent Transmission System Operator (MISO) and PJM Interconnection (PJM). The analysis of joining MISO and PJM covered a ten year study period from 2013 through 2022. The analysis was modeled after a similar study, EKPC RTO Membership Assessment[1], performed by Charles River Associates (CRA) for East Kentucky Power Corporation in their consideration of joining PJM.

- **RTO membership is unfavorable.** LKE's RTO Membership Analysis shows an unfavorable ten-year present value for RTO membership ranging from ($103) M for PJM to ($216) M for MISO.
- **Key driver is "backbone" transmission costs.** Allocation of large transmission expansion projects costs across RTO members is the primary cost driver of RTO membership.

2 Methodology

LKE Transmission Strategy and Planning assembled a cross–functional team for the RTO Membership Analysis.[2] The team was comprised of representatives from Transmission Policy & Tariffs, Federal Regulation & Policy, Regulated Trading and Dispatch, and Economic Analysis. The CRA EKPC RTO Membership Assessment was used as a general guideline for this analysis.

- The methodology for the LKE analysis was consistent with the methodology and testimony from the 2006 MISO exit proceedings.
- The methodology took into consideration changes to the tariff structures and business practices of the RTOs since the exit proceedings.

The intent of the analysis was to incorporate updated data and information to assess the costs and benefits of RTO membership at a high level, as opposed to an exhaustive

[1] March 2012 http://psc.ky.gov/pscscf/2012%20cases/2012-00169/20120503_ekpc_application_volume%201.pdf, Exhibit RLL-2

[2] The Compliance Department was apprised of all meetings to ensure maintenance of Standards of Conduct between Transmission function and Trading function employees.

analysis. These results were viewed as a threshold to determine if further in-depth study is warranted.

3 Key Assumptions

This analysis was conducted for a ten year horizon, 2013 through 2022, a period identical to the CRA study conducted for EKPC. The following key simplifying assumptions were incorporated into the analysis:

- LKE would continue to maintain its own capacity to meet a target planning reserve margin established consistently with current processes.
- No changes in locational marginal prices (LMP) due to planned RTO transmission expansions
- No impact from Firm Transmission Rights/Auction Revenue Rights (FTR/ARR) and congestion cost
- No impact from allocation of over collection of marginal losses[3]
- No impact from uplifts or make whole payments other than those identified
- No impact from potential transmission cost sharing within alternative, non-RTO Order 1000 regional planning region

4 Cost / Benefit Components

4.1 Allocation of "Backbone" Transmission Expansion Costs

The key driver of the outcome of this analysis was the allocation of "backbone" transmission expansion costs.

- For PJM, transmission expansion costs of $176 million (present value) represent more than half of the estimated absolute cost of RTO membership (excluding the benefits).
- For MISO these costs are $241 million (present value), approximately 60% of the estimated absolute cost of membership (excluding the benefits).

4.1.1 MISO Multi-Value Projects

Under current MISO policy, the cost of new transmission projects that address energy policy and/or provide widespread benefits across the footprint are considered "multi-value projects" (MVP). The cost of MVP are allocated 100% "postage stamp" to load,

[3] MISO collects incremental value of financial losses through the locational marginal price (LMP), which can result in over–collection. MISO has a process to allocate any over–collection back to the load serving entities.

i.e., all load pays the same rate for MVP irrespective of where located in the footprint, and are recovered under Schedule 26A of the MISO Tariff. LKE's share of the $5.4 billion in MVP projects currently identified in the Midwest ISO Transmission Expansion Planning (MTEP) process is based on the "indicative annual charges for approved MVP" published on the MISO website[4], applied to LKE loads projected per the 2013 Business Plan. As a new member, LKE would most likely be subject to the full cost allocation for expansion without any phase-in period.[5]

4.1.2 PJM Regional Transmission Expansion Planning

Under current PJM policy, the cost of new "backbone" high voltage transmission projects approved under its annual Regional Transmission Expansion Planning (RTEP) process is allocated on a uniform basis to all PJM loads based on the non-coincident annual peak of each PJM transmission zone. These charges are recovered under Schedule 12 of the PJM tariff. "Backbone" facilities comprise "Regional Facilities" that operate above 500 kV and "necessary lower voltage facilities" that operate below 500 kV that must be constructed or strengthened to support new Regional Facilities.[6] As a new member, LKE would most likely be subject to the full cost allocation for expansion without any phase-in period. The allocation to LKE for projects documented in the RTEP within this analysis period has been estimated using PJM's allocation methodology and is a key cost driver for the PJM case.

4.2 Modeled Components

Two components of the analysis, Operating Reserve and Trade Benefits, were estimated by Generation Planning (GP) using the Companies' planning models. Because the models were already developed for other planning purposes, only minimal changes were required to use the models to estimate these components.

4.2.1 Operating Reserve

The reduced operating reserve capacity benefits of joining MISO or PJM were estimated by reducing the Companies' "spinning reserve" requirement from 230 MW to 100 MW, for a present value benefit of $14 M. GP revised the operating reserve input in the Companies' reliability planning software, SERVM, which resulted in a target system planning reserve margin (RM) of 15% (1% lower than the existing target RM of 16%).[7]

---

[4] https://www.midwestiso.org/_layouts/MISO/ECM/Redirect.aspx?ID=135589

[5] For discussion of the "unique circumstances" surrounding Entergy joining Midwest ISO that justify Energy's five year MVP exemption and eight year MVP cost phase-in, see 139 FERC¶ 61,056 at ¶¶ 70,181,213.

[6] CRA Study, p. 12.

[7] With the existing 16% RM target, GP would choose to purchase temporary capacity through a PPA in years with an annual RM between 14% and 15% and would choose permanent capacity in a year with a RM below 14%. With

RTO Membership Analysis

GP used this new RM to evaluate the impact to the Companies' expansion plan using a spreadsheet model to calculate the expected RM and using Strategist software.

The table below shows the expected RMs with no new capacity after Cane Run 7 in 2015 and the corresponding capacity additions needed with the existing and new target RMs.

	RM w/o New Capacity	Existing Expansion Plan (16% RM Target)	New Expansion Plan (15% RM Target)
2016	14.7%	165 MW PPA	NA
2017	14.1%	165 MW PPA	NA
2018	12.5%	605 MW CCCT	605 MW CCCT

With the new 15% target RM, the 165 MW Power Purchase Agreements (PPAs) in 2016 and 2017 in the existing expansion plan could be avoided, resulting in an estimated cost savings of $9.6 M each year. However, the absence of the PPAs results in higher expected system production costs of approximately $0.2 M in both 2016 and 2017, as estimated by GP using PROSYM software.

4.2.2 Trade Benefits

The trade benefits of joining MISO or PJM were estimated by GP using PROSYM as lower native load production costs and higher off-system sales (OSS) margins that resulted from the following:

- Reducing the spinning reserve requirement from 230 MW to 100 MW
- Eliminating RTO expenses for OSS and purchases
- Eliminating 3rd party transmission expenses for purchases
- Eliminating LG&E-KU transmission expenses for OSS and purchases
- Eliminating $2 "costless adder" for OSS and purchases

The eliminated LG&E-KU transmission and $2 costless adder expenses were deducted from the total savings because they do not represent actual savings to the Companies. The PJM and MISO analyses used electricity price forecasts specific to each RTO.

- The resulting net trade benefits total between $11 M and $15 M annually over the study period for each RTO
- The present value of trade benefits is approximately $90 M for both PJM and MISO.

the new 15% RM target, a PPA would be chosen for years with RMs between 13% and 14%; permanent capacity would be chosen below 13%.

4.3 Other Components

4.3.1 Administrative charges

Both MISO and PJM have various tariff schedules to recover the administration cost of operating the markets and providing services to their respective footprints. For MISO, these costs were estimated using $/MWh cost projections contained in the MISO 2011 Budget presentation published on their website[8]. Administrative costs for PJM were estimated based upon the costs noted in the CRA study.

4.3.2 Transmission Revenue

Both MISO and PJM allocate third-party transmission revenues to the transmission owners in their respective footprints. MISO uses a formula based on allocation of plant in service and transmission flows to allocate transmission revenue. This allocation was assumed to be approximately $1 M per year to LKE, loosely based upon prior experience in MISO. The projected allocation to LKE from PJM was estimated using the PJM transmission revenues shown in the CRA study, multiplied by LKE's estimated proportion of PJM's total transmission revenue requirement, which calculated to be approximately 2.7%.

4.3.3 Uplift Costs

Both MISO and PJM have various mechanisms for allocating uplift costs that result from operations of the markets and payments made to others that are not offset by revenues. Typically, for both RTOs, these costs are the result of committing units in real-time that were not committed in the day-ahead market. In MISO these costs are referred to as "revenue sufficiency guarantee" (RSG) costs and, in the PJM market, as "operating and balancing reserve cost". Both RTOs also have other sources of these "revenue insufficient" costs. For MISO, RSG cost was assumed to be a net zero for LKE, but a load ratio share of the historic Revenue Neutrality Uplift cost of $100 million per year was assumed.[9] For this analysis, the PJM allocation of these costs to LKE was assumed to be negligible, which is consistent with the CRA study.

4.3.4 FERC Charges

Under FERC regulations, the annual FERC charge is assessed to all RTO energy for load, and not just "wholesale" load as LKE is assessed outside of an RTO. For this analysis, the

---

[8] https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/BOD/BOD/2011/20111208/20111208%20BOD%20Item%2006%20%20VI.A%202012%20Budget%20Public%20Final.pdf

[9] Load ratio share roughly estimated based on LKE peak load of 7200 and total MISO peak load of ~107,000 or 6.6%

current FERC assessment charges were escalated for inflation and applied to LKE Energy for load as given in the 2013 Business Plan.

4.3.5 Net Zero Components

Two components, congestion cost/ARR/FTR and ancillary services market, have been identified that would be considered of net zero benefit. It is expected that the value of the ARR/FTR may equal or exceed the congestion costs; however, the net cost or benefit will not be known with certainly until such rights are issued. A company may choose to self-supply ancillary services and be no worse off than before joining an RTO. While there could be some potential benefit in the RTO market, there is no means to estimate the value of such benefit.[10]

4.3.6 Eliminated Administration Charges

Membership in either PJM or MISO would result in a re-alignment of internal cost for the provision of certain services. For the purposes of this analysis, it was assumed that LKE would no longer need the current Independent Transmission Operator (ITO) or Reliability Coordinator (RC) services provided by TranServ and TVA, respectively. There also likely would be a reduction in cost in the balancing authority services provided by internal staffing. This reduction would be offset to some degree by increases in internal staffing to manage the day to day operations in the RTO, as well as for back office settlement of the RTO statements and invoices on a daily basis.

4.3.7 De-Pancaking

LKE currently pays "depancaking" cost to certain entities as a result of the 2006 MISO exit.[11] It is assumed that all of these payments would cease if LKE were to join either PJM or MISO.

[10] See Charles River Associates EKPC RTO Membership Assessment (March 2012)
[11] LKE pays costs for certain entities to keep them from having to pay more for transmission now than when the Companies were in MISO, known as depancaking costs.

RTO Membership Analysis

5 MISO Summary

												Present Value Rate
												6.75%
Cost		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	NPV
	MISO Admin Cost ($M)	-11.3	-11.0	-11.0	-11.4	-11.8	-12.2	-12.6	-13.1	-13.5	-14.1	-85.4
	MISO MVP XM Expansion Cost ($M)	-5.9	-12.1	-20.7	-33.0	-37.9	-43.6	-51.1	-56.8	-55.9	-55.3	-241.3
	LKE Internal Staffing/Equipment Cost ($M)	-0.5	-0.5	-0.5	-0.5	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-3.9
	MISO Congestion Cost/ARR/FTR ($M)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	MISO Misc. Uplift Cost ($M) - Revenue Neutrality Uplift	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-46.9
	MISO Ancillary Services Market ($M)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	MISO FERC Fees (Incremental of Present) ($M)	-1.5	-1.6	-1.6	-1.7	-1.8	-1.9	-2.0	-2.1	-2.2	-2.3	-13.0
	LKE Lost XM Revenue from 3rd Parties	-3.0	-3.1	-3.2	-3.2	-3.3	-3.4	-3.5	-3.6	-3.7	-3.7	-23.6
	Sum of Cost	-28.8	-34.8	-43.6	-56.6	-62.0	-68.3	-76.3	-82.7	-82.6	-82.7	-414.0
Benefits		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	NPV
	MISO XM Revenue Allocation ($M)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	7.1
	MISO Trade Benefits (Production Costs) ($M)	11.1	12.3	12.3	11.6	12.1	12.4	13.2	12.7	14.9	15.6	89.7
	MISO Operating Reserve Margin Capacity Benefits ($M)	0.0	0.0	0.0	9.4	9.3	0.0	0.0	0.0	0.0	0.0	13.9
	LKE Elimination of TVA RC Cost ($M)	2	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.5	15.7
	LKE Elimination of ITO Cost ($M)	3.0	3.1	3.2	3.2	3.3	3.4	3.5	3.6	3.7	3.7	23.6
	LKE Elimination of De-Pancaking ($M)	6.8	7.1	6.2	6.1	6.2	6.4	6.5	6.7	6.9	7.1	46.8
	LKE Elimination of TEE Group Admin Charge ($M)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.7
	Sum of Benefits	24.0	25.6	24.8	33.6	34.3	25.6	26.6	26.5	29.0	30.0	197.5
	Net of Cost + Benefits	-4.8	-9.2	-18.8	-23.0	-27.7	-42.7	-49.7	-56.2	-53.6	-52.7	-216.5

RTO Membership Analysis

6 PJM Summary

Present Value Rate 6.75%

Cost	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	NPV
PJM Admin Cost ($M)	-11.4	-11.4	-11.6	-12.0	-12.4	-12.8	-13.2	-13.8	-14.2	-14.8	-89.3
PJM Backbone XM Expansion Cost ($M)	0.0	-12.6	-27.0	-27.0	-27.0	-27.0	-27.0	-40.4	-40.4	-40.4	-176.3
LKE Internal Staffing/Equipment Cost ($M)	-0.5	-0.5	-0.5	-0.5	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-3.9
PJM Congestion Cost/ARR/FTR ($M)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PJM Misc. Uplift Cost ($M)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PJM Ancillary Services Market ($M)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PJM FERC Fees (Incremental of Present) ($M)	-1.5	-1.6	-1.6	-1.7	-1.8	-1.9	-2.0	-2.1	-2.2	-2.3	-13.0
LKE Lost XM Revenue from 3rd Parties	-3.0	-3.1	-3.2	-3.2	-3.3	-3.4	-3.5	-3.6	-3.7	-3.7	-23.6
Sum of Cost	-16.4	-29.1	-43.9	-44.5	-45.1	-45.7	-46.3	-60.4	-61.1	-61.9	-306.0

Benefits	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	NPV
PJM XM Revenue Allocation ($M)	1.5	1.6	1.6	1.7	1.7	1.7	1.8	1.8	1.9	1.9	12.0
PJM Trade Benefits (Production Costs) ($M)	12.6	12.9	11.7	10.9	11.3	12.2	13.0	14.2	14.6	15.2	90.2
PJM Reduced Operating Reserve Margin Capacity Benefits ($M)	0.0	0.0	0.0	9.3	9.4	0.0	0.0	0.0	0.0	0.0	13.9
LKE Elimination of TVA RC Cost ($M)	2	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.5	15.7
LKE Elimination of ITO Cost ($M)	3.0	3.1	3.2	3.2	3.3	3.4	3.5	3.6	3.7	3.7	23.6
LKE Elimination of De-Pancaking ($M)	6.8	7.1	6.2	6.1	6.2	6.4	6.5	6.7	6.9	7.1	46.8
LKE Elimination of TEE Group Admin Charge ($M)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.7
Sum of Benefits	26.0	26.8	24.9	33.4	34.2	26.1	27.2	28.8	29.5	30.5	203.0
Net of Cost + Benefits	9.6	-2.3	-19.0	-11.2	-10.9	-19.6	-19.0	-31.6	-31.6	-31.3	-103.0

7 Additional Considerations and Uncertainties

7.1 NERC Compliance Requirements

Since the companies own and operate certain facilities used in interstate commerce or that have the potential to impact the bulk electric system, the Companies are required to comply with Reliability Standards for planning and operating the bulk electric system, as developed by the North American Electric Reliability Corporation (NERC). Under current operations, LG&E/KU Transmission Owner (TO) are responsible for over 1,200 NERC compliance requirements falling under the Reliability Standards. It is estimated that slightly over 300 of these requirements would be performed by an RTO and no longer an internal function if the companies were to join and RTO. While this reduction is noted qualitatively, the study does not estimate a financial cost/benefit related to compliance.

7.2 Regulatory Environments – MISO, PJM

There has been considerable realignment of RTO memberships since 2006. Examples include the departure from MISO of First Energy and Duke-Ohio. Both entities are now PJM transmission owning members. MISO has retained and, with the joining of Entergy, BREC, and Dairyland Power, gained members who operate in non-contestable load areas, while PJM has solidified membership of transmission owners operating in states that have retail access and unbundled utilities.[12] Given this realignment between MISO and PJM membership, it is likely that more of Kentucky's regulatory paradigm and LKE's traditional regulated utility business model would be accommodated in MISO versus PJM. For example, the entities within MISO that had been advocating for capacity markets are simply not as politically strong as they once may have been. Moreover, membership in PJM would almost certainly pit LKE interests against those of the traditional PPL companies on matters of significance to all concerned.

7.3 Future RTO Market/Program Implementation

The costs/benefits of "markets" or "programs" that each RTO may implement in the future are uncertain and so cannot be reflected in this analysis.

8 Conclusion

The results of this threshold analysis reveal that a more in depth study of the cost and benefits of RTO membership is not warranted at this time. Further, the study results confirm the prudency of LKE continuing with the establishment the Southeast Order 1000 Planning Region.

[12] Ameren-Illinois's continued membership in MISO being a notable exception.